Canadian Natural Gas

›› Review of 2004 & Outlook to 2020

January 2006

›› Natural Gas Division
Petroleum Resources Branch
Energy Policy Sector

Natural Resources Canada | Ressources naturelles Canada

Canada

Foreword

The *Canadian Natural Gas: Review of 2004 & Outlook to 2020* is an annual working paper prepared by the Natural Gas Division of Natural Resources Canada. It provides summaries of natural gas industry trends in Canada and the United States (US). Mexico is largely excluded from the report*.

As natural gas advisors to the Minister of Natural Resources Canada, we publish this report to obtain feedback on our interpretations of natural gas issues. The objective of this report is to provide an understanding of the current state of the North American natural gas market in a format that can be quickly and easily read.

New Report Structure
The report is divided into three regions (North America, Canada, and the US) and provides a structured analysis of natural gas market fundamentals (supply, demand, price, etc.) over the past year (2004), for the short-term (2005 and 2006), and the long-term (to 2020).

The main sections of the report are composed of graphs, with limited text comments. The executive summary is only text and provides a cohesive narrative of the entire report. For an in-depth analysis of the North American natural gas market, the reader can review Part I of the report *"North American Natural Gas Market,"* which includes a review of 2004, as well as short-term and long-term outlooks. Part II and III of the report – the Canada and US sections – provides more detailed natural gas fundamentals analysis within each country.

*In January 2005, the Canadian, Mexican and US governments published a trilateral report (*North American Natural Gas Vision*), which provides detailed information and statistics for Canada, Mexico and the US. The report is available at www.ngas.nrcan.gc.ca.

Sources
Various sources were used in preparing this report, including private consultants, industry associations, and federal government agencies in Canada and the US. Our main sources of statistical data were the National Energy Board (NEB), the US Energy Information Administration (EIA), and Statistics Canada (StatsCan).

While every effort is made to provide the most recent data, many sources are continually revising their data. As a result, data for 2003 may differ from what was reported in last year's version of this report.

Natural Gas Division Website
This report is available online at our Web Site: http://www.ngas.nrcan.gc.ca/. Other Natural Gas Division reports, including previous versions of this report, are also available at this Web Site. Printed copies of this report are available in black and white. The internet version appears in full colour format. Clients with colour printers can generate a colour version of the report by printing the internet version.

Obtaining a Paper Copy
To obtain a black and white paper copy of this report, call (613) 992-9612, or fax your request to (613) 995-1913, or send an email to Diane Boisjoli at dboisjol@nrcan.gc.ca.

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Natural Gas Division

Natural Gas Division Background
The Natural Gas Division is part of the Petroleum Resources Branch, which also includes the Oil Division, the Frontier Lands Management Division, and the Energy Infrastructure Protection Division.

The Natural Gas Division provides technical, regulatory, policy and economic information and advice on natural gas issues to the Minister of Natural Resources Canada and the federal government.

The Natural Gas Division also advises the Minister of Natural Resources Canada on matters related to statutory obligations under the *National Energy Board Act* and the *Transportation Safety Board Act*. The Natural Gas Division also manages the Pipeline Arbitration Secretariat.

We Value Your Feedback
We appreciate your comments, suggestions, and questions. Questions and comments regarding the “Review of 2004” can be directed to Paul Cheliak at (613) 995-0422 (pcheliak@nrcan.gc.ca) or Dan Cowan at (613) 996-5411 (dcowan@nrcan.gc.ca). Questions and comments regarding the “Outlook to 2020” can be directed to Kevin Fenech at (613) 992-8377 (kfenech@nrcan.gc.ca). Suggestions and comments regarding any part of the report can be directed to the Natural Gas Division by filling out the feedback form found at the back of the report (pg. 83).

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Canadian Natural Gas
Review of 2004 & Outlook to 2020

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Executive Summary

›› Review of 2004 & Outlook to 2020

The 2004 Landscape

Global economic growth set a 27-year record in 2004 at 5.1%. The US posted the strongest gains of the G7 countries with a 4.4% increase in Gross Domestic Product (GDP), while Canada's GDP grew by 2.8%.

For the second consecutive year, the appreciation of the Canadian dollar was amongst the year's most striking economic events in Canada. The Canadian dollar rose on average another 5 cents against the US dollar, following a 7-cent increase in 2003. Inflation and interest rates remained at historically low levels in 2004. The low cost of borrowing helped fuel significant investment. The scale of energy investment in 2004 dwarfed all other industries.

Rising energy prices challenged the rising dollar as one of 2004's most significant economic events. As crude oil prices breached US $50 per barrel, distant futures prices suggest, and most analysts expect, that higher energy prices are here to stay. Higher energy prices outweighed the depressing effect of the appreciating Canadian dollar, and helped fuel another record trade surplus for Canada.

Executive Summary

A New Era for the North American Natural Gas Market

During the 1990's, intra-Alberta, AECO or NIT (Canada's main natural gas pricing point) natural gas prices* were relatively low, averaging CDN $1.68 per Gigajoule (GJ) between 1991 and 1999. However, since mid-2000, prices have been within a new higher range and continue to trend higher. Intra-Alberta prices averaged CDN $5.67/GJ from mid-2000 to the end 2004.

North America's natural gas market has entered a new era. Higher natural gas prices, which are now seen as a feature of the natural gas market, at least over the medium-term, primarily reflect the inability of North American natural gas production to keep pace with ever-increasing demand.

Review of 2004

In 2004, prices reached record levels across North America. Early in the year, cold temperatures and high demand were managed by high storage levels and prices remained under CDN $7.00/GJ in Alberta. However, prices began to track upward throughout the summer months, reaching CDN $7.12/GJ in June. Higher prices were attributed to concerns about natural gas production and increases in world crude oil prices. Average AECO prices remained within the CDN $6.00 – CDN $7.50/GJ range for the remainder of the year. For the calendar year 2004, Alberta prices averaged CDN $6.52/GJ, 3% greater than 2003 and 65% greater than 2002. Although average prices across North America reached record levels in 2004, consumers could have faced even higher prices were it not for record high storage levels.

*Appendix 1 provides a brief history and description of the intra-Alberta natural gas commodity price and information about the Alberta natural gas hub.

Executive Summary (continued)

Drilling Hits Record Highs, Production Remains Flat
For the second consecutive year, higher natural gas prices induced record drilling across North America. In Canada, a record number of natural gas wells were drilled – 15,627, 15% higher than 2003.

The shallow natural gas pools in western Saskatchewan and eastern Alberta continue to attract significant attention from producers because they are quick and cheap to drill and almost always find natural gas. However, in 2004, the deeper gas pools located in the Foothills region of Alberta and northeastern BC attracted a great deal of attention. In 2004, 75% of natural gas wells drilled were shallow, while 25% were drilled into deeper pools. This compares to 2003 when the split was 79%-21% shallow-to-deep. Increased deep drilling yielded two large natural gas discoveries – one by Shell in the Alberta Foothills and another by Talisman in northeastern BC.

Despite record drilling in 2004, Canadian natural gas production totalled 5,906 billion cubic feet (Bcf) – an increase of less than 0.5% over 2003, following two consecutive years of declines. Regionally, Alberta accounted for 79% of total Canadian production, British Columbia 14%, Saskatchewan 4%, Nova Scotia 2% and Northwest Territories, Yukon and Ontario 1%. The production treadmill in the WCSB has never been more pronounced (i.e., more and more wells drilled are required simply to maintain production).

In addition to the production treadmill in the WCSB, natural gas production from the Sable Offshore Energy Project declined for the third consecutive year in 2004. Sable gas production peaked in December 2001, averaging nearly 590 MMcf per day, and has been declining ever since. In 2004, Sable production declined to 143 Bcf compared to 184 Bcf in 2002 despite the addition of a fifth field – South Venture – which began producing in late 2004.

The story in the US is much the same as in Canada – higher drilling and no response in natural gas supply. While the US natural gas rig count was 17% higher and the number of gas wells drilled increased 15%, production fell 1% (113 Bcf). The largest loss was recorded in the Gulf Offshore (409 Bcf), while gains were recorded in the Midcontinent (103 Bcf), Gulf Onshore (103 Bcf) and the Rockies (109 Bcf).

Moderate Natural Gas Demand Growth in Canada and US
North American natural gas demand recovered slightly in 2004, increasing by 0.3% after a 4% decline in 2003. Demand growth in western North America and the South Atlantic more than offset losses in eastern Canada and the US northeast, midwest and Gulf regions. Natural gas demand in the US central region remained flat relative to 2003.

Canadian natural gas demand increased 34 Bcf or 1.2% compared to 2003. Combined, core and industrial demand, increased 107 Bcf in western Canada, while in eastern Canada, the same sectors saw a decline of 36 Bcf. Core demand growth was attributable to colder weather in western Canada, while industrial demand growth was largely driven by oil sands operations in Alberta.

In the US, natural gas demand increased 41 Bcf, or 0.2% compared to 2003. Core demand losses of 500 Bcf were offset by increased industrial and power generation demand, particularly in the west. After declining more than 1 Tcf since 2001, Gulf Coast demand showed signs of stabilizing in 2004.

Executive Summary (continued)

Increases in US LNG Imports and Canadian Natural Gas Exports Offset US Production Declines

In 2004, LNG was imported to the US through four receiving terminals – (i) Lake Charles, Louisiana; (ii) Elba Island, Georgia; (iii) Cove Point, Maryland; and, (iv) Everett, Massachusetts. Although small, LNG continues to increase its share of US supply, accounting for nearly 3% of total US supply in 2004, from 2% in 2003.

In 2002, LNG imports to the US reached 229 Bcf, accounting for 6% of total imported natural gas, while the gain in 2004 to 652 Bcf, or 16% of total US imports nearly tripled 2002's total.

Canadian gross natural gas exports to the US increased by 110 Bcf, while US imports of LNG increased by 145 Bcf – a total of 255 Bcf. The combination of increased imports from Canada and increased US LNG imports more than offset the 1% decline (113 Bcf) in US natural gas production in 2004.

Overall, physical export flows from Canada to the US were 3,602 Bcf in 2004, an increase of 3% compared to 2003 levels. Canadian natural gas imports from the US totalled 441 Bcf in 2004, essentially unchanged from the 437 Bcf in 2003. As a result, net Canada-to-US natural gas exports increased by 4% from 3,044 Bcf in 2003, to 3,161 Bcf in 2004.

On a regional basis, physical exports to the US west region increased 8%, exports to the Midwest increased 3%, while exports to the US northeast declined by 1%. Increased exports were the result of higher Canadian natural gas production, minimal Canadian demand growth and strong industrial and power generation demand in the US west.

Despite an appreciating Canadian dollar in 2004, which has a tendency to reduce export revenues, international border export revenues set a new record in excess of CDN $26.7 billion. Increased export revenues were supported by increased export volumes and higher natural gas prices.

Rapid Summer Injections Lead to Record Storage Levels

In 2004, North American natural gas storage levels reached a record level of 3,776 Bcf, 4% higher than 2003 and 6% higher than 2002.

Attaining high storage levels in 2004 did not come easily. In early 2004, cold weather prompted high residential and commercial demand, resulting in large, early withdrawals from storage. As a result, storage levels on April 1st, 2004 (the beginning of the injection season) were 1,162 Bcf, 8% lower than the 5-year average.

However, cool summer temperatures across North America in 2004 allowed natural gas that would have been consumed as fuel for gas-fired electric generators to be placed into storage. Summer storage injections were very strong, resulting in a North American storage level on November 1st, 2004 (the start of the winter withdrawal season), that surpassed 3,700 Bcf. For comparison, the five year average for November 1st is about 3,430 Bcf.

Throughout November and December of 2004, temperatures eased in comparison to 2003 and by the end of the heating season (April 2005), there was 215 Bcf more natural gas in storage than April 2004.

Executive Summary (continued)

Continued Strong Prices in 2004
The tight balance between natural gas supply and demand in North America, as well as high world crude oil prices, resulted in record natural gas prices in Canada and the US.

The average price in 2004 at AECO was CDN $6.52/GJ, 3% higher than the previous record set in 2003, while the average at NYMEX (US' main natural gas pricing point in Louisiana) was US $6.30/MMBtu.*

Regionally, the largest price increase was in the Rockies, which increased 28% over 2003 average prices. Rockies prices continue to increase as new pipelines connect Rockies gas to markets in the Pacific Northwest and California, thereby equilibrating prices between regions. Rockies prices have increased 158% since 2002. In the eastern markets (Dawn, Boston), prices began to rise above their western counterparts mainly due to colder winter weather in the US Northeast, which frequently experiences winter price spikes due to insufficient pipeline capacity into the large demand centres of Boston and New York City.

Natural gas demand and prices are also affected by crude oil and distillate fuel oil (lighter fuel oils distilled off during the refining process of crude oil and used for space heating and electric power generation) prices as some industries can switch to natural gas when the price of oil rises.

*Canadian natural gas prices are typically measured in CDN $/GJ, whereas US natural gas prices are commonly referenced in US $/MMBtu. One GJ is approximately equal to 0.948 MMBtu. The tables in Appendix 4 display the prefixes for commonly used units in the North American natural gas industry and related approximate natural gas conversion factors.

Crude oil prices have been at historically high levels recently due to strong global demand and disruptive events in oil-producing countries adding uncertainty to the reliability of supplies. In 2004, West Texas Intermediate (WTI) oil prices (the benchmark in the US) averaged US$41.42/barrel, up $10.28 or 33% over 2003 levels.

Natural gas continues to trade at a discount to distillate fuel oil, which is backing the strength in natural gas demand and supporting higher natural gas prices.

The 2004 winter offered some relief to consumers as storage levels were high and overall North America experienced a warmer-than-usual winter. Without these bearish fundamentals at work, natural gas prices could have spiked to record levels, as was seen in 2001 and 2003.

Canadian Gas Reserves Down, US Gas Reserves Up
In 2004, producers managed to keep North American reserves flat with the year-earlier levels (reserves data has a one year lag). In the US, reserves as of January 1st, 2004 were 189 Tcf, up 2% from a year earlier while Canadian reserves fell 4% to 56.6 Tcf – the result of downward revisions in Alberta and offshore Nova Scotia.

Reserve trends are a powerful indicator of future production. In the past, reserve additions greater than production have signaled future production increases. Reserve additions in recent years have approximately equaled or have been lower than production, signaling flat supply for the medium-term.

Short-term Outlook – Continued High Prices and Limited Production Growth

Natural gas production has struggled to keep pace with demand. As a result, the market price of natural gas reflects an extremely 'tight' balance between natural gas supply and demand.

Natural gas prices have increased steadily from a 2003 average Alberta spot price of CDN $6.31/GJ, to average $6.52/GJ in 2004 to $7.09/GJ over the first nine months of 2005.

In the short-term (through to the end of 2006), North American natural gas prices are expected to be driven largely by storage levels, weather, the strength of the economy, drilling and supply growth, as well as world crude oil prices.

On April 1st, 2005, about 2,123 Bcf of natural gas was required to be injected into storage to reach 3.5 Tcf by November 1st, 2005, 215 Bcf less than on April 1st, 2004. However, as of September 1st, 2005, 406 Bcf of natural gas still remains to be injected to reach 3.5 Tcf by November 1st, 30% more than September 2004 levels. Erosion of the North American storage surplus in 2005 is the result of increased natural gas-fired power generation demand for air conditioning units during 2005's warmer-than-normal summer, as well as shut-in production from Hurricanes Katrina and Rita in the Gulf of Mexico.

For the 2005-2006 winter heating season, the key wildcard will be the weather. If the winter is much colder than normal, natural gas prices will likely increase further. Conversely, if the winter is very mild, natural gas prices could decline.

Besides storage and weather, natural gas drilling and production, and crude oil prices will influence natural gas prices. The NEB forecasts that nearly 17,000 wells will be drilled in 2005, surpassing last year's record figures. Canadian natural gas production in 2005 and 2006 is expected to remain near the 2004 level, despite record levels of drilling in recent years.

Surging crude oil prices are contributing to higher natural gas prices. The average WTI crude oil price for the first half of 2005 was US$51.39/bbl, 40% higher than the same period in 2004.

Given these factors, natural gas prices are expected to remain high in the short-term, with Alberta prices averaging CDN $12.50/GJ between November 2005 and March 2006.

Outlook to 2020 – Changing Natural Gas Supply Portfolio

Our longer-term forecasts of natural gas fundamentals rely on publicly available forecasts from the National Energy Board (Canada) and the Energy Information Administration (US), as well as the forecasts of various private consultants on retainer to the Department.

We average these forecasts to derive what could be described as a "consensus" scenario. For example, we assume natural gas demand in 2020 will be equal to the average of selected demand forecasts for 2020. The intention is simply to give readers an understanding of the range of views from various sources.

In 2020, US natural gas demand is expected to reach about 28.4 Tcf; Canadian demand 4.1 Tcf, for a North American total of 32.5 Tcf. This is an increase of 7.2 Tcf, or 28% above actual 2004 demand levels, and represents an average annual increase of about 1% per annum. Industrial and electric power generation demand is expected to account for most of this increase.

Executive Summary (continued)

In 2020, this demand would be satisfied by: US Lower-48 natural gas production of 19 Tcf; Alaska natural gas production of 1.9 Tcf; western Canadian conventional natural gas production of 3.1 Tcf; western Canadian unconventional natural gas production of 1 Tcf; Scotian natural gas of 0.5 Tcf; MacKenzie Delta natural gas of 0.6 Tcf; Canadian LNG imports of 0.4 Tcf; and nearly 6 Tcf of LNG imports to the US.

These forecasts suggest that the North American natural gas supply portfolio will look significantly different in 2020 when compared to the current situation. For example, in 2004, western Canadian conventional natural gas production was about 5.7 Tcf, accounting for approximately 23% of total North American natural gas supply. However, by 2020, it is expected that western Canadian conventional natural gas production will be about 3 Tcf, accounting for only 10% of total North American natural gas supply.

Forecasted declines in conventional natural gas production are largely offset by greater expectations regarding western Canadian unconventional natural gas production, Mackenzie Delta and Alaska natural gas, and the importing of foreign LNG into North America, including into Canada.

About 6.4 Tcf of LNG is expected to be imported to North America in 2020, which compares to last year's "consensus" expectations for LNG imports of 4.4 Tcf in 2020. In 2020, LNG imports are expected to account for approximately 20% of total North American natural gas supply. Today, LNG imports represent only 2% of total North American supply.

Mackenzie Delta natural gas is also included in the Canadian production forecasts. The average of the forecasts shows MacKenzie Delta gas supply at about 0.62 Tcf, or 1.7 Bcf/day by 2020. In 2020, Mackenzie Delta natural gas production is expected to account for nearly 2% of North American natural gas supply.

A forecast of future potential natural gas production from the North Slope of Alaska is included in the overall US supply mix. According to the forecasters surveyed, natural gas production from Alaska is expected to average 1.9 Tcf, or approximately 5.1 Bcf/day by 2020. In 2020, Alaska natural gas production is expected to account for nearly 6% of North American natural gas supply.

A review of various forecasts shows a 'consensus' that both Mackenzie Delta and Alaska natural gas will arrive, but there is disagreement amongst observers regarding the timing of when this natural gas will begin to flow.

US nominal natural gas prices are expected to average about US $5.55/MMBtu between 2005 and 2015, reaching nearly $6.50 by 2020. Alberta nominal prices are expected to average about CDN $6.25/GJ between 2005 and 2015, reaching about $6.75 by 2020.

Long-term forecasts are typically produced annually, while short-term forecasts are usually updated monthly to reflect current market conditions. The short-term Canadian and US natural gas price forecasts found on pages 18 and 19 of the report are more recent (4th quarter 2005) than the long-term forecasts (1st quarter 2005), and thus better reflect the current high price environment.

Executive Summary (continued)

The “consensus” export forecast is calculated using various forecasters’ views on Canadian natural gas production and demand. The “consensus” view shows net exports remaining relatively flat over the 2005-2020 time frame, hovering between 2.5 Tcf and 3.2 Tcf per year.

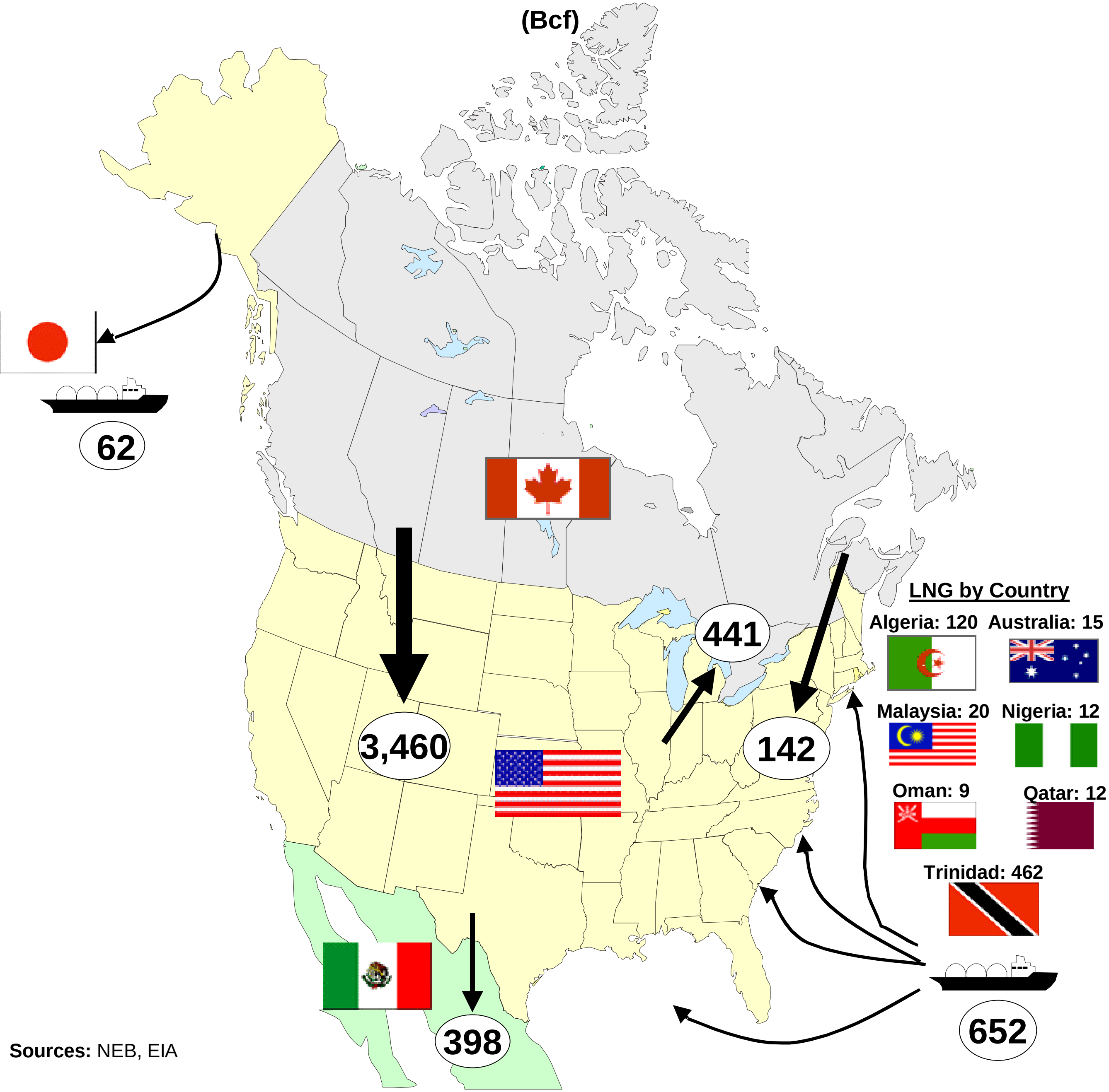
Given assumptions about Canadian natural gas production, exports, and industry price forecasts, producer plant gate revenues from natural gas sales are expected to reach CDN $48.4 billion by 2020, exceeding record revenues of $41.5 billion in 2004.

Overall, the forecasts of natural gas market fundamentals suggest a slight dampening in North American natural gas demand growth from levels of approximately 2% per annum in the past decade. This is the result of higher natural gas prices. A changing North American natural gas supply portfolio is also expected, which would include more unconventional natural gas, Mackenzie Delta and Alaska natural gas, and increased LNG imports from abroad.

Part I: North American Natural Gas Market

›› Review of 2004

Map 1
2004 North American Natural Gas Flows
(Bcf)



Sources: NEB, EIA

Map 1 summarizes natural gas trade flows in North America. Canada supplies the US with approximately 15% of US natural gas requirements every day. Most of this natural gas comes directly from western Canada, although a smaller amount is exported through eastern Canada. While Canada is a net exporter of natural gas, it does import some natural gas in southern Ontario.

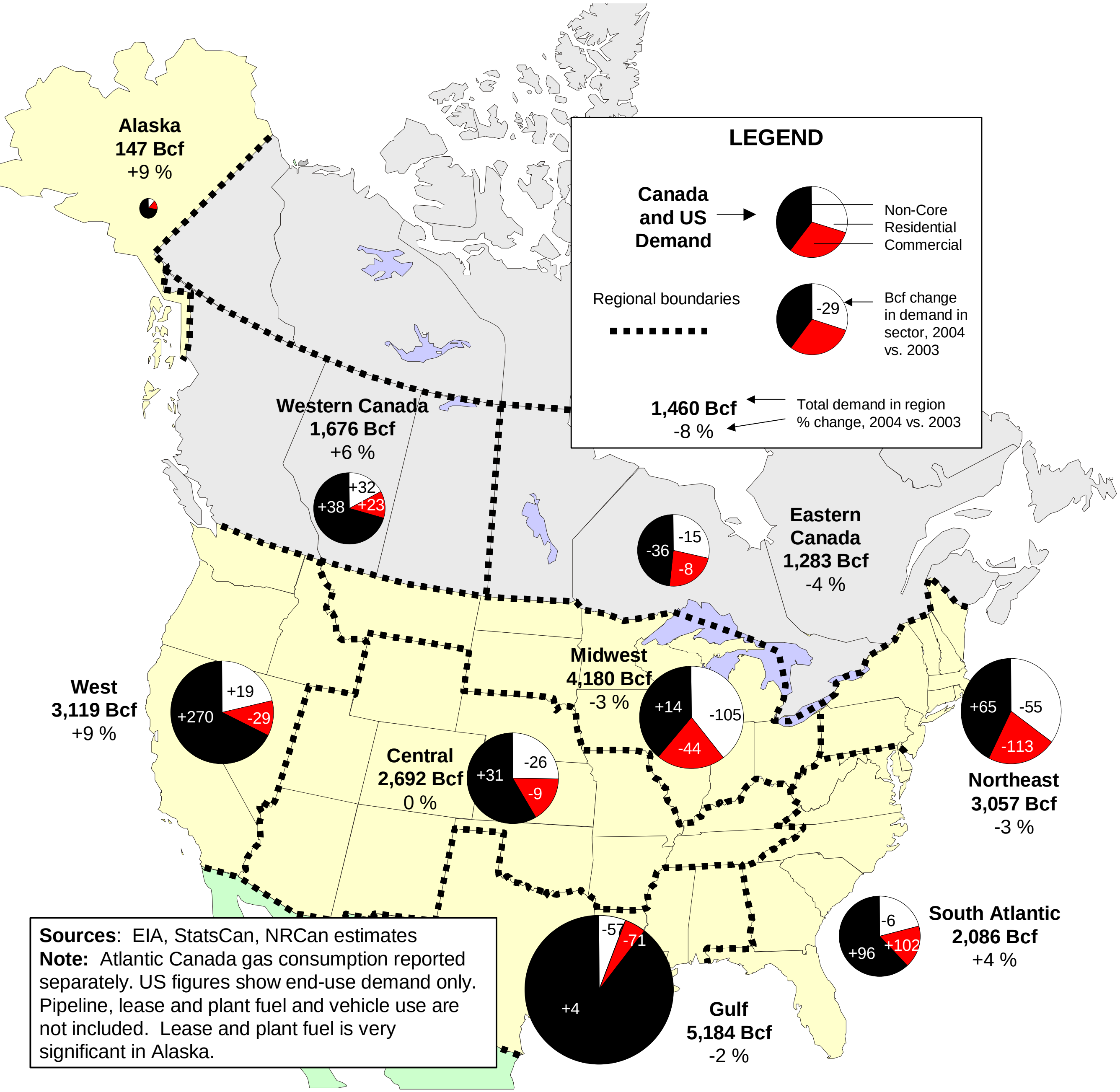
The US is a net importer of natural gas. Their imports come from Canada (85%) and from abroad in the form of LNG (15%).

In 2004, Trinidad and Algeria were the largest suppliers of LNG to the US. It is expected that LNG imports will continue to grow in the coming years as new LNG receiving terminals are built in Canada, the US and Mexico.

The US exports some natural gas in the form of LNG from Alaska to Japan.

The US, once a net importer of natural gas from Mexico, exported nearly 400 Bcf of natural gas to Mexico (no imports) in 2004.

Map 2
2004 North American Natural Gas Demand (Bcf)



Sources: EIA, StatsCan, NRCan estimates
Note: Atlantic Canada gas consumption reported separately. US figures show end-use demand only. Pipeline, lease and plant fuel and vehicle use are not included. Lease and plant fuel is very significant in Alaska.

Map 2 shows the locations and scale of natural gas demand in North America. Also shown are the changes in demand compared to last year, by region and by sector.

Increased industrial consumption and a colder than normal winter in western Canada boosted western Canada's natural gas demand by 6% in 2004. In contrast, a warmer than usual winter heating season in eastern Canada resulted in a 4% reduction in natural gas demand. The reduced demand in eastern Canada was shared roughly proportionately across the different sectors of the economy.

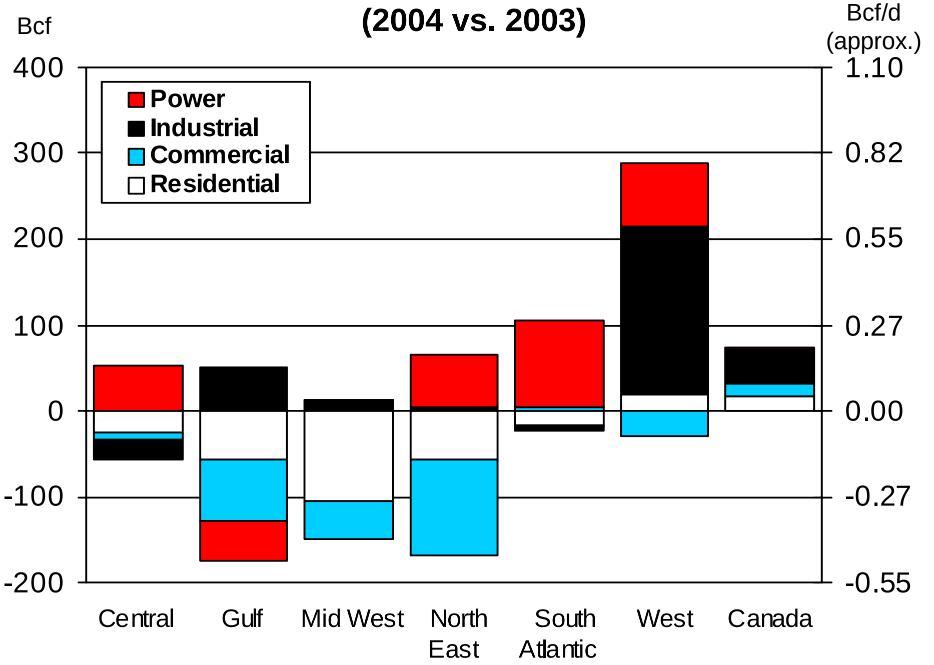
In the US, the largest change in natural gas demand occurred in the west, largely a result of significantly increased use of natural gas for power generation and for industrial applications.

Table 1
Demand for North American Natural Gas

	2004 (Bcf)	2003 (Bcf)	Change (Bcf)	Change (%)
US Residential	4,879	5,078	-199	-3.9%
US Commercial	2,984	3,217	-233	-7.2%
US Industrial	7,399	7,139	260	3.6%
US Electric Power	5,352	5,135	217	4.2%
US Other[1]	1,802	1,806	-4	-0.2%
Total US Demand	**22,416**	**22,375**	**41**	**0.2%**
US LNG Exports	62	64	-2	-3.1%
US Exports to Mexico	397	333	64	19.2%
Total US Gas Disposition	**22,875**	**22,772**	**103**	**0.5%**
Canada Residential	658	641	17	2.6%
Canada Commercial	498	484	15	3.1%
Canada Industrial	1,045	1,005	40	4.0%
Canada Electric Power	298	295	3	1.1%
Canada Other[2]	460	500	-40	-8.1%
Total Canadian Demand	**2,959**	**2,925**	**34**	**1.2%**
TOTAL N.A. DEMAND	**25,375**	**25,300**	**75**	**0.3%**
TOTAL N.A. DISPOSITION	**25,834**	**25,697**	**137**	**0.5%**

Sources: EIA, StatsCan **Notes:** [1]Other includes pipeline and distribution use, lease and plant fuel and vehicle fuel. [2]Other includes pipeline compressor fuel, processing fuel and line losses.

Figure 1
Regional and Sectoral Demand Changes
(2004 vs. 2003)



Sources: EIA, StatsCan **Note**: Excludes pipeline lease and plant fuel and vehicle use.

Table 1 shows total North American demand increased by 0.3% in 2004. This follows a 4% reduction in natural gas demand that occurred in 2003.

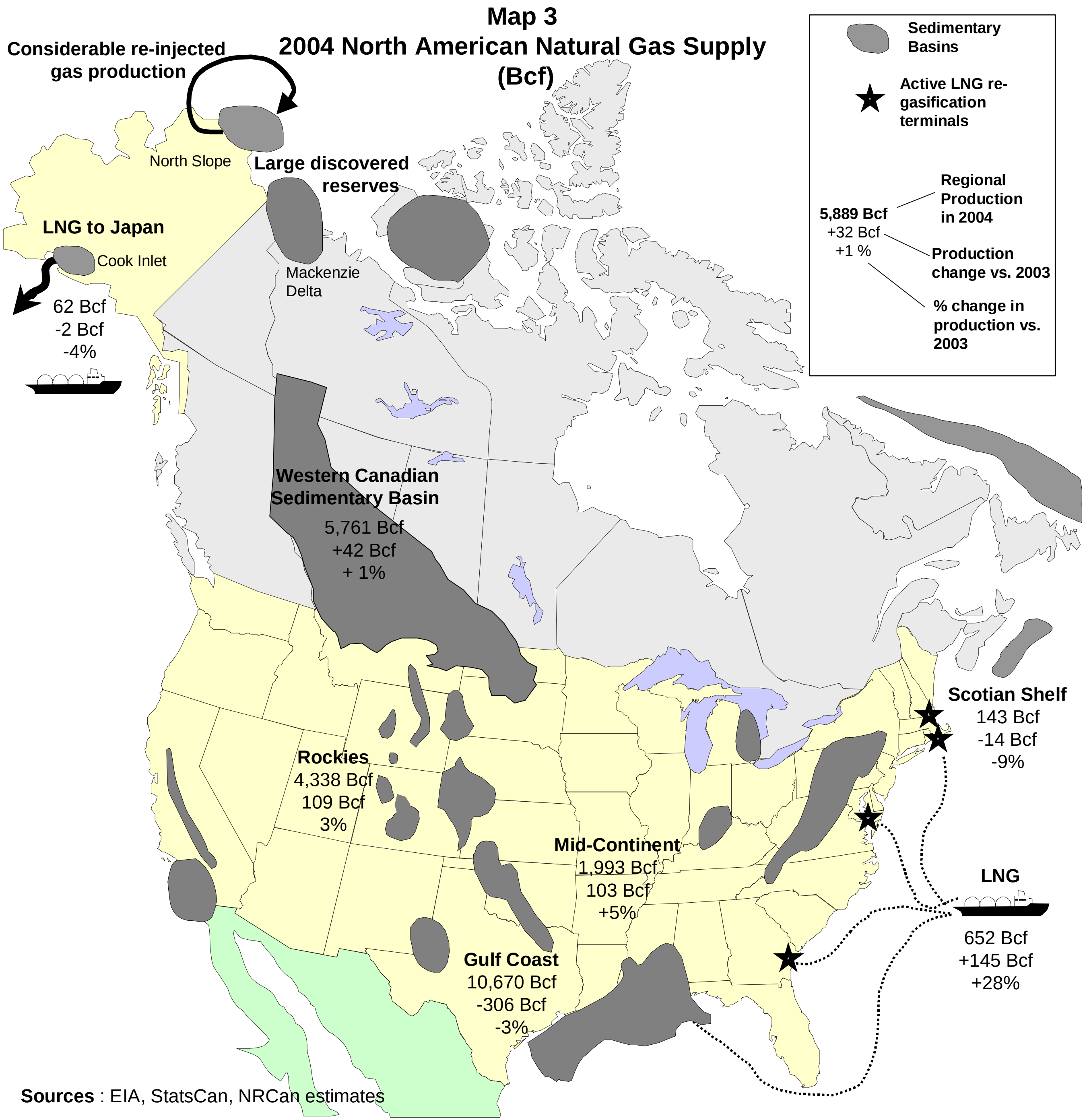
Total US demand increased by 0.2% in 2004 as losses in US residential and commercial demand were more than offset by increased industrial and power generation demand. Increased industrial demand reflects a buoyant US economy. Growing exports to Mexico also boosted US gas disposition.

All Canadian sectors of the economy reported increased demand ranging from 1% for power generation to 4% for industrial, except 'other', which declined by 8%.

Figure 1 shows year-over-year changes in North American natural gas demand by region and by sector. The non-core sectors of the economy (power generation and industrial) increased in most regions across North America and accounted for the majority of the growth in demand. The pronounced increase in natural gas consumption in the west is consistent with increased Canadian exports to that region.

Natural gas for power generation continued to lead the demand growth in most jurisdictions.

In 2004, the US Gulf Coast appeared to stabilize somewhat after shedding over 600 Bcf of natural gas demand in 2003.



Sources : EIA, StatsCan, NRCan estimates

Map 3 shows the major natural gas producing basins of Canada and the US. In 2004, lower US production, moderately higher Canadian production, and increased US LNG imports led to an overall 0.1% decrease in North American supply.

In Canada, WCSB production rebounded 1% (42 Bcf) in 2004 after falling 4% in 2003, while Sable Island production continued its descent, falling 9% (14 Bcf).

In the US, production fell 1%. Gulf Coast production (includes onshore and offshore) fell 306 Bcf, or 3%; Mid-continent production increased 103 Bcf, or 5%; and Rockies production increased 109 Bcf, or 3%.

Partially offsetting the decline in domestic US production were increased LNG imports, which increased 28% or 145 Bcf.

In 2004, US LNG imports accounted for nearly 3% of US natural gas supply. LNG continues to become an increasingly important source of natural gas for North America.

Table 2
North American Natural Gas Supply

	2004 (Bcf)	2003 (Bcf)	Change (Bcf)	Change (%)
Gulf Onshore[1]	6,866	6,763	103	2%
Gulf Offshore[2]	3,804	4,213	-409	-10%
Total Gulf	10,670	10,975	-306	-3%
US Midcontinent[3]	1,993	1,890	103	5%
US Rockies[4]	4,338	4,228	109	3%
Other US	1,923	1,942	-20	-1%
Total US Production	**18,923**	**19,036**	**-113**	**-1%**
Western Canada[5]	5,761	5,719	42	1%
Scotian Shelf	143	157	-14	-9%
Total Canada Production[6]	**5,904**	**5,876**	**28**	**0.5%**
Total N.A. Production	**24,827**	**24,912**	**-85**	**-0.3%**
US Net LNG Imports	590	445	145	33%
US Net Mexican Imports	-398	-333	-65	20%
US Supplementals[7]	55	65	-10	-15%
Total N.A. Supply	**25,074**	**25,089**	**-16**	**-0.1%**

Sources: EIA, StatsCan, NRCan estimates. **Notes:** [1] AL, LA, MS, TX [2] Federal Offshore Gulf of Mexico [3] KS, OK [4] CO, NM, UT, WY [5] Includes minor Ontario production. [6] Canadian production is marketable gas plus reprocessing shrinkage. [7] Synthetic natural gas, propane-air, refinery gas, biomass gas, air injected for stabilization of heating content, and manufactured gas commingled and distributed with natural gas.

Table 2 compares regional Canadian and US natural gas supply sources over the past two years. Total net North American natural gas supply decreased 16 Bcf in 2004. US production increases from the onshore regions could not offset the large production losses in the offshore Gulf of Mexico. The largest additions to supply came from LNG imports and the Rockies region. In Canada, production increased by 28 Bcf or less than 1%.

Table 3
North American Gas Drilling Indicators

	2004	2003	Change (04 vs. 03)	Change (%)
Active Oil & Gas-Directed Rigs:				
Gulf Onshore [1]	594	523	71	13%
Gulf Offshore [2]	92	105	-13	-13%
Total Gulf	686	629	57	9%
US Midcontinent [3]	172	142	30	21%
US Rockies [4]	217	174	43	25%
Other US [5]	117	107	10	9%
Total Oil and Gas-Directed Rigs:	**1,192**	**1,052**	**140**	**13%**
Total US Gas Wells Drilled	**21,739**	**18,907**	**2,832**	**15%**
Total Gas-Directed Rigs: [6]	**1,023**	**871**	**152**	**17%**
Canadian Gas Wells Drilled:				
Shallow [7]	11,664	10,982	682	6%
Deep [8]	3,963	2,950	1,013	34%
Total Canada [9]	**15,627**	**13,932**	**1,695**	**12%**
North American Gas Wells Drilled	**37,366**	**32,839**	**4,527**	**14%**

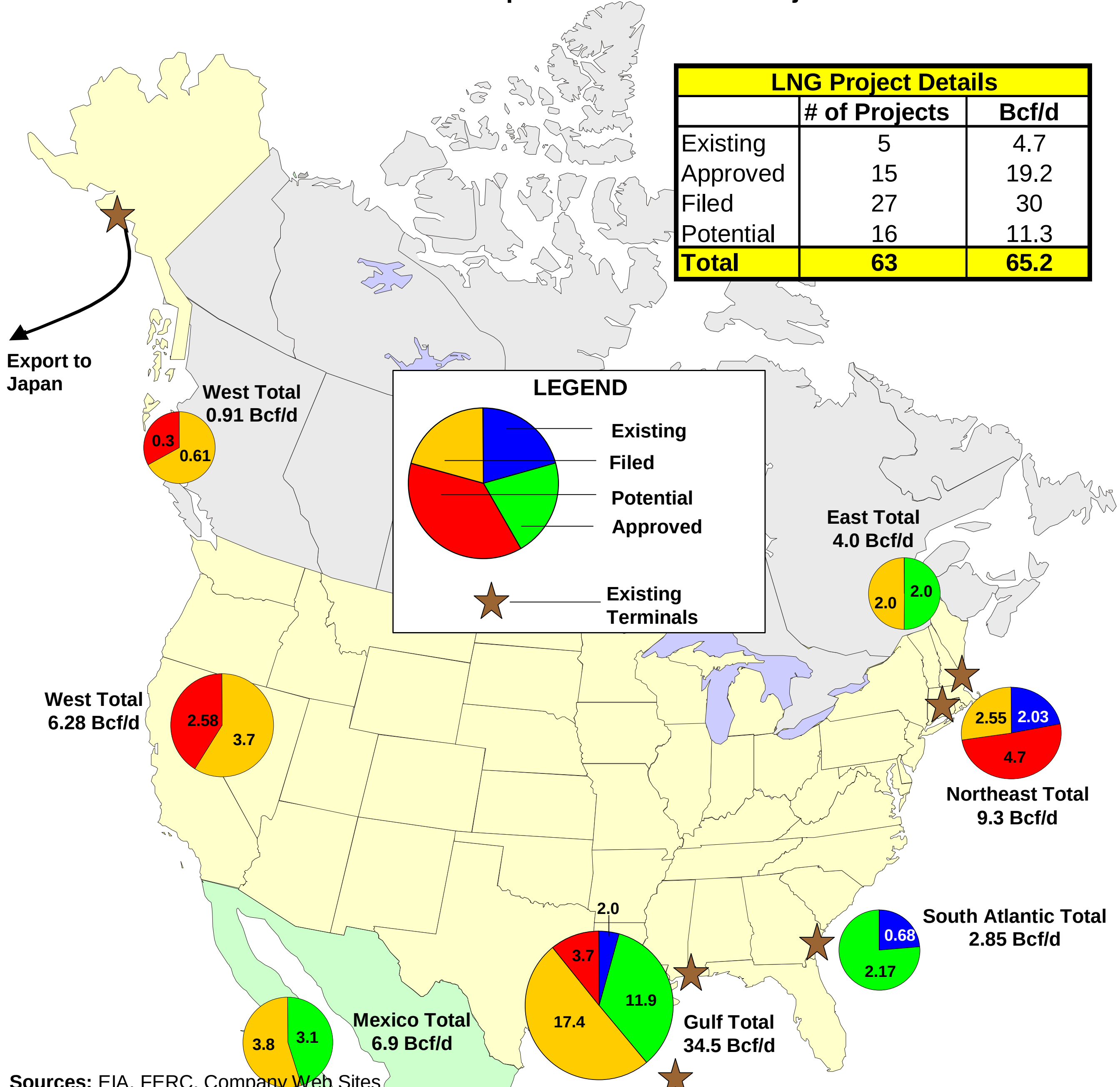
Sources: EIA, Texas RRC, Baker Hughes, Daily Oil Bulletin. **Notes:** [1] AL, LA, MS & TX onshore. [2] AL, LA, MS & TX offshore [3] AR, KS & OK. [4] CO, NM, UT & WY. [5] Remaining US. [6] Average total weekly gas-directed rig count. [7] Alberta East of 4th meridian gas wells, plus Saskatchewan gas wells. 8 Alberta W5 and W6 meridian gas wells, plus all British Columbia gas wells. [9] Total number of Western Canadian gas wells.

Table 3 summarizes North American crude oil and natural gas drilling in 2003 and 2004. In the US, total gas wells drilled increased 15%. This is directly attributable to the increase in active natural gas-directed rigs, which accounted for 92% of all the active rigs in 2004, compared to 84% in 2003.

In Canada, total gas wells drilled increased 12%, surpassing the 15,000 well mark for the first time in history.

Excluding the offshore Gulf of Mexico, drilling rose across all of North America in 2004.

Map 4
North American Liquefied Natural Gas Projects



LNG Project Details

	# of Projects	Bcf/d
Existing	5	4.7
Approved	15	19.2
Filed	27	30
Potential	16	11.3
Total	**63**	**65.2**

Sources: EIA, FERC, Company Web Sites

Map 4 provides a summary of North America's existing, approved, filed and potential LNG import terminals. LNG developers have proposed 56 new (i.e., green-field sites)* LNG import terminals (as of May 2005) in Canada, the US, Mexico and the Bahamas. Projects are in various stages of development (e.g., terminals in the US Gulf Coast and Mexico are under construction, while other proposals have yet to file with regulatory authorities).

If all the proposed LNG import terminals were built, they would have the capacity to supply nearly 90% of today's North American demand.

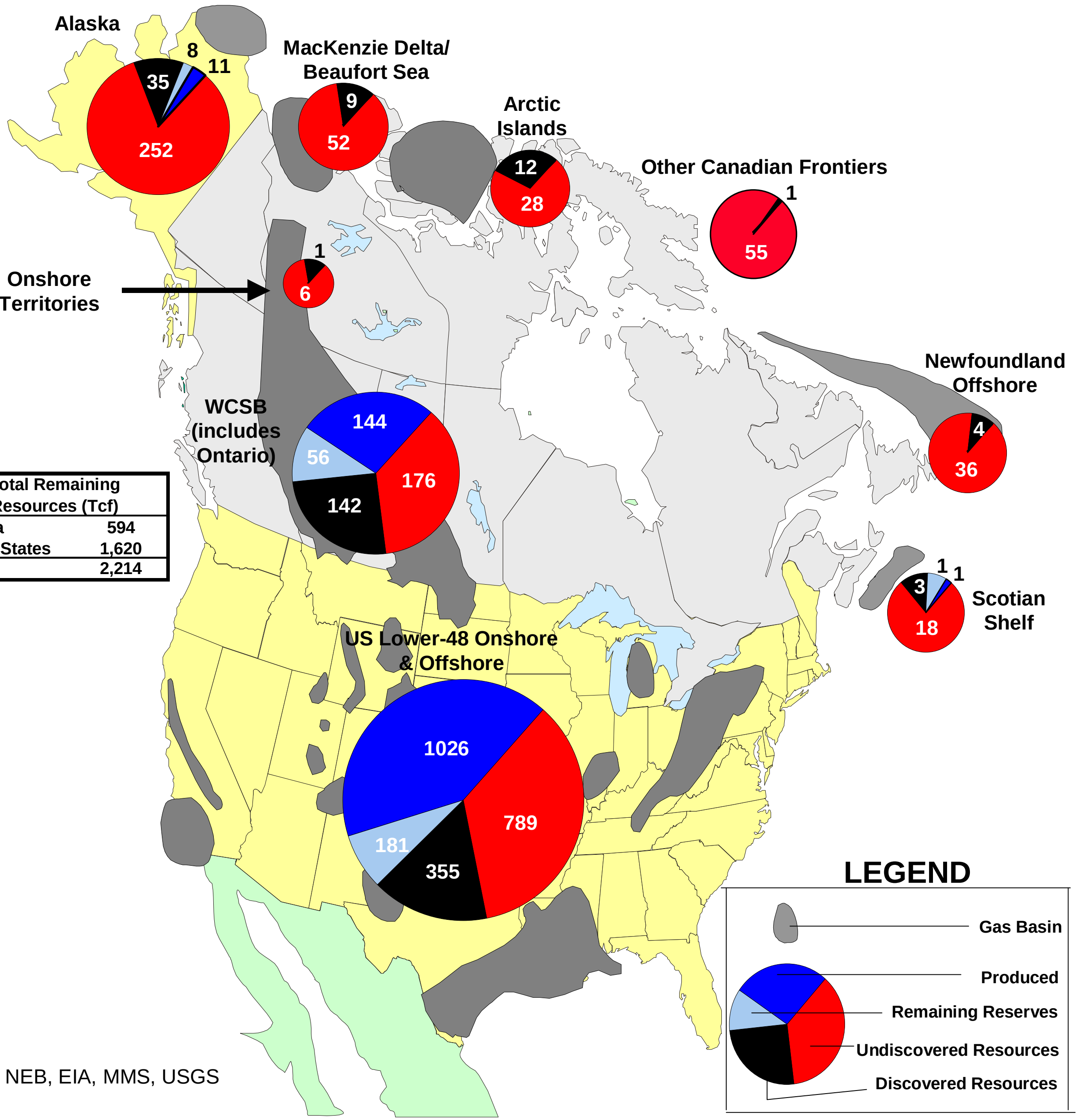
Thirteen new North American LNG import terminals with a capacity of about 17.6 Bcf/d have been approved for construction by authorities in Canada, the US and Mexico.

A total of 43 other proposed LNG terminals (i.e., 33 in the US, 5 in Mexico and 5 in Canada) would provide nearly 42 Bcf/d of natural gas send out capacity. Of the 43 projects, 24 have been filed with regulatory authorities – 4 in Canada and 20 in the US.

Appendix 3 provides more information about LNG development in North America.

*This figure does not include the five existing US LNG import terminals and two approved expansions at existing terminals in Lake Charles, Louisiana and Elba Island, Georgia.

Map 5
Canadian and US Natural Gas Resources and Reserves (Tcf)



Total Remaining Resources (Tcf)	
Canada	594
United States	1,620
Total	2,214

Sources: NEB, EIA, MMS, USGS

Map 5 shows the locations and scale of cumulative natural gas production, reserves, discovered resources and undiscovered resources in Canada and the US.

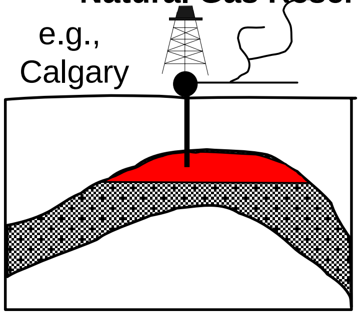
Cumulative North American natural gas production is 1,170 Tcf – 1,026 Tcf produced in the US and 144 Tcf produced in Canada.

The most current estimate for ultimate potential of natural gas in Canada, including proved reserves, is 594 Tcf.

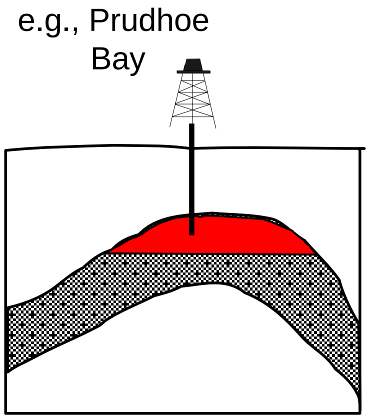
The NEB estimates that 80 Tcf of undiscovered unconventional natural gas resources exist in the WCSB. Unconventional natural gas resources includes coalbed methane, tight gas, and shale gas.

Based on estimates from MMS and USGS, the remaining US natural gas resource base, including proved reserves, is 1,620 Tcf.

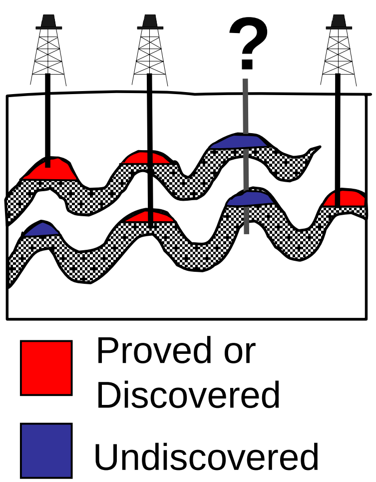
Figure 2
Natural Gas Reserves and Resources: Definitions



Proved Reserves: Estimated quantities of gas in known drilled reservoirs, which are near existing pipelines and markets. Gas volumes are known with considerable certainty to be recoverable in future years under existing technological and economic conditions.



Discovered Resources: Estimated quantities of gas in known drilled reservoirs, which are too remote to be connected to existing pipelines and markets. If pipelines were built, gas volumes would be recoverable under existing technological and economic conditions.



Undiscovered Resources: An estimate, inferred from geological data, of gas volumes thought to be recoverable under current or anticipated economic and technological conditions, but not yet discovered by drilling. May be near or remote from pipelines.

Source: NRCan

Table 4
North American Natural Gas Reserves and Resources

(Tcf)	Proved Reserves (Jan.1/04)[1]	Discovered Resources[2]	Undiscovered Resources	Ultimate Potential
Alberta	42.5	122	62	227
British Columbia	9.2	14	27	50
Saskatchewan	3.1	5	1	9
Mainland Territories	0.4	1	6	7
Unconventional Resources[3]	0	0	80	80
Total Western Canada	**55.2**	**142**	**176**	**373**
Ontario	0.4	1	1	2
Nova Scotia	0.8	3	18	22
Total Eastern Canada	**1.2**	**4**	**19**	**24**
Grand Banks and Labrador	0	4	36	40
Mackenzie/Beaufort	0	9	52	61
Arctic Islands	0	12	28	40
Other Frontier	0	1	55	56
Total Frontier	**0**	**26**	**171**	**197**
Total Canada[4]	**56**	**171**	**366**	**594**
US Onshore and State Offshore	148	322	320	790
US Federal Offshore	22	68	362	452
Unconventional Resources[3]	19	0	359	377
Total US	**189**	**390**	**1,041**	**1,620**
Total North America	**245**	**561**	**1,407**	**2,214**

Sources: NEB, CAPP, EIA, USGS, MMS **Notes:** [1] Resource estimates are as of the latest estimates generated by the NEB, CAPP, USGS and MMS. They were not necessarily generated in the current year, nor at the same time. [2] Discovered resources excludes reserves [3] Unconventional gas is comprised of coalbed methane, shale gas, and tight gas. [4] Canadian reserves data is from CAPP. All other Canadian resource numbers are from the NEB's "Canada's Conventional Natural Gas Resources" (April 2004), the NEB's "Canada's Energy Future: Scenarios for Supply and Demand to 2025" (July 2003), and the NEB/AUEB report "Alberta's Ultimate Potential for Natural Gas (2005).

Table 4 reports proved reserves, discovered resources, and undiscovered resources.

The total remaining US natural gas resource base, including proved reserves is 1,620 Tcf. At 2004 levels of domestic production, the US has about an 86-year supply of natural gas.

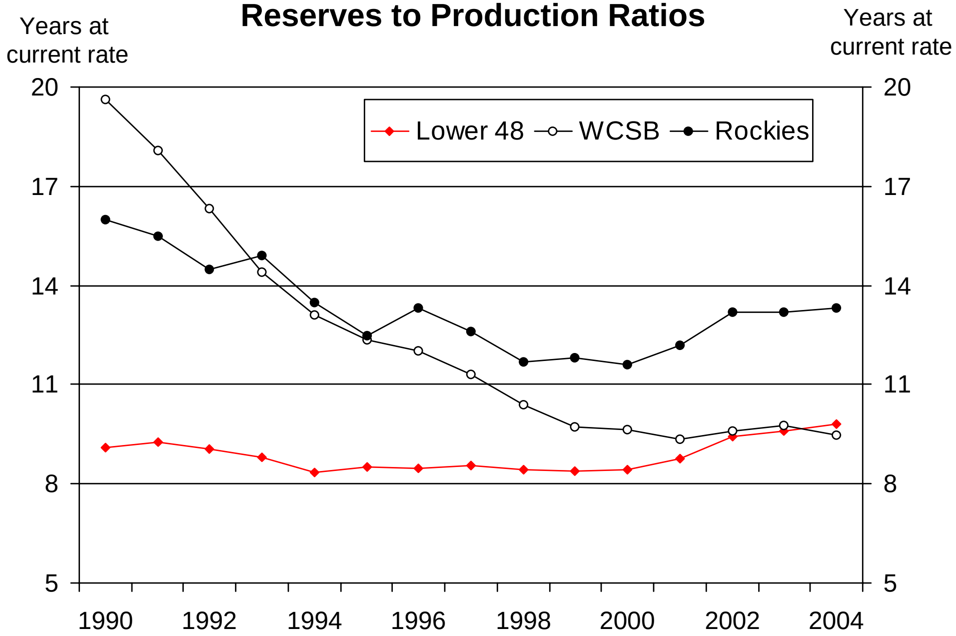
Based on estimates from the NEB and CAPP, Canada's total remaining natural gas resource base, including proved reserves is 594 Tcf. At 2004 levels of domestic production, Canada has about a 100-year supply of natural gas.

Table 5
North American Natural Gas Reserves

Tcf	Jan. 1, 2004	Jan. 1, 2003	Change (Tcf)	Change (%)
Gulf Onshore[1]	60.1	57.9	2.2	4%
Gulf Offshore[2]	22.0	24.7	-2.7	-11%
Total Gulf	**82.1**	**82.5**	**-0.4**	**0%**
US Midcontinent[3]	21.9	21.5	0.4	2%
US Rockies[4]	58.8	56.8	2.0	4%
Other US	26.2	26.0	0.2	1%
Total US Reserves	**189.0**	**186.8**	**2.2**	**1%**
Western Canada[5]	55.2	56.7	-1.5	-3%
Scotian Shelf	0.8	2.0	-1.2	-60%
Other Canada [6]	0.4	0.4	0.0	0%
Total Canada	**56.4**	**59.1**	**-2.7**	**-5%**
TOTAL N.A. Reserves	**245.4**	**245.9**	**-0.5**	**0%**

Sources: EIA and CAPP. **Notes:** [1] TX, LA, MS, & AL onshore plus TX & AL state offshore. [2] TX & LA federal Gulf of Mexico offshore. [3] AR, KS, & OK. [4] CO, MT, NM, UT, & WY. [5] BC, AB,SK & northern territories [6] Ontario and Quebec.

Figure 3
Reserves to Production Ratios



Sources: EIA, NEB, CAPP

Natural gas reserve data has a one year lag. The lag is due to the time required to compile and assess the data collected by producers from their natural gas wells. The latest reserve figures show data as of January 1, 2004.

In the US, gas reserves increased by about 2 Tcf (1%), largely attributable to continued reserve additions in the Rockies and the Gulf Onshore – a result of increased activity in these areas.

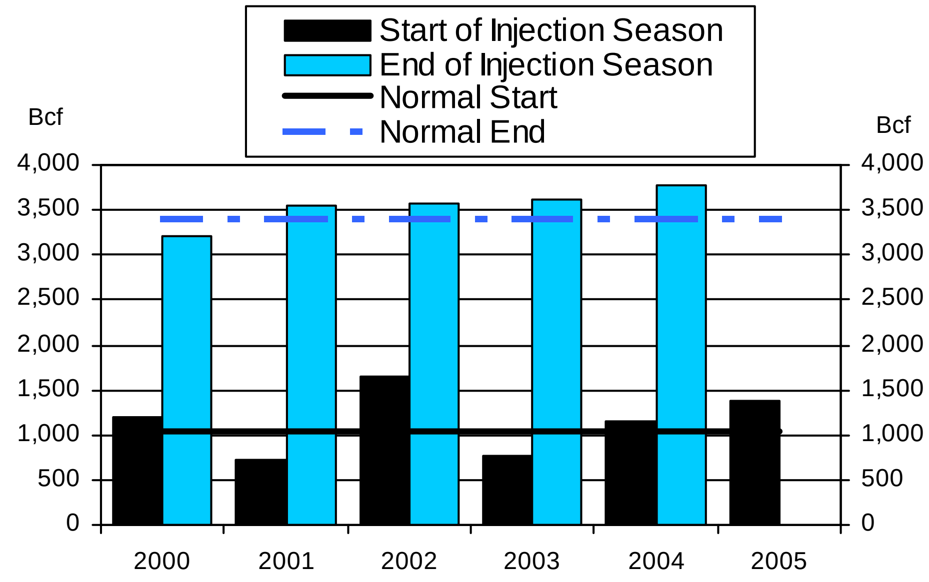
Using CAPP figures, Canadian reserves declined by 5% to 56.4 Tcf, due to a large, one-time negative reserve revision in Alberta and a 1.2 Tcf or 60% downgrade at the Sable Offshore Energy Project. Offsetting these declines were modest reserve additions in British Columbia and Saskatchewan.

Reserve to production (R/P) ratios are a measure of the amount of time to deplete gas reserves at current production levels if no new reserves are found. It is expected that as an area becomes more mature, the R/P ratio will tend to fall. Figure 3 depicts the R/P ratios of three areas, each at varying stages in their productive lives.

In Canada, the maturing nature of the WCSB is depicted by a declining R/P ratio in the 1990s and a flattening ratio thus far in the 2000s. The WCSB now has a slightly lower R/P ratio than the US Lower 48 states. The lowest R/P ratio in North America exists in the US Gulf Coast Offshore, where the R/P ratio is 5.8.

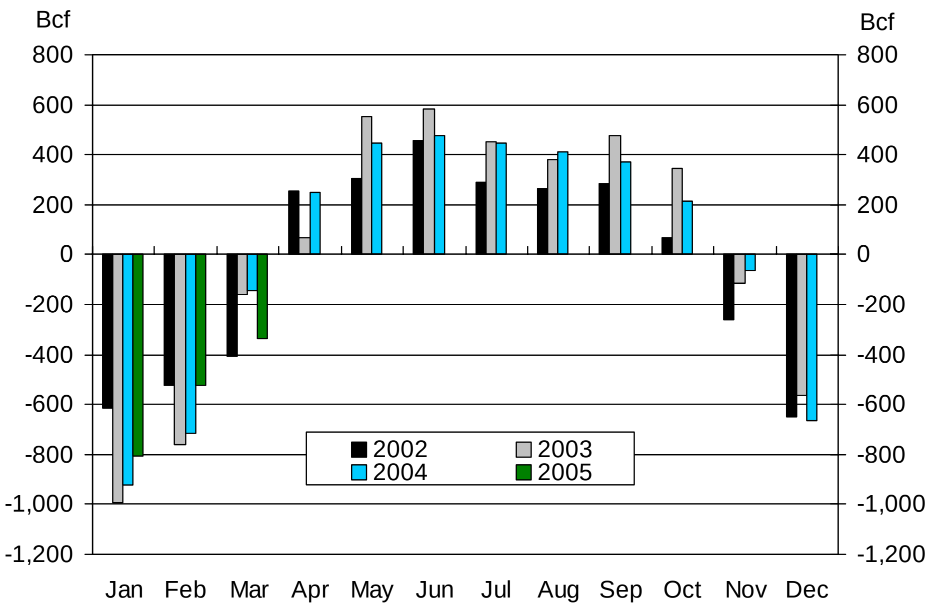
The only major supply region which remains quite immature is the US Rockies, where the R/P ratio has increased 18% from 11.6 years in 2000 to 13.3 years in 2004.

Figure 4
North American Storage Levels



Sources: Canadian Enerdata and EIA

Figure 5
North American Storage Injection/Withdrawal Rates



Source: Gas Daily

The natural gas storage injection season begins on April 1st and ends on November 1st. North American storage balances at the start and end of various past injection seasons are shown in Figure 4. Also shown is the normal average storage level (1999-2003) of 1,150 Bcf for the start, and 3,400 Bcf for the end of injection season. At the start of the 2004 injection season, North American storage was 1,162 Bcf, 403 Bcf higher than the same period in 2003, and slightly above the historical average.

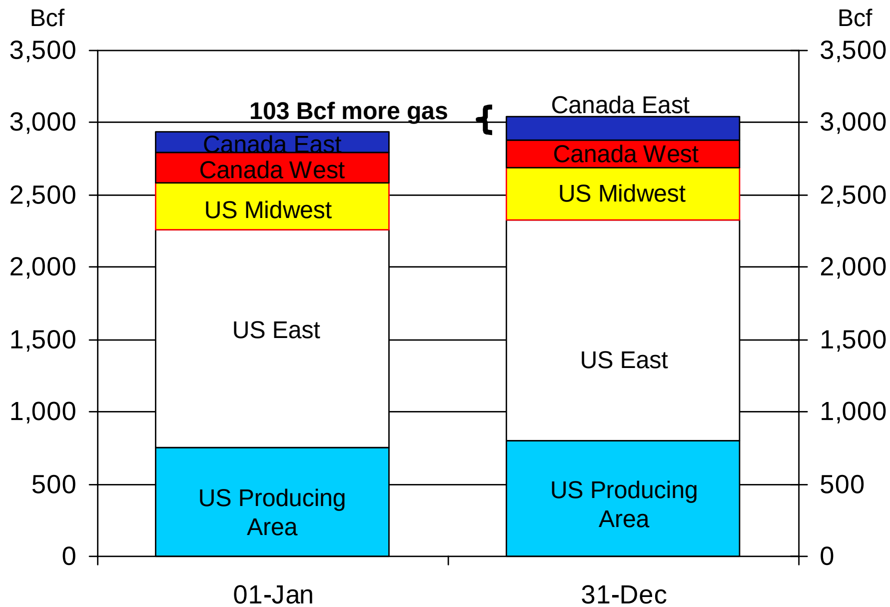
Due to a milder 2004/2005 winter across much of North America, natural gas storage levels have remained high. April 1st 2005 storage levels are 1,378 Bcf, 19% higher than April 1st 2004 and 32% higher than the 5-year average.

Figure 5 compares monthly North American natural gas storage injection (positive) and withdrawal (negative) levels for the years 2002, 2003, and 2004 and part of 2005. Natural gas withdrawals from storage represent an additional source of supply. Conversely, injections into storage represent an additional amount of demand, which has to compete with other sectors, such as power generation for air conditioning in the summer.

In January and February 2004, there were more withdrawals than January and February 2002, but less than January and February 2003. However, in March and November 2004 there were a combined 460 Bcf less withdrawals than 2002 and 70 Bcf less than 2003. For comparison, 460 Bcf is equivalent to approximately 15% of the average North American storage supply on November 1st.

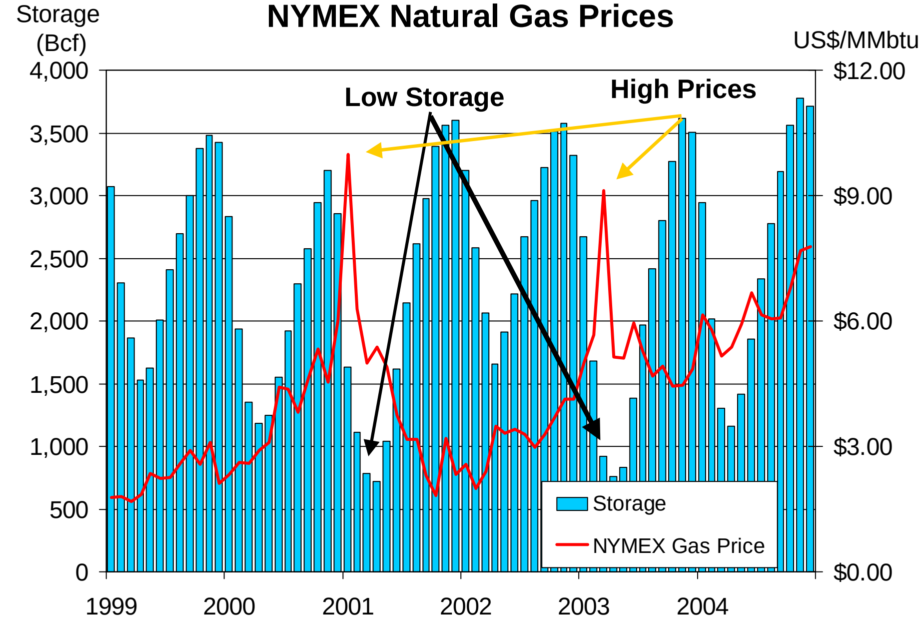
In early 2005 (Jan and Feb), withdrawal levels were lower than previous years because of warmer weather.

Figure 6
North American Storage Changes During 2004



Sources: Canadian Enerdata, EIA and NRCan estimates

Figure 7
Natural Gas Storage Levels and NYMEX Natural Gas Prices



Sources: EIA, GLJ

North American storage increased slightly through the 2004 calendar year. On Jan 1st, 2004, North American storage was 2,942 Bcf. On December 31st, there was 3,045 Bcf of natural gas in storage. Thus, during the calendar year 2004 there was a net storage build of 103 Bcf.

Storage balances at the start and end of the year are particularly important in reconciling unequal annual natural gas demand and supply figures.

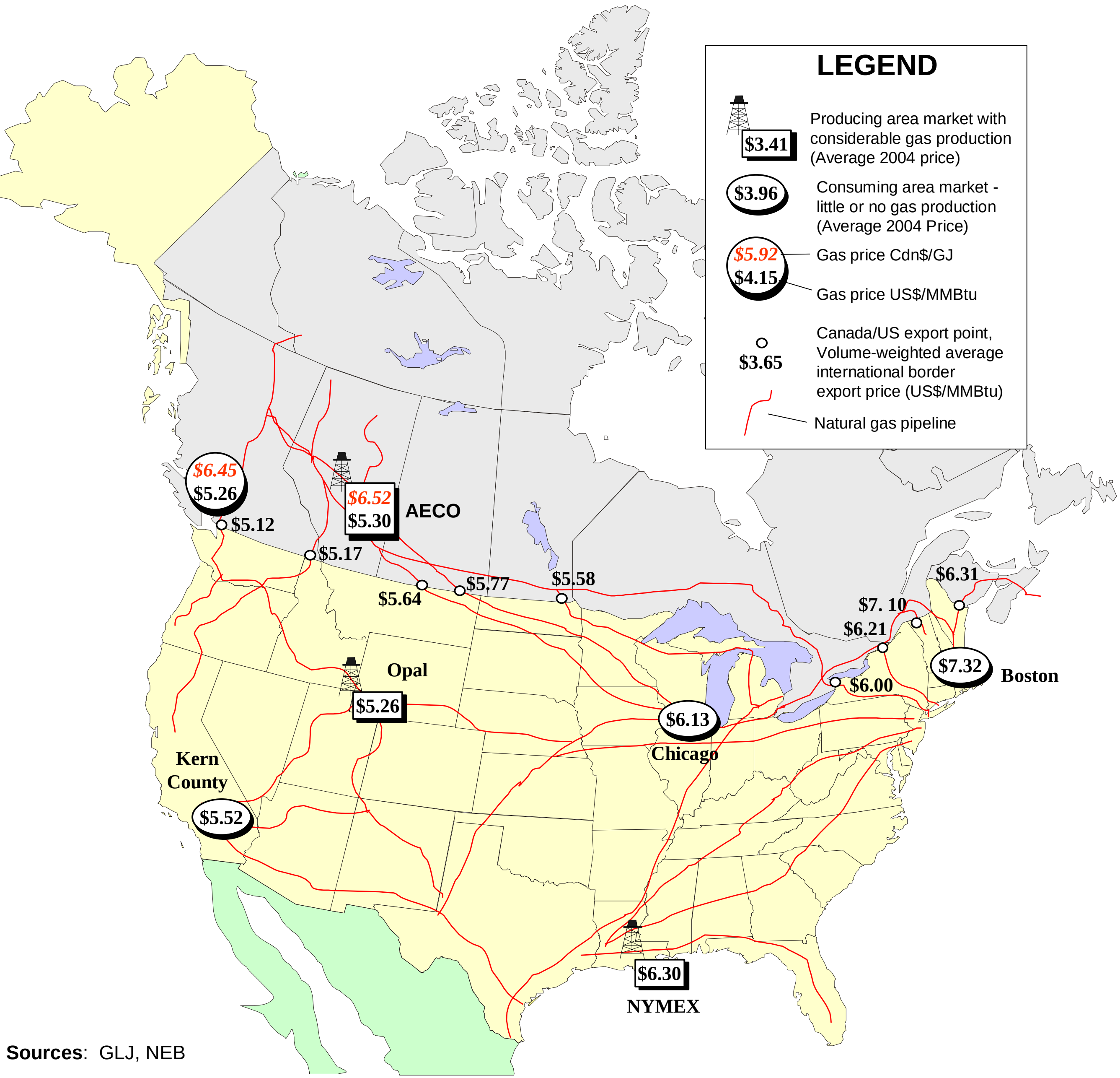
> **Note: Once storage movements are accounted for, supply and demand figures should be equal. However, in Canada and the US, figures typically do not balance due to measurement problems. To reconcile this, the EIA includes a balancing item, which was 143 Bcf for 2004. This means that US demand was higher than supply in 2004. In Canada, demand was 74 Bcf higher than supply.**

Figure 7 shows the traditional inverse relation between North American natural gas storage volumes and prices.

Historically, high storage levels send a signal to the market that there are adequate supplies for the coming winter and prices would tend to fall. This is evident in 2002. Conversely, low storage levels send a signal to the market that supplies are tight, as was the case in 2001 and 2003, and prices typically respond by increasing.

However, in 2004, record high storage levels were unable to moderate natural gas prices (although they did mitigate a severe price spike). Many analysts conclude that high crude oil prices had an outweighing bullish effect on natural gas prices.

Map 6
2004 Canadian and US Natural Gas Prices



Sources: GLJ, NEB

Map 6 shows natural gas prices for 2004 at various hubs throughout Canada and the US. Prices shown are the annual average of 12 monthly prices, except for prices at export border points, which are volume-weighted average prices.

Typically, the lowest prices are at the wellhead in the lowest cost supply areas, such as in Alberta and the Rockies in the US. The highest prices are the market areas furthest from supply, such as the US northeast and eastern Canada. These areas must pay significant pipeline costs in addition to the commodity cost.

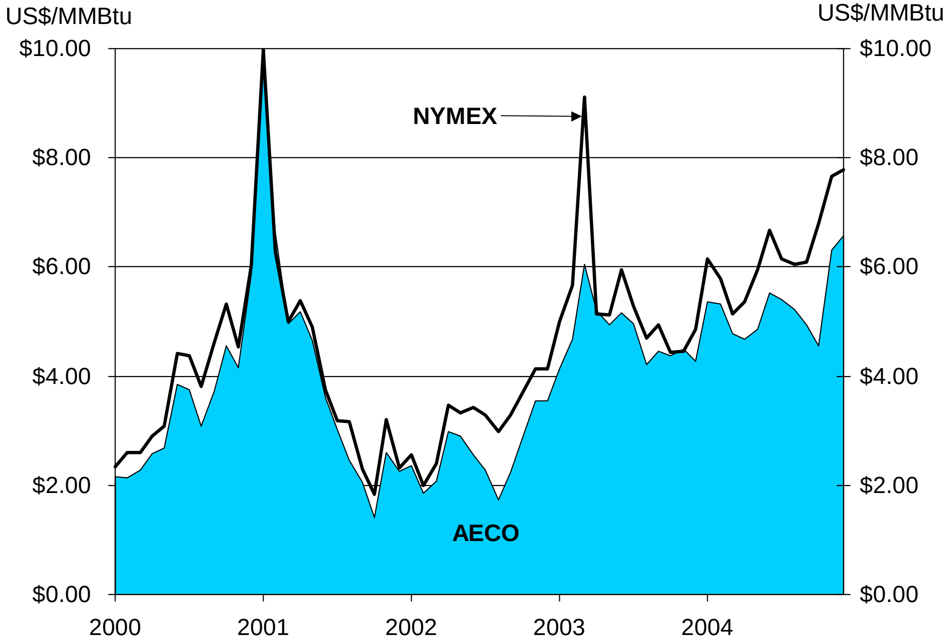
In 2004, natural gas prices reached record levels across all locations in Canada and the US. Numerous factors contributed to higher prices, primarily high crude oil prices, and a tight natural gas supply and demand balance.

Table 6
Regional Natural Gas Prices

Region	2004 Avg. ($US/MMBtu)	2003 Avg. ($US/MMBtu)	Change ($US/MMBtu)	Change (%)
AECO-C (Southern Alberta)	$5.30	$4.75	$0.55	12%
NYMEX (Louisiana)	$6.30	$5.39	$0.91	17%
Kern County (California)	$5.52	$4.49	$1.03	23%
Huntingdon/Sumas (B.C.)	$5.26	$4.66	$0.60	13%
Opal (Rockies)	$5.26	$4.13	$1.14	28%
Chicago	$6.13	$5.46	$0.67	12%
Boston	$7.32	$6.35	$0.97	15%
Dawn (Ontario)	$6.35	$5.62	$0.73	13%

Source: GLJ

Figure 8
AECO and NYMEX Natural Gas Prices



Source: GLJ

Prices were higher in all major regions of North America in 2004, surpassing their previous record levels set in 2003. In Alberta, prices were up 12%, after increasing 84% in 2003. In Louisiana, Henry Hub prices averaged US $6.30/MMBtu in 2004, an increase of 17% of 2003 levels, after increasing 67% in 2003.

The largest price increase occurred in the Rockies, where prices rose 28% after more than doubling in 2003. New pipeline capacity that has become available in the past two years has resulted in a greater integration of Rockies natural gas to other markets such as California, thereby leading to higher Rockies prices.

The most moderate price increases occurred in Alberta, British Columbia, Ontario and Chicago.

The two key North American price hubs are the intra-Alberta market (AECO) and the Henry Hub in Louisiana (NYMEX). A NYMEX-Alberta differential of US $0.50/MMBtu is considered normal. Between 2000 and 2004, the NYMEX-Alberta differential averaged US $0.60/MMBtu.

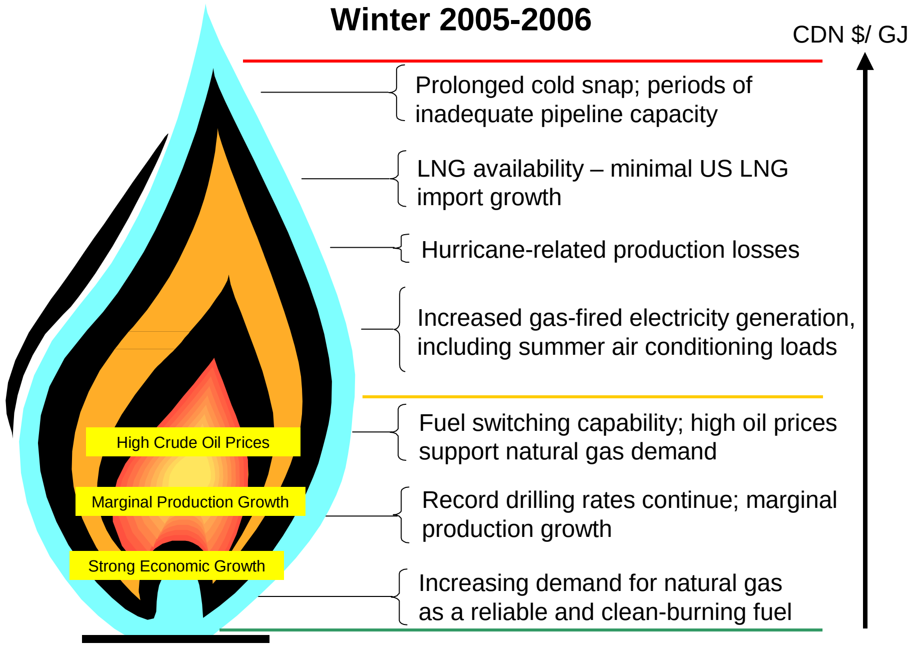
At times, short-term disconnects will occur between Alberta and NYMEX. In 2001, the smallest differential in a decade was registered, at US $0.23/MMBtu. However, differentials have since increased. In 2004, NYMEX averaged US $6.30/MMBtu, Alberta US $5.30/MMBtu, for a differential of $1.00.

2004 differentials peaked at US $2.24/MMBtu in October and reached a minimum of $0.37 in March.

Part I: North American Natural Gas Market

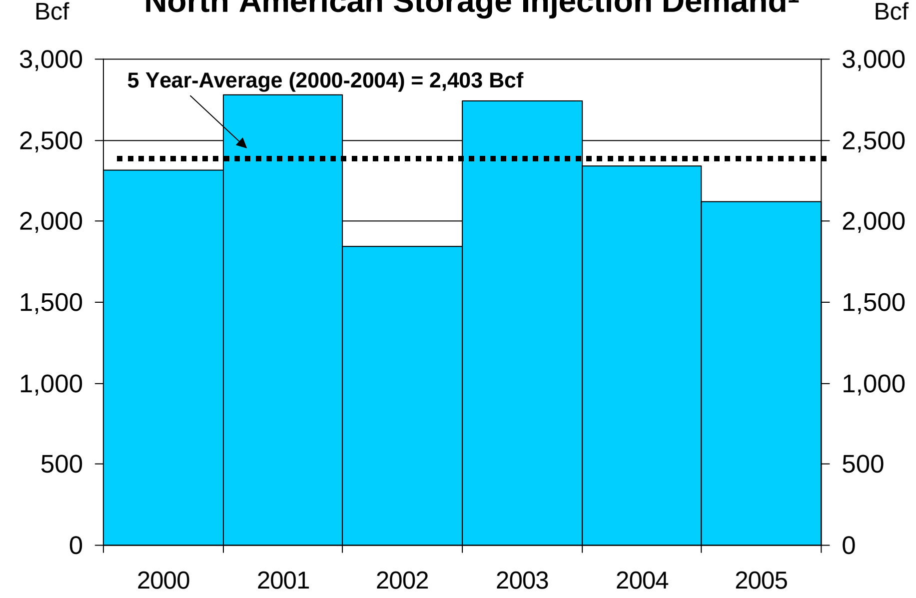
›› Short-Term Outlook

Figure 9
North American Natural Gas Price Drivers: Winter 2005-2006



Source: NRCan **Note:** For illustrative purposes only.

Figure 10
North American Storage Injection Demand[1]



Sources: EIA, Enerdata **Note:** (1) The amount of natural gas that is required to be injected into storage to reach 3.5 Tcf by November 1st.

North American natural gas prices are determined in a continental marketplace and are subject to the forces of supply and demand.

Given the long time lags involved in bringing new natural gas supply to market, natural gas users bear the brunt of the adjustment required to clear the markets in the short-term. This demand response is made mostly by large industrial natural gas users and power generators who have more fuel flexibility and price sensitivity than do residential and commercial customers.

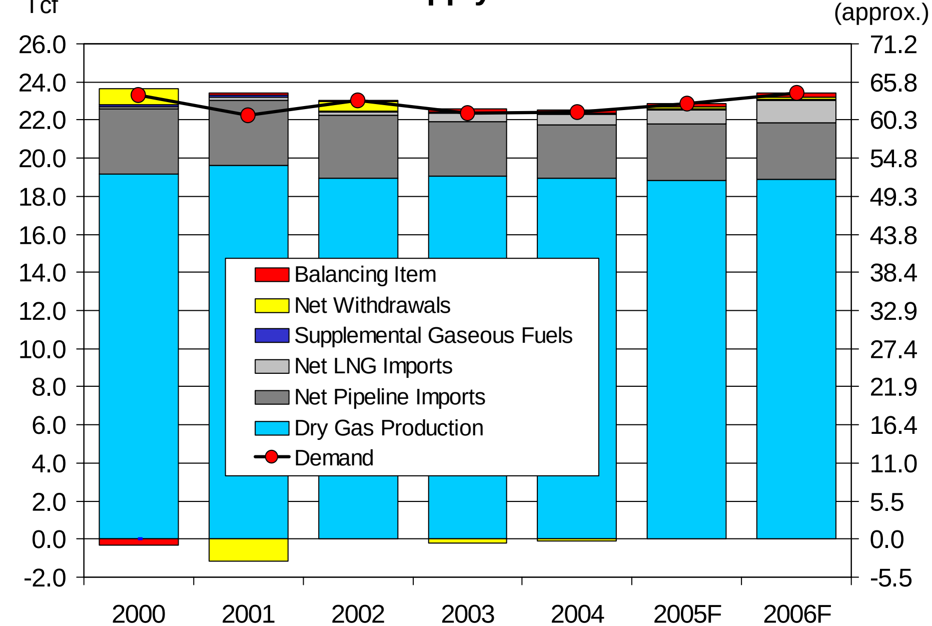
In the short-term (through to the end of 2006) natural gas prices are expected to be driven by weather conditions, the strength of the economy, natural gas drilling and productive capacity, storage levels, LNG import and pipeline availability, and the cost of other choices of available energy, particularly crude oil.

Natural gas storage levels have a significant impact on prices. Low storage levels send a signal to the market that there is a smaller supply cushion and prices will rise, while high storage levels signal to the market that there is greater supply flexibility and prices tend to fall.

Natural gas storage reached near record levels by November 1st, 2004. Storage throughout the winter of 2004-2005 remained at comfortable levels and helped to prevent any significant price spikes, as were experienced in 2001 and 2003.

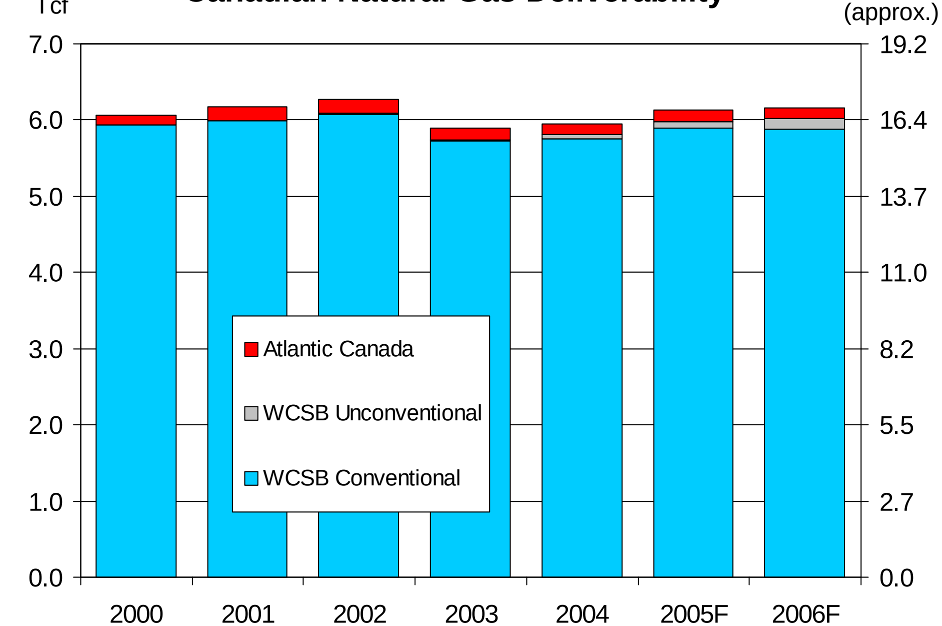
On April 1st, 2005, approximately 2,123 Bcf of natural gas was required to be injected into storage to reach 3.5 Tcf by November 1st, 2005, 215 Bcf less than on April 1st, 2004. However, as of September 1st, 2005, 406 Bcf of natural gas still remains to be injected to reach 3.5 Tcf by November 1st – 30% more than September 2004 levels, primarily a result of hot 2005 summer temperatures and production losses from Hurricanes Katrina and Rita.

Figure 11
US Natural Gas Supply-Demand Balance



Source: EIA **Note:** Balancing item represents the difference between the sum of the components of natural gas supply and the sum of components of natural gas demand.

Figure 12
Canadian Natural Gas Deliverability



Source: NEB

According to the EIA, total US natural gas supply is expected to increase about 4% from 22.32 Tcf in 2004 to 23.22 Tcf in 2006.

Dry natural gas production is expected to remain flat at about 18.92 Tcf between 2004 and 2006. Net pipeline imports are only expected to increase from 2.81 Tcf in 2004 to 2.95 Tcf in 2006.

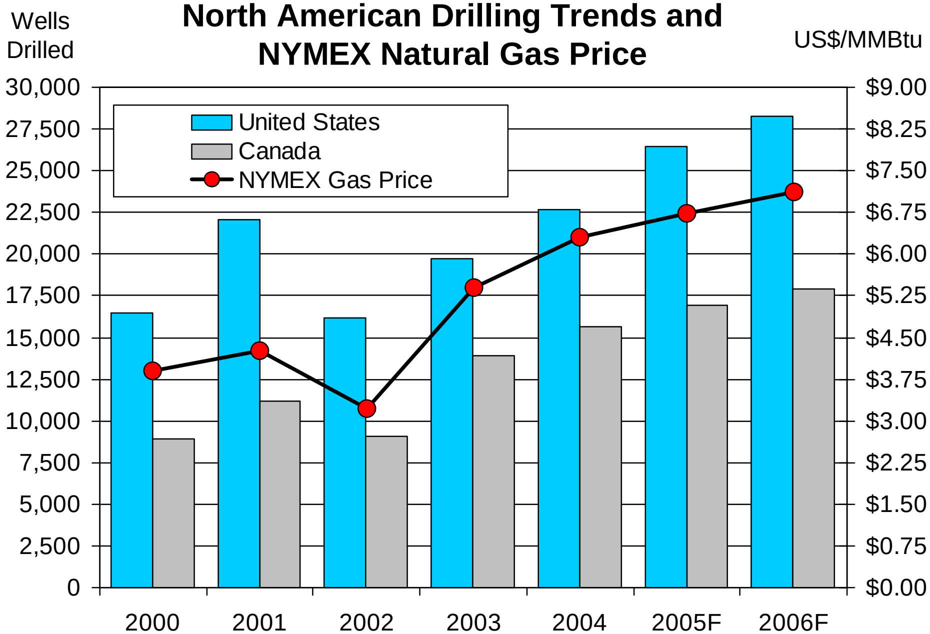
LNG imports are expected to account for the majority of the 5% growth in total US natural gas supply over the short-term. In 2004, net LNG imports were 0.59 Tcf, and represented approximately 2.6% of total natural gas supply. According to the EIA forecast, net LNG imports are expected to be closer to 1.16 Tcf in 2006, nearly double 2004 volumes. Net LNG imports are expected to account for more than 5% of total US natural gas supply in 2006.

According to the NEB, Canadian annual average natural gas deliverability is expected to increase slightly from 16.6 Bcf per day in 2003 to 16.9 Bcf per day in 2006.

Modest production increases are attributable to higher drilling levels and in particular, an increase in coalbed methane production from about 0.1 Bcf per day in 2004 to 0.4 Bcf per day in 2006. Conventional natural gas production in western Canada and offshore Nova Scotia maintain deliverability levels around 16 Bcf per day and 0.4 Bcf per day respectively through to the end of 2006.

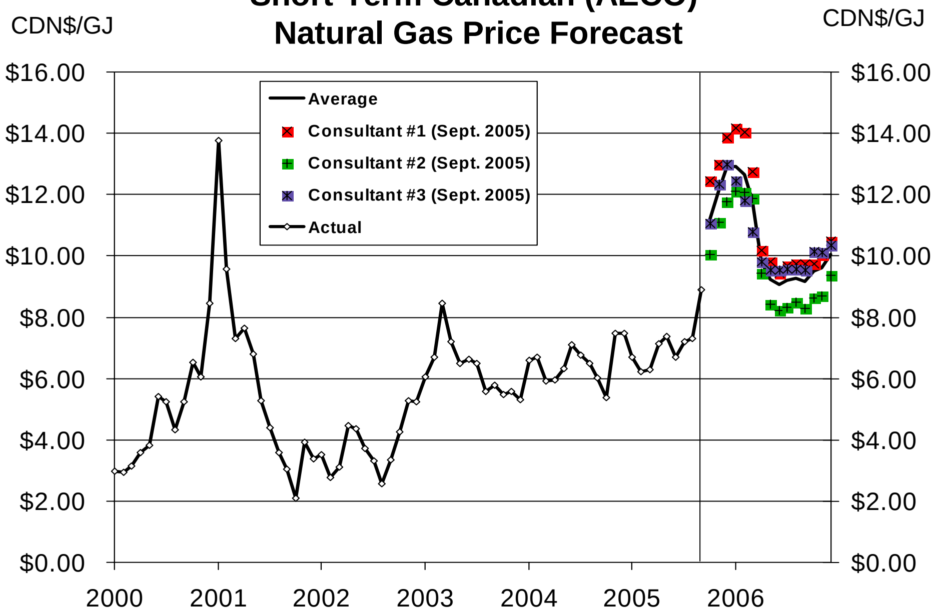
Despite the rapid rise in coalbed methane production, its contribution to overall Canadian deliverability remains relatively modest, at about 2% by 2006.

Figure 13
North American Drilling Trends and NYMEX Natural Gas Price



Sources: EIA, NEB, Daily Oil Bulletin and various consultants. **Notes:** (1) US and Canadian drilling forecasts from EIA and NEB, respectively. (2) Price forecast represents an average or "consensus" view of forecasts of various organizations. (3) Historical numbers from EIA and Daily Oil Bulletin.

Figure 14
Short-Term Canadian (AECO) Natural Gas Price Forecast



Source: GLJ and various consultants. **Note:** AECO actuals from GLJ.

Natural gas producers continue to respond to higher prices by drilling at record levels. Over the first half of 2005, the US natural gas rig count averaged 1,137, about 17% higher than the first half of 2004. The EIA forecasts that 26,500 wells will be drilled in 2005 and 28,250 wells in 2006, 30% more than 2004 levels.

In Canada, 7,285 wells were drilled in the first half of 2005, approximately the same as in the first half of 2004. Flat drilling numbers are due to wet weather and flooding, which hindered drilling capabilities in June and July. Drilling is expected to increase substantially in the second half of 2005.

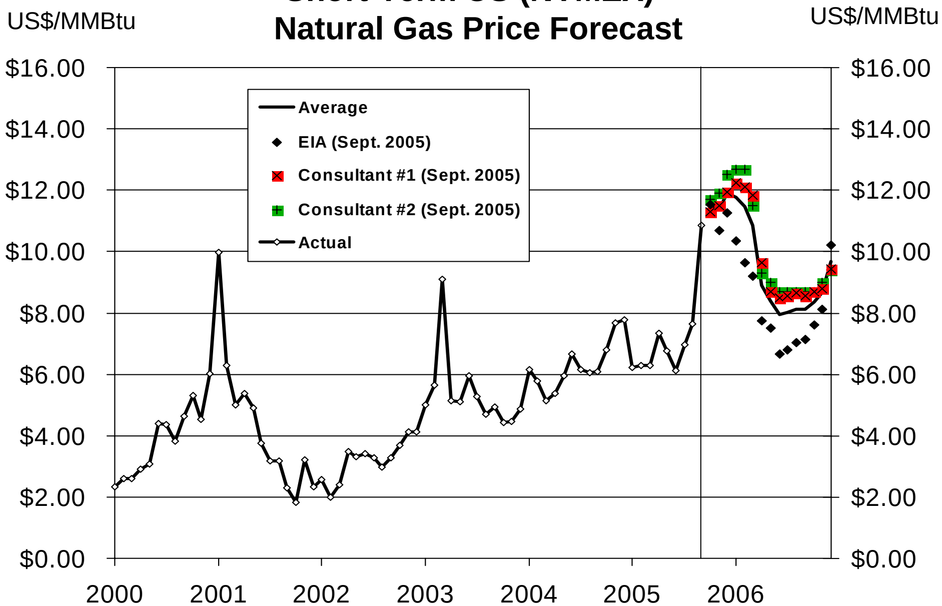
The NEB forecasts that 16,900 wells will be drilled in 2005, 8% more than actual 2004 levels. In 2006, the NEB forecasts that 17,900 wells will be drilled, of which more than 2,100 or 12% will be CBM.

Figure 14 compares three forecasts of Canadian natural gas prices through to the end of 2006. Thus far in 2005 (Jan-Sept.), Canadian natural gas prices have averaged CDN $7.09/GJ, about 10% greater than the same period last year.

According to the forecasters surveyed, Canadian natural gas prices are expected to average CDN $12.50/GJ between November 2005 and March 2006, 80% higher than the $7.00/GJ average price last winter. Canadian natural gas prices are expected to remain relatively high, averaging CDN $10.20/GJ in 2006.

Figure15

Short-Term US (NYMEX) Natural Gas Price Forecast



Source: EIA and various consultants. **Note:** Henry Hub actuals from EIA.

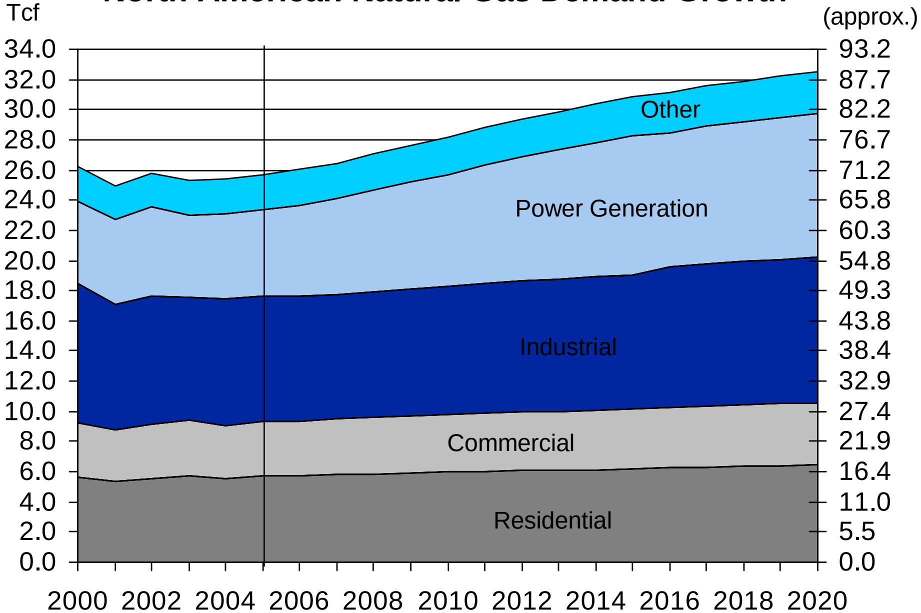
US natural gas prices averaged US $7.16/MMBtu in 2005 (Jan-Aug), 23% greater than the same period last year. High natural gas prices are attributable to strong North American economic growth, increased demand for natural gas for electricity generation, plateaus in natural gas production from conventional supply basins in North America, production losses as a result of Hurricanes Katrina and Rita in the Gulf of Mexico, and record world crude oil prices.

In the wake of recent hurricane activity, many analysts have revised their short-term natural gas price forecasts upwards. According to the forecasters surveyed (as of September 2005), US natural gas prices are expected to average US $11.50/MMBtu between November 2005 and March 2006, an increase of 67% over actual prices last winter. In 2006, the average price at Henry Hub is forecast to be US $9.20/MMBtu, 45% greater than the actual 2004 average price of $6.30/MMBtu.

Part I: North American Natural Gas Market

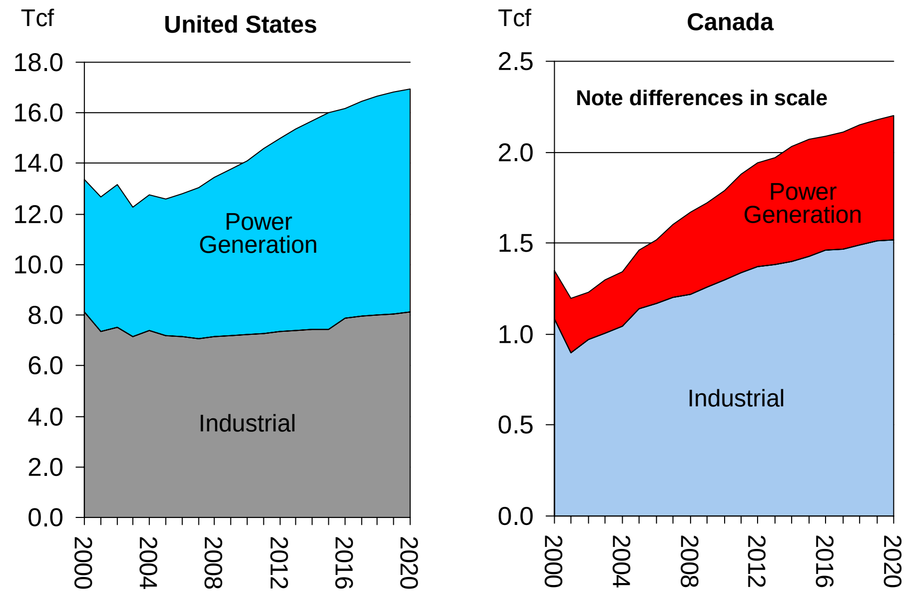
›› Outlook to 2020

Figure 16
North American Natural Gas Demand Growth



Sources: EIA, NEB, TransCanada and various consultants. **Notes:** (1) Represents an average or "consensus" view of forecasts of various organizations. (2) Historical numbers from EIA and StatsCan.

Figure 17
North American Non-Core Demand Forecasts



Sources: EIA, NEB and various consultants. **Notes:** (1) Represents an average or "consensus" view of forecasts of various organizations. (2) Historical numbers from StatsCan and EIA.

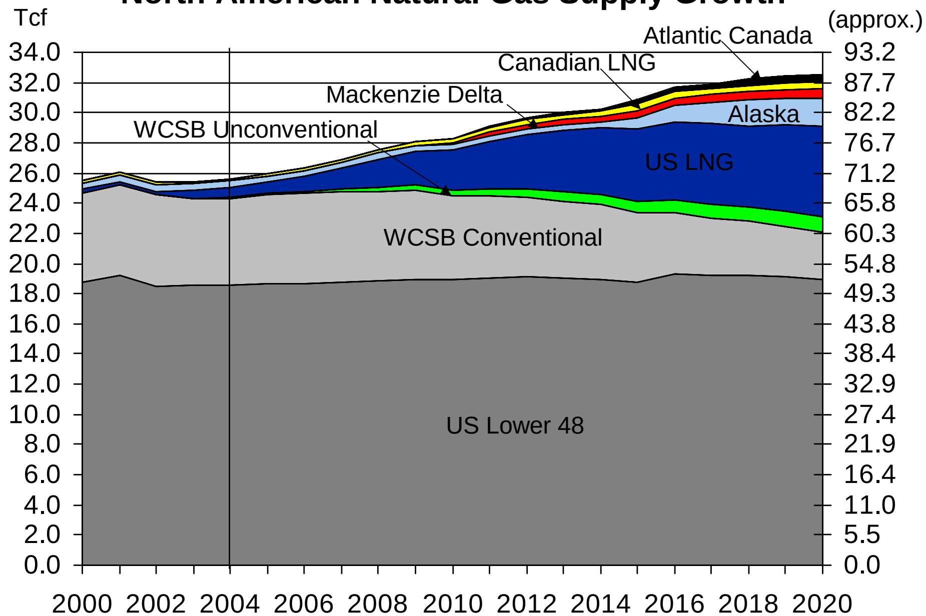
Figure 16 displays an average or "consensus" view regarding the future North American natural gas demand. Averaging the forecasts of US and Canadian gas demand results in a "consensus" forecast of about 32.5 Tcf by 2020. Much of the growth is due to increased demand in the Canadian (Alberta) industrial sector and both the US and Canadian power generation sectors.

Given actual natural gas demand of 25.3 Tcf in 2004, this forecast implies that North America will need an additional 7.2 Tcf of annual gas supply by 2020.

Figure 17 shows a "consensus" view of industrial and power generation demand in Canada and the US. Averaging various US non-core demand forecasts results in a "consensus" forecast of about 17 Tcf by 2020, or 60% of total US demand. Given actual US non-core demand of 12.7 Tcf in 2004, this forecast represents an average annual growth rate of about 10%.

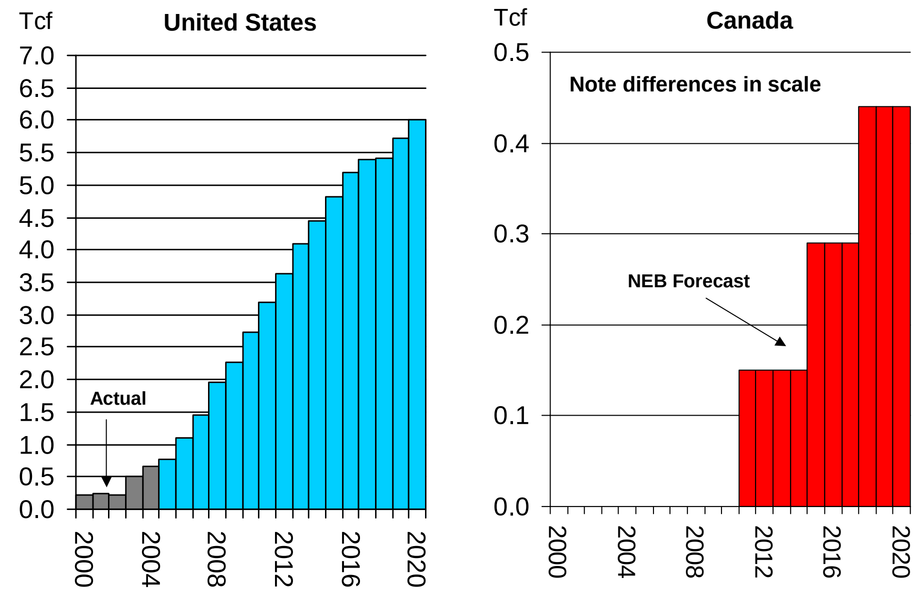
In 2004, Canada's industrial and power generation sectors consumed 1.3 Tcf of natural gas. This represents only 10% of the natural gas consumed in the US' non-core sector. The average of the forecasts shows Canadian non-core demand at 2.2 Tcf by 2020. This represents an increase of 0.9 Tcf, or about 70%, when compared to actual 2004 Canadian non-core demand.

Figure 18
North American Natural Gas Supply Growth



Sources: EIA, NEB, CERI, TransCanada and various consultants. **Notes:** (1) Represents an average or "consensus" view of forecasts of various organizations. (2) Historical numbers from EIA, StatsCan and CNSOPB.

Figure 19
North American LNG Import Forecasts



Sources: EIA, NEB, and various consultants. (1) Represents an average or "consensus" view of forecasts of various organizations. (2) Historical numbers from EIA.

In 2004, North American natural gas supply was 24.9 Tcf. Averaging various US and Canadian natural gas supply forecasts results in a "consensus" forecast of North American gas supply of about 32.5 Tcf by 2020. This represents an increase of 7.6 Tcf, or about 30%, when compared to actual 2004 North American natural gas supply.

According to the "consensus" view, conventional natural gas from western Canada is forecast to decline from 6 Tcf in 2007 to about 3 Tcf in 2020.

Northern natural gas and CBM from western Canada are expected to make up for some of the declines in conventional North American natural gas production. However, according to the "consensus" view, it is clear that the future growth in natural gas supply is expected to come from LNG development in both Canada and the US.

Figure 19 displays an average or "consensus" view regarding US LNG imports and the NEB's LNG forecast from its 2003 energy supply and demand report.

US LNG imports are expected to be the largest incremental supply of natural gas to the North American natural gas market by the end of the forecast period. In 2004, the US imported 652 Bcf of LNG, representing about 3% of US consumption. Averaging various US LNG forecasts results in a "consensus" view of 6 Tcf in 2020, representing nearly 20% of total US consumption or approximately equal to current Canadian natural gas production.

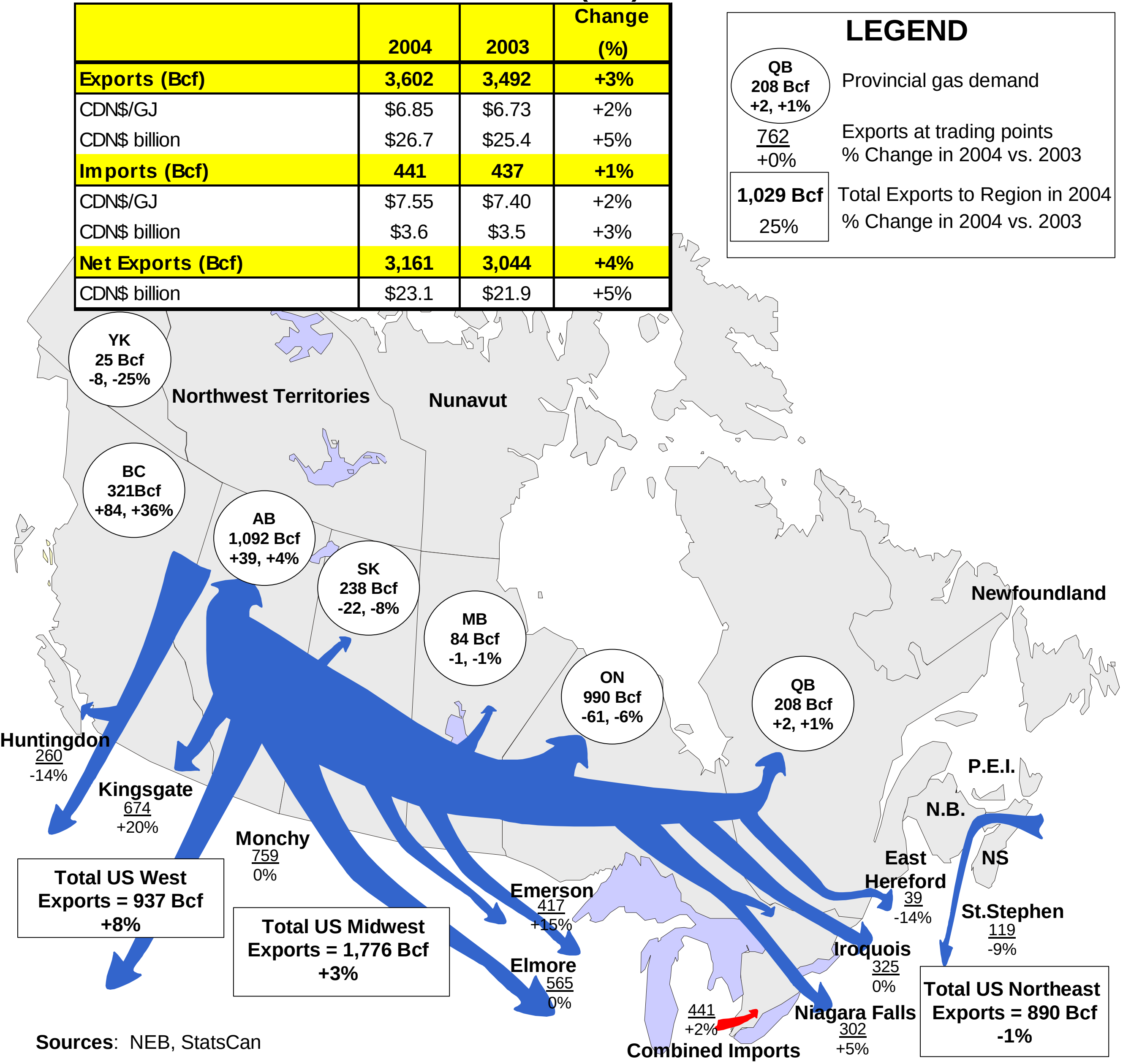
The NEB forecasts that Canadian LNG imports will equal 1.2 billion cubic feet per day, or 0.44 Tcf in 2020.

Part II: Canadian Natural Gas Market

›› Review of 2004

Map 7
2004 Domestic and Export Markets
(Bcf)

	2004	2003	Change (%)
Exports (Bcf)	**3,602**	**3,492**	**+3%**
CDN$/GJ	$6.85	$6.73	+2%
CDN$ billion	$26.7	$25.4	+5%
Imports (Bcf)	**441**	**437**	**+1%**
CDN$/GJ	$7.55	$7.40	+2%
CDN$ billion	$3.6	$3.5	+3%
Net Exports (Bcf)	**3,161**	**3,044**	**+4%**
CDN$ billion	$23.1	$21.9	+5%



Sources: NEB, StatsCan

Map 7 illustrates the flow of Canadian natural gas from producing regions to domestic and export markets. Net exports to the US increased 3% in 2004. Regionally, exports increased 8% in the west, 3% in the midwest and declined 1% in the northeast.

Natural gas trade increased both in volume (4%) and value (5%) in 2004. Approximately 96%, or 3,460 Bcf of all export volumes flowed through 9 major export points. The majority of natural gas exports occurred at Kingsgate, Monchy and Elmore with Kingsgate posting the strongest year-over-year increase with a 20% gain.

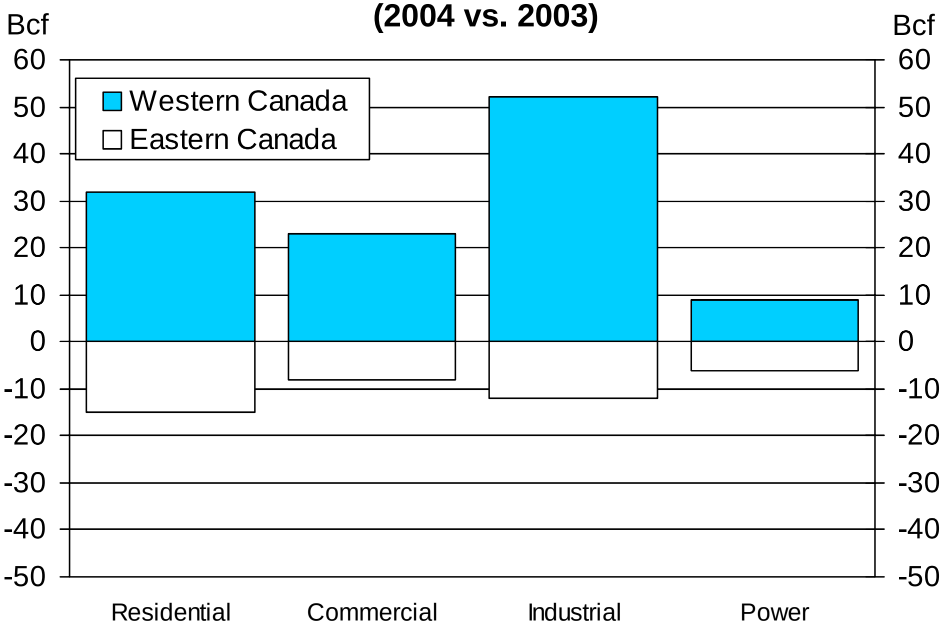
Canadian natural gas imports were relatively unchanged in 2004 at 441 Bcf. 55% of imports came through the Vector pipeline at Courtright, while 21% were imported through St. Clair. The balance was imported through various small and sometimes intermittent import points.

Table 7
Canadian Natural Gas Demand

Sector	2004	2003	2002	2001	2000
Bcf:					
Residential	658	641	620	578	621
Commercial	498	484	486	443	438
Industrial	1,045	1,005	970	897	1,083
Electric	298	295	261	301	268
Other	460	500	399	478	462
Total	**2,959**	**2,925**	**2,736**	**2,697**	**2,872**
Percentage:					
Residential	22%	22%	23%	22%	22%
Commercial	17%	17%	18%	16%	15%
Industrial	35%	34%	35%	33%	38%
Electric	10%	10%	10%	11%	9%
Other	16%	17%	15%	18%	16%

Source: StatsCan **Note:** Other gas includes pipeline compressor fuel, processing fuel, and line losses.

Figure 20
Canadian Sectoral Demand Changes
(2004 vs. 2003)



Sources: StatsCan, Alberta Energy and Utilities Board (AEUB) **Note**: Excludes "Other" uses for natural gas including compressor stations and line losses.

Canadian natural gas demand was 2,959 Bcf in 2004, 1% more than in 2003, and 3% greater compared to 2000.

Canadian natural gas demand is dominated by the industrial sector, historically accounting for between 33% and 38% of total demand. Combined, the residential and commercial sectors account for nearly 40% of total Canadian natural gas demand.

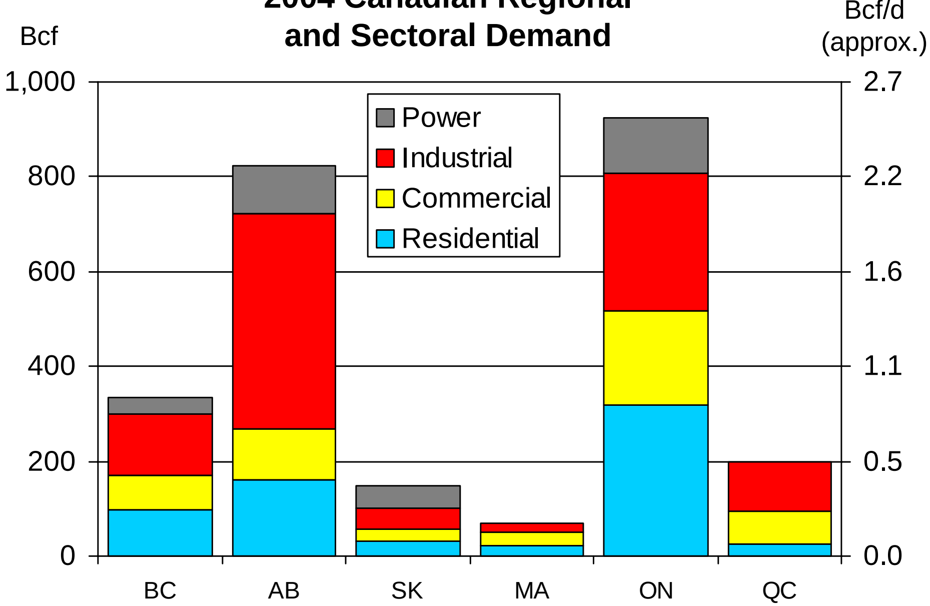
In 2004, the percentage distribution of natural gas demand was virtually unchanged when compared to 2003.

Figure 20 shows sectoral demand changes in western and eastern Canada from 2003 to 2004. While Canadian demand increased 1% in 2004, demand in western and eastern Canada increased 6% and declined 4%, respectively.

In eastern Canada, residential demand fell 15 Bcf, while commercial demand declined 8 Bcf, largely in response to milder winter weather. The industrial and power sectors also saw demand losses of 12 Bcf and 6 Bcf, respectively.

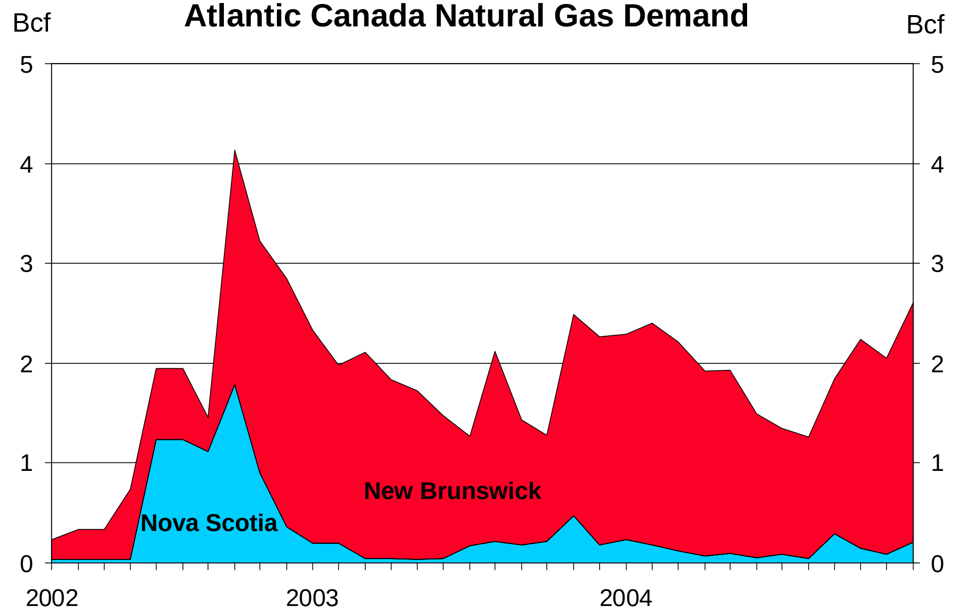
In 2004, residential and commercial demand in western Canada increased by 32 Bcf and 23 Bcf, respectively. Industrial demand growth in western Canada – primarily BC and Alberta – was largely responsible for overall demand gains in 2004. Western Canada industrial demand increased 52 Bcf in 2004.

Figure 21
2004 Canadian Regional and Sectoral Demand



Sources: StatsCan, NRCan estimates

Figure 22
Atlantic Canada Natural Gas Demand



Source: StatsCan

Figure 21 illustrates Canadian demand for natural gas in 2004 by region and sector.

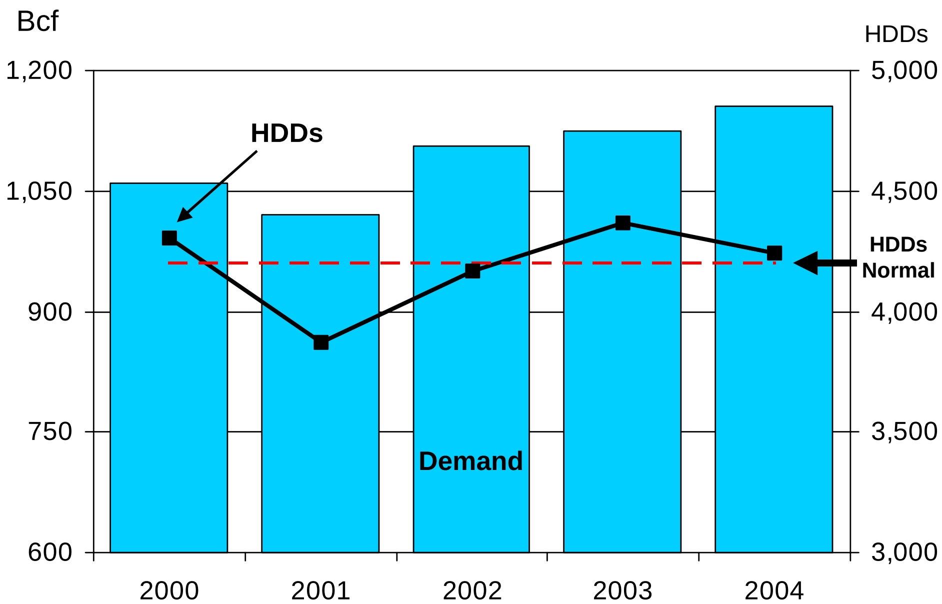
Natural gas use in Alberta is dominated by its industrial sector, consuming approximately 455 Bcf of gas in 2004, representing more than half of Alberta's natural gas demand and more than all of BC's total demand.

Ontario, the most populous province, accounted for the most gas used by any single province (excluding transportation use and reprocessing shrinkage). Ontario's demand for natural gas is dominated by core markets (residential and commercial natural gas users). In 2004, Ontario's core sector consumed about 518 Bcf of natural gas, more than 50% of Ontario's total demand.

Figure 22 shows the demand for natural gas in Nova Scotia (NS) and New Brunswick (NB). Demand for natural gas in Atlantic Canada was approximately 24 Bcf in 2004, 2 Bcf or 1% greater than in 2003.

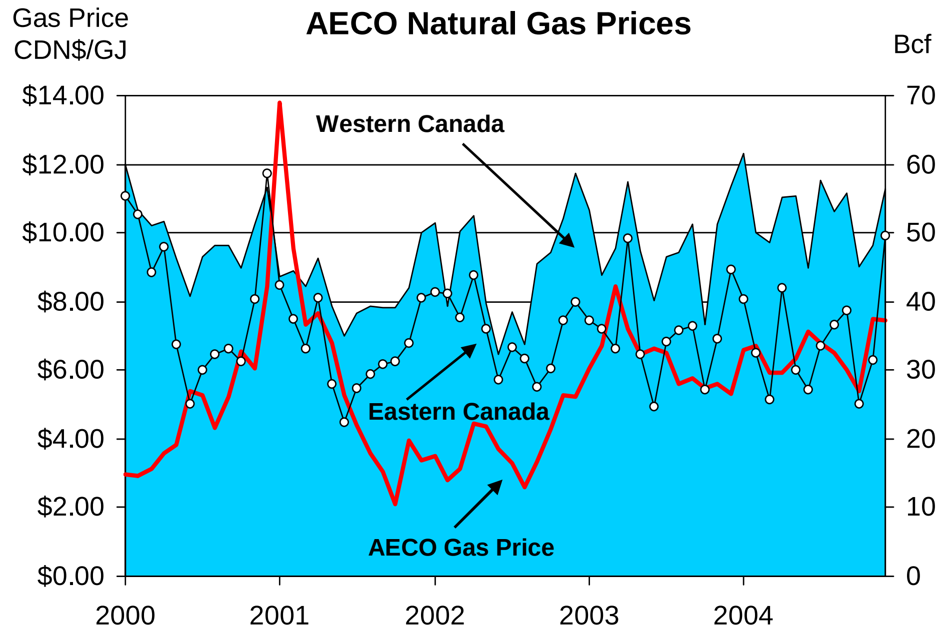
Canadian natural gas consumption in Atlantic Canada varies between 10 and 25 percent of the total natural gas produced in the region, the remainder is exported to the US northeast. The gas purchased domestically, however, may be up to several times the amount consumed, which indicates that some natural gas is traded or re-sold amongst the area players. Currently, four buyers account for over 90% of the natural gas consumed and purchased in the domestic market. The main distributors of natural gas in Atlantic Canada are Heritage Gas in Nova Scotia and Enbridge Gas in New Brunswick.

Figure 23
Canadian Heating Degree Days and Core Demand



Sources: StatsCan, NRCan estimates

Figure 24
Canadian Industrial Gas Demand vs. AECO Natural Gas Prices



Sources: StatsCan, GLJ, NRCan estimates

Figure 23 displays the correlation between core demand and HDDs in Canada. Historically, HDDs have been closely correlated to core demand; more HDDs yield higher core natural gas demand.

The dashed red line represents the 'normal' number of HDDs, which is the average HDD value over a fixed standard period of years. The 'normal' number of HDDs is 4,201, derived using 1995-2000 as the fixed time period.

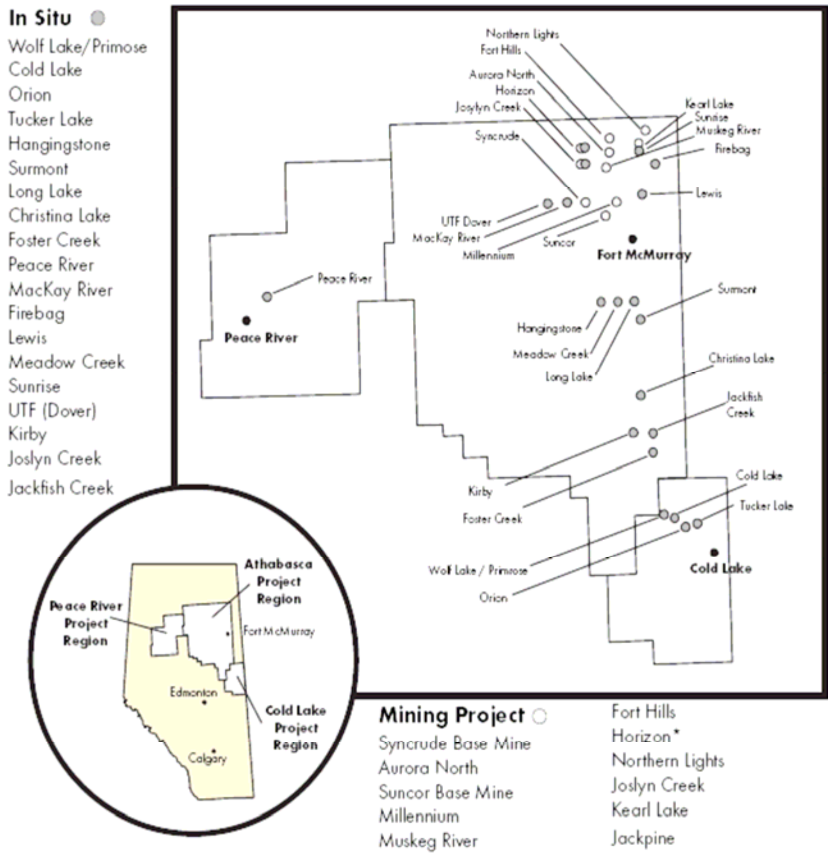
While uncharacteristic, this trend reversed in 2004 as core demand increased 3% and HDD's declined 3%. There were 4,244 HDD's in Canada in 2004, 43 more than normal but 124 less than in 2003, which was recorded as the coldest winter since 1996.

Industrial demand in eastern and western Canada generally move together in response to natural gas price changes. In 2001, Canadian natural gas prices averaged CDN $5.91/GJ, 23% higher than 2003 and industrial demand responded, falling 9%. In 2002 prices dropped, averaging $3.83/GJ and industrial demand responded by increasing 8%.

However, despite higher natural gas prices in the past two years, industrial gas demand has been on the rise. In 2003, natural gas prices averaged $6.31/GJ, yet industrial natural gas demand rebounded 6% over 2002 levels, despite a 65% increase in prices.

In 2004, industrial gas demand was 1,045 Bcf, 632 Bcf (60%) in western Canada and 413 Bcf (40%) in eastern Canada. This represents a 4% increase over 2003. Alberta's increased natural gas demand for oil sands operations is largely responsible for sustained industrial natural gas demand despite higher natural gas prices.

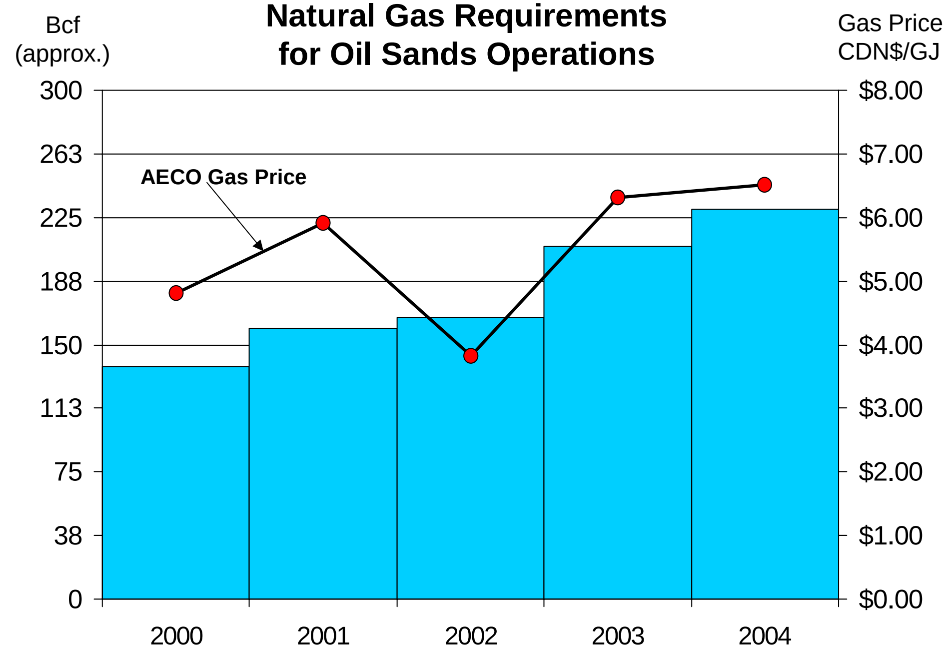
Figure 25
Canadian Oil Sands Project Locations



* Includes plans for both in situ and mining.

Source: NEB

Figure 26
Natural Gas Requirements for Oil Sands Operations



Source: NEB

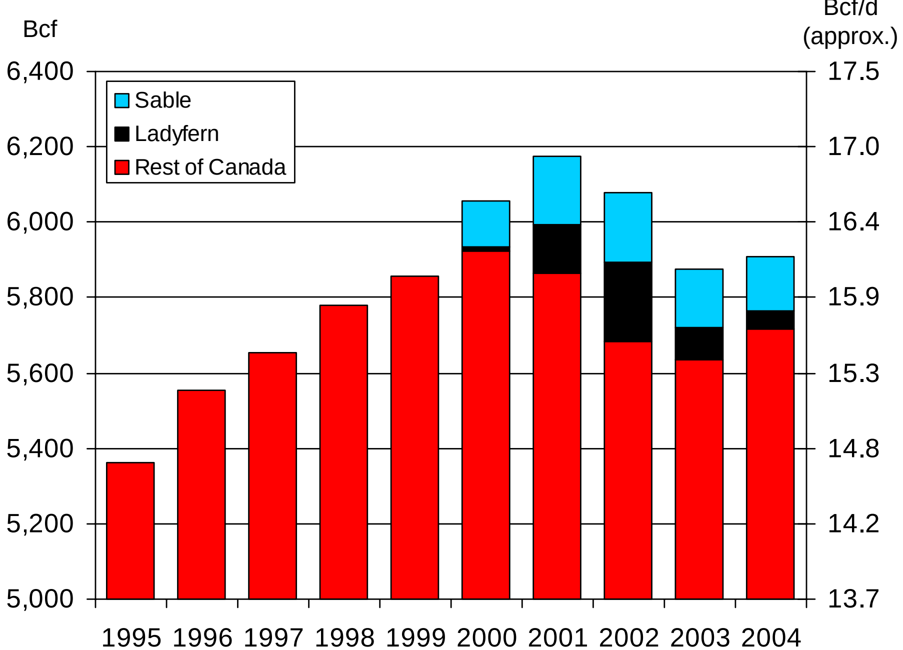
Figure 25 outlines existing oil sands operations in the Peace River, Athabaska, and Cold Lake regions of Alberta.

Alberta's bitumen deposits are one of the largest hydrocarbon deposits in the world, containing 15% of the world's known proven oil reserves. Alberta oil sands production now exceeds 1 million barrels per day, accounting for 31% of Canada's total oil production. Canadian companies will spend close to US$7 billion on further oil sands capital investments in 2005.

Oil sands operations consume large amounts of energy. The use of natural gas as a fuel for oilsands operations began when natural gas was much less expensive. However, higher natural gas prices since 2000 are causing companies to search for alternate recovery methods which do not consume as much, if any, natural gas. Currently, natural gas costs can be as much as 60% of total operating costs for in situ projects which often use steam assisted gravity drainage.

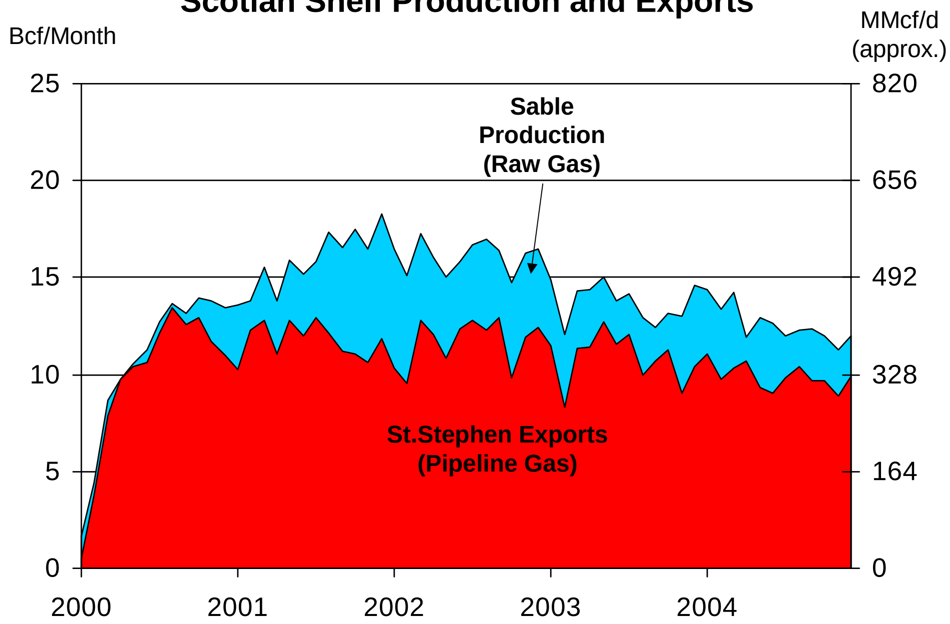
Despite efficiency improvements and reduced intensity of natural gas consumption per barrel of synthetic crude oil, growing production of synthetic crude oil is forecast to significantly increase the natural gas required to sustain oil sands operations. Alberta currently consumes about 225 Bcf or 0.6 Bcf/d of natural gas to fuel oil sands operations. This amounts to 21% of Alberta's total natural gas demand.

Figure 27
Canadian Natural Gas Production



Sources: StatsCan, CNSOPB, BC Energy and Mines, NEB, NRCan estimates

Figure 28
Scotian Shelf Production and Exports



Sources: CNSOPB, NEB

Canadian marketable natural gas production was 5,904 Bcf in 2004, an increase of 0.5% after falling 4% in 2003.

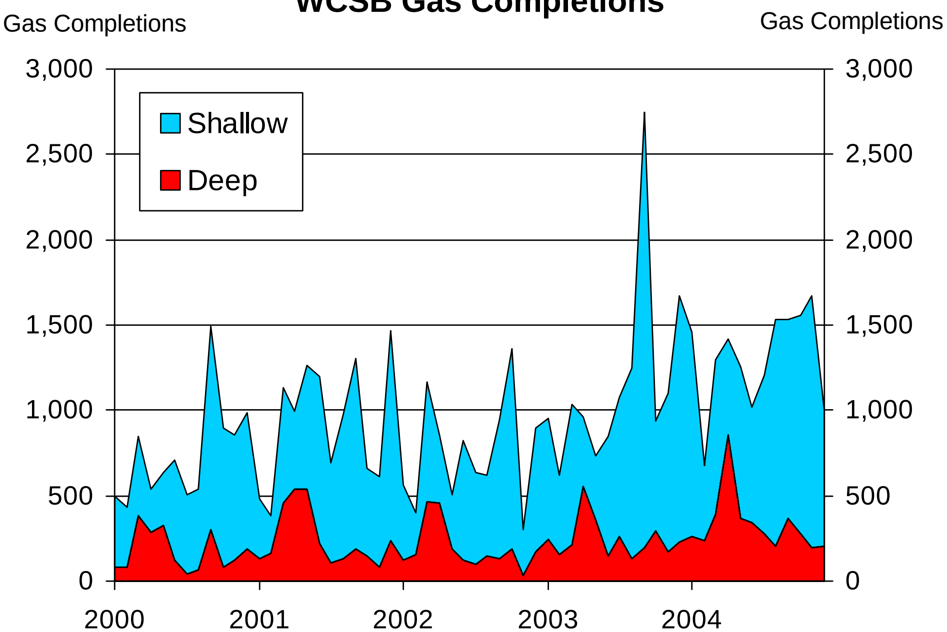
Production from Sable Island continues to fall, despite the addition of a fifth field – South Venture. Sable production averaged 420 MMcf/d in 2004, down from 450 MMcf/d in 2003.

Production from the Ladyfern natural gas field in northeastern BC continued its decent in 2004, falling 41% in 2004 to 47 Bcf after peaking at 187 Bcf in 2002. However, overall production in BC increased 2% in 2004. Production in Alberta remained flat as a result of intense drilling and increased coalbed methane production. Production from Saskatchewan increased 14 Bcf, while Yukon and Northwest Territories production fell a combined 8 Bcf.

Natural gas production from the Sable Offshore Energy Project (SOEP), offshore Nova Scotia, which began in 2000, accounts for a large amount of growth in Canadian natural gas supply. Sable natural gas production peaked in December 2001, averaging nearly 590 MMcf/d, and has been declining ever since. In 2004, Sable production declined to 143 Bcf compared to 184 Bcf in 2003. The fifth field – South Venture – began producing in late 2004.

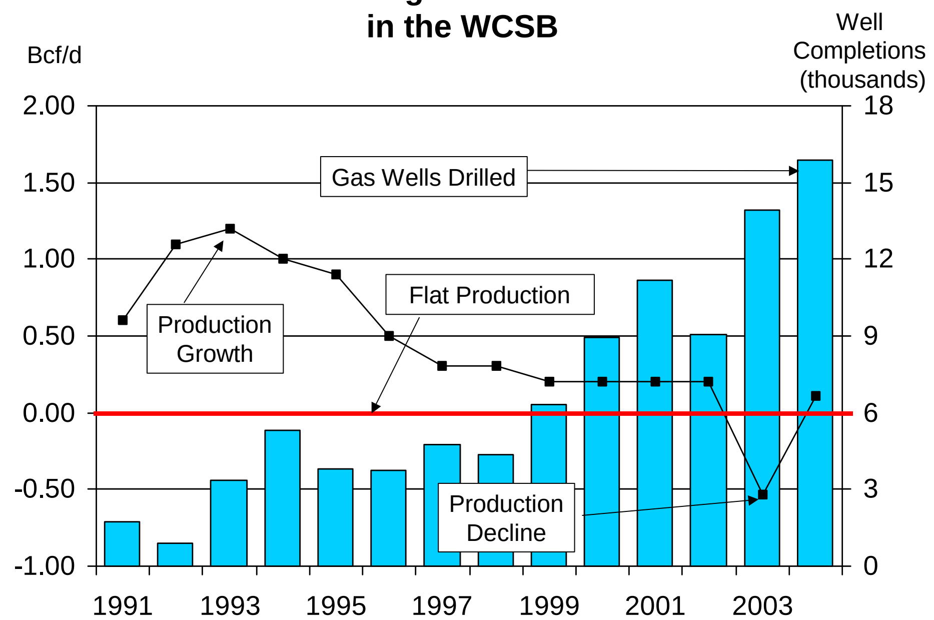
Most Scotian Shelf natural gas is exported to the US via St.Stephen, New Brunswick. Approximately 73% of Sable natural gas was exported to the US in 2004, with the remaining 27% consumed in Atlantic Canada.

Figure 29
WCSB Gas Completions



Source: Daily Oil Bulletin

Figure 30
Production Change and Gas Wells Drilled in the WCSB



Sources: StatsCan, CAPP, Daily Oil Bulletin

Although 2003 was a historically busy year in the WCSB, drilling was still able to increase by 12% in 2004.

Over 15,600 gas wells were drilled last year in the WCSB, surpassing the previous record of 13,900 in 2003. An average of over 40 natural gas wells were drilled every day, or over 1,300 per month in 2004. This compares to 1998 when only 365 wells were drilled per month, and 1992, when less then 1,000 wells were drilled all year.

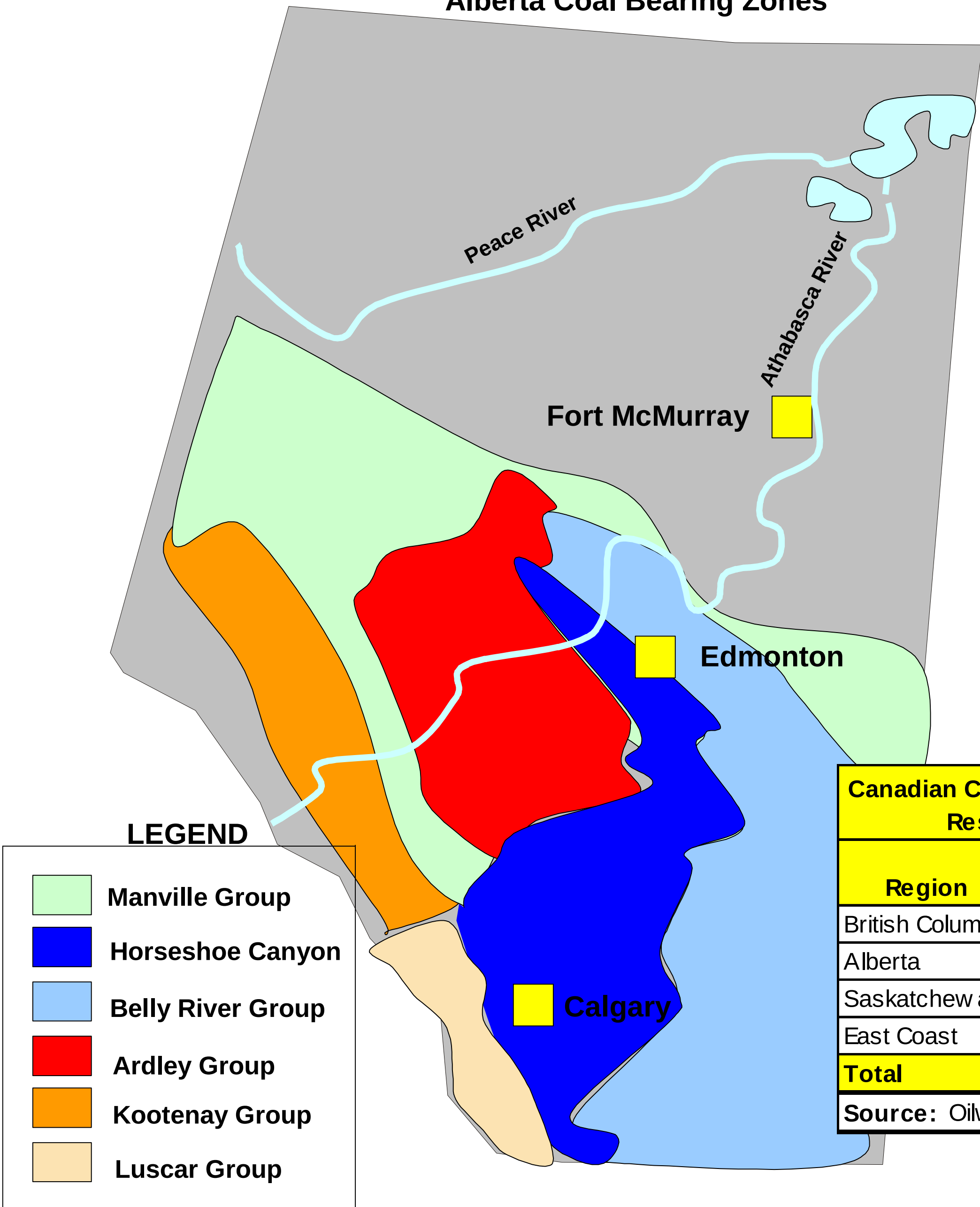
While the shallow drilling trend continued in 2004, growing by 6%, deep drilling increased 35% compared to 2003. 25% of the wells drilled in the WCSB in 2004 were deep wells, compared to 21% in 2003.

Figures 30 shows the relation between natural gas wells drilled and year-over-year natural gas production movements in the WCSB. The red line represents zero production growth.

In the early 1990's, about 4,000 new wells were being drilled each year in the WCSB and production was increasing steadily. This compares with nearly 14,000 wells drilled in 2003, and an actual production decline of 0.53 Bcf/d. In 2004, more than 15,600 wells were drilled, yet western Canada production only increased by about 0.11 Bcf/d.

Despite record drilling, production remains relatively flat because exploration is now finding smaller and smaller pools, due to the increasing maturity of the WCSB. High levels of drilling activity are being offset by lower initial productivity of new wells and, in some cases, higher decline rates. This requires a considerable increase in drilling activity simply to maintain total production.

Map 8
Alberta Coal Bearing Zones



Canadian Coalbed Methane Resources	
Region	**Gas-in-Place (Tcf)**
British Columbia	90
Alberta	412
Saskatchewan	15
East Coast	22
Total	**539**
Source: Oilweek Magazine	

Source: Alberta Energy and Utilities Board

Map 8 illustrates various coal deposits in Alberta. These deposits are the source of current and future CBM development from Alberta.

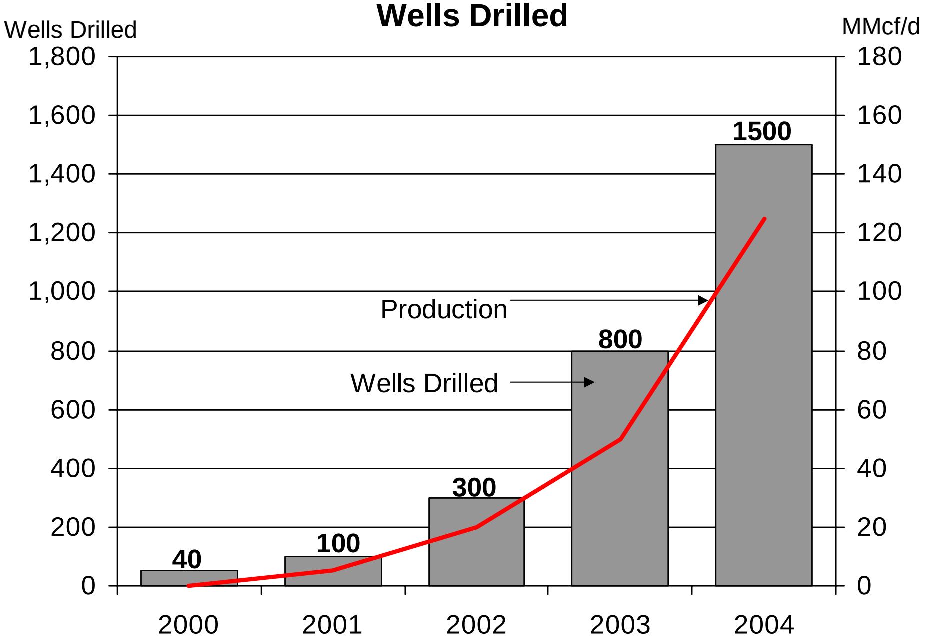
The Horseshoe canyon coals, while containing relatively low concentrations of natural gas, benefit from being shallow, dry and have a high permeability. Therefore, they are inexpensive to drill and do not have water disposal issues. Currently, all CBM production in Canada comes from the Horseshoe Canyon

Shown in green are the Manville coals. While these coals contain the largest potential resource, Manville coals present a production challenge as they are located deeper, and possess a low permeability. In addition, the Manville coals produce saline water, which must be re-injected into deep aquifers, a costly process.

In addition, there are 4 other coal bearing zones in Alberta, the Belly River Group, Ardley Group, Kootenay Group and Luscar Group.

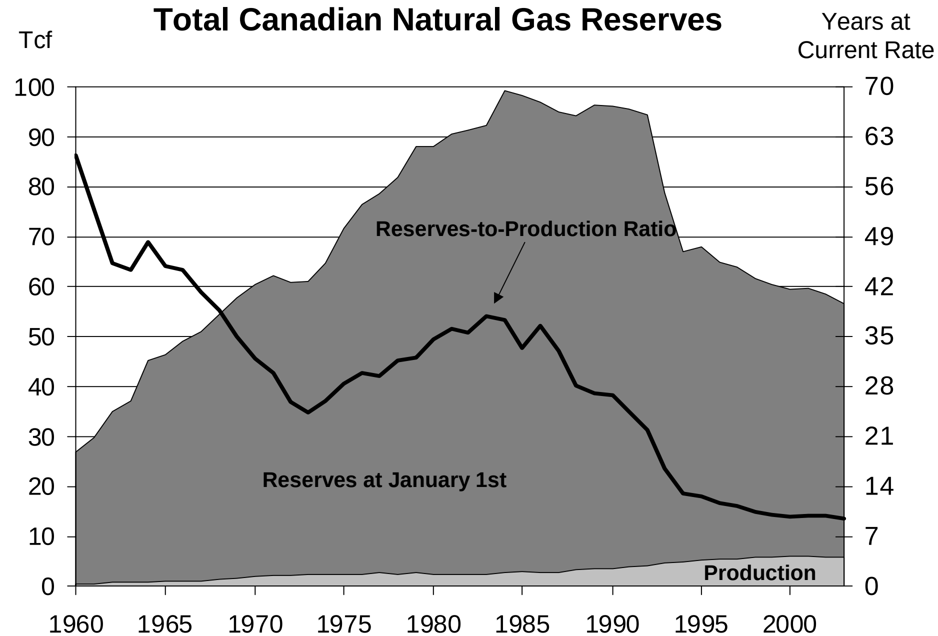
Canada's total CBM gas-in-place estimate is 539 Tcf. The portion which is economically recoverable is still unknown.

Figure 31
Alberta Coalbed Methane Production and Wells Drilled



Sources: NEB, NRCan Estimates

Figure 32
Total Canadian Natural Gas Reserves



Sources: NEB, StatsCan, CAPP

Figure 31 depicts CBM drilling and production in Alberta. In 2004, 1,500 CBM wells were drilled in Alberta, nearly double that of 2003. Further, the National Energy Board anticipates the number of CBM wells drilled will double again in 2005.

CBM production at year-end 2004 was approximately 125 MMcf/d (equivalent to 30% of current Sable Island natural gas production), coming from 1,500 wells drilled.

Production from a CBM well is significantly lower than that of a conventional well drilled in the WCSB. Typically, between 6-8 CBM wells are required to obtain the same level of production from that of a conventional, shallow natural gas well in Alberta.

A comparison of proved reserves and production on the same scale is illustrative for the purpose of analyzing basin maturity.

Canadian reserves peaked in 1983, but fell very quickly until 1994, when the drop became less precipitous. Canadian reserves are still falling, though the declines appear to be slowing. This trend continued in 2004, as Canada's natural gas reserves declined by 2.6 Tcf to 56.5 Tcf, due in large part to downward revisions in Alberta and offshore Atlantic Canada.

Canada's R/P ratio fell rapidly through the mid 1980's and 1990's. Canada's R/P ratio currently sits at 9.78 (comparable to the US ratio). This compares to the Canadian R/P ratio of 37.5 twenty years ago, before natural gas markets were deregulated.

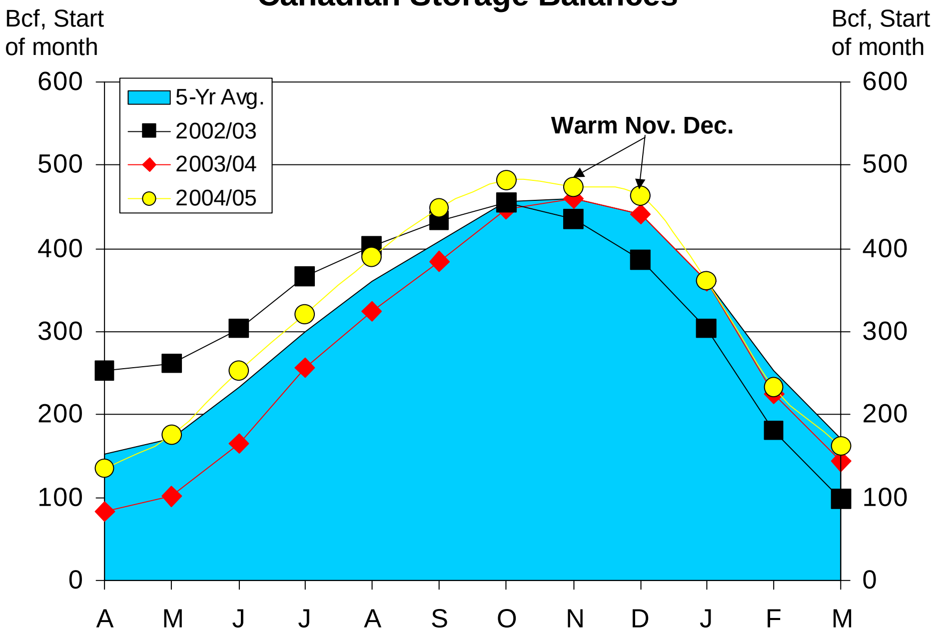
Table 8

Proposed Canadian LNG Import Terminals					
Proponent(s) (Name)	**Location**	**Cost ($CDN)**	**Send-Out Capacity (Bcf/d)**	**Earliest Start Date**	**Status/Notes**
APPROVED PROJECTS					
Anadarko Petroleum Corporation (Bear Head LNG)	Canso Strait, NS	$650 million	1.00	2008	Received federal-provincial environmental assessment approval in August 2004.
Irving Oil Limited/Repsol YPF (Canaport LNG Project)	Saint John, NB	$750 million	1.00	2008	Received federal-provincial environmental assessment approval in August 2004.
PROJECTS UNDER REVIEW					
Enbridge/Gaz Métro/ Gaz de France (Rabaska)	Beaumont, QC	$700 million	0.50	2009	Undergoing federal-provincial environmental assessment. Process commenced June 2004.
Keltic Petrochemicals	Goldboro, NS	$4 billion[1]	1.00	2009	Undergoing federal-provincial environmental assessment. Process commenced August 2004.
Kitimat LNG Inc.	Kitimat, BC	$500 million	0.61	2009	Undergoing federal-provincial environmental assessment. Process commenced August 2004.
TransCanada/Petro-Canada (Cacouna Energy Project)	Gros Cacouna, QC	$660 million	0.50	2009	Undergoing federal-provincial environmental assessment. Process commenced September 2004.
ANNOUNCED PROJECTS					
Westpac Terminals Inc.	Prince Rupert, BC	$200 million	0.30	2009	Project not yet under environmental assessment / regulatory review.
TOTAL CANADA			**4.91**		
Sources: NRCan, industry press, and company websites. **Note:** (1) Integrated petrochemical plant and LNG import terminal.					

Table 8 provides information on the seven LNG import facilities proposed for Canada. While Canada does not yet import LNG, there are numerous proposals to construct LNG import facilities in Atlantic Canada, Quebec and British Columbia, many of which are involved in the environmental assessment (EA) / regulatory review process. The combined send-out capacity of all proposed Canadian LNG import projects is nearly 5 Bcf/d, with costs ranging from CDN $200 – $750 million, depending on the scope and size of the project. Keltic Petrochemicals' LNG proposal for Goldboro, Nova Scotia is estimated to cost CDN $4 billion, but also includes a petrochemical plant, a cogeneration power plant and a new access highway. Other projects not mentioned in the above table are also under consideration, including an LNG import terminal being proposed for Saguenay, Quebec.

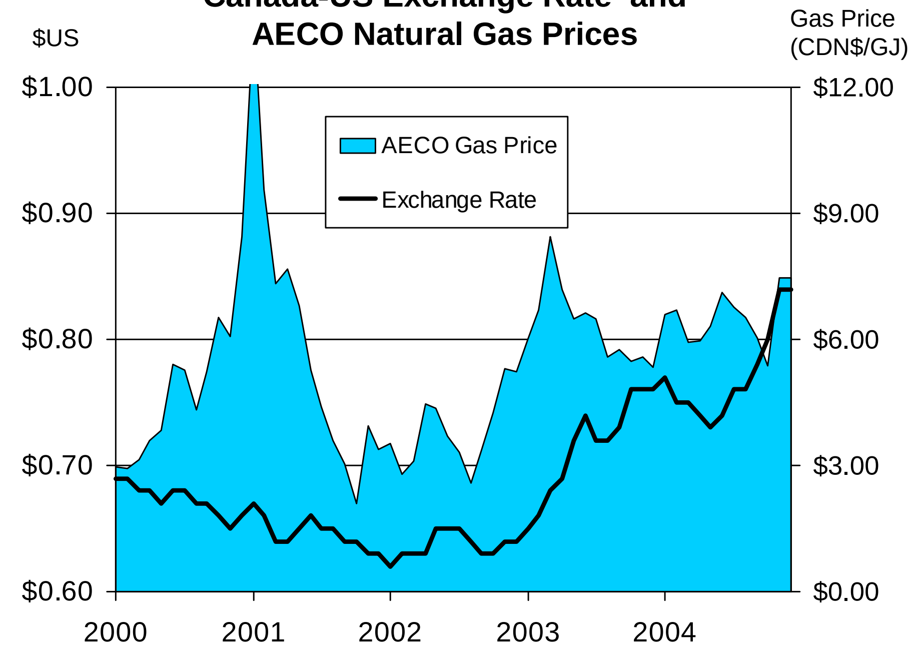
For Canada, LNG facilities would require approximately CDN $500 million each in investment. These facilities would provide a new source of natural gas supply for Canadian consumers and an opportunity for Canadian pipelines to expand. Appendix 3 provides more details on the Canadian LNG import projects.

Figure 33
Canadian Storage Balances



Source: NRCan estimates from Canadian Enerdata

Figure 34
Canada-US Exchange Rate[1] and AECO Natural Gas Prices



Source: GLJ **Note:** (1) U.S. dollars required to purchase one Canadian dollar.

Moderate weather throughout the 2004/2005 storage cycle allowed storage to remain at reasonable levels.

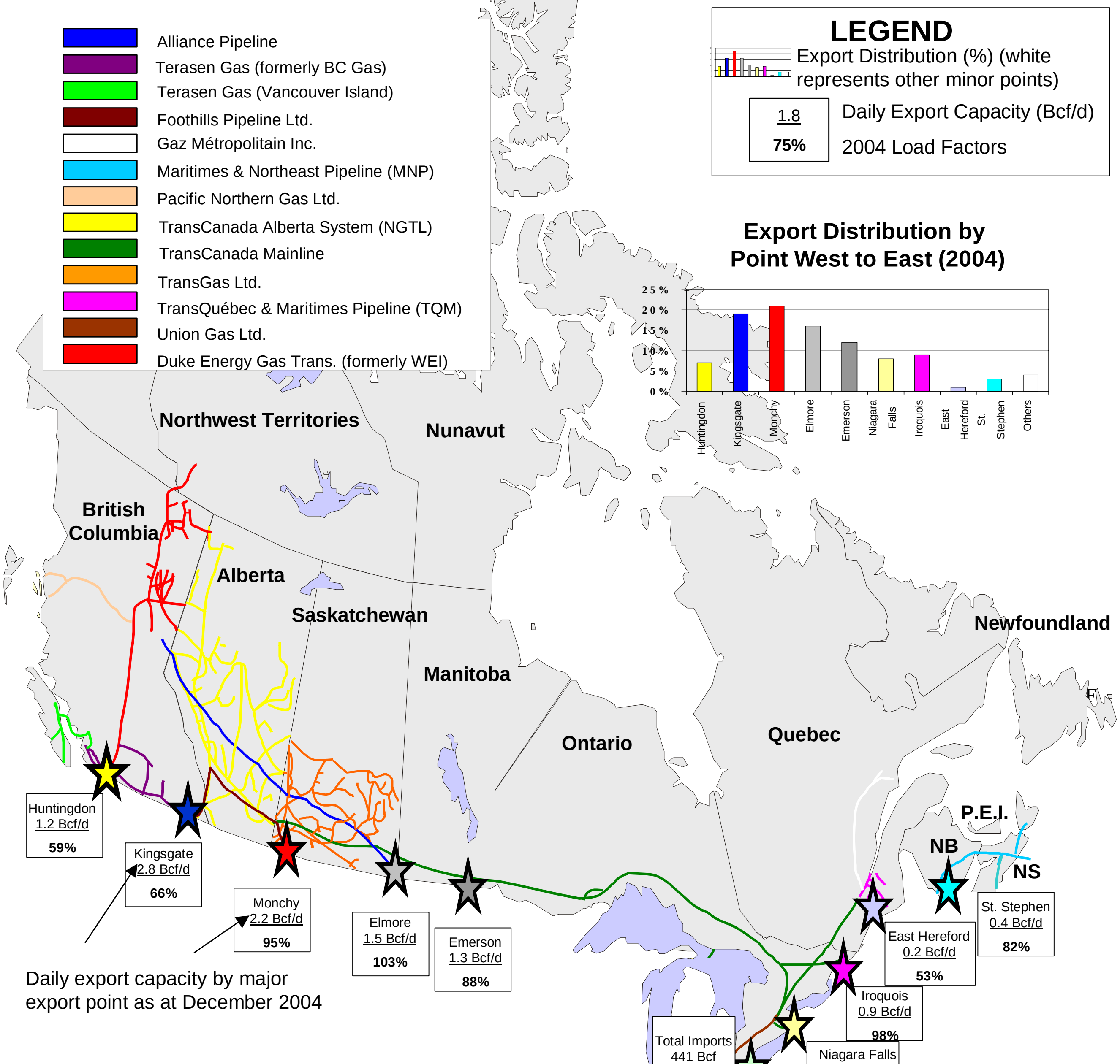
In the summer of 2004, cooler weather across Canada reduced natural gas demand for power generation allowing storage operators to aggressively inject natural gas into storage.

Approaching the 2004/2005 winter heating season, temperatures across Canada remained warm in November, but dipped in December and January, drawing down storage levels. However, high injections during the summer of 2004, allowed storage to remain high. Storage levels as of April 1st 2005, are 130 Bcf, flat compared to April 1st, 2004.

Canadian and US gas markets are highly integrated, with prices generally tracking one another. As a result, fluctuating exchange rates affect Canadian natural gas prices. For several years, the value of the Canadian dollar had been declining relative to the US dollar (up to 2003), in effect, increasing the price for natural gas in Canadian dollars.

However, for the second consecutive year, the appreciation of the Canadian dollar was among the year's most striking economic events in Canada. The Canadian dollar rose, on average, another 5 cents against the US dollar, following a 7-cent increase in 2003. An appreciating Canadian dollar puts downward pressure on Canadian prices. To illustrate, if the Canada-US exchange rate had been equal to the 2000 exchange rate of US$0.67, the average 2004 Canadian natural gas price would have been CDN$7.17/GJ, rather than the CDN$6.52/GJ, as was actually the case.

Map 9
2004 Export Pipeline Capacities and Export Markets



Sources: NEB, GLJ

Map 9 presents the location of major Canadian natural gas transmission infrastructure including Canadian export pipeline capacities at major border points.

Also shown are the average load factors for the year 2004. Load factors are a ratio of the actual amount of natural gas contracted to flow through a pipeline vs. the physical capacity of a pipeline to carry gas. A load factor can exceed 100% as was the case for both Elmore and Niagara Falls in 2004.

In 2004, total gross exports to the US were 3,602 Bcf, an increase of about 3% over 2003.

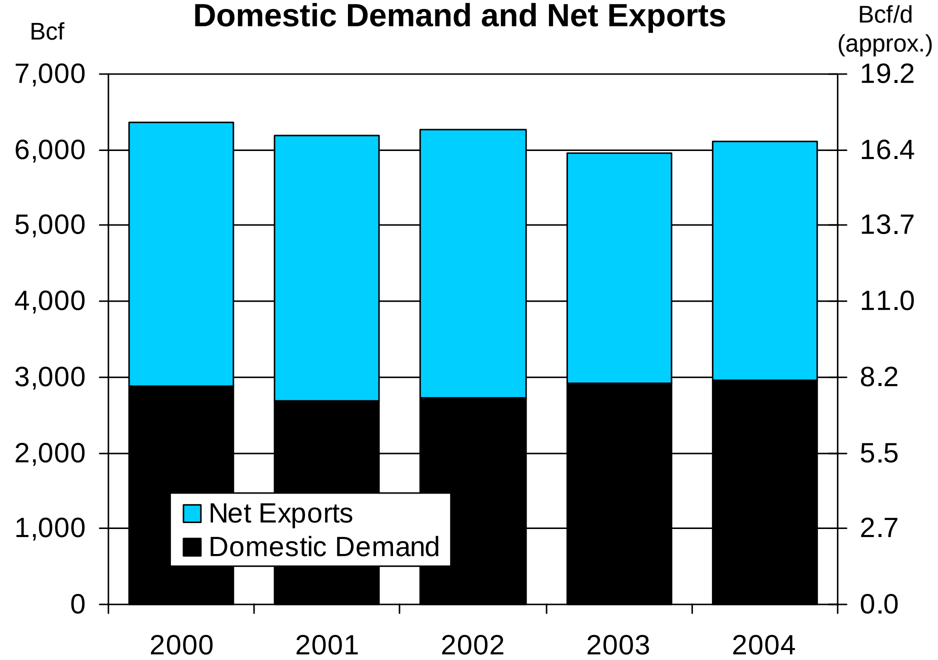
In terms of volumes, the inset chart shows that the majority of natural gas exports occurred at Monchy, Kingsgate, Elmore and Emerson.

Table 9
Domestic Demand and Canadian Exports

	2004 (Bcf)	2003 (Bcf)	2004 vs 2003 (Bcf)	% Change 2004 vs 2003
Gross Exports to US West	937	866	72	8%
Gross Exports to US Midwest	1,776	1,716	60	3%
Gross Exports to US Northeast	890	899	-9	-1%
Total Gross Exports[1]	3,602	3,481	121	3%
Imports from US	441	437	4	1%
Net Exports[2]	**3,161**	**3,044**	**117**	**4%**
Western Canada Demand	1,676	1,582	94	6%
Eastern Canada Demand	1,283	1,342	-59	-4%
Total Canadian Demand	**2,959**	**2,924**	**35**	**1%**
Net Exports	3,161	3,044	117	4%
Canadian Demand	2,959	2,914	45	2%
Total Canadian Gas Sold[3]	**6,120**	**5,958**	**162**	**3%**

Sources: NEB, StatsCan and NRCan estimates. **Notes:** [1] Gross exports are gas flows into the US from Canada which were identified as exports. This differs from some gas going into the US Great Lakes pipeline, which flows uninterrupted back into Canada. This gas is not considered to be an export or an import, rather, it is Canadian gas sold to the domestic market. [2] Net exports are gross exports less imports. [3] Total Canadian gas sold equals net exports plus Canadian demand.

Figure 35
Domestic Demand and Net Exports



Sources: StatsCan, NEB, NRCan estimates

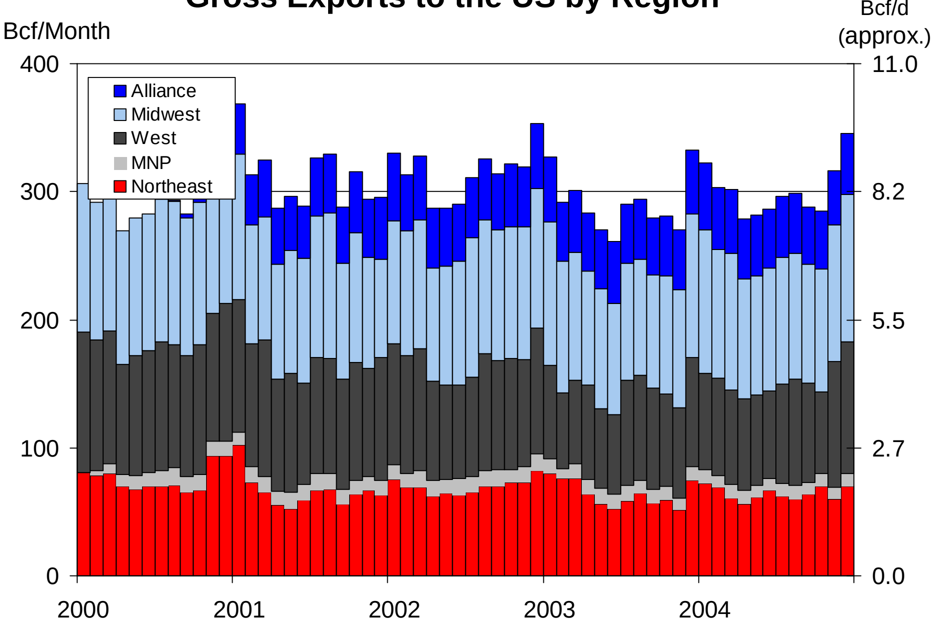
Gross exports to the US increased by 3% while net Canadian natural gas exports increased by 4% in 2004 relative to 2003. While imports increased by 1%, the volumes were not sufficient to dampen export growth. The most pronounced growth in exports occurred in the US west where volumes increased by 8% or 72 Bcf. This is consistent with increased demand in the US west.

Overall, Canadian natural gas demand increased by 1%. Increased western Canadian natural gas demand was partially offset by reduced eastern Canadian natural gas demand in 2004.

Total Canadian natural gas sold increased by 3%, recovering from the 4% reduction posted in 2003. In 2004, both domestic demand and net exports increased by 1% and 4% respectively relative to 2003.

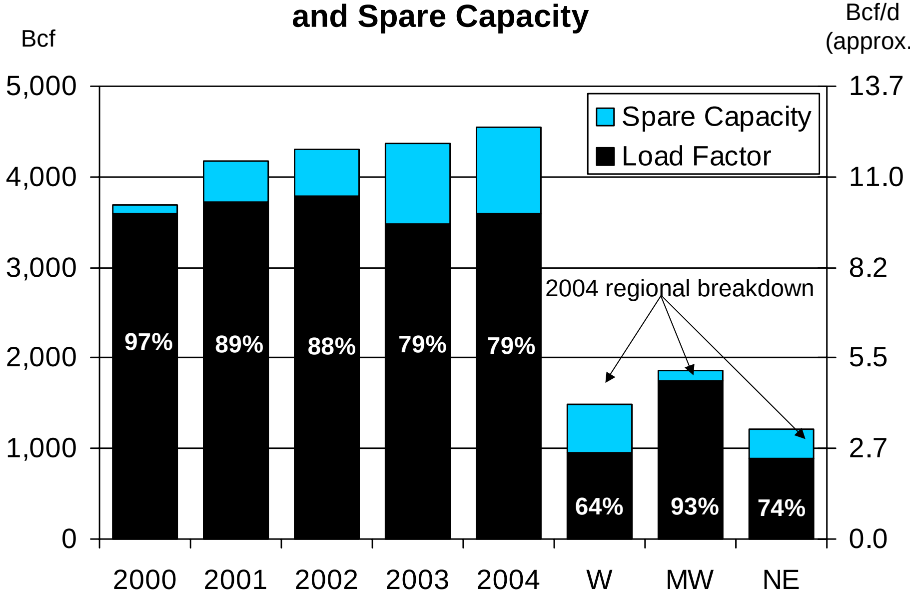
Canada remains a strong exporter of natural gas to the US with net exports accounting for 52% of total Canadian natural gas sold and nearly 16% of US natural gas demand.

Figure 36
Gross Exports to the US by Region



Source: NEB **Note:** Northeast exports exclude the volumes exported through the MNP pipeline. Midwest exports exclude the volumes exported through the Alliance pipeline.

Figure 37
Canadian Export Pipeline Load Factor and Spare Capacity



Source: GLJ

Natural gas exports continue to demonstrate seasonal variation by peaking in the heating months and generally reaching their lowest levels in the warmer summer and shoulder months (April and November).

Relative to 2003, exports to the US have been trending slightly downwards on the Maritimes and Northeast Pipeline (MNP). Alliance Pipeline continues to maintain relatively steady volumes due to their long-term contracts for capacity.

Exports to the US west and midwest regions trended upwards relative to 2003. This is consistent with US demand figures, which show considerably increased demand in the US west, largely to fuel gas-fired power generators.

Figure 37 shows contracted Canadian exports relative to export capacity for the years 2000 through to 2004. While export capacity has been increasing over the years, so too has spare capacity. Increased exports in 2004 did not affect the overall load factor for Canadian export pipelines on account of increasing overall capacity.

Most of the increased exports in 2004 took place in the US west. The 2004 load factor in the west jumped from 51% in 2003 to 64% in 2004.

Atlantic Canada maintains considerable spare capacity, particularly at East Hereford and St. Stephen.

Table 10
Domestic and International Border Export Prices

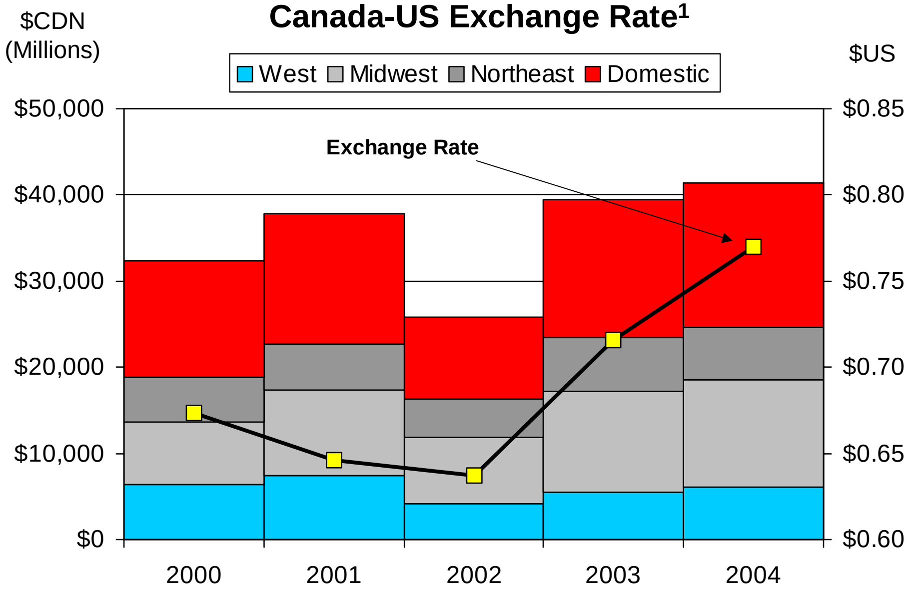
		International Border Export Prices				US Prices	Canadian Markets			
Year	**Month**	**West $US/MMBtu**	**MW $US/MMBtu**	**NE $US/MMBtu**	**Average $US/MMBtu**	**NYMEX $US/MMBtu**	**AECO $Cdn/GJ**	**AECO $US/MMBtu**	**Huntingdon $US/MMBtu**	**Westcoast St 2 $US/MMBtu**
2002		**$2.72**	**$3.13**	**$3.49**	**$3.07**	**$3.22**	**$3.83**	**$2.57**	**$2.68**	**$2.56**
2003		**$4.70**	**$5.13**	**$5.46**	**$5.10**	**$5.39**	**$6.31**	**$4.75**	**$4.66**	**$4.53**
2004	January	$5.23	$5.82	$6.68	$5.91	$6.15	$6.58	$5.36	$5.20	$4.99
	February	$4.97	$5.47	$6.14	$5.53	$5.77	$6.70	$5.32	$5.20	$4.99
	March	$4.68	$4.98	$5.52	$5.06	$5.15	$5.93	$4.71	$4.42	$4.21
	April	$4.68	$5.11	$5.69	$5.16	$5.37	$5.95	$4.73	$4.51	$4.30
	May	$4.93	$5.46	$5.85	$5.41	$5.94	$6.33	$4.98	$5.02	$4.82
	June	$5.32	$5.96	$6.45	$5.91	$6.68	$7.12	$5.45	$5.58	$5.38
	July	$5.24	$5.77	$6.19	$5.73	$6.14	$6.78	$5.27	$5.20	$4.99
	August	$5.11	$5.53	$5.93	$5.52	$6.05	$6.51	$5.19	$5.34	$5.13
	September	$4.63	$4.84	$5.04	$4.83	$5.08	$6.02	$4.84	$4.56	$4.34
	October	$4.68	$5.21	$5.49	$5.13	$5.72	$5.38	$4.41	$4.65	$4.43
	November	$6.19	$7.08	$6.66	$6.64	$7.63	$7.48	$6.32	$7.18	$6.95
	December	$6.22	$6.89	$7.25	$6.78	$7.98	$7.46	$6.58	$6.23	$6.00
2004	**Average**	**$5.15**	**$5.68**	**$6.07**	**$5.64**	**$6.14**	**$6.52**	**$5.26**	**$5.26**	**$5.04**
2003	**Average**	**$4.70**	**$5.13**	**$5.46**	**$5.10**	**$5.39**	**$6.31**	**$4.75**	**$4.66**	**$4.53**
2003/04	**% Change[1]**	**10%**	**11%**	**11%**	**11%**	**14%**	**3%**	**11%**	**13%**	**11%**

Sources: GLJ, NEB, NRCan estimates **Notes:** [1] Annual percentage change of prices between the years 2003 and 2004.

International border export prices are closely correlated to the NYMEX price. As NYMEX natural gas prices increased (14%) in 2004 compared to 2003, so did the Canadian international border export prices (11%). Export prices are lowest in the producing region of western Canada and highest in the consuming and sometimes pipeline-constrained northeast.

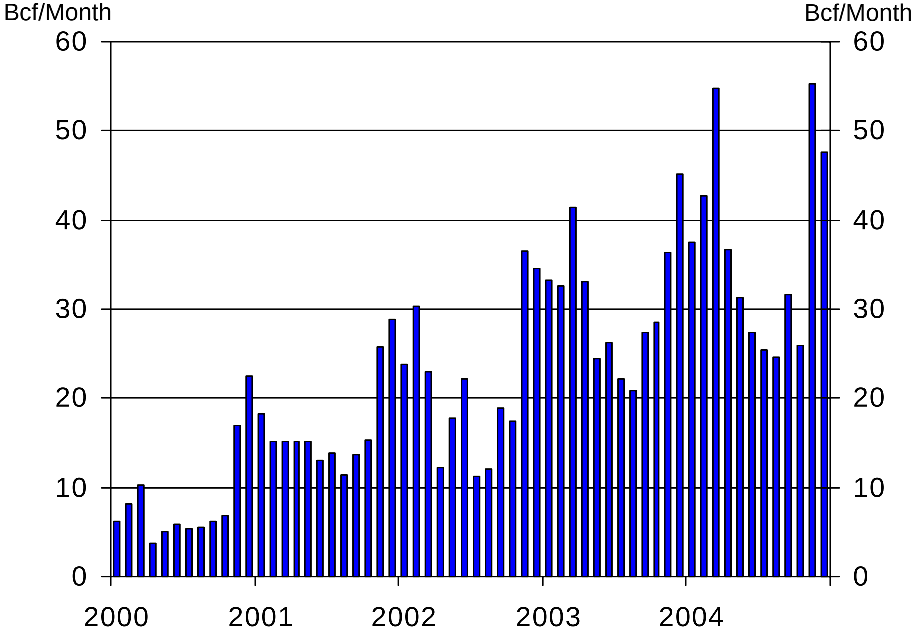
In 2004, the AECO natural gas price averaged CDN$6.52/GJ, with a low of $5.38/GJ and a high of $8.78/GJ. AECO spot prices were 3% higher in 2004 relative to 2003. While the price of natural gas in Canadian dollars only increased by about 3% in 2004, the effect was much more significant once the appreciating dollar is taken into account. AECO prices in $US/MMBtu increased by 11% in 2004.

Figure 38
Export Plantgate Revenues vs. Canada-US Exchange Rate[1]



Sources: GLJ, NEB. **Note:** (1) U.S. dollars required to purchase one Canadian dollar.

Figure 39
Canadian Natural Gas Imports



Source: NEB

2004 natural gas plant gate export revenues set a new record by posting revenues of approximately CDN $24.7 billion and domestic sales of CDN $16.8 billion. Total revenues were supported by increased exports and strong natural gas prices.

Export revenues were negatively impacted by an appreciating Canadian dollar. In 2004, the value of the Canadian dollar averaged US $0.77. As the Canadian dollar appreciates relative to the US dollar, as it did in 2003 and 2004, exporters receive less revenue for their natural gas when the revenue is converted to Canadian currency. However, the US' robust demand for Canadian natural gas, combined with strong natural gas prices more than offset any decline in producer revenue that occurred as a result of the appreciating Canadian dollar.

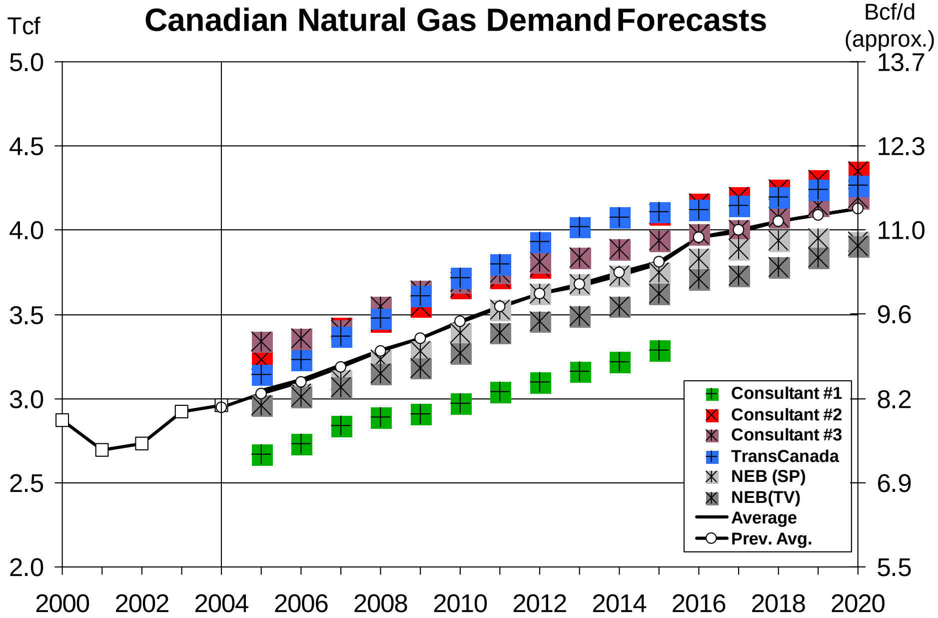
Figure 39 shows trends for Canadian natural gas imports. Natural gas is imported into Canada primarily though Courtright and St. Clair import points in southern Ontario. These points averaged 652 MMcf/d and 223 MMcf/d respectively in 2004. In recent years Canadian imports have been climbing for various reasons. The Dawn trading hub located in Chatham, Ontario, provides shippers with numerous options for the sale of their natural gas. Liquidity of trade is preferred by shippers and numerous transportation routes exist to ship natural gas to Dawn. Also, since 2000, the Alliance pipeline has provided an alternative to TransCanada's Canadian Mainline for delivering gas to Southern Ontario via Chicago.

Natural gas imports in 2004 were relatively flat compared to 2003, increasing by only 1% from 437 to 441 Bcf.

Part II: Canadian Natural Gas Market

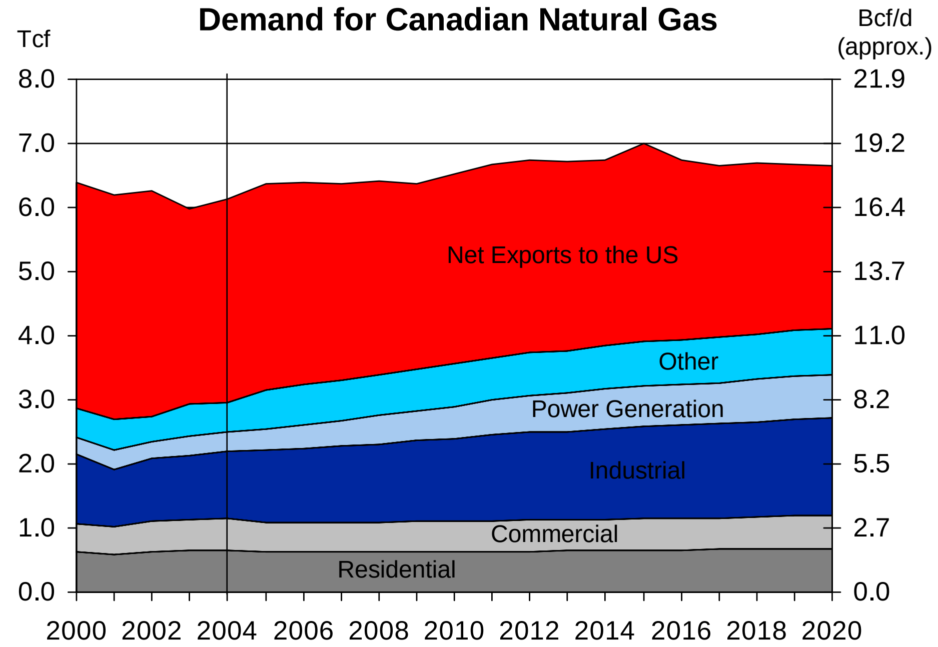
›› Outlook to 2020

Figure 40
Canadian Natural Gas Demand Forecasts



Sources: NEB, TransCanada and various consultants. **Notes:** (1) Historical numbers from StatsCan. (2) TransCanada's demand forecast includes NGL extraction at the Alberta straddle plants.

Figure 41
Demand for Canadian Natural Gas



Sources: NEB, TransCanada, and various consultants. **Notes:** (1) Represents an average or "consensus" view of forecasts of various organizations. (2) Historical numbers from StatsCan and NEB.

Figure 40 displays six forecasts of Canadian natural gas demand, along with the average of the forecasts, as well as the average from last year.

The average of the forecasts shows Canadian natural gas demand at about 4.1 Tcf by 2020. This represents an annual growth rate of about 2.1% per year over the entire forecast period.

The "consensus" view is unchanged from the previous year's forecast, which also showed Canadian natural gas demand at 4.1 Tcf in 2020. This is different than the US, where the long-term natural gas demand forecasts have been revised downwards.

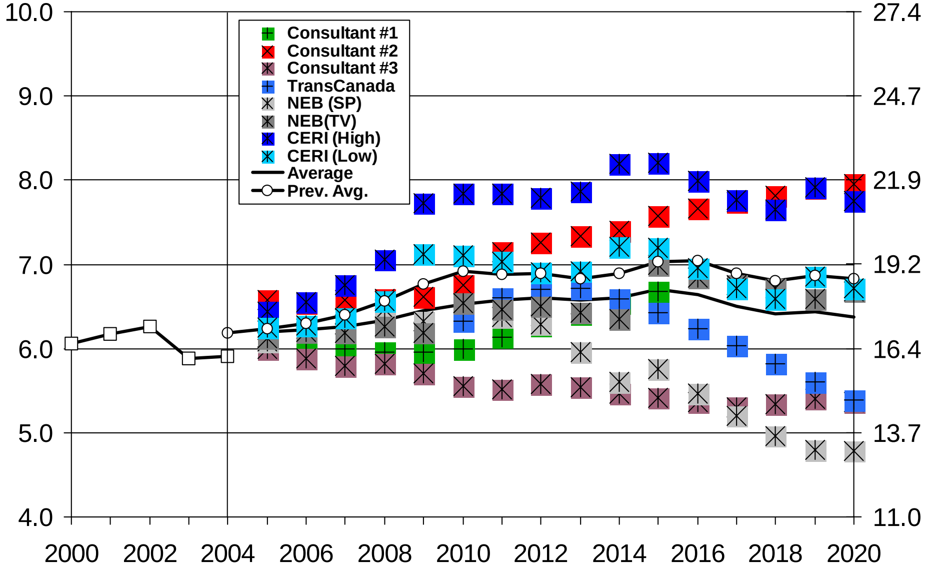
Figure 41 displays an average or "consensus" view regarding the future demand for Canadian natural gas by sector.

Total domestic demand is expected to reach approximately 3 Tcf by 2005, 3.5 Tcf in 2010, 3.8 Tcf in 2015 and 4.1 Tcf in 2020. Increasing demand is expected to be largely driven by growth in Alberta's energy intensive industrial sector and power generation in Alberta and Ontario.

According to the "consensus" view, Canadian natural gas exports to the US are not expected to grow significantly over the forecast period, hovering between 2.5 and 3.2 Tcf.

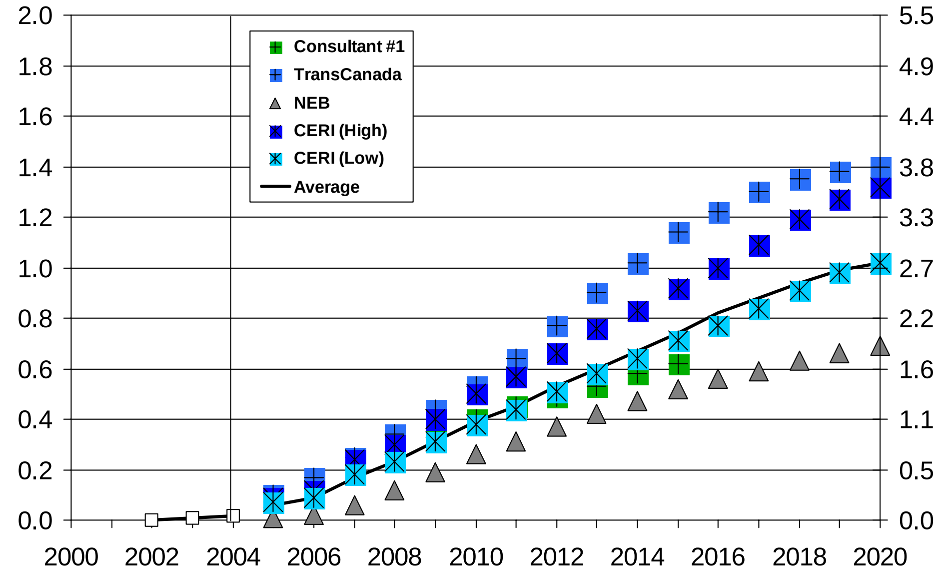
Total demand for Canadian gas is expected to reach 6.7 Tcf by 2020, 10% greater than actual demand levels in 2004.

Figure 42
Canadian Natural Gas Production Forecasts



Sources: NEB, CERI, TransCanada and various consultants. **Note:** Historical numbers from StatsCan.

Figure 43
Western Canada Coalbed Methane Production Forecasts



Sources: NEB, CERI, TransCanada, consultant and industry press. **Note:** Historical numbers from StatsCan.

Figure 42 shows eight forecasts of Canadian natural gas production. Canadian production includes: Western Canadian conventional and unconventional natural gas; Atlantic Canada; and, Mackenzie Delta natural gas. The average of the forecasts shows Canadian production hovering between 6 and 7 Tcf over the forecast period, reaching 6.4 Tcf by 2020. This represents an annual average increase of only 0.2%.

The average of the previous year's forecast showed Canadian natural gas production at about 6.8 Tcf in 2020, about 6% greater than the current forecast at 2020.

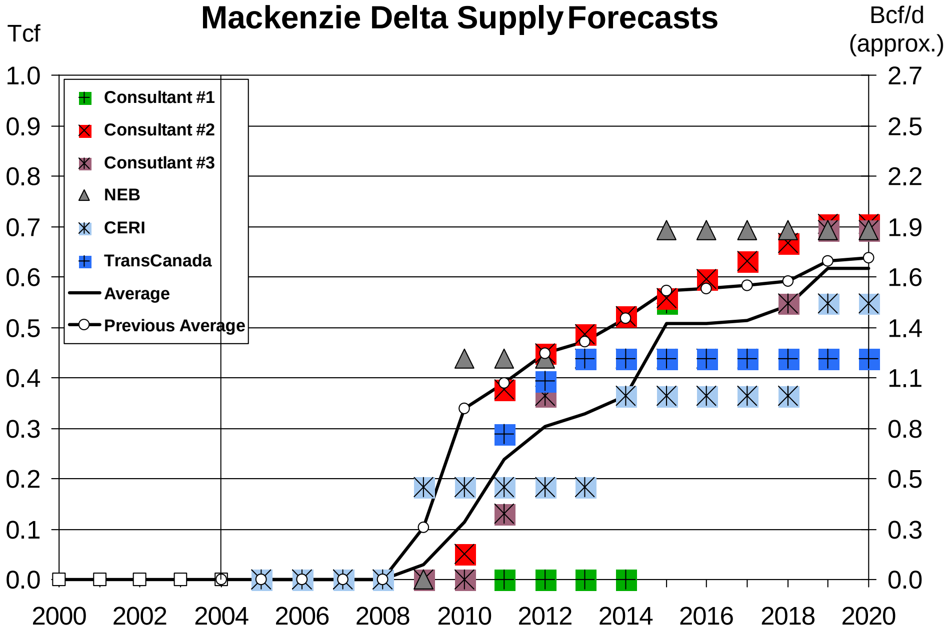
This range in forecasts suggests uncertainty about Canada natural gas production among industry observers.

Figure 43 shows six forecasts of western Canada coalbed methane production.

CBM production at year end 2004 was approximately 125 MMcf/d. The average of the forecasts shows western Canada coalbed methane production reaching 1 Tcf or 2.7 Bcf/d by 2020. This represents an average annual increase of about 20% over the entire forecast period.

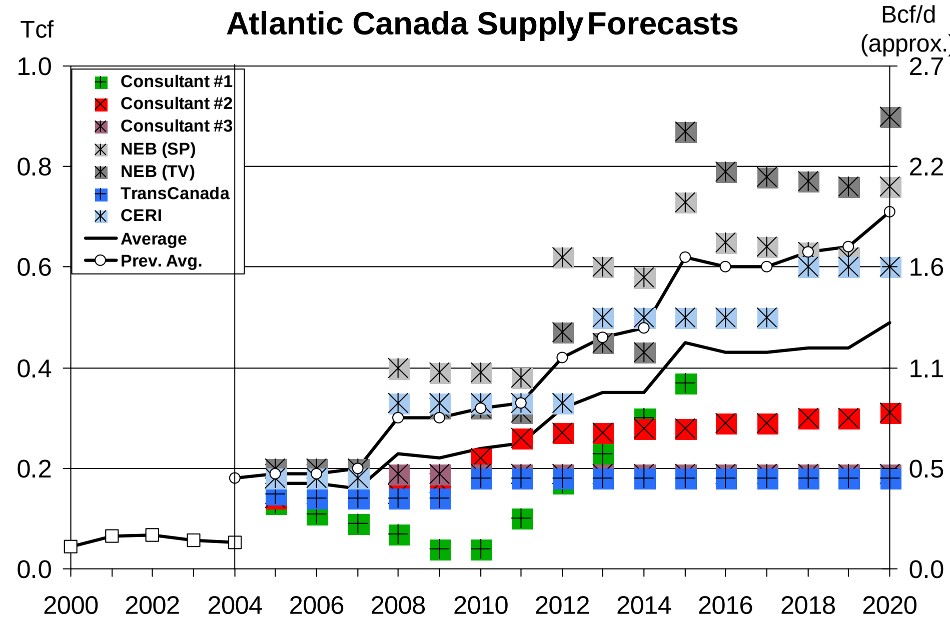
CBM is expected to become increasingly important to the Canadian natural gas production mix. Given that the "consensus" view shows total Canadian natural gas production to be 6.4 Tcf by 2020, CBM production is expected to account for approximately 16% of total natural gas production in 2020.

Figure 44
Mackenzie Delta Supply Forecasts



Sources: NEB, CERI, TransCanada, and various consultants.

Figure 45
Atlantic Canada Supply Forecasts



Sources: NEB, CERI, TransCanada and various consultants. **Note:** Historical numbers from CNSOPB.

Figure 44 shows six forecasts of Mackenzie Delta gas supply, as well as the average forecast and the previous year's average.

Of the forecasts surveyed, the earliest Mackenzie Delta gas supplies would arrive is 2009. Given the current status of the project, the first natural gas is not expected to flow until 2011. The average of the forecasts shows Mackenzie Delta gas supply at about 0.62 Tcf, or 1.7 Bcf/day by 2020.

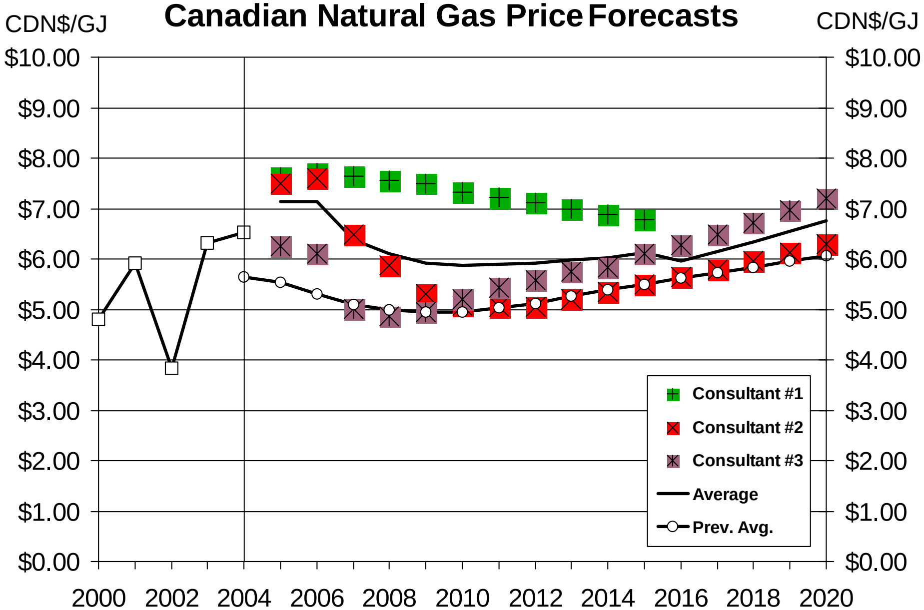
The average of the previous year's forecast showed Mackenzie Delta natural gas production at about 0.64 Tcf, or 1.8 Bcf/day by 2015, slightly more than the current forecast at 2020.

The forecasts shows a "consensus" that Mackenzie Delta natural gas supply will arrive, but there is uncertainty regarding its timing.

Figure 45 shows seven forecasts of Atlantic Canada natural gas production, as well as the average forecast and the previous year's average. In this figure, Atlantic Canada is defined to include: offshore Nova Scotia (Sable and its surroundings, Deep Panuke, deep offshore), onshore Nova Scotia and New Brunswick, and Newfoundland.

The average of the forecasts shows Atlantic Canada natural gas supply at about 0.5 Tcf by 2020. This is a downward revision in expectations compared to last year's average.

Figure 46
Canadian Natural Gas Price Forecasts



Source: Various consultants. **Notes:** (1) Historical are AECO actuals from GLJ. (2) Forecast prices are AECO. (3) Some forecasts were converted from $US to $CDN using an exchange rate of US $1.00 to CDN $1.30 over the entire forecast period. (4) Nominal dollars.

Figure 46 compares three nominal dollar forecasts of Canadian natural gas prices at the AECO-C hub in Alberta.

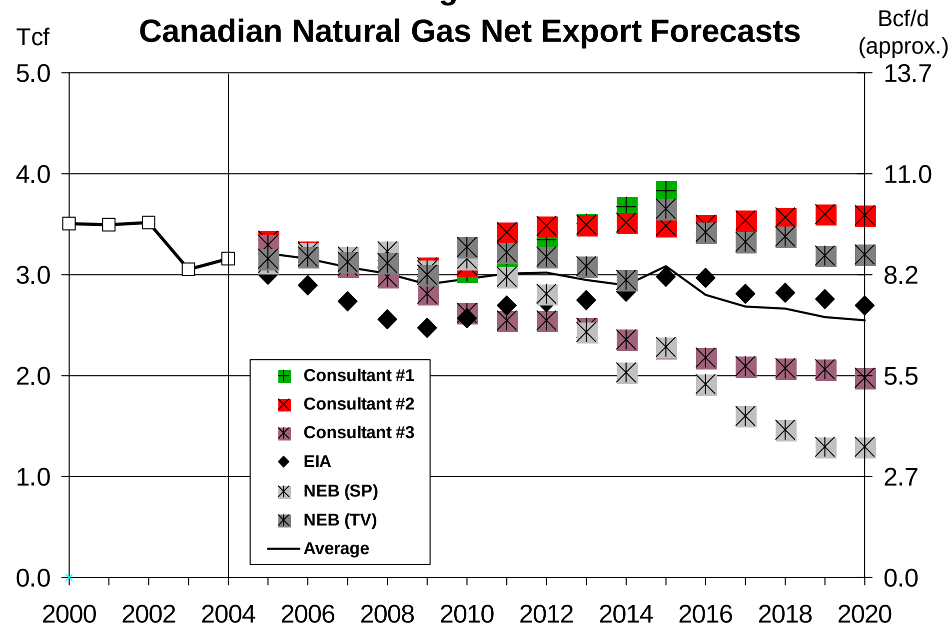
In 2004, the Canadian natural gas price was CDN $6.52/GJ. Prices are expected to average approximately CDN $7.15/GJ in 2005, gradually falling until 2009. After 2009, prices are expected to hover between CDN $5.90 and $6.80/GJ through to 2020.

The average forecast for 2015 and 2020 sees natural gas prices at CDN $6.12/GJ and CDN $6.76/GJ, respectively.

The average of the previous year's forecast showed prices at CDN $6.10/GJ in 2020, 11% less than the current forecast at 2020.

According to the forecasters surveyed, between 2005 and 2020, Canadian natural gas prices are expected to average CDN $6.30/GJ.

Figure 47
Canadian Natural Gas Net Export Forecasts



Sources: EIA, NEB, and various consultants. **Notes:** (1) NEB export forecasts were deduced from Canadian natural gas production and demand projections contained within the NEB's *Canada's Energy Future: Scenarios for Supply and Demand to 2025*, July 2003. (2) Historical numbers from NEB.

Figure 47 shows five forecasts of Canadian natural gas exports, including the "consensus" view or average of the different forecasts.

In 2004, Canada's natural gas net exports to the US were about 3.2 Tcf. The "consensus" view shows Canadian natural gas net exports falling to about 3.0 Tcf by 2010, then hovering in that range to 2015, before declining to 2.5 Tcf by 2020. This represents a decline of 0.7 Tcf, or about 22%, when compared to actual 2004 Canadian natural gas net exports to the US.

The "consensus" view of declining natural gas net exports over the forecast period is a result of expectations that Canada's domestic natural gas consumption will increase more rapidly than its production.

Table 11
Export Volumes and Domestic Sales

(Bcf)	2000	2001	2002	2003	2004	2005	2010	2015	2020
Huntingdon (Westcoast)	356	324	335	304	263	-	-	-	-
Kingsgate (TCPL)	833	781	696	562	674	-	-	-	-
Total US West	**1,189**	**1,105**	**1,031**	**866**	**937**	**-**	**-**	**-**	**-**
Monchy (TCPL)	784	744	768	763	759	-	-	-	-
Emerson (TCPL)	491	390	397	362	417	-	-	-	-
Elmore (Alliance)	73	526	568	567	565	-	-	-	-
Miscellaneous	30	31	37	24	35	-	-	-	-
Total US Midwest	**1,378**	**1,691**	**1,770**	**1,716**	**1,776**	**-**	**-**	**-**	**-**
Iroquois (TCPL)	363	319	323	323	326	-	-	-	-
Niagara Falls (TCPL)	423	326	327	288	302	-	-	-	-
Chippawa (TCPL)	37	54	104	81	74	-	-	-	-
St. Stephen (MNP)	117	141	143	130	119	-	-	-	-
East Hereford (TCPL)	34	39	48	45	38	-	-	-	-
Cornwall (TCPL)	8	9	8	7	8	-	-	-	-
Napierville (TCPL)	19	33	19	19	18	-	-	-	-
Phillipsburg (TCPL)	8	6	7	6	5	-	-	-	-
Highwater (TCPL)	15	5	0	0	0	-	-	-	-
Total US Northeast	**1,024**	**932**	**979**	**899**	**890**	**-**	**-**	**-**	**-**
Total Gross Exports	**3,591**	**3,728**	**3,780**	**3,481**	**3,602**	**3,625**	**3,306**	**3,292**	**2,983**
Total Canadian Demand	**2,872**	**2,697**	**2,736**	**2,925**	**2,959**	**3,049**	**3,451**	**3,803**	**4,131**
Imports to Canada[1]	**80**	**228**	**260**	**437**	**441**	**400**	**400**	**400**	**400**
Total Net Exports	**3,511**	**3,500**	**3,520**	**3,044**	**3,161**	**3,225**	**2,906**	**2,892**	**2,583**
Total Domestic Sales[2]	**2,792**	**2,469**	**2,476**	**2,488**	**2,518**	**2,649**	**3,051**	**3,403**	**3,731**
Total Sales[3]	**6,383**	**6,197**	**6,256**	**5,969**	**6,120**	**6,274**	**6,357**	**6,695**	**6,715**

Sources: NEB, StatsCan, TransCanada, CERI, and various consultants. **Notes:** [1] Imports are assumed to equal 400 Bcf per year over the forecast period. [2] Domestic sales equal to Canadian demand less imports. [3] Total sales equals gross exports plus domestic gas sales.

In 2004, Canadian natural gas demand was 2.9 Tcf, while Canada exported (net) about 3.2 Tcf to the US, for a total sales figure of 6.1 Tcf. Our export forecast is determined using "consensus" forecasts of Canadian demand and production. Gross exports decline over the forecast period, falling to about 3 Tcf by 2020. Although gross export volumes are forecast to decline, higher domestic sales over the forecast period result in a total sales figure of 6.7 Tcf in 2020, 10% higher than actual sales in 2004. According to the "consensus" forecast, natural gas exports will account for 44% of total sales in 2020, compared to 58% in 2004. In other words, less Canadian natural gas supply is expected to be exported to the US, while more will be consumed domestically.

Table 12
Export and Domestic Revenue Forecast

EXPORT SALES:	Gross Export Volumes (Bcf)	US NYMEX Price (US$/MMBtu)	Export International Border Price (US$/MMBtu)	Export Plant Gate Netback (US$/MMBtu)	Export Plant Gate Revenues (Million $US)	Export Plant Gate Revenues (Million $CDN)
2001	3,728	$4.27	$4.30	$3.94	$14,797	$22,759
2002	3,780	$3.22	$3.06	$2.72	$10,353	$16,248
2003	3,481	$5.39	$5.12	$4.74	$16,622	$23,414
2004	3,602	$6.30	$5.64	$5.29	$19,039	$24,659
2005	3,625	$6.27	$6.17	$5.87	$21,279	$27,280
2010	3,356	$5.23	$5.13	$4.83	$16,209	$20,781
2015	3,482	$5.70	$5.60	$5.30	$18,455	$23,660
2020	2,951	$6.46	$6.36	$6.06	$17,883	$22,927

DOMESTIC SALES:	Domestic Sales (Bcf)	Alberta Price (US$/MMBtu)	PlantGate Netback (US$/MMBtu)	Domestic Plant Gate Revenues (Million $US)	Domestic Plant Gate Revenues (Million $CDN)	**TOTAL Plant Gate Revenues** (Million $CDN)
2001	2,469	$4.05	$3.90	$9,688	$15,001	**$37,760**
2002	2,476	$2.58	$2.43	$6,054	$9,504	**$25,752**
2003	2,488	$4.75	$4.60	$11,519	$16,094	**$39,508**
2004	2,518	$5.30	$5.15	$12,968	$16,810	**$41,469**
2005	2,649	$5.78	$5.63	$14,914	$19,120	**$46,401**
2010	3,051	$4.76	$4.61	$14,065	$18,032	**$38,814**
2015	3,403	$4.97	$4.82	$16,402	$21,029	**$44,689**
2020	3,731	$5.48	$5.33	$19,886	$25,495	**$48,422**

Source: Historical export information is from NEB data. **Notes:** Historical domestic netbacks are estimates only, and were calculated using Alberta prices, less US $0.15/MMBtu to yield a plantgate netback, which was then multiplied by domestic sales for a revenue estimate. Future domestic netbacks and revenues use forecast Alberta prices and were calculated similarily. Future export netbacks were assumed to equal forecast NYMEX prices less US$0.40/MMBtu. Resultant netback multiplied by forecast export sales. Exchange rate conversions assume $US0.78 per $CDN for the entire forecast period. Domestic sales assumed to equal Canadian demand less imports. Imports are assumed to equal 400 Bcf per year over the entire forecast period.

Table 12 provides estimates of producer revenues to 2020, given "consensus" forecasts of natural gas prices, gross export volumes and domestic sales.

For the second consecutive year, total plant gate revenues reached record levels in 2004 – about CDN $41.5 billion. This represents a significant increase of about 240% when compared with 1997 revenues of CDN $12.1 billion. According to price and volume forecasts, producer revenues will surpass 2004 levels, reaching about CDN $48.4 billion by 2020.

Part III: United States Natural Gas Market

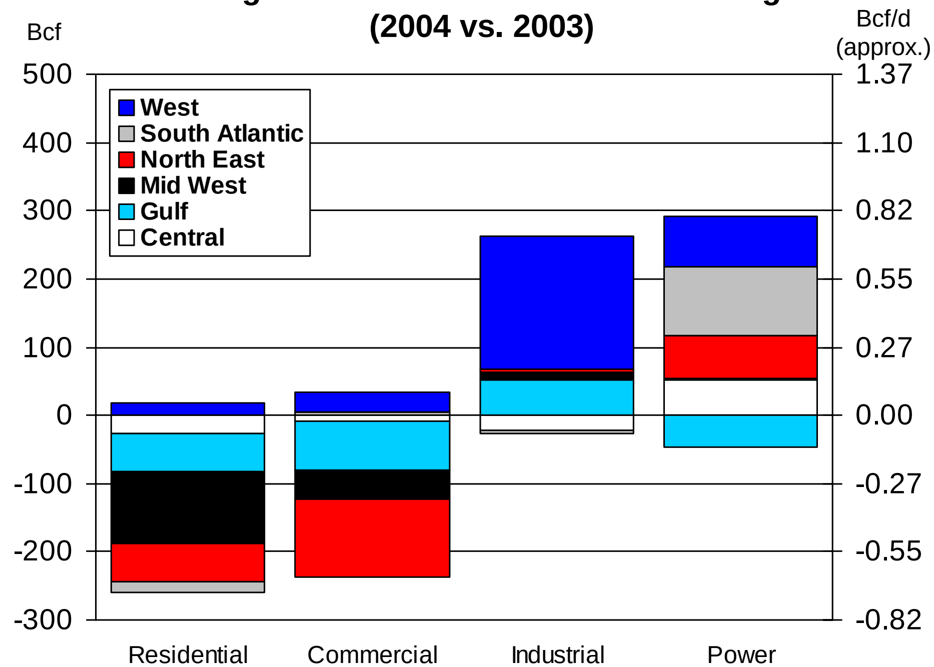
›› Review of 2004

Table 13
US Natural Gas Demand

Sector	2004	2003	2002	2001	2000
Bcf:					
Residential	4,879	5,078	4,889	4,771	4,996
Commercial	2,984	3,217	3,144	3,023	3,182
Industrial	7,399	7,139	7,507	7,344	8,142
Power	5,352	5,135	5,672	5,342	5,206
Other	1,802	1,806	1,795	1,758	1,806
Total	22,416	22,375	23,007	22,239	23,333
Percentage:					
Residential	22%	23%	21%	21%	21%
Commercial	13%	14%	14%	14%	14%
Industrial	33%	32%	33%	33%	35%
Power	24%	23%	25%	24%	22%
Other	8%	8%	8%	8%	8%

Source: EIA **Note:** Other includes natural gas plant use, and pipeline transmission and distribution

Figure 48
US Regional and Sectoral Demand Changes
(2004 vs. 2003)



Source: EIA

In 2004, US natural gas demand increased by 0.2% from 22.3 Tcf to to 22.4 Tcf. The industrial and power generation sectors were responsible for the majority of these increases.

Looking back over the past 5 years, natural gas demand by sectors has been relatively constant for the core sectors of residential and commercial. However industrial demand has declined since about 2001, largely in response to higher gas prices. In 2004, industrial natural gas demand increased 260 Bcf or 4% compared to 2003.

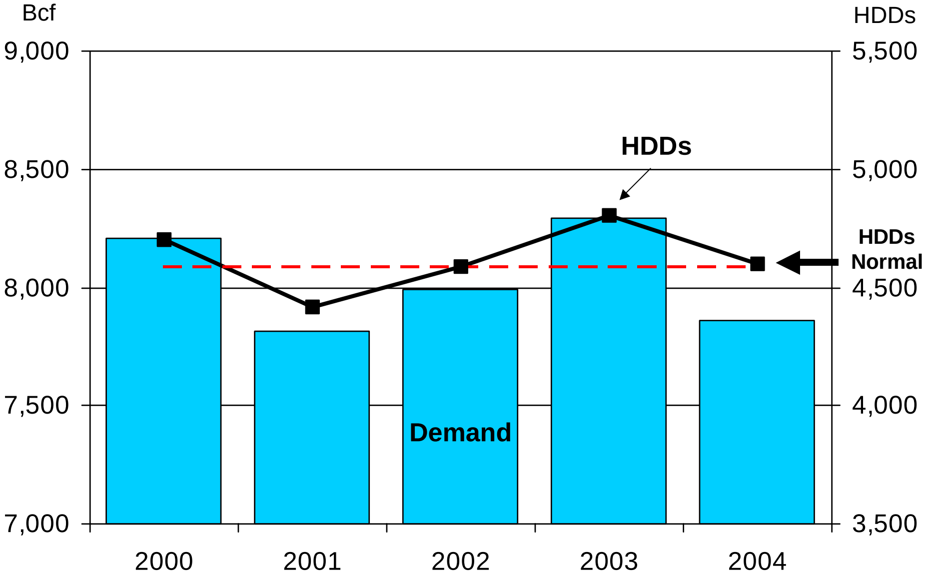
Figure 48 provides detail on the specifics of the marginal increased demand for natural gas in the US in 2004. Both the core sectors demanded less gas in 2004 than in 2003. This is largely a reflection of more moderate temperatures in both the summer cooling and the winter heating seasons.

However, the industrial and power generation sectors more than offset the core demand losses by posting fairly significant increases. The US west accounted for much of the increased demand, both on the industrial and power generation fronts. The trend towards increased gas for power is clearly seen in most regions of the US.

The pronounced increase in natural gas demand in the west is consistent with increased Canadian exports to that region.

Figure 49

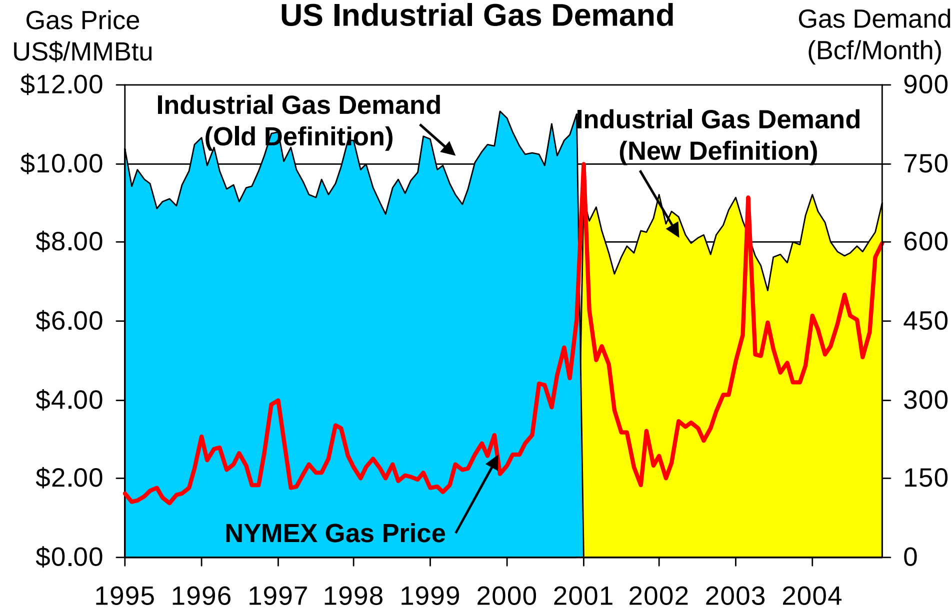
US Heating Degree Days and Core Demand



Sources: EIA, NOAA

Figure 50

NYMEX Natural Gas Prices vs. US Industrial Gas Demand



Sources: EIA, GLJ. **Note:** In April 2003, the EIA revised its industrial demand definitions, retroactive to January 2001.

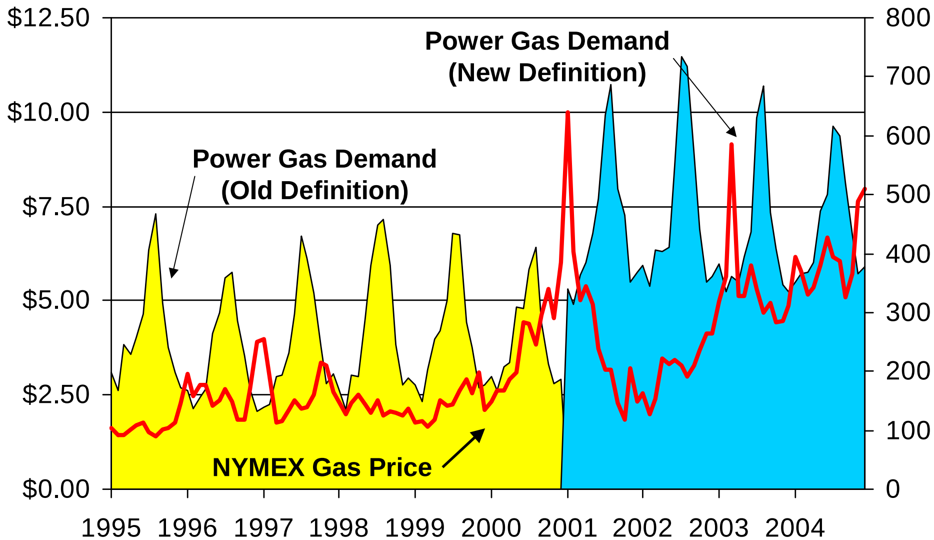
Figure 49 displays the correlation between core demand and HDDs in the US. The dashed red line represents the 'normal' number of HDDs, which is the average HDD value over a fixed standard period of years. The 'normal' number of HDDs is 4,588, derived using 1990-2000 as the fixed time period.

In 2004, HDDs and core demand were, once again closely correlated, as core demand decreased by 5% and HDDs decreased by 4%. There were 4,597 HDD's in the US in 2004, only 9 more than normal, but 209 less than in 2003.

Figure 50 shows monthly US industrial natural gas demand data. In April 2003, the EIA radically changed its industrial gas demand definition and statistics retroactive to 2001, causing the volumes consumed to be smaller than previously reported. Industrial natural gas demand now excludes combined heat and power applications whose primary business is to sell electricity to consumers.

Industrial natural gas demand was 7,399 Bcf in 2004, posting a gain of 260 Bcf or 3.6% over 2003 levels, despite even higher natural gas prices. At least to some extent, the demand destruction that has occurred since 2001 as a result of higher natural gas prices appears to be slowing down, or even reversing, as the remaining industrial natural gas base becomes even more efficient with their natural gas use.

Figure 51
NYMEX Natural Gas Prices vs. US Power Generation Gas Demand



Sources: EIA, GLJ **Note:** In April 2003, the EIA revised its EG demand definitions, retroactive to January 2001.

Table 14
US Electric Generation (GWhrs)

Industry	Year 2004	2003	2002	2001	% Change from 2003	2004 % Share of Generation
Coal	1,976	1,974	1,933	1,904	0%	50%
Oil	99	103	95	125	-4%	3%
Natural Gas	700	650	691	639	8%	18%
Other Gas[1]	15	16	11	9	-4%	0%
Nuclear	789	764	780	769	3%	20%
Hydro	270	276	256	208	-2%	7%
Renewables	89	87	87	78	2%	2%
Other	16	14	6	5	13%	0%
Total	**3,953**	**3,883**	**3,858**	**3,737**	**1.8%**	**100%**

Source: EIA, **Notes:** [1]Other gas includes blast furnace gas, propane, and other manufactured waste gases derived from fossil fuels.

Figure 51 shows monthly natural gas demand for power generation in the US. In April 2003, the EIA changed its power generation definition and statistics, retroactive to 2001. The new definition attributes more natural gas demand to the power generating sector as it now includes the gas used by industrial power plants that identify themselves as producing mainly power, rather than heat. This was previously reported as natural gas demand in the industrial sector.

Natural gas for power generation continues to peak in the summer months reflecting increased power demand for air conditioning loads. In 2004, US power generation gas demand was 5,352 Bcf, an increase of 217 Bcf, or 4% over 2003 levels.

Total power generation in the US increased by 2% between 2003 and 2004. The generation fuel mix has remained relatively stable in recent years. While natural gas provides about 18% of total power generation in the US, power generation continues to be dominated by coal which accounts for 50% of the fuel used for utility power generation.

Of the principle fossil fuels, natural gas-fired power generation posted the largest year-over-year increase, with an 8% gain over 2003 levels. This trend is forecast to increase in the coming years. Most new power generation capacity is expected to be fuelled by natural gas, because natural gas-fired generators appear to have advantages over coal-fired generators, including lower capital costs, higher fuel efficiency, shorter construction lead times, and lower emissions. as new gas-fired generators are built in response to environmental pressure and increased demand for electricity.

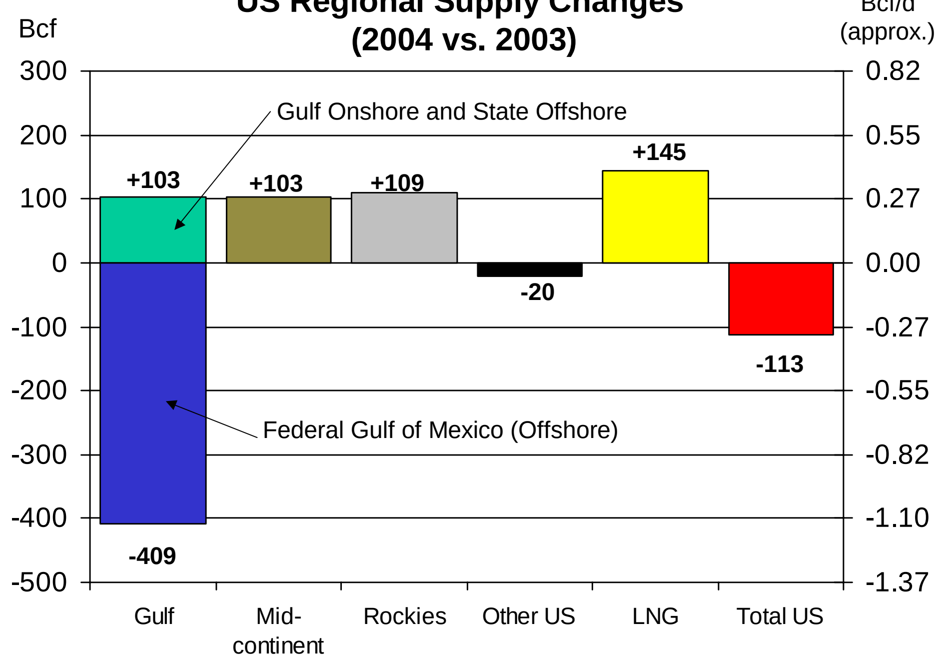
High crude oil prices in 2004 had a moderating effect on oil-fired power generation.

Table 15
US Natural Gas Supply Changes
(2004 vs. 1997)

Region	2004 (Bcf)	1997 (Bcf)	Change (Bcf)	Change (%)
Gulf Offshore	3,804	4,880	-1,076	-22%
Gulf Onshore	6,866	6,821	45	1%
Mid-Continent	1,993	2,275	-282	-12%
Rockies	4,338	3,037	1,301	43%
Other[1]	1,923	1,817	106	6%
Canadian Imports	3,602	2,899	703	24%
LNG	652	78	574	736%

Source: EIA **Note:** (1) Includes Alaska

Figure 52
US Regional Supply Changes
(2004 vs. 2003)



Sources: EIA, StatsCan, CNSOPB, NRCan estimates

Table 15 compares the contribution of natural gas supply sources towards total US supply between 1997 and 2004.

Comparing the two years, the largest supply increases have come from the Rockies (1,301 Bcf – 43% increase), Canadian imports (703 Bcf – 24% increase), and LNG (574 Bcf – 736% increase).

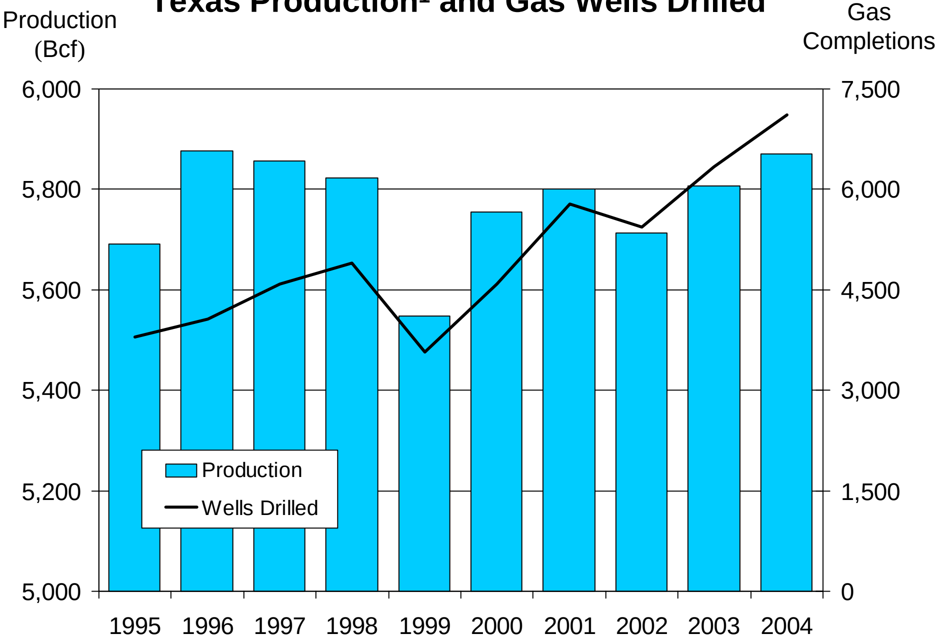
The largest supply losses have come from US offshore (1,076 Bcf – 22% decrease) and the US Mid-continent (282 Bcf – 12% decrease).

In total, US supply sources have increased 6%, or 1,136 Bcf between 1997 and 2004.

In 2004, US natural gas production fell 113 Bcf, or 1%. US Gulf Coast offshore production fell a staggering 409 Bcf, or 10% from 2003, partly as a result of Hurricane Ivan. The Category-4 hurricane destroyed seven production platforms and damaged 13 sub-sea natural gas pipelines. As a result of infrastructure damage, Hurricane Ivan caused a significant reduction in natural gas production. The production shut-ins were as high as 6.5 Bcf/d of natural gas representing about 53% of the total daily natural gas production in the Gulf of Mexico. Large Gulf offshore declines were also a result of reduced drilling and fewer economically viable natural gas pools.

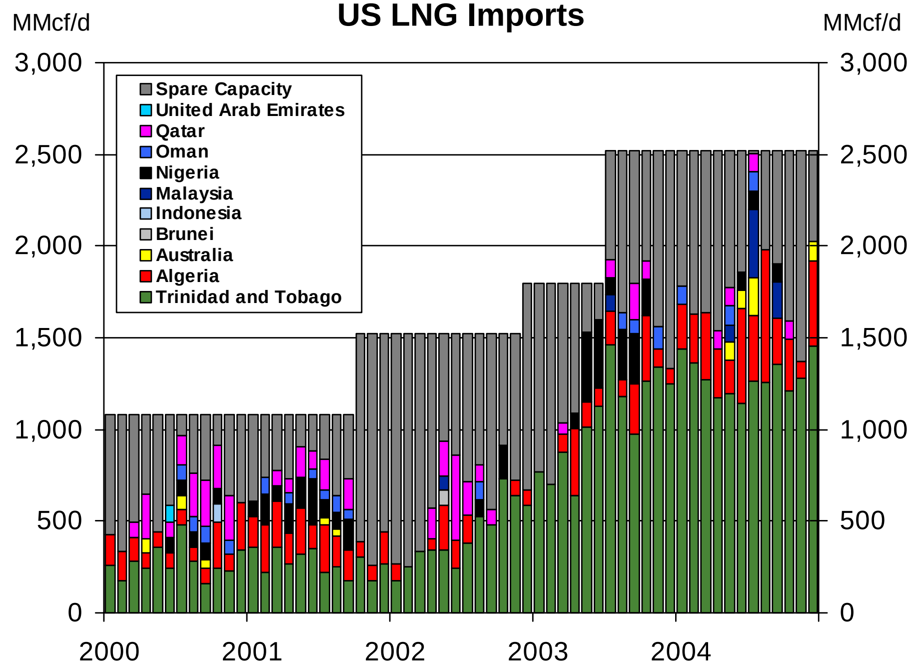
However, US Gulf Coast onshore production increased 103 Bcf, or 2%, while the US Mid-continent increased 103 Bcf. Rockies production also increased 109 Bcf. LNG imports also helped offset domestic production losses. Total LNG imports in 2004 were 652 Bcf, 145 Bcf or 33% greater than 2003 LNG import volumes.

Figure 53
Texas Production[1] and Gas Wells Drilled



Source: Texas Railroad Commission **Note:** (1) Represents marketable (wet) natural gas production.

Figure 54
US LNG Imports



Sources: EIA, Company websites

Historically, onshore Texas has produced between 25% and 35% of total US natural gas, the largest percentage of any US state. As a result, Texas natural gas production is an excellent indicator of overall trends in US natural gas activity.

Texas marketable natural gas production was nearly 5.9 Tcf in 2004, 1% greater than in 2003, equivalent to about 90% of total Canadian natural gas production in 2004.

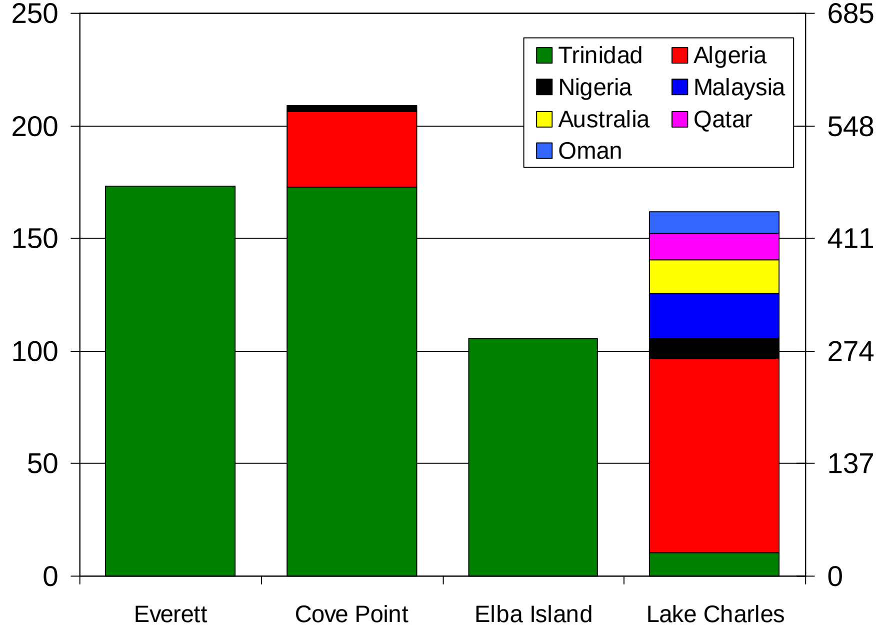
While Texas natural gas production has been relatively stable since 2000, more wells are required to deliver the same quantities of natural gas. For example, 65% more natural gas wells were drilled in 2004, compared with 2000. This illustrates, that despite historically high amounts of drilling, Texas natural gas production has been unable to increase significantly.

Imports from Trinidad and Tobago represented 71% of all US LNG imports in 2004. Algeria, once the sole supplier of LNG to the US, remains the second largest exporter of LNG to the US at 18% of all LNG supplies.

Total US LNG imports have grown steadily since 2002, however, spare capacity does exist. The base load capacity of the four operating LNG import terminals is 2.52 Bcf/d. The US imported, on average, 1.8 Bcf per day of LNG in 2004, or approximately 71% of total available base load capacity.

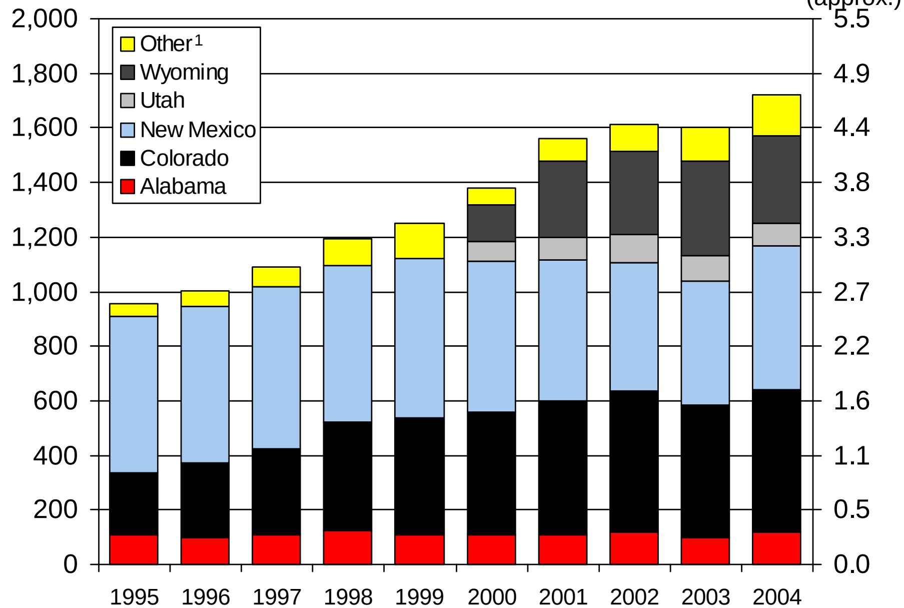
Several factors limit US LNG import terminal receiving capability including: limited spare global liquefaction capacity; reduced opportunities to divert cargoes to the US because of normal (or worse) weather in Asia and Europe; and, inadequate economic incentives to divert LNG spot cargoes to US LNG import terminals because of sustained, high crude oil prices.

Figure 55
2004 US LNG Imports



Source: EIA

Figure 56
US Coalbed Methane Production



Source: EIA **Note:** (1) Other includes Oklahoma, Pennsylvania, Utah, Virginia, West Virginia, and Wyoming. However, beginning in 2000, other excludes Utah and Wyoming.

LNG is imported into the US via 4 LNG receiving terminals – Lake Charles, LA; Elba Island, GA; Cove Point, MD; and Everett, MA. Volumes through Lake Charles were 445 MMcf/d; Elba Island, 290 MMcf/d; Cove Point, 575 MMcf/d; and Everett, 475 MMcf/d. In addition, a fifth LNG import terminal – the Excelerate Energy Bridge Project – commenced operation in March 2005. The terminal, located offshore Louisiana, is the first of its kind in the US.

In 2004, the US imported a record amount of LNG from seven countries, receiving 652 Bcf (accounting for nearly 3% of total US natural gas supply), an increase of 28% over 2003.

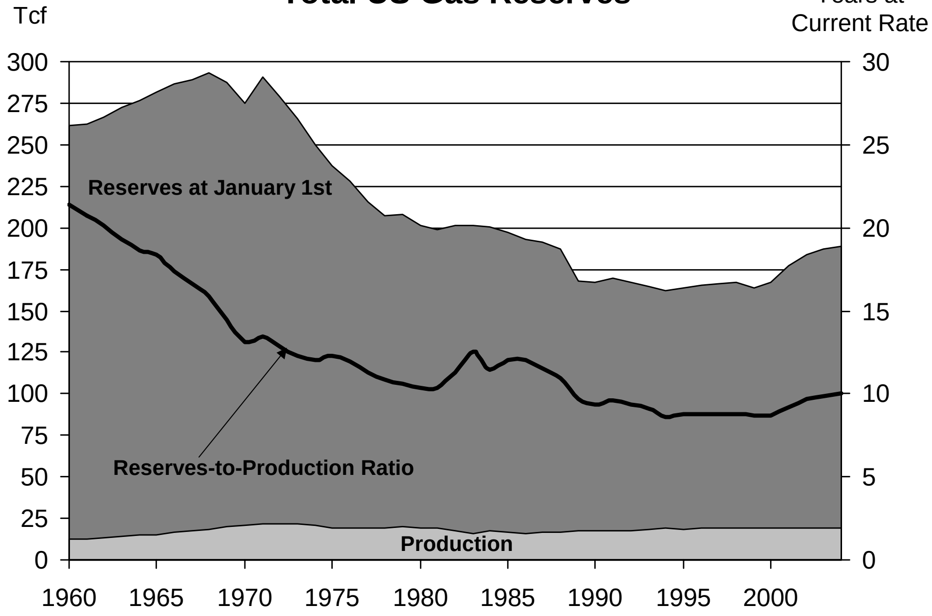
The Cove Point LNG facility was the most active in 2004, accounting for approximately 33% of total imported volumes, followed by Everett (27%), Lake Charles (25%) and Elba Island (15%).

CBM activity is well established in the US. As of January 1, 2005, US CBM natural gas reserves were 18.39 Tcf, or 10% of total US natural gas proved reserves in 2004. The largest known concentrations of CBM are in the Rocky Mountains of Wyoming, Montana, northern New Mexico, southern Colorado, eastern Utah, and Alabama.

In 2004, CBM production was 1,720 Bcf, an increase of 120 Bcf, or 7% over 2003 levels, and nearly 80% higher than 1995 production levels. Alabama and New Mexico accounted for more than 80% of the CBM production growth in 2004.

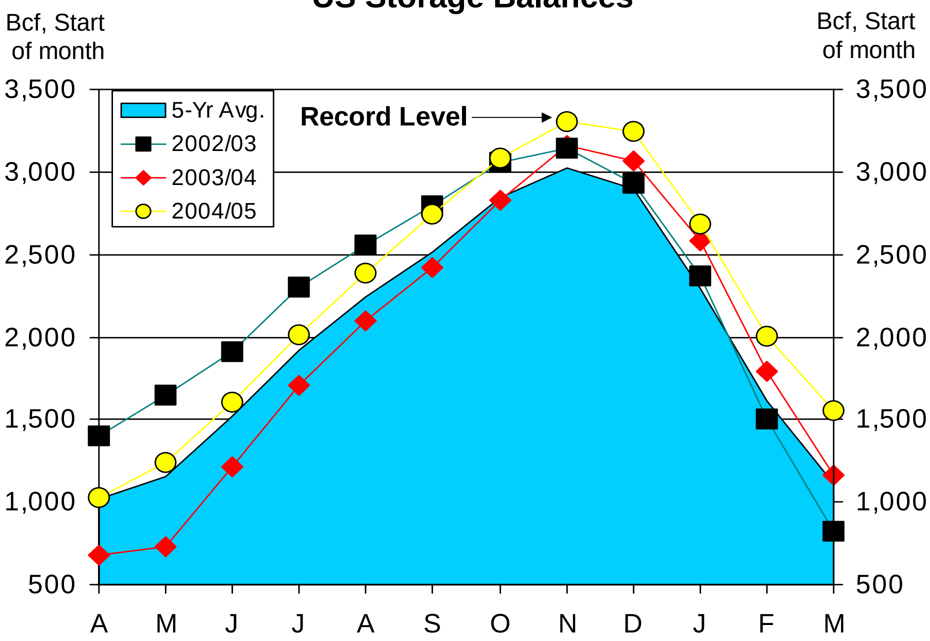
In 1995, CBM production accounted for 5% of total US natural gas production, while in 2004 CBM production represented about 9% of total US natural gas production.

Figure 57
Total US Gas Reserves



Source: EIA

Figure 58
US Storage Balances



Source: NRCan estimates from EIA

A comparison of proved reserves and production (R/P ratio) on the same scale is useful for analyzing the maturity of an area.

US reserves peaked in 1970 at about 290 Tcf, with an R/P ratio of 13.4, meaning that the US had just over 13 years of gas left if they continued to produce at the same rate and did not find any new gas.

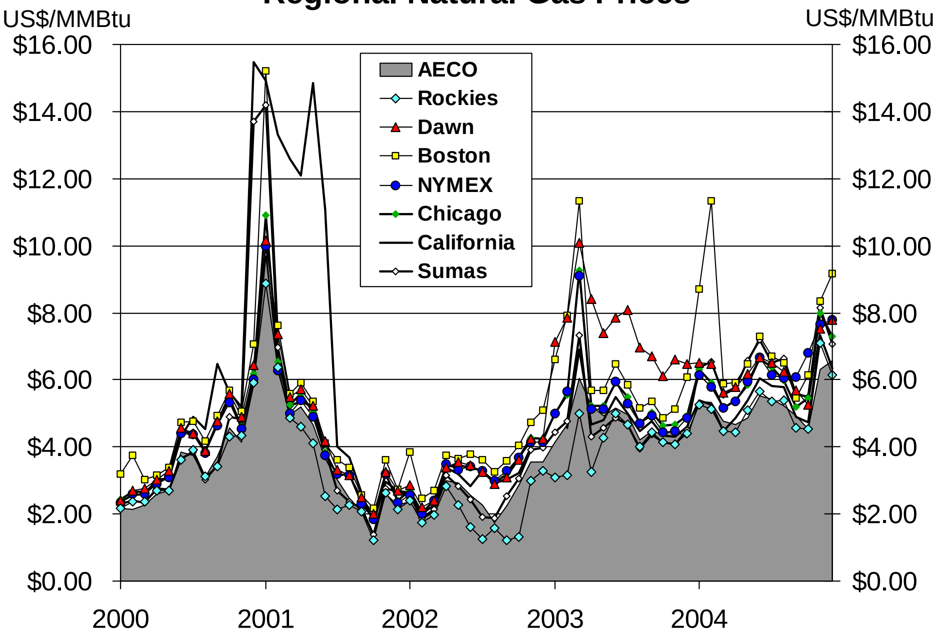
Following this peak, US reserves declined rapidly. Between 1971 and 1991, US reserves fell by more than 40%. However, belying that trend, US reserves have increased in 10 of the last 11 years, standing at 189 Tcf at the beginning of 2004. The current US R/P ratio stands at about 10 years. In large part, this reflects the increased importance of coalbed methane and tight gas. These types of wells produce only a small percentage of their reserves each year, thus driving up the R/P ratio.

US natural gas storage levels in 2004/2005 were very healthy. US storage operators were able to inject record amounts of natural gas into storage throughout the summer due to lower natural gas demand for power generation. The US reached record storage levels, peaking at over 3,300 Bcf by November 2004.

The winter remained seasonably warm throughout most of the US, easing the demand for natural gas from storage.

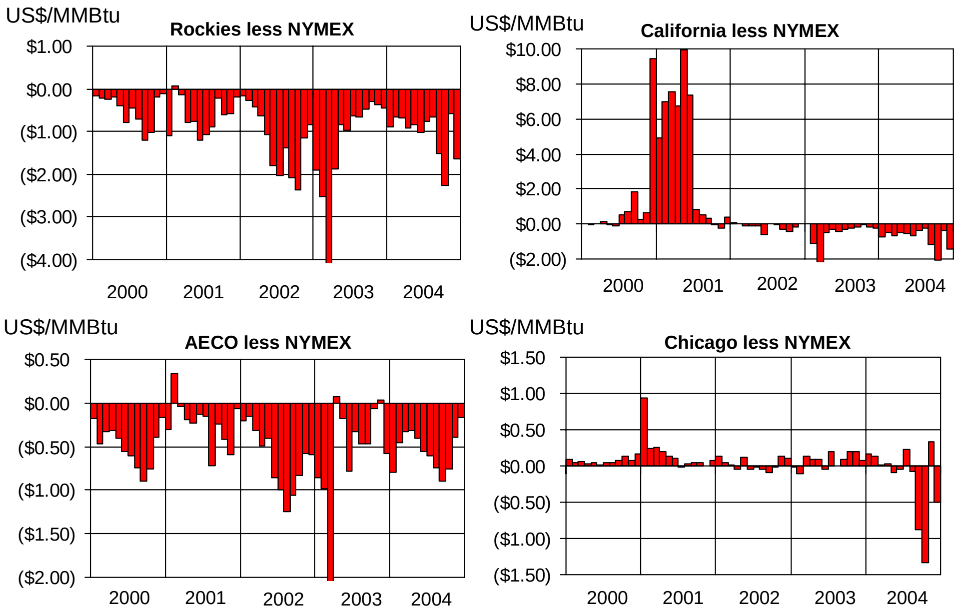
Continued warm spring weather resulted in an April 1st, 2005 storage level of 1,248 Bcf, 21% higher than April 1st 2004 and 30% higher than the 5-year average.

Figure 59
Regional Natural Gas Prices



Source: GLJ

Figure 60
Natural Gas Price Differentials



Source: GLJ

Monthly spot prices in major North American regions are shown in Figure 40. Generally, large price differentials are an indication that transportation capacity between locations is constrained. The most vivid recent display of market disparities was the much higher western US natural gas prices witnessed in 2001, due to the California energy crisis.

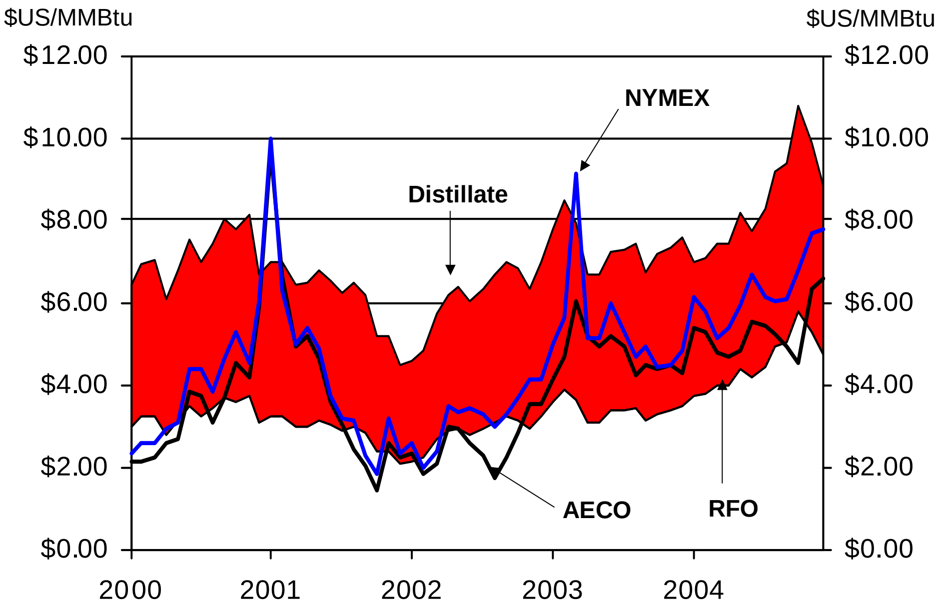
While 2004 prices reached record levels, large disconnects were not experienced (with the exception of Chicago-NYMEX in the latter months of the year). In the winter, there is a disconnect between eastern consuming regions such as Dawn and Boston, from the western and southern producing regions. This trend continued in 2004 as temperatures fell in the US northeast, resulting in a surge in demand.

The difference in the price of natural gas between two market areas is called a differential. Figure 60 compares the differentials between the NYMEX price at Henry Hub and other major North American natural gas hubs.

In 2004, the AECO and California differentials continued to widen (became less expensive compared to the Henry Hub price). In the Rockies, prices continued to increase relative to NYMEX as new pipeline development allowed natural gas production to exit the region, bringing prices in line with the rest of North America, similar to the effect the Alliance pipeline had on Alberta prices in 2000.

Large differentials between NYMEX and Chicago in late 2004 are a result of Hurricane Ivan, which resulted in large production losses, and higher demand in Chicago being satisfied by cheaper natural gas supplies from Alberta and the Rockies as more expensive supplies from the Gulf Coast were being directed to US northeast markets.

Figure 61
Oil vs. Natural Gas Price Relationship



Source: NEB

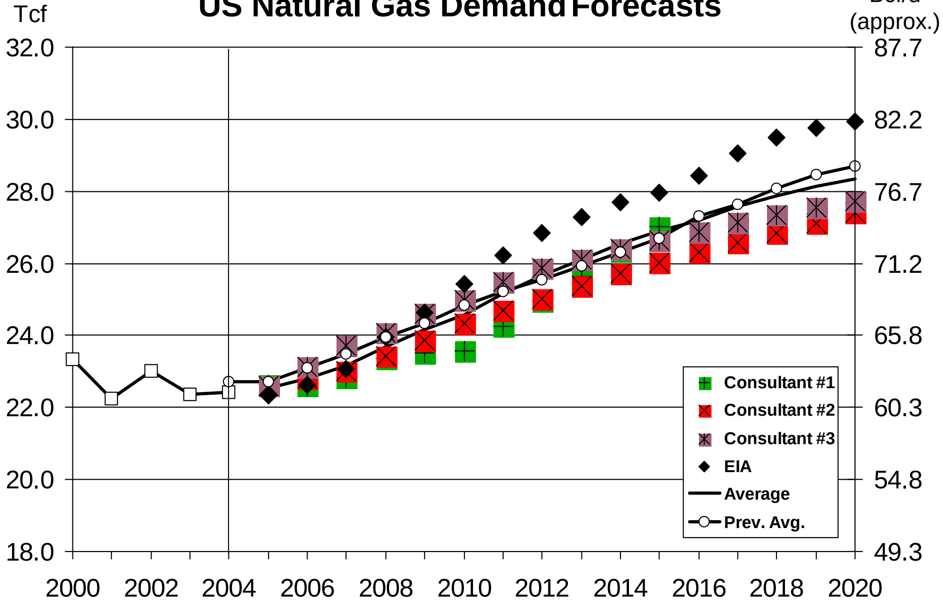
Figure 61 depicts the price of natural gas against two competing crude oil derived fuels – residual fuel oil (RFO) and distillate. The upper limit of the red band represents the price of distillate, while the lower limit of the band represents RFO. When the price of natural gas surpasses the lower portion of the band, it means that RFO is selling at a discount to natural gas. The same analysis can be used looking at distillate.

This graph shows that while natural gas prices have been historically high since early 2001, they are still at the lower end of competing fuels and therefore still selling within the range of competing fuels. At times, such as mid 2004, the AECO price for natural gas was selling at a discount to both RFO and distillate.

Part III: United States Natural Gas Market

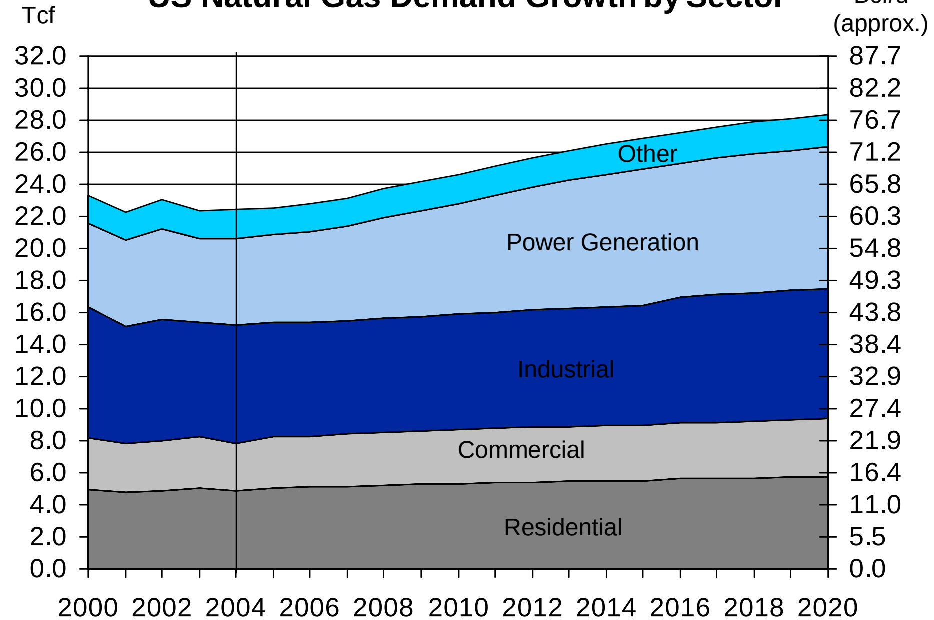
›› Outlook to 2020

Figure 62
US Natural Gas Demand Forecasts



Sources: EIA and various consultants. **Note:** Historical numbers from EIA.

Figure 63
US Natural Gas Demand Growth by Sector



Sources: EIA and various consultants. **Notes:** (1) Represents an average or "consensus" view of forecasts of various organizations. (2) Historical numbers from EIA.

Figure 62 displays three forecasts of US gas demand, along with the average of the forecasts, as well as the average from last year.

The average of the forecasts shows US gas demand at 26.9 Tcf by 2015, increasing to 28.3 Tcf by 2020. This represents an average increase of about 1.6 % per year.

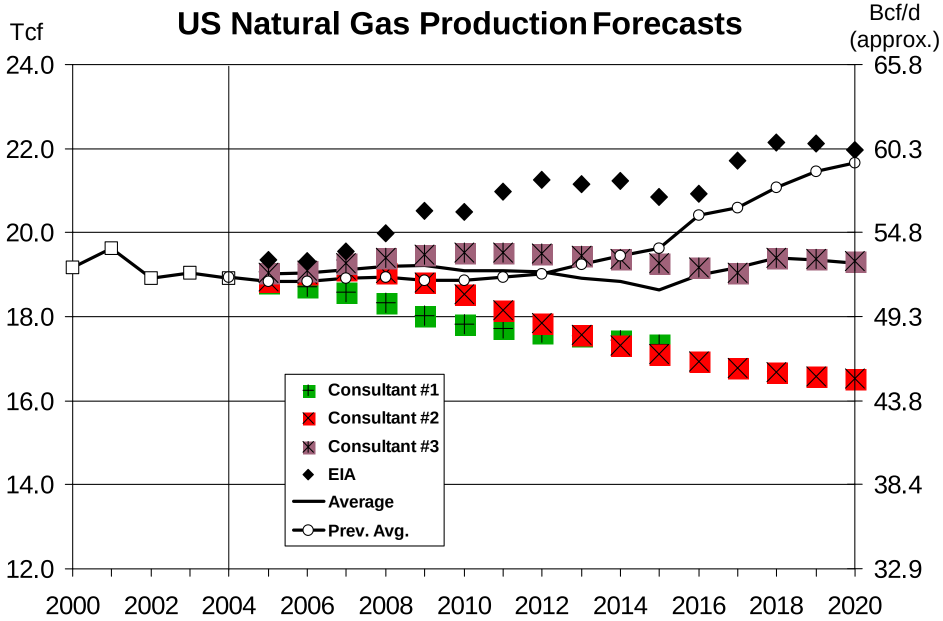
The average of the previous year's forecast showed US gas demand at 28.7 by 2020, 0.4 Tcf more than the current forecast at 2020. Current average forecasts for US demand have been revised downwards, primarily due to lower conventional natural gas production expectations and substantially higher prices.

Figure 63 displays an average or "consensus" view regarding the future of US natural gas demand by sector.

The average of the forecasts shows total US natural gas consumption increasing from 22.4 Tcf in 2004 to 28.3 Tcf in 2020. This represents an increase of nearly 6 Tcf, or 26%, when compared to actual 2004 US natural gas demand.

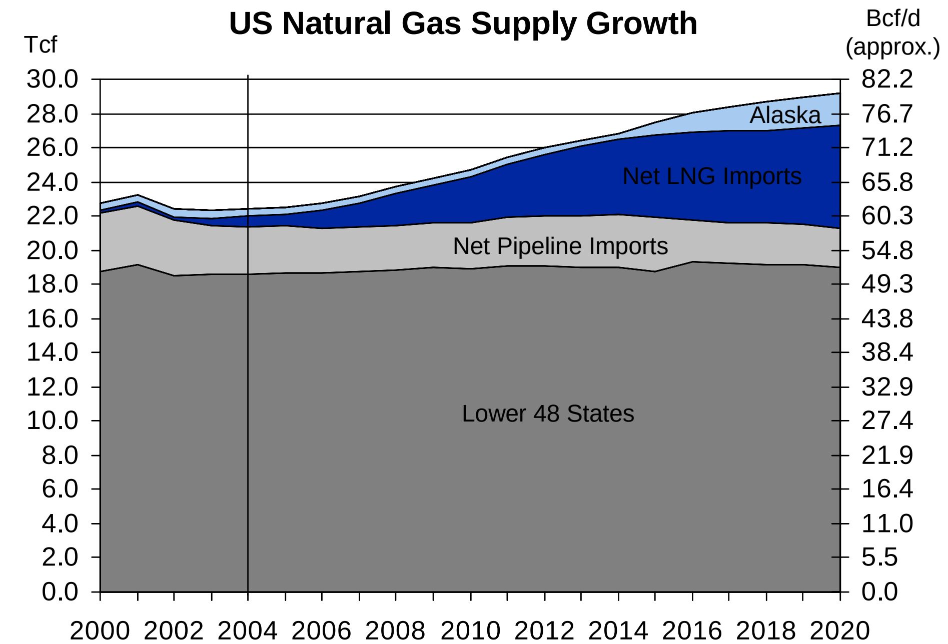
In the power generation sector, natural gas consumption is projected to increase from 5.4 Tcf in 2004 to 8.9 Tcf in 2020, accounting for 31% of total demand for natural gas in 2020 as compared with 24% in 2004. The increase will come from both the construction of new gas-fired generating plants and higher capacity utilization at existing plants.

Figure 64
US Natural Gas Production Forecasts



Sources: EIA and various consultants. **Note:** Historical numbers from EIA.

Figure 65
US Natural Gas Supply Growth



Sources: EIA and various consultants. **Notes:** (1) Represents an average or "consensus" view of forecasts of various organizations. (2) Historical numbers from EIA.

Figure 64 shows four forecasts for US natural gas production. The average shows US natural gas production increasing to 19.3 Tcf by 2020, or 0.2% per year over the forecast period.

The average of the previous year's forecast showed US gas production at 20.4 Tcf by 2015, greater than the current forecast view for 2020.

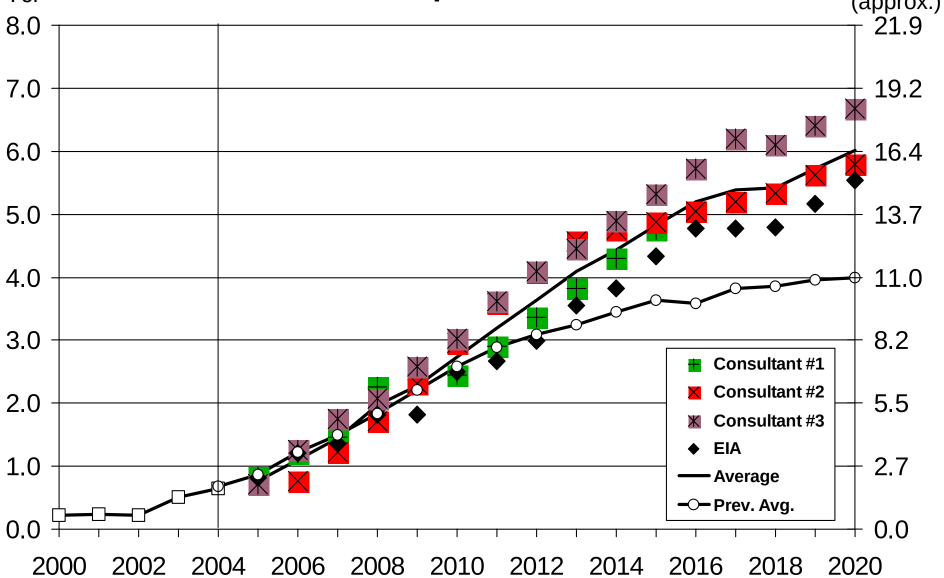
There are considerable differences in opinion about US natural gas production. This wide range in forecasts suggests uncertainty about US supply among industry observers.

Figure 65 shows an average or "consensus" view regarding sources of US natural gas supply growth. Averaging various US natural gas supply forecasts results in a "consensus" forecast of 27.5 Tcf in 2015 and 29 Tcf in 2020.

In 2004, net US pipeline imports represented 12% of total US natural gas supply, while net US LNG imports accounted for 2% of total supply.

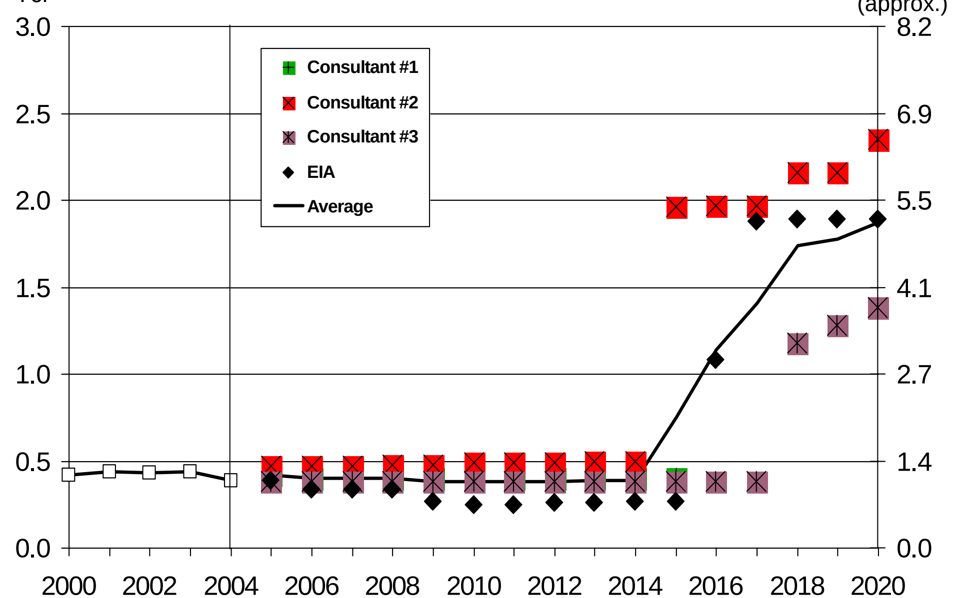
In 2020, US natural gas supply would be satisfied by: Lower 48 natural gas production of 19 (65% of total); net pipeline imports of 2.3 Tcf (8% of total), net LNG imports of nearly 6 Tcf (21% of total) and Alaska natural gas production of 1.9 Tcf (6% of total).

Figure 66
US LNG Import Forecasts



Sources: EIA and various consultants. **Note:** Historical numbers from EIA.

Figure 67
Alaska Natural Gas Production Forecasts



Sources: EIA and various consultants. **Note:** Historical numbers from EIA.

Figure 66 shows four forecasts of US LNG imports, as well as the average forecast and the previous year's average. The average of the four forecasts shows LNG imports rising to 4.8 Tcf by 2015 and approximately 6 Tcf by 2020, equal to about 20% of total US natural gas supply. This forecast represents an increase of about 5.4 Tcf or more than 800% greater than actual US LNG imports in 2004.

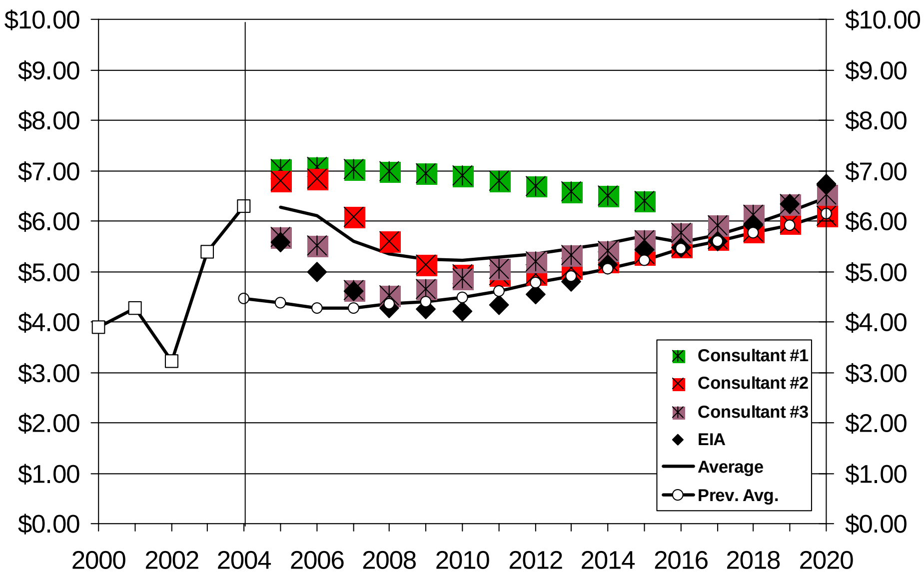
The average forecast in our report last year showed US LNG imports at 3.6 Tcf by 2015 and 4 Tcf by 2020, significantly lower than the current forecast of 6 Tcf by 2020. Upward revised forecasts can be attributed to growing concerns regarding conventional North American natural gas production and sustained high natural gas prices.

In 2004, southern Alaska produced about 390 Bcf of natural gas. About 16%, or 62 Bcf of this natural gas was exported to Japan via LNG tankers. The remaining 328 Bcf was consumed within Alaska. Industrial natural gas usage accounts for about 70% of the statewide total.

The much larger natural gas reserves located in northern Alaska are stranded by the lack of a means of transportation to market.

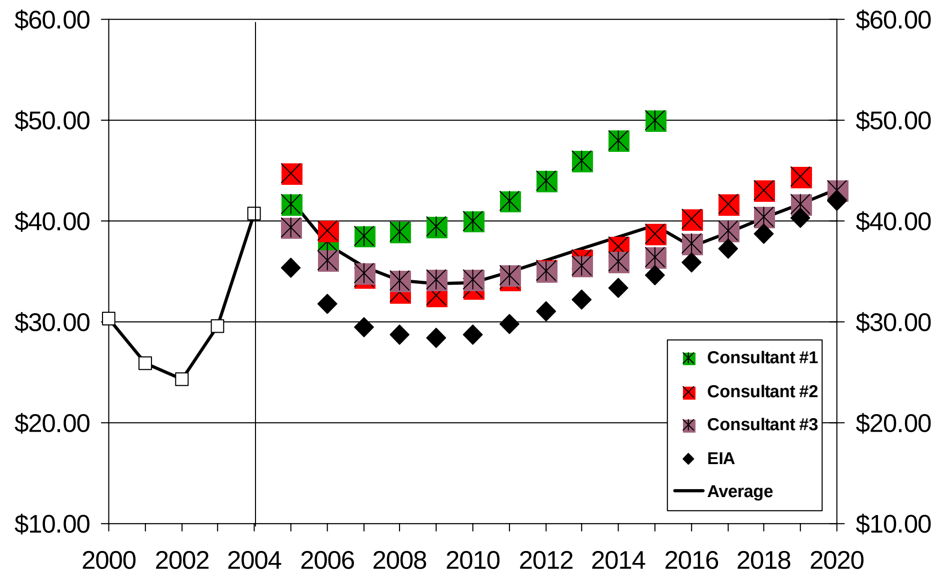
According to the forecasters surveyed, the earliest the North Slope Alaska natural gas pipeline would begin transporting Alaska natural gas to the Lower 48 would be 2015. The "consensus" view shows Alaska natural gas production at about 1.9 Tcf by 2020, or about 5.2 Bcf/d.

Figure 68
US Natural Gas Price Forecasts



Sources: EIA and various consultants. **Notes:** (1) Historical prices are NYMEX actuals from GLJ. The forecast prices represent Gulf Coast Henry Hub prices, except EIA, which is an average US wellhead price. (2) Some forecasts were converted from constant to nominal dollars.

Figure 69
WTI Crude Oil Price[1] Forecasts



Sources: EIA and various consultants. **Notes:** (1) Represents West Texas Intermediate crude oil price at Cushing, Oklahoma. (2) Historical prices are from EIA. (3) Some forecasts were converted from constant to nominal dollars.

Figure 68 compares four nominal dollar forecasts of US natural gas prices at Henry Hub in Louisiana.

In 2004, the US natural gas price was US $6.30/MMBtu. The average of the forecast shows that prices are expected to remain above US $6.00/MMBtu for the next two years before falling into the US $5.50 – 6.50/MMBtu range to the end of the forecast period.

The average forecast for 2015 and 2020 sees natural gas prices at US $5.70/MMBtu and 6.50/MMBtu, respectively. According to the forecasters surveyed, between 2005 and 2020, US natural gas prices are expected to average about US $5.70/MMBtu.

Price expectations have risen approximately 15%, when compared to our survey last year.

Figure 69 shows four nominal dollar forecasts of WTI crude oil prices.

In 2004, WTI crude oil prices averaged US$41.42 per barrel. This was an increase of US$10.28, or 33% over the 2003 average price of US$31.14.

The average of the forecasts shows that WTI crude oil prices will decline from 2004 record levels, averaging US $35.25/bbl between 2006 and 2009.

WTI crude oil prices are expected to average US $37.80/bbl over the entire forecast period, 10% lower than actual 2004 levels.

Appendix 1

›› Intra-Alberta, AECO, and NIT Prices

Intra-Alberta, AECO, and NIT Prices

Canada's natural gas market operates within an open and integrated North American natural gas market. Natural gas prices are determined in a continental marketplace and are subject to the forces of supply and demand.

Canada's reference natural gas commodity price is the intra-Alberta spot month price. This is a wholesale price in a producing area for large volumes of natural gas bought under 1-month contracts. The natural gas is bought and sold while it is within the NOVA Gas Transmission Ltd. (NGTL) pipeline in Alberta. In other words, the status of the natural gas at the time of purchase or sale is "delivered to NOVA." The NOVA pipeline is extensive and covers most of the province of Alberta. It is also called the Alberta Hub or TransCanada's Alberta System. The intra-Alberta price is also commonly referred to as the AECO price or the NIT price. The term AECO was coined when prices of natural gas exchanged at the Alberta Energy Company (AECO) Suffield storage facility (which is connected to the Nova pipeline) began to be reported. AECO is now operating as EnCana, the result of a merger of PanCanadian and Alberta Energy Company in 2002. NIT stands for Nova Inventory Transfer - the price of natural gas exchanged while it is in the NOVA pipeline. All three terms - the intra-Alberta price, the AECO price, or the NIT price - refer to the same thing - the price of natural gas that is exchanged while it is in, or accessible to, the NOVA Pipeline.

An important price-discovery mechanism for intra-Alberta natural gas prices is the Natural Gas Exchange (NGX). NGX is a company that facilitates natural gas trades between buyers and sellers. NGX insures both buyer and seller against payment or delivery default, while keeping their identities confidential. For this, NGX charges a small fee per unit of natural gas exchanged. NGX publishes the average price of these trades. Contracts to deliver natural gas during particular months are made each day through NGX. For example, during September 2005, buyers and sellers were making deals through NGX to exchange natural gas which would flow in October 2005. The October 2005 intra-Alberta spot month price published by NGX at the end of September is the average of all exchanges made during September 2005 for natural gas to be delivered in October 2005.

The Alberta Hub and the intra-Alberta market is one of the most important natural gas hubs/markets in North America, due to the large volume of natural gas flowing through the hub every day, and the large volume of natural gas exchanged at this location. About 12 billion cubic feet of natural gas flows through NOVA each day. Due to re-sales of natural gas, the volume of natural gas bought and sold at the Alberta Hub is much larger. The importance of the hub is also enhanced by the large volume of underground natural gas storage connected to the hub in Alberta, and the extensive connections to other pipelines, which lead to domestic and export markets outside of Alberta. The importance of the Alberta Hub is reflected in the fact that the intra-Alberta natural gas spot price is one of North America's leading natural gas price-setting benchmarks.

Appendix 2

›› Canadian Natural Gas Liquids

Canadian Natural Gas Liquids

In addition to methane (the main component of natural gas), natural gas contains natural gas liquids (NGLs) that are comprised mainly of ethane, butane and propane in varying quantities. NGLs, particularly ethane, are feedstocks for various petrochemical production facilities in Canada.

In Alberta, NGLs are extracted from the pipeline quality gas flowing through the NOVA Gas Transmission Ltd. (NGTL) pipeline system, at one of 9 straddle plants located at Empress (six plants), Cochrane, Joffre, or Edmonton. Several smaller field processing plants also extract NGLs in order for the natural gas to meet pipeline specifications. Alberta straddle plants negotiate contracts with the owners of the natural gas moving through NGTL, under which the straddle plant obtains “extraction rights” for the NGLs in the gas.

The stripped ethane and other NGLs then belong to the straddle plant owner, and are typically sold to petrochemical companies. Once extracted, Alberta ethane can move to Alberta markets on the extensive ‘Alberta Ethane Gathering System’, or, it may be transported to Sarnia via the Cochin pipeline. Straddle plants typically sell ethane under medium to long-term supply agreements to petrochemical companies in Alberta.

The Alberta Petrochemical Industry

Alberta has a large petrochemical industry, which is founded mainly on ethylene produced from ethane. This large industry was built on the availability of low-cost ethane feedstocks, which helps offset Alberta’s distance to chemical product markets. The two main petrochemical complexes in Alberta are owned by NOVA Chemicals in Joffre and Dow Chemical in Fort Saskatchewan. Other petrochemical operations in Alberta include BP Canada, Shell Chemicals, Celanese, and AT Plastics.

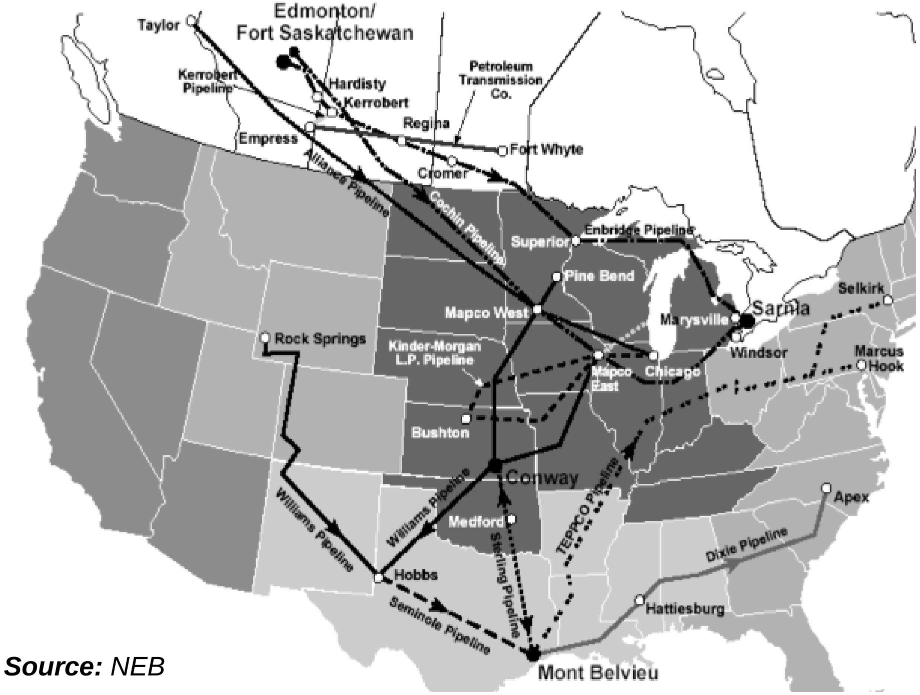
There are currently sufficient NGLs to support modest expansion in Alberta’s existing petrochemical capacity, but insufficient volumes of feedstock to support any major new investment. A major new natural gas development is required in order to secure additional NGLs for any significant future Alberta petrochemical industry development. The most promising source for these NGLs is northern gas.

NGL Pipelines and Market Hubs

There are four NGL trading hubs in North America. Fort Saskatchewan (north of Edmonton) and Sarnia are the two Canadian hubs, while Conway (Kansas) and Mont Belvieu (Texas) are the US hubs. Fort Saskatchewan is considered a hub on account of its large underground storage facilities, a captive petrochemical market and it is connected to the other NGL trading hubs via pipelines and the nearby straddle plant in Edmonton. The following map shows the principle NGL pipelines and hubs in North America. Included is the Alliance Pipeline which transports rich natural gas, (high NGL content) to Chicago.

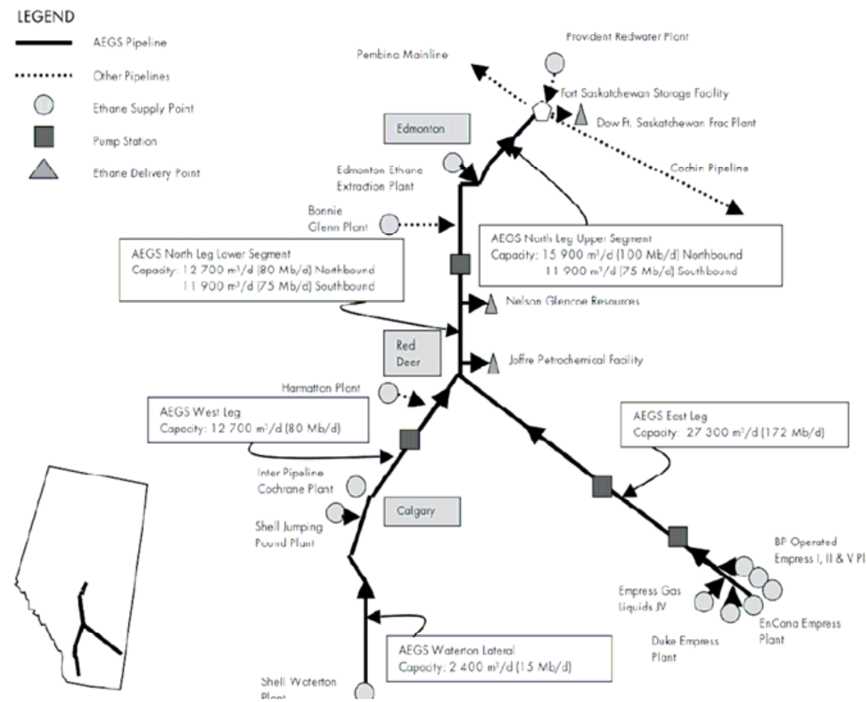
Canadian NGL exports represent only about 10% of US demand. Just as North American natural gas prices are set by the Henry Hub price, the price for Canadian NGLs is set by the North American price (with adjustments made for location and transportation). Mont Belvieu, given its high concentration of petrochemical industries, storage, pipeline, fractionation, and refinery facilities is the largest NGL consuming area in North America and is sometimes considered the "price setter" for North American NGL markets.

North American NGL Trading Hubs and Pipelines



Source: *NEB*

AEGS System



Source: *NEB*

Alberta Ethane Gathering System

Feeding the North American NGL pipelines and hubs are NGL gathering systems. In Alberta, the Alberta Ethane Gatherings System (AEGS) receives liquids from Alberta's nine straddle plants. The AEGS is owned by Fort Chicago Energy Partners, a Canadian company. AEGS consists of 1,324 km of lines with a capacity of 322,000 barrels per day. AEGS connects Alberta's ethane supply with Alberta's primary petrochemical facilities near Joffre and Fort Saskatchewan, and with ethane storage caverns, and export delivery systems, such as the Cochin pipeline to the US. A map of the AEGS is shown at the right.

AEGS system, consists of three pipeline legs:

The East Leg, with a capacity of 172,000 bbls/d, extends from the four straddle plants near Empress to inter-connections with petrochemical facilities and the AEGS North Leg near Joffre;

The West Leg, with a primary capacity of 80,000 bbls/d, starts near Waterton and extends north to a second straddle plant near Cochrane and then connects to petrochemical facilities and the AEGS North Leg near Joffre; and,

The North Leg, a bi-directional line with system capacity of up to 100,000 bbls/d extends from Joffre to Edmonton where it connects to the Edmonton straddle plant, prior to extending to its terminus at Fort Saskatchewan where it connects with ethane storage caverns, other pipelines, and petrochemical facilities.

The two primary customers of the ethane shipped on AEGS are NOVA Chemicals and Dow Chemical. AEGS supplies virtually all of the ethane required by the NOVA Chemicals and Dow Chemical Joffre ethylene facilities, and approximately 50% of the ethane required at the Dow Fort Saskatchewan ethylene facility. NOVA Chemicals has two wholly-owned ethylene crackers in Joffre, and is a 50:50 partner with Dow in a third. All are on the same site. Dow has its wholly-owned crackers on a single site in Fort Saskatchewan.

Future NGL Supplies

In view of declining Alberta ethane production, the petrochemical industry and straddle plant operators are eager to increase ethane supply. Northern natural gas, (Mackenzie Delta and Alaska) offer the possibility of satisfying this demand. While both Mackenzie and Alaskan natural gas deposits contain NGLs, typically Mackenzie Delta is referred to as relatively lean – lower ethane content – and Alaska as rich – high ethane content. Gaining economic access to the NGLs contained in northern natural gas would help fuel the expansion of Alberta’s petrochemical industry.

Conclusions

The Alberta petrochemical industry has significant gains to make from an increased supply of natural gas liquids, notably from the Mackenzie Delta and Alaska. Infrastructure utilization in Alberta could be boosted if northern natural gas connected with NGTL for liquids to be extracted at existing straddle plants and then shipped to petrochemical facilities in the North via the AEGS.

Appendix 3

›› Liquefied Natural Gas in North America

Liquefied Natural Gas in North America

Liquefied Natural Gas - Description

Liquefied natural gas, or LNG, is simply natural gas in its liquid state. When natural gas is chilled to a temperature of about minus 160 degrees Celsius (or minus 260 degrees Fahrenheit) at atmospheric pressure, it condenses to a clear, colourless, and odourless liquid. LNG is non-corrosive and non-toxic. The liquefaction process removes any oxygen, carbon dioxide, sulphur compounds and water contained within the natural gas, resulting in an LNG composition of mostly methane with small amounts of other hydrocarbons and nitrogen. Liquefaction reduces the volume by approximately 600 times, thereby allowing one tanker to deliver as much natural gas in one shipment as it would take 600 ships to deliver if the gas was in its natural gaseous form. The average tanker can deliver 2-3 Bcf of natural gas, enough to heat 2-3 million Canadian homes for one year. These large volumes make it economic to transport natural gas across oceans and makes a global natural gas market place possible.

North America's Need for Increased LNG Imports

Canada operates within an integrated North American natural gas market, where natural gas can be bought from many supply sources and delivered to any market through an extensive North American pipeline grid. Canadian natural gas requirements are met by domestic sources, as Canada produces natural gas in excess of what is required for domestic consumption. In comparison, the US consumes more natural gas than it produces, therefore natural gas imports are required to make up the difference. US natural gas imports are currently satisfied by pipeline via Canada and by large ocean tankers that carry LNG (e.g., Trinidad and Tobago).

Until recently, natural gas has been expensive to convert to LNG and end-use natural gas prices in North America did not justify the need for and expense of new LNG infrastructure. However, production from conventional North American natural gas basins is flattening, demand for natural gas continues to be robust, and prices have risen. This situation has opened the door for increased LNG imports. In addition to higher domestic natural gas prices, technological advances that have lowered the cost of liquefying and transporting LNG are also enabling LNG to become more cost competitive with conventionally-produced North American natural gas.

Trunkline LNG Lake Charles, LA LNG Import Terminal

Source: *Trunkline LNG*

The US is the key market for growth in the LNG industry, as it currently accounts for 25% of the natural gas consumed in the world every day. In 2004, there were four LNG import terminals operating in the US. Combined, they imported 652 billion cubic feet (Bcf), accounting for nearly 3% of US natural gas consumption. A fifth US LNG import terminal, Excelerate's offshore Gulf of Mexico facility, was added in March 2005.

The "consensus" LNG forecast (pg. 64) suggests that US LNG imports will reach nearly 6 Tcf, or 16.4 Bcf per day by 2020, an increase of 14.6 Bcf per day over 2004 levels. This will require that existing US LNG import facilities are expanded and that new or "green-field" facilities are built.

North American LNG Proposals

In addition to the expansions that are occurring at existing US LNG import facilities, there are more than fifty proposals for the development of LNG import facilities in the US, Bahamas, Canada, and Mexico, many of which are focused on supplying natural gas to US markets.

As of May 2005, LNG developers have proposed 56 new LNG import terminals in the Bahamas, Canada, Mexico, and the US, the majority of which are located in the US. The LNG proposals are in various stages of development (e.g., facilities on the US Gulf Coast and in Mexico are under construction, while other proposals have yet to file with regulatory authorities).

To date, thirteen new North American LNG import terminals with a capacity of about 17.6 Bcf per day have been approved for construction by authorities in Canada, the US and Mexico. In addition, two import terminals located in the Bahamas (destined to serve the Florida market via sub-sea pipeline) are awaiting approval by Bahamian authorities, while the pipeline portion of each of the projects has been approved by the Federal Energy Regulatory Commission.

If all the proposed LNG import terminals were to be built, they would have a combined import capacity of more than 60 Bcf per day or 22 Tcf per year, representing 90% of the total natural gas demand that exists today in both the US and Canada and three times the amount of LNG currently used by the entire world.

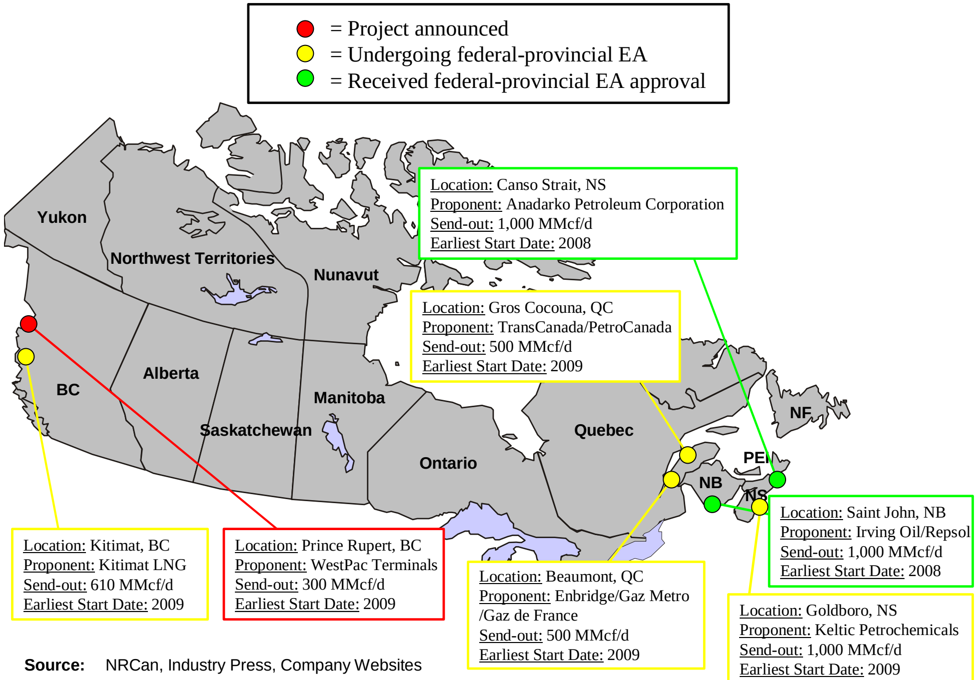
Therefore, not all of these LNG projects are required nor will be built. Only those LNG terminals that secure the necessary natural gas supply in a competitive global LNG market, are economic, and obtain the required regulatory permits are likely to be built.

To meet expectations of an additional 14.6 Bcf per day of LNG by 2020 would require that twelve green-field LNG import facilities – each with a capacity of approximately 1.2 Bcf per day – be built.

LNG Potential in Canada[1]

While Canada does not yet import LNG, there are numerous proposals to construct LNG import facilities in Atlantic Canada, Quebec and British Columbia, many of which are currently involved in the regulatory review process. The LNG projects being contemplated for Atlantic Canada are, for the most part, "import-for-re-export projects," as the demand for natural gas in Atlantic Canada is met entirely by natural gas production offshore Nova Scotia. The Quebec LNG projects

Proposed Canadian LNG Import Terminals



Source: NRCan, Industry Press, Company Websites

would mainly supply markets in Quebec and Ontario. Currently, Quebec is almost entirely dependent on western Canada for its natural gas supply. The projects being proposed in British Columbia (BC) are largely to supply natural gas to consumers on Vancouver Island and in the Lower Mainland.

The figure above shows the location, and provides various details, of the proposed Canadian LNG import projects.

In addition to the approximately CDN $500 million each in investment, the development of any Canadian LNG import terminal, will require pipeline takeaway capacity in order to deliver natural gas to market. In some cases, this will mean the expansion (i.e., added compression or looping) or extension of an existing pipeline system, while in other cases, this will require that a new pipeline system be built.

Currently, there are seven proposals to construct LNG import facilities in Canada, six of which have undergone or are currently involved in the environmental assessment (EA) / regulatory review process.[2] In August 2004, two of the seven LNG proposals – Irving Oil's and Anadarko Petroleum Corporation's (formerly Access Northeast Energy's) – received federal-provincial EA approval. Four other LNG projects – Gaz Métro et al.'s (in Quebec), TransCanada's (also in Quebec), Keltic Petrochemicals' (in Nova Scotia), and Kitimat LNG's (in BC) – are currently involved in the EA / regulatory review process. The final project – WestPac in BC – has not yet begun the EA / regulatory review process. Other projects (which do not appear on the map due to their preliminary nature) are also under consideration, including an LNG import terminal being proposed for Saguenay, Quebec.

Conclusions

Both industry and government analysts project continued growth in North American demand for natural gas and a decreasing ability for domestic natural gas producers to meet that demand. Greater LNG imports represent one way to address this expected growth in demand. Given the stage of development of the various Canadian projects, it appears likely that the North American natural gas picture will include several Canadian LNG import facilities.

[1]In September 2005, NRCan published a report, *'Canadian Liquefied Natural Gas (LNG) Import Projects: September 2005 Update'* The report is available at http://www.ngas.nrcan.gc.ca/.

[2]In September 2005, NRCan published a document, *'LNG Regulatory Requirements.'* The document is a compendium of all the major regulatory approvals currently needed by the respective levels of government for the design, siting and construction of an LNG import terminal in Canada. The document is available at http://www.ngas.nrcan.gc.ca/.

Appendix 4

›› Tables

List of Figures, Maps and Tables

List of Acronyms

Acronyms	
AECO	Alberta Energy Company storage facility
AB	Alberta
AGA	American Gas Association
BC	British Columbia
CAPP	Canadian Association of Petroleum Producers
CBM	coal bed methane
CGA	Canadian Gas Association
CNSOPB	Canada-Nova Scotia Offshore Petroleum Board
DOB	Daily Oil Bulletin
EA	environmental assessment
EIA	Energy Information Administration
EUB	Alberta Energy and Utilities Board
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GLJ	Gilbert Lausten Jung Associates Limited
HDD's	heating degree days
LDC	local distribution company
LNG	liquefied natural gas
MB	Manitoba
MMS	Minerals Management Service
NA	North America

Acronyms	
NB	New Brunswick
NEB	National Energy Board
NFLD	Newfoundland
NGL's	natural gas liquids
NOAA	National Oceanographic and Atmospheric Administration
NRCan	Natural Resources Canada
NS	Nova Scotia
NYMEX	New York Mercantile Exchange
ON	Ontario
PEI	Prince Edward Island
QB	Quebec
RFO	residual fuel oil
R/P	reserves to production ratio
RRC	Texas Railroad Commission
SK	Saskatchewan
SOEP	Sable Offshore Energy Project
StatsCan	Statistics Canada
US	United States
USGS	United States Geological Survey
WCSB	Western Canadian Sedimentary Basin
WTI	West Texas Intermediate

Units and Conversion Factors

Units	
Prefix	**Multiple**
MMcf	Million Cubic Feet
MMcf/d	Million Cubic Feet Per Day
Bcf	Billion Cubic Feet
Bcf/d	Billion Cubic Feet Per Day
Tcf	Trillion Cubic Feet
GJ	Gigajoule
MMBtu	Million British Thermal Units
GWhrs	Gigawatt Hours

Approximate Natural Gas Conversions			
British Thermal Units (BTU)	**Cubic Feet (CF)**	**Gigajoules (GJ)**	**1,000 Cubic Meters (10^3 m^3)**
1 Million (1 MMBtu)	1,000 (1 Mcf)	1.055	0.028
0.948 Million	0.948	1	0.027
35.3 Million	35,315	37.3	1

We Value Your Feedback

As natural gas advisors to the Minister of Natural Resources Canada, we publish this report to initiate dialogue with the industry and obtain feedback on our interpretations of natural gas issues. The objective of this report is to provide an understanding of the overall North American natural gas picture in a format that can be quickly read.

In an effort to provide the highest quality report to our readers, the Natural Gas Division welcomes your comments and suggestions on this years report: *Canadian Natural Gas: Review of 2004 and Outlook to 2020.*

Please print and fax the completed form to Paul Cheliak or Kevin Fenech at (613) 995-1913. We also welcome comments via email. You may send your comments to Paul Cheliak (pcheliak@nrcan.gc.ca) or Kevin Fenech (kfenech@nrcan.gc.ca).

Comments

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