Canadian Natural Gas

Review of 2003 & Outlook to 2020

December 2004

Natural Gas Division

Petroleum Resources Branch

Energy Policy Sector

Foreword

The *Canadian Natural Gas: Review of 2003 & 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 and also reviews Canadian natural gas exports. Mexico is largely excluded from the report.

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. This report is also used as input for other NRCan reports such as *Canada's Energy Outlook*. 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.

Structure of the Report

The main section of the report is composed of graphs, with limited text comments. This is a structured look at market fundamentals (supply, demand, etc.) over the past year (2003), for the near term (2004 and early 2005), and the long-term (to 2020). This analysis was completed first. The executive summary was prepared last, uses the analysis completed in the main section, and ties it into a cohesive narrative. The executive summary is all text – no graphs – and is presented at the beginning of the report.

Sources

Various sources were used in preparing this report, including private consultants, industry associations, and federal government agencies in Canada and the United States. 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 2002 may differ from what was reported in last year's report.

Format of the Report

The report has been formatted in landscape orientation – as was the case last year – to be more easily read on a computer screen. Most pages show two graphics and accompanying text.

Natural Gas Division Website

This report is available online at our website: www.ngas.nrcan.gc.ca. Other Natural Gas Division reports, including previous versions of this report, are also available at this 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 therefore generate a colour version of the report by printing the internet version.

Obtaining a Paper Copy

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

Natural Gas Division

Questions and Comments

We appreciate your comments and questions. Comments and questions regarding the "Review of 2003" can be directed to Paul Cheliak at (613) 995-0422 (pcheliak@nrcan.gc.ca). Comments and questions regarding the "Outlook to 2020" can be directed to Kevin Fenech at (613) 992-8377 (kfenech@nrcan.gc.ca). Comments and questions regarding any part of the report can be directed to John Foran at (613) 992-0287 (jforan@nrcan.gc.ca).

Natural Gas Division Background

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

The Natural Gas Division provides expert 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.

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Review of 2003
Canada's natural gas market operates within an integrated North American market, where natural gas is bought from many supply sources and delivered to multiple market centers through an extensive North American pipeline grid. Natural gas is traded on a daily basis with prices reflecting demand and supply factors in both Canada and the US.

Since mid-2000, North American natural gas prices have been within a new higher range. Alberta (AECO) prices have averaged CDN $5.45/Gigajoule (GJ) from mid-2000 to end 2003. Within this period of new higher prices, 2002 was a year of relatively low prices, with an average of CDN$3.83/GJ that year.

However, as the market entered the 2002/03 winter heating season, prices began to increase, reaching CDN$5.25/GJ in December, and $8.45 in March. Higher prices were attributable to colder weather, concerns about natural gas production, and increases in world crude oil prices. For calendar year 2003, Alberta prices averaged CDN$6.31/GJ, 65% greater than the previous year. Prices remained high throughout 2003, largely as a result of growing concerns regarding natural gas production, low storage levels, a strengthening industrial economy, increased Canadian demand, and robust crude oil prices.

Drilling Hits Record Highs, Yet Production Remains Flat
Higher natural gas prices induced record drilling levels across North America. In Canada, a record number of natural gas wells were drilled in 2003 – 13,932 wells – 54% greater than the previous year, and 24% more than the previous record set in 2001. In western Canada, the shallow drilling trend continued.

Nearly 80% of Canadian natural gas wells drilled were in the low productivity, shallow areas of Saskatchewan and eastern Alberta.

Canadian production levels were disappointing, given healthy prices and record drilling. Canadian natural gas production fell for the second consecutive year, declining 4% in 2003, following a 1% decrease in 2002. WCSB production declined 194 Bcf, or 4%, largely attributed to a production drop of 127 Bcf from the once prolific Ladyfern natural gas field in northeastern BC.

Natural gas production from the Sable Offshore Energy Project (SOEP) fell 27 Bcf, or 14% in 2003. Sable natural gas production peaked in December 2001, averaging nearly 590 MMcf per day, and has been declining ever since. While the second phase of SOEP (Alma 1) came on stream in December 2003, producing approximately 125 MMcf/d, Alma 1 has only helped to replace declining Tier 1 production.

The US natural gas rig count in 2003 was 29% higher than 2002 levels and US gas production increased 1%, or 105 Bcf. Production gains were recorded in the Midcontinent (79 Bcf), Rockies (71 Bcf), and Gulf Onshore (161 Bcf), while a loss was recorded in the Gulf Offshore (-188 Bcf).

Natural Gas Demand Increases in Canada; Decreases in US
Overall in 2003, Canadian natural gas demand increased by 178 Bcf, to 2,914 Bcf, or 7% compared to 2002. Demand in the US fell 1,141 Bcf, or 5%, to 21,877 Bcf.

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Core demand (i.e., residential and commercial) accounted for 38% of total North American demand in 2003. Core market natural gas demand increased across North America in 2003, largely because of very cold weather at the end of the 2002/03 winter heating season. 2003 was the coldest year in Canada and in the US, since 1996 and 1997, respectively.

In 2003, Canadian industrial and power generation demand for natural gas increased by 6% and 8%, respectively. Canadian industrial demand was up 59 Bcf, driven mainly by Alberta oil sands natural gas demand, which was up 29% in 2003. Oil sands operations consumed 220 Bcf of natural gas in 2003.

In the US, the situation was reversed – industrial demand declined 8% and power demand declined 13%. Industrial natural gas demand in the US fell 591 Bcf in 2003, after recording small gains in 2002. As a result of high prices, some price sensitive industrial users were forced to close their facilities, reduce production, switch fuels or substitute production from overseas facilities where natural gas prices are typically less expensive. Declines in power generation demand were largely the result of a very mild summer across the major natural gas consuming regions of the US.

Natural gas used for power generation has increased significantly over the past decade. Most new power generation capacity installed in North America in recent years has been natural gas-fired, due to its scalability, low capital cost, and low environmental impact. Despite this trend, in 2003 US natural gas demand for power generation fell by 742 Bcf. Canadian natural gas demand for power rose by 21 Bcf in 2003.

Increases in US LNG Imports offset Decreases in Canadian Natural Gas Exports

There are four LNG receiving terminals in the US – (i) Lake Charles, Louisiana; (ii) Elba Island, Georgia; (iii) Cove Point, Maryland; and, (iv) Everett, Massachusetts – all of which are currently active. LNG is becoming a very important part of the US natural gas supply mix, accounting for nearly 2% of total US supply in 2003.

LNG imports of 507 Bcf accounted for nearly 13% of all natural gas imported into the US in 2003, up significantly from the 228 Bcf, or 6% contribution to total imports in 2002. Canadian natural gas exports to the US declined by 299 Bcf, while US imports of LNG increased by 279 Bcf. US LNG imports almost completely offset the decline in pipeline imports from Canada.

Overall, physical export flows from Canada to the US were 3,481 Bcf in 2003, declining 8% from 2002 levels. Canadian natural gas imports from the US totalled 371 Bcf in 2003, an increase of 111 Bcf over 2002 levels. As a result, net Canada to US exports fell significantly from 3,520 Bcf in 2002, to 3,110 Bcf in 2003. This represents a decline of 12%.

On a regional basis, physical exports to the US West region fell 16%, exports to the Midwest fell 3%, while exports to the US Northeast fell 8%. The main reasons for declining exports were: high Canadian demand, flat North American production, US pipeline expansions in the Rockies and low US demand.

Despite lower export volumes in 2003, producer export revenues surpassed record 2001 levels of CDN$22.8 billion, reaching CDN$23.4 billion. In 2003, revenues increased by CDN$7.23 billion, or 44% over 2002, due to higher natural gas prices.

Storage Swings in 2003

Cold weather and high core demand in early 2003 resulted in early, substantial withdrawals from storage. As a result, North American storage levels on April 1, 2003 (the start of the spring injection season), were 759 Bcf, 54% lower than 2002 levels of 1,656 Bcf. For comparison, the five year average for April is about 1,260 Bcf, 40% higher than April 2003 levels. Lower US demand allowed for large and much needed injections into storage throughout the summer of 2003. Storage peaked at the start of November at 3,620 Bcf, 4% above the normal level of 3,484 Bcf.

In November and December of 2003, temperatures eased in comparison to 2002. Due to warmer weather, storage levels by year-end 2003 were 282 Bcf higher than year-end 2002. By the end of the heating season (April 2004), there was 403 Bcf more natural gas in North American storage than in April 2003. Market fears over low storage levels were a factor in keeping prices high in 2003 and into 2004.

Strong Prices in 2003

After falling across the continent in 2002, natural gas prices rebounded strongly in 2003. Prices in 2003 reached record or near record highs in all major regions of North America. For example, in 2003, NYMEX prices were 67% higher while Alberta prices were 85% higher. It appears natural gas prices have now moved permanently into the US$4-6/MMBtu range. There are several reasons for this change in pricing and in 2003 these included; low storage inventories, high crude oil prices, cold weather, and flat production.

Weather can play a significant role in determining natural gas prices, and is often referred to as the demand "wild card". During the first quarter of 2003 the US northeast and Canada experienced frigid winter temperatures, which increased demand, bringing prices at the NYMEX above US$6.50/MMBtu. At about the same time, natural gas production slipped below expectations, fueling high prices. Cooler weather throughout the second and third quarters eased summer demand for natural gas-fired electrical generation, but prices remained high, due to continued storage concerns. As a result, NYMEX prices averaged US$5.40/MMBtu and US$4.97/MMBtu for the second and third quarter of 2003 respectively. Throughout the last quarter of 2003 storage fears began to diminish and NYMEX prices moderated slightly, averaging US$4.58/MMBtu.

Regionally, the largest price increase was in the Rockies, which more than doubled 2002 average prices. This was a result of increased pipeline capacity in the region, creating greater interconnectivity between the Rockies and the Pacific Northwest and California, thereby equilibrating prices between regions. Prices in the eastern markets began to rise above their western counterparts, with Boston, NYMEX and Dawn prices tracking higher. This was mainly due to colder winter weather in the US Northeast which created a surge in demand and also resulted in large disparities between Boston and AECO prices.

Since many industrials and power generators can switch from natural gas to crude oil-derived fuels, world crude oil prices influence natural gas demand and prices. In 2003, West Texas

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Intermediate oil prices averaged $30/barrel, up $5 over 2002. Thus, high oil prices supported high natural gas prices throughout 2003.

Canadian Reserves Down, US Reserves Up
Reserves data comes out about one year after the fact. US proved reserves as of January 1, 2003 were 187 Tcf, up 2% from a year earlier. Canadian proved reserves as of January 1, 2003 were 58.7 Tcf, down 2% from year-earlier levels. Total North American reserves rose 1% as new identified proved reserves were greater than production.

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 – Tight Market
Natural gas prices have risen steadily from a 2002 Alberta spot price of CDN$3.83/GJ, to average $6.31/GJ in 2003 to $6.48/GJ over the first seven months of 2004. Key factors affecting natural gas prices have been a continuing tight supply-demand balance, high world crude oil prices, and relatively strong economic growth. Prices might have been even higher if it were not for a fairly warm winter in 2003/04, which allowed natural gas storage inventories to build, entering the 2004 summer above normal levels.

On April 1st, 2004, 2,338 Bcf needed to be injected into storage to reach 3.5 Tcf by November 1st. Injections into storage this summer have been more than adequate, as mild weather reduced demand in the core and non-core sectors. As of October 1st, industry is on track to reach, or even surpass, 3.5 Tcf in preparation for the winter heating season.

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

Besides storage and weather, natural gas drilling and production, and crude oil prices will influence natural gas prices. Canadian natural gas well completions have increased steadily since 2002. During the first 7 months of 2004, 8,634 wells have been drilled, 43% more than the same period in 2003. It is expected that more than 14,000 wells will be drilled in 2004, surpassing last year's record figures.

While deliverability in the WCSB continues to be a concern, there is some positive news. According to preliminary Statistics Canada data, natural gas production rose 2% over the first five months of 2004 compared with last year, largely the result of record drilling in 2003.

Despite record levels of drilling for natural gas in North America, only minor improvements in the supply picture are likely through 2005. Therefore, natural gas prices are expected to remain high. Alberta prices averaged CDN$6.31/GJ in 2003 and are expected to average $7.25/GJ over the 2004/05 winter heating season. For the 2005 calendar year, a "consensus" view shows Alberta prices at CDN $7/GJ.

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Outlook to 2020 – Downward Revisions
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 nearly 29 Tcf; Canadian demand 4 Tcf, for a North American total of 33 Tcf. This is an increase of 8.2 Tcf, or 33% above 2003 demand levels, and represents an average annual increase of about 1.5% per year. Industrial and electric power generation demand is expected to account for most of this increase.

In 2020, this demand would be satisfied by: US natural gas production of 21.7 Tcf; Western Canadian natural gas production of 5.5 Tcf; Scotian natural gas of 0.7 Tcf; MacKenzie Delta natural gas of 0.6 Tcf; Canadian LNG imports of 0.4 Tcf; and nearly 4 Tcf of LNG imports to the US.

Compared to our report last year, North American supply forecasts have been revised downwards, largely the result of declining expectations regarding conventional North American natural gas production. However, forecasted declines in conventional production are largely offset by greater expectations regarding the importation of foreign LNG into North America, including into Canada.

About 4.4 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 2 Tcf in 2015. In 2020, LNG imports are expected to account for more than 13% of total North American natural gas supply.

MacKenzie Delta natural gas is also included in the Canadian production forecasts. The average of three forecasts shows MacKenzie Delta natural gas production coming on stream in 2010 at nearly 1 Bcf/d, and reaching 0.64 Tcf, or about 1.8 Bcf/d by 2020.

This year, 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 EIA, Alaska natural gas is expected to come on stream in 2018, initially delivering 4 Bcf/d of natural gas to markets in Canada and the Lower 48.

US nominal natural gas prices are expected to average about US$4.50/MMBtu in 2004, reaching more than $6.00 by 2020. Alberta nominal prices are expected to average CDN$5.60/GJ in 2004, with an average price of $5.40 over the forecast period. Price expectations have increased in the past two years.

In previous versions of this report, our export forecast began with assumptions about export pipeline capacity, then applied gradually increasing load factors on that capacity to yield rising exports. Since last year, we can no longer use that methodology, as it appears that exports are now limited by supply, rather than by export capacity. Accordingly, the "consensus" export forecast simply incorporates various forecasters' views on Canadian production and demand. The "consensus" view shows net exports remaining relatively flat over the 2004-2020 time period, hovering between 2.7 Tcf and 3.5 Tcf per year.

According to "consensus" views, US LNG imports are expected to surpass US pipeline imports of Canadian natural gas by about 2015. Our "consensus" forecast shows US LNG imports of approximately 3.6 Tcf in 2015, while gross imports of Canadian natural gas are forecast to equal about 3.5 Tcf.

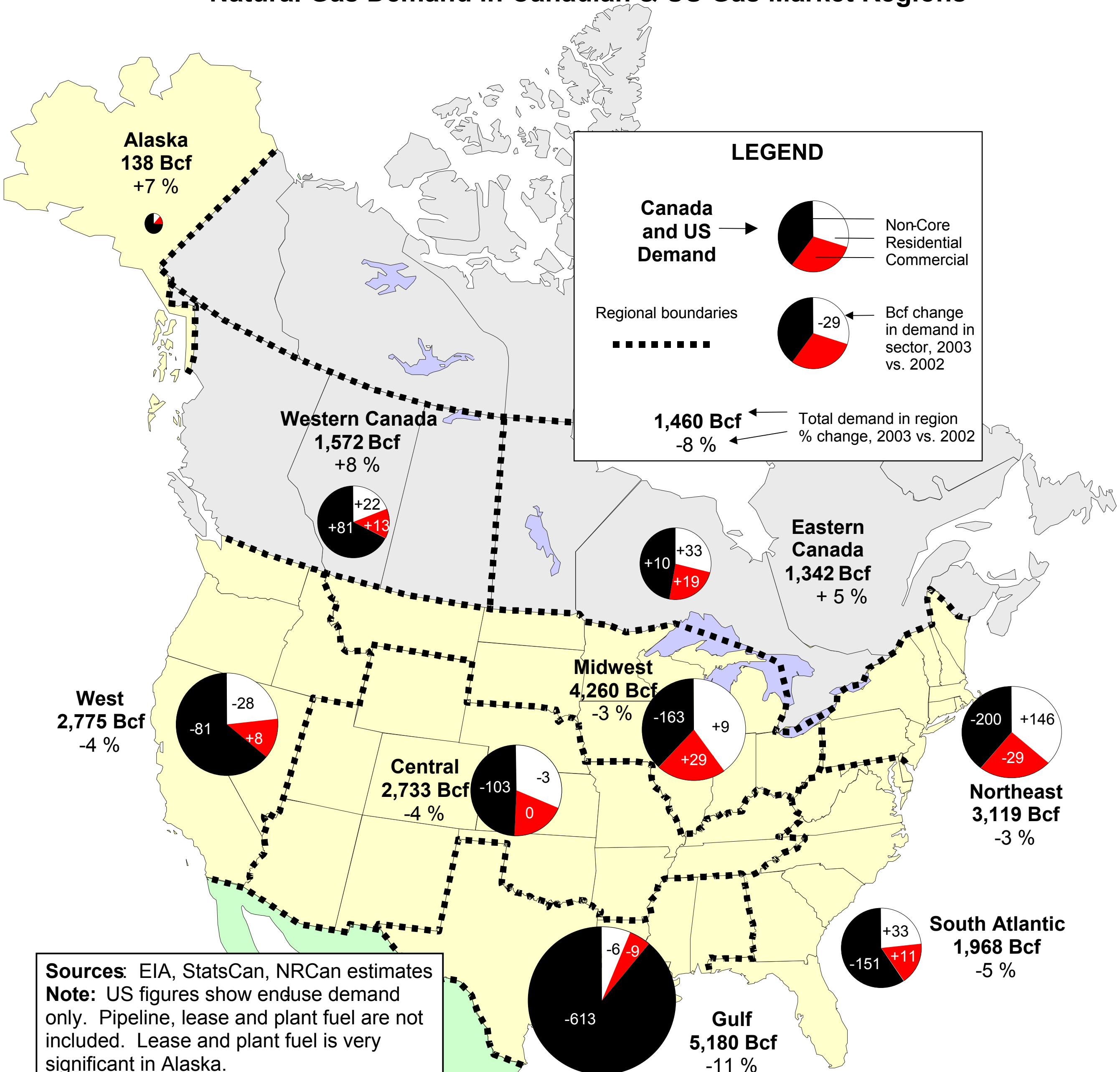
Given assumptions about Canadian natural gas production, exports, and industry price forecasts, producer plant gate revenues from natural gas sales are expected to reach CDN $46.6 billion by 2020, exceeding record revenues of $39.9 billion in 2003.

Overall, the forecasts of natural gas market fundamentals suggest a slight slowing in growth compared to historical trend patterns. It appears that "the times they are a-changin'"…..

Review of 2003

Natural Gas Demand

Map 1
Natural Gas Demand in Canadian & US Gas Market Regions



Sources: EIA, StatsCan, NRCan estimates
Note: US figures show enduse demand only. Pipeline, lease and plant fuel are not included. Lease and plant fuel is very significant in Alaska.

The locations and scale of natural gas demand in North America[1] are shown on the map. Also shown are the changes in demand compared to last year, by region and sector.

Overall, in 2003, the demand for natural gas in North America decreased 4%. US demand fell 5%, while Canadian demand increased 7%. The largest losses were felt in the Gulf and South Atlantic regions of the US. Demand for gas increased 7% in Alaska.

Non-core demand was down in every region of the US, most especially in the Gulf and the Northeast. In Canada, non-core demand increased 6% in 2003.

Colder weather experienced in the northern and eastern areas of North America in 2003 resulted in gas demand increases in the residential and commercial sectors.

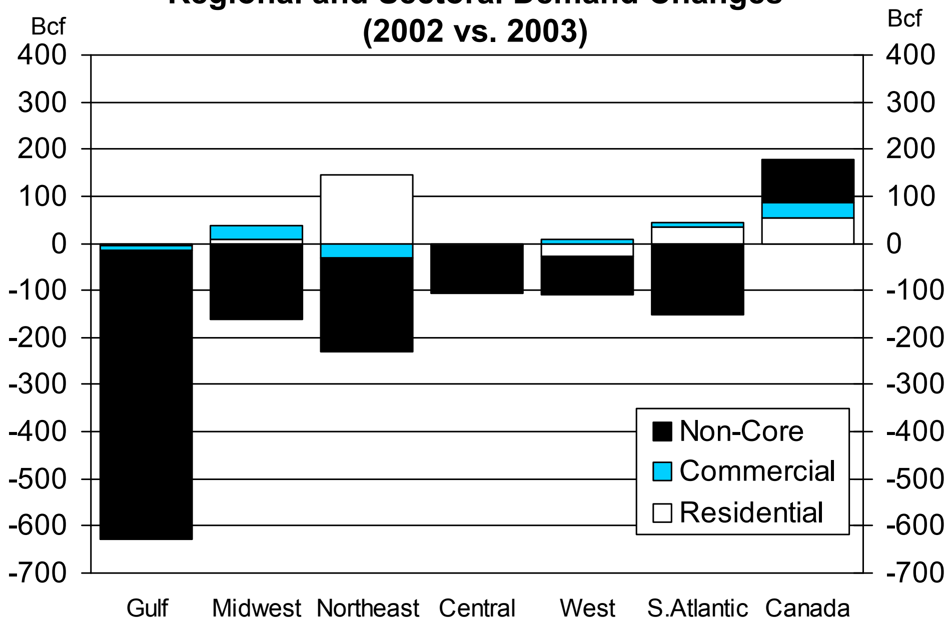
[1] Mexico is generally excluded from this report.

Table 1
Demand for North American Natural Gas

	2003 (Bcf)	2002 (Bcf)	Change (Bcf)	Change (%)
US Residential	5,085	4,890	195	4%
US Commercial	3,127	3,103	24	1%
US Industrial	6,966	7,557	-591	-8%
US Electric Power	4,929	5,672	-742	-13%
US Other[1]	1,769	1,796	-27	-2%
Total US Demand	**21,877**	**23,018**	**-1,141**	**-5%**
US LNG Exports	64	63	1	2%
US Exports to Mexico	333	263	70	27%
Total US Gas Disposition	**22,274**	**23,344**	**-1,070**	**-5%**
Canada Residential	675	620	55	9%
Canada Commercial	518	486	32	7%
Canada Industrial	1,029	970	59	6%
Canada Electric Power	282	261	21	8%
Canada Other[2]	410	399	11	3%
Total Canadian Demand	**2,914**	**2,736**	**178**	**7%**
TOTAL N.A. DEMAND	**24,791**	**25,754**	**-963**	**-4%**
TOTAL N.A. DISPOSITION	**25,188**	**26,080**	**-892**	**-3%**

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 (2002 vs. 2003)



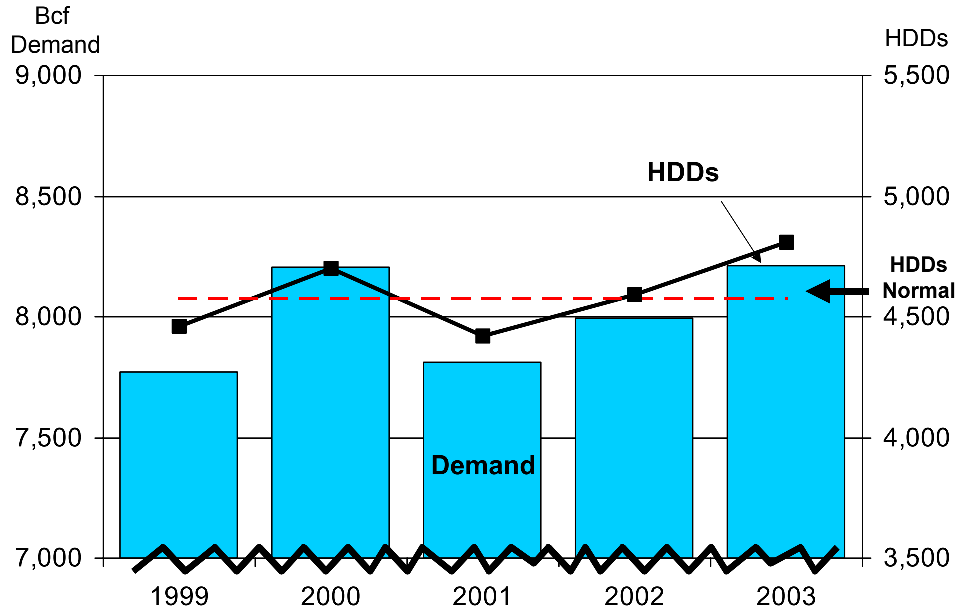
Sources: EIA, StatsCan, NRCan estimates **Notes:** Producer use & pipeline fuel is not shown.

Total North American gas demand was down 4% in 2003. In the US, core (residential and commercial) demand saw a combined 219 Bcf gain, or 3%, due to colder than normal weather. US gas used by industrials and for power generation fell 1,333 Bcf, or 11%. The decline was a result of high natural gas prices, making natural gas use for industrial purposes uneconomic.

Canadian demand in 2003 was 2,914 Bcf, 7% higher than 2002. Increases in core demand were driven by colder than normal temperatures across much of the country. Non-core demand increases were driven by and higher electric power demand and an upswing in industrial demand.

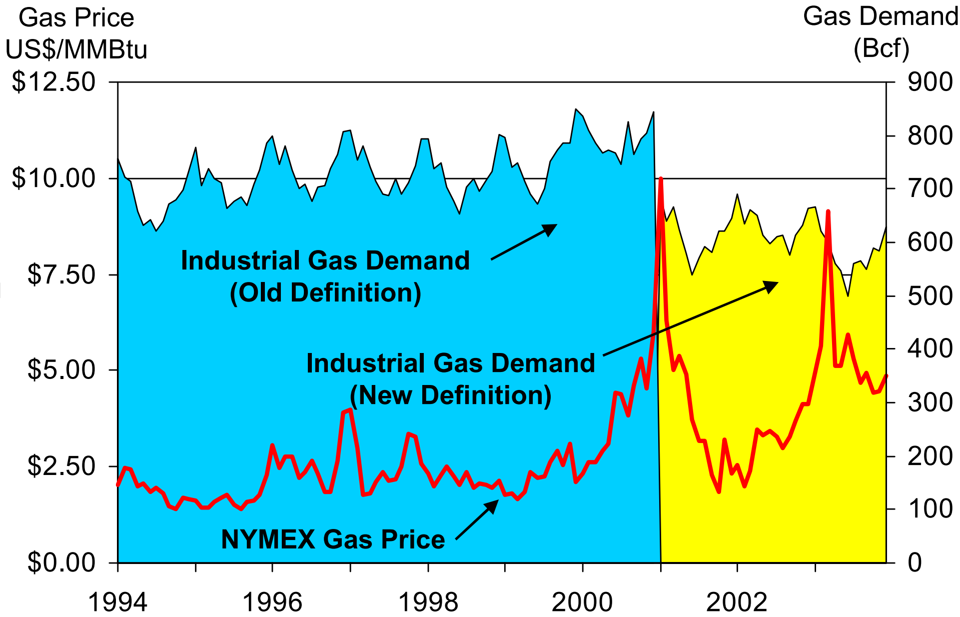
North American natural gas consumption was 963 Bcf, or 4% lower in 2003. Contributing to this decrease was the large non-core demand losses felt in all regions, except Canada. The Gulf of Mexico, which has the greatest gas demand of all North American regions saw huge declines in non-core demand over 2002. The US northeast also experienced large declines in non-core demand, which was partially offset by higher residential demand. Commercial demand changes were relatively insignificant in 2003.

Figure 2
US Heating Degree Days & Core Demand



Sources: EIA, NOAA

Figure 3
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.

As a long-term trend, heating degree days have been closely correlated to core demand; higher numbers of degree days yield higher core gas demand. This is because the majority of core gas demand is used for heating and in response to colder weather (more heating degree days), demand for heat from gas increases.

In 2003, heating degree days and core demand were once again closely correlated as demand rose 3% and heating degree days rose 5% when compared to 2002.

2003 saw 216 more heating degree days than 2002, and recorded the highest levels of heating degree days since 1997.

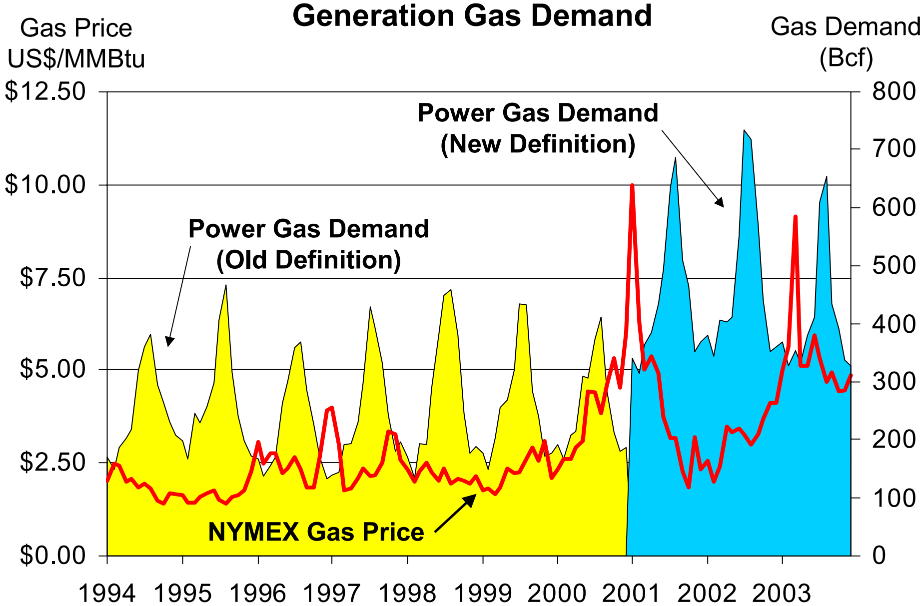
In 2003, the EIA radically changed its industrial gas demand definition and statistics, causing the volumes consumed to be smaller than previously presented.

The graph above shows the EIA's former industrial demand numbers as well as its new numbers. By any measure, US industrial demand is declining in response to high gas prices. In 2003, industrial sector natural gas demand fell 8%, or nearly 600 Bcf from 2002 levels.

Industrial gas users are closing facilities in North America and moving to areas of the world where gas prices are lower.

Figure 4

NYMEX Gas Price 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 2

US Electric Generation (Thousand MwHrs)

Industry	Year			% Change	Industry
	2003	2002	2001	from 2002	%
Coal	1,970,272	1,933,131	1,903,955	2%	51%
Oil	118,256	94,568	124,880	25%	3%
Natural Gas	629,206	691,004	639,129	-9%	17%
Other Gas	10,937	11,464	9,040	-5%	0%
Nuclear	763,726	780,064	768,825	-2%	21%
Hydro	266,340	255,586	208,137	4%	6%
Renewables	84,176	86,921	77,983	-3%	2%
Other	5,078	5,716	4,690	-11%	0%
Total	**3,847,991**	**3,858,454**	**3,736,639**	**0%**	**100%**

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

Figure 4 shows monthly natural gas demand for power generation in the US. In 2003, the EIA also changed its power generation definition and statistics, retroactive to 2001. The new definition attributes more gas demand to the power generating sector as it now includes the gas used by those industrial power plants that identify themselves as producing mainly power, rather than heat. This was previously reported as gas demand in the industrial sector.

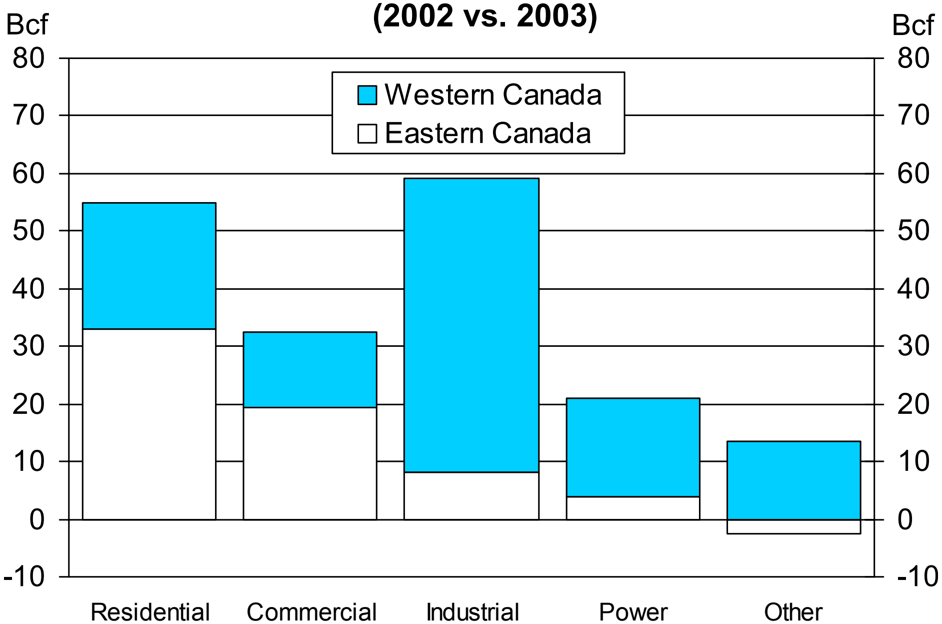
In the US, natural gas demand for power generation has climbed from less than 3 Tcf in 1997 to 5.7 Tcf in 2002. In 2003, gas demand for power generation fell 13%, or 742 Bcf.

In 2003, total US electric industry generation from all sources was flat compared with 2002.

Electricity generated from natural gas posted a 9% loss, a reversal from the previous year. However, oil use for power generation rose by 25% in 2003, largely due to lower oil prices relative to natural gas prices. This gain in oil usage is in striking contrast to a 24% loss in 2002 compared to 2001.

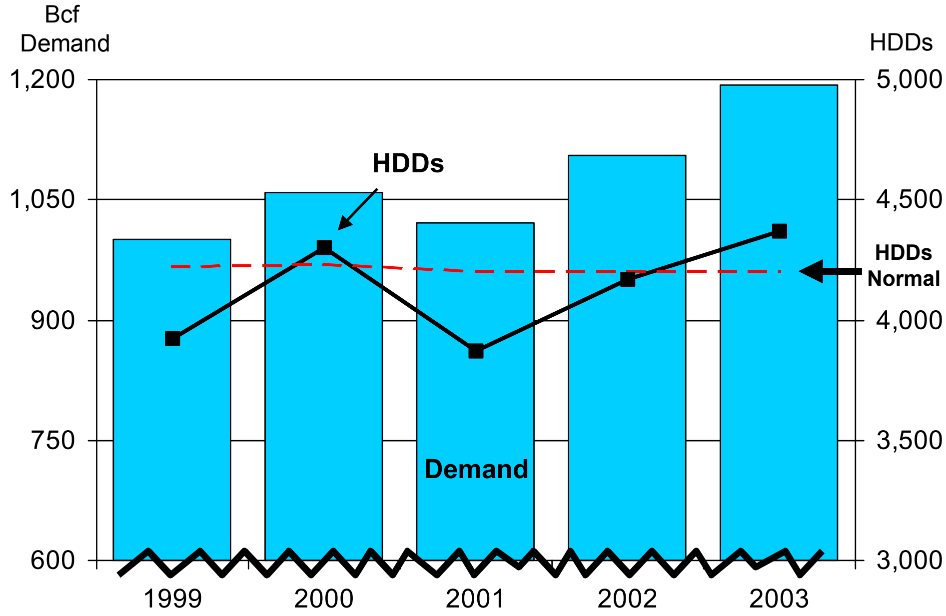
The percentage distribution of fuel type for electrical generation has remained relatively flat in recent years, with coal continuing to represent more than half of all electricity generation.

Figure 5
Canadian Sectoral Demand Changes (2002 vs. 2003)



Sources: StatsCan, Alberta Energy and Utilities (AEUB).

Figure 6
Canadian Heating Degree Days & Core Demand



Sources: StatsCan, NRCan estimates

Figure 5 shows sectoral demand changes in western and eastern Canada from 2002 to 2003. Demand for natural gas in Canada increased 7% in 2003. Demand in Western and Eastern Canada were up 8% and 5%, respectively. Residential and commercial demand were up significantly in response to colder than normal weather throughout the heating season of 2003.

Non-core demand also increased throughout Canada, but particularly in the West. High Western industrial gas demand was centralized in Alberta and Saskatchewan, each up 15% over 2002 levels, while British Columbia and Manitoba were down 8% and 7%, respectively. In Alberta alone, industrial gas demand was up by 40 Bcf over 2002, primarily due to oil sands operations, which in 2003 consumed 220 Bcf of natural gas.

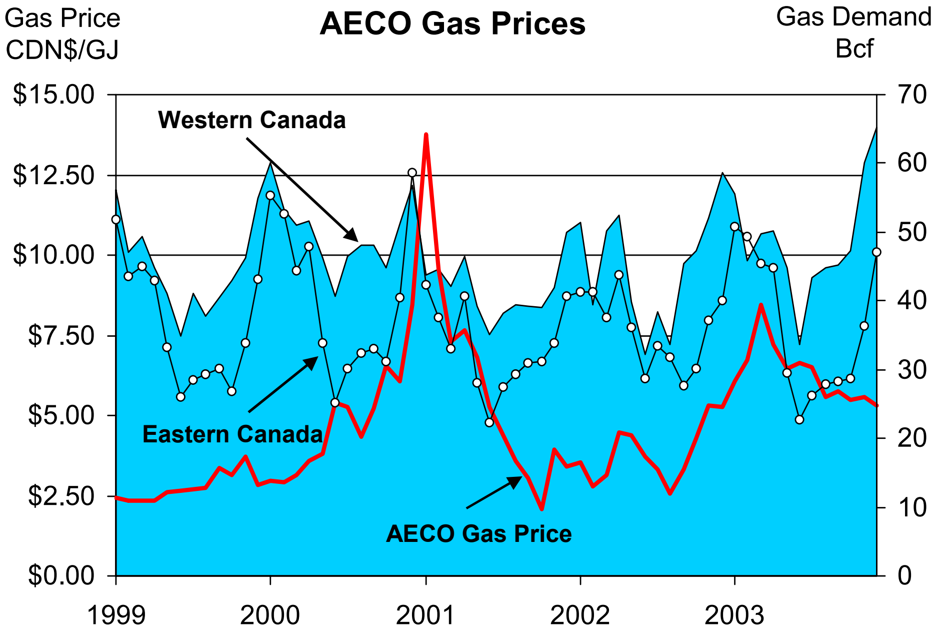
The correlation between core demand and heating degree days is strong in Canada.

Heating degree days increased 5% and core demand increased 8%. This result is consistent with historical patterns and reinforces the link between weather patterns and core demand.

In 2003, Canada's HDD's surpassed 4,300, marking the coldest Canadian winter since 1996, when Canada registered over 4,700 HDD's.

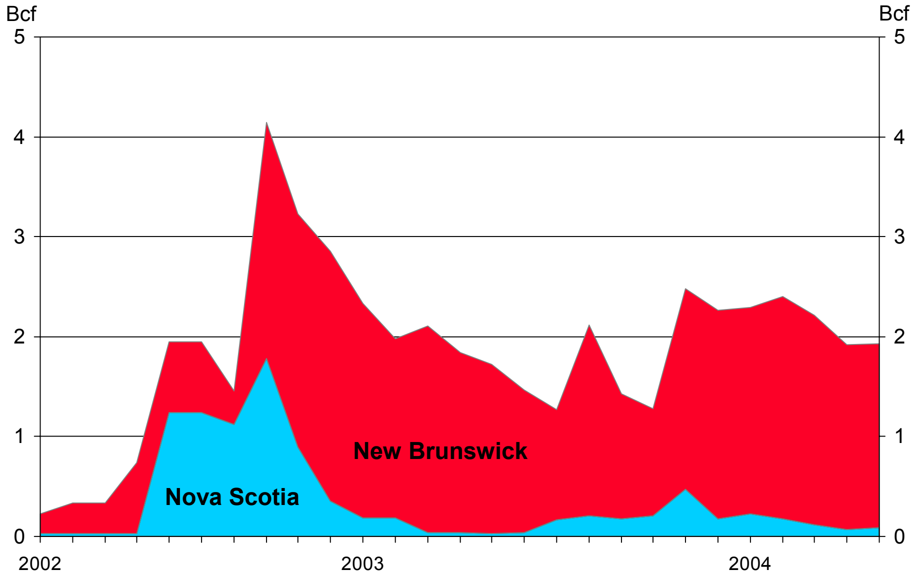
There were 167 more HDD's in Canada than normal in 2003. This makes 2003 a significantly colder year than 2002, and therefore resulted in increased residential and commercial natural gas demand.

Figure 7
Canadian Industrial Gas Demand vs. AECO Gas Prices



Sources: StatsCan, GLJ, NRCan estimates

Figure 8
Maritimes Natural Gas Demand



Source: StatsCan

In Canada, Eastern and Western industrial demand generally move together. Historically, Canadian industrial gas demand has not traditionally been very price sensitive. However, since the price spike during the winter of 2000/2001, the Canadian industrial gas market has become much more volatile and unpredictable.

In 2001, Canadian natural as prices averaged CDN $5.91/GJ and industrial demand responded, falling 9% in 2001. In 2002 prices dropped, averaging $3.83/GJ and industrial demand increased 8%. In 2003, natural gas prices averaged $6.31/GJ, their highest level on record, yet 2003 industrial gas demand rebounded 6% over 2002 levels, despite an 85% increase in prices.

Figure 8 shows the demand for natural gas in Nova Scotia (NS) and New Brunswick (NB). Demand for natural gas in the Maritimes was 22 Bcf in 2003 and 17 Bcf in 2002.

Canadian natural gas consumption in the Maritimes varies between 10 and 25 percent of the total gas produced in the region, with the remainder exported to the US. The gas purchased domestically, however, may be up to several times the amount consumed, which indicates that some gas is traded or re-sold amongst the area players. Currently, four buyers account for over 90 per cent of the natural gas consumed and purchased in the domestic market.

The main distributors of natural gas in Atlantic Canada are Heritage Gas in NS, and Enbridge Gas New Brunswick in NB.

Table 3
Canadian Natural Gas Demand

Sector	2003	2002	2001	2000	1999
Bcf:					
Residential	675	620	578	621	590
Commercial	518	486	443	438	412
Industrial	1,029	970	897	1,083	971
Electric	282	261	301	268	198
Other	410	399	478	462	530
Total	**2,914**	**2,736**	**2,697**	**2,872**	**2,700**
Percentage:					
Residential	23%	23%	22%	22%	22%
Commercial	18%	18%	16%	15%	15%
Industrial	35%	35%	33%	38%	36%
Electric	10%	10%	11%	9%	7%
Other	14%	15%	18%	16%	20%

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

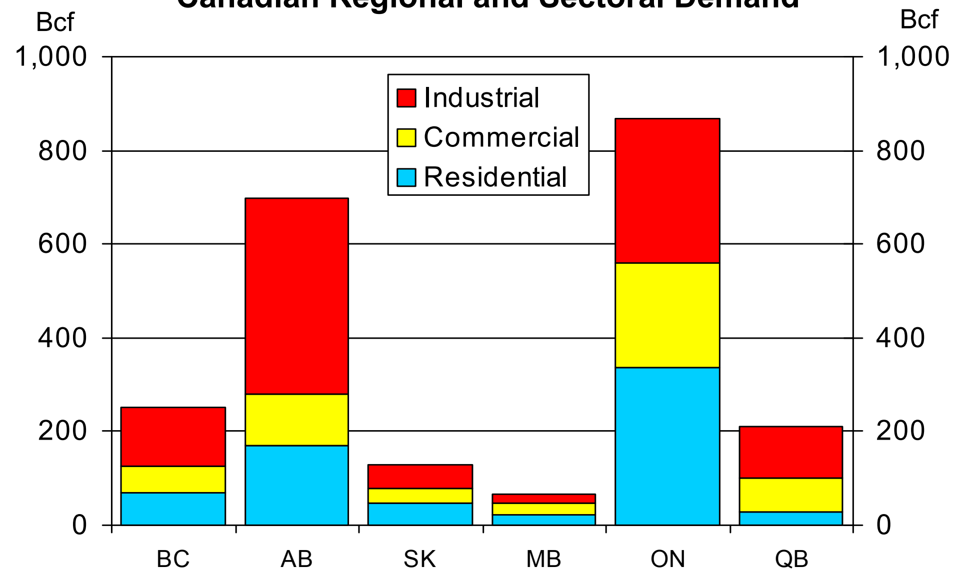
In 2003, total Canadian natural gas demand increased 7%.

The percentage distribution of gas demand remained virtually identical when compared to 2002.

Industrial gas sales accounted for the largest portion of natural gas sold in Canada in 2003, with 35% of the market. This is a decline in the sector's former take of domestic natural gas demand of around 38%.

Residential gas demand remained at 23%, electric demand remained at 10%, commercial at 18%, while other gas was down slightly from 15% to 14%.

Figure 9
Canadian Regional and Sectoral Demand



Sources: StatsCan, NRCan estimates

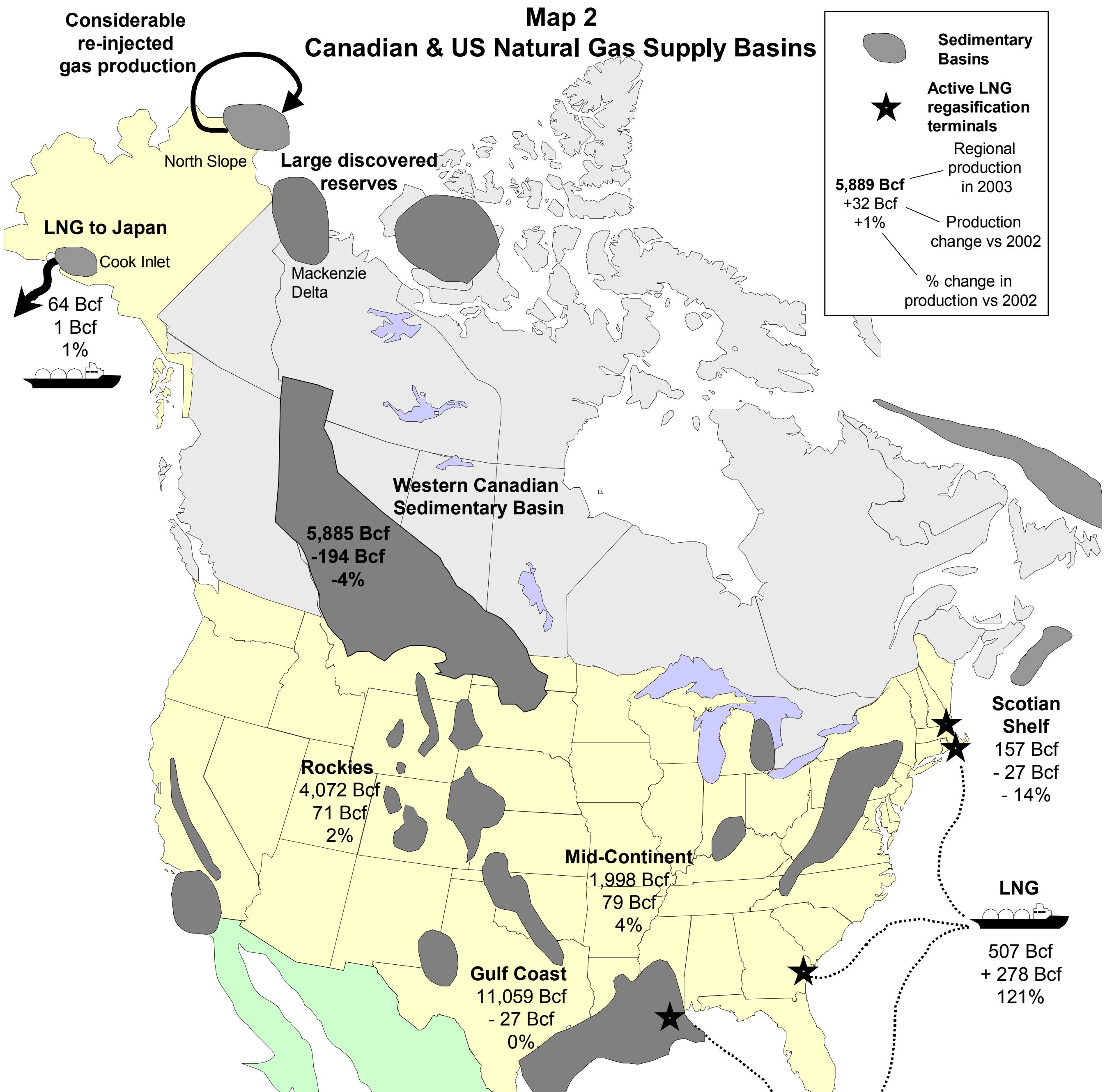
The figure above illustrates Canadian demand for natural gas in 2003 by region and sector.

Natural gas use in Alberta is dominated by its industrial sector, consuming nearly 420 Bcf of gas in 2003, or 40% of total Alberta gas demand.

Ontario, the most populous province, accounted for the most gas used by any single province. Ontario's demand for gas is dominated by its many residential and commercial gas users. In 2003, Ontario's core sector consumed nearly 560 Bcf of gas, representing almost 20% of all natural gas consumed in Canada.

Review of 2003

Natural Gas Supply



Sources: EIA, StatsCan, NRCan estimates

Map 2 shows the major natural gas producing basins of Canada and the US. In 2003, supply was lower in Canada, but higher in the US.

The largest supply reduction of any region in North America occurred in the WCSB, where production declined by 194 Bcf, despite record drilling.

While the Gulf Coast saw a slight production decline in 2003, this was offset by production increases in other areas, notably the Mid-Continent, where production increased by 4% compared to 2002.

Net LNG imports by the US were up 121% in 2003. Total LNG volumes remain minor at about 2% of total US supply. However, LNG continues to become an even more important source of incremental supply to North America.

Table 4
North American Gas Supply

	2003 (Bcf)	2002 (Bcf)	Change 02 vs 03	% Change 02 vs 03
Gulf Onshore[1]	6,798	6,637	161	2%
Gulf Offshore[2]	4,261	4,449	-188	-4%
Total Gulf	11,059	11,086	-27	0%
US Midcontinent[3]	1,988	1,910	79	4%
US Rockies[4]	4,072	4,000	71	2%
Other US	1,949	1,968	-18	-1%
Total US Production	**19,068**	**18,964**	**105**	**1%**
Western Canada[5]	5,885	6,079	-194	-3%
Scotian Shelf	157	184	-27	-14%
Total Canada Production[6]	**6,042**	**6,263**	**-221**	**-4%**
Total N.A. Production	**25,110**	**25,226**	**-116**	**0%**
US Net LNG Imports	443	165	278	169%
US Net Mexican Imports	-333	-261	-72	27%
US Supplementals[7]	65	68	-3	-4%
Total N.A. Supply	**25,285**	**25,198**	**88**	**0%**

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 4 summarizes total North American natural gas supply over the past two years. Total North American production decreased 116 Bcf, or change of less than 1% from 2002. US production increased by 105 Bcf, which is a turnaround from last year when the US had a domestic supply decline of 653 Bcf. Canadian production decreased by 221 Bcf, or 4%. The largest production decline occurred in western Canada, where increased drilling (as seen in Table 5) did not result in increased production.

Table 5
North American Gas Drilling Indicators

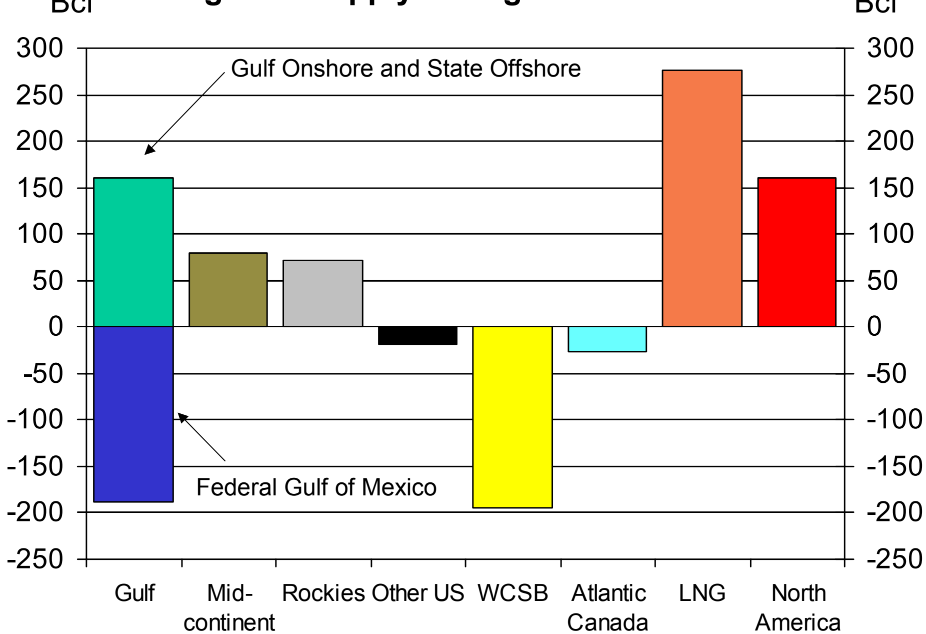
	2003	2002	Change 03 vs 02	% Change 03 vs 02
Active Oil & Gas-Directed Rigs: [1]				
Gulf Onshore [2]	523	402	121	30%
Gulf Offshore [3]	105	109	-3	-3%
Total Gulf	629	511	118	23%
US Midcontinent [4]	142	99	43	43%
US Rockies [5]	174	123	52	42%
Other US [6]	107	98	10	10%
Total US	**1,052**	**830**	**222**	**27%**
Active Gas-Directed Rigs: [7]				
Total US	**871**	**673**	**197**	**29%**
Canadian Gas Wells Drilled:				
Shallow [8]	10,982	6,804	4,178	61%
Deep [9]	2,950	2,266	684	30%
Total Canada [10]	**13,932**	**9,070**	**4,862**	**54%**

Sources: Texas RRC, Baker Hughes, Daily Oil Bulletin. **Notes:** [1] Number of wells not available, so average total weekly oil and gas-directed rig count used. [2] AL, LA, MS & TX onshore. [3] AL, LA, MS & TX offshore [4] AR, KS & OK. [5] CO, NM, UT & WY. [6] Remaining US. [7] Average total weekly gas-directed rig count. [8] Alberta West of 4th meridian gas wells, plus Saskatchewan gas wells. [9] Alberta W5 and W6 meridian gas wells, plus all British Columbia gas wells. [10] Total number of Western Canadian gas wells.

Table 5 summarizes North American crude oil and natural gas drilling over the past two years. Total active natural gas-directed rigs accounted for 84% of all active crude oil and natural gas rigs in the US. This is an increase from 2002, when 81% of all active rigs in the US were drilling for natural gas.

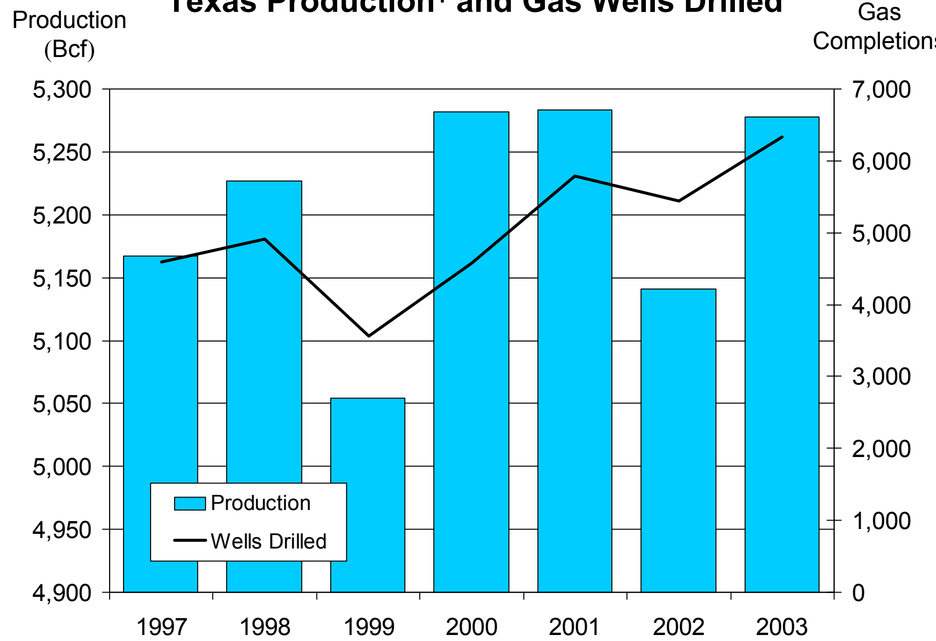
Generally, drilling rose across North America in 2003 compared to 2002, especially in the central regions. For example, in Canada, gas well completions were up 54%, with shallow wells accounting for 79% of all natural gas wells drilled. In the US, total active gas-directed rigs increased by 29%.

Figure 10
Regional Supply Changes: 2002 vs. 2003



Sources: EIA, StatsCan, CNSOPB, NRCan estimates

Figure 11
Texas Production[1] and Gas Wells Drilled



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

In 2003, North American gas production fell 117 Bcf. Production fell 4% in Canada and increased 1% in the US.

The WCSB and the US Gulf Coast offshore were responsible for the largest gas production declines, falling 194 Bcf and 188 Bcf, respectively. The most significant production increase occurred in the US Gulf Coast onshore region, where 161 Bcf more gas was produced in 2003 compared to 2002. As a result, total production from the Gulf of Mexico remained flat.

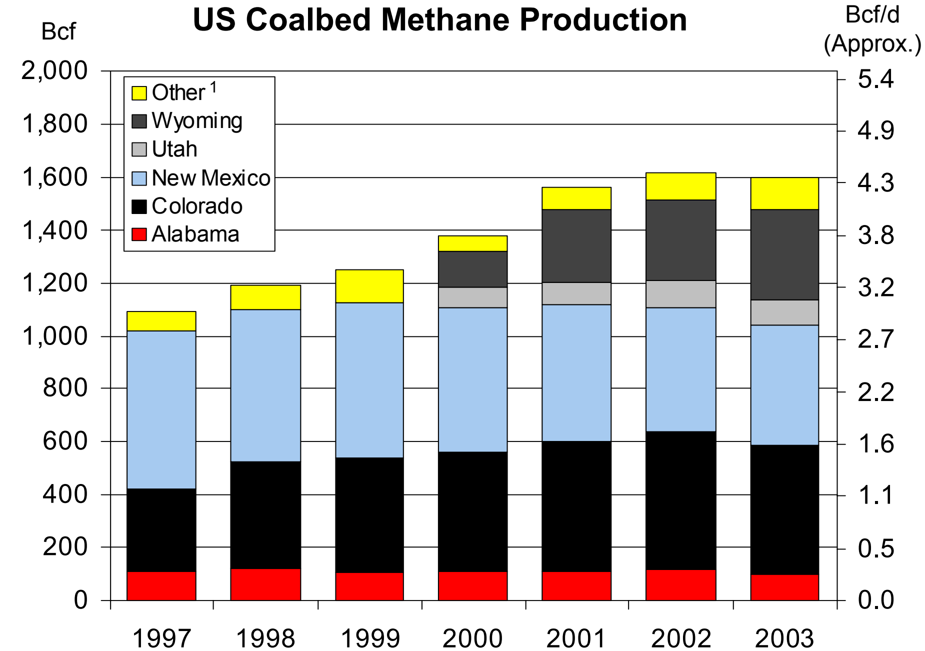
Although total domestic North American gas production declined in 2003, significant increases in LNG imports to the US, led to an overall increase of 164 Bcf in total North American supply.

Historically, Texas has produced between 30 and 35% of total US natural gas production, the largest percentage of any US state. As a result, Texas production is an excellent indicator of overall trends in US natural gas activity.

Texas marketable natural gas production (i.e., wet) was nearly 5.3 Tcf in 2003, 3% greater than in 2002. However, between 1997 and 2003, Texas natural gas production has hovered between 5 and 5.3 Tcf, a total increase of only 6%.

While Texas natural gas production was equivalent in 2000, 2001, and 2003, 35% more natural gas wells were drilled in 2003, compared with 1997. This illustrates, that despite historically high amounts of drilling, Texas natural gas production has been unable to increase by any significant amount over the past few years.

Figure 12
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.

Table 6
Summary of CBM Activity in Canada (2003)

British Columbia			Alberta Plains		
Coal Zone	**Projects**	**%**	**Coal Zone**	**Projects**	**%**
Gates	11	42%	Manville	39	43%
Elk	7	27%	Horseshoe Canyon	41	46%
Fernie	1	4%	Ardley	10	11%
Other	7	27%			
Total	**26**	**100%**	**Total**	**90**	**100%**

Source: Perspective Consultants Inc.

Coalbed methane (CBM) activity is well established in the US, with the largest known concentrations being in the Rocky Mountains of Wyoming, Montana, northern New Mexico, southern Colorado, eastern Utah, and Alabama. Large deposits of CBM are known and being developed in the Powder River Basin, San Juan Basin, Uinta Basin, Piceance Basin, and Raton Basin.

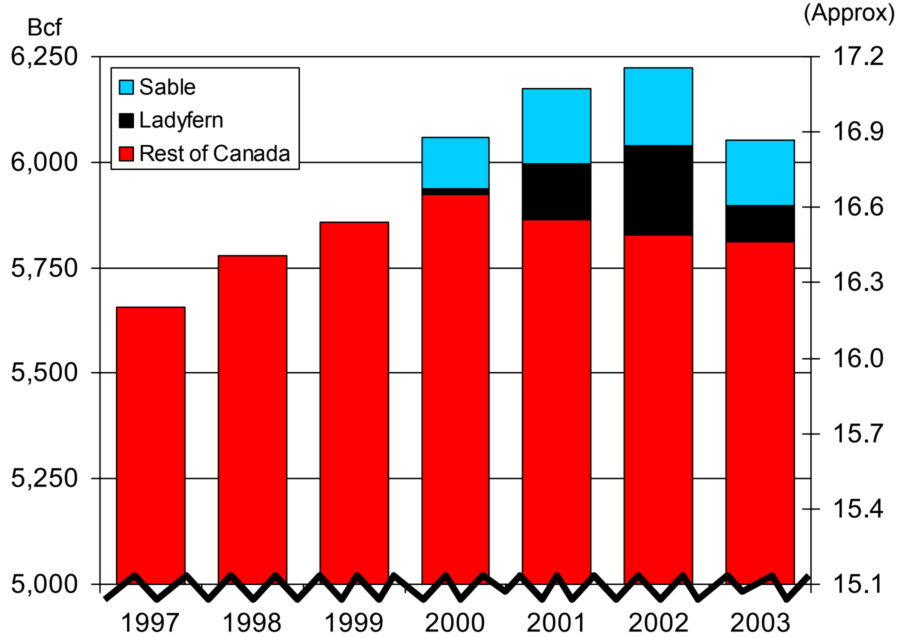
CBM production has increased every year since 1997, growing nearly 50% between 1997 and 2002. However, in 2003, CBM production remained flat (1,600 Bcf), accounting for 8% of total US natural gas production. Wyoming was only region that witnessed a significant CBM production increase in 2003 – 42 Bcf or 14% greater than 2002 levels.

Canadian CBM is slowly moving from an exploration phase into development mode. In the Alberta Plains, approximately 43% of projects have targeted the Manville Group, 46% have targeted the Horseshoe Canyon Formation, while around 11% exist in the Ardley zone. Since November 2003, 24 projects have been added to the Horseshoe Canyon coal zone, emphasizing the attractiveness of the dry and shallow CBM plays of this zone.

In British Columbia, the majority of activity is on the Gates Formation at around 42%, while activity in the Elk Formation represents approximately 27%. The remaining 30% of activity exists in other zones.

With respect to wells drilled over time, as of December 2003 the Alberta Energy and Utilities Board estimates that there were approximately 1015 CBM wells in Alberta, with 80% being drilled in the Horseshoe Canyon Formation. Production as of September 2004 is estimated at 70 MMcf/d.

Figure 13
Canadian Natural Gas Production

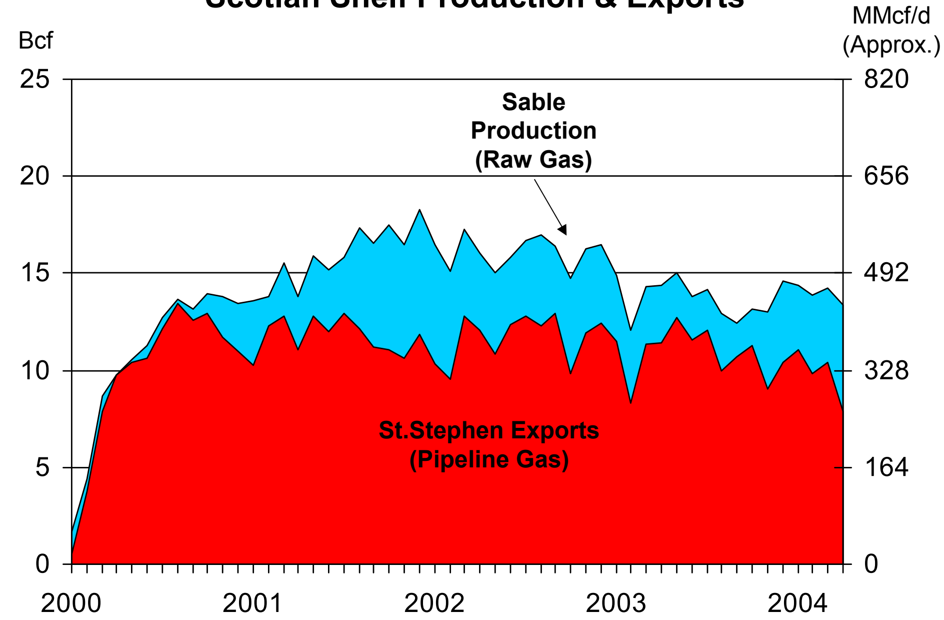


Sources: StatsCan, CNSOPB, BC Oil and Gas Commission, NEB, NRCan estimates

Canadian production declined 4% in 2003 – a 15% decline at Sable Island, a 60% decline at the once prolific Ladyfern natural gas field, and a 2% decline in the rest of Canada (i.e., western Canada and Ontario).

As predicted, production from the Ladyfern gas field in northeastern BC plummeted in 2003 after nearly doubling in 2002. Ladyfern was responsible for about 70% of total production declines in western Canada. Including Ladyfern, western Canadian natural gas production fell by about 0.5 Bcf per day, or 4%

Figure 14
Scotian Shelf Production & Exports



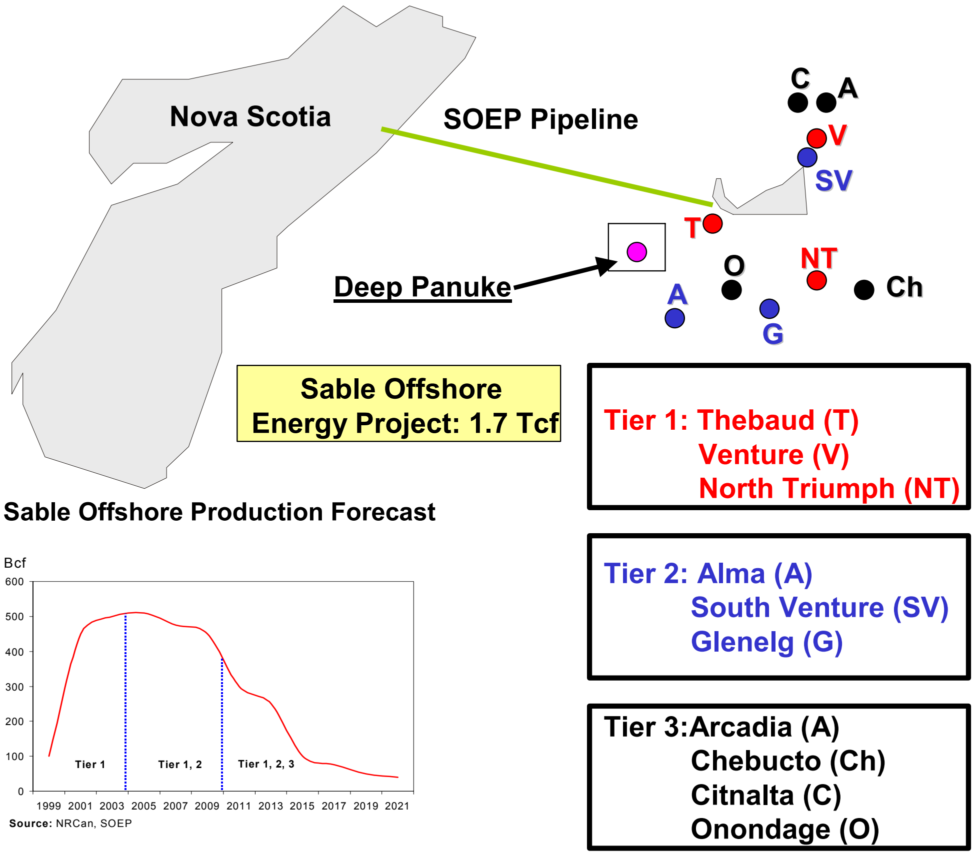
Sources: CNSOPB, NEB

Natural gas production from the Sable Offshore Energy Project (SOEP), offshore Nova Scotia, which began in 2000, has accounted for a large amount of growth in Canadian natural gas supply. However, in 2003, Sable production declined to 157 Bcf compared to 184 Bcf in 2002, representing a decrease of 14%.

Sable gas production peaked in December 2001, averaging nearly 590 MMcf per day, and has been declining ever since.

As shown in Figure 14, most of the natural gas is exported to the US via St.Stephen, New Brunswick. Approximately 79% of Sable natural gas was exported to the US in 2003, with the remaining 21% being consumed in Atlantic Canadian markets.

Map 3
East Coast Offshore Natural Gas Activity



Map 3 above shows natural gas activity off the coast of Nova Scotia. This includes the Sable Offshore Exploration Project (SOEP) and Encana's Deep Panuke project.

Scotian Shelf Reserves

There is an estimated 3.6-5.2 Tcf of discovered, and 4.8 Tcf of undiscovered natural gas in the Sable sub-basin. Also, in a 2002 report the Canadian Nova Scotia Petroleum Board estimated undiscovered gas resources in the deep portion of the Scotian basin to range between 15-41 Tcf.

Exploration

Since 1998, 12 of the 15 wells drilled offshore Nova Scotia have been unsuccessful in finding commercial quantities of natural gas. In 2003, 5 exploratory wells were drilled in the east coast offshore each with disappointing results. Based on drilling commitments and announced plans, the Nova Scotia Department of Energy expects that 2-4 new wells could be drilled offshore Nova Scotia by the end of 2004, bringing total wells drilled for 2003-2004 to 8-10.

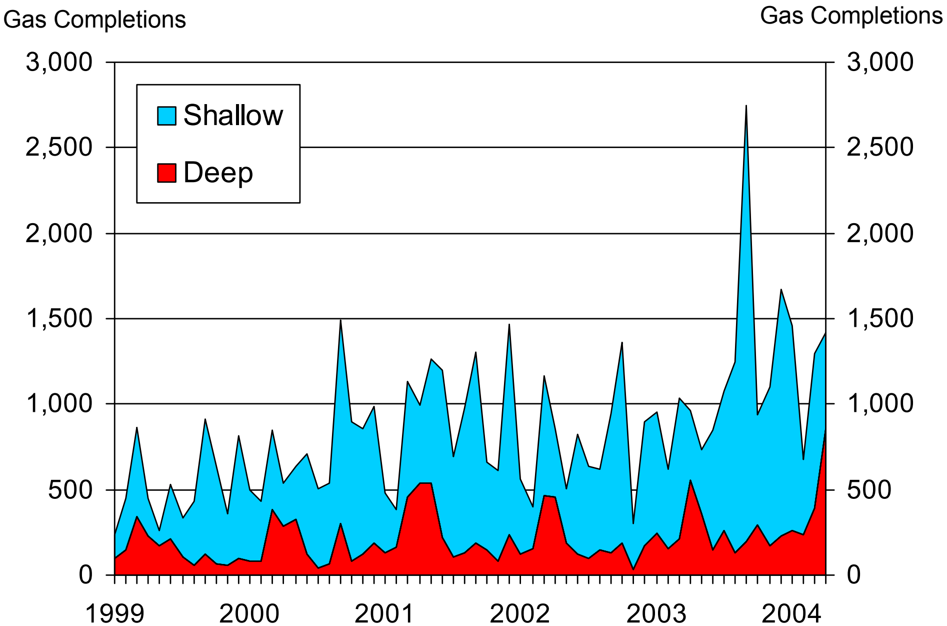
SOEP

The SOEP represents about 3% of Canada's natural gas production. In 2003, SOEP production levels fell 14% from 2002 and 9% from 2001. SOEP is owned by ExxonMobil, Shell Canada, Imperial Oil, Emera Offshore, and Mosbacher Operating Ltd. SOEP currently incorporates the production of gas from 4 separate fields (all 3 in Tier 1, and Alma in Tier 2) around Sable Island at a rate of 500 MMcf/d. Fabrication work continues on the South Venture development, with hopes to flow gas in late 2005. The Glenelg field, which was forecast to come on stream by 2007 has been found to be uneconomical as a stand alone project. Total estimated recoverable reserves are approximately 1.7 Tcf.

Deep Panuke

In February 2003, Encana's Deep Panuke project was suspended. In announcing their decision not to proceed further with the regulatory process, Encana indicated that they require more time to develop an understanding of options including design and commercial improvement.

Figure 15
WCSB Gas Completions



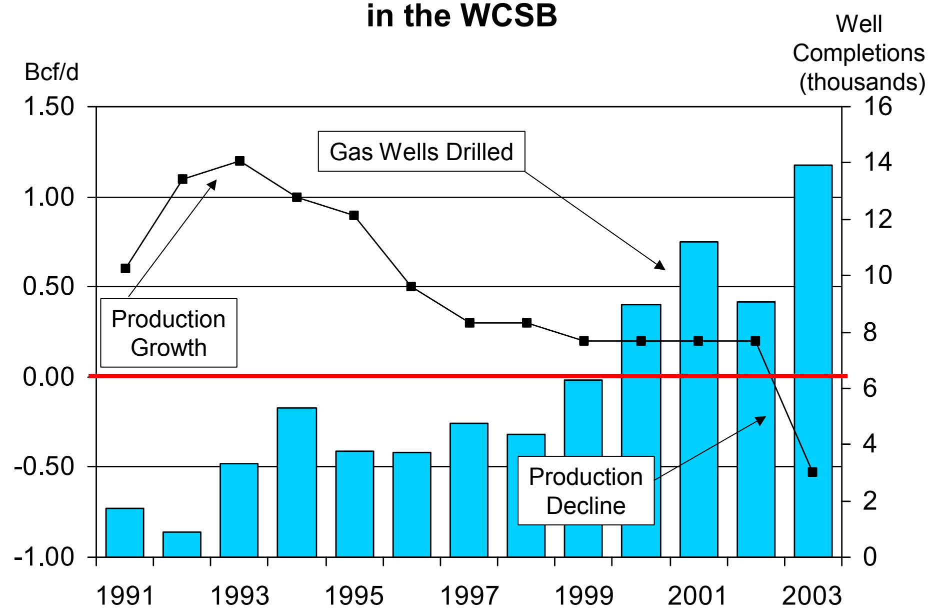
Source: Daily Oil Bulletin

Although 2002 was a historically busy year in the WCSB, drilling in the WCSB was still able to increase by a staggering 54% in 2003.

Overall, almost 14,000 wells were drilled last year in the WCSB, setting a new record, which was previously 11,150 in 2001. An average of over 38 wells were drilled every day, or over 1,100 per month. This compares to 1998 when only 365 wells were being drilled per month, on average.

Shallow drilling continues to boom, growing by 61% compared to 2002. Shallow drilling also raised its overall percentage of wells drilled, accounting for 79% of all wells drilled in Canada in 2003, compared to 75% in 2002. This is an increase of over 4,000 shallow wells compared to last year.

Figure 16
Production Change and Gas Wells Drilled in the WCSB

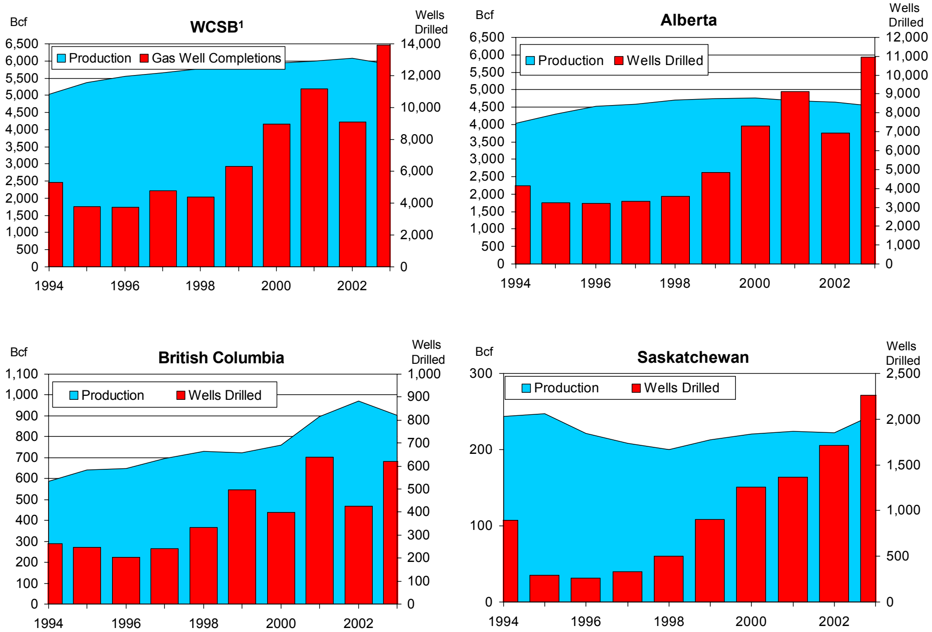


Sources: StatsCan, CAPP, Daily Oil Bulletin

Figure 16 shows the relationship between gas wells drilled and gas supply growth in the WCSB. In the early 1990's, production growth was significant relative to the amount of drilling activity.

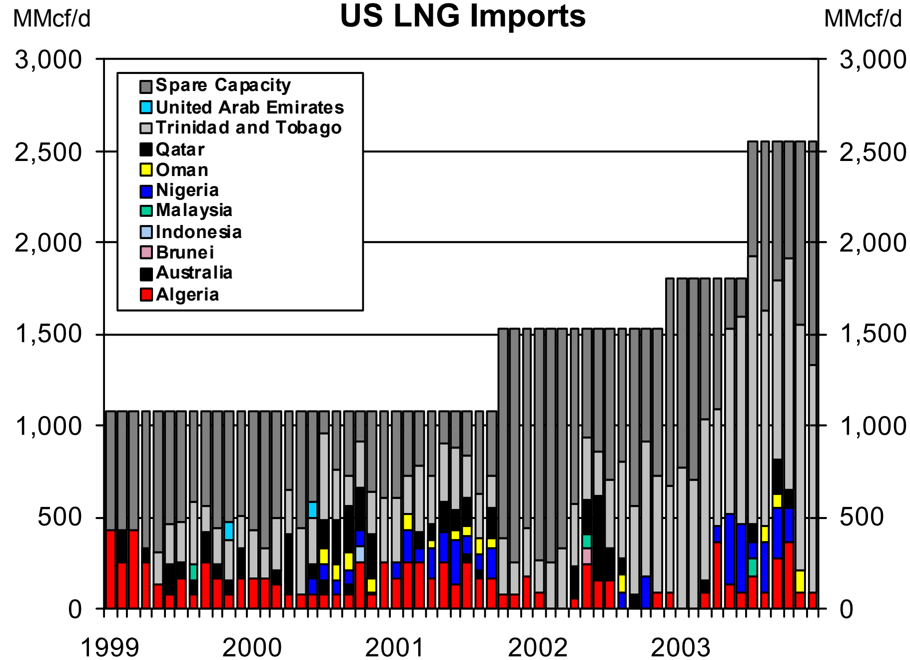
However, as the basin continues to mature, drilling activity has increased, well productivity has decreased and decline rates have increased. Despite record drilling in recent years, WCSB natural gas production has been increasing at a decreasing rate consistently since 1993. In fact, for the first time, the WCSB saw a production decline in 2003.

Figure 17
Production and Natural Gas Wells Drilled by Province



Sources: StatsCan, CAPP, Daily Oil Bulletin **Note:** (1) Includes BC, AB, SK, YK, NWT, MB

Figure 18
US LNG Imports



Sources: EIA, Company websites

Figure 17 shows the relationship between gas wells drilled and gas production by region.

In 2003, 13,900 wells were drilled in the WCSB, 53% more than 2002. However, despite record drilling, Western Canadian production fell 194 Bcf, or 3%. In Alberta, production fell 129 Bcf or 3% despite an 58% increase in drilling. In British Columbia production fell 70 Bcf or 7% despite a 45% increase in drilling. In Saskatchewan, production increased 27 Bcf or 11%, following a 32% increase in drilling. Other areas in the WCSB include the Yukon and Northwest Territories. Production in these areas fell 9 Bcf and 7 Bcf respectively.

In 2003, the US imported a record amount of LNG, receiving 507 Bcf. This is an increase of 121% over 2002. Despite this, LNG continues to account for a small percentage – only 2% of total natural gas supply in the US.

Imports from Trinidad and Tobago represented 75% of all US LNG imports in 2003. Algeria, once the sole supplier of LNG to the US, remains the second largest exporter of LNG to the US at 11% of all LNG supplies, followed closely by Nigeria, who supplied 10%. These three countries combined, account for 96% of all US LNG imports.

With the reopening of Dominion's Cove Point facility in Maryland, total US LNG import capacity increased to 2.5 Bcf per day. Since 1999, total LNG import capacity has increased by nearly 1.5 Bcf per day or 136%.

Table 7
Proposed Canadian LNG Import Terminals

Operator (Name)	Location	Send-Out Capacity (Bcf/d)	Earliest Start Date	Status
Projects Under Review				
Anadarko Petroleum Corporation (Bear Head)	Canso Strait, NS	1.00	2007	Received federal-provincial environmental assessment approval in August 2004.
Irving Oil Limited (Canaport)	Saint John, NB	1.00	2007	Received federal-provincial environmental assessment approval in August 2004.
Enbridge/Gaz Métro/ Gaz de France (Rabaska)	Beaumont, QC	0.50	2008	Undergoing federal-provincial environmental assessment. Process commenced June 2004.
Keltic Petrochemicals	Goldboro, NS	0.50	2008	Undergoing federal-provincial environmental assessment. Process commenced August 2004.
Galveston LNG	Kitimat, BC	0.61	2008	Undergoing federal-provincial environmental assessment. Process commenced August 2004.
TransCanada/Petro-Canada (Cacouna Energy Project)	Gros Cacouna, QC	0.50	2009	Undergoing federal-provincial environmental assessment. Process commenced September 2004.
Other Announced Projects				
Westpac Terminals	Prince Rupert, BC	0.3	2009	Conceptual. Project not yet under review.
Statia Terminals	Canso Strait, NS	0.50	2009	Conceptual. Project not yet under review.
TOTAL CANADA		**4.91**		

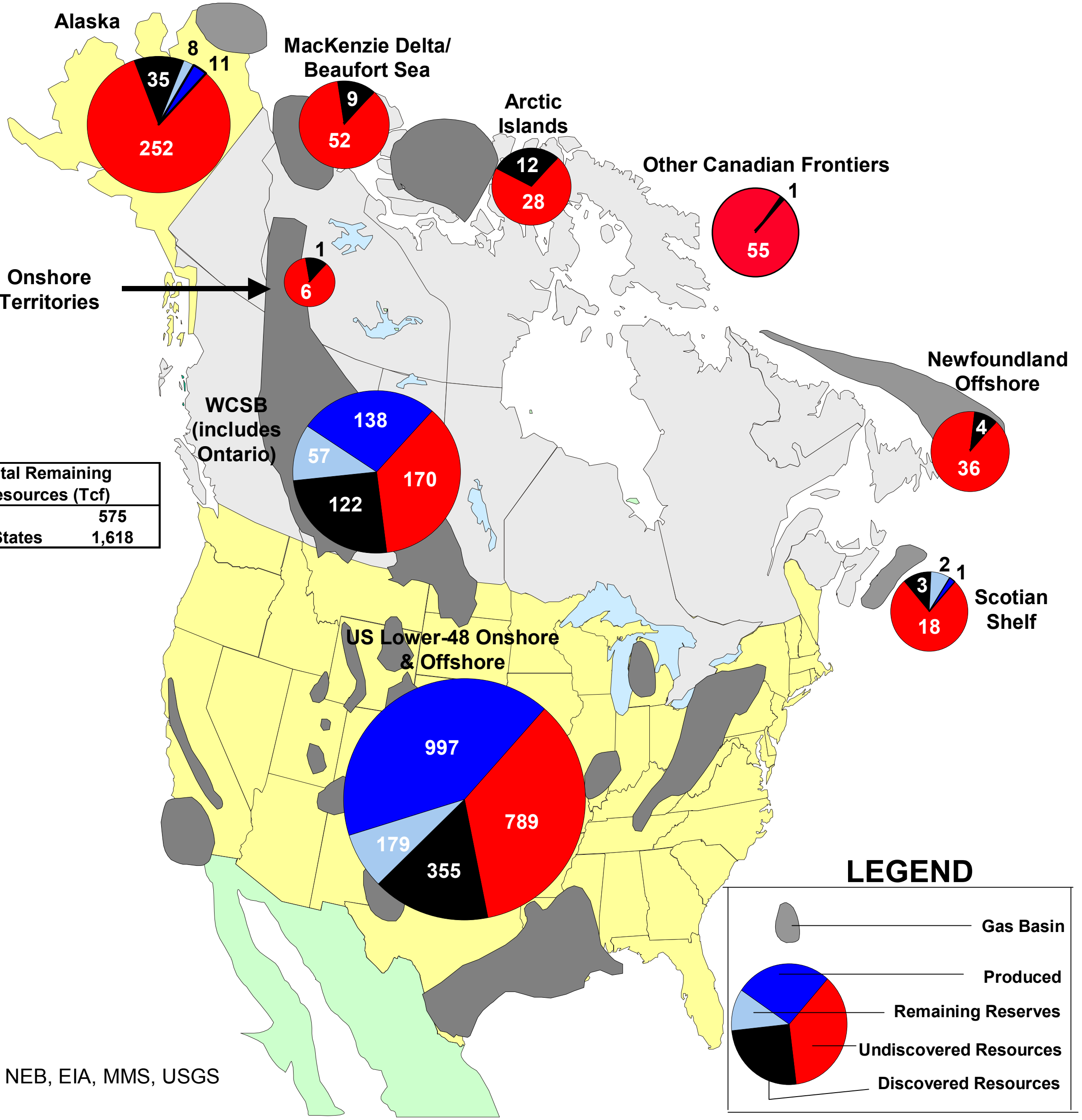
Sources: Industry press and company websites.

There are currently eight LNG import terminals being proposed for Canadian sites. Two of these proposals – Irving Oil's and Anadarko Petroleum Corporation's (who acquired Access Northeast Energy's Bear Head LNG project) – received federal-provincial environmental assessment (EA) approval in August 2004. Four other projects – Gaz Métro et al's, Keltic Petrochemical's, Galveston LNG's and TransCanada's – are in the early stages of the EA review process. The other two projects are more conceptual in nature, only having been announced. More information about Canadian LNG projects can be found in Appendix 2.

Review of 2003

Natural Gas Resources and Reserves

Map 4
Canadian & US Natural Gas Resources and Reserves (Tcf)



Total Remaining Resources (Tcf)	
Canada	575
United States	1,618

Sources: NEB, EIA, MMS, USGS

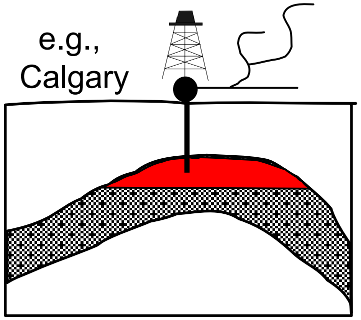
Map 4 shows the locations and scale of cumulative natural gas production, reserves, discovered resources and undiscovered resources in Canada and the US.

The NEB's most current estimate for ultimate potential of conventional natural gas in Canada, including proved reserves, is 495 Tcf. For comparison, 1,008 Tcf of natural gas, has already been produced in the US.

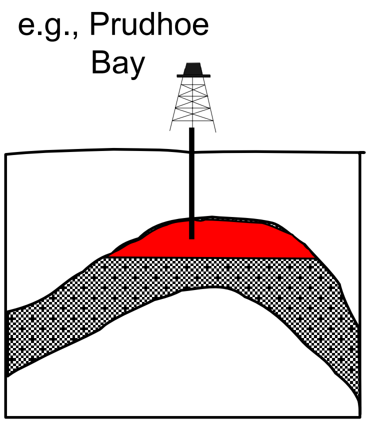
The NEB estimates that another 80 Tcf of undiscovered unconventional natural gas resources exist in the WCSB. Unconventional natural gas resources includes coalbed methane, tight gas, and shale gas.

Based on estimates from MMS and USGS, the US natural gas resource base, including proved reserves, is 1,618 Tcf.

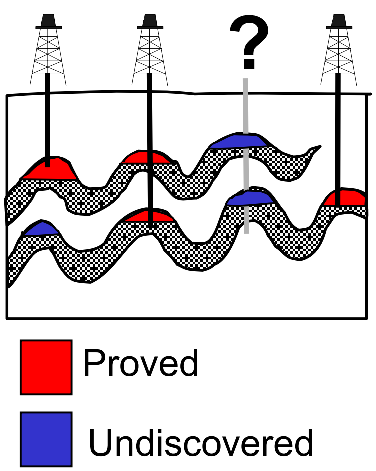
Figure 19



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 8

North American Gas Reserves and Resources[1]

(Tcf)	Proved Reserves (Jan.1/03)	Discovered Resources[2]	Undiscovered Resources	Total Remaining Resources
Alberta	45	101	61	207
British Columbia	9	14	27	50
Saskatchewan	3	5	1	9
Mainland Territories	0	1	6	7
Unconventional Resources[3]	0	0	80	80
Total Western Canada	**57**	**121**	**175**	**353**
Ontario	0	1	1	2
Nova Scotia	2	3	18	23
Total Eastern Canada	**2**	**4**	**19**	**25**
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]	**59**	**151**	**365**	**575**
US Onshore and State Offshore	144	322	320	785
US Federal Offshore	25	68	362	455
Unconventional Resources[3]	18	0	359	377
Total US	**187**	**390**	**1,041**	**1,618**
Total North America	**246**	**541**	**1,406**	**2,193**

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) and the NEB's "Canada's Energy Future: Scenarios for Supply and Demand to 2025" (July 2003).

Figure 19 graphically defines proved reserves, discovered resources, and undiscovered resources.

The total US natural gas resource base, including proved reserves is 1,618 Tcf. At 2002 levels of domestic production, the US has about an 85 year supply of natural gas.

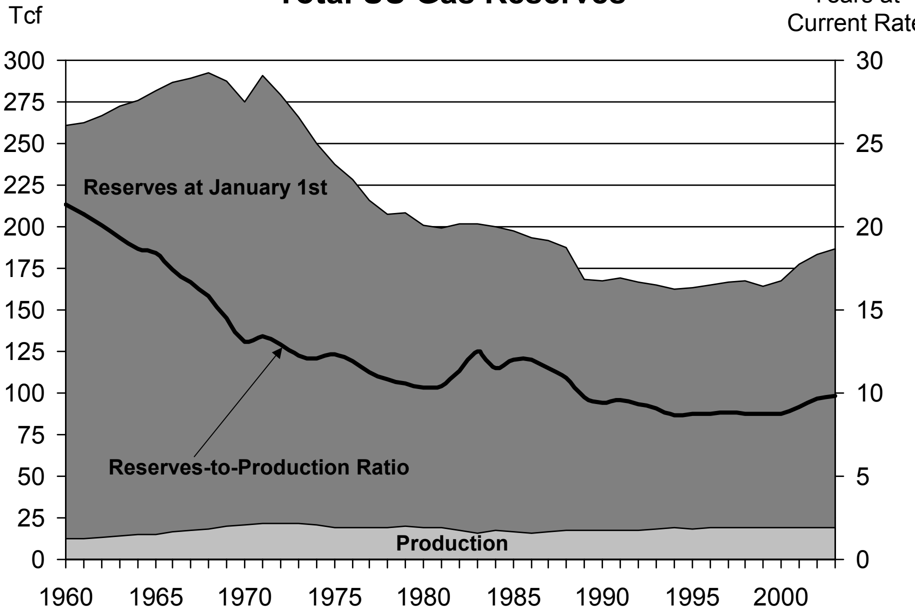
Based on estimates from the NEB, Canada's total gas resource base, including proved reserves is 575 Tcf. At 2002 levels of domestic production, Canada has about a 77 year supply of natural gas.

Table 9
North American Natural Gas Reserves

Bcf	Jan. 1, 2003	Jan. 1, 2002	Change 03 vs 02	% Change 03 vs 02
Gulf Onshore[1]	57,885	57,914	-29	0%
Gulf Offshore[2]	24,689	26,496	-1,807	-7%
Total Gulf	**82,574**	**84,410**	**-1,836**	**-2%**
US Midcontinent[3]	21,519	20,275	1,244	6%
US Rockies[4]	56,776	53,816	2,960	6%
Other US	26,077	24,959	1,118	4%
Total US Reserves	**186,946**	**183,460**	**3,486**	**2%**
Western Canada[5]	55,911	56,671	-760	-1%
Scotian Shelf	1,982	2,178	-196	-9%
Other Canada [6]	854	941	-87	-9%
Total Canada	**58,746**	**59,789**	**-1,043**	**-2%**
TOTAL N.A. Reserves	**245,692**	**243,249**	**2,443**	**1%**

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. [6] Includes northern territories and Ontario.

Figure 20
Total US Gas Reserves



Source: EIA

Reserve data for any given year comes out almost one full year later. The latest reserve figures show reserves as of January 1, 2003.

In the US, gas reserves increased by about 3.5 Tcf, largely attributable to reserve additions of 3 Tcf in the Rockies region.

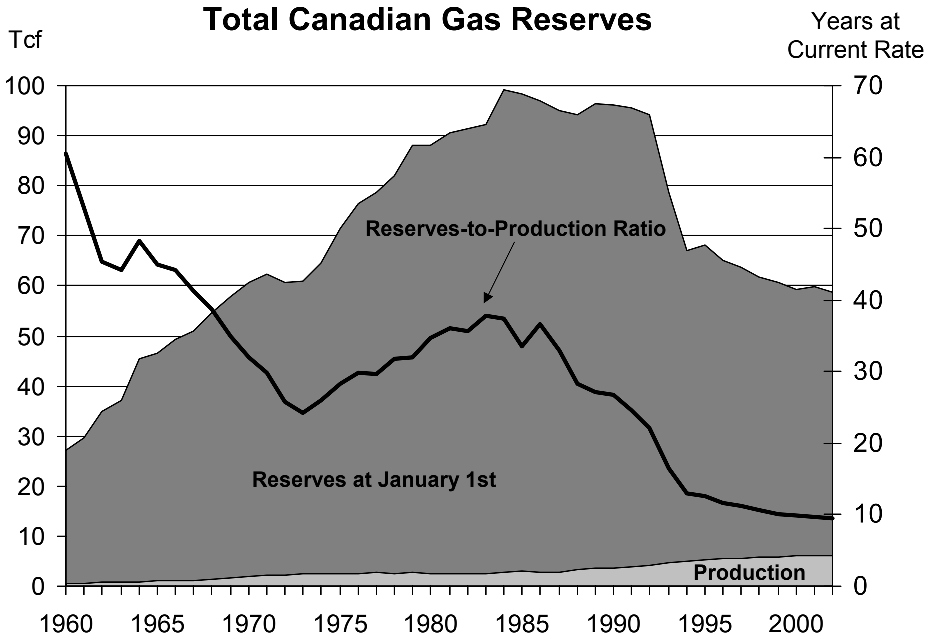
This is in contrast to Canada, where reserves fell by just over 1 Tcf. Natural gas reserves in western Canada decreased by 1.5% from year-end 2001 to 56.7 Tcf, replacing 86% of its 2002 production versus 109% in 2001. Atlantic Canada offshore reserves decreased by approximately the annual production offshore Nova Scotia.

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

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

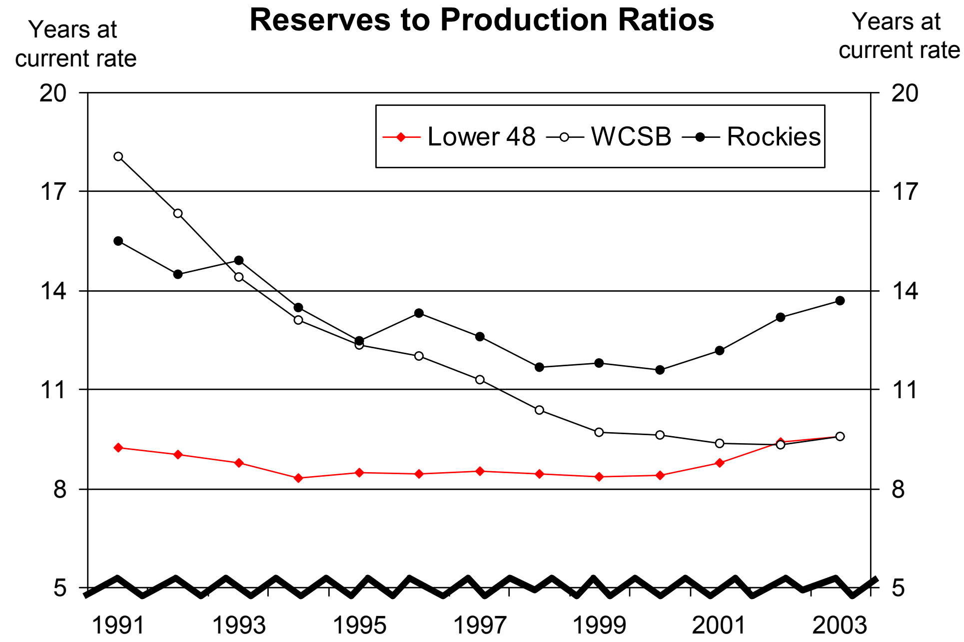
Following this peak, US reserves declined rapidly. Between 1971 and 1991, US reserves fell by more than 40%. However, belying that trend, US reserves have increased in 9 of the last 10 years, standing at 187 Tcf at the beginning of 2003. This has also raised their R/P ratio to 9.8 years.

Figure 21
Total Canadian Gas Reserves



Sources: NEB, StatsCan, CAPP

Figure 22
Reserves to Production Ratios



Sources: EIA, NEB, CAPP

A similar comparison of total Canadian gas reserves shows a different story. Canadian reserves peaked in 1983, but fell very quickly until 1994, when the drop became less precipitous. Part of this drop was due to large negative revisions, which removed old reserves that had been on the books for some time. Canadian reserves are still dropping, though the declines appear to be slowing. This trend continued in 2002, as reserves dipped another 1,043 Bcf by the beginning of 2003.

Canada's R/P ratio has also fallen rapidly since 1983 and now sits at 9.78 – comparable to the current US ratio. This compares to the Canadian R/P ratio of 37.5 twenty years ago, before natural gas markets were deregulated.

R/P ratios, as we have seen, are an indication 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 22 depicts the R/P ratios of three areas of different ages in North America.

The maturing nature of the WCSB can be seen by its declining R/P ratio and recent flattening. The WCSB now has the same R/P ratio as the US Lower 48 states, which is the most mature area in North America.

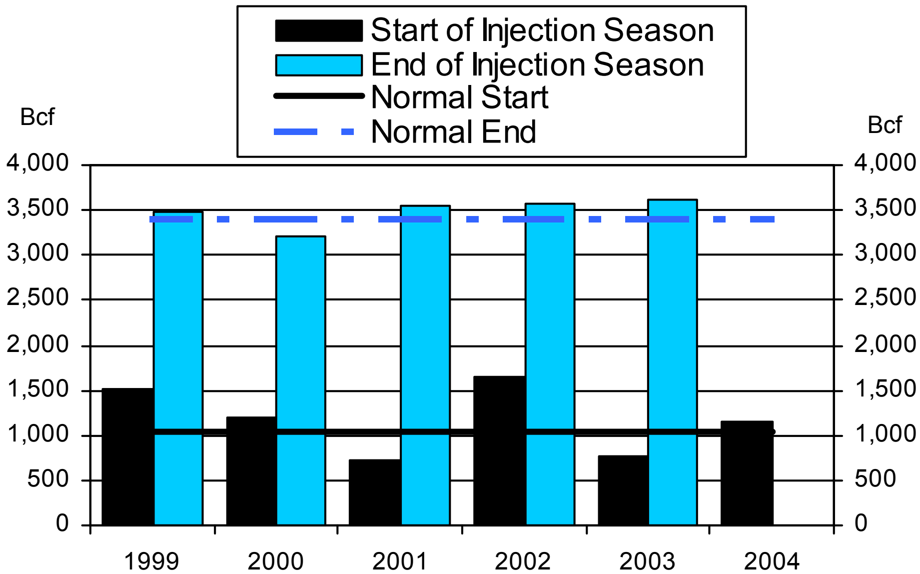
The only major supply region which remains quite immature is the US Rockies, where the R/P ratio has increased each year since 2000. In 2003, the Rockies R/P ratio was 13.7 years.

Review of 2003

Natural Gas Storage

Figure 23

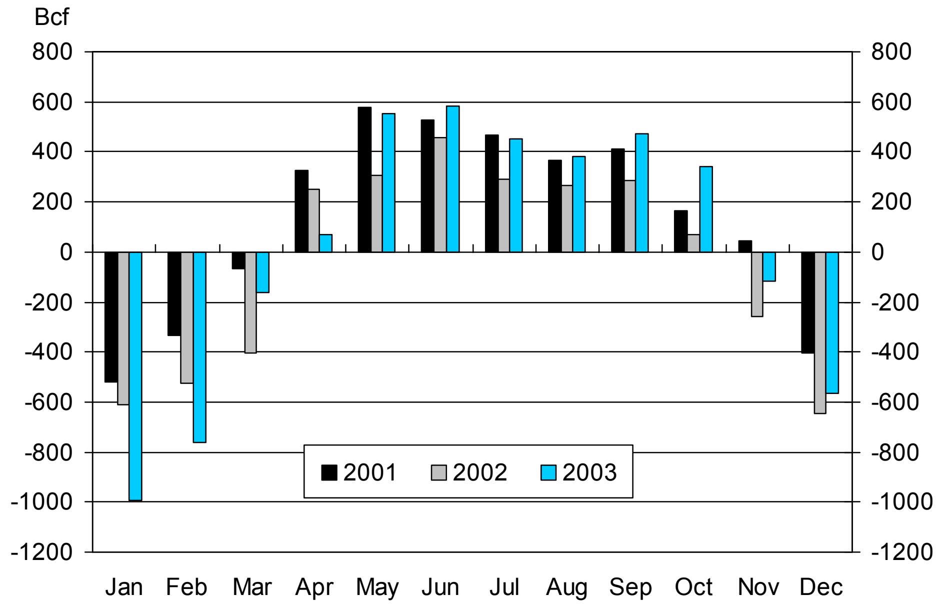
North American Storage Levels



Sources: Canadian Enerdata and EIA

Figure 24

North American Storage Injection/Withdrawal Levels



Source: Gas Daily

The 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 23. Also shown is the normal average storage level (1998-2002) of 3,500 Bcf for the start, and 1,000 Bcf for the end of injection season. At the start of the 2003 injection season, North American storage was 759 Bcf, 283 Bcf below normal levels. Storage levels at the start of the 2004 injection season were 1,162 Bcf, 403 Bcf higher than the same period in 2003.

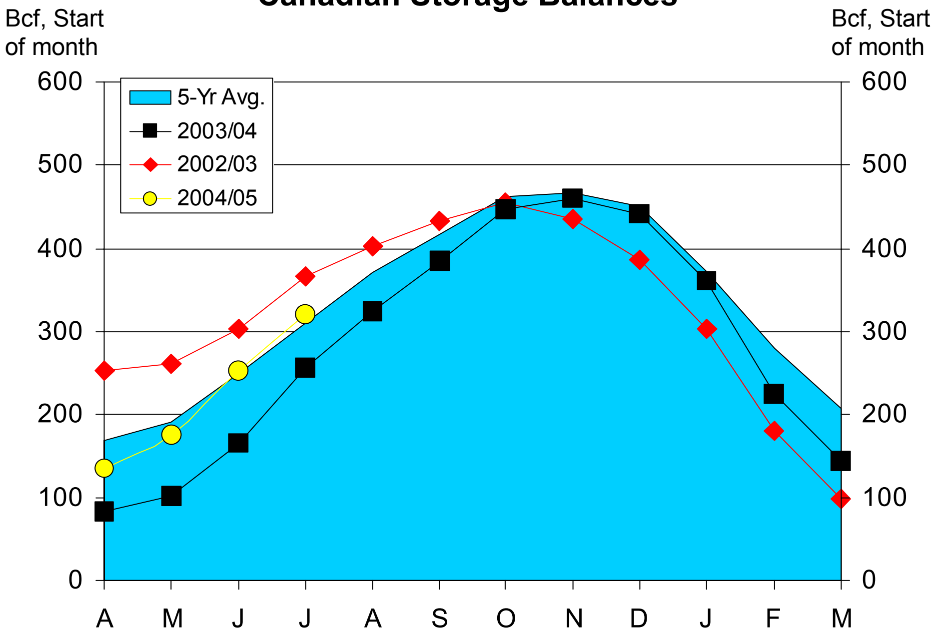
For Canada and the US to reach 3,500 Bcf by November 1st 2004, 2,338 Bcf or 11 Bcf/d of gas will have to be injected. In 2003 storage injection demand was 12.8 Bcf/d, or 1.8Bcf/d higher.

Figure 24 compares monthly North American natural gas storage injection (positive) and withdrawal (negative) levels for the years 2001, 2002, and 2003. 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 of 2003 nearly 1.8 Tcf of natural gas was withdrawn and consumed by the market, representing the largest two month storage withdrawal in over a decade. For comparison, 1.8 Tcf is equivalent to 50% of North American storage supplies on November 1, 2003.

Figure 25

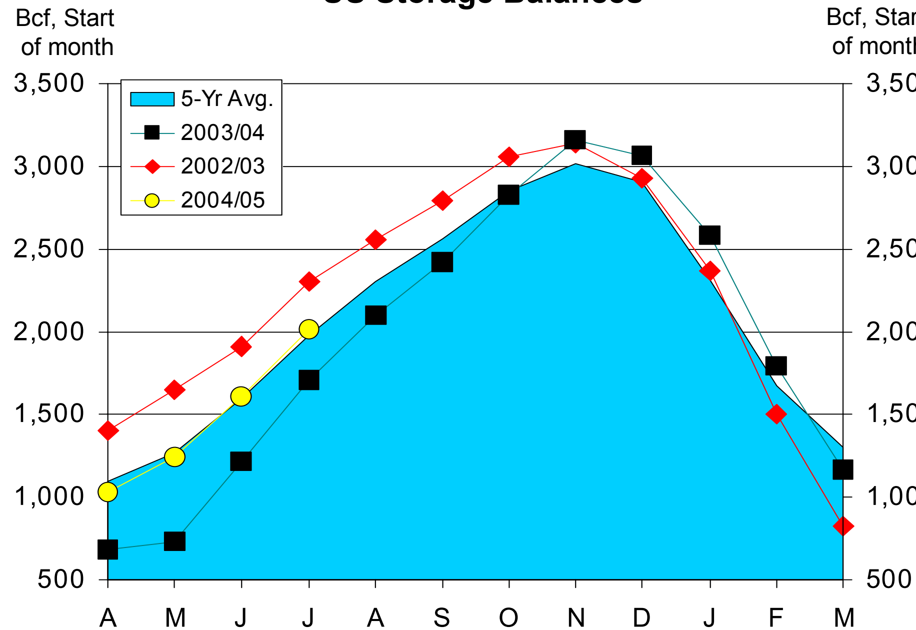
Canadian Storage Balances



Source: NRCan estimates from Canadian Enerdata weekly data.

Figure 26

US Storage Balances



Source: NRCan estimates from EIA weekly data.

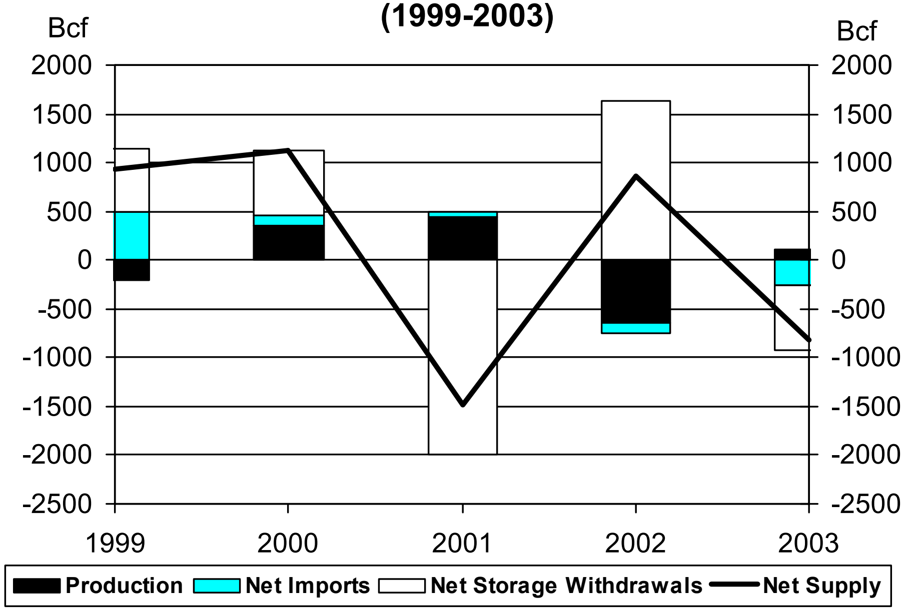
The 2003 Canadian storage situation was a complete reversal from 2002. In 2003 storage balances on April 1 were 83 Bcf, 67% below the previous year. Despite this low level, injections totaled 380 Bcf to reach the 5-year average.

Going into the spring 2004 injection season, Canadian storage balances are 66% greater than last year. With storage levels in a comfortable position this year, much less gas will be required for storage injections before next winter.

The US storage image in 2003/2004 mirrored the Canadian situation. Storage balances on April 1 2003 were at 676 Bcf, 52% below the previous year. US injections totaled 2,487 Bcf to surpass the 5-yr average.

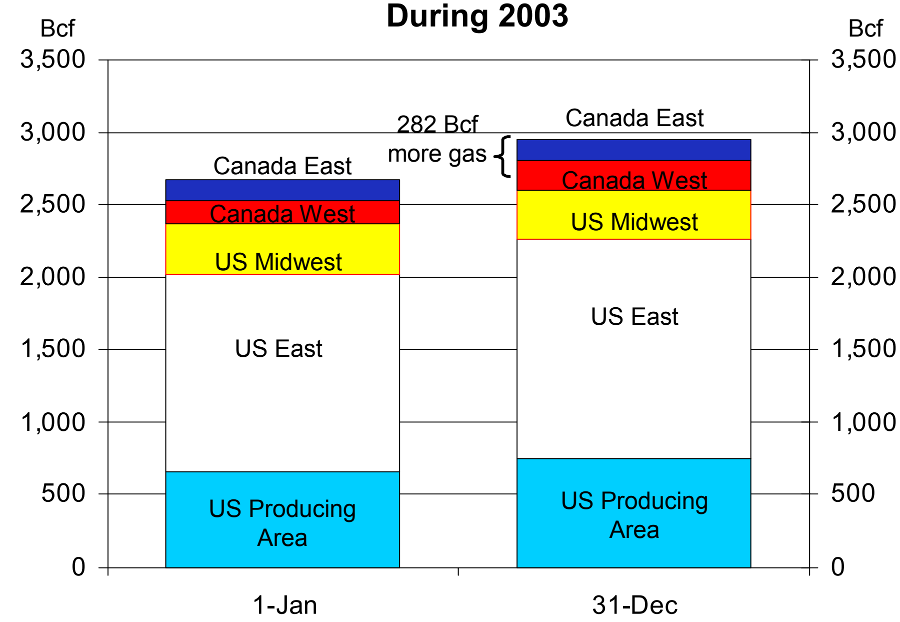
Heading into the 2004 injection season, US storage balances are 52% greater that last year. Given current storage levels, reaching the US 5-year average by November 1 should be attainable.

Figure 27
US Natural Gas Supply Differences (1999-2003)



Source: EIA

Figure 28
North American Storage Changes During 2003



Sources: Canadian Enerdata, EIA, NRCan estimates.

Figure 27 illustrates US natural gas supply differences between the years of 1999-2003. There are four sources of US natural gas supply including domestic production, net imports, net storage withdrawals, and supplemental volumes. Supplemental volumes are defined by the EIA as "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.

In 2003, natural gas supplies were 817 Bcf lower compared to 2002, driven mainly by a decreased draw down from storage. US production increased 104 Bcf after falling 650 Bcf in 2002. US net imports fell by about 260 Bcf in 2003.

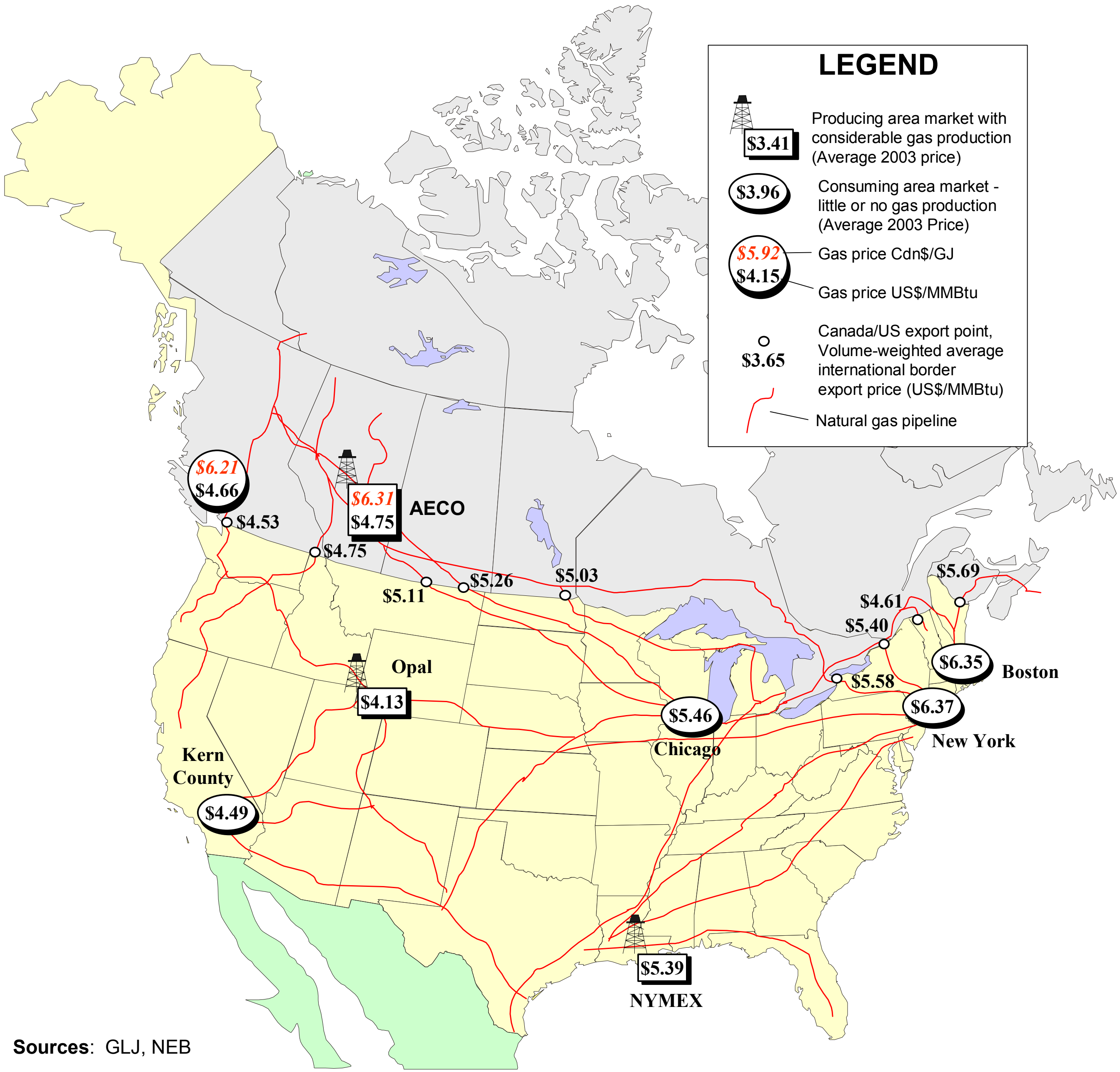
North American storage increased through the calendar year. On Jan 1st, 2003 North American storage was 2,671 Bcf. On December 31st, there was 2,953. Thus, during calendar year 2003 there was a net storage build of 282 Bcf. The largest absolute increase was in the Eastern United States where storage increased by 152 Bcf. The largest decrease was in the Western United States, where storage levels fell 17 Bcf.

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

Review of 2003

Natural Gas Prices

Map 5
Canadian & US Natural Gas Prices in 2003



Sources: GLJ, NEB

Map 5 shows natural gas spot (monthly) market prices for 2003 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 northeast US and eastern Canada. These areas must pay significant pipeline costs in addition to the commodity cost.

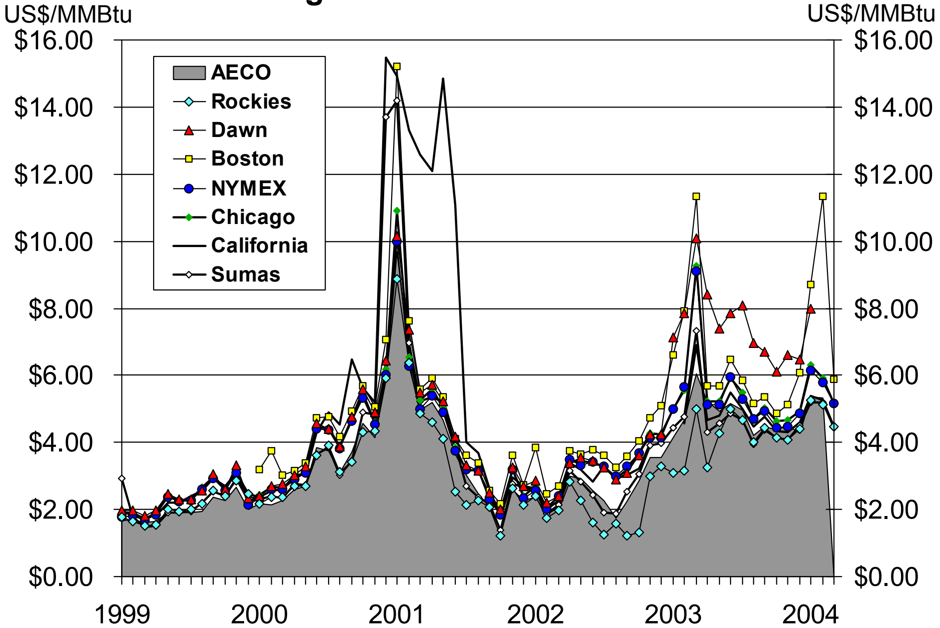
In 2003, gas prices were higher across Canada and the US. Numerous factors contributed to higher prices, including storage concerns, flat production, high oil prices, and cold weather.

Table 10
Regional Natural Gas Prices

Region	2003 Avg. ($US/MMBtu)	2002 Avg. ($US/MMBtu)	Change 03 vs 02	% Change 03 vs 02
AECO-C (Southern Alberta)	$4.75	$2.58	$2.17	84%
NYMEX (Louisiana)	$5.39	$3.22	$2.16	67%
Kern County (California)	$4.49	$2.97	$1.52	51%
Huntingdon/Sumas (B.C.)	$4.66	$3.99	$0.67	17%
Opal (Rockies)	$4.13	$2.04	$2.09	102%
Chicago	$5.46	$3.25	$2.21	68%
Boston	$6.35	$3.71	$2.64	71%
Dawn (Ontario)	$5.62	$4.85	$0.76	16%

Source: GLJ

Figure 29
Regional Natural Gas Prices



Source: GLJ

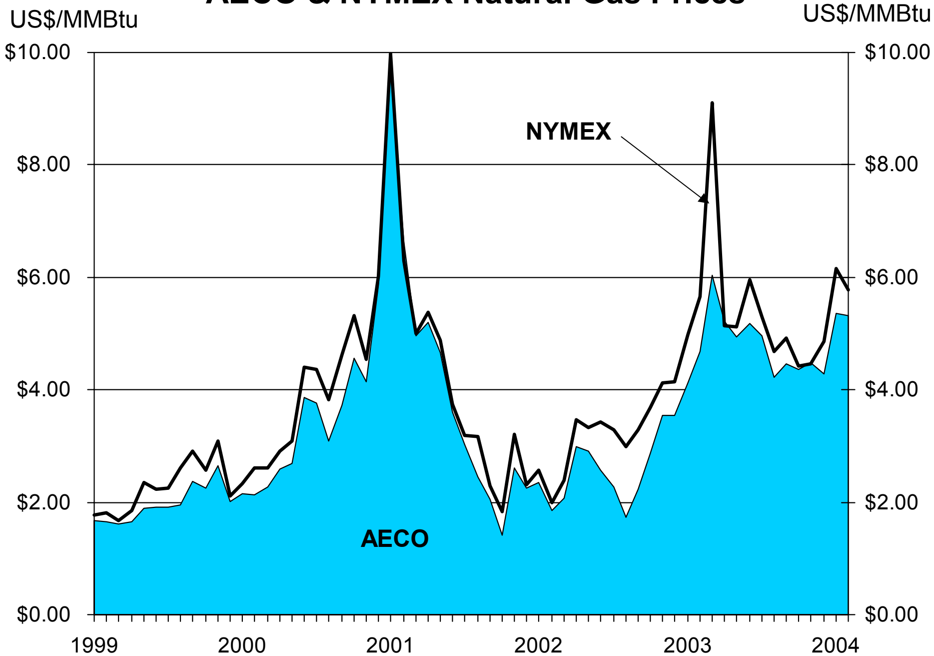
After falling across the continent in 2002, natural gas prices increased in 2003. Prices were higher in all major regions of North America in 2003. Compared to 2002, 2003 Alberta prices were up 84%, while NYMEX prices increased 67%.

The largest price increase occurred in the Rockies, where prices more than doubled their 2002 average prices. The most moderate price increases occurred in Ontario and Huntingdon/Sumas in British Columbia.

Monthly spot prices in major North American regions are shown in Figure 29. 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 prices witnessed in 2001, due to the California energy crisis.

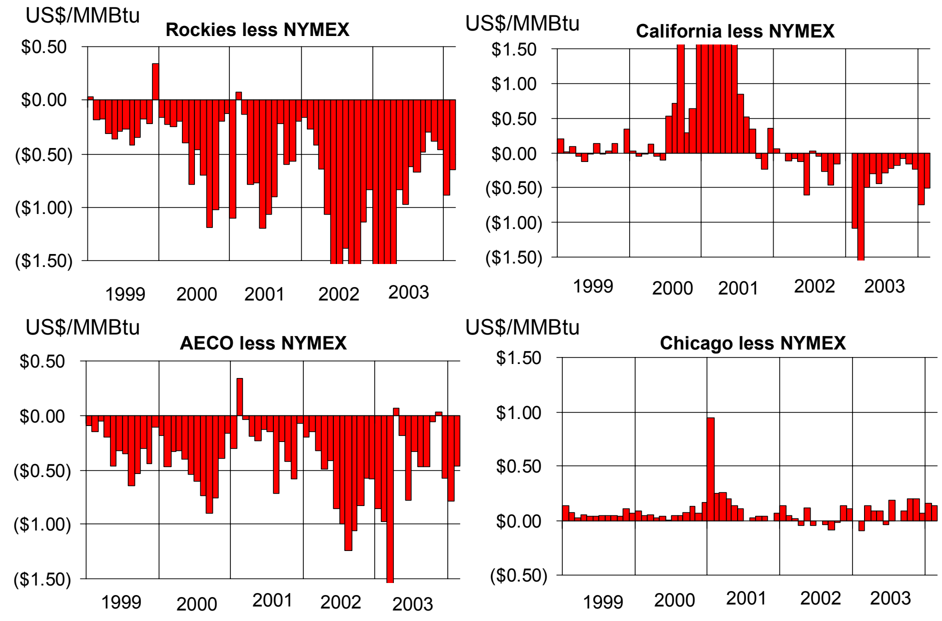
In 2003, a disconnect between regions occurred once again as eastern prices began to rise above their western counterparts, with Boston, NYMEX, and Dawn prices tracking higher. This disconnect was mainly due to colder winter weather in the US northeast, which created a surge in demand. However, insufficient pipeline capacity resulted in large disparities between Boston and AECO natural gas prices.

Figure 30
AECO & NYMEX Natural Gas Prices



Source: GLJ

Figure 31
Natural Gas Price Differentials



Source: GLJ

The two key North American price hubs are the intra-Alberta market (i.e., AECO) and the Henry Hub in Louisiana (NYMEX). A NYMEX-Alberta differential of US$0.50/MMBtu is considered normal. Between 1999 and 2004, the NYMEX-Alberta differential averaged US$0.49/MMBtu.

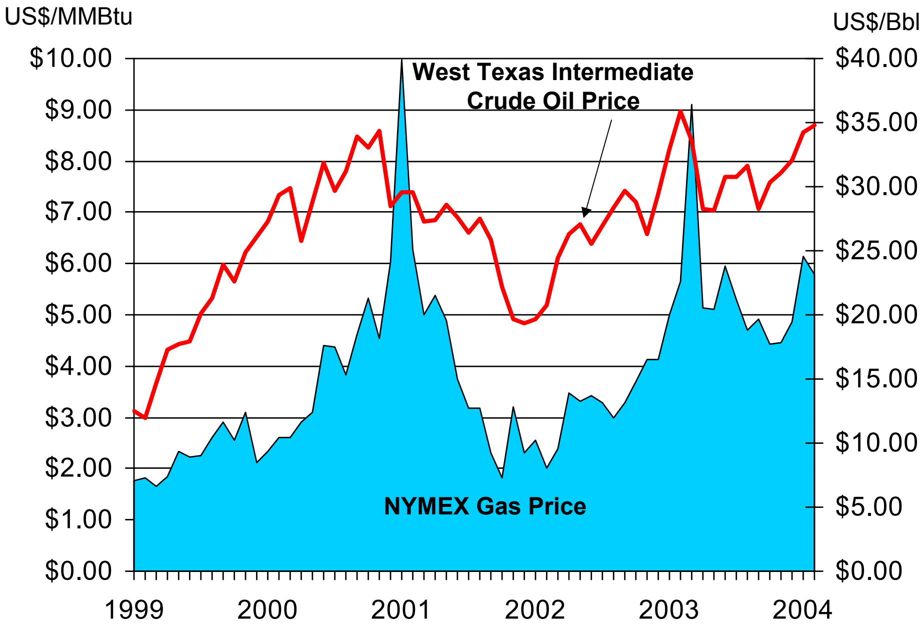
At times, short-term disconnects will occur between Alberta and NYMEX. In 2001, the smallest differential in a decade was registered, at US$0.23/MMBtu. However, differentials have since increased. In 2003 NYMEX averaged US$5.39/MMBtu, Alberta US$4.75/MMBtu, for a differential of $0.64.

The first quarter of 2003, where the differential averaged US$1.64/MMBtu, accounted for much of the differential for the year.

Differentials generally widened in 2003, with the exception of of AECO-NYMEX, where the differential remained the same – $0.64. The Chicago-NYMEX differential, while it continues to be modest, more than doubled from $0.03 to $0.08. The Rockies-Opal price differential increased by 6% from $1.18 to $1.26.

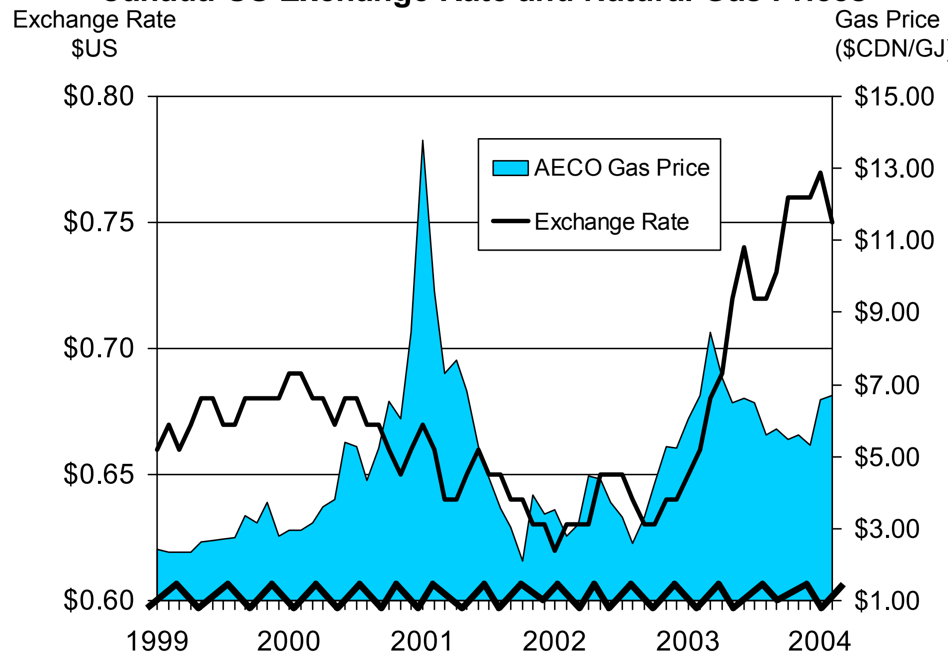
The big story continues to be California, where prices continue to fall. Prices were down 51% compared to 2002. The differential between NYMEX and California climbed from $0.17 in 2002 to $0.52 in 2003, an increase of 214%. This is especially impressive when compared to 2001, when California prices averaged $3.77 higher than NYMEX.

Figure 32
Crude Oil and Natural Gas Prices



Sources: EIA, GLJ

Figure 33
Canada-US Exchange Rate and Natural Gas Prices



Source: GLJ

The figure above displays the relationship between West Texas Intermediate crude oil prices and natural gas prices. Many industrials and power generators have the ability to switch between gas and crude-oil derived fuels, thus world crude oil prices can influence natural gas demand and prices.

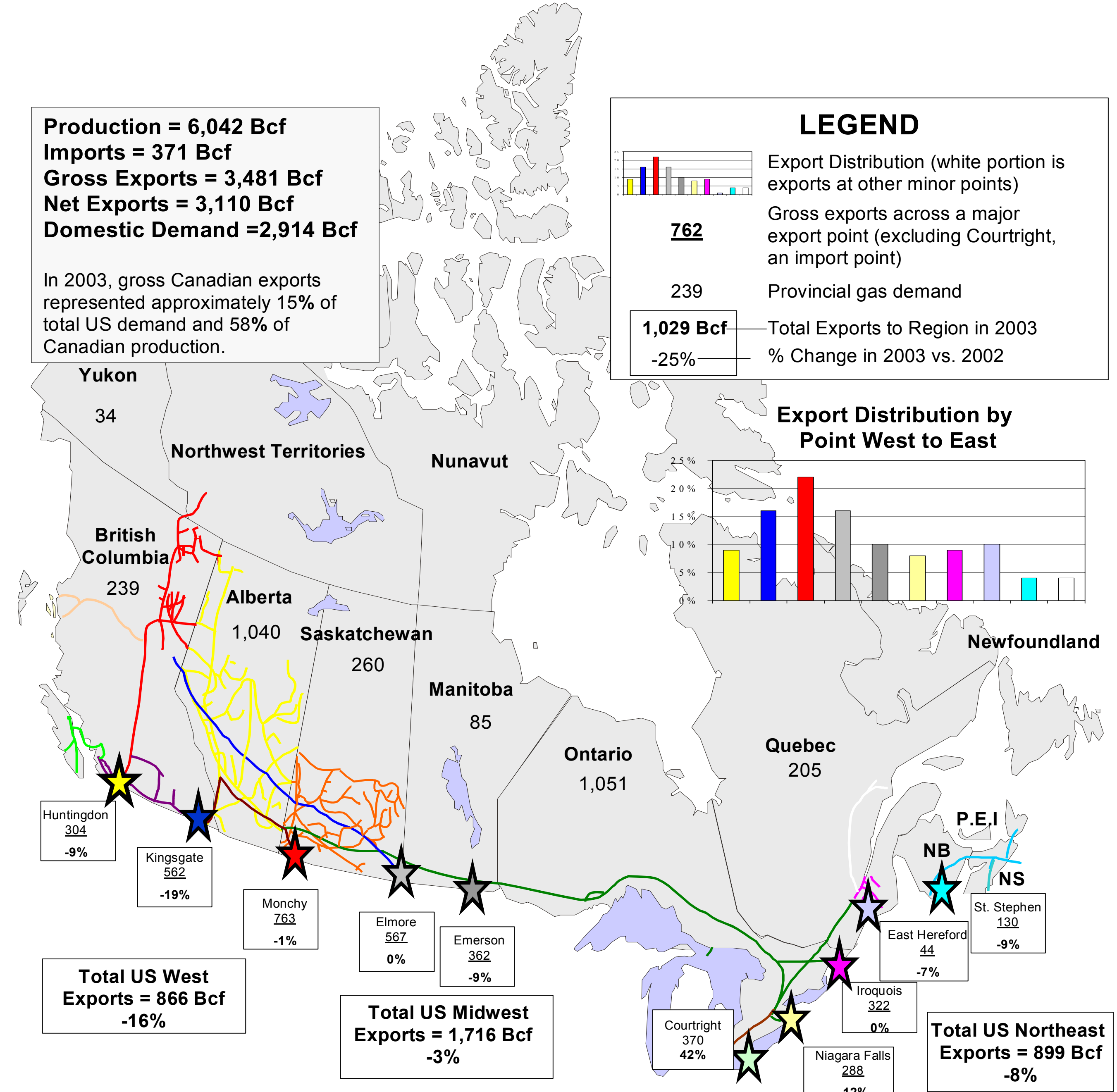
In 2003, WTI crude oil prices averaged US$29.58 per barrel. This was an increase of US$5.30 over the 2002 average price of US$24.28. With Iraq supply still much lower than historical levels and the high degree of uncertainty in the Middle East supply region, higher oil prices seem certain for the short-term. With both gas and oil prices at historically high levels, industrial consumers have less incentive to switch fuels.

Canadian and US gas markets are highly integrated, with prices generally tracking one another. As a result, exchange rate changes affect Canadian gas prices. For several years, the value of the Canadian dollar has been declining relative to the US dollar, in effect, increasing the price for natural gas in Canadian dollars.

This trend reversed in 2003, when the value of the Canadian dollar averaged US$0.72, $0.06 higher than 2002. An appreciating Canadian dollar means the price for natural gas in Canadian dollars is declining. To illustrate, if the Canada-US exchange rate in 2003 had been equal to the 2000 exchange rate of US$0.67 , the average 2003 Canadian natural gas price would have been CDN$6.76/GJ, rather than the CDN$6.31/GJ as was actually the case.

Review of 2003

Canadian Exports, Imports
& Domestic Sales



Sources: NEB, Pipeline Companies **Note:** Courtright is an import point.

This map shows natural gas export and import volumes at various points throughout Canada and the US. The chart shows the percentage distribution of exports through each associated point.

In 2003, total gross exports to the US were 3,481 Bcf, a decrease of 8% from 2002. Approximately 96%, or 3,342 Bcf of all export volumes flowed through 9 major export points. Lower export volumes can be attributed to flat Canadian production, increased domestic demand, increased US LNG imports, and lower US demand.

Regionally, exports to the US west region fell 16%, exports to the US midwest fell 3%, and exports to the US northeast fell 8%.

Canadian natural gas imports, most of which flow through the Vector pipeline at Courtright, increased 42%, on top of a 20% increase in 2002.

Table 11
Domestic Demand and Canadian Exports

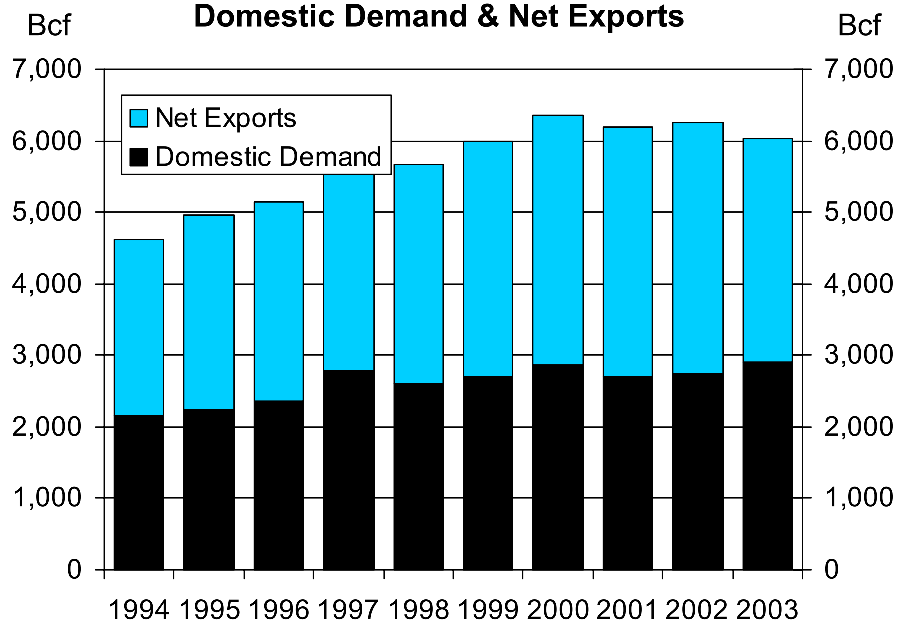
	2003 (Bcf)	2002 (Bcf)	2003 vs 2002 (Bcf)	% Change 2003 vs 2002
Gross Exports to US West	866	1,031	-166	-16%
Gross Exports to US Midwest	1,716	1,770	-54	-3%
Gross Exports to US Northeast	899	979	-80	-8%
Total Gross Exports[1]	3,481	3,780	-299	-8%
Imports from US	371	260	111	43%
Net Exports[2]	**3,110**	**3,520**	**-410**	**-12%**
Western Canada Demand	1,572	1,455	117	8%
Eastern Canada Demand	1,342	1,280	62	5%
Total Canadian Demand	**2,914**	**2,735**	**179**	**7%**
Net Exports	3,110	3,520	-410	-12%
Canadian Demand	2,914	2,735	179	7%
Total Canadian Gas Sold[3]	**6,024**	**6,255**	**-231**	**-4%**

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.

Gross Canadian natural gas exports decreased by 8% in 2003, marking the first year gross exports have fallen. Net exports decreased by 12% as imports were up 42% over 2002. Imports have increased over 100% over the past four years.

Canadian gas demand was up 7% in 2003, therefore the effect of lower exports on total Canadian gas sold was minimized.

Figure 34
Domestic Demand & Net Exports

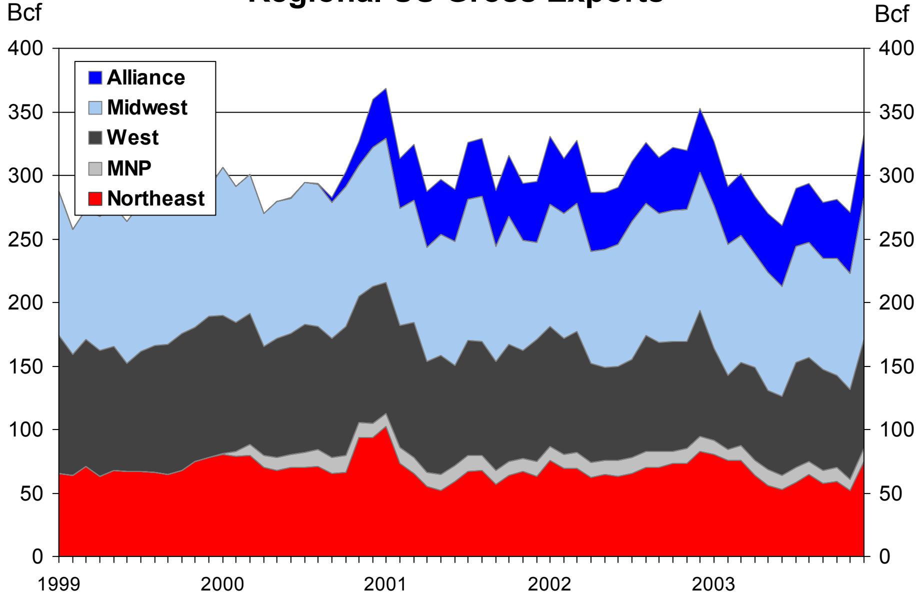


Source: StatsCan, NEB, NRCan estimates.

Net exports declined for the second straight year, falling 410 Bcf from 2002. Due to the maturity of the Canadian resource base, this may be the first sign of an emerging long-term trend.

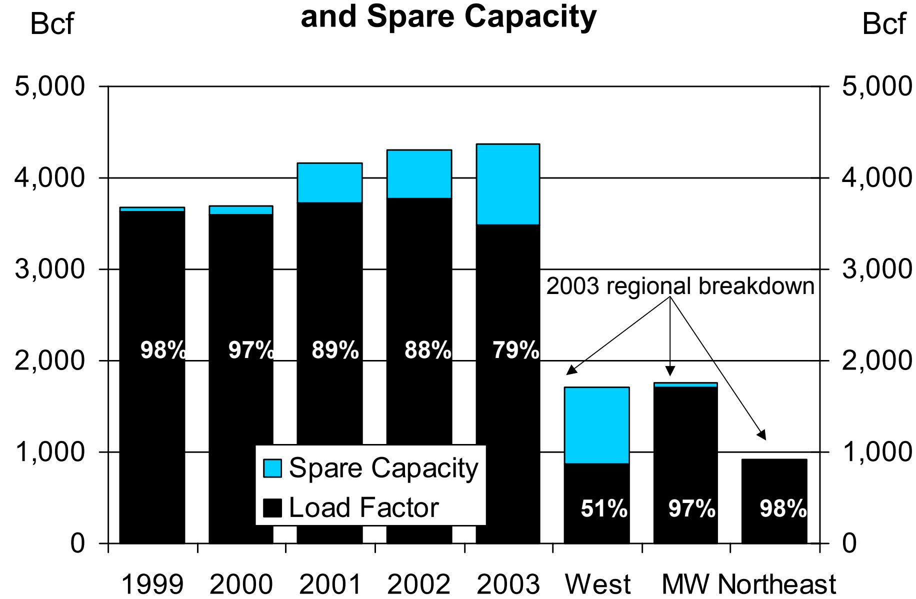
Despite the large decline in exports in 2003, Canada remains a strong exporter of natural gas as exports accounted for 58% of total Canadian gas sold and 15% of US natural gas consumption.

Figure 35
Regional US Gross Exports



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

Figure 36
Canadian Export Pipeline Load Factor and Spare Capacity



Sources: NEB, GLJ

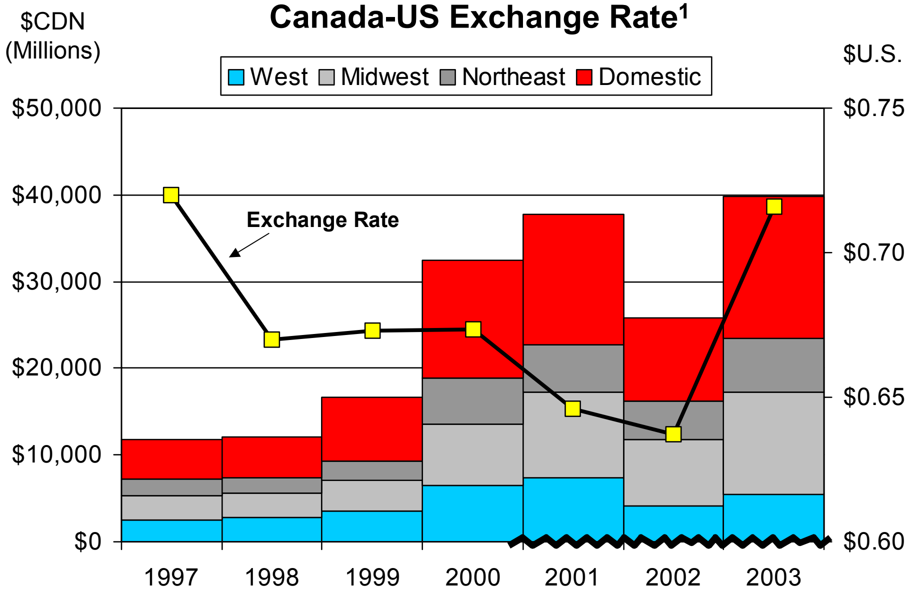
Natural gas gross exports to the US decreased 8% this year. Exports in 2002 increased only 1%, well below the historical average of 5% annual growth. Due to a maturing WCSB, achieving historical 5% growth rates in exports will be a significant challenge.

In 2003, the Alliance Pipeline accounted for 33% of exports to the US midwestern region. Similarly, the Maritimes and Northeast Pipeline accounted for 17% of all exports to the US northeastern region.

Figure 36 shows Canadian net exports (load factor) and the spare pipeline capacity for the years 2000 through 2003. Since 2000 the spare capacity on Canadian export pipelines has been steadily increasing. In 2003, there was 892 Bcf of spare export capacity, of which 13 Bcf was in the Northeast, 43 Bcf in the Midwest and 837 Bcf in the West. In 2000, there was only 96 Bcf of spare pipeline capacity, 2001 440 Bcf, and 2002 519 Bcf.

There are five fundamental reasons for the large export losses to the US west; 1) higher Canadian demand and flat Canadian production; 2) higher storage levels in 2003; 3) lower US demand; 4) increased imports of LNG to the US; and, 5) increased production from the US Rockies, and 5) an expansion of the Kern River Pipeline, enabling more natural gas to flow west from the US Rockies.

Figure 37
Export Plantgate Revenues vs. Canada-US Exchange Rate[1]

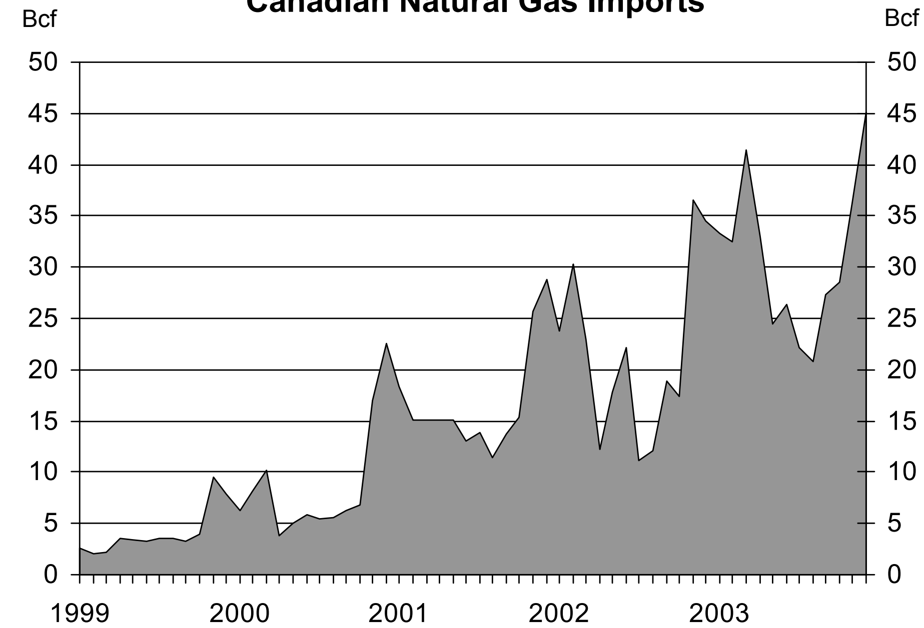


Sources: GLJ, NEB. **Note:** (1) U.S. dollars required to purchase one Canadian dollar.

Despite lower export volumes in 2003, total export revenues reached record levels – more than CDN$23 billion, 44% higher than in 2002. Domestic revenues also increased by 73% to CDN $16.4 billion.

In 2003, the value of the Canadian dollar averaged US $0.72. As the Canadian dollar rises relative to the US dollar, which was the case in 2003, exporters receive less for their natural gas when the revenue is converted to Canadian currency. If the exchange rate in 2003 had been equal to the exchange rate the previous year, export revenues would have been CDN $26.34 billion, rather than the CDN $23.41 billion, as was actually the case. The US' robust demand for Canadian natural gas and higher prices, however, more than offset any decline in producer revenue as a result of the appreciation of the Canadian dollar.

Figure 38
Canadian Natural Gas Imports



Source: NEB

Figure 38 shows Canadian imports of natural gas from 1999 to 2003. Natural gas is imported into Canada primarily though the Courtright import point in southern Ontario. In recent years imports have been steadily climbing because the Dawn trading hub located in Chatham, Ontario provides shippers with numerous options for the sale of their natural gas and liquidity of trade is preferred by shippers and numerous transportation routes exist to ship gas to Dawn, including the more recent construction of the Vector pipeline, which transported approximately 700 MMcf/d through the Courtright import point in 2003.

Natural gas imports in 2003 were 43% higher than 2002, and 650% higher than 1999.

Table 12
Domestic and International Border Export Prices

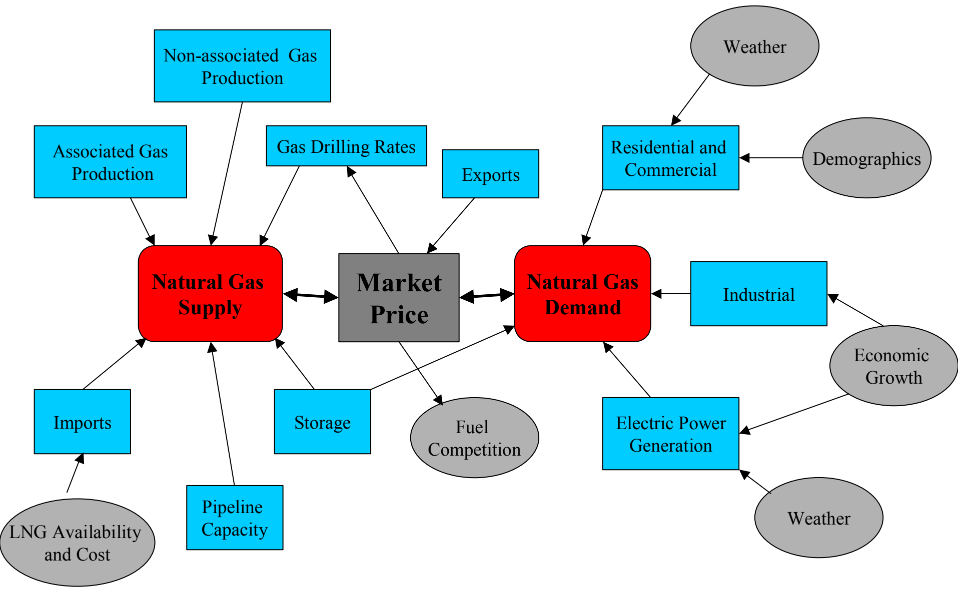
		International Border Export Prices				US Prices	Canadian Markets			
Year	**Month**	**West $US/MMBtu**	**MW $US/MMBtu**	**NE $US/MMBtu**	**Average $US/MMBtu**	**NYMEX $US/MMBtu**	**AECO $Cdn/GJ**	**AECO $US/MMBtu**	**Huntingdon $US/MMBtu**	**Westcoast St 2 $US/MMBtu**
2002		**$2.72**	**$3.13**	**$3.49**	**$3.07**	**$3.22**	**$3.83**	**$2.57**	**$2.68**	**$2.56**
2003	January	$4.33	$4.72	$5.38	$4.81	$4.99	$6.04	$4.13	$4.44	$4.16
	February	$4.62	$5.39	$6.14	$5.38	$5.66	$6.71	$4.68	$4.76	$4.55
	March	$6.46	$7.95	$7.74	$7.38	$9.11	$8.45	$6.04	$7.32	$7.90
	April	$4.54	$5.04	$5.22	$4.94	$5.14	$7.20	$5.21	$4.29	$4.22
	May	$4.73	$5.04	$5.21	$4.99	$5.12	$6.48	$4.94	$4.58	$4.41
	June	$5.05	$5.53	$5.73	$5.44	$5.95	$6.63	$5.17	$4.87	$4.67
	July	$4.77	$5.11	$5.42	$5.10	$5.30	$6.50	$4.96	$4.65	$4.45
	August	$4.39	$4.60	$4.90	$4.63	$4.69	$5.58	$4.22	$3.93	$3.73
	September	$4.53	$4.65	$4.97	$4.72	$4.93	$5.77	$4.46	$4.36	$4.17
	October	$4.22	$4.39	$4.70	$4.44	$4.44	$5.47	$4.37	$4.14	$3.94
	November	$4.24	$4.25	$4.75	$4.41	$4.45	$5.59	$4.49	$4.08	$3.87
	December	$4.51	$4.94	$5.39	$4.95	$4.86	$5.32	$4.28	$4.50	$4.29
2004	January	$5.21	$5.82	$6.71	$5.91	$6.15	$6.58	$5.36	$5.20	$4.99
	February	$4.95	$5.47	$6.14	$5.52	$5.77	$6.70	$5.32	$5.20	$4.99
	March	$4.12	$4.40	$4.74	$4.42	$5.15	$5.93	$4.71	$4.42	$4.21
2004	**Average (YTD)**	**$4.76**	**$5.23**	**$5.86**	**$5.28**	**$5.69**	**$6.40**	**$5.13**	**$4.94**	**$4.73**
2003	**Average (YTD)**	**$5.14**	**$6.02**	**$6.42**	**$5.86**	**$6.59**	**$7.07**	**$4.95**	**$5.51**	**$5.54**
2003	**Average**	**$4.70**	**$5.13**	**$5.46**	**$5.10**	**$5.39**	**$6.31**	**$4.75**	**$4.66**	**$4.53**
2002/03	**% Change[1]**	**73%**	**64%**	**57%**	**66%**	**67%**	**65%**	**85%**	**74%**	**77%**
2003/04	**% Change[2]**	**-7%**	**-13%**	**-9%**	**-10%**	**-14%**	**-9%**	**4%**	**-10%**	**-15%**

Sources: GLJ, NEB, NRCan estimates **Notes:** [1] Annual percentage change of prices between the years 2002 and 2003. [2] Year-to-date percentage change of prices between the years 2003 and 2004 (January to March).

Natural gas prices reached record highs across North America in 2003. In 2003, the AECO price averaged CDN$6.31/GJ, with a low of $5.32 and a high of $8.45. AECO spot prices were 65% higher in 2003. International border export prices and Canadian domestic prices closely tracked the NYMEX price in 2003. In 2003, natural gas prices in the export market averaged US$5.10/MMBtu, an increase of 66% over 2002. AECO spot prices increased similar to international border while NYMEX, Westcoast St.2 and Huntingdon prices increased on average 75%. AECO spot prices averaged $CDN6.40/GJ during the first quarter of 2004, while NYMEX prices averaged $US5.69/MMBtu.

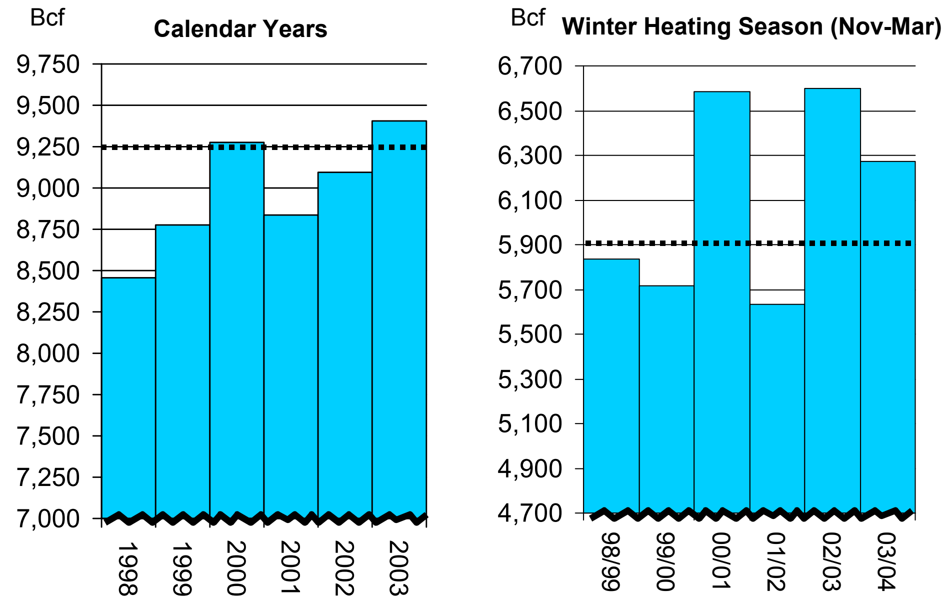
Short-Term Outlook

Figure 39
Natural Gas Price Drivers



Source: NRCan

Figure 40
North American Core Market Demand



Sources: EIA, StatsCan and StatsCan estimates.

Natural gas prices are driven by supply and demand fundamentals. On the demand side, gas prices are driven mainly by weather, economic growth and fuel competition. On the supply side, production, drilling rates, storage and available pipeline capacity contribute to changes in natural gas prices.

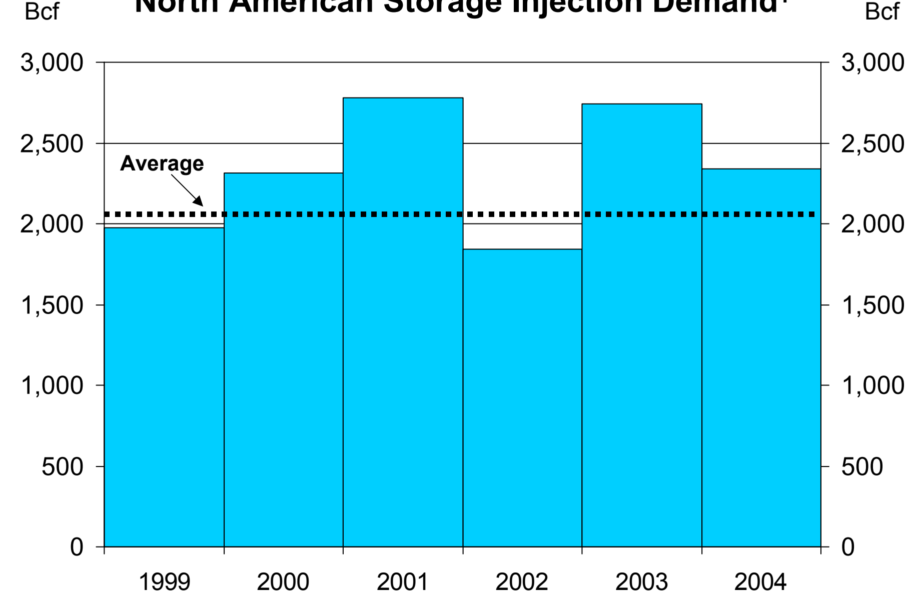
In the short-term (through to the end of the winter 2004/2005), natural gas prices are expected to be driven by weather, storage levels, natural gas production growth and world crude oil prices.

This section compares the state of price drivers in 2003 and early 2004 to normal or past extreme levels. This comparison can give an idea of the market's tendencies in the short-term.

Normal North American core demand lies in the 9,250 Bcf range, while normal North American core winter demand is about 5,900 Bcf (dashed lines). The winter heating season (i.e., Nov-Mar) accounts for about 65% of total core North American natural gas demand requirements in any given year.

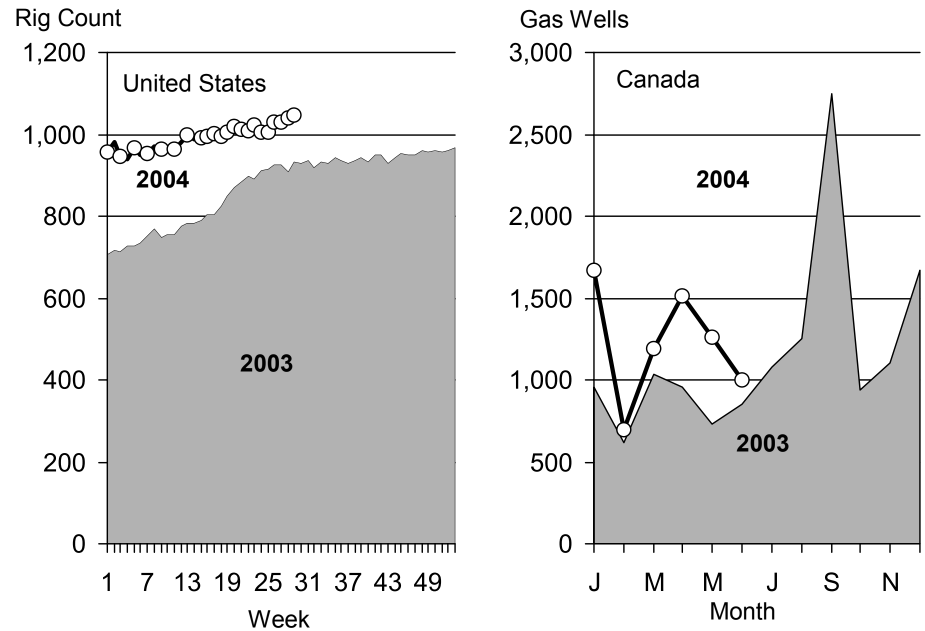
Since 1998, with the exception of 2000 and 2003, North American calendar year temperatures have been normal or above normal. In 2003, North American core demand increased 3%, largely attributable to a colder than normal end of winter period (i.e., Jan-Mar). These colder temperatures caused core demand to increase by about 550 Bcf over the same period in 2002. If it were not for these colder temperatures, core demand over the 2003 calendar year could have been below 2002 levels.

Figure 41
North American Storage Injection Demand[1]



Sources: EIA, Enerdata **Note:** (1) As of April 1st of each year, North American natural gas injections required to reach 3.5 Tcf of natural gas in storage by November 1st.

Figure 42
North American Gas Drilling Trends



Sources: Baker Hughes, Daily Oil Bulletin

On April 1st, 2004, about 2,338 Bcf was required to be injected into storage to reach 3.5 Tcf by November 1st, 2004, in preparation for the upcoming winter heating season. The situation was reversed in 2003, when nearly 2,750 Bcf was required as of April 1st, 2003.

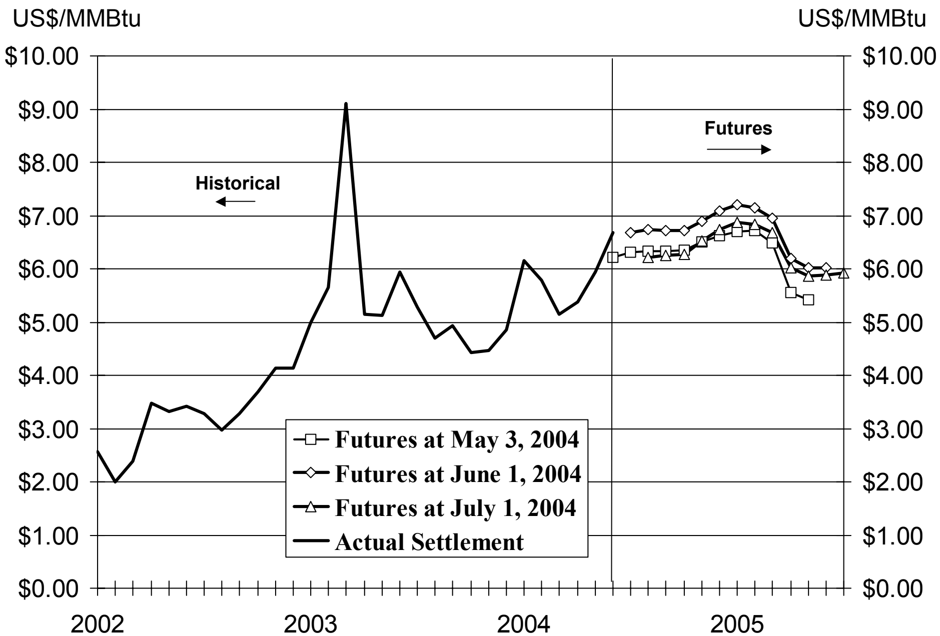
A warmer than normal 2003-2004 winter heating season left North American natural gas storage levels relatively high going into the summer cooling season. During the summer of 2003, storage injections were substantially higher than normal due to below average temperatures. As of September 1st 2004, only 310 Bcf remains to be injected – 56% less than the previous year – to reach 3.5 Tcf by November 1st.

On the supply side, North American natural gas drilling in 2004 is above last year's levels. Over the first 29 weeks of 2004, the US natural gas rig count is about 22% higher than in 2003, averaging 991 rigs per week. Similarly in Canada, during the first half of 2004, 7,330 natural gas wells have been drilled, a 43% increase over 2003.

Higher drilling activity typically implies increased gas production, although the results are not usually seen until the following year. High gas prices in 2004, similar to gas prices witnessed in 2003, has and should continue to prompt high levels of drilling in North America over the duration of the year. Many analysts agree that the number of wells drilled in Canada in 2004 will surpass the previous record of 13,932 set in 2003.

Figure 43

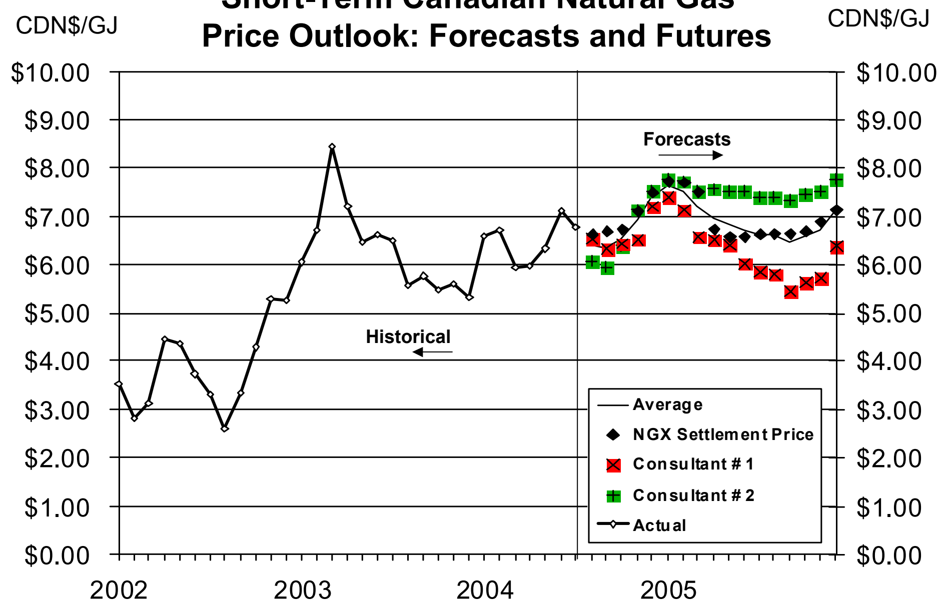
NYMEX Henry Hub Natural Gas Futures Prices



Source: GLJ

Figure 44

Short-Term Canadian Natural Gas Price Outlook: Forecasts and Futures



Source: GLJ, NGX and various consultants. **Note:** (1) AECO actuals from GLJ.

The NYMEX natural gas futures contracts are traded for 36 months. For example, the January 2005 natural gas futures contract began trading in December 2002. This contract will stop trading on December 29, 2004. The trading of this contract provides daily closing (settlement) prices for the contract. These settlement prices indicate what the natural gas market is willing to buy and sell for purchases in January 2005 with the information they have today. For example, the average settlement price for January 2005 – at the three different settlement dates shown above – is US$ 6.62/MMBtu.

All three forward curves follow a general trend, and together suggest that, natural gas prices will hover between US $5.40 - $7.20/MMBtu from June 2004 through to July 2005.

Figure 44 compares two forecasts of Canadian natural gas prices through to the end of 2005. Also, the futures prices traded on the Natural Gas Exchange (NGX) on July 27, 2004, are displayed. Futures prices and forecasts are often very comparable to one another.

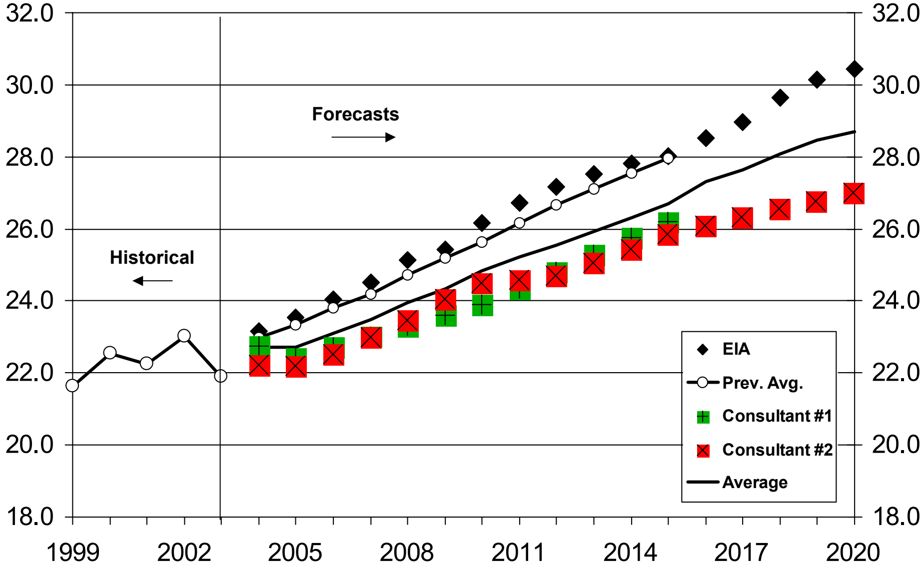
According to the two forecasters surveyed (provided as of June and July 2004, respectively), and assuming normal winter weather, prices are expected to average CDN $7.25/GJ between November 2004 and March 2005. The average price in 2005 is forecast to be CDN $6.90/GJ.

For comparison, on July 27, 2004, the average settlement price for natural gas during the upcoming winter was CDN $7.50/GJ. The average settlement price for 2005 was CDN $7.00/GJ.

Outlook to 2020

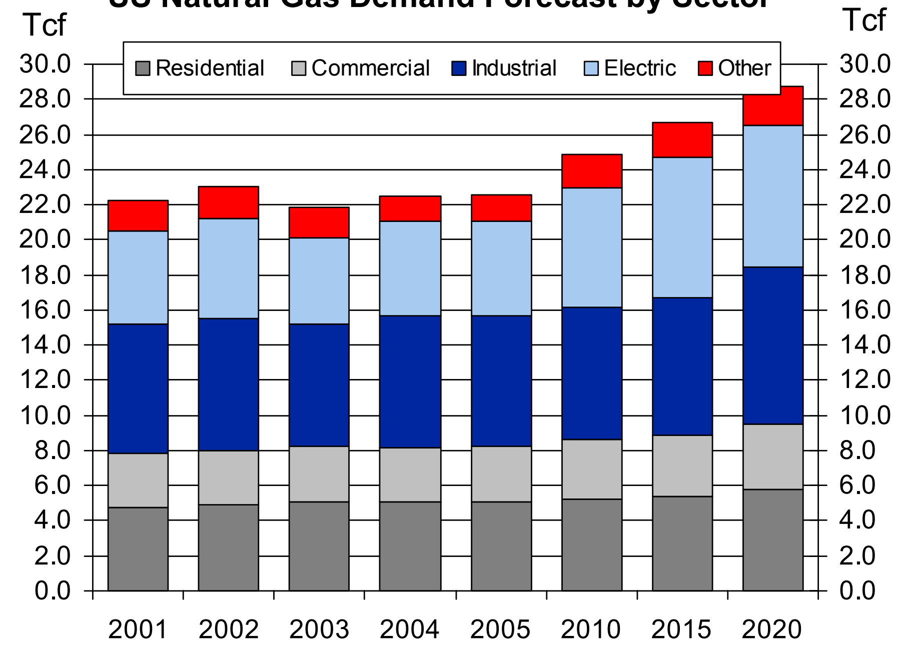
Natural Gas Demand

Figure 45
US Natural Gas Demand Forecasts



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

Figure 46
US Natural Gas Demand Forecast by Sector



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

Figure 45 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 26.7 Tcf by 2015, increasing to 28.7 Tcf by 2020. This represents an average increase of about 1.5 % per year.

The average of the previous year's forecast showed US gas demand at 28 Tcf by 2015, more than a Tcf higher than the current forecast at 2015. Thus, current average forecasts for US demand have been revised downwards, primarily due to lower natural gas production expectations and substantially higher prices.

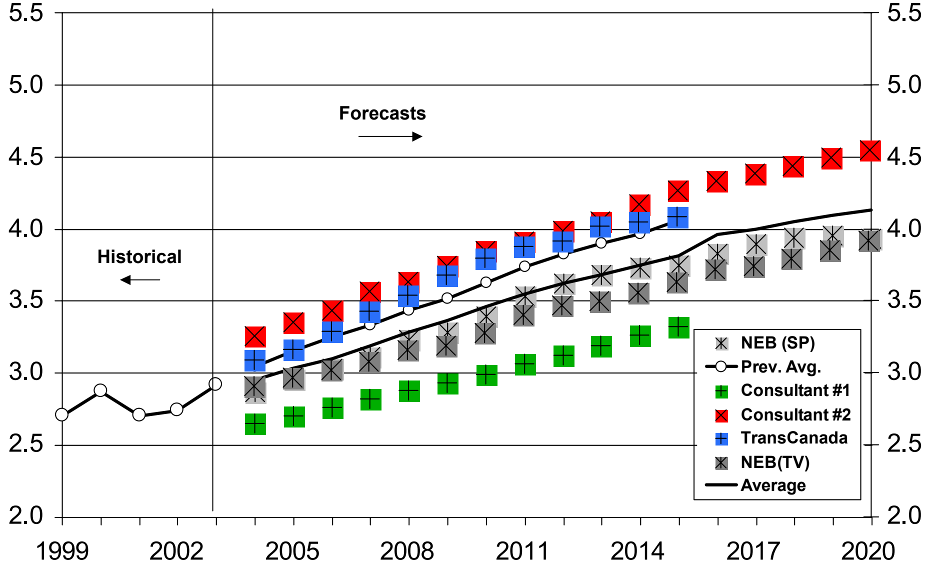
Figure 46 displays an average or "consensus" view regarding the future of US natural gas demand by sector.

The average of the forecasts shows US gas demand at more than 28 Tcf by 2020. This represents an increase of more than 6 Tcf, or 28%, when compared to actual 2003 US demand.

Residential and commercial US natural gas demand is forecast to remain quite stable, only growing at an average annual rate of about 1%. According to the 'consensus' view, core demand will account for about one quarter of total demand growth.

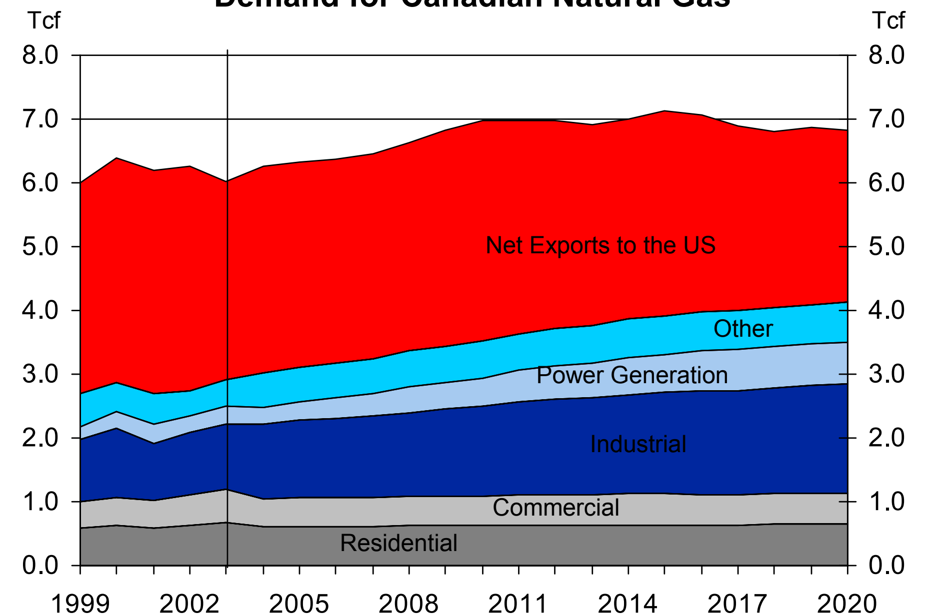
The industrial and power generation sectors are expected to account for most of the demand growth in the US, increasing at about 1.1% and 2.5% per year, respectively.

Figure 47
Canadian Natural Gas Demand Forecasts



Sources: NEB, TransCanada and various consultants. **Notes:** (1) Historical numbers from StatsCan.

Figure 48
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 47 displays five forecasts of Canadian gas demand, along with the average of the forecasts, as well as the average from last year.

The average of the forecasts shows Canadian 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 average of the previous year's forecast showed Canadian gas demand at nearly 4.1 Tcf by 2015, the same as the current forecast at 2020. Thus, current average forecasts for Canadian demand have been revised downwards.

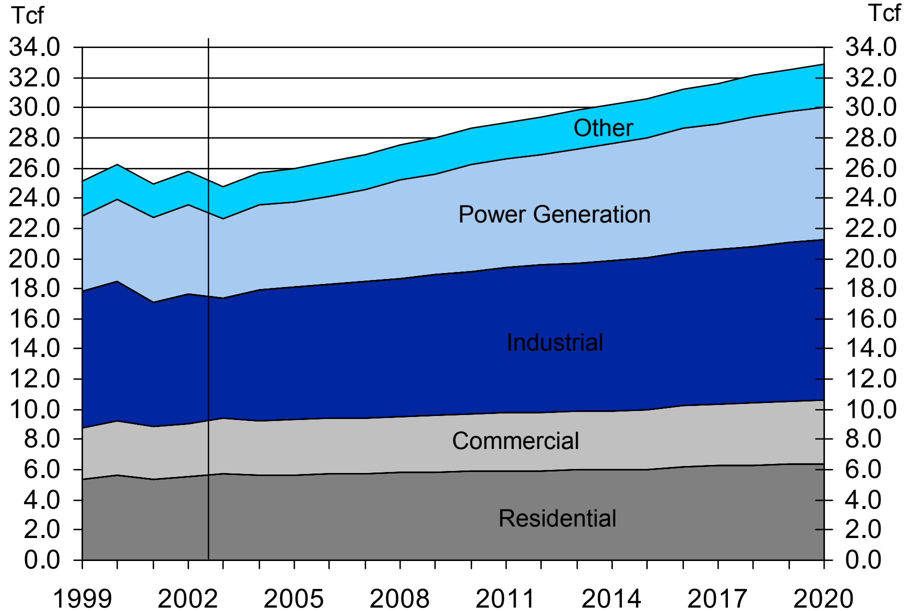
Figure 48 displays an average or "consensus" view regarding the future demand for Canadian natural gas.

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.

According to the "consensus" views of Canadian natural gas demand and production, exports to the US are not expected to grow significantly over the forecast period, hovering between 2.7 and 3.5 Tcf.

Total demand for Canadian gas is expected to reach 6.8 Tcf by 2020, 13% greater than actual demand levels in 2003.

Figure 49
North American Natural Gas Demand Growth[1]



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.

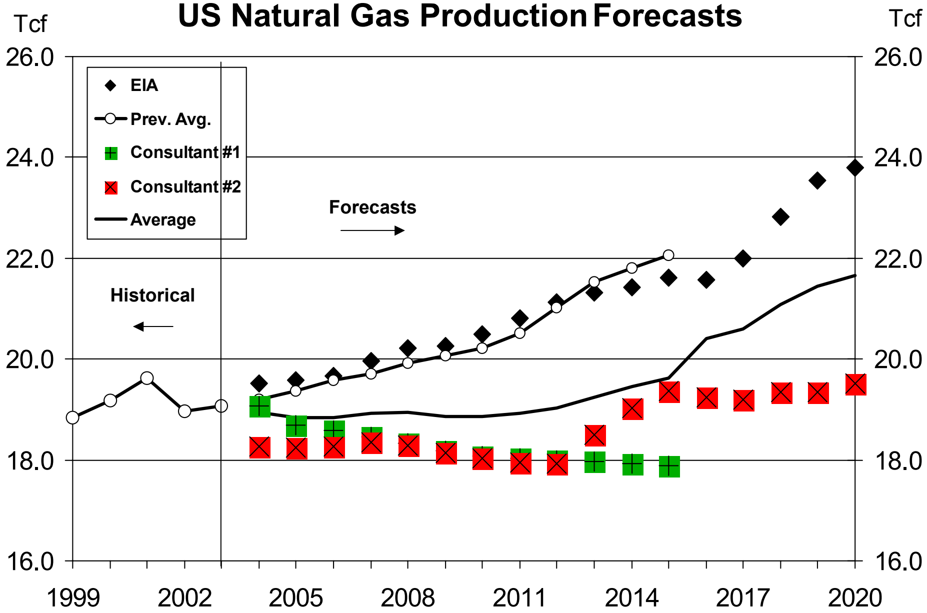
Figure 49 displays an average or "consensus" view regarding the future of North American gas demand. Summing the average forecasts of US and Canadian gas demand results in a "consensus" forecast of about 33 Tcf by 2020. As shown in Figure 49, much of the growth is due to increased demand in the industrial and power generation sectors.

Given actual gas demand of 24.8 Bcf in 2003, this forecast implies that North America will need an additional 8.2 Tcf of annual gas supply by 2020.

Outlook to 2020

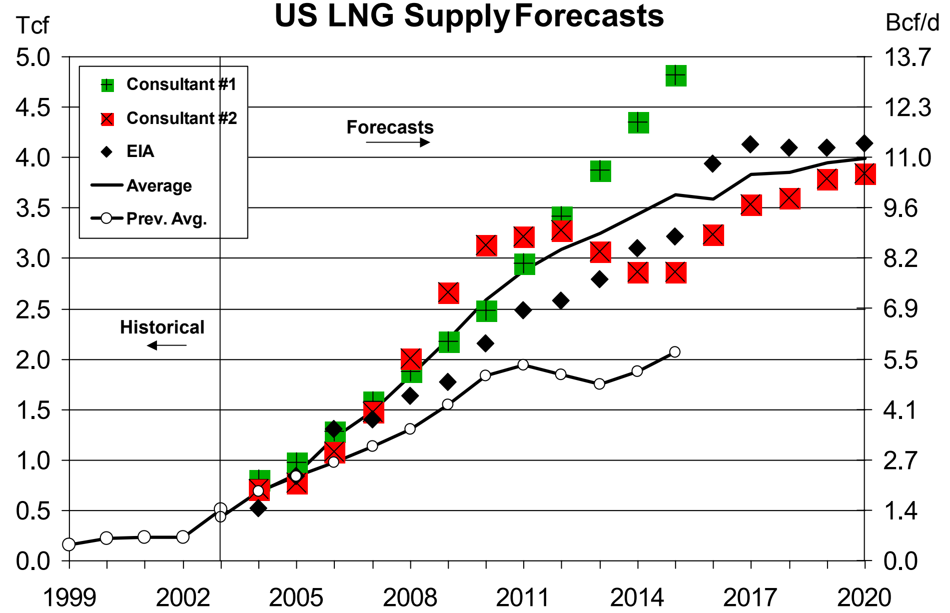
Natural Gas Supply

Figure 50
US Natural Gas Production Forecasts



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

Figure 51
US LNG Supply Forecasts



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

Figure 50 shows three forecasts for US gas production. The average sees US production increasing to 21.7 Tcf by 2020, or 0.8% per year over the forecast period.

The average of the previous year's forecast showed US gas production at 22 Tcf by 2015, greater than the current forecast view for 2020.

There are considerable differences in opinion about US gas production. Some forecasts have northern gas in the mix at some point over the forecast period.

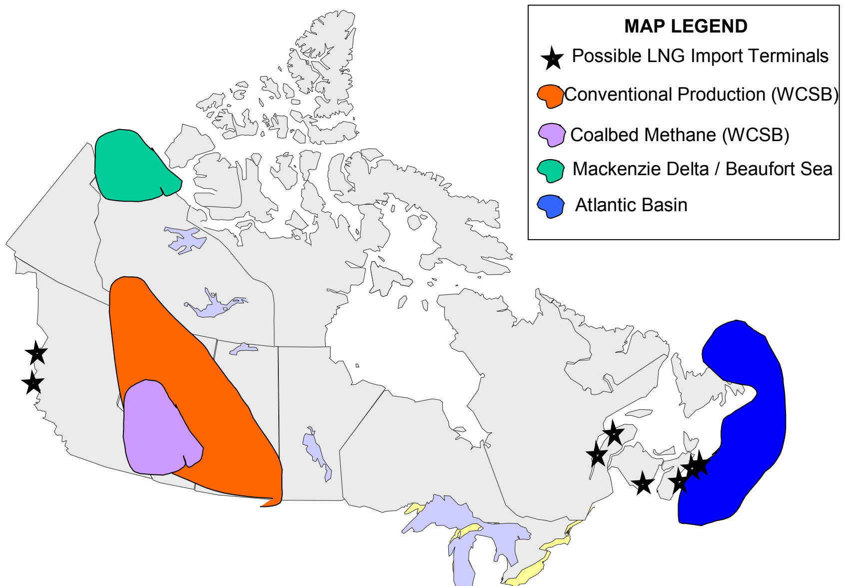
This range in forecasts suggests uncertainty about US supply among industry observers.

Figure 51 shows three forecasts of LNG supply, as well as the average forecast and the previous year's average. The average of the three forecasts shows LNG imports rising to 3.6 Tcf by 2015, nearly 600% greater than actual US LNG imports in 2003.

The average sees US LNG imports reaching about 4 Tcf by 2020, accounting for about 12% of total North American natural gas supply.

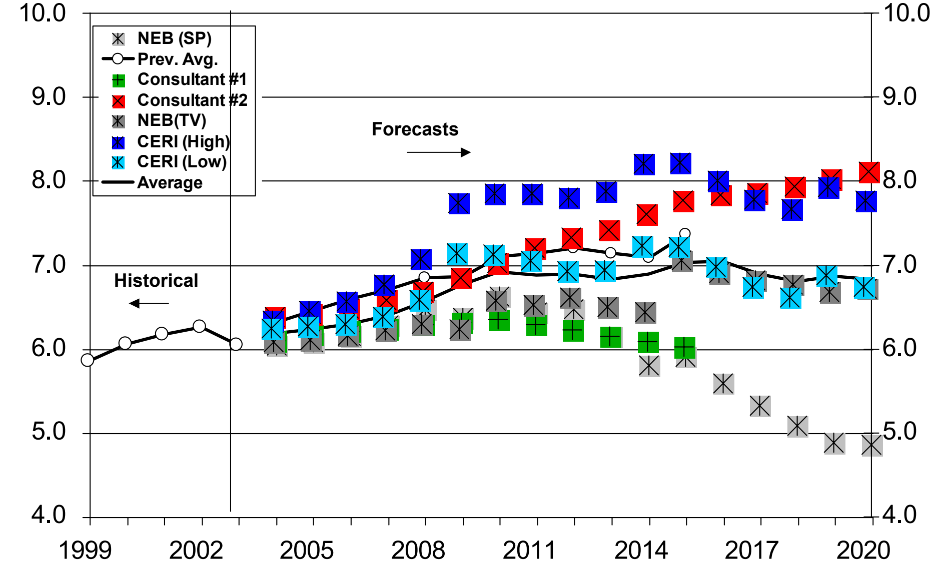
The average forecast in our report last year showed US LNG supply at 2.1 Tcf by 2015, significantly lower than the current forecast of 3.6 Tcf by 2015. Upward revised forecasts can be attributed to growing concerns regarding conventional North American natural gas production.

Map 7
Possible Canadian Incremental Natural Gas Sources



Source: NRCan **Note:** Size of shapes are not representative of total natural gas reserves in each basin

Figure 52
Canadian Natural Gas Production Forecasts



Sources: NEB, CERI, and various consultants. **Note:** (1) Historical numbers from StatsCan.

Canada's conventional gas supplies were the "engine of growth" for the North American natural gas market in the 1990's. However, the conventional reservoirs and producing areas of the Western Canadian Sedimentary Basin (WCSB) are maturing and now require very high drilling rates simply to maintain current levels of production.

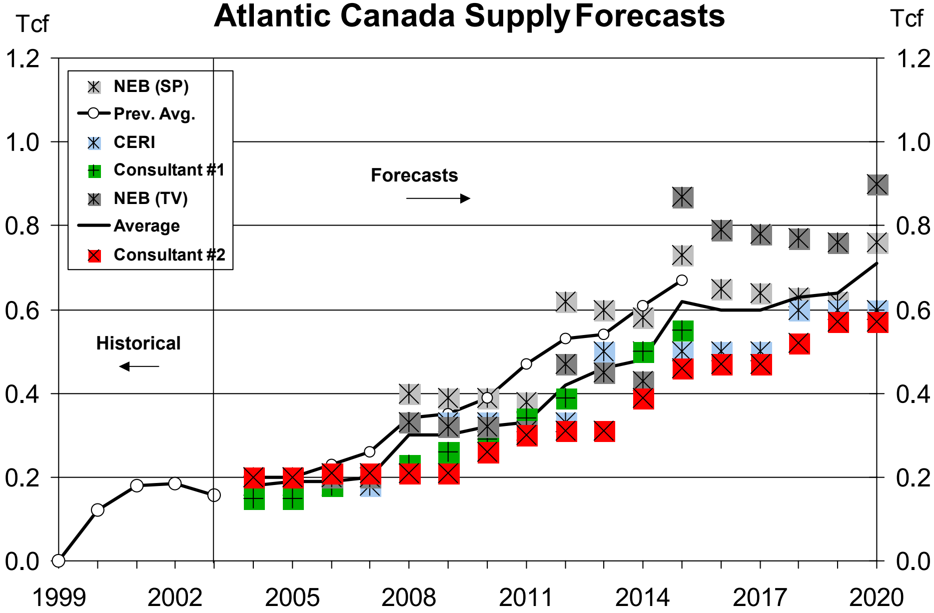
Other possible sources of natural gas supply for Canada beyond what is currently being produced from the WCSB and Sable Island include: (i) domestic gas via the east coast (e.g., Deep Panuke and Newfoundland) and the Mackenzie Delta, (ii) unconventional coalbed methane from the WCSB and (iii) imported liquefied natural gas (LNG) from foreign countries. These additional sources of supply are not expected to become available in any significant quantity before 2007.

Figure 52 shows six 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 reaching 6.8 Tcf by 2020. This represents an annual average increase of 0.6%.

The average of the previous year's forecast showed Canadian natural gas production at about 7.4 Tcf in 2015, about 8% greater than the current forecast at 2020.

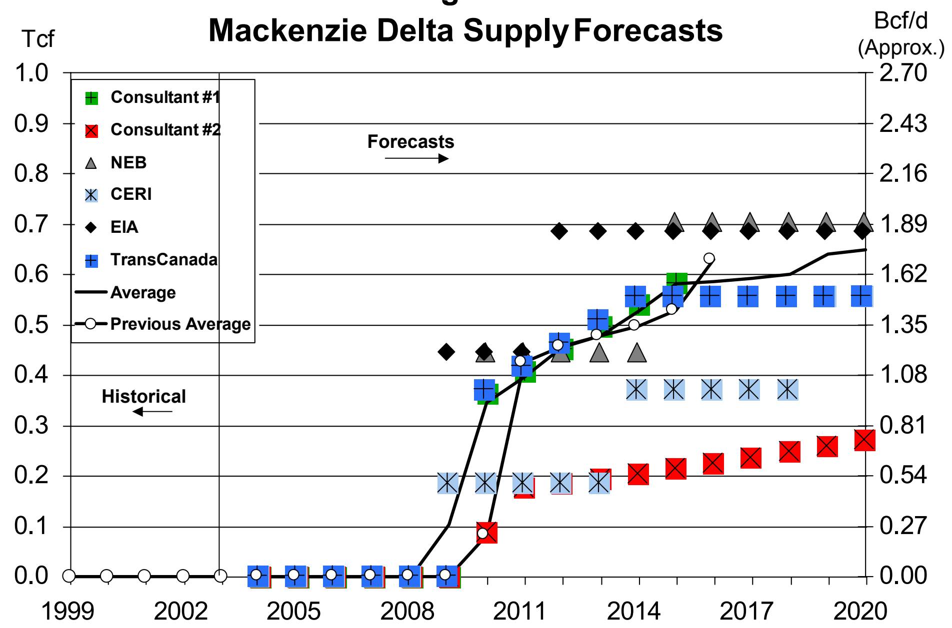
Downgraded forecasts can be attributed to a maturing WCSB, as well as uncertainties regarding natural gas reserves and supply in Atlantic Canada.

Figure 53
Atlantic Canada Supply Forecasts



Sources: NEB, CERI and various consultants **Note:** (1) Historical numbers from CNSOPB.

Figure 54
Mackenzie Delta Supply Forecasts



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

Figure 53 shows five forecasts of Atlantic Canada natural gas supply, as well as the average forecast and the previous year's average. In this figure, Atlantic Canada is defined to include: Sable and its surroundings, Deep Panuke, Nova Scotia deep offshore and Newfoundland. The forecast does not include any potential natural gas from the Laurentian Basin or Prince Edward Island.

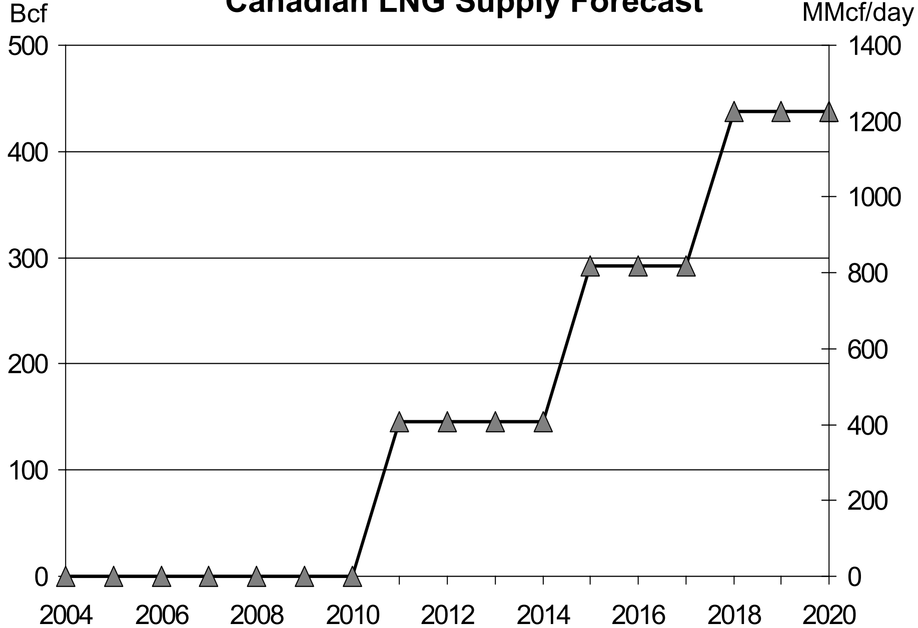
The average of the forecasts shows Scotian Shelf supply at about 0.7 Tcf by 2020, the same as the previous year's forecast at 2015.

Figure 54 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. The average of the forecasts shows MacKenzie Delta gas supply at about 0.64 Tcf, or 1.8 Bcf/day by 2020.

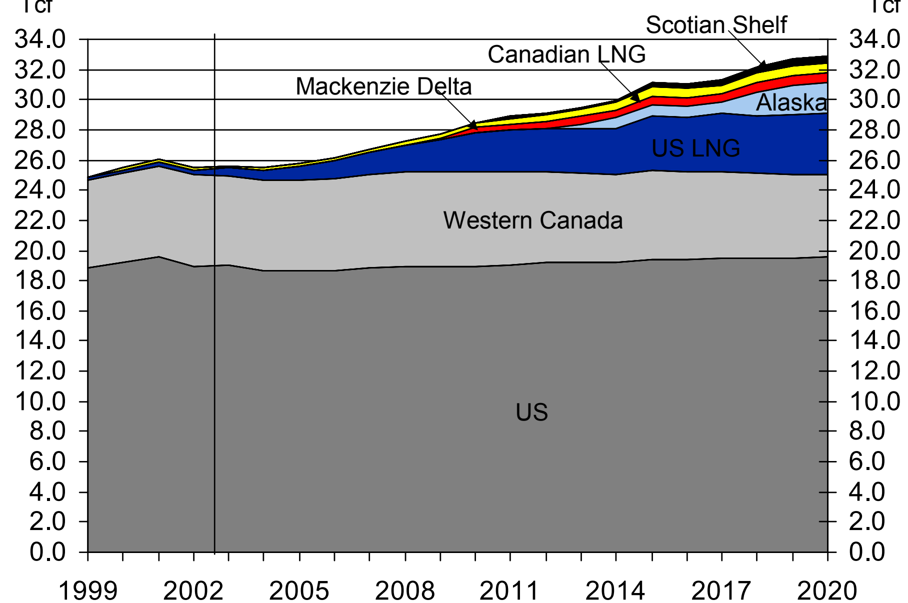
The average of the previous year's forecast showed Mackenzie Delta natural gas production at about 0.62 Tcf, or 1.7 Bcf/day by 2015, slightly less than the current forecast at 2020.

Figure 55
Canadian LNG Supply Forecast



Source: NEB, *Canada's Energy Future: Scenarios for Supply and Demand to 2025*, July 2003

Figure 56
North American Natural Gas Supply Growth[1]



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 55 provides the National Energy Board's view of future Canadian liquefied natural gas imports.

Currently, Canada does not import any LNG. In order to supply natural gas for Canadian needs, as well as to export additional natural gas supplies to the United States, there are eight proposals to construct LNG import facilities in Canadian ports.

In its report, the NEB forecasts that Canadian LNG imports will equal 1.2 billion cubic feet per day, or 0.44 Tcf in 2020. According to the 'consensus' view of Canadian natural gas supply in 2020, LNG would represent about 6% of total Canadian supply.

Averaging various US and Canadian gas supply forecasts results in a "consensus" forecast of North American gas supply of 30.9 Tcf by 2015 and about 33 Tcf by 2020.

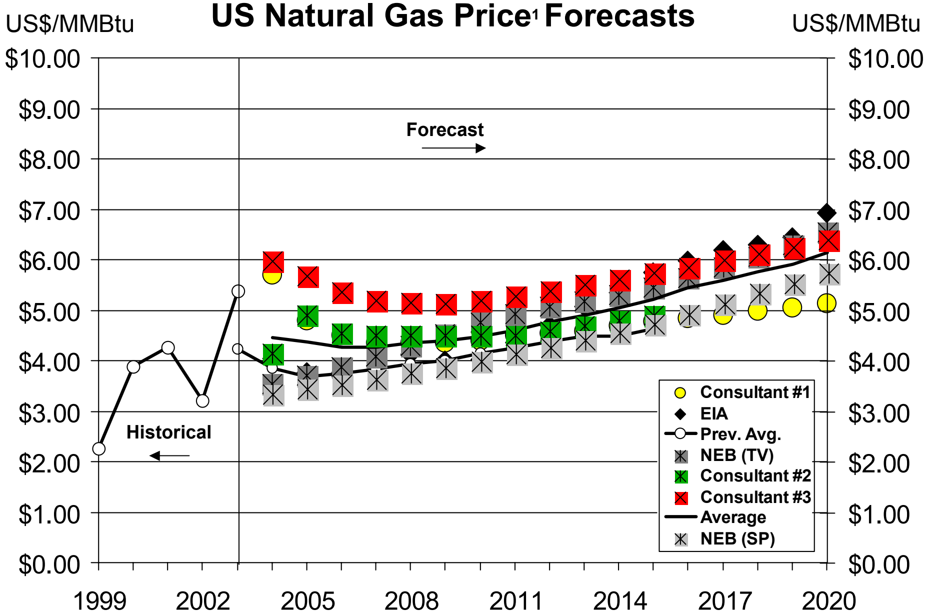
The current "consensus" view of North American natural gas supplies is less than last year's forecasts, which resulted in a "consensus" forecast of 32 Tcf by 2015.

The largest incremental supplies of natural gas to the North American market at the end of the forecast period, in order of magnitude, are: US LNG imports, Alaska natural gas, Mackenzie Delta natural gas, Atlantic Canada gas, and Canadian LNG imports.

Outlook to 2020

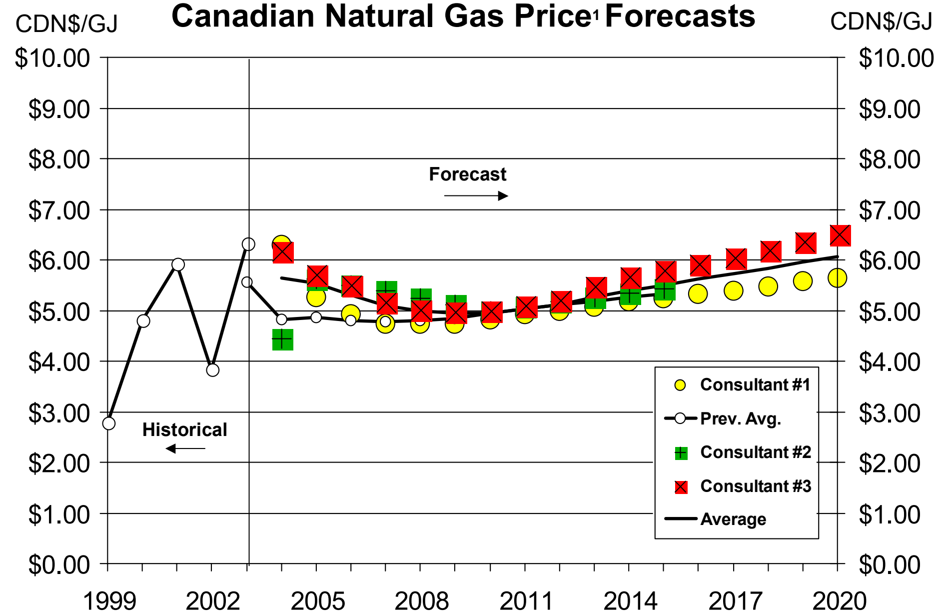
Natural Gas Prices

Figure 57
US Natural Gas Price[1] Forecasts



Sources: EIA, NEB 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 58
Canadian Natural Gas Price[1] Forecasts



Sources: Various consultants **Notes:** (1) Historical are AECO actuals from GLJ. (2) Forecast prices are Alberta. (3) Some forecasts were converted from $US. (4) Nominal dollars.

Figure 57 compares six nominal dollar forecasts of US natural gas prices. The average shows that US prices are expected to be less than 2003 levels in the short-term, but closer to or more than 2003 levels over the latter half of the forecast period.

According to the forecasters surveyed, prices are expected to average US$4.46/MMBtu in 2004. Between 2005 and 2020, US gas prices are expect to average between US$4.20 and $6.15/MMBtu.

Compared to our survey last year, US price expectations have risen again. Last year, the average price outlook for 2015 was US$4.63/MMBtu, 14% lower than the 2015 forecast price this year – US$5.23/MMBtu.

Figure 58 compares three nominal dollar forecasts of Canadian natural gas prices at the AECO-C hub in Alberta.

Prices are expected to average approximately CDN$5.65/GJ in 2004, and will continue to hover between CDN$5 and $6/GJ over the entire forecast period.

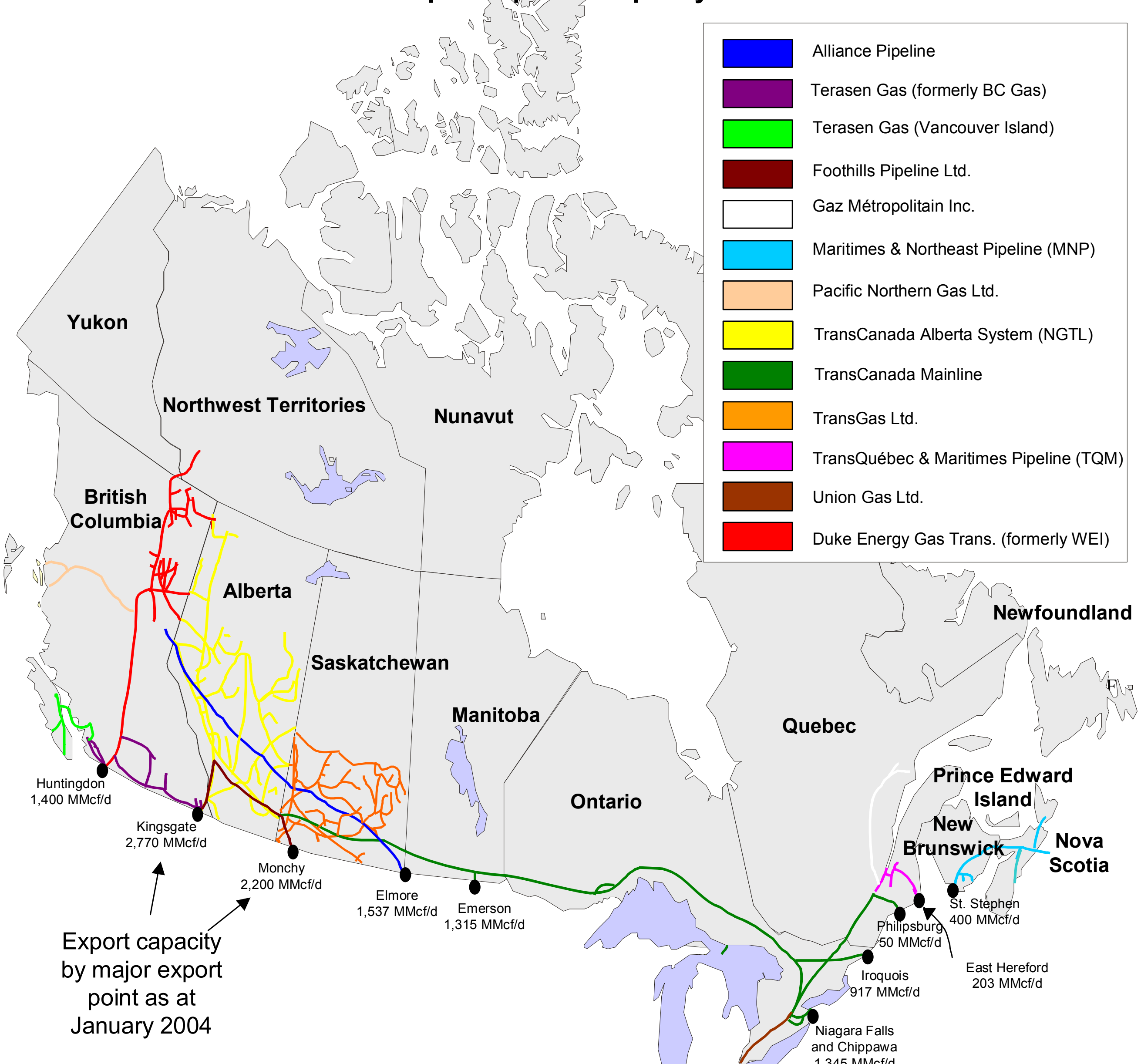
The average forecast for 2015 and 2020 sees gas prices at CDN$5.50/GJ and CDN$6.10/GJ, respectively.

Compared to our survey last year, Canadian price expectations have risen slightly. Last year, the average price outlook over the forecast period was about CDN$5.00/GJ, 8% less or CDN $0.40/GJ less than the average price forecast this year.

Outlook to 2020

Canadian Exports & Domestic Sales

Map 8
Major Canadian Natural Gas Pipelines and Export Pipeline Capacity



Source: GLJ

The location of major Canadian natural gas pipelines (transmission and distribution), as well as export capacity at major border points are presented on Map 8.

The Canadian natural gas market is served by seven major transmission pipelines (Duke Energy Gas Transmission, TransCanada Pipelines, Foothills, Alliance, Union, TQM and MNP), which also interconnect with the US pipeline network at nine major export points.

TransCanada Pipelines is one of the largest transporters of gas in North America. In 2003, the ‘Alberta System’ delivered 10.6 Bcf/d of gas.

Nearly 75% of total Canadian export pipeline capacity is served by five major export points (i.e., Huntingdon, Kingsgate, Monchy, Elmore, and Emerson).

Table 13
Export Pipeline Capacity by Major Export Point
(MMcf/d)

Export Point[1]	Connecting Pipeline	2000[a]	2001[b]	2002[c]	2003[d]	2004-2020	
		Year end Capacity[2]	Year end Capacity	Year end Capacity	Year end Capacity	Increment	Year end Capacity
Huntingdon (Westcoast)[3]	Westcoast, Northwest Pipeline	1 097	1 097	1 097	1 400		1 400
Kingsgate (TCPL)[4]	TCPL AB, TCPL BC, GTN	2 565	2 565	2 565	2 770		2 770
Total US West		**3 662**	**3 662**	**3 662**	**4 170**		**4 170**
Alberta/Montana	TCPL AB, Montana Power	50	20	40	50		50
Monchy (TCPL)	TCPL AB, Foothills, Northern B.	2 200	2 200	2 200	2 200		2 200
North Portal	Transgas, Williston Basin	20	20	20	20		20
Elmore (Alliance)	Alliance CDN, Allliance US	0	1 550	1 550	1 537		1 537
Emerson (TCPL)[5]	TCPL, Viking, GIGT	1 140	2 524	2 524	1 315		1 315
Sprague	TCPL, Centra Gas	26	70	26	26		26
Total US Midwest		**3 436**	**6 384**	**6 360**	**5 148**		**5 148**
St. Clair[6]	Union, MichCon	200	70	70	70		70
Ojibway (Windsor)	Union, Panhandle Eastern	150	200	200	200		200
Chippawa (TCPL)	TCPL, Empire Pipeline	489	470	499	500		500
Niagara Falls (TCPL)	TCPL, Tennesess	854	825	883	845		845
Iroquois (TCPL)	TCPL, Iroquois	903	831	894	917	73	990
Cornwall (TCPL)	TCPL, Niagara Gas	37	28	63	63		63
Napierville (TCPL)	TCPL, North Country Gas	62	62	61	61		61
Phillipsburg (TCPL)	TCPL, Vermont Gas	48	48	50	50		50
Highwater (TCPL)[7]	TCPL, Portland Gas	31	25	25	25		25
East Hereford (TCPL)	TCPL, Portland Natural Gas	172	236	198	203		203
St. Stephen (MNP)[8]	MNP CDN, MNP US	400	500	400	400	400	800
Total US Northeast		**3 346**	**3 295**	**3 343**	**3 334**	**473**	**3 807**
Total Export Capacity		**10 444**	**13 341**	**13 365**	**12 652**	**473**	**13 125**

Sources: Pipeline Companies, GLJ. **Notes:** [1] Where TCPL is listed, we have not shown TCPL's Alberta Transmission system (perviously NOVA Transmission). It is to be understood that TCPL Alberta is the upsteam Alberta system connecting to TCPL (at Empress). [2] For most of the TCPL export points, capacity shown is firm contracted capacity. Actual physical capacity may exceed firm contracted capacity. [3] Westcoast expansion completed November 2003. [4] TransCanada expansion completed December 2003. [5] Contracted capacity included an extra 1.3 Bcf in 2001 and 2002 as TransCanada contracted for extra capacity to potentially use its Great Lakes System as opposed to the Northern route on the Mainline. [6] Gas can by physically exported or imported. [7] Highwater was shut down in February 2001. [8] MNP's 400 MMcf/d expansion project has been conditionally approved by the NEB, however, the Deep Panuke project, which justifies the expansion is under review. [a] Data as of Nov 1, 2000. [b] Data as of Dec 6, 2001. [c] Data as of Aug 8, 2002. [d] Data as of Jan, 8 2004.

Table 13 displays Canada's major export points, connecting pipelines and year-end capacities at each major export point.

Total physical export capacity was 12,652 MMcf/d at the end of 2003, a decrease of about 5% from the previous year.

Nearly 96%, or 12,137 MMcf/d of total physical export capacity is served by 11 export points.

The table also displays estimates of future year-end capacities, through to 2020, based on information provided by pipeline companies.

Total export capacity currently cannot be filled due to insufficient gas supply. Pipeline capacity is seldom used at 100% load factors. In recent years, the best fill rate for total export capacity was about 95%.

Table 14
Export Volumes and Domestic Sales

(Bcf)	2000	2001	2002	2003	2004	2005	2010	2015	2020
Huntingdon (Westcoast)	356	324	335	304	-	-	-	-	-
Kingsgate (TCPL)	833	781	696	562	-	-	-	-	-
Total US West	**1,189**	**1,105**	**1,031**	**866**	**-**	**-**	**-**	**-**	**-**
Monchy (TCPL)	784	744	768	763	-	-	-	-	-
Emerson (TCPL)	491	390	397	362	-	-	-	-	-
Elmore (Alliance)	73	526	568	567	-	-	-	-	-
Miscellaneous	30	31	37	24	-	-	-	-	-
Total US Midwest	**1,378**	**1,691**	**1,770**	**1,716**	**-**	**-**	**-**	**-**	**-**
Iroquois (TCPL)	363	319	323	323	-	-	-	-	-
Niagara Falls (TCPL)	423	326	327	288	-	-	-	-	-
Chippawa (TCPL)	37	54	104	81	-	-	-	-	-
St. Stephen (MNP)	117	141	143	130	-	-	-	-	-
East Hereford (TCPL)	34	39	48	45	-	-	-	-	-
Cornwall (TCPL)	8	9	8	7	-	-	-	-	-
Napierville (TCPL)	19	33	19	19	-	-	-	-	-
Phillipsburg (TCPL)	8	6	7	6	-	-	-	-	-
Highwater (TCPL)	15	5	0	0	-	-	-	-	-
Total US Northeast	**1,024**	**932**	**979**	**899**	**-**	**-**	**-**	**-**	**-**
Total Gross Exports	**3,591**	**3,728**	**3,780**	**3,481**	**3,541**	**3,515**	**3,762**	**3,517**	**2,997**
Total Canadian Demand	**2,872**	**2,697**	**2,736**	**2,914**	**2,950**	**3,026**	**3,457**	**3,809**	**4,128**
Imports to Canada[1]	**80**	**228**	**260**	**371**	**300**	**300**	**300**	**300**	**300**
Total Net Exports	**3,511**	**3,500**	**3,520**	**3,110**	**3,241**	**3,215**	**3,462**	**3,217**	**2,697**
Total Domestic Sales[2]	**2,792**	**2,469**	**2,476**	**2,543**	**2,650**	**2,726**	**3,157**	**3,509**	**3,828**
Total Sales[3]	**6,383**	**6,197**	**6,256**	**6,024**	**6,191**	**6,241**	**6,919**	**7,027**	**6,825**

Sources: NEB, StatsCan, TransCanada, CERI, and various consultants. **Notes:** [1] Imports are assumed to equal 300 Bcf per year over the forecast period. [2] Domestic sales equal to Canadian demand less imports. [3] Total sales equals gross exports plus domestic sales.

Table 14 shows an estimate of Canadian natural gas exports and domestic sales. In previous years, we used a load-factor based approach to determine our export forecast. However, since last year, the export forecast has been determined using "consensus" forecasts of Canadian demand and production.

Using this approach, gross exports would remain relatively flat over the forecast period, reaching 3.77 Tcf by 2010, then falling to 2.99 Tcf by 2020. Decreased export volumes between 2010 and 2020 can be attributed to a "consensus" view that demand will grow at a faster rate than production over this 10 year time period.

Table 15
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$)
2000	3,591	$3.89	$3.85	$3.51	$12,631	$18,887
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
2005	3,515	$4.38	$4.28	$3.98	$13,990	$19,985
2010	3,762	$4.48	$4.38	$4.08	$15,349	$21,927
2015	3,517	$5.23	$5.13	$4.83	$16,987	$24,267
2020	2,997	$6.15	$6.05	$5.75	$17,233	$24,618

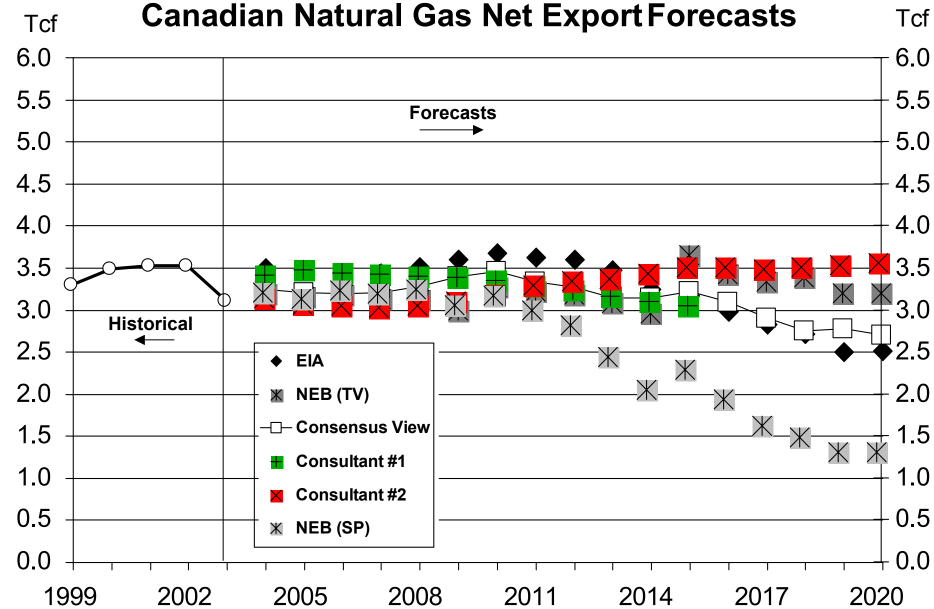
DOMESTIC SALES:	Domestic Sales (Bcf)	Alberta Price (US$/MMBtu)	PlantGate Netback (US$/MMBtu)	Domestic Plant Gate Revenues (Million US$)	Domestic Plant Gate Revenues (Million Cdn$)	**TOTAL Plant Gate Revenues** (Million Cdn$)
2000	2,792	$3.40	$3.25	$9,100	$13,513	**$32,400**
2001	2,469	$4.05	$3.90	$9,688	$15,001	**$37,760**
2002	2,476	$2.58	$2.43	$6,054	$9,504	**$25,752**
2003	2,543	$4.75	$4.60	$11,774	$16,449	**$39,863**
2005	2,726	$3.89	$3.74	$10,195	$14,565	**$34,550**
2010	3,157	$3.57	$3.42	$10,797	$15,424	**$37,351**
2015	3,509	$3.87	$3.72	$13,053	$18,648	**$42,915**
2020	3,828	$4.17	$4.02	$15,389	$21,984	**$46,602**

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 (see report) and were calculated similarly. Future export netbacks were assumed to equal forecast NYMEX prices (see report) less US$0.40/MMBtu. Resultant netback multiplied by forecast export sales. Exchange rate conversions assume $US0.70 per $CDN for the entire forecast period. Domestic sales assumed to equal Canadian demand less imports. Imports are assumed to equal 300 Bcf per year over the entire forecast period.

Table 15 provides estimates of producer plant gate revenues to 2020, given "consensus" forecasts of natural gas prices, gross export volumes and domestic sales.

Total plant gate revenues reached record levels in 2003 – about CDN $39.9 billion – an increase of 73% over the previous year. According to price and volume forecasts, producer revenues will surpass 2003 levels, reaching about CDN $46.6 billion by 2020. Predictions for higher forecasted revenues are mainly the result of higher natural gas price outlooks.

Figure 59
Canadian Natural Gas Net Export Forecasts



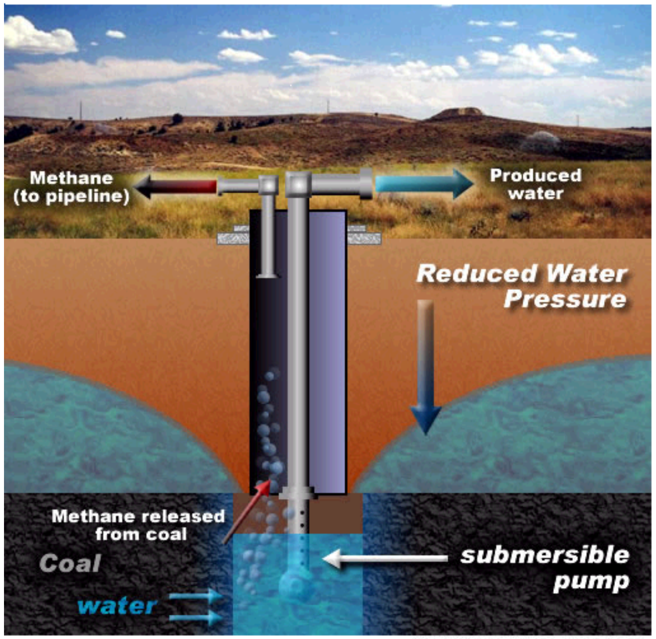
Sources: EIA, NEB, NRCan and various consultants. **Notes:** (1) NEB export forecasts were deduced from Canadian natural gas production and demand projections contained within the NEB's *Canada's Energy Future: Scenarios for Supply and Demand to 2025*, July 2003. (2) Historical numbers from NEB.

Figure 59 shows five forecasts of Canadian natural gas exports, including the "consensus" export forecast calculated in Table 15.

The "consensus" view shows Canadian gas net exports reaching nearly 3.5 Tcf by 2010, then declining to 2.7 Tcf by 2020. This forecast was generated by calculating the difference between the "consensus" views of Canadian gas production and demand.

Appendix 1

Coalbed Methane in Canada



SOURCE: ***ALL Consulting***

Coalbed Methane - Description

Coalbed methane (CBM), also known as natural gas from coal (NGC), is natural gas found within underground coal deposits. The methane is contained within coal seams. Coal seams typically are layers of coal which have varying degrees of fractures within them. In these coal seams, methane is absorbed or attached to the coal. Pressure from the overlying rock and the water in the fractures between pieces of coal keeps the methane absorbed onto the coal.

To produce CBM, the coal seams are penetrated by well bores, and fluids and gases within the coal fractures are allowed to flow via steel production tubing to the surface. The resulting loss of pressure in the reservoir causes methane to "de-sorb" or release from the coal surfaces. A schematic of a typical CBM well is shown on the right.

CBM Production in Canada and the Lower 48

CBM exploration has been undertaken in an episodic fashion in Canada since the early 1980's, resulting in about 140 largely unsuccessful exploration wells by 2000. Since 2000, strong natural gas prices coupled with concerns about conventional supplies has greatly accelerated interest in Canadian CBM. As of late 2003, there were 116 CBM projects underway in Canada. A total of 90 projects were operating in Alberta, and 26 in BC. The significance of these projects ranges from exploration and experimental schemes, to commercial operations. The first commercial operation in Canada was completed in February 2002 (by EnCana and MGV located in southern Alberta).

Recent industry forecasts for 2004 indicate that between 1000-1200 CBM wells will be drilled in Alberta alone, with others being drilled in British Columbia and Nova Scotia. Most of this activity will occur on the shallower, dry plains coals of the Horseshoe Canyon/Belly River in southern Alberta. Additional wells will be drilled in the Manville and Ardley coals in south-central Alberta. Although Canadian production at this time is limited (70 mmcf/d), there is intense interest in this resource by domestic and international companies and it is expected that exploration programs underway in Alberta and British Columbia will soon announce additional commercial production. Numerous oil and gas companies are entering, and currently operating in Canada's CBM industry. In many cases Canadian companies are partnering with US partners that have US CBM production experience. The table on the next page highlights the major players involved in Canadian CBM exploration and production.

Natural Gas Companies Involved in Canadian CBM Activity	
Anadarko Corp	Diaz Resources
Apache Canada Ltd.	Dominion Energy
APF Energy Trust	Fairborne Energy
Canadian Natural Resources Ltd.	Murphy Oil
Bonterra Energy Corp.	Northbridge Exploration
Burlington Resources	Northrock Resources Ltd.
Devon Canada Corp.	Peace River Corp.
Encana	Penn West Petroleum
Enerplus Resources	Promax Energy Inc.
EOG Resources	Resolute Energy Corp.
Koch Oil	Talisman Energy
MGV Energy Inc.	Thunder Energy
Nexen Canada	Trident Energy

Source: GLJ

Most of the world's CBM production is in the US, where more than 20 years of exploration and the drilling of more than 20,000 wells has resulted in an annual production of 1.3 Tcf annually, or approximately 8% of US natural gas production. Most of the US production comes from the San Juan Basin of Colorado and New Mexico, the Powder River Basin of Wyoming and the Black Warrior Basin of Alabama, although there is limited production from other localities.

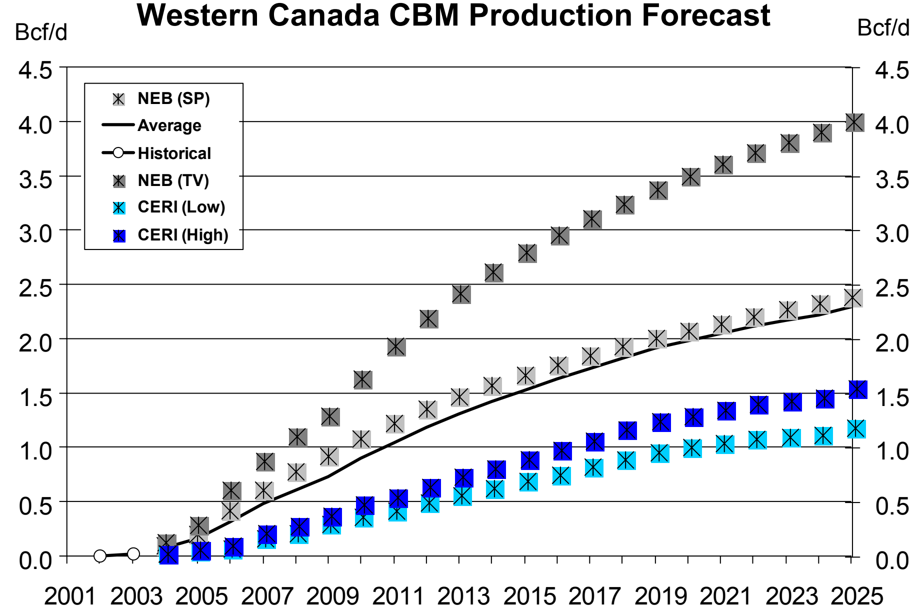
The production of CBM in Canada is different than in the US. The primary reason is coal characteristics. Each coal formation has its own unique set of geological characteristics that must be overcome to extract the methane from the coal. Characteristics include coal rank, quality, composition, and thickness. Each of these geological characteristics affect the ability and the amount of recoverable methane. In general Canadian coal seams are thinner than US coal seams and therefore unique production techniques must be used to extract commercial quantities of methane.

Therefore, the Canadian experience in extracting methane from the coal seams will differ within geological regions of the country, and in particular, from producing regions in the US.

CBM Production Forecasts

Forecasts from CERI and the NEB illustrate the potential future levels of CBM production in Canada. CERI forecasts that CBM production could reach 1.5 Bcf/d by 2025. The National Energy Board's 'high case' forecast that CBM could account for up to 20% of Canada's gas production by 2025 (i.e., more than 1 Tcf/year). Given these forecast it is expected that CBM will become increasingly important to the Canadian natural gas production profile into 2025.

Western Canada CBM Production Forecast



Sources: NEB, CERI

CBM Production and the Environment

Environmental issues are amongst the largest barriers to CBM production in Canada. The main environmental concern surrounding CBM development is the production and disposal of water.

In Canada, the amount of by-product water produced during the dewatering stage of a CBM well varies significantly depending on the coal location. In Alberta there are three coal bearing areas under development; 1) Horseshoe Canyon, 2) Ardley, and 3) Manville. Each area has distinctively different water producing characteristics. To date, the Horseshoe Canyon coals produce little or no water, the Ardley coals are either dry or wet and the Manville coals produce considerable brackish (salty) water. Regardless of the area, the production, use and disposal of water in Canada is well regulated. Regulation in Alberta comes from the BC Oil and Gas Commission, who works closely with other agencies, such as the Ministry of Water, Land and Air Emissions. Regulation in Alberta comes from two primary sources: Alberta Energy (AE), and the Alberta Energy and Utilities Board (EUB). AE is the body which is responsible more for examining royalty structure and the economics of activities, while the EUB is tasked with monitoring companies compliance with current provincial regulation. Produced water in Alberta and British Columbia must be re-injected deep into the ground, as it is in all oil and gas activity. All water must meet stringent quality standards before any form of surface release is considered. Re-injection is also carefully monitored ensuring produced water is injected well below fresh water aquifers.

Conclusion

Tightening North American natural gas supplies and higher gas prices have sparked an increased interest in the development and production of Canada's Coalbed methane resources. In place reserves of CBM stretch from Vancouver Island to Cape Breton totalling an estimated 187-586 Tcf. The average forecast predicts that Canada could be producing about 2 Bcf/d of natural gas from CBM reservoirs by 2015. There are, despite recent interest, varying degrees of environmental, financial, technical and economic constraints to consider in order to commercialize CBM production in Canada. As Canadian technology, regulation, and producer interest in CBM increase, its position in the Canadian natural gas supply profile will undoubtedly increase.

Appendix 2

Liquefied Natural Gas in Canada

Liquefied Natural Gas in Canada

Liquefied Natural Gas - Description

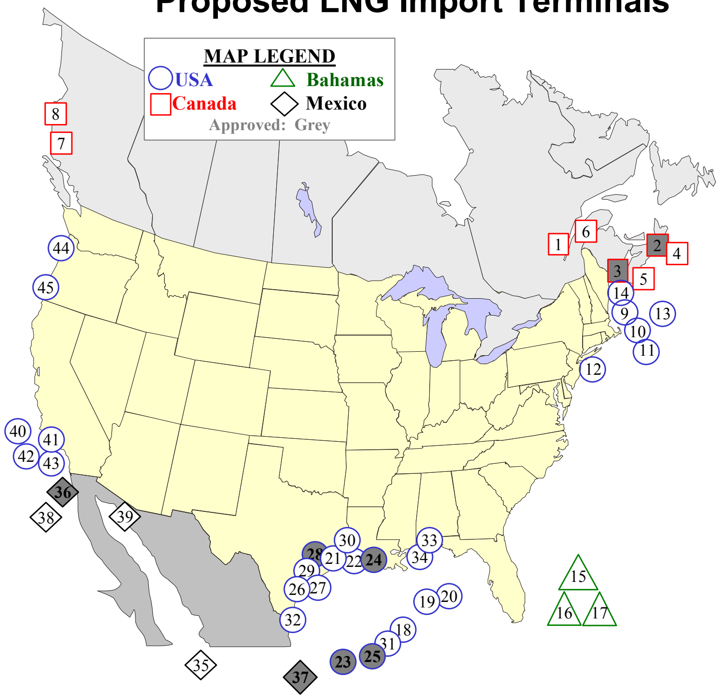
Liquefied Natural Gas (LNG) is natural gas that has been cooled to the point that it condenses to a liquid, which occurs at approximately –160º C. Liquefaction reduces the volume by approximately 600 times, thereby allowing one tanker to deliver as much natural gas in one shipment as it would take 600 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.

LNG in North America

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.

The US is the key market for growth in the LNG industry, as it currently accounts for 25% of the world's natural gas demand. There are four LNG import terminals in the US. Combined, they imported 540 billion cubic feet (Bcf) in 2003, accounting for 2% of US natural gas consumption. Analysts predict that LNG imports will account for 15 - 20% of US natural gas consumption by 2025. This will require that existing US LNG import facilities are expanded and that new facilities are built. In addition to the expansions that have or are expected to occur at the four existing US LNG import facilities, there are currently more than three dozen proposals for the development of LNG import facilities in the US, Canada, Mexico and the Bahamas, almost all of which are entirely destined to supply gas to the US markets. The map to the right shows the numerous LNG import facilities being proposed for North America.

Proposed LNG Import Terminals



Source: NRcan Note: * US pipeline approved; LNG terminal pending in Bahamas

1. Beaumont, QC (Gaz Metro et al)
2. Strait of Canso, NS (Anadarko)
3. Saint John, NB (Irving Oil)
4. Strait of Canso, NS (Statia Terminals)
5. Goldboro, NS (Keltic Petrochemicals)
6. Gros Cacouna, QC (TransCanada et al)
7. Kitimat, BC (Galveston LNG)
8. Prince Rupert, BC (WestPac Terminals)
9. Somerset, MA (Somerset LNG)
10. Fall River, MA (Weaver's Cove)
11. Providence, RI (Keyspan)
12. Logan, NJ (BP)
13. Offshore Boston, MA (Excelerate)
14. Pleasant Point, ME (Quoddy Bay)
15. Ocean Cay, Bahamas (AES Corporation)*
16. Freeport, Bahamas (Tractebel LNG)*
17. Grande Bahama Island, Bahamas (El Paso)
18. Gulf of Mexico (ConocoPhillips)
19. Offshore, LA (Shell)
20. Offshore, LA (Freeport McMoRan Energy)
21. Sabine, TX (ExxonMobil)
22. Sabine, LA (Cheniere)
23. Gulf of Mexico – Port Pelican (ChevronTexaco)
24. Cameron, LA (Sempra)
25. Gulf of Mexico – Energy Bridge (Excelerate/El Paso)
26. Corpus Christi, TX (Cheniere)
27. Corpus Christi, TX (ExxonMobil)
28. Freeport, TX (Cheniere/ConocoPhilips)
29. Ingleside, TX (Occidental)
30. Port Arthur, TX (Sempra)
31. Gulf of Mexico (ExxonMobil)
32. Brownsville, TX (Cheniere)
33. Mobile Bay, AL (ExxonMobil)
34. Mobile Bay, AL (Cheniere)
35. Lazaro Cardenas, MX (Tractebel/Respol)
36. Ensenada, MX (Sempra/Shell)
37. Altamira, Tamaulipas, MX (Shell/Total)
38. Tijuana, MX (ChevronTexaco)
39. Puerto Libertad, MX (Sonora Pacific LNG)
40. Offshore, CA (BHP Billiton)
41. Long Beach, CA (SES/ConocoPhillips)
42. Offshore, CA (Crystal Energy)
43. Offshore, CA (ChevronTexaco)
44. St. Helens, OR (Port Westward LNG)
45. Coos Bay, OR (Energy Projects Development)

LNG Potential in Canada

Currently, Canada does not import any LNG. In order to supply natural gas for Canadian needs, as well as to export additional natural gas supplies to the United States, there are eight proposals to construct LNG import facilities in Canada, six of which have undergone or are currently involved in the environmental assessment (EA) portion of the regulatory review process. The other two projects are more conceptual in nature, only having been announced. These projects are not yet under EA / regulatory review. A description and status on all proposed Canadian LNG import projects is provided below.

Anadarko Petroleum Corporation Bear Head LNG Facility

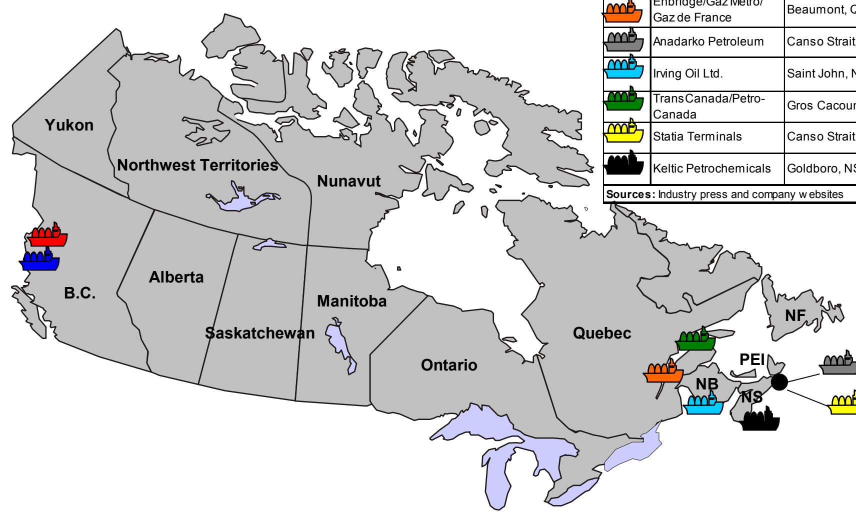
On August 12, 2004, days after receiving its federal – provincial environmental assessment approval, Access Northeast Energy was sold to Anadarko Petroleum Corporation, a Houston-based company. Anadarko Petroleum Corporation is proposing to construct an LNG import terminal at Bear Head, Richmond County, in the Strait of Canso in Nova Scotia.

Anadarko expects to receive all the requisite permits and approvals it requires to construct and operate the terminal by the end of 2004. The LNG terminal is expected to be in commercial operation, with a 1 Bcf/d send-out capacity, by November 2007.

Irving Oil Canaport LNG Facility

Irving Oil Limited plans to develop a 1 Bcf/d brown-field (i.e., already industrialized area) LNG import facility in Saint John, New Brunswick. In August 2004, Irving received both federal and provincial environmental assessment approvals. Irving expects to receive all the requisite permits and authorizations in time to begin construction in early 2005, with a start-up date of 2007.

Proposed Canadian LNG Import Terminals



	Operator	Location	Earliest Start Date
	Galveston LNG	Kitimat, BC	2008
	Westpac Terminals Inc.	Prince Rupert, BC	2009
	Enbridge/Gaz Métro/ Gaz de France	Beaumont, QC	2008
	Anadarko Petroleum	Canso Strait, NS	2007
	Irving Oil Ltd.	Saint John, NB	2007
	TransCanada/Petro-Canada	Gros Cacouna, QC	2009
	Statia Terminals	Canso Strait, NS	2009
	Keltic Petrochemicals	Goldboro, NS	2008

Sources: Industry press and company websites

Source: NRcan

Gaz Métro's et al Rabaska LNG Facility

In partnership with Enbridge and Gaz de France, Gaz Métro is proposing to construct a 500 MMcf/d LNG import facility on the Saint Lawrence River, near Rabaska, Québec. The facility is expected to be in commercial operation by 2008.

Keltic Petrochemicals Goldboro LNG Facility

Keltic Petrochemicals' application for regulatory permits regarding its petrochemical and LNG facility was filed with federal and provincial agencies in August 2004. The facilities will be located adjacent to the Sable Offshore Energy Plant in the Goldboro Industrial Park. The complex is estimated at a cost of CDN $4 billion and could be in operation by late 2008.

Galveston LNG Kitimat LNG Facility

Galveston LNG, a Calgary-based company, is proposing to construct a CDN $300 million LNG import facility near the Port of Kitimat in British Columbia. Initial natural gas send-out capacity will be 610 MMcf/d of natural gas, with a start-up date of late 2008.

TransCanada/Petro-Canada Gros Cacouna LNG Facility

TransCanada Corporation, in partnership with Petro-Canada, is proposing to construct a $660 million, 500 MMcf/d LNG import facility on the Saint Lawrence River in Gros Cacouna, Quebec. The facility would include two storage tanks capable of holding 6.8 Bcf of gas. Regulatory filing is anticipated in mid-2005, with construction beginning in 2007, and operations beginning in 2009.

Other Canadian LNG Projects

Two other LNG projects, which are more conceptual in nature at this stage, are also being proposed for Canada.

Calgary-based WestPac Terminals Inc.(WestPac) is proposing to construct an LNG import facility just 60 kilometres north of Kitimat at Prince Rupert, BC. The proponent has linked up with government-owned Ridley Terminals. The new LNG facility would use the existing docking facilities at Ridley Island, which were once used to ship coal. The initial send-out capacity envisioned for the LNG facility is 300 MMcf/d, with a potential start-up date in 2009.

Statia Terminals, a Nova Scotia-based company is planning to construct a 0.5 Bcf/d LNG import facility at the Strait of Canso. Further project details have not been released.

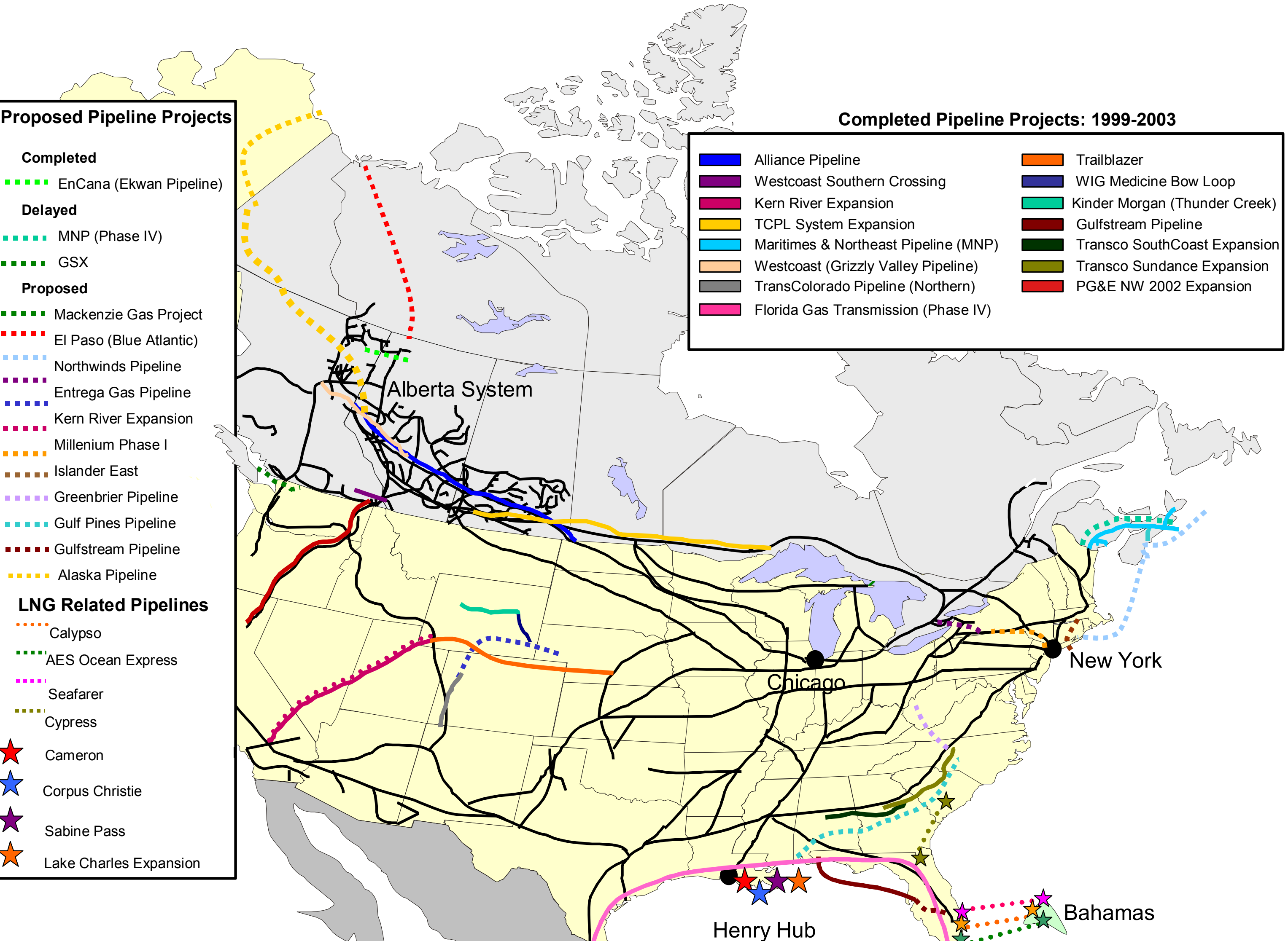
NEB Forecast of Canadian LNG Imports

The NEB, in its July 2003 *'Canada's Energy Future: Scenarios for Supply and Demand to 2025'* report, forecast that Canadian LNG imports will reach 1.2 billion cubic feet per day by 2025, or 10 percent of projected Canadian gas demand in 2025.

Appendix 3

North American Natural Gas Pipelines:
Five Year Review & Outlook

North American Natural Gas Pipelines: Five Year Review & Outlook



Sources: Pipeline companies, industry press and various consultants

North America's natural gas pipeline system is an integrated grid of pipelines connecting markets from coast to coast.

The map on the left provides a visual representation of the pre-1999 system (black lines), major constructed pipelines (solid coloured lines), proposed pipelines (dashed coloured lines) and proposed LNG-related pipelines (dashed lines with stars). The map also includes system expansions (solid coloured lines), which are either added compression or looping to an existing pipeline. Looping projects use small amounts of pipeline but add significant capacity to an existing system. Therefore, the existing pipeline is drawn for representation, e.g., Kern River expansion.

As demand or production for natural gas in North America grows, the demand for pipelines to transport the natural gas also grows. Since 1999, nearly 7 Bcf/d of major pipeline capacity has been added to the pipeline grid in various regions across North America. Also, there is currently an additional 12.5 Bcf/d of proposed pipeline and nearly 10.6 Bcf/d of LNG associated pipeline.

Major North American Gas Pipeline Projects: 1999-2003

Company (Pipeline)	Year In-Service	From Location	To Region	Capacity (MMcf/d)
Canada				
Alliance Pipeline Ltd. (Alliance Pipeline)	2000	British Columbia	Midwest	1,500
Westcoast (Southern Crossing)	2000	British Columbia	Pacific Coast	250
Westcoast (Grizzly Valley and Weejay Lateral)	2003	British Columbia	Pacific Coast	116
TransCanada Pipelines System Expansion	1999	Saskatchewan	Northeast	95
Maritimes & Northeast Pipeline Ltd. (M&NP)	1999	Nova Scotia	Northeast	400
			Total	**2,361**
US Rockies				
Kern River Expansion	2003	Wyoming	Pacific Coast	900
WIG Medicine Bow Loop Expansion	2000	Wyoming	Interior West	675
Kinder Morgan (Thunder Creek Gathering System)	1999	Wyoming	Various	450
TransColorado Pipeline (Northern)	1999	Colorado	Pacific Coast	300
Trailblazer 2002 System Expansion	2002	Colorado	Midwest	300
			Total	**2,625**
Gulf Coast				
Gulfstream Pipeline	2002	Alabama	Southeast	1,130
Florida Gas Transmission (Phase IV)	2003	Texas	Southeast	120
Transco Sundance Expansion	2002	Texas	Southeast	230
PG&E NW 2002 Expansion	2002	Washington	Pacific Coast	200
Transco SouthCoast Expansion	2000	Alabama	Southeast	200
			Total	**1,880**
TOTAL ALL REGIONS				**6,866**

Sources: Industry press, company websites, and various consultants.

Since 1999, there have been 15 major North American pipeline projects (i.e., new pipelines or expansions of existing systems via added compression or pipeline looping). Of the 15, five are located in Canada (3 in BC, 1 in SK and 1 in NS), five in the US Rockies (3 in WY, 2 in CO), and five in the US Gulf Coast (2 in AB, 2 in TX, 1 in DC). Although major expansions occurred in the US Gulf Coast, western Canada, and the US Rockies, only the pipeline expansions in the US Rockies were supported by increased production.

Capacity additions in Canada total more than 2.5 Bcf/d, primarily serving the US market. The largest Canadian project was the Alliance pipeline project, with a capacity of 1.5 Bcf/d, transporting natural gas from northeast BC to the Chicago hub. In the US, Rockies additions total over 2.8 Bcf/d, primarily serving US west coast markets, while Gulf Coast expansions total over 1.8 Bcf/d, serving primarily the southeast market.

As of August 2004, there were eight major North American LNG-related pipeline proposals. The combined capacity of the eight projects is more than 10 Bcf/d, although the viability of all eight proposals being constructed is minimal. Of the eight proposals, 3 are located in Louisiana, 3 in the Bahamas, 1 in Georgia, and 1 in Texas, all destined for Southeast delivery points. The proposed pipelines are located onshore or offshore, depending on the configuration of the LNG facilities. Onshore pipelines would run from an onshore re-gasification facility directly into the North American pipeline system. Offshore sub-sea pipelines would run from offshore LNG offloading facilities into onshore re-gasification terminals and then into the pipeline system.

LNG-Related Natural Gas Pipeline Proposals

Company (Pipeline)	Receipt Point	Delivery Point	Capacity (MMcf/d)	In-Service Date	Status
Corpus Chrisitie Pipeline	Corpus Christie LNG facility, TX	Southwest	2,700	2007	Filed with FERC; dependant on FERC approval of nearby LNG facility
Cheniere (Sabine Pass Pipeline)	Sabine Pass LNG facility, LA	Southwest	2,700	2007	Filed with FERC; dependant on FERC approval of nearby LNG facility
Sempra (Cameron Pipeline)	Cameron LNG facility, LA	Southwest	1,500	2007	Approved by FERC
Southern Louisiana	Lake Charles LNG facility, LA	Southwest	900	2005	Open Season
Tractebel (Calypso Pipeline)	Tractabel LNG facility, Bahamas	Southeast	832	2006	Approved by FERC; construction dependent on approval of LNG facility
AES (Ocean Express Pipeline)	AES Corp. LNG facility, Bahamas	Southeast	842	2007	Approved by FERC; construction dependent on approval of LNG facility
Seafarer Pipeline	High Rock LNG facility, Bahamas	Southeast	750	2008	Filed with FERC; construction dependent on approval of LNG facility
Cypress Natural Gas Pipeline	Georgia	Southeast	310	2007	Open Season
TOTAL			**10,534**		

Sources: Industry press, company websites, and various consultants.

Major North American Natural Gas Pipeline Proposals

Company (Pipeline)	From Location	To Region	Capacity (MMcf/d)	Year In-Service	Status
Canada					
Westcoast (Southern Mainline Expansion)	Macleod Lake, British Columbia	Huntingdon, British Columbia	200	N/A[1]	NEB approval (2003) Project cancelled
Maritimes & Northeast Pipeline (Phase IV Expansion)	Nova Scotia	Canada and US Northeast	400	N/A	NEB approval (2002) Project delayed
Georgia Strait Crossing (GSX)	Huntingdon, BC	Vancouver Island	190	N/A	NEB approval (2003) Project delayed
EnCana (Ekwan Pipeline)	Fort Nelson, BC	Alberta	418	2004	NEB approval (2003)
Mackenzie Gas Project	Northwest Territories	WCSB	1 000	2009	Under review
El Paso (Blue Atlantic)	Offshore Nova Scotia	Canada and US Northeast	1 000	N/A	Project Deferred
Northwinds Pipeline	Ontario	US Northeast	500	N/A	N/A
Total Potential Capacity			**3 708**		
Alaska					
Alaska Natural Gas Pipeline	Alaska North Slope	Alberta	4 000	2018	Under consideration
US Rockies					
Entrega Gas Pipeline	Colorado	Midwest	1 300	2005	Notice of intent to file with FERC
Kern River Expansion	Wyoming	Pacific Coast	500	2006	Open Season
Total Potential Capacity			**1 800**		
US Northeast					
Millenium Phase I	New York	US Northeast	500	2006	Approved by FERC
Duke Energy and Keyspan (Islander East)	Connecticut	US Northeast	260	2004	Project on hold pending necessary state permits
Total Potential Capacity			**760**		
US Southeast					
Dominion (Greenbrier Pipeline)	West Virginia	Southeast	600	2007	24 Month Extension
Gulf Pines Pipeline	West Virginia	Southeast	600	2007	Project announced
Gulfstream Pipeline	Alabama	Southeast	1 000	2004	Construction phase
Total Potential Capacity			**2 200**		
TOTAL ALL REGIONS			**12 468**		

Sources: Industry press, company websites, and various consultants. **Note:** [1] N/A means not applicable or is unknown.

According to our 'consensus' forecast, North American natural gas demand is forecast to increase from 24.8 Tcf in 2003 to 33 Tcf by 2020. To satisfy increased market demand, new pipelines must be constructed to deliver the natural gas to market centers.

As of August 2004, there were 15 major North American pipeline proposals with a total added capacity of nearly 12.5 Bcf/d, although some projects will likely not be constructed.

Proposed capacity additions by region are: Canada, 3.7 Bcf/d, Alaska, 4 Bcf/d, US Rockies, 1.8 Bcf/d, US Northeast, 0.76 Bcf/d and US Southeast, 2.2 Bcf/d.

In October 2004, proponents of the Mackenzie Gas Project submitted its Environmental Impact Statement and filed regulatory applications with the appropriate authorities.

Mackenzie Delta natural gas is expected to flow by 2009, with an initial start-up capacity of 1 Bcf/d.

According to the EIA, Alaska natural gas is expected to come on stream in 2018, initially delivering 4 Bcf/d of gas to markets in Canada and the Lower 48.

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