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Canadian Natural Gas

Review of 2002 & Outlook to 2015

November 2003

Natural Gas Division
Petroleum Resources Branch
Energy Sector

Canada

Foreword

The *Canadian Natural Gas 2002 Market Review & Outlook* is an annual working paper prepared by the Natural Gas Division of Natural Resources Canada. It provides summaries of North American natural gas industry trends and reviews Canadian 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 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 (2002), for the near term (2003/early 2004), and the long-term (to 2015). 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 front 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 (US). Our main sources of statistical data were the National Energy Board (NEB), the US Energy Information Administration (EIA), and Statistics Canada (StatsCan).

Some data for 2002 is still preliminary and contains problems, a major one being the large "balancing item" (unaccounted for gas) relating to the US. In 2002, because of data problems, US supply is about 610 billion cubic feet (Bcf) greater than demand, even after accounting for storage movements.

Furthermore, between the March and April 2003 issues of the EIA's Natural Gas Monthly (NGM), dramatic changes to US production and consumption data series, definitions, and data sources were made. For more information on these changes, refer to the EIA's website: http://www.eia.doe.gov/

Format of the Report

The report has been formatted in landscape orientation this year to be more easily read on a computer screen. Most pages show 2 graphics and accompanying text per page.

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 the review and outlook, are also available at this site. Printed copies of this report are available, in black and white. The internet version is in full colour. 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 email dboisjol@nrcan.gc.ca.

Rapport aussi disponible en français

Natural Gas Division

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

The Natural Gas Division and the Petroleum Resources Branch are within the Energy Sector. Other Branches within the Energy Sector include the Electricity Resources Branch, the Energy Policy Branch (responsible for climate change files), the Office of Energy Efficiency, the Office of Energy Reseach and Development and the CANMET Energy Technology Branch.

The Energy Sector is one of the four main sectors of Natural Resources Canada, the others being the Earth Sciences Sector (which includes the Geological Survey of Canada), the Minerals and Metals Sector, and the Canadian Forest Service.

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

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Review of 2002 & Outlook to 2015

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Review of 2002

In the beginning of 2002, core market natural gas demand was low as a result of a very mild 2001/2002 winter. Industrial sector demand for gas was down, due to the industrial restructuring caused by the very high natural gas prices of 2001, continuing concern by industrials about gas prices, and an industrial production slowdown. Finally, power generation demand was down, since gas use for power mostly occurs in summer, and is always low in the winter and spring.

Low demand meant that gas storage operators began the 2002 injection season with relatively high storage balances. High storage generally means lower prices, and gas prices began the year fairly low – about US$2.50/MMBtu at Henry Hub and CDN$3.50/GJ in Alberta. Gas drilling, which follows prices, was considerably lower than it had been in late 2000 and most of 2001. The US gas rig count in 2002 was down 30% from 2001 levels, and Canadian gas well completions fell 20%.

In the background, the market appeared to recognize that North American producing natural gas wells were flowing at essentially full capacity. This, by 2002, was normal procedure, the result of a gradual tightening of the balance between productive capacity and demand over the years, and the result also of the increasing reliance on gas storage and price movement (i.e. demand destruction) to manage temporary supply/demand imbalances.

As 2002 progressed, drilling and demand remained low, while storage remained well above five-year average levels. Despite such relatively mild market fundamentals, prices began to take off in the second quarter of 2002. By November, US gas prices at Henry Hub cracked the US$4/MMBtu level, while Alberta prices exceeded CDN$5/GJ.

In hindsight, the main reason for this price run-up appears to have been concern that production growth was stalling, combined with worry that the winter of 2002/2003 might be abnormally cold. It is our view that concern about North American supply became the major natural gas market issue during 2002.

Market concern about stalling production was driven by low drilling levels, and numerous media, government, and research reports. As the year wore on, production data began to come out, revealing that production was in fact declining. Overall, North American production in 2002 was down 3% from 2001.

Core Markets in 2002

Core markets include residential and commercial demand. This sector is the most volatile in terms of changes in demand from one year to the next. All the volatility in demand is driven by weather. If normalized to remove the effects of changing weather, demand in this sector would be flat – i.e., there is very little structural change in this sector. Even though the number of gas-using furnaces is increasing, the higher efficiency of new furnaces as older ones are replaced means that weather-adjusted demand does not materially change from year to year.

Weather causes this sector to see wide swings in demand from one calendar year to the next, and even larger swings from one winter to the next. In fact, looking simply at calendar year changes is misleading. While core demand in 2002 was slightly higher compared to 2001, the winter of 2002/2003 saw core demand jump by an estimated 700 Bcf from the previous winter. This huge jump in demand (700 Bcf is equal to 3% of all North American gas demand) was the major factor driving natural gas prices to the US$9/MMBtu level (Henry Hub) and CDN$8.50/GJ level (Alberta) in February 2003.

The Industrial Sector in 2002
The industrial sector uses gas for chemical feedstock, process or space heat as well as a small amount of power generation. Industrial process demand includes gas used in melting or heating metal, drying paint, food products or paper, or manufacturing fertilizers or methanol. As of their April 2003 reporting period, the EIA has made a more concerted effort to exclude industrial power generation from the industrial sector statistics, and put those figures in the power generation sector.

Industrial gas demand in the US had fallen 10% in 2001, and fell another 3% in 2002. This type of demand has now fallen from 8,142 Bcf in 2000 to 7,178 Bcf in 2002. This represents a tremendous restructuring of gas demand.

The Power Generation Sector in 2002
Gas used for power generation has increased in recent years. Most new power generation capacity installed in North America in recent years has been gas-fired, due to its scalability, low capital cost, and low environmental impact. Gas use in North American power generation (including cogeneration by industrial plants) increased 4% in 2002. Power generation demand has increased from 5,474 Bcf in 2000 to 5,800 in 2002, a total increase of 326 Bcf, or 6%, over this period.

Before 2000, the price of the fuel for these plants was competitive. More recently, rising natural gas prices have become an issue and this is perhaps one reason for the slowing down of growth in this sector. Demand growth averaged 9% per year over the 1997-2000 time period, but was only 3% in 2001 and 4% in 2002.

US Gas Production in 2002
There is a lot of month-to-month variability in gas production. Because of this, trends can be difficult to spot at first. One must also consider gas demand and the call on production. Sometimes production falls simply because demand falls, and not because of a lack of gas production capacity. However, when gas production falls while prices are high, it can be inferred that capacity to increase production is just not there; otherwise producers would have increased production.

In 2002, US gas production fell 3.2%, or 629 Bcf. Almost all of the loss of production (529 Bcf) occurred in the Gulf Coast states of Texas, Louisiana, and Alabama - both in the onshore and offshore producing areas.

The cause of the production drop was obvious – lower gas drilling. The US Gulf coast offshore gas rig count fell 20%, while gas completions in onshore Texas fell 6%. Less obvious was why drilling would drop so much. Gas prices in 2002 seemed to be relatively attractive compared to past years. While Henry Hub gas prices did fall 35% from 2001 levels, to average US$3.80/MMBtu in 2002, this was still well above the gas price of every other previous year except for 2000 and 2001. While gas prices of $3.80 would have sparked a drilling boom in the 1990s, this was not the case in 2002. Things have changed.

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Canadian Gas Production in 2002

Canadian gas production was relatively flat in 2002. As with the US, production levels were somewhat disappointing, given relatively healthy prices and gas drilling levels well above those of the 1990s. Canadian production declined 1% in 2002 – a 1.1% decline in Western Canada and a 2.8% increase at Sable, offshore Nova Scotia.

In 2002, total gas completions in Canada fell 20%. About 75% of Canadian gas wells drilled were in the shallow areas. Canadian gas drilling in recent years has become more and more focused on shallow, low-productivity areas of Saskatchewan and eastern Alberta. While cheap to drill and very lucrative, these wells produce little gas, and a large increase in the number of these wells drilled will not increase production much overall.

There were also some high-profile disappointments that contributed to the unease about Canadian supply. Several expensive offshore Nova Scotia wells came up dry, and EnCana announced its Deep Panuke offshore production project was on hold. In Western Canada, the large new Ladyfern field went into steep decline after only 2 ½ years of production.

Not all stories were negative. EnCana announced its Greater Sierra play in northeast BC, where it expects to be able to recover more than half of an estimated 5 Tcf of gas in place. In addition, several companies started coalbed methane production pilot projects.

However, the producing industry in both Canada and the US seems to be fundamentally different than it was in the 1990s.

Reserves in 2002

Reserves data comes out about one year after the fact. US proved reserves as of January 1, 2002 were 183.5 Tcf, up 3.4% from a year earlier. Canadian proved reserves as of January 1, 2002 were 60.1 Tcf, up 1% from year-earlier levels. Reserves rose slightly 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. As reserve additions in recent years have approximately equaled production, this seems to be signaling flat supply for the medium-term.

Storage in 2002

Mild weather and low core demand in early 2002 meant lower than normal storage withdrawals. As a result, storage levels by the start of the spring injection season, April 2002, were already at 1,656 Bcf. A more usual April level is about 1,260 Bcf. As a result, injections into storage during 2002 did not have to be as large as during a normal storage injection season. Storage peaked at the start of November at 3,579 Bcf, only slightly above the normal level of 3,484 Bcf.

Due to cold weather, storage withdrawals during the withdrawal season were heavy. By year-end 2002, there was 557 Bcf less gas in storage than year-end 2001. By the end of the heating season (April 2003), there was 898 Bcf less than April 2002. As storage dipped below year-earlier and normal levels, prices rose.

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Prices in 2002

On average, 2002 prices were much lower than 2001 prices. NYMEX prices were 25% lower; Alberta prices were 35% lower.

Natural gas prices have become very volatile over the past 3 years. This is evident from the spread between the lowest and highest monthly prices during 2002. Henry Hub prices were US$2.00/MMBtu in February, and $4.14 in December. Alberta prices went from CDN$2.58/GJ in August to $5.29 in November.

The largest influence on North American natural gas prices is storage levels. In early 2002, storage levels were high relative to normal levels for springtime, and prices were lower. By late 2002, storage levels were low, and prices were much higher.

Because many industrials and power generators can switch from gas to crude-oil derived fuels, world crude oil prices influence gas demand and prices. In early 2002, West Texas Intermediate crude oil prices were between US$20 - $25 per barrel. By late 2002, with the Iraq war looming, prices exceeded $30/barrel. Thus, high oil prices also supported high gas prices in late 2002.

Regionally, Rockies gas prices fell far below other market prices during 2002. The causes for this were two-fold. First, rebounding hydro-electric generation during summer 2002 reduced the call on Rockies production. Secondly, available Rockies production capacity was trapped in the area by a lack of exit pipeline capacity. Rockies to Henry Hub price differentials increased from US$0.16/MMBtu in January 2002 to $2.38 by October.

As Rockies prices drive prices in the Pacific Northwest and California (important markets for Canadian gas), this also affected Canadian gas export and domestic prices. Canadian gas prices are influenced by US prices, since Canadian buyers must offer prices which result in Canadian producer netbacks equal to those which can be gained from US sales.

In 2002, netbacks from US Midwest and Northeast sales were attractive, but netbacks from Pacific Northwest and California sales were not. This meant that domestic buyers only had to match the lower netbacks and this led to lower Canadian prices. Alberta to Henry Hub price differentials increased from CDN$0.24/GJ in February to $1.85 by August.

Exports in 2002

Physical export flows from Canada to the US were virtually unchanged in 2002 versus 2001, at 3,755 Bcf. Because Canadian imports of US gas increased by 45 Bcf, net Canada to US exports fell slightly, from 3,500 Bcf in 2001 to 3,483 Bcf in 2002.

Export revenues were down sharply because of lower average prices in 2002 vs 2001. Export revenues fell from CDN$22.8 billion to $16.2 billion.

Regionally, exports to the US West region fell, as exporters preferred to send gas to the Midwest or Northeast, where prices and netbacks were considerably higher.

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Short-term Outlook

There are 2 factors that promise to dominate natural gas prices over the short-term, e.g., through the end of the winter of 2003/2004. These factors are storage levels and the weather. Two other factors will be important – natural gas production growth and world crude oil prices.

Storage levels and the weather relate mainly to core markets – the residential and commercial sectors. Simplifying somewhat, the North American market today functions such that core market demand is satisfied first. Core markets cannot switch fuels and will buy gas at even high prices.

Any additional supply then goes to industrials and power generators – the non-core sector. If there is limited additional supply, prices rise to ration supply by encouraging non-core plant shutdowns or fuel switching away from gas. If gas supply is relatively abundant, prices fall to encourage non-core customers to return to gas.

Given low North American storage levels on April 1, 2003, 2,750 needed to be injected into storage to reach 3.5 Tcf by November 1, 2003. This was the reverse of the situation in 2002, when only 1,844 Bcf was required to be injected as of April 1, 2002.

Fortunately, injections into storage this summer have been at record levels. As of September 1st, industry is on track to reach 3.5 Tcf by November 1st, 2003.

As always, the type of winter that occurs in 2003/2004 could swing markets into lower or higher prices. Under all foreseeable gas supply scenarios for 2003/2004; if the winter is extremely colder than normal, gas prices will be high. Similarly, if the winter is very mild, gas prices will decline.

Though gas prices may be higher this winter, prices might have soared even more if not for the combination of mild summer weather and industrial cutbacks in recent months.

The remaining two important factors – gas production and oil prices – could swing markets if the storage and weather picture is not dominant, e.g. if storage and weather are normal.

Last year the lack of substantial gas production growth supported high gas prices in North America. If production growth exceeds core demand growth, prices will fall to encourage industrial and power generation load to return to gas. Alternately, if core demand growth exceeds production growth, storage will be drawn down, and prices will rise.

Late in 2002, high oil prices tended to preclude gas-to-oil fuel switching in the non-core sector, and supported high natural gas prices. Although the Iraq war has now ended, world crude oil prices remain in the US$30/Barrel range. If lower crude oil prices come about in 2003 and 2004, this could be a depressing factor for North American natural gas prices.

On balance, this coming winter natural gas prices are expected to be fairly moderate, with benchmark US prices expected to average US$4.30/MMBtu over the short-term.

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Outlook to 2015

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 consultants on retainer to the Department.

We use averages of the various organizations to derive what could be described as a "consensus" scenario. For example, we assume gas demand in 2015 will be equal to the average of selected demand forecasts for 2015.

US gas demand in 2015 is expected to reach 28 Tcf; Canadian demand 4 Tcf, for a North American total of 32 Tcf. This is an increase of 9.2 Tcf over 2002 demand. Industrial and electric power generation (by utilities and by non-utilities generating power) is expected to consume most of this increase.

This demand would be satisfied by: US gas production of 22.1 Tcf; Western Canadian production of 6.5 Tcf; Scotian gas of 0.7 Tcf; MacKenzie Delta gas of 0.6 Tcf and over 2 Tcf of LNG imports to the US.

Compared to our report last year, North American production forecasts have been revised downwards. In addition, compared to expectations last year (1.2 Tcf of LNG imports by 2010), LNG is now seen as a much more important component of future North American gas supply.

There are no Canadian imports of LNG or Newfoundland natural gas production included in the Canadian supply forecasts.

However, MacKenzie Delta gas is now included in the Canadian production forecasts. The average of 3 forecasts shows MacKenzie Delta production reaching 0.62 Tcf, or 1.6 Bcf/day by 2015.

Few forecasters have included Alaska gas in the US supply picture by 2015. However, forecasters are constantly re-evaluating this issue.

US nominal natural gas prices are expected to average about US$4.25/MMBtu in 2003, reaching the $4.60 range by 2015. Alberta nominal prices are expected to average CDN$5.50/GJ in 2003, with an average price of $5.00 over the forecast period. Price expectations have increased somewhat since last year's report.

Several relatively small expansions of Canadian export pipelines are now proposed, and are included in our outlook. We do not assume pipeline capacity in our forecast until it is well along in the regulatory process. However, the era of major export-oriented natural gas pipeline expansions, such as Alliance, appears to be over.

We recognize that additional pipeline capacity from Canada to the US, over and above the capacity assumed in our outlook, could be constructed in the 2003-2015 timeframe.

The "consensus" view shows net exports remaining relatively flat over the 2003-2015 time period, hovering between 3.22 Tcf and 3.47 Tcf per year. 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. This year, we can no longer use that methodology, as it is clear 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.

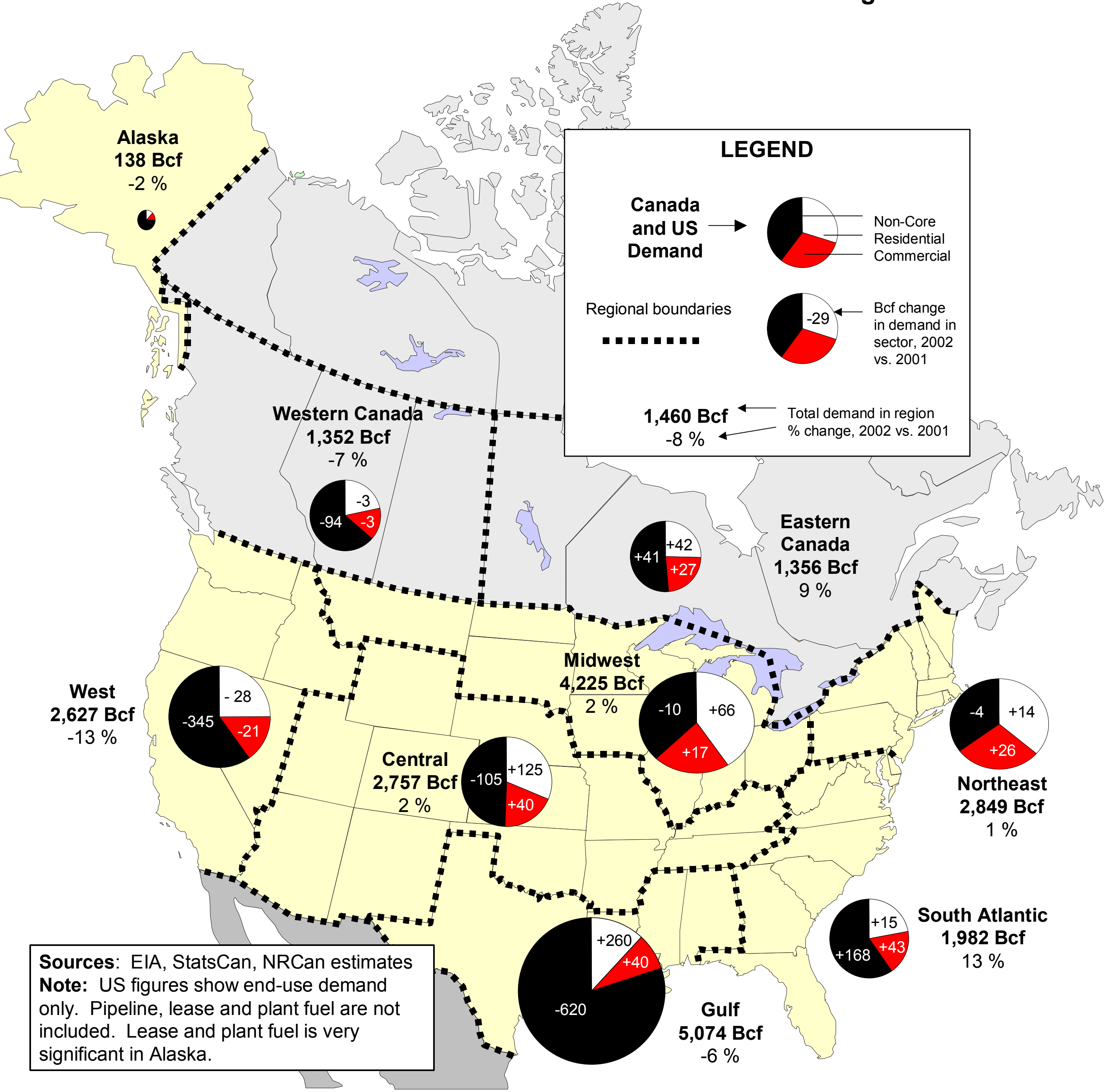
Given our assumptions about Canadian production and exports, and industry price forecasts, producer plant gate revenues from natural gas sales are expected to surpass peak 2001 levels over the outlook period. Revenues are expected to reach CDN $40.2 billion by 2015, almost doubling the $24 billion level of 2002.

Northern pipelines could significantly alter the Canadian natural gas supply, demand, and export scenarios.

Review of 2002

Natural Gas Demand

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



Sources: EIA, StatsCan, NRCan estimates
Note: US figures show end-use 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.

In 2002, the largest demand growth in North America occurred in the South Atlantic. There were significant decreases in demand in both the Canadian and American western regions.

Industrial demand was also generally down, most especially in the producing areas of the US Gulf and Western Canada, and in the US West consuming region.

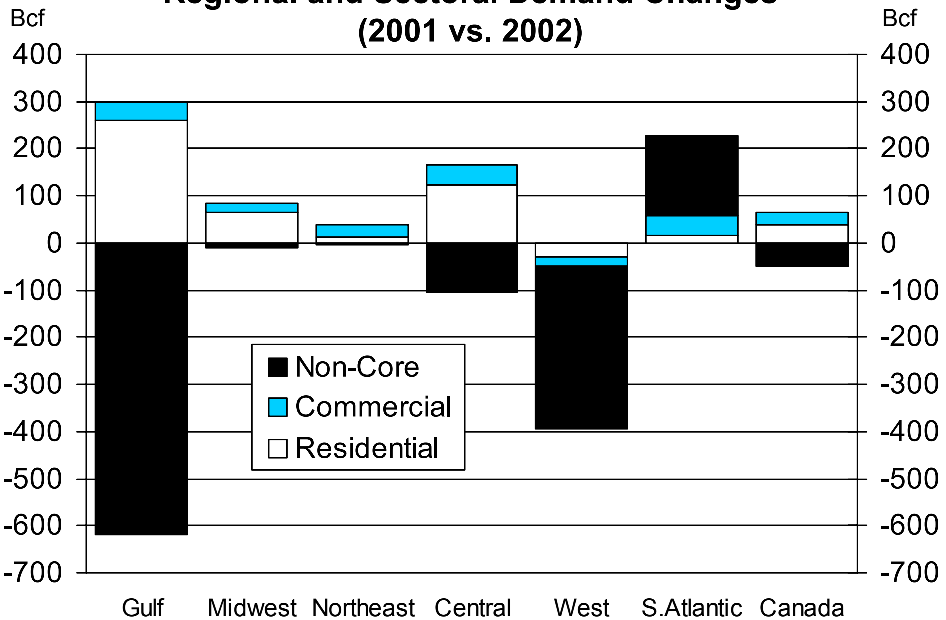
[1] Mexico is part of North America, but is generally excluded from this report.

Table 1
Demand For North American Natural Gas

	2002 (Bcf)	2001 (Bcf)	Change (Bcf)	Change (%)
US Residential	4,914	4,776	138	3%
US Commercial	3,113	3,038	75	2%
US Industrial	7,178	7,363	-185	-3%
US Electric Power	5,552	5,343	209	4%
US Other	1,696	1,727	-31	-2%
Total US Demand	**22,453**	**22,247**	**206**	**1%**
US LNG Exports	63	66	-3	-5%
US Exports to Mexico	263	140	123	88%
Total US Gas Disposition	**22,779**	**22,453**	**326**	**1%**
Canada Residential	617	578	39	7%
Canada Commercial	468	443	25	6%
Canada Industrial	931	897	34	4%
Canada Electric Power	297	301	-3	-1%
Canada Other	394	478	-83	-17%
Total Canadian Demand	**2,708**	**2,697**	**12**	**0%**
TOTAL N.A. DEMAND	**25,161**	**24,944**	**218**	**1%**
TOTAL N.A. DISPOSITION	**25,487**	**25,150**	**338**	**1%**

Sources: EIA May 2003 Natural Gas Monthly, StatsCan, NRCan estimates.

Figure 1
Regional and Sectoral Demand Changes (2001 vs. 2002)



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

Total North American gas demand was up 1% in 2002. US demand increased 1%, due to weather effects on core (residential and commercial) markets. US non-core demand was unchanged.

Canadian demand was slightly up in 2002, driven by small increases in the core and industrial sectors.

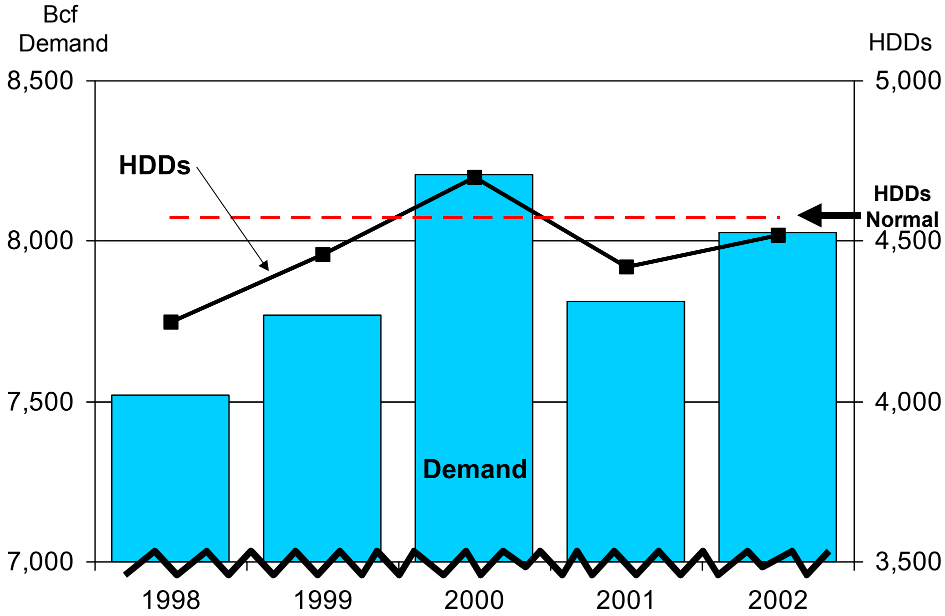
Note that in its April 2003 Natural Gas Monthly, the EIA radically changed the definitions of the industrial and power generation demand sectors. Further detail on US non-core demand is provided later in this section.

North American natural gas consumption overall was up 1% in 2002. However, there were important changes in certain sectors and regions. Non-core demand fell in every region except the South Atlantic, where demand was up in all sectors.

The Gulf of Mexico has the greatest gas demand of all North American regions, but saw huge declines in non-core demand over 2002. The West also experienced large declines in non-core demand. Canadian non-core demand also dropped in 2002, with a 50 Bcf loss of gas demanded.

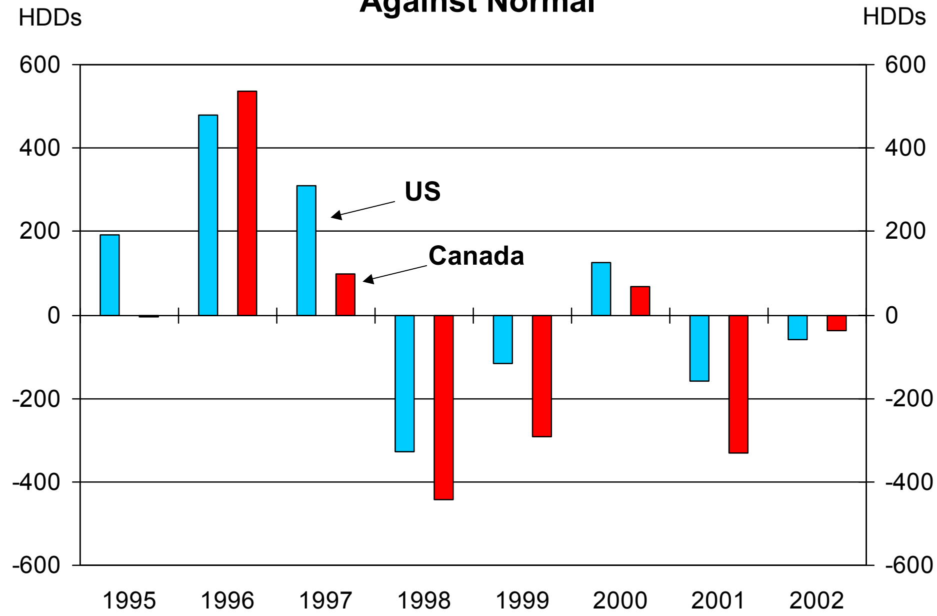
This decline in non-core demand was largely driven by declining industrial demand, which has fallen due to high gas prices.

Figure 2
US Heating Degree Days & Core Demand



Sources: EIA Natural Gas Monthly (May 2003), NOAA

Figure 3
North American Heating Degree Days Against Normal



Sources: NOAA, StatsCan

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.

This year, heating degree days and core demand were once again closely correlated as demand rose 3% and heating degree days rose 2% when compared to 2001.

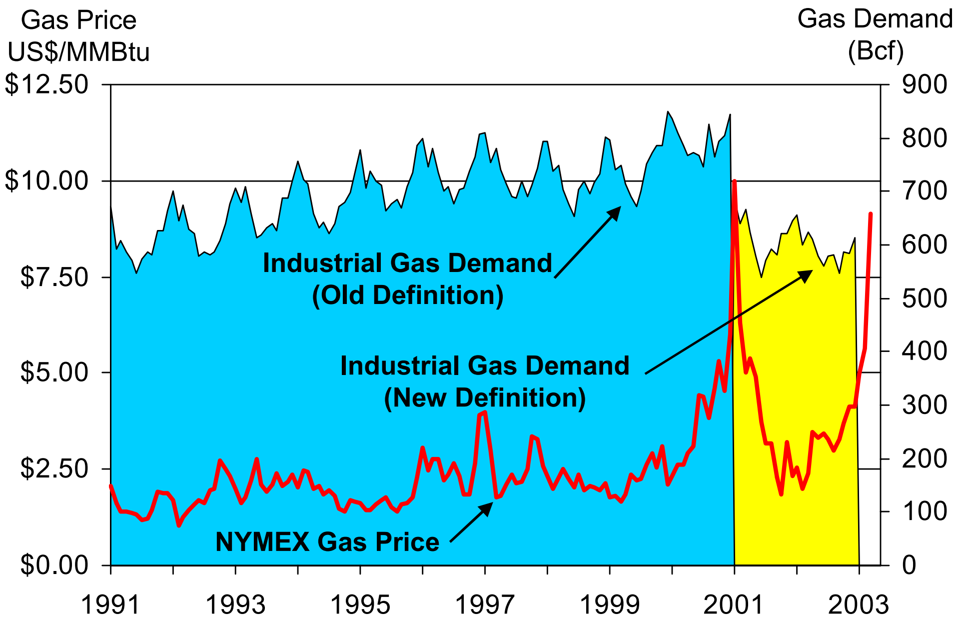
2002 saw 182 fewer heating degree days than the recent high experienced in 2000.

The climates of the United States and Canada are very similar. Due to this, both countries tend to have similar temperatures in relation to the normal. This was the case in 2002.

In 2002, the US had 58 fewer heating degree days than normal. This continues a recent trend of temperatures being close to normal. This is also the second straight year where there were fewer heating degree days than normal in the US.

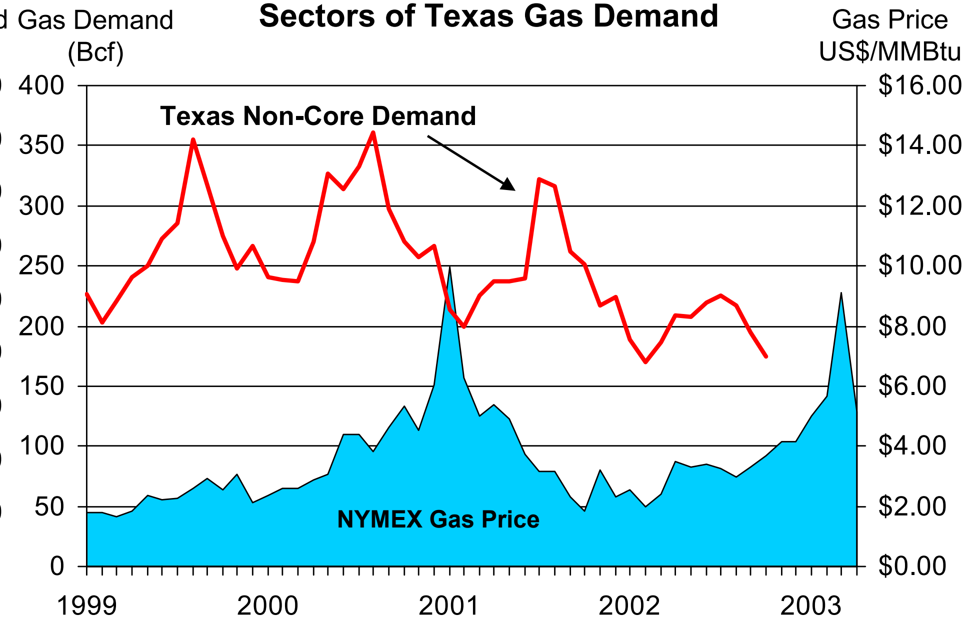
The picture in Canada was very similar. We also had less heating degree days, finishing with 38 fewer heating degree days than normal in 2002 and continued a recent trend of warmer temperatures.

Figure 4
Gas Prices vs. US Industrial Gas Demand



Sources: EIA Natural Gas Monthly (May 2003), GLJ, Friedenberg. **Note:** In April 2003, the EIA revised its industrial demand definitions, retroactive to January 2001.

Figure 5
Demand Destruction in the Non-Core Sectors of Texas Gas Demand



Sources: EIA, GLJ, Friedenberg

The EIA has radically changed its industrial gas demand definition and statistics. The graph above shows the EIA's former industrial demand numbers as well as their new numbers. By any measure, US industrial demand is declining in response to high gas prices. Within the Industrial sector (new definition), gas demand fell 3% from 2001. This is in addition to a 10% fall in 2000.

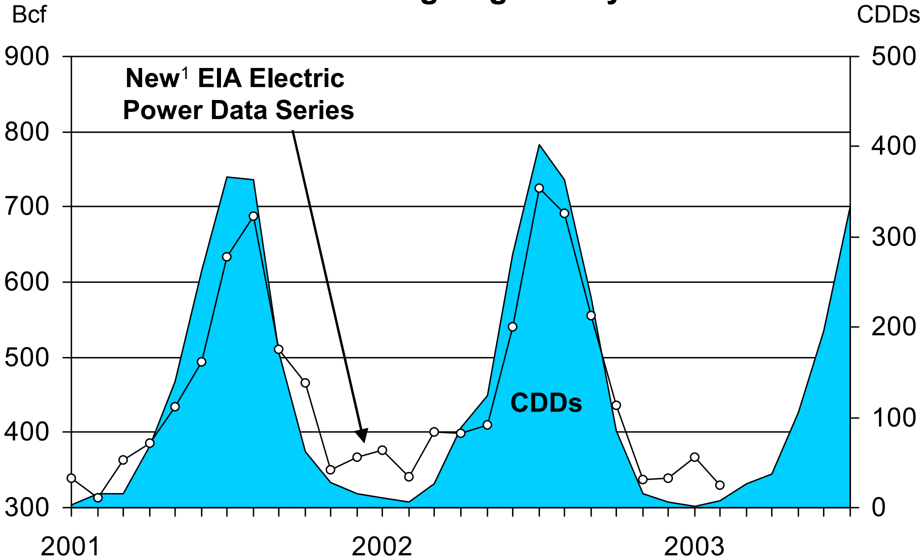
Industrial gas users are closing facilities in North America and moving to areas of the world where gas prices are lower. Demand in industrial plants using gas for heat and power generation (cogeneration) has not fallen off as dramatically.

The above figure analyses Texan non-core (Industrial and Power Generation) gas markets. In Texas this past year, high natural gas prices have resulted in industrial and electric generation restructuring. By mid-2000 demand in these sectors began to fall as prices rose. Continuing high prices in these highly price-sensitive sectors has resulted in demand destruction.

Texas non-core demand did not return to previous levels even when price pressures temporarily eased in late 2001 and early 2002.

Figure 6

US Power Generation Gas Demand & Cooling Degree Days



Sources: EIA (NGM, EPM), NOAA. **Notes:** [1] From May 2003 NGM.

Table 2

US Electric Industry Generation (Thousand MwHrs)

Industry	Year				% Change
	1999	2000	2001	2002	from 2001
Coal	1,881,087	1,996,265	1,903,955	1,926,442	1%
Oil	118,061	111,221	124,880	89,857	-28%
Natural Gas	556,396	601,038	639,129	685,839	7%
Other Gas[1]	14,126	13,955	9,040	12,118	34%
Nuclear	728,254	753,893	768,825	780,064	1%
Hydro	313,439	270,034	208,137	254,873	22%
Renewables	79,423	80,906	77,983	83,810	7%
Other	4,024	4,794	4,690	5,553	18%
Total	**3,694,810**	**3,832,106**	**3,736,639**	**3,838,556**	**3%**

Source: EIA Electric Power Monthly - Table 1.1 **Notes:** [1]Other gas includes blast furnace gas, propane, and other manufactured waste gases derived from fossil fuels.

As with Industrial demand, the EIA has radically revised its electric power sector definition and statistics. This graph shows the new EIA total power demand series.

The EIA's new data series includes gas used in industrial power plants which identify themselves as producing mainly power, rather than heat. This series is driven by cooling degree days, which increase with hotter weather.

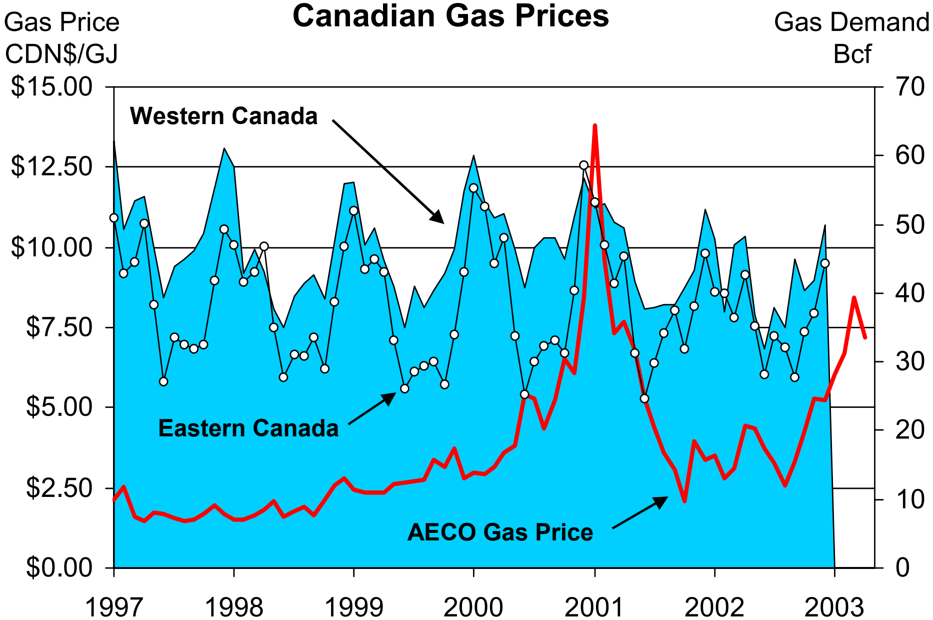
Cooling degree days were up 9% from 2001. As is expected with an increase in cooling degree days, the EIA's new electric power series also grew, showing a 4% increase from last year.

In the US, total electrical generation from all sources rose 3% in 2002. Electricity generated from natural gas exceeded this industrial average by posting a 7% gain.

Oil use for power generation fell by 28% in 2002, largely due to high world crude oil prices, especially in the latter half of 2002.

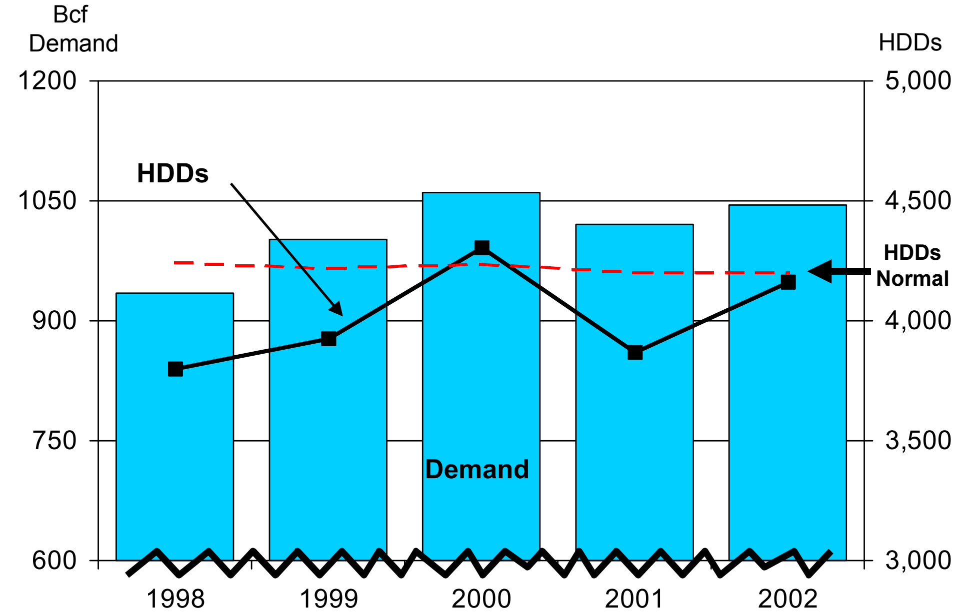
Power generation from natural gas increased 7% despite only seeing a 4% increase in gas demanded. This is because of increased efficiencies realized by power plant improvements.

Figure 7
Canadian Industrial Gas Demand vs. Canadian Gas Prices



Sources: StatsCan, NRCan estimates, GLJ, Friedenberg

Figure 8
Canadian Heating Degree Days & Core Demand



Source: StatsCan, NRCan estimates

In Canada, Eastern and Western industrial demand generally move together. Unlike the US, Canadian industrial gas demand has not traditionally been very price sensitive. However, that seems to have changed since the high prices of early 2001 caused demand to decline.

Annual Canadian industrial demand has fallen by 152 Bcf since 2000, a decline of 14%.

The sustained higher prices that we are currently experiencing will likely exert a strong downward pressure on industrial demand in the future.

The correlation between core demand and heating degree days, as in the US, is strong in Canada.

Heating degree days increased 5% and core demand increased 2%. This result is consistent with historical patterns and reinforces the link between weather patterns and core demand.

There were 38 fewer HDDs in Canada than normal in 2002. This makes 2002 a mild year for Canada and likely resulted in decreased domestic natural gas demand.

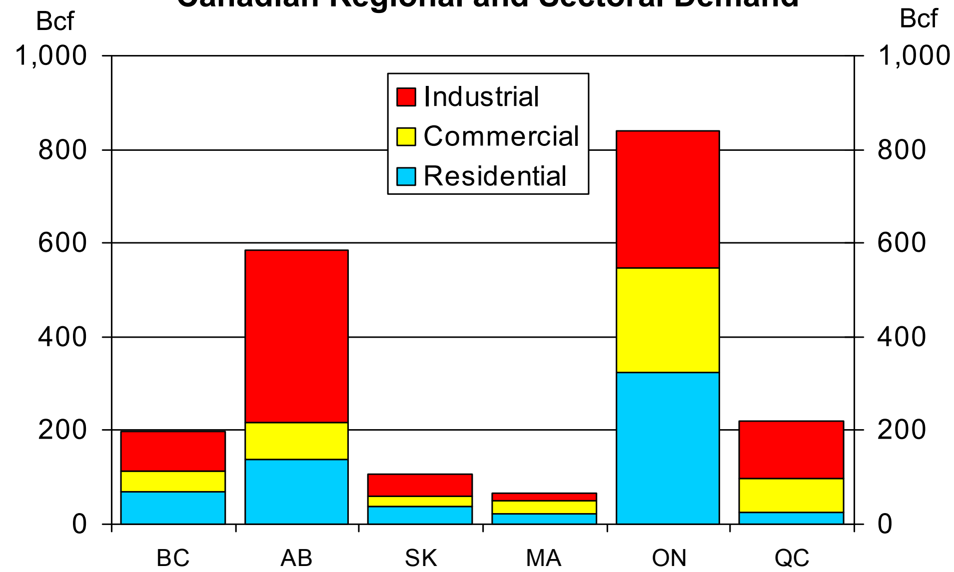
Table 3
Canadian Natural Gas Demand

Sector	2002	2001	2000	1999	1998
Bcf:					
Residential	617	578	621	590	552
Commercial	468	443	438	412	382
Industrial	931	897	1,083	971	981
Electric	297	301	268	198	214
Other	394	478	462	530	470
Total	2,708	2,697	2,872	2,700	2,598
Percentage:					
Residential	23%	22%	22%	22%	21%
Commercial	17%	16%	15%	15%	15%
Industrial	34%	33%	38%	36%	38%
Electric	11%	11%	9%	7%	8%
Other	15%	18%	16%	20%	18%

Sources: StatsCan, NRCan estimates

Figure 9

Canadian Regional and Sectoral Demand



Source: StatsCan, NRCan estimates

In 2002, total Canadian gas demand remained virtually flat when compared to 2001.

Industrial gas sales accounted for the largest portion of natural gas sold in Canada in 2002, with 34% of the market. This is a decline in the sector's former take of domestic natural gas demand of around 38%.

Residential gas demand slightly increased its share of overall demand with 23% of all domestic use.

The figure above illustrates Canadian demand for natural gas in 2002 by region and sector.

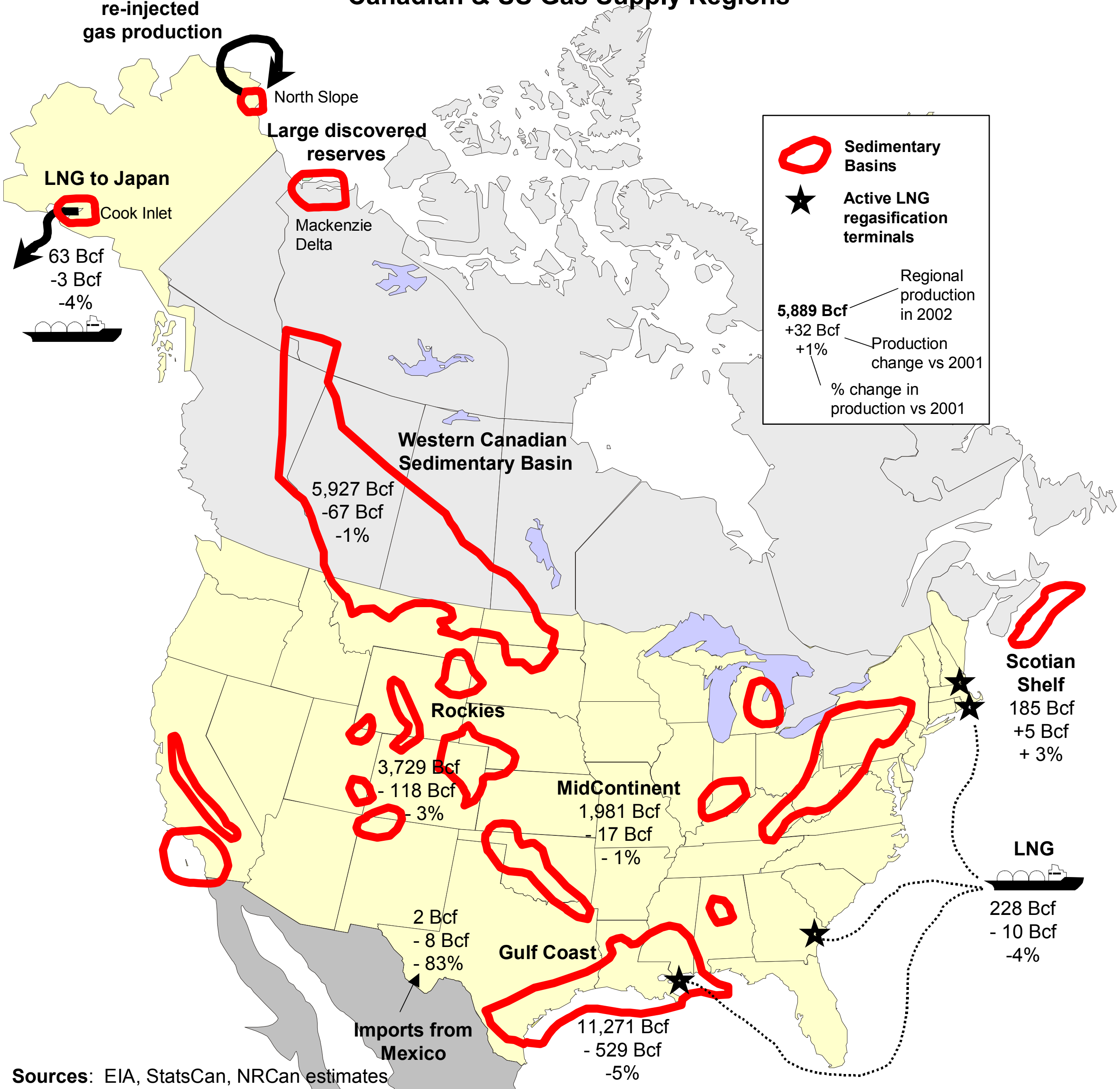
Total domestic demand in 2002 stayed at about the same level as last year. Canadian natural gas use was divided almost exactly in half between Eastern and Western Canada. Ontario, the most populous province, accounted for the most gas used by any single province while Alberta, the fourth largest province by population, accounted for the second most natural gas used, mainly the result of its industrial gas requirements.

Ontario has a very limited provincial natural gas supply and relies extensively on pipelines to deliver the gas it uses.

Review of 2002

Natural Gas Supply

Map 2
Canadian & US Gas Supply Regions



Sources: EIA, StatsCan, NRCan estimates

This map shows the major natural gas producing basins of Canada and the US. In 2002, supply was lower in all major regions across Canada and the US. The largest supply reduction occurred on the US Gulf Coast, which incurred a loss of 525 Bcf, or 5% compared to 2001. Production from other US regions was fairly static in 2002.

Western Canadian production fell by 67 Bcf or 1.1% in 2002. During the past three years, Western Canadian production has remained fairly flat despite 29,188 wells being drilled over that same period, with record drilling in 2001.

Net LNG imports to the US were down 4.1% in 2002. Total LNG volumes remain minor, however LNG continues to be an important source of incremental supply to North America.

Table 4
North American Gas Supply

	2002 (Bcf)	2001 (Bcf)	Change (Bcf)	Change (%)
Gulf Onshore[1]	6,935	6,988	-53	-0.8%
Gulf Offshore[2]	4,336	4,812	-476	-9.9%
Total Gulf	11,271	11,800	-529	-4.5%
US Midcontinent[3]	1,981	1,998	-17	-0.9%
US Rockies[4]	3,729	3,847	-118	-3.1%
Other US	2,066	2,031	35	1.7%
Total US Production	**19,047**	**19,676**	**-629**	**-3.2%**
Western Canada[5]	5,927	5,994	-67	-1.1%
Scotian Shelf	185	180	5	2.8%
Total Canada Production	**6,112**	**6,174**	**-62**	**-1.0%**
Total N.A. Production	**25,159**	**25,850**	**-691**	**-2.7%**
US Net LNG Imports	165	172	-7	-4.1%
US Net Mexican Imports	-261	-130	-131	-100.8%
US Supplementals	80	86	-6	-7.0%
TOTAL N.A. SUPPLY	**25,143**	**25,978**	**-835**	**-3.2%**

Sources: EIA May 2003 NGM, StatsCan, NRCan estimates. **Note:** Canadian production is marketable gas plus reprocessing shrinkage. 1. = AL, LA, MS, TX (Gulf onshore + State offshore). 2. = AL, LA, TX (Federal Gulf of Mexico). 3. = KS, OK. 4. = CO, NM, UT, WY. 5. Includes minor Ontario production.

The table above shows our estimate of North American natural gas production for 2002. Total North American production decreased 2.7% in 2002. US production decreased 629 Bcf, or 3.2%, while Canadian production decreased by 62 Bcf, or 1%. The largest production declines occurred in the Gulf offshore region. Gulf offshore declines were responsible for more than 75% of the drop in in North American production in 2002.

Table 5
North American Gas Drilling Indicators

	2002	2001	2000	% Change 02 vs 01	% Change 01 vs 00
Gulf Onshore[1]	5,439	5,787	4,580	-6%	26%
Gulf Offshore[2]	95	118	117	-19%	1%
Total Gulf[3]	511	696	553	-27%	26%
US Midcontinent[3]	99	154	125	-36%	23%
US Rockies[3]	123	176	143	-30%	23%
Other US[3]	98	130	97	-25%	34%
Total US[2]	**691**	**939**	**720**	**-26%**	**30%**
Canada Shallow[4]	6,804	8,225	6,855	-17%	20%
Canada Deep[5]	2,266	2,946	2,092	-23%	41%
Total Canada[6]	**9,070**	**11,171**	**8,947**	**-19%**	**25%**

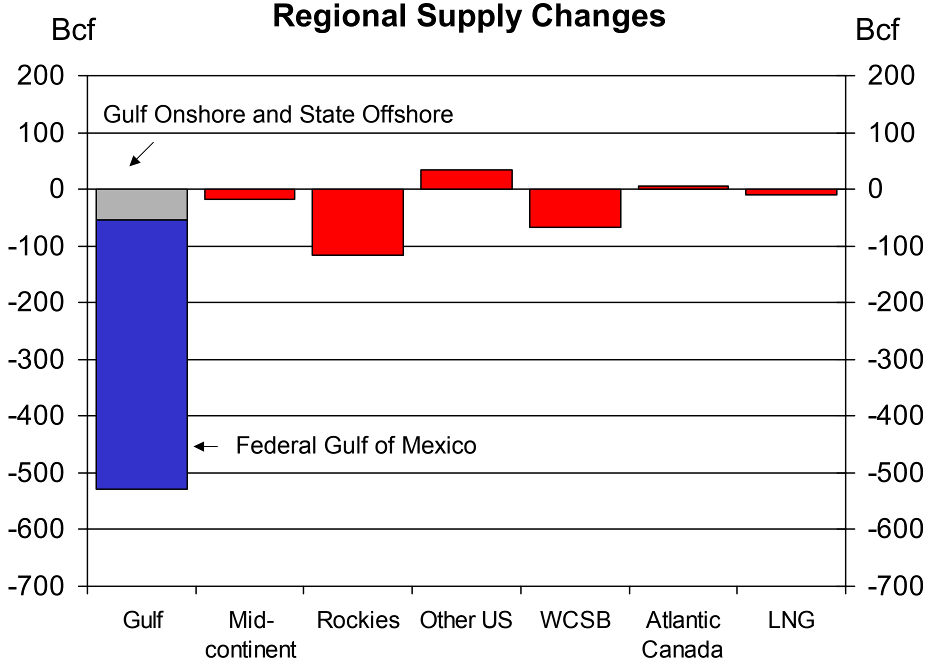
Sources: Texas RRC, Baker Hughes, Daily Oil Bulletin. **Notes:** (1) Texas onshore gas completions only. This is the major portion of Gulf onshore drilling. (2) Average weekly gas-directed rig count (Baker Hughes). Number of wells not available. (3) Average total weekly rig count including oil-directed and gas-directed rigs. (4) Alberta West of 4th meridian gas wells, plus Saskatchewan gas wells. (5) Alberta W5 and W6 meridian gas wells, plus all British Columbia gas wells. (6) Total number of Western Canadian gas wells.

The table at left also shows that net LNG imports declined slightly, while US gas exports to Mexico increased significantly, in part to fuel new gas-fired generating units.

The table above shows an overview of North American drilling statistics. In regions where gas well numbers are not available, rig counts have been provided as an alternative.

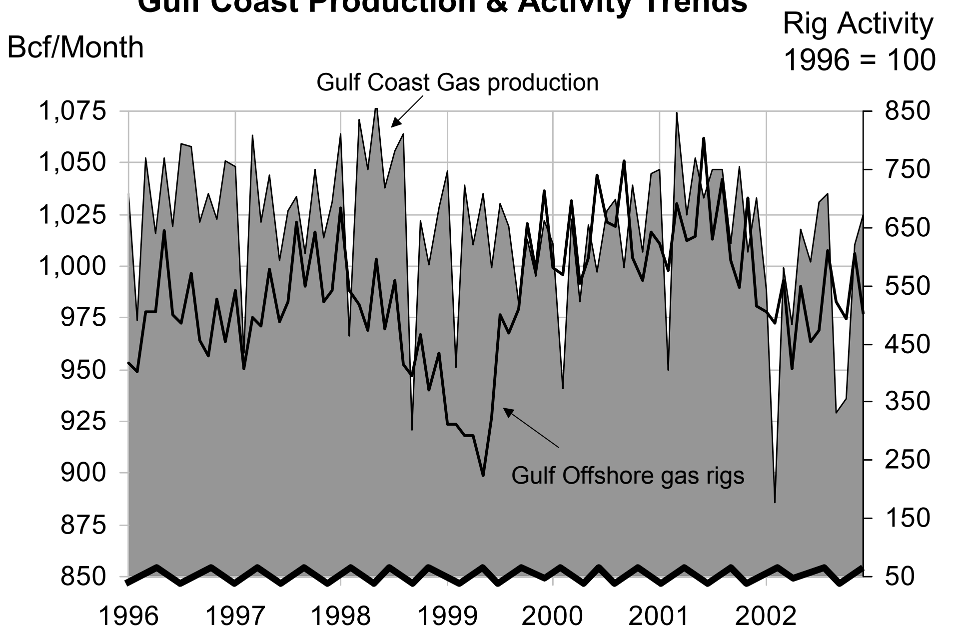
Generally, drilling fell across North America in 2002 compared to 2001, in response to lower gas prices. In Canada, gas well completions were down about 19%; in the US, the average weekly gas-directed rig count declined by 26%.

Figure 10
Regional Supply Changes



Sources: EIA, StatsCan, CNSOPB, NRCan estimates

Figure 11
Gulf Coast Production & Activity Trends



Sources: EIA, Texas RRC, Baker Hughes

In 2002, North American gas production fell 2.7% (a decline of 3.2% in the US and 1% in Canada).

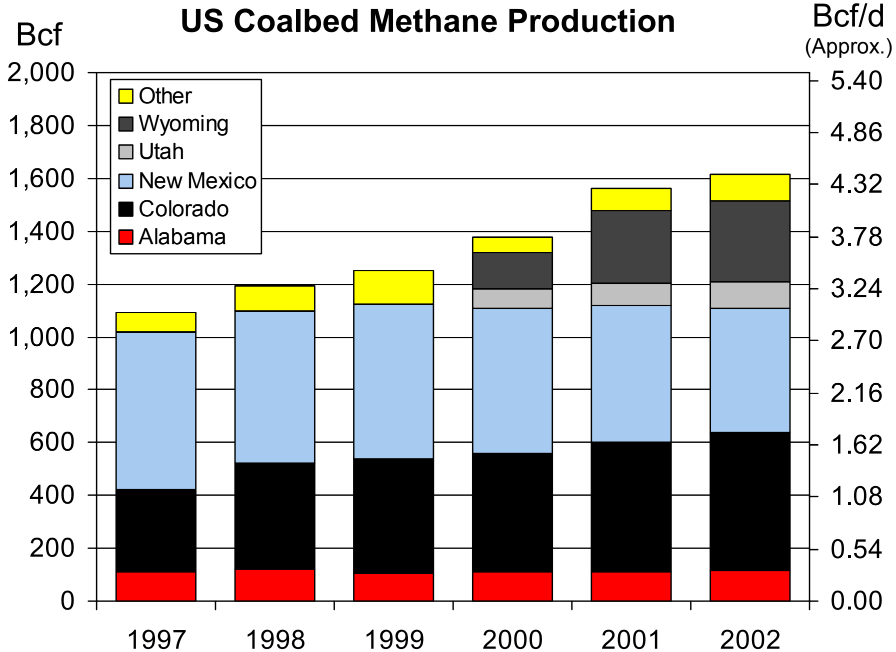
The problem area for gas supply in 2002 was the Gulf Coast offshore, which accounted for the bulk of the decline in North American gas production. The Gulf of Mexico saw a decline of 476 Bcf (4.5%) over 2001 levels.

Western Canadian production declined by 1% in 2002. Scotian production increased slightly by 5 Bcf (2.8%) in 2002.

Lower gas prices in the second half of 2001, resulted in less drilling activity in the Gulf offshore in 2002. Some rigs were also inactive during the latter half of 2002 as a result of two storms in the Gulf of Mexico: Tropical Storm Isadore and Hurricane Lili., which in turn impacted Gulf Coast production. The two storms accounted for a loss of about 50 Bcf or 10% of production losses offshore the Gulf of Mexico.

However, the major reason for a decline in gas production in the Gulf coast in 2002 came as a result of the rapid initial decline rates of many wells that were completed in 2001. Many of these wells were step-out wells and re-completions with steep initial decline rates and small reserves.

Figure 12
US Coalbed Methane Production



Source: EIA **Notes:** (1) Other includes Oklahoma, Pennsylvania, Utah, Virginia, West Virginia, and Wyoming. (2) Beginning in 2000, other excludes Utah and Wyoming.

US coalbed methane (CBM) production accounts for about 8% of total US natural gas production and more than 35% of Rockies (Wyoming, Utah, Colorado and New Mexico) gas production.

Since 1997, US CBM production has grown at an average annual rate of 8%. US CBM production grew by 3% in 2002 to 1,614 Bcf. Increased CBM production can largely be attributed to increased production in Wyoming and Utah.

Canadian CBM is slowly moving from an exploration phase into development mode. A recent estimate shows Canadian CBM gas production averaging between 15 and 25 Million cubic feet (MMcf) per day.

Table 6
Rockies Pipeline Expansion Projects

Company	Receipt Point	Delivery Point	Expansion Capacity (MMcf/d)	In-service Date	Status
(1) Kern River 2003	WY	CA	900	May 2003	In-service
(2) El Paso Cheyenne Plains Gas Pipeline	WY	KS	560	Aug 2005	Applied to FERC
(3) Williston Basin Grasslands	WY, MT	WY, MT, ND	80	Nov 2003	Approved by FERC
(4) Northwestern Pipeline Expansion	WY	OR	175	Nov 2003	Approved by FERC
(5) Questar Southern Trails (West Zone)	UT	CA	120	NA	18 Month Extension
(6) Kinder Morgan's Silver Canyon Express	CO	AZ	750	July 2006	Open Season
(7) Kern River 2006 Expansion	WY	CA	500	Late 2005-Early 2006	Plan to File
(8) Southern Star's Western Frontier	WY	OK	540	Late 2006-Early 2007	Open Season
(9) Northwest Pipeline Rockies Expansion	WY	ID	365	Oct 2003	Construction Phase
(10) Northern Border Bison Pipeline	WY	MO	240	Nov 2005	Plan to File
TOTAL			**4,512**		

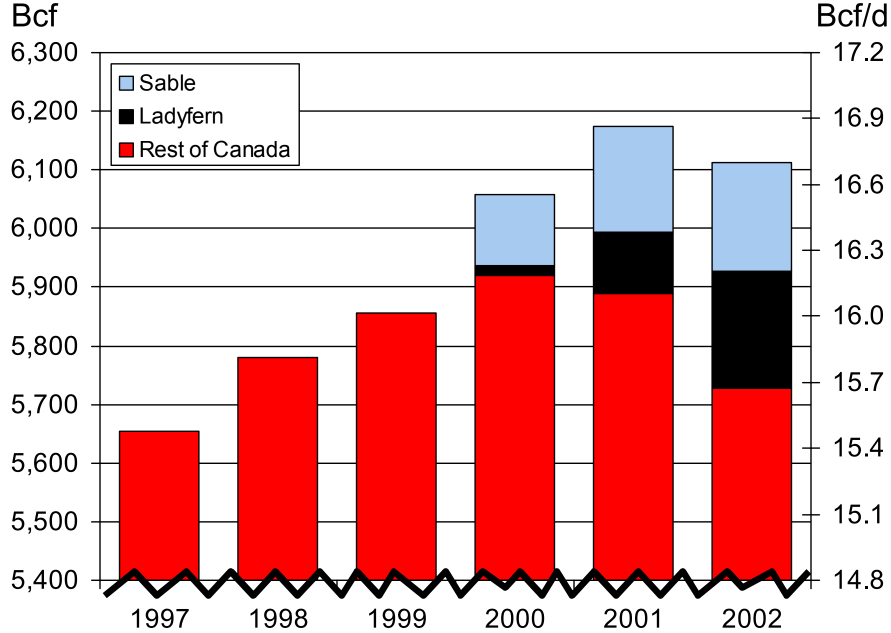
Sources: EIA, Company Websites and FERC filings. **Note:** Other projects are also being considered.

In recent years, rapid production growth, limited local demand growth and a limited increase in export pipeline capacity, had resulted in a surplus of gas supplies, which had depressed prices in the Rockies region well below those of NYMEX.

Increased production can be attributed to the coalbed methane (CBM) boom, particularly in the Power River Basin. CBM now accounts for more than 35% of Rockies gas production.

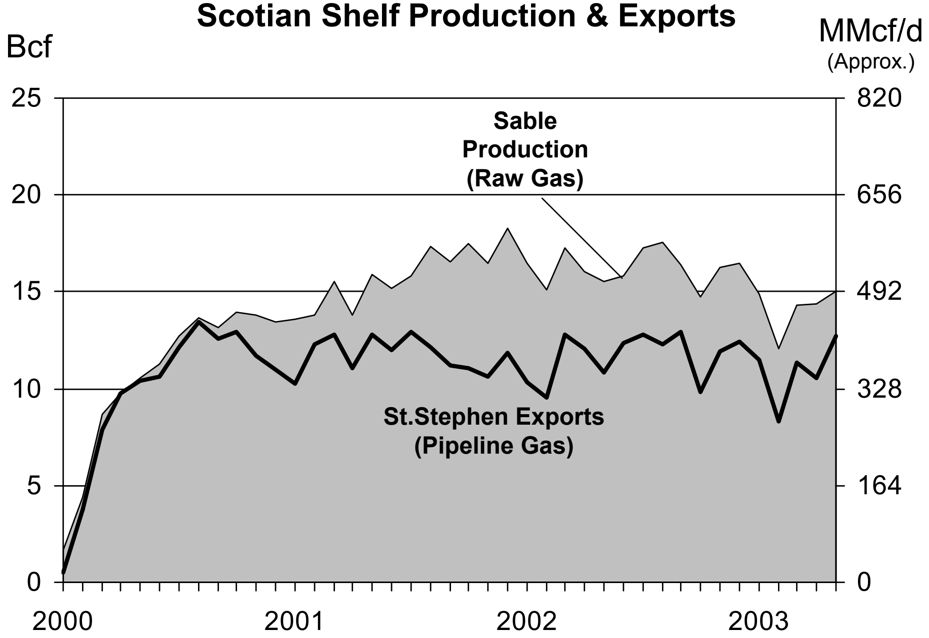
Four projects, including Kern River 2003, Cheyenne Plains, Northwestern and Grasslands are expected to increase pipeline capacity out of Wyoming, providing near-term basis relief.

Figure 13
Canadian Natural Gas Production



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

Figure 14
Scotian Shelf Production & Exports



Sources: CNSOPB, NEB

Canadian production was down by 1% in 2002—a 1.1% decline in Western Canada and a 2.8% increase at Sable, offshore Nova Scotia.

Production from the Ladyfern gas field in northeastern BC nearly doubled in 2002, accounting for 3.4% of Western Canadian production. However, Ladyfern production is believed to have peaked in mid-2002, meaning that production should fall significantly in 2003.

Excluding production from Ladyfern, Western Canadian production was down nearly 3%. Thus, if it were not for Ladyfern, Canada's gas production could have been much lower in 2002.

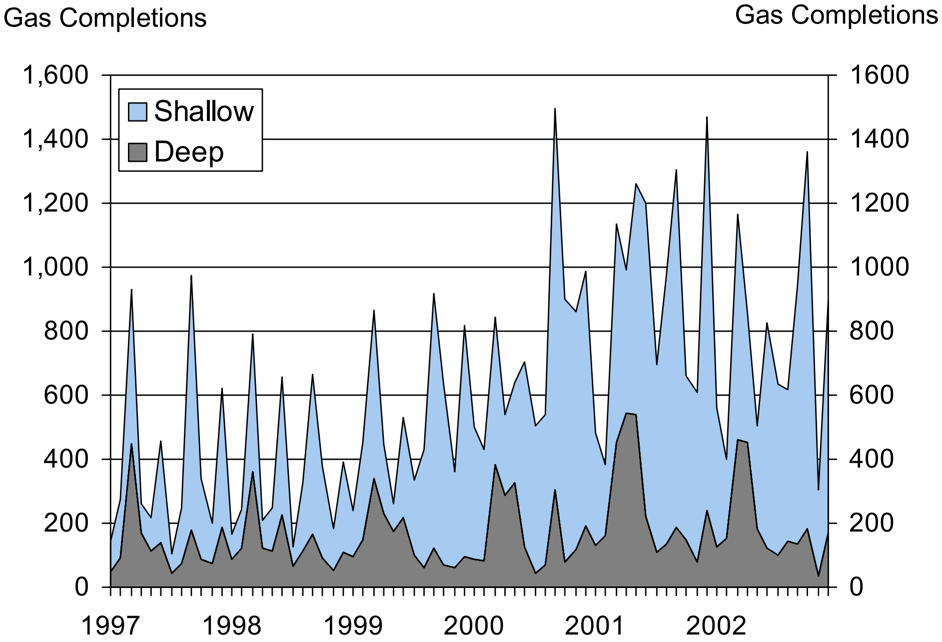
The Sable Offshore Energy Project (SOEP), offshore Nova Scotia, has accounted for a large amount of growth in Canadian natural gas supply. In 2002, Sable production averaged 534 MMcf/d, an increase of nearly 3% over the previous year, and an increase of 54% over 2000, Sable's first year of production.

However, Sable production now appears to be declining. Over the first seven months of 2003, Sable production has averaged 454 MMcf/d, 15% less than the first seven months of 2002.

As shown in the figure, most of the gas is exported to the US via St.Stephen, New Brunswick. Approximately 75% of Sable gas is exported to the US northeast, while the remaining 25% is consumed locally in Atlantic Canadian markets.

Figure 15

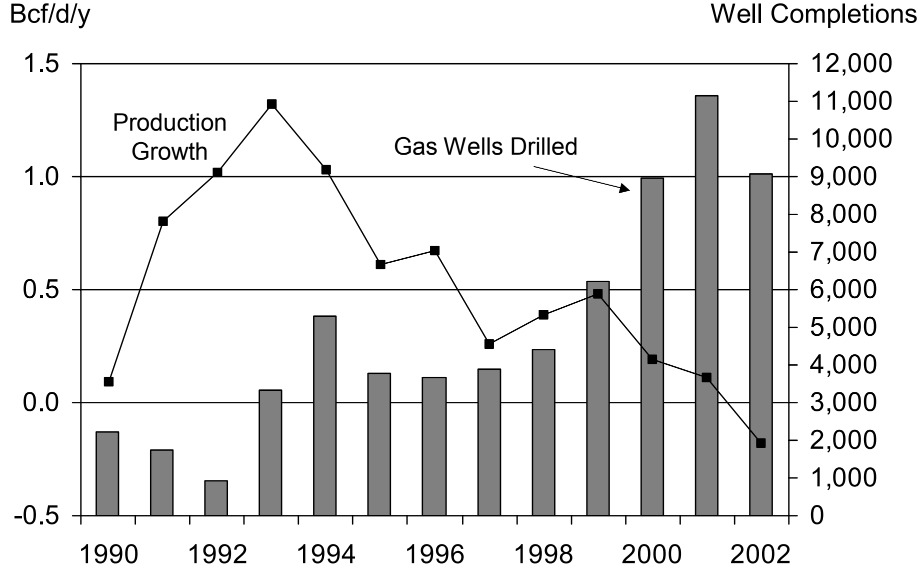
WCSB Gas Completions



Source: Daily Oil Bulletin

Figure 16

WCSB Production Growth and Gas Wells Drilled



Sources: StatsCan, CAPP, Daily Oil Bulletin

Total available rigs in the WCSB has increased by 240, or 37% in the past ten years. Nonetheless, in 2002, the average number of active rigs was the third lowest in the past decade, coupled with the lowest rig utilization (47%) over that time.

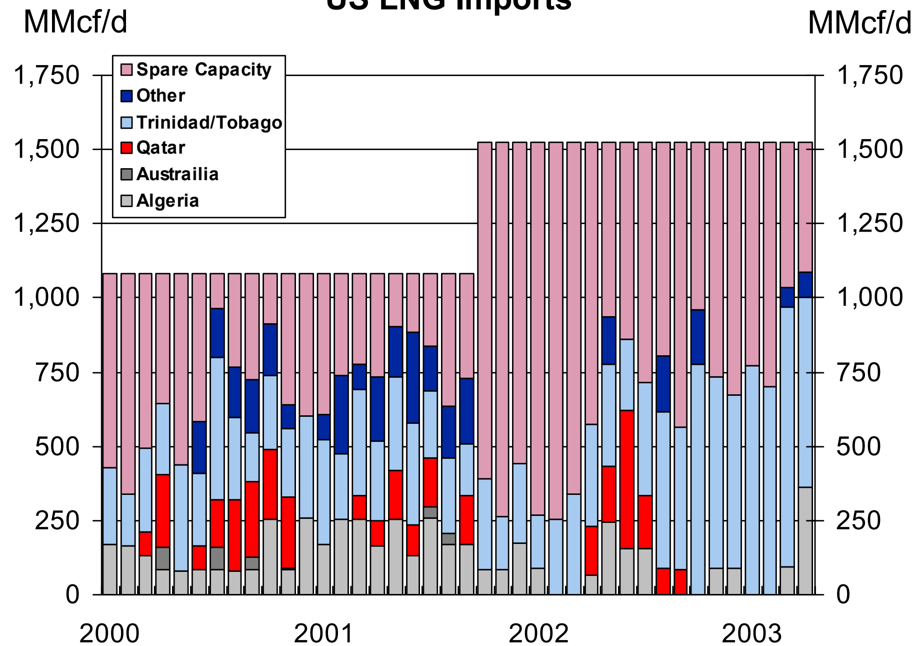
While gas well drilling was averaging around 300 wells per month in 1997, by 2001, this had grown to nearly 1,000 wells per month. Although western Canadian drilling was down 19% in 2002, averaging 755 wells per month, it was still the second largest number of gas wells ever drilled in a calendar year.

Most of the increase in drilling over the past 5 years has been in the shallow parts of the WCSB.

The above graph 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. Between 1990-1993, 8200 wells were drilled with total supply growth of about 3.2 Bcf/d.

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 production growth has been declining consistently since 1999. Despite the fact that more than 35,400 wells were drilled between 1999 and 2002, basin supply only increased by 0.8 Bcf/d. This situation implies that higher levels of drilling are necessary, simply to maintain production at current levels.

Figure 17
US LNG Imports



Source: EIA

In 2002, LNG imports averaged 625 MMcf/d, representing less than 1% of total gas used in the US. LNG imports totaled 228 Bcf in 2002, 4% lower than the previous year.

Imports from Trinidad and Tobago represented about 65% of total US LNG imports in 2002. Algeria, once the sole supplier of LNG to the US, provided 27 Bcf, or 12% of all LNG supplies.

LNG import capacity utilization amounted to about 55% in 2001 and 40% in 2002. Decreased utilization in 2002, came as a result of both, less imports and increased capacity.

LNG imports have increased significantly in 2003 – 108 Bcf (Jan-Apr), 150% more than the first four months of 2002.

Table 7
US LNG Import Terminals

LNG Receiving Terminal	Firm Sendout Capacity (MMcf/d)	Possible Expansion Capacity: Sendout (MMcf/d)	Total Sendout Capacity (MMcf/d)	2002 Average Sendout (MMcf/d)
1. Everett, MA (Owner: Tractabel)	450	480	930	301
2. Lake Charles, LA (Owner: CMS)	630	570	1200	277
3. Cove Point, MD (Owner: Dominion)	750	250	1000	**
4. Elba Island, GA (Owner: El Paso)	445	360	805	47
TOTALS	**2,375**	**1,660**	**3,935**	**625**

Sources: EIA, Office of Oil and Gas, January 2003 and Company websites **Cove Point LNG import terminal was re-activated in July 2003. Since 1995, Cove Point had been providing storage services to LDC's.

A very small quantity of natural gas is imported to the US in the form of liquefied natural gas (LNG). Currently, there are four US LNG importation terminals located at Lake Charles, LA., Everett, Mass., Cove Point, Md. and Elba Island, GA. The combined send out capacity from these four facilities, prior to any expansion, was approximately 2.38 Bcf/d.

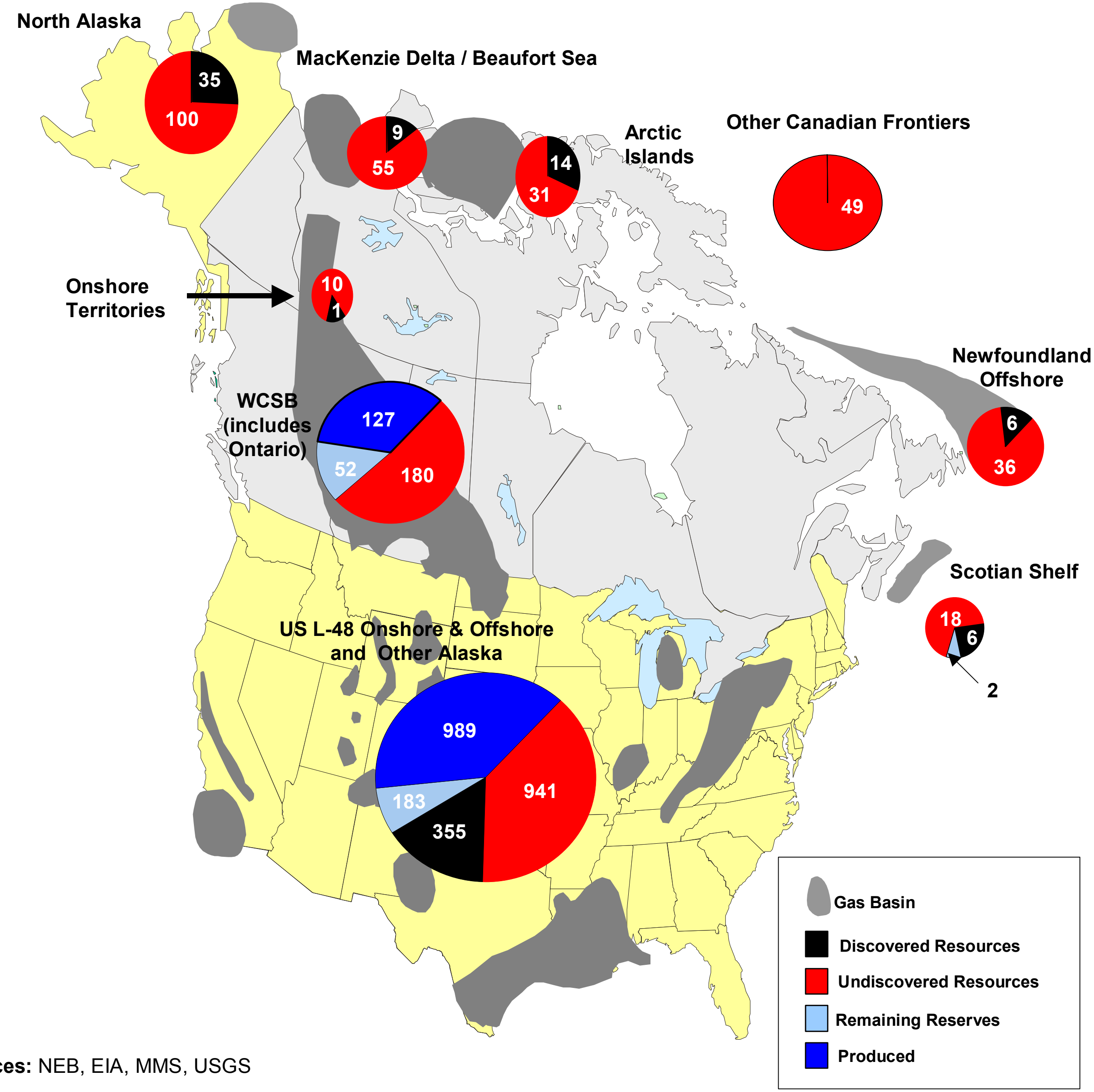
The Everett and Lake Charles facilities have been operating for some time; the other two were mothballed. However, Elba Island and Cove Point were re-activated in late 2001 and July 2003, respectively.

Upon reactivation, Cove Point became the largest US LNG import facility, with 1 Bcf/d of send-out capacity. The proposed expansion plans of the remaining three facilities is expected to add another 1,410 MMcf/d of capacity by 2005/2006.

Review of 2002

Natural Gas Resources and Reserves

Map 3
Canadian & US Natural Gas Resources and Reserves
(Tcf)



Sources: NEB, EIA, MMS, USGS

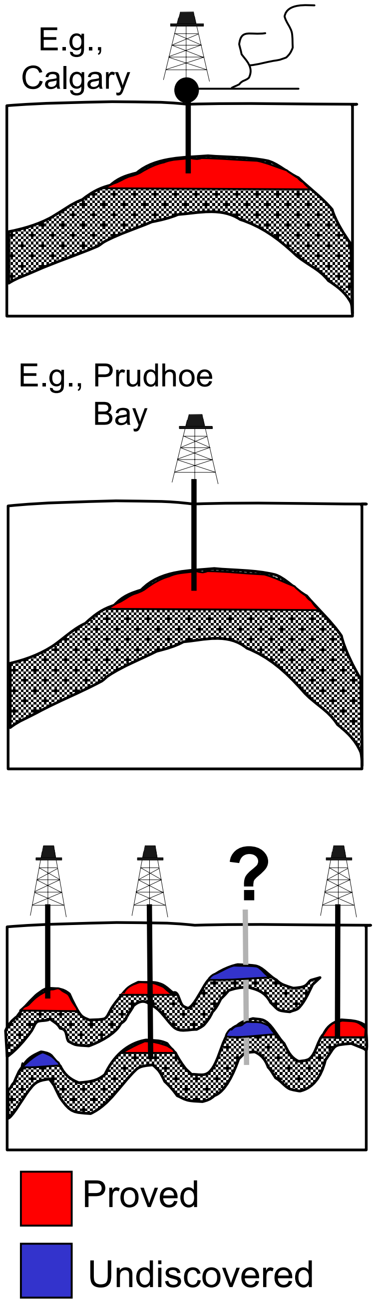
The locations and scale of cumulative natural gas production, reserves, discovered resources and undiscovered resources in North America are shown on the map.

Based on estimates from the NEB (i.e. Techno-Vert), Canada's total natural gas resource base, including cumulative production and undiscovered resources is 596 Tcf.

The NEB estimates that there exists 80 Tcf of undiscovered CBM resources in the WCSB, accounting for more than 20% of the NEB's total undiscovered resource estimate.

Based on estimates from MMS and USGS, the US's total natural gas resource base, including cumulative production and undiscovered resources is 2,603 Tcf.

Figure 18



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.1/02)	Discovered Resources	Undiscov-ered Resources	Total Remaining Resources
Alberta	45	0	70	115
British Columbia	9	0	28	37
Saskatchewan	3	0	1	4
Mainland Territories	1	1	10	12
Unconventional Resources[2]	0	0	80	80
Total Western Canada	**58**	**1**	**189**	**248**
Ontario	0	0	1	1
Nova Scotia	2	6	18	26
Total Eastern Canada	**2**	**6**	**19**	**27**
Grand Banks and Labrador	0	6	36	42
Mackenzie/Beaufort	0	9	55	64
Arctic Island	0	14	31	45
Other Frontier	0	0	49	49
Total Frontier	**0**	**29**	**171**	**200**
Total Canada	**60**	**36**	**379**	**475**
US Onshore and State Offshore	139	322	320	781
US Federal Offshore	27	68	362	457
Unconventional Resources[3]	18	0	359	377
Total US	**183**	**390**	**1,041**	**1,614**
TOTAL N.A.	**243**	**426**	**1,420**	**2,089**

Sources: NEB, USGS, MMS **Notes:** (1) Resource estimates are as of the latest estimates generated by the NEB, USGS and MMS. They were not necessarily generated in the current year, nor at the same time. NEB data (under its Techno-Vert scenario) taken from "Canada's Energy Future: Scenarios for Supply and Demand to 2025," released in July 2003. (2) Unconventional gas in the WCSB is comprised of CBM and tight gas. (3) Unconventional gas in the US represents coalbed methane, located predominantly in the Rocky Mountain region.

The figure at left graphically defines proved reserves, discovered resources, and undiscovered resources.

The total US natural gas resource base, including proved reserves is 1,614 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 475 Tcf. At 2002 levels of domestic production, Canada has about a 77 year supply of natural gas.

Table 9
North American Natural Gas Reserves

	Jan. 1, 2002 (Bcf)	Jan. 1, 2001 (Bcf)	Jan. 1, 2000 (Bcf)	Bcf Change 2002 vs. 2001	% Change 02 vs 01	% Change 01 vs 00
Gulf Onshore[1]	57,914	56,088	54,363	1,826	3.3%	3.2%
Gulf Offshore	26,496	26,172	25,451	324	1.2%	2.8%
Total Gulf	84,410	82,260	79,814	2,150	2.6%	3.1%
US Midcontinent	20,275	20,579	19,838	-304	-1.5%	3.7%
US Rockies	48,143	48,143	41,875	0	0.0%	15.0%
Other US	25,857	26,445	25,879	-588	-2.2%	2.2%
Total US Reserves	**183,460**	**177,427**	**167,406**	**6,033**	**3.4%**	**6.0%**
Western Canada	57,515	56,937	58,078	578	1.0%	-2.0%
Scotian Shelf	2,190	2,381	2,502	-191	-8.0%	-4.8%
Other Canada [2]	413	415	430	-2	-0.5%	-3.5%
Total Canada	**60,118**	**59,733**	**61,010**	**385**	**0.6%**	**-2.1%**
TOTAL N.A. Reserves	**243,578**	**237,160**	**228,416**	**6,418**	**2.7%**	**3.8%**

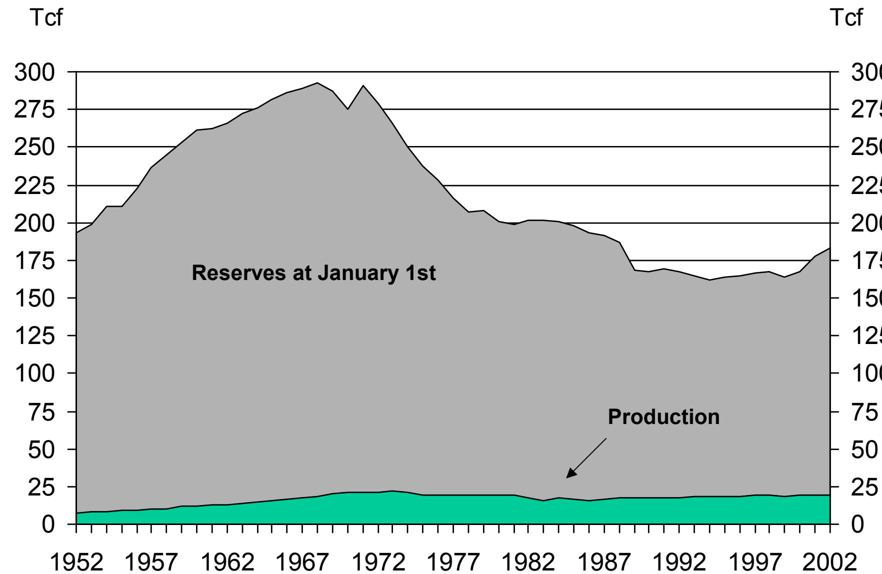
Sources: EIA US Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2001 Annual Report (US data), and Canadian Association of Petroleum Producers (Canadian data). **Notes:** (1) Gulf onshore includes all reserves in Texas, Louisiana, Mississippi and Alabama onshore, plus the state offshore reserves of those states. (2) Mainly Ontario.

Reserve data for any given year comes out almost one full year later. For example, reserve changes for 2001 were released in Canada (November/02) and in the US (September/02). The latest reserve figures show reserves as of January 1, 2002.

North American reserves at January 2002 were 2.7% higher than they were in January 2001. Year-over-year, gas reserves in the WCSB increased by 1% to 57,515 Bcf. US gas reserves increased by 3.4% to 183,460 Bcf. The majority of reserve additions came from the Gulf coast, particularly in Texas, which saw reserve additions of nearly 1,450 Bcf.

Reserve trends are a powerful indicator of future production. In the past, reserve additions greater than production, have signaled future production increases. As reserve additions in recent years have approximately equaled production, this tends to be signal flat supply for the medium-term.

Figure 19
Total US Gas Reserves



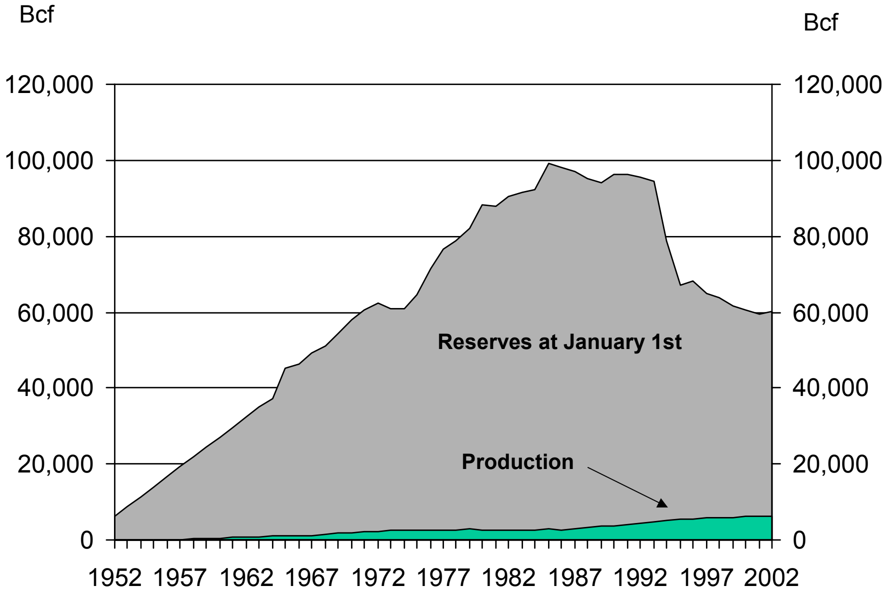
Source: EIA

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

US reserves peaked in 1970 at about 290 Tcf, with an R/P ratio of 13.4. Following this peak, US reserves declined rapidly. Between 1971 and 1991, US reserves fell by more than 40%. However, US reserves have increased in 7 of the last 8 years.

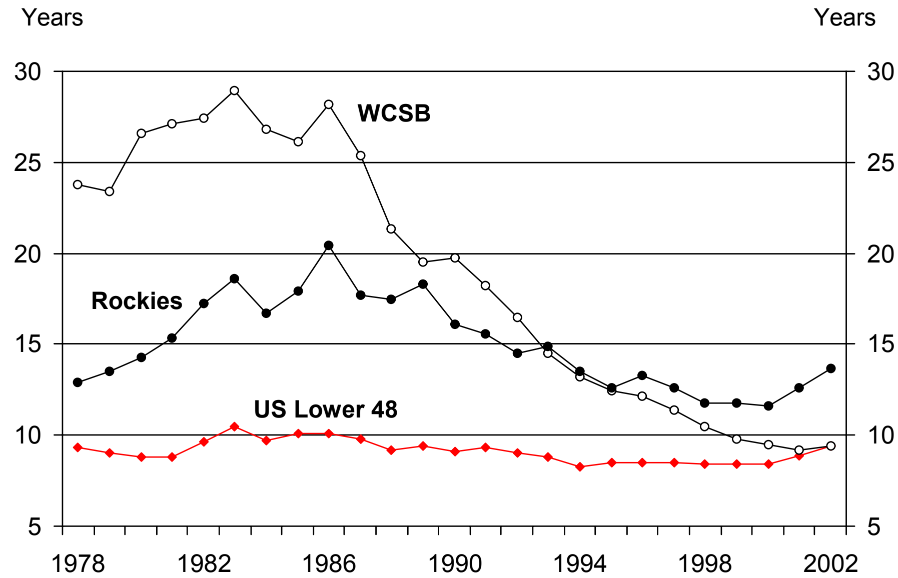
During 2001, US reserves increased significantly, largely due to increases in Wyoming, Colorado and Texas. Coalbed methane accounted for 9.6% of all US gas reserves in 2001.

Figure 20
Total Canadian Gas Reserves



Source: CAPP

Figure 21
Reserves to Production Ratios



Sources: EIA, CAPP

A similar comparison of total Canadian gas reserves shows a different story. Canadian reserves peaked in 1983, and fell very quickly to 1994. 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. However, during 2001, Canadian reserves increased by 385 Bcf, on the strength of natural gas drilling in conventional areas.

Canadian gas production has been increasing ever since gas was discovered more than 100 years ago. However, it has recently begun to shows signs of leveling out.

Reserves to production (R/P) ratios are an indication of the maturity level in a specific area. This figure depicts the maturing nature of the WCSB which has seen its R/P ratio in steady decline since 1991. The WCSB now has the same R/P ratio as the US Lower 48 states.

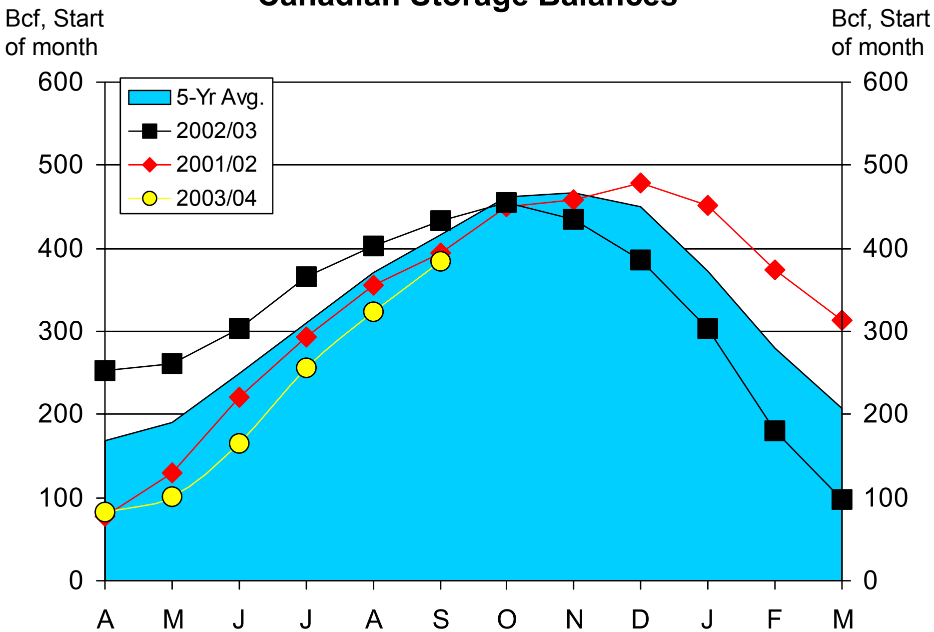
The only major supply region which remains quite immature is the US Rockies, where the R/P ratio has increased each year since 2000. In 2002, the Rockies R/P ratio was 13.7 years.

The stability of the R/P ratio, overall reserves, and the near equality of production and reserve additions in recent years, all seems to indicate a relatively stable period of gas production for the next few years.

Review of 2002

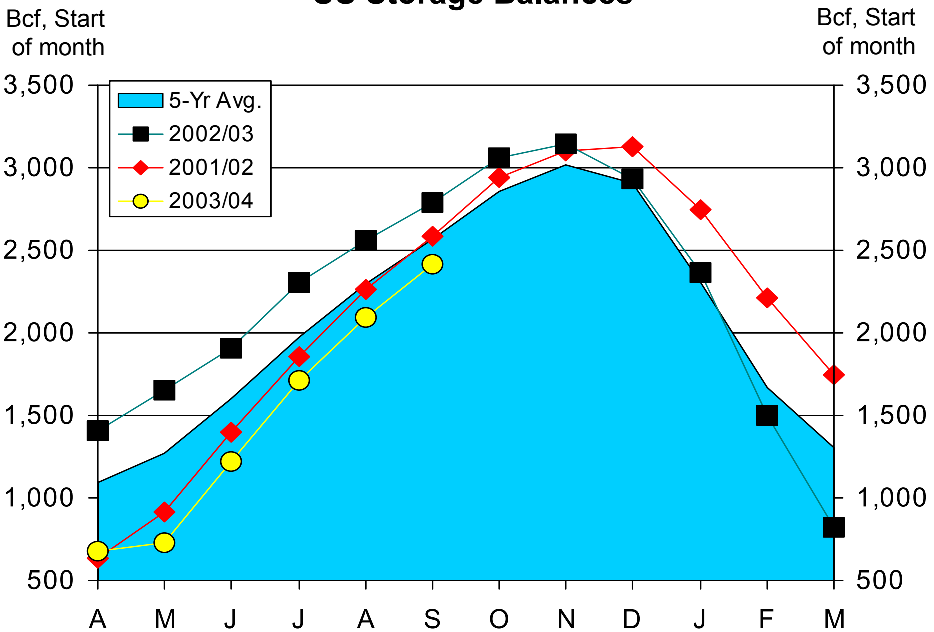
Natural Gas Storage

Figure 22
Canadian Storage Balances



Source: NRCan estimates from Canadian Enerdata and CGA weekly data.

Figure 23
US Storage Balances



Source: NRCan estimates from EIA and AGA weekly data.

Canadian storage balances have dramatically declined since their high in October 2002, falling to just 83 Bcf in April 2003.

Compared to 2002, April storage volumes were down 67%, meaning that Canada would have to inject 384 Bcf of gas during storage injection season in order to reach last year's storage levels at the end of storage injection season in November. Since then, storage levels have come up and as of September 2003, are only 8% below normal.

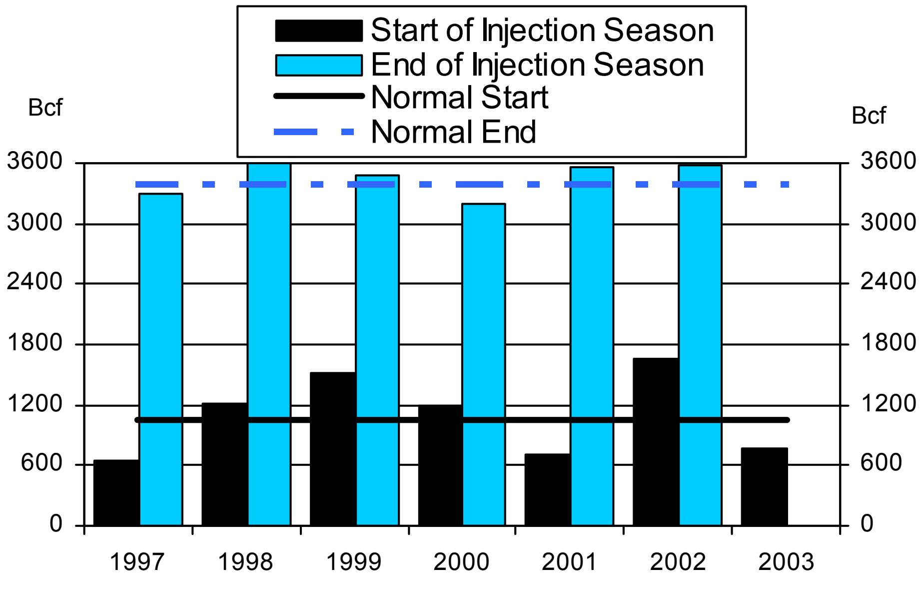
During 2002-2003, 170 Bcf of gas was withdrawn from storage.

US storage balances remained high throughout the year, but fell below both last year's levels and the five-year average due to cold weather demand. Storage in April 2003 compared to 2002 fell 727 Bcf and was 38% below the five-year average.

The US needed to inject 2,469 Bcf of gas during storage injection season in order to reach last year's levels at the end of storage injection season. By September, that number had fallen to 728 Bcf, or 364 Bcf per month, a manageable amount.

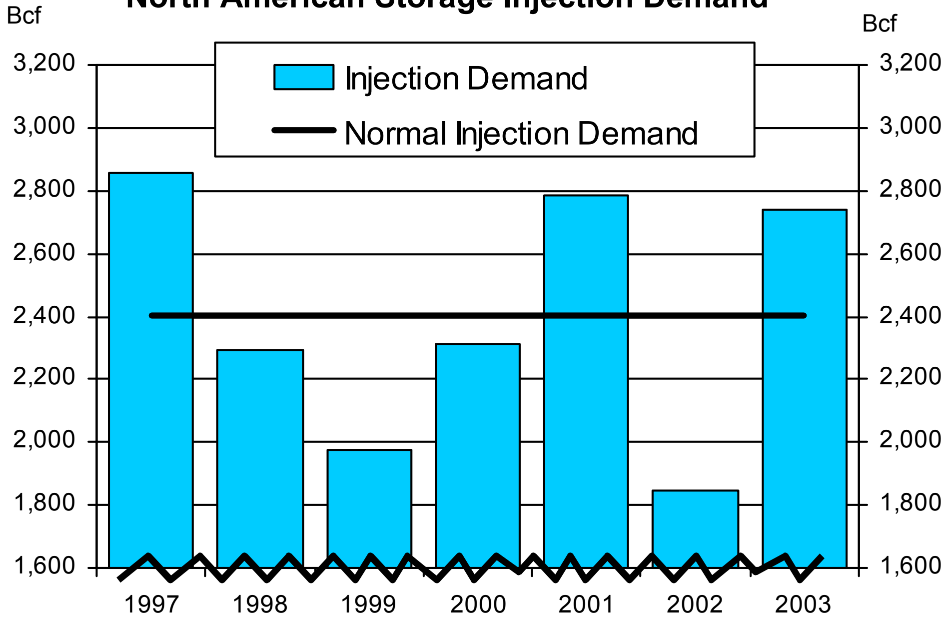
During 2002-2003, 727 Bcf of gas was withdrawn from storage.

Figure 24
North American Storage Levels



Sources: Canadian Enerdata, CGA, EIA, AGA

Figure 25
North American Storage Injection Demand



Sources: Canadian Enerdata, CGA, EIA, AGA, NRCan Estimates

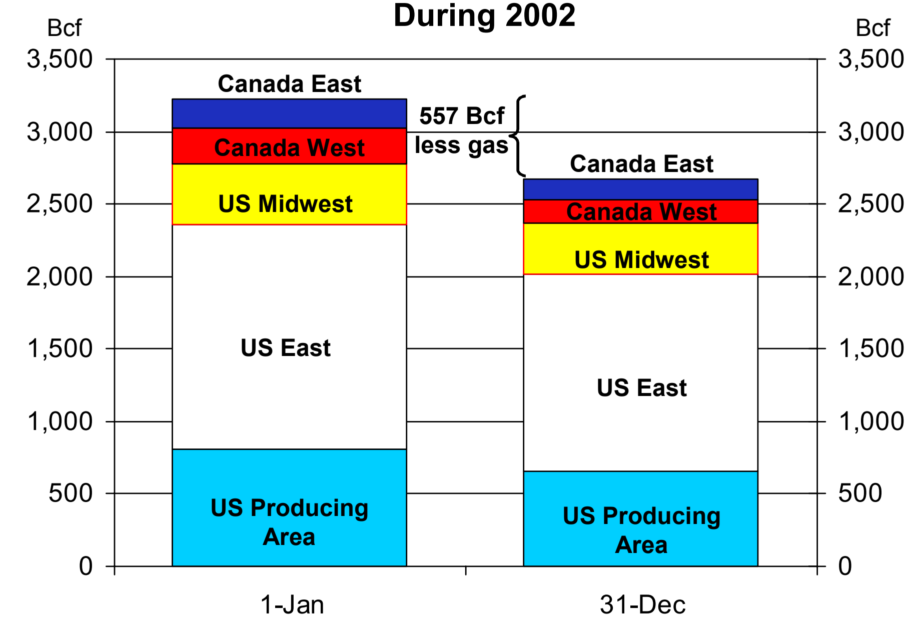
The storage injection season begins on April 1st and ends on November 1st. North American storage balances at the start and end of various past injection seasons are shown above. Also shown is the normal (average of 1997–2001) level for the start and end of injection season. At the start of the 2003 injection season, North American storage is significantly below normal levels. However, this is a similar situation to the ones that existed in the spring of 1997 and 2001.

If North America is to reach the November 1st, 2002 storage level, 2,820 Bcf of gas will have to be injected during the 2003 storage injection season.

As noted in the previous graph, on April 1st, the storage injection season begins. From then until November 1st, there is a race to fill storage to adequate levels in order to meet winter gas demand. The above graph shows the amount of storage which would have had to been injected over the April 1st to November 1st period in order to reach 3,500 Bcf, which is the average November 1st fill level over 1997 – 2001.

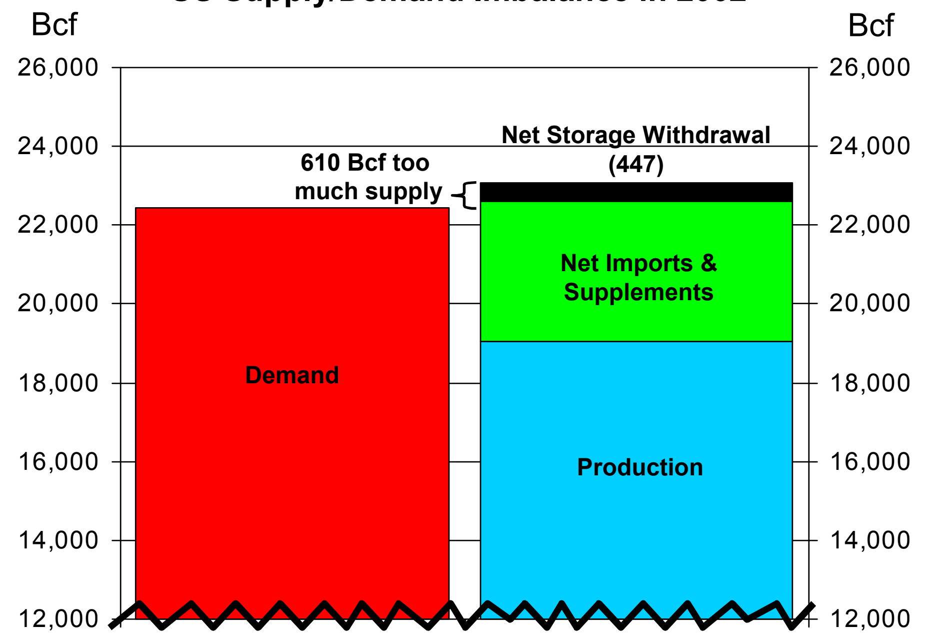
If Canada and the US are to reach normal storage levels by November 2003, gas injections this summer will have to be much heavier than they were last year. Gas demand by storage operators in 2003 will be roughly 2,750 Bcf over the 213 day summer injection season, or 12.9 Bcf per day. In 2002, storage operator demand for injection gas was only about 8.6 Bcf per day.

Figure 26
North American Storage Changes During 2002



Sources: CGA, Canadian Enerdata, EIA, NRCan estimates

Figure 27
US Supply/Demand Imbalance in 2002



Source: EIA Natural Gas Monthly – Table 2 (May 2003)

North American storage decreased through the calendar year. The largest absolute decrease was in the Eastern United States where storage declined by 191 Bcf. The largest percentage decrease was in Eastern Canada, where storage levels fell 34%. In total, North American storage shrank 557 Bcf, equaling a 17% reduction between January and December.

In effect, the gas market borrowed supply from storage in 2002, by using a 557 Bcf draw down of storage.

This chart shows the US "balancing item". Due mainly to accounting differences at the supply and demand ends, US supply and demand never exactly match, even after accounting for storage movements. In 2002, either demand was underestimated or supply was overestimated, or both.

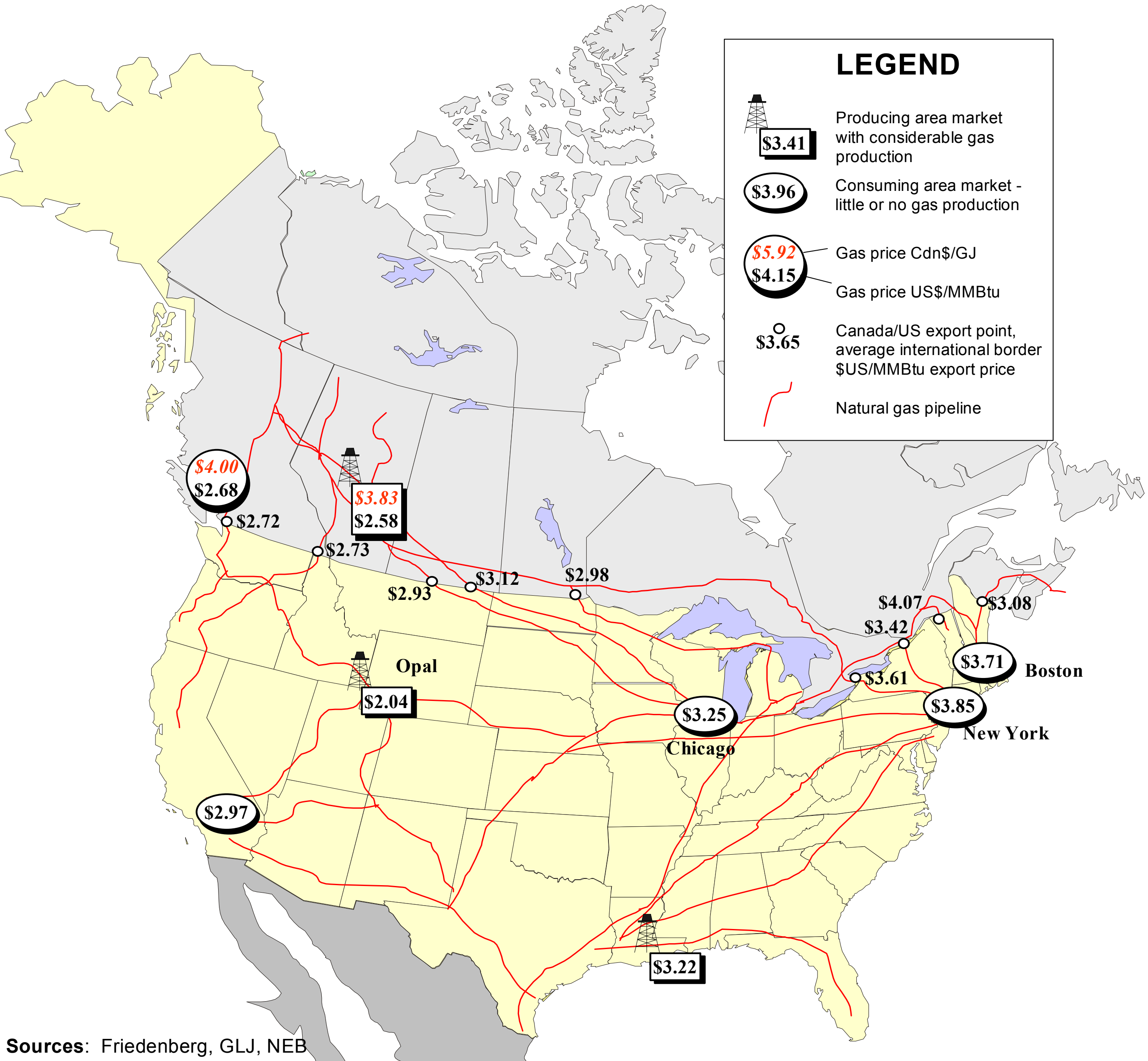
May 2003 EIA figures show a negative 610 Bcf "balancing item" for 2002—supply is higher than demand.

This is high, but still fairly typical. The balancing item was –113 in 1999, -271 in 2000 and 46 in 2001.

Review of 2002

Natural Gas Prices

Map 4
Canadian & US Natural Gas Prices



Sources: Friedenberg, GLJ, NEB

The map shows natural gas spot (monthly) market prices for 2002 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. These areas must pay significant pipeline costs in addition to the commodity cost.

In 2002, gas prices were lower across Canada and the US. Numerous factors contributed to lower prices, including milder weather, high storage levels, declining industrial demand and a weak economy, particularly in the US.

Table 10
Regional Natural Gas Prices[1]

Region	2002 Avg.	2001 Avg.	2000 Avg.	% Change 02 vs 01	% Change 01 vs 00
AECO-C	$2.58	$4.05	$3.40	-36%	19%
NYMEX	$3.22	$4.27	$3.89	-25%	10%
California	$2.97	$8.04	$5.00	-63%	61%
Huntingdon	$2.68	$4.57	$4.15	-41%	10%
Opal	$2.04	$3.65	$3.41	-44%	7%
Chicago	$3.25	$4.45	$3.96	-27%	12%
Dracut	$3.71	$5.16	$4.41	-28%	17%
Dawn	$3.28	$4.58	$4.06	-28%	13%

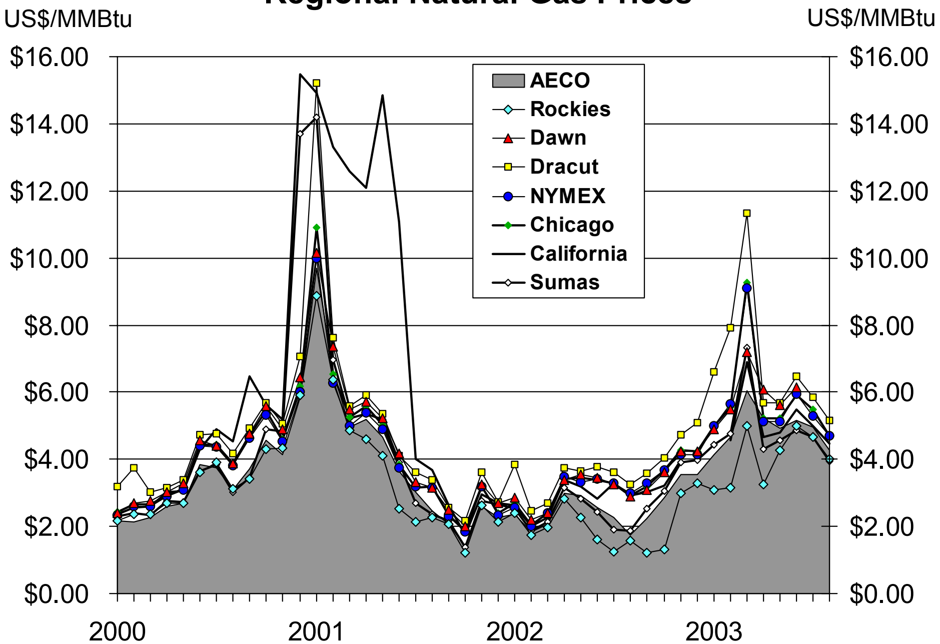
Sources: Friedenberg, GLJ. **Note:** (1) All prices are in $US/MMBtu.

In 2002, prices were lower across all major regions in North America. Alberta prices averaged US$2.58/MMBtu, 36% lower than in 2001. NYMEX gas prices were 25% lower in 2002.

The largest price decrease occurred in California, falling by more than 63%. Prices in BC and in the Rockies also fell significantly.

Significant demand destruction, particularly in the industrial sector, combined with warmer weather, a weakening US economy and higher than normal storage levels throughout most of 2002, ensured that gas prices remained moderate, relative to 2001. Although some industrials switched back to natural gas as prices moderated, a weaker economy and concerns over gas price volatility ensured that industrial demand remained weak in 2002. However by late 2002, concerns about a lack of supply, rising oil prices, and a recovering economy had the tendency to drive prices upwards again.

Figure 28
Regional Natural Gas Prices

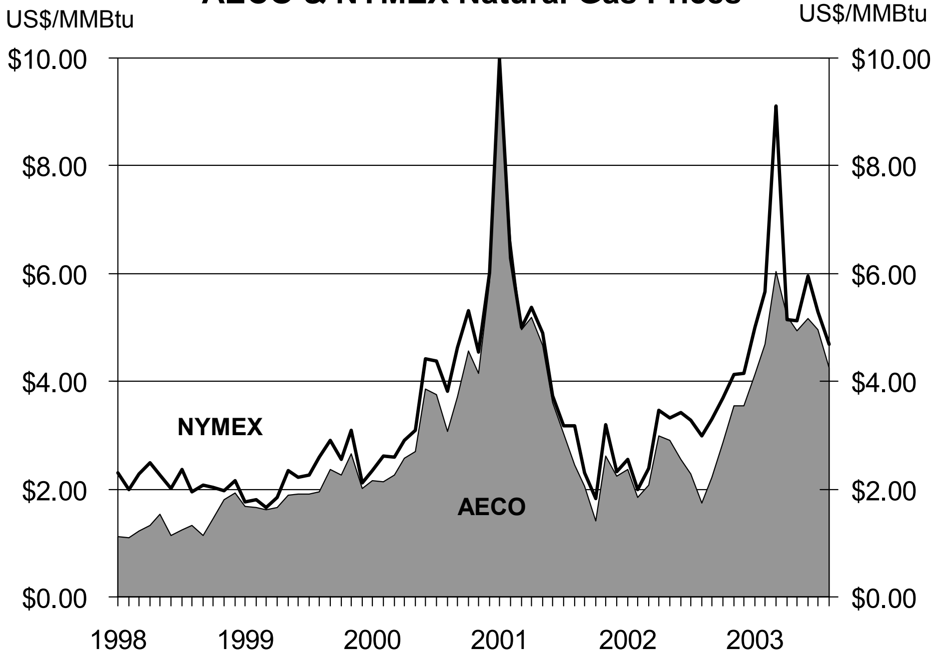


Source: Friedenberg, GLJ

Monthly spot prices in major North American regions are shown above. Generally, large price differentials are an indication that transportation capacity between locations is constrained.

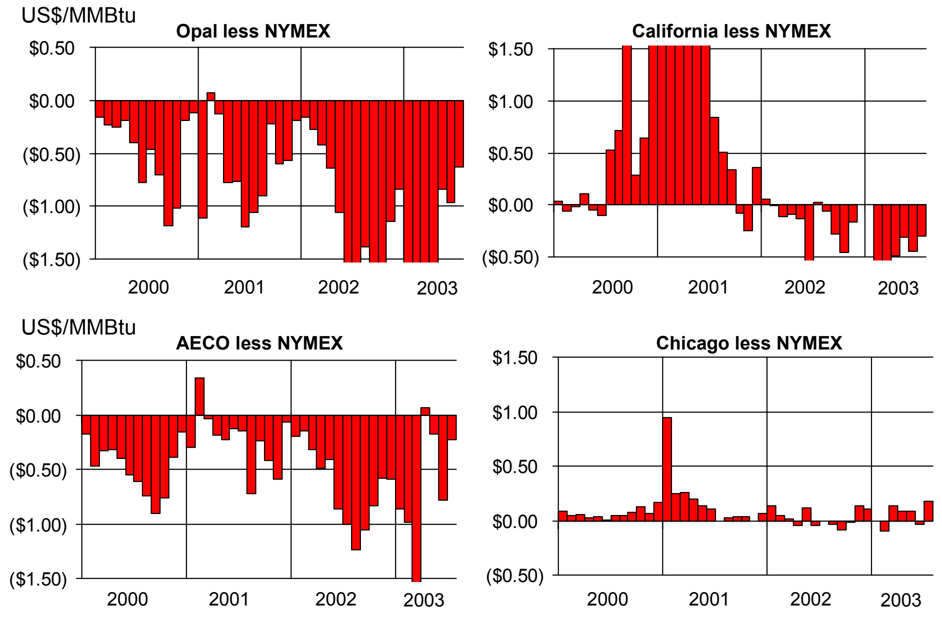
In early 2001, California and BC prices were disconnected, mainly the result of California's energy crisis. By late 2001, regional prices had reintegrated as milder weather, fuel-switching and a weakening economy led to large demand losses, placing downward pressure on prices. In June 2002, California and the Rockies prices again began to disconnect from other markets, but this time prices were lower, rather than higher from other markets. Gas became trapped in the Rockies and fell to as low as US$1.20/MMBtu in September, more than US $2/MMBtu lower than the NYMEX price. The Rockies-NYMEX differential averaged US$1.18/MMBtu for 2002.

Figure 29
AECO & NYMEX Natural Gas Prices



Source: Friedenberg, GLJ

Figure 30
Natural Gas Price Differentials

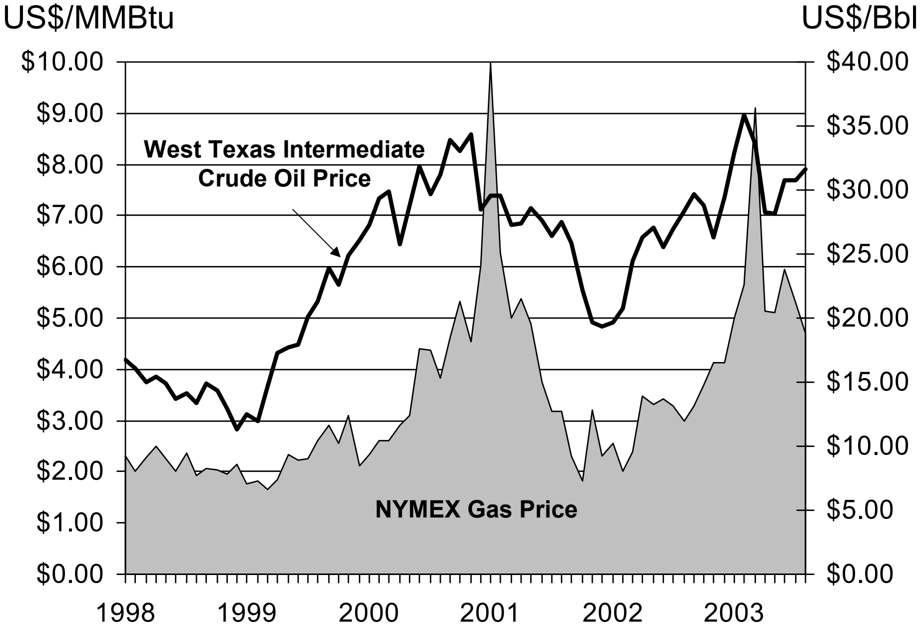


Source: Friedenberg, GLJ

The two key North American price hubs are the intra-Alberta market and the Henry Hub in Louisiana (NYMEX). A NYMEX-Alberta differential of US$0.50/MMBtu is considered normal. Between 1999 and 2002, the NYMEX-Alberta differential averaged US $0.42/MMBtu. At times, short-term disconnects will occur between Alberta and NYMEX. In 2002, NYMEX averaged US$3.22/MMBtu, Alberta US$2.58/MMBtu, for a differential of $0.64. In April 2002, the differential widened, averaging US$0.79/MMBtu from April through December. This was mainly due to relatively lower prices in two of the major Canadian export markets -- the Pacific Northwest and California. Low prices in these markets reduced incentives to move Canadian gas in that direction. This gas backed up in Alberta, lowering Alberta prices somewhat.

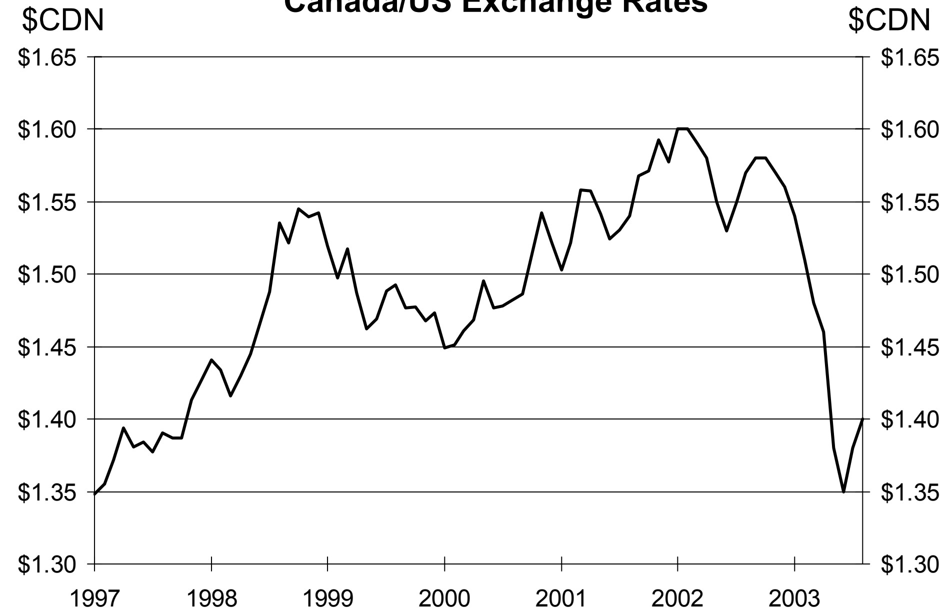
Differentials continued to widen in 2002, and in some cases changed directions as well. California prices were higher than NYMEX in 2001, but lower in 2002. Regionally, Rockies gas prices (Opal) fell far below other market prices during 2002. The causes for this were two-fold. First, rebounding western US hydro-electric generation during summer 2002 meant less gas was needed for power generation, and reduced the call on Rockies production. Secondly, available Rockies production capacity was trapped in the area by a lack of exit pipeline capacity. Rockies to Henry Hub price differentials increased from US$0.16/MMBtu in January 2002 to $2.38 by October. Low Rockies prices also affected prices in the Pacific Northwest, California, and Alberta.

Figure 31
Crude Oil and Natural Gas Prices



Sources: Economagic, Friedenberg, GLJ

Figure 32
Canada/US Exchange Rates



Source: Bank of Canada. **Note:** Canadian dollars required to purchase one US dollar.

The chart above displays the relationship between world 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 gas demand and prices.

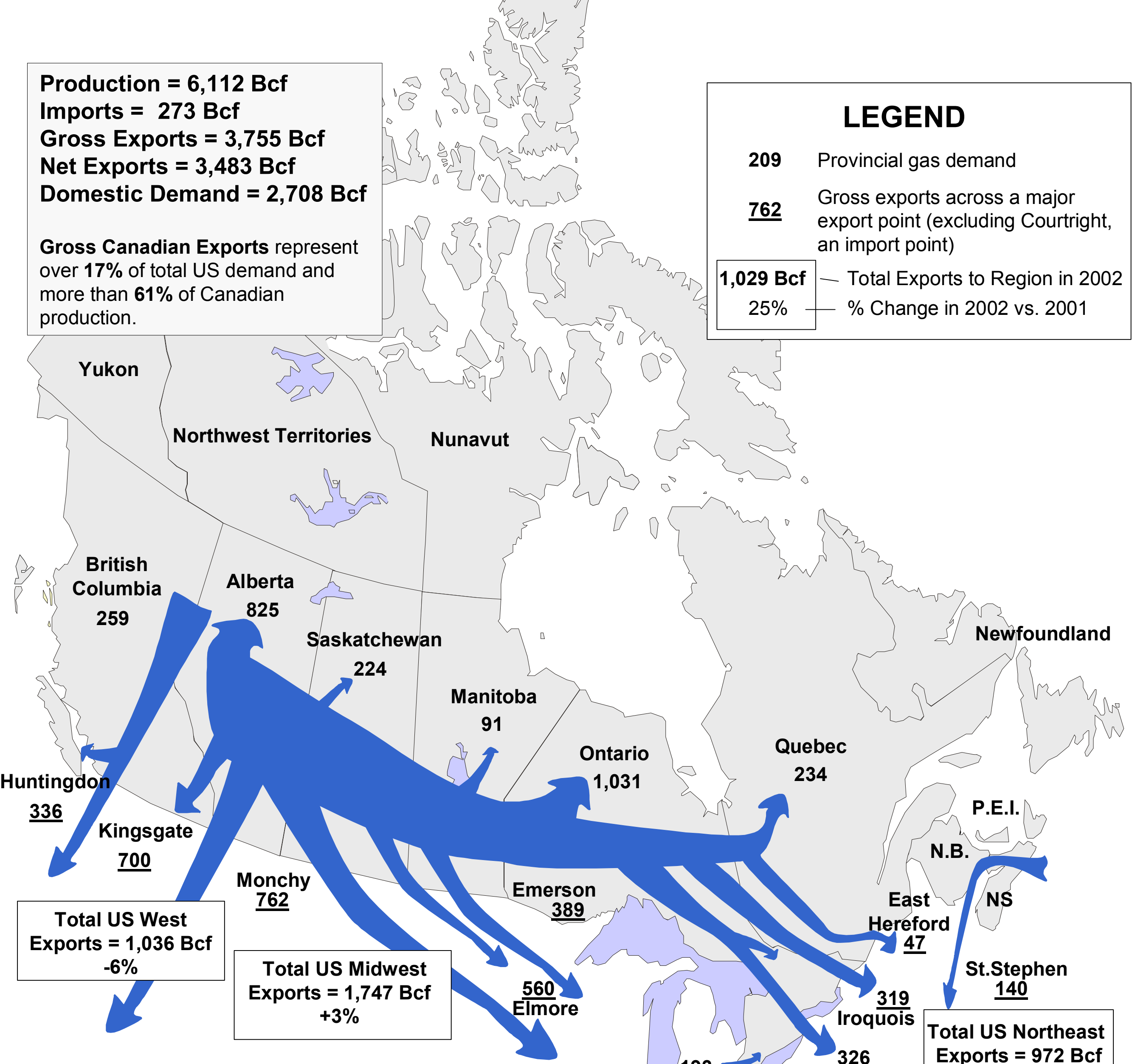
In early 2002, West Texas Intermediate (WTI) crude oil prices were between US$20 - $25 per barrel. By late 2002, with the Iraq war looming and a Venezuelan oil strike, prices exceeded $30/barrel. Thus, high oil prices also supported high gas prices in late 2002. With both gas and oil prices at historically 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. To illustrate, if the Canada-US exchange rate in 2002 had been equal to the 1997 exchange rate, the average 2002 Canadian gas price would have been CDN$3.40/GJ, rather than the $3.83/GJ, as was actually the case. In 2002, the value of the Canadian dollar averaged CDN$1.57 for US$1.00, CDN$0.02 weaker than the previous year. However, in 2003, the direction of exchange rates has shifted, with the Canadian dollar now showing strength versus the US currency.

Review of 2002

Canadian Export & Domestic Sales

Figure 25
Domestic and Export Markets



Sources: NEB, StatsCan

This map shows natural gas export and import volumes at various hubs throughout Canada and the US. Volumes shown are the total volumes moved throughout 2002.

Last year, exports to the US West decreased by 6%, on top of a 7% decrease in 2001. The US Midwest and Northeast both saw small increases in exports.

Regionally, exports to the US West region fell, as exporters preferred to send gas to the Midwest or Northeast, where prices and netbacks were considerably higher.

Imports of US gas to Canada, largely through Courtright, increased 20%, but were offset by higher exports in 2002.

Total consumption of Canadian gas stayed stable in 2002, with both domestic demand and exports staying virtually flat.

Table 11
Domestic Demand and Canadian Exports

	2002 (Bcf)	2001 (Bcf)	2002 vs 2001 (Bcf)	% Change 2002 vs 2001
Gross Exports to US West	1,036	1,104	-68	-6%
Gross Exports to US Midwest	1,747	1,692	55	3%
Gross Exports to US Northeast	972	932	41	4%
Total Gross Exports	3,755	3,728	28	1%
Imports from US	273	228	45	20%
Net Exports	**3,483**	**3,500**	**-17**	**0%**
Western Canada Demand	1,352	1,451	-99	-7%
Eastern Canada Demand	1,356	1,245	111	9%
Total Canadian Demand	**2,708**	**2,697**	**12**	**0%**
Net Exports	3,483	3,500	-17	0%
Canadian Demand	2,708	2,697	12	0%
Total Canadian Gas Sold	**6,191**	**6,196**	**-5**	**0%**

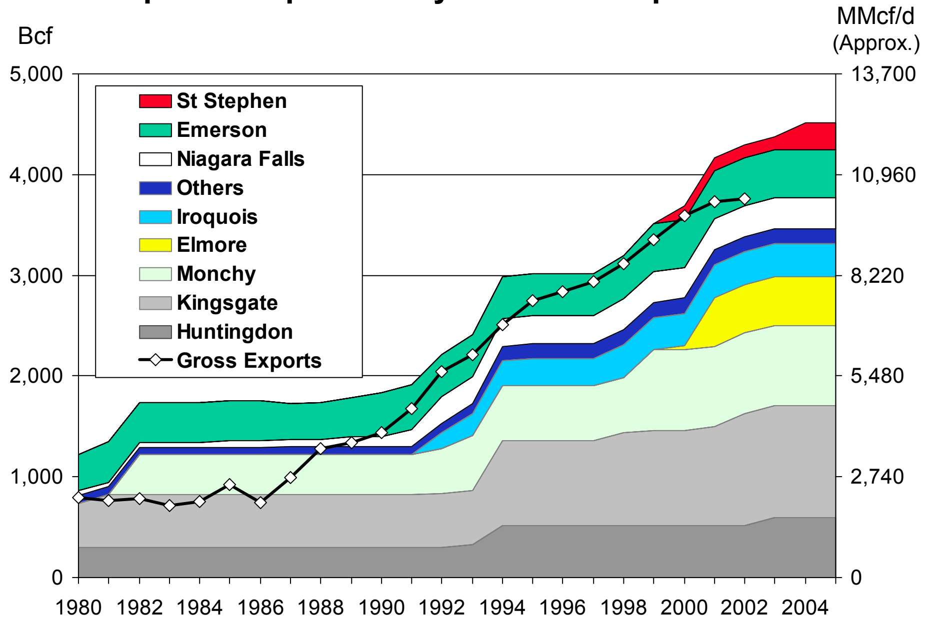
Sources: Export and import flows from NEB. Canadian demand from StatsCan and NRCan estimates. **Notes:** Gross exports are gas flows into the US from Canada which were identified as exports. This differs from some gas going into the US Great Lakes pipeline, which flows uninterrupted back into Canada.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

Canadian exports remained flat in 2002, despite a rise in imports, which have increased by more than 70% over the past two years.

Gross exports to the US West declined 6% because of increased hydro use and the growth of gas supply from the US Rockies region.

Canadian domestic demand remained stable, with Western Canada's 7% decline in demand being balanced by a 9% increase in the East. Total Canadian gas sold declined by only 5 Bcf, despite relatively high prices.

Figure 33
Pipeline Capacities by Canadian Export Point

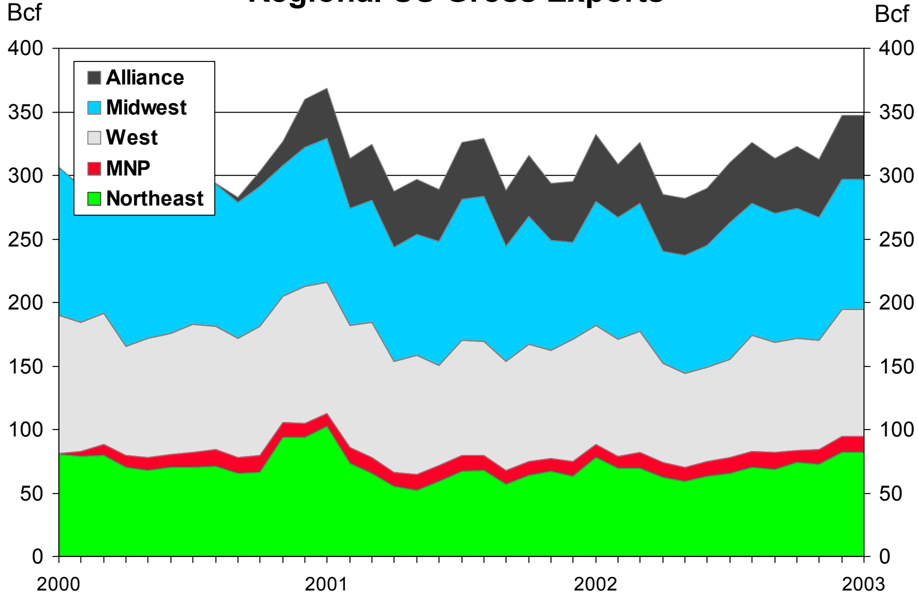


Sources: NEB, NRCan estimates, Pipeline Companies, Regulatory Filings

The above graph shows the total Canadian export pipeline capacity at the various export points. In the early 1980s, Canadian export capacity was expanded with additions on the east and west leg of the ANGTS pre-build. During the regulated period, the load factor was in the 50% range.

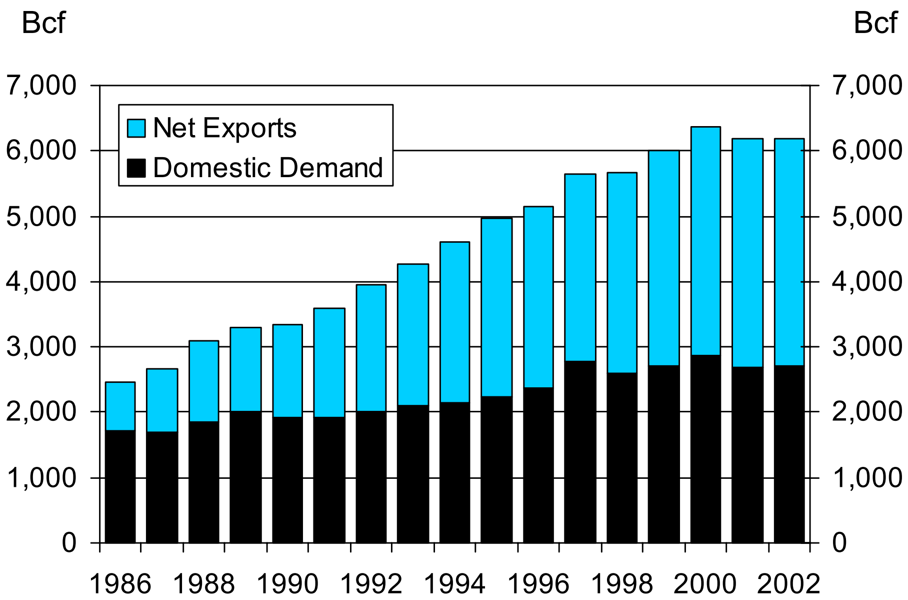
After deregulation in the mid-1980s, the load factor began to rise, reaching 80% by the early 1990s. This prompted many new pipeline construction projects, especially in the US northeast and midwest regions. The latest expansions have taken place in western markets such as NWPL in the PNW and PGT in the PNW and California.

Figure 34
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 35
Domestic Demand & Net Exports



Source: StatsCan, NEB, NRCan estimates

Natural gas gross exports to the US only increased 1% this year, below the historical average of 5% annual growth.

Regionally, gross exports to the US Northeast and Midwest regions posted growth of 5% and 2% respectively. However, exports to the US West did not fare as well, declining 6% compared to 2001.

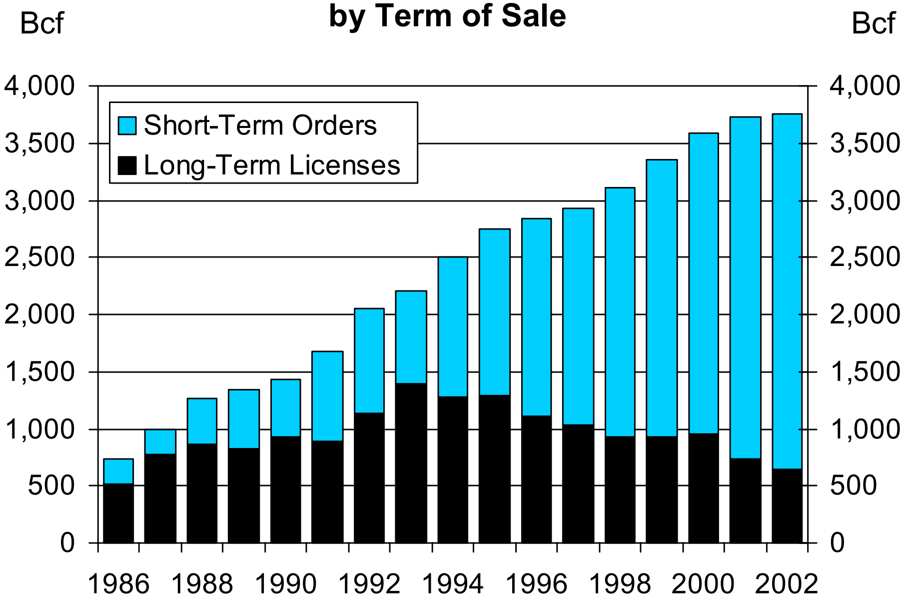
In 2002, the Alliance Pipeline accounted for 32% of exports to the US midwestern region. Similarly, the Maritimes and Northeast Pipeline accounted for 14% of all exports to the US northeastern region.

Net exports declined for the first time in 16 years, falling 17 Bcf, or just under 1%, from 2001. Due to the maturity of the Canadian resource base, this may be the first sign of an emerging long-term trend.

On the positive side, there was a small increase in domestic sales of approximately 12 Bcf, signalling that there remains a continuing demand for natural gas in Canada.

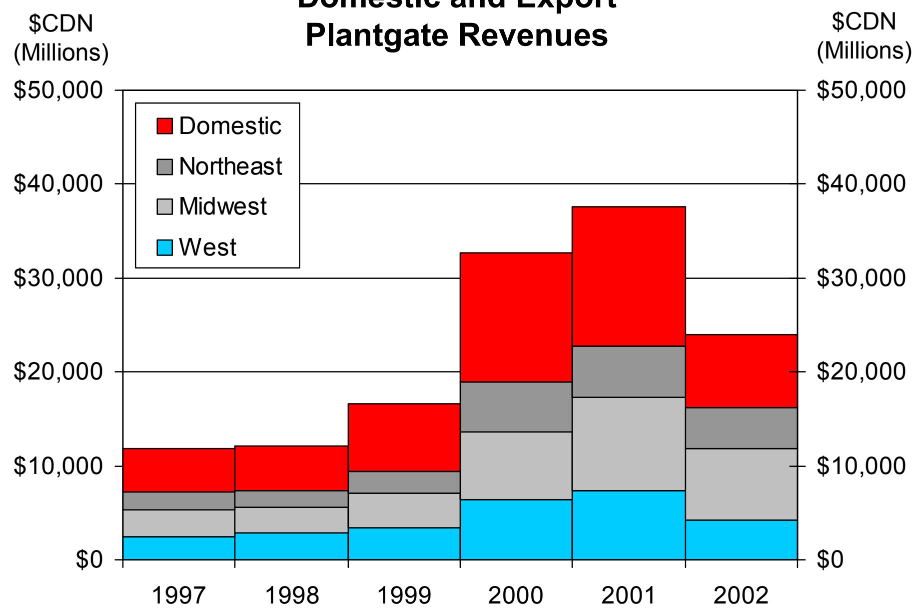
Despite the small decline in exports in 2002, Canada remains a strong exporter of natural gas as exports accounted for 56% of total Canadian gas sold.

Figure 36
Natural Gas Gross Export Volumes by Term of Sale



Source: NEB

Figure 37
Domestic and Export Plantgate Revenues



Sources: Friedenberg, NEB, NRCan estimates. **Notes:** Domestic plant gate revenue is an estimate only. See Table 16, p.59 for further detail.

The National Energy Board (NEB) must approve the terms of an export arrangement via either a long-term license or a short-term order (2 years or less).

There continues to be a shift towards short-term orders, as they accounted for 83% of all export sales in 2002. This is an increase over 2001, where short-term orders accounted for 80% of all sales and a massive switch from 1986, where short-term orders accounted for only 30% of all exports.

Plantgate revenue is the revenue earned by producers at the wellhead. These figures tumbled in 2002, with total revenues falling 36%. All regions declined, however, the largest fall was domestically, where revenues were nearly halved, losing over $7 billion. Domestic revenues have not been this low since 1999.

Total plantgate revenue from exports also declined, falling 29% compared to 2001. Over $3 billion of revenue was lost from the US West alone, as revenues there declined by 43%.

Table 12
Domestic and International Border Export Prices

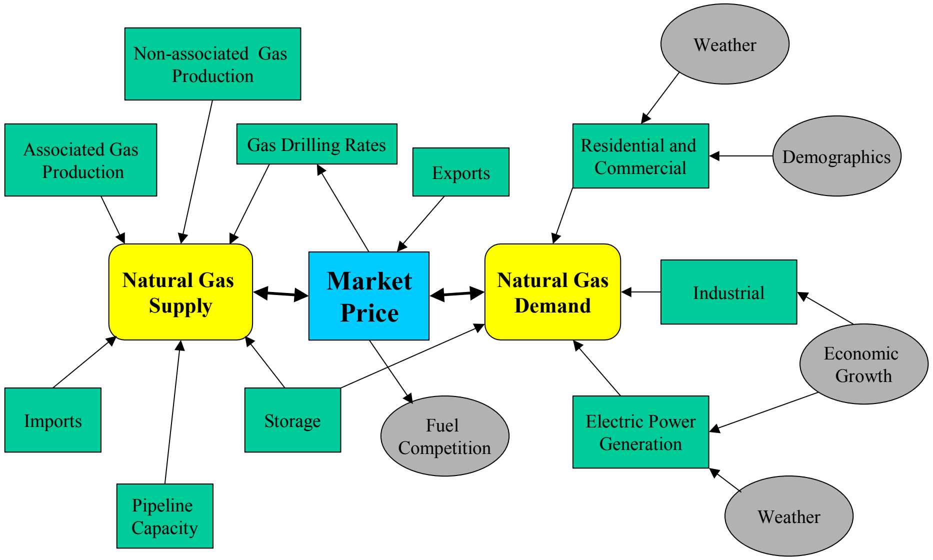
Year	Month	West US/MMBtu	MW US/MMBtu	NE US/MMBtu	Average US/MMBtu	NYMEX US/MMBtu	AECO Cdn/GJ	AECO US/MMBtu	Huntingdon US/MMBtu	Westcoast St 2 US/MMBtu
		International Border Export Prices				US Prices	Canadian Markets			
2002	January	$2.61	$2.48	$2.99	$2.65	$2.56	$3.52	$2.36	$2.52	$2.37
	February	$2.05	$2.04	$2.61	$2.19	$2.00	$2.79	$1.85	$1.87	$1.91
	March	$2.28	$2.46	$2.90	$2.52	$2.39	$3.12	$2.06	$2.13	$2.11
	April	$2.93	$3.16	$3.56	$3.20	$3.47	$4.46	$2.96	$3.15	$3.12
	May	$3.03	$3.17	$3.53	$3.22	$3.32	$4.36	$2.91	$2.82	$2.94
	June	$2.57	$3.05	$3.46	$3.03	$3.42	$3.71	$2.53	$2.42	$2.39
	July	$2.13	$2.81	$3.38	$2.78	$3.28	$3.30	$2.26	$1.90	$1.56
	August	$2.01	$2.62	$3.22	$2.60	$2.98	$2.58	$1.74	$1.87	$1.59
	September	$2.63	$2.94	$3.54	$3.01	$3.29	$3.34	$2.25	$2.54	$2.32
	October	$3.30	$3.41	$3.93	$3.51	$3.69	$4.27	$2.86	$3.06	$2.88
	November	$3.56	$3.91	$4.28	$3.91	$4.13	$5.29	$3.54	$3.92	$3.86
	December	$3.56	$4.03	$4.53	$4.03	$4.14	$5.25	$3.52	$3.96	$3.61
2003	January	$4.28	$4.75	$5.29	$4.81	$4.99	$6.04	$4.13	$4.44	$4.21
	February	$4.62	$5.39	$6.15	$5.45	$5.66	$6.71	$4.68	$4.76	$4.63
	March	$6.78	$7.95	$7.75	$7.64	$9.11	$8.45	$6.04	$7.32	$8.09
	April	$4.54	$5.05	$5.22	$4.96	$5.14	$7.20	$5.21	$4.29	$4.27
	May	$4.73	$5.04	$5.21	$5.01	$5.12	$6.48	$4.94	$4.58	$4.38
2003	**Average (YTD)**	**$4.99**	**$5.63**	**$5.92**	**$5.57**	**$6.00**	**$6.98**	**$5.00**	**$5.08**	**$5.12**
2002	**Average**	**$2.72**	**$3.01**	**$3.49**	**$3.05**	**$3.22**	**$3.83**	**$2.57**	**$2.68**	**$2.56**
2001	**Average**	**$4.47**	**$4.07**	**$4.51**	**$4.30**	**$4.27**	**$5.91**	**$4.07**	**$4.57**	**$4.14**
2001/02	**% Change[1]**	**-39%**	**-26%**	**-23%**	**-29%**	**-25%**	**-35%**	**-37%**	**-41%**	**-38%**
2002/03	**% Change[2]**	**52%**	**47%**	**53%**	**49%**	**46%**	**52%**	**49%**	**49%**	**49%**

Sources: Friedenberg, GLJ, NEB, NRCan estimates **Notes:** [1] Annual percentage change of prices between the years 2001 and 2002. [2] Year-to-date percentage change of prices between the years 2002 and 2003 (January to May).

In 2002, the AECO price averaged CDN$3.83/GJ, with a low of $2.58 and a high of $5.29. AECO spot prices were 35% lower in 2002. International border export prices and Canadian domestic prices closely tracked the NYMEX price in 2002. In 2002, natural gas prices in the export market averaged US$3.05/MMBtu, a decrease of 29% over 2001. Natural gas prices for 2002 decreased across all regions compared to 2001. Domestic prices declined more than international border and NYMEX prices. However, since August 2002, all prices increased, picking up momentum in the winter months. In 2003, prices have increased (Jan-May) by an average of approximately 50% in all regions throughout North America.

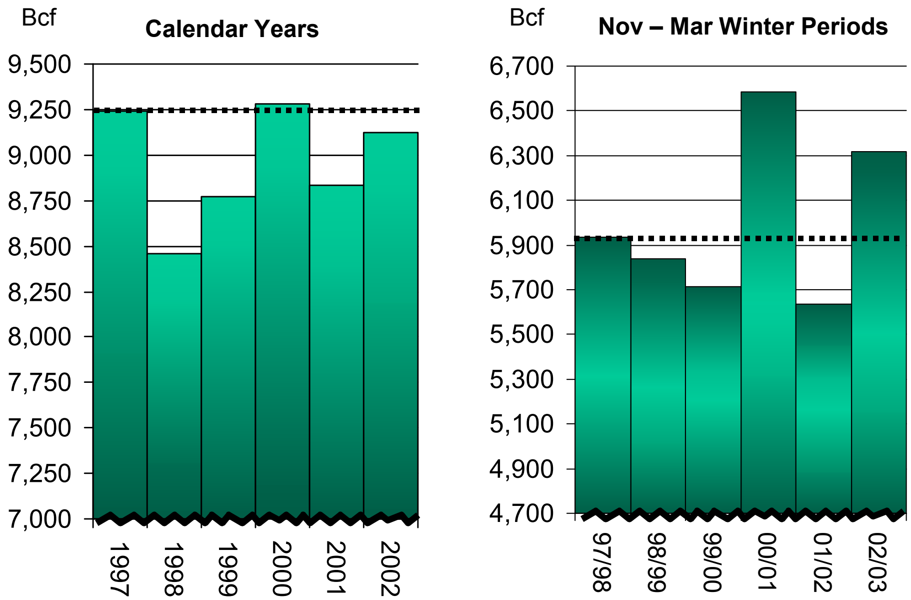
Short-Term Outlook

Figure 38
Natural Gas Price Drivers



Source: NRCan

Figure 39
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 export pipeline capacity contribute to changes in natural gas prices.

In the short-term (through to the end of the winter 2003/2004), natural gas prices are expected to be driven by weather, storage levels, natural gas production growth and world crude oil prices.

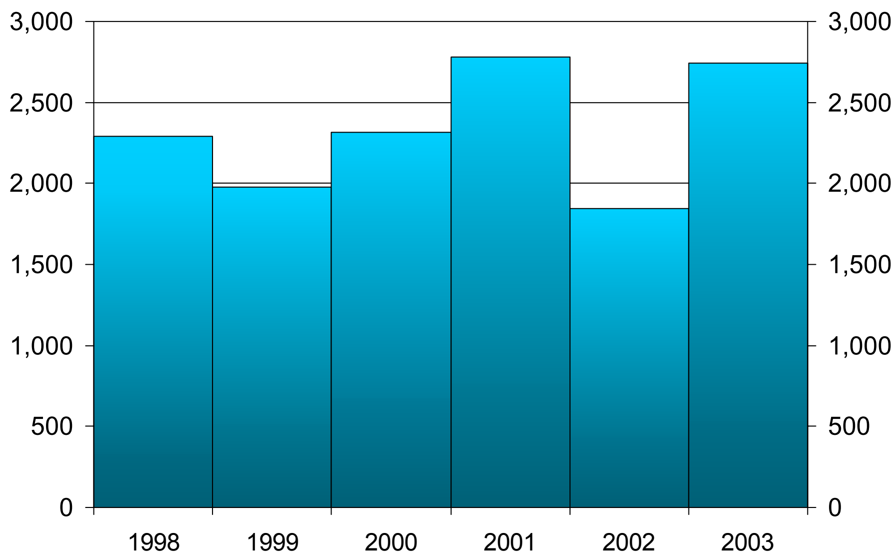
This section compares the state of these drivers in 2002 and early 2003 to normal or past extreme levels. This can give an idea of the market's tendencies in the short-term.

Over the past several years, North American calendar year temperatures have been normal or below normal. Accordingly, core demand has been average. Normal North American core demand would be in the 9,250 Bcf range (dashed line).

For the November through March winter seasons, 2001/02 was warm, and 2002/2003 was cold. Normal North American core winter demand is about 5,900 Bcf (dashed line).

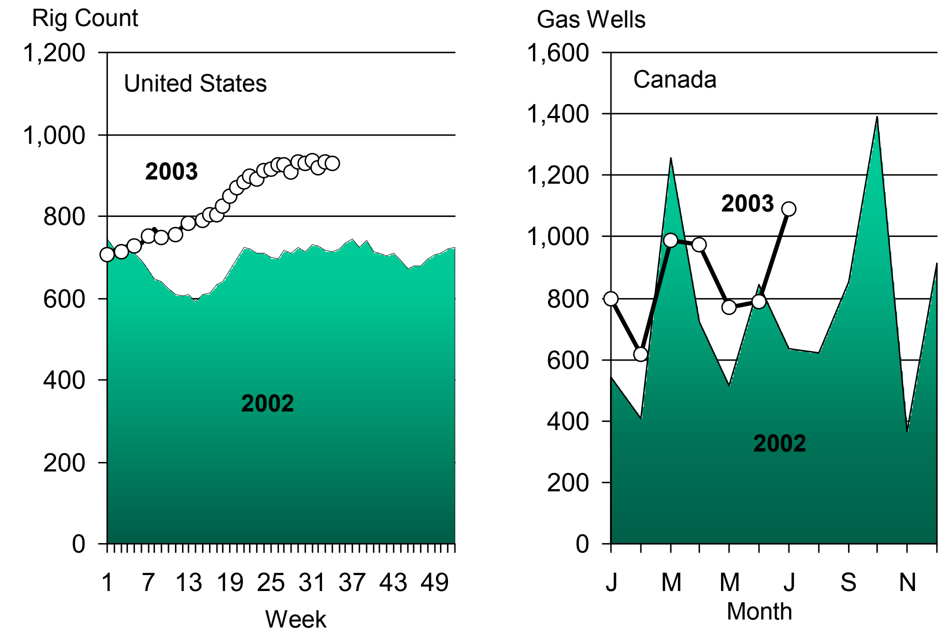
A colder than normal November and December last year, caused core demand to increase by more than 660 Bcf over the same period the previous year. If it were not for these colder temperatures, core demand over the 2002 calendar year would have been even lower.

Figure 40
North American Storage Injection Demand:
(As of April 1 of each year, Bcf Gas Injections Required To Reach 3.5 Tcf North American Storage by following Nov. 1)



Sources: EIA, Enerdata

Figure 41
North American Gas Drilling Trends



Sources: Baker Hughes, Daily Oil Bulletin

Given low North American storage levels on April 1st, 2003, nearly 2,750 Bcf was required to be injected into storage to reach 3.5 Tcf by November 1st, 2003. The situation was reversed in 2002, when only 1,844 Bcf was required as of April 1st, 2002.

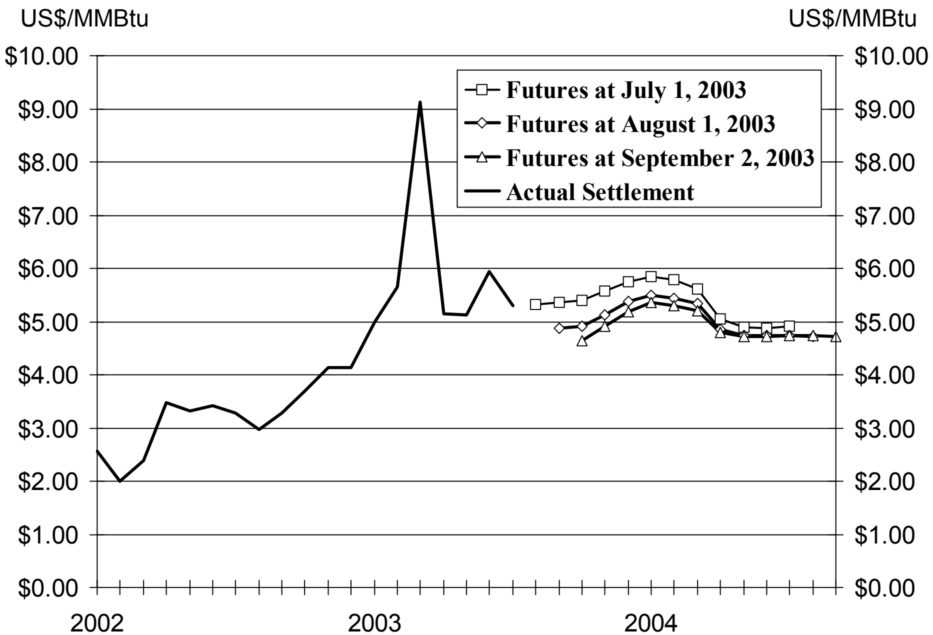
In June and July 2003, storage injections were substantially higher than average. As of September 1st, operators have caught up, and now only 698 Bcf remains to be injected to reach 3.5 Tcf by November 1st, 2003. Many analysts forecast that North American storage will be at or near normal levels by November 1st, 2003, in preparation for the winter of 2003/2004.

On the supply side, US and Canadian gas drilling in 2003 is above last year's levels. Over the first 33 weeks of 2003, the US natural gas rig count is about 22% higher than in 2002, averaging 830 rigs per week. Similarly, during the first seven months of 2003, the number of gas wells drilled in Canada (6,032) has increased by about 22% over 2002 levels.

Higher drilling levels is usually considered positive for gas supply and negative for gas prices.

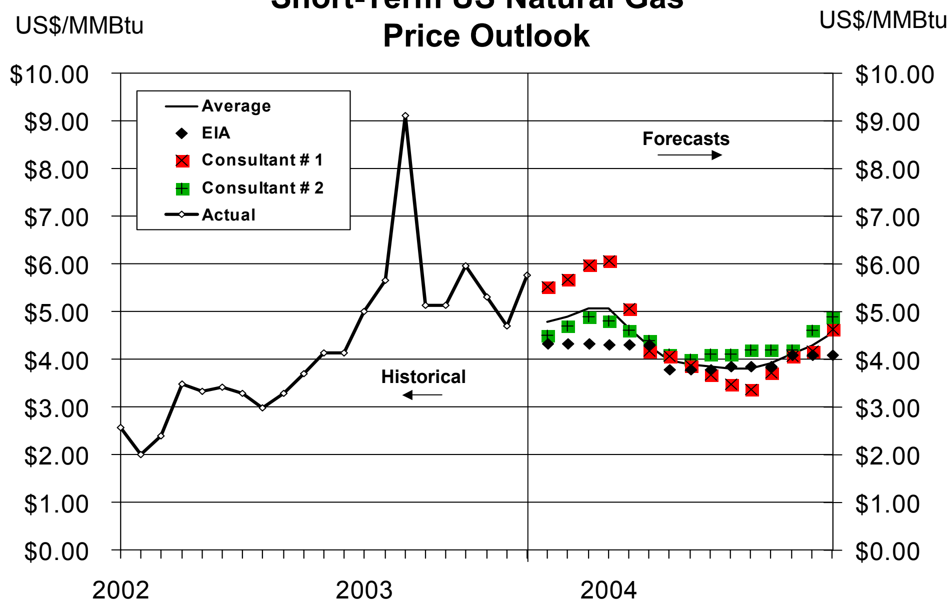
Although gas prices have levelled off since March 2003 (when they were CDN$8.45/GJ at AECO and US$9.13/MMBtu at NYMEX), prices have been much higher in 2003, which has and will prompt more drilling over the duration of the year.

Figure 42
US Futures Prices



Source: GLJ

Figure 43
Short-Term US Natural Gas Price Outlook



Source: Various consultants. **Note:** (1) NYMEX actuals from GLJ. (2) The forecast prices represent Gulf Coast Henry Hub prices, except EIA, which is an average US wellhead price.

The NYMEX natural gas futures contracts are traded for 36 months. For example, the July 2004 natural gas futures contract began trading in June 2001. This contract will stop trading on June 28, 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 July 2004 with the information they have today. Note that future gas settlement prices at three different dates are shown above.

These forward curves suggest that natural gas prices will hover between US$4 -$6/MMBtu through to September 2004.

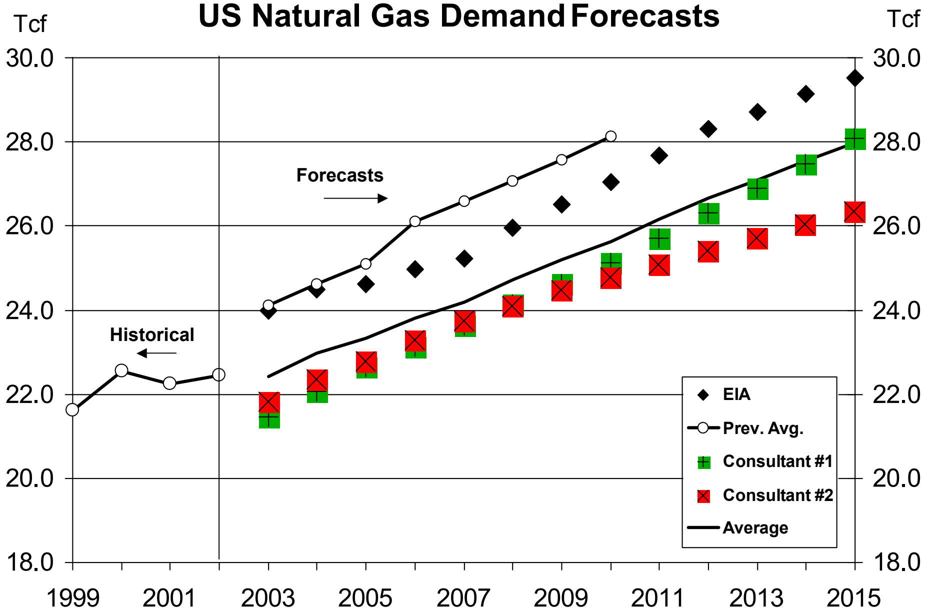
Figure 43 compares three forecasts of US natural gas prices through to the end of 2004. According to the forecasters surveyed, assuming normal weather, prices are expected to average between US$4.50-$6/MMBtu during the winter of 2003/2004.

US natural gas prices are expected to be slightly lower in 2004, averaging US$4.20/MMBtu over the year. High natural gas prices in 2003 have resulted in strong gas-directed drilling activity. The prospects of lower natural gas prices in 2004 are the result of expectations of a modest increase in natural gas production from higher drilling, as well as increased LNG imports.

Outlook to 2015

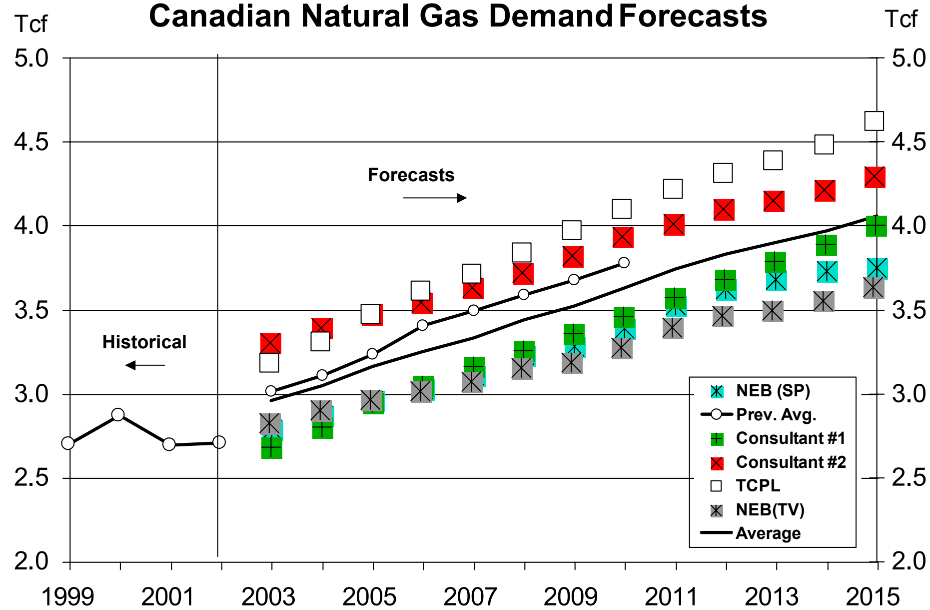
Natural Gas Demand

Figure 44
US Natural Gas Demand Forecasts



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

Figure 45
Canadian Natural Gas Demand Forecasts



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

Figure 44 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 28 Tcf by 2015. This represents an average increase of about 1.8 % per year.

The average of the previous year's forecast showed US gas demand at 28 Tcf by 2010, the same as the current forecast at 2015. Thus, current average forecasts for US demand have been revised downwards.

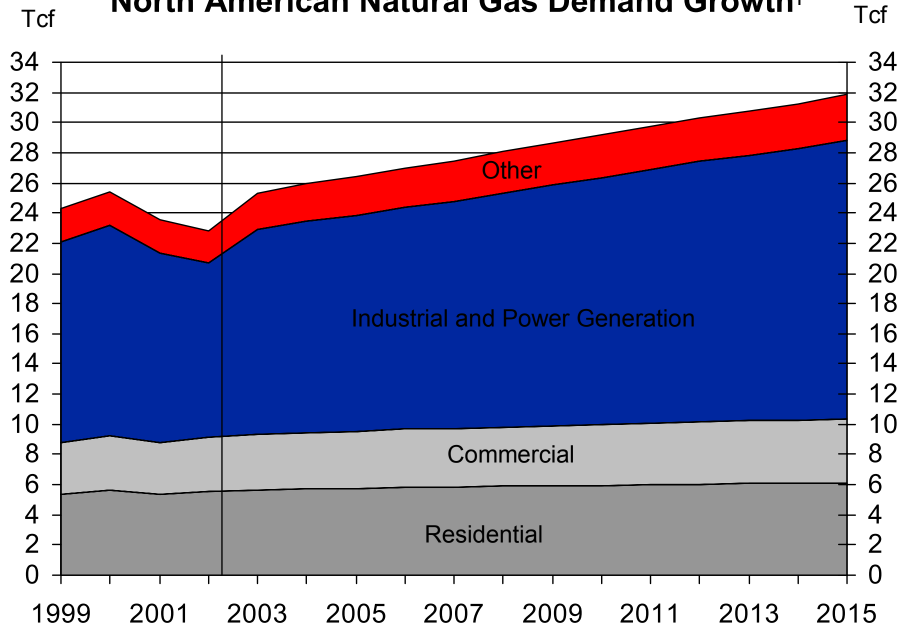
Figure 45 displays five forecasts of Canadian gas demand, along with the average of the forecasts, and the average from the previous year.

The average of the forecasts shows Canadian gas demand at 4 Tcf by 2015. This represents an average increase of about 2.7 % per year.

The average of the previous year's forecast showed Canadian gas demand at 3.8 Tcf by 2010. Current average forecasts for Canadian demand have been revised downwards.

Figure 46

North American Natural Gas Demand Growth[1]



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

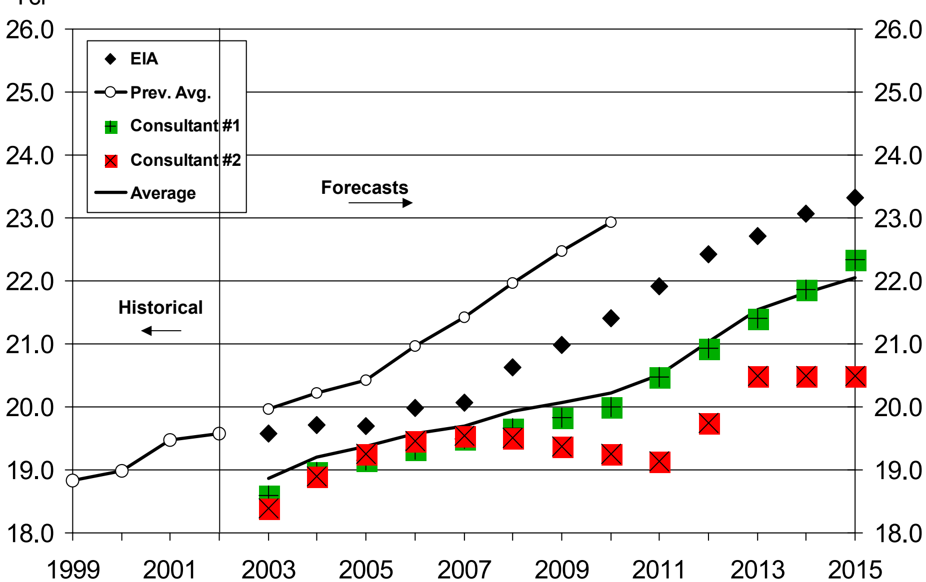
Figure 46 displays an average or "consensus" view regarding the future of North American gas demand. Summing the average forecasts of US and Canadian gas demand results in a "consensus" forecast of gas demand of about 32 Tcf by 2015. As shown in the figure, much of the growth is due to increased demand in the industrial and power generation sectors.

Given actual gas demand of 22.8 Bcf in 2002, this forecast implies that North America will need an additional 9.2 Tcf of annual gas supply by 2015.

Outlook to 2015

Natural Gas Supply

Figure 47
US Natural Gas Production Forecasts



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

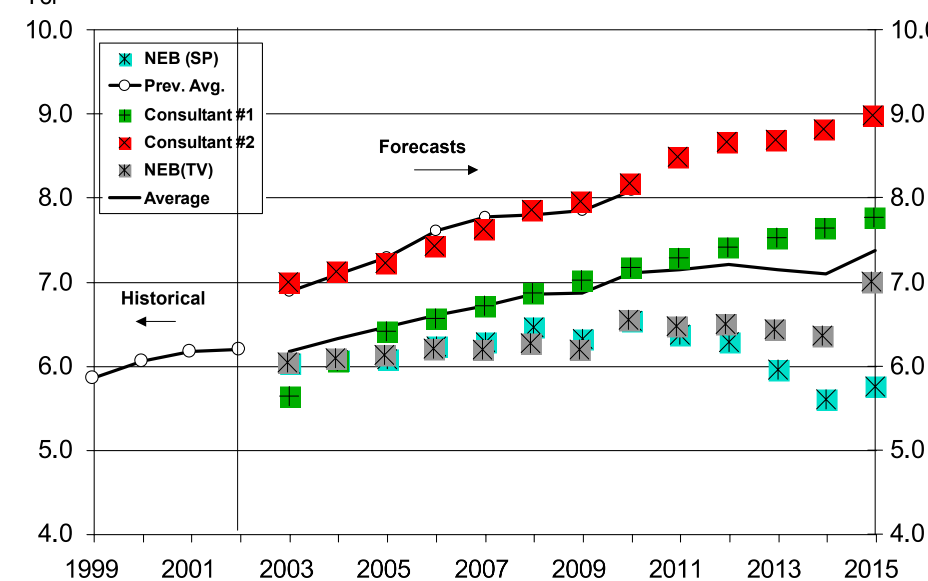
Figure 47 shows three forecasts for US gas production. The average sees US production increasing to 22.1 Tcf or 1.3% per year over the forecast period.

The average of the previous year's forecast showed US gas production at 23 Tcf by 2010, greater than the current forecast view for 2015.

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 some industry observers.

Figure 48
Canadian Natural Gas Production Forecasts



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

Figure 48 shows 3 forecasts of Canadian gas production. The average of the forecasts shows Canadian production reaching 7.4 Tcf by 2015. This represents an average annual increase of 1.5%.

The average of the previous year's forecast showed Canadian gas production at about 8 Tcf by 2010, greater than the current forecast at 2015.

Downgraded forecasts can be attributed to a maturing WCSB, in which production declined in 2002, as well as uncertainties regarding natural gas reserves and supply in Atlantic Canada.

Table 13
Possible LNG Import Terminals

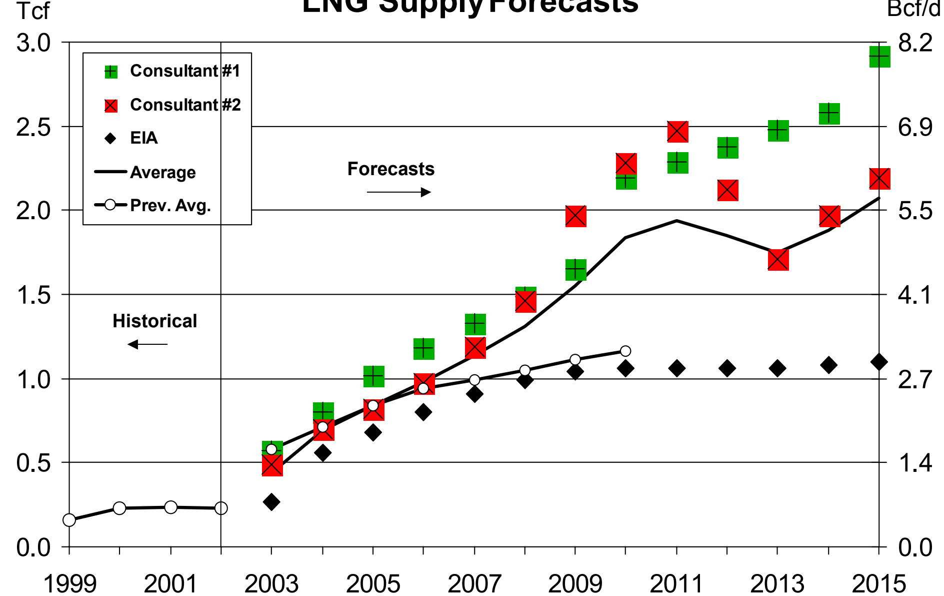
Operator (Name)	Location	Send-Out Capacity (Bcf/d)	Earliest Start Date	Principal Supplier
ConocoPhillips (Rosarito)	Baja California, MX	0.75	2006	Indonesia
Marathon Oil (Tijuana)	Baja California, MX	0.75	2006	Indonesia
Sempra (Costa Azul)	Baja California, MX	1.00	2006	Bolivia, Pacific Basin
Royal Dutch/Shell (Ensenada)	Baja California, MX	0.75	2006	Southern Pacific Basin
Cheniere (Corpus-Christie)	Texas	2.00	2007	Trinidad, Venezuela
Cheniere (Freeport)	Texas	1.00	2007	Trinidad, Venezuela
Sempra (Cameron)	Louisiana	0.75	2007	Nigeria, Qatar
AES (Ocean Express)	Bahamas	0.85	2006	Nigeria, Trinidad
Irving Oil (Canaport)	St.John, NB	0.50	2006	Atlantic Basin
Access Northeast (Canso Strait)	Point Tupper, NS	0.75	2007	Atlantic Basin
TransCanada and ConocoPhillips (Fairwinds)	Harpswell, Maine	0.50	2009	Atlantic Basin
Total Capacity		**9.60**		

Sources: EIA, Office of Oil and Gas, January 2003, Lukens Energy Group, Industry Press and Company websites. **Note:** Other import projects are also being considered.

Due to concerns regarding short-term natural gas supply, LNG is being considered as a viable option to domestic supplies. As of June 2003, the Department of Energy reported 25 planned or proposed terminals.

At least three Canadian entities – Irving Oil, Access Northeast Energy, and TransCanada – have plans to build LNG projects in Canada and the US.

Figure 49
LNG Supply Forecasts



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

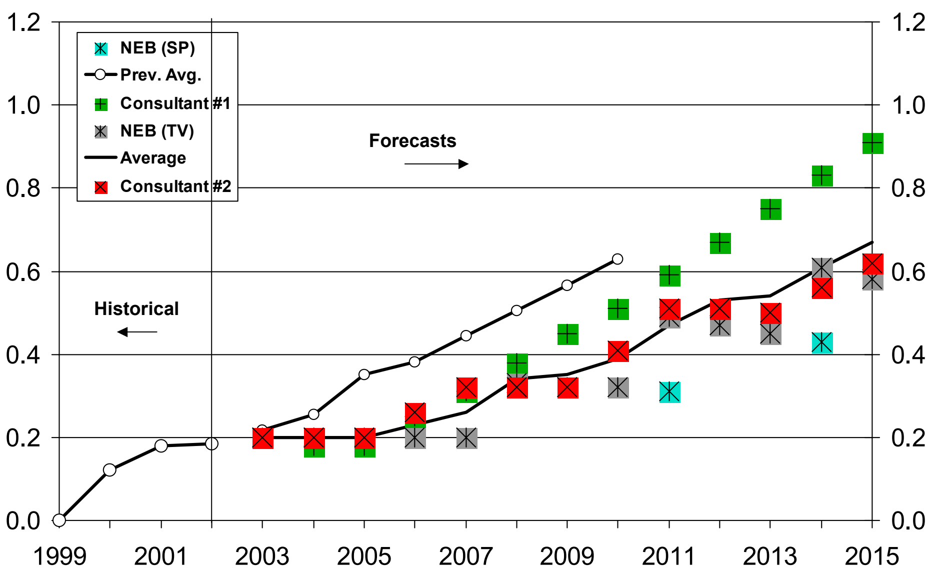
Figure 49 shows three forecasts of LNG supply, as well as the average forecast and the previous year's average.

An average of various forecasts sees LNG imports to the US reaching more than 2 Tcf by 2015.

The average forecast in our report last year showed US LNG supply at 1.2 Tcf by 2010, compared to the current forecast of 1.8 Tcf by 2010. Upward revised forecasts can be attributed to concerns regarding North American natural gas production.

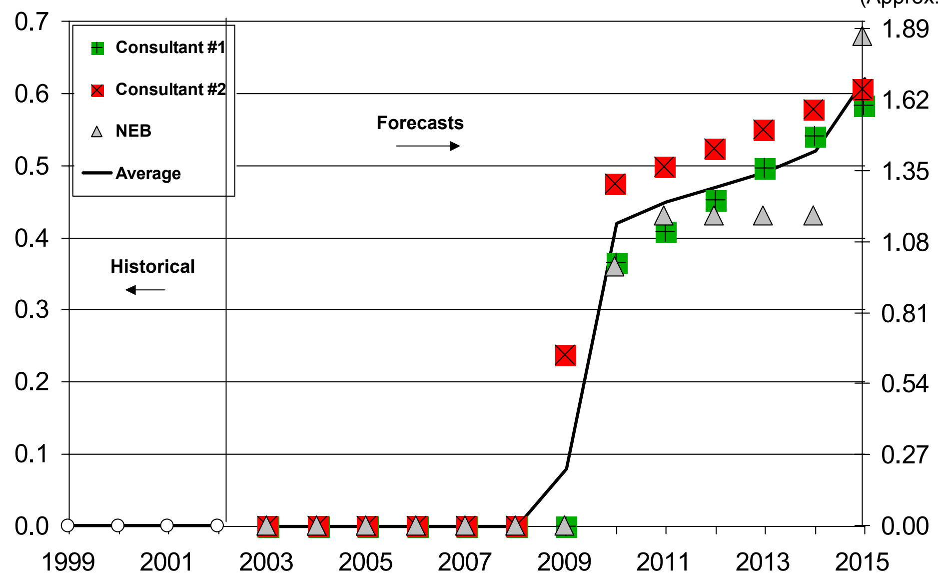
Sharper LNG growth can also be attributed to the re-activation in 2001 and 2003 of the Elba Island and Cove Point LNG receiving terminals, respectively.

Figure 50
Scotian Shelf Supply Forecasts



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

Figure 51
Mackenzie Delta Supply Forecasts



Sources: NEB and various consultants.

The figure above shows three forecasts of Scotian gas supply, as well as the average forecast and the previous year's average.

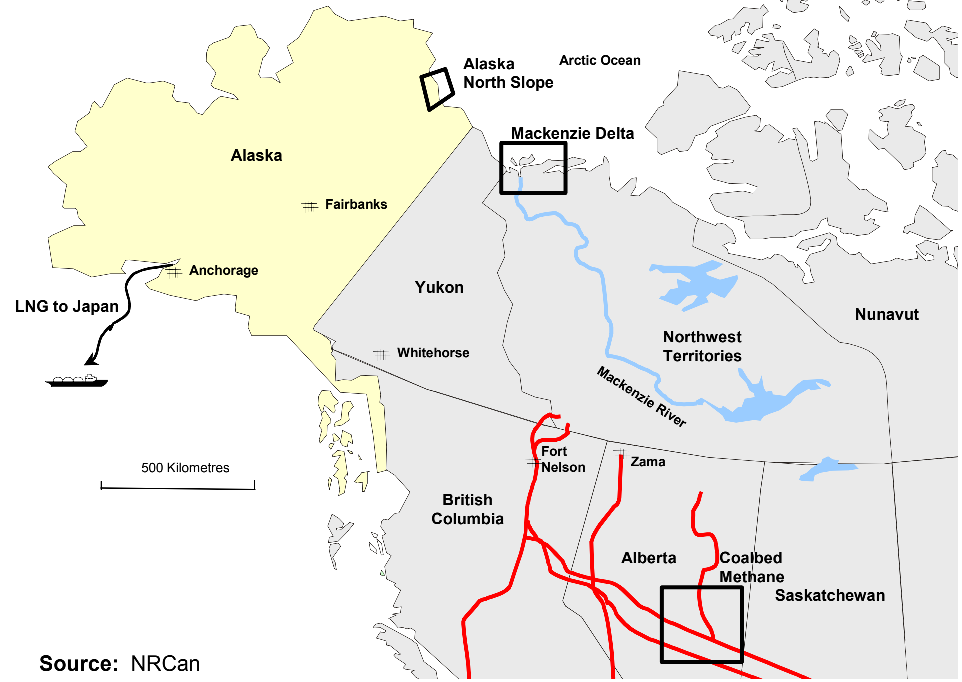
The average of the forecasts shows Scotian Shelf supply at nearly 0.7 Tcf by 2015.

The average forecast in our report last year showed Scotian Shelf supply at 0.63 Tcf by 2010, compared to the current forecast of 0.53 Tcf by 2010. Downward revised forecasts can be attributed to recent setbacks, including EnCana's decision to postpone its Deep Panuke project, Shell Canada's downgrading of reserves at the Sable Island natural gas project, and poor exploration drilling results.

Figure 51 above shows three forecasts of MacKenzie Delta gas supply, as well as the average forecast.

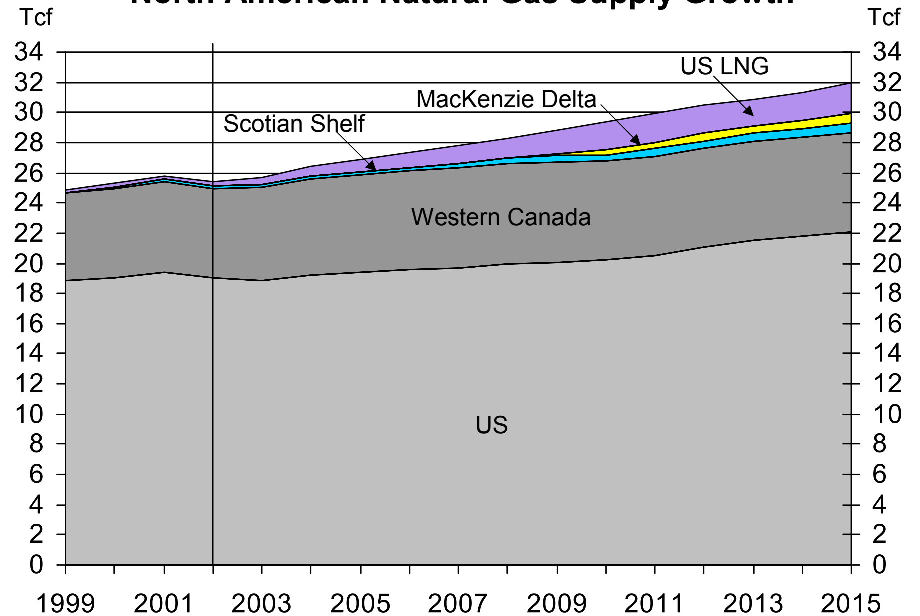
Of the forecasts surveyed, the earliest MacKenzie Delta gas supplies would arrive is 2009. The average of the forecasts shows MacKenzie Delta gas supply at about 0.62 Tcf, or slightly more than 1.6 Bcf/day by 2015.

Map 6
Possible Incremental Gas Sources



Source: NRCan

Figure 52
North American Natural Gas Supply Growth[1]



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

Other possible sources of gas supply include northern gas and coalbed methane (CBM).

With no pipeline application to date, many forecasts to 2010 do not include Alaska's North Slope gas. However, there is a possibility that MacKenzie Delta gas will flow by 2009, and many forecasts do include MacKenzie Delta gas after 2010.

To date, estimates show that approximately 10-15 CBM pilot projects have been or are currently operating in Alberta, with about 300 wells drilled. A recent estimate shows Canadian CBM gas production, the majority in Alberta, at between 15 and 25 Million cubic feet (MMcf) per day.

Averaging various US and Canadian gas supply forecasts results in a "consensus" forecast of North American gas supply of 29.5 Tcf by 2010 and about 32 Tcf by 2015.

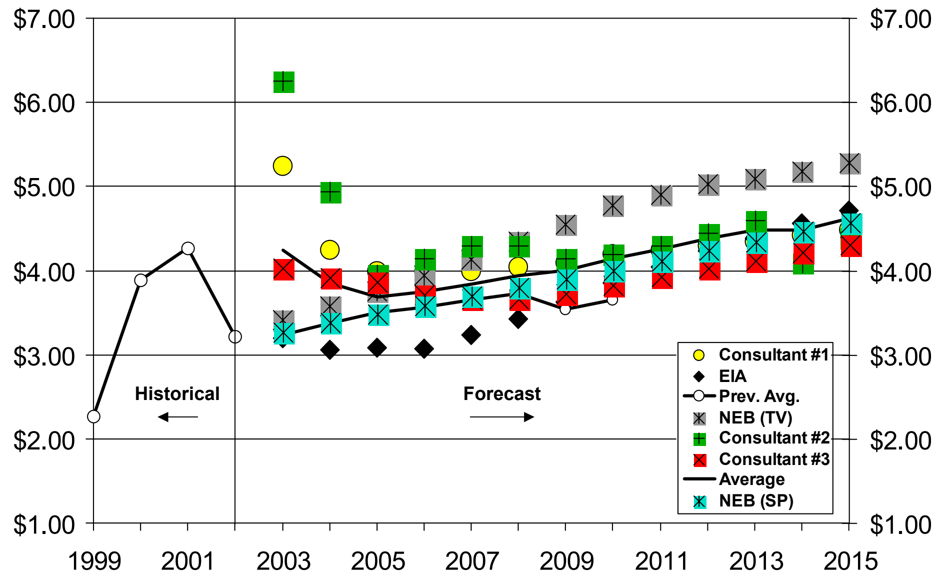
The current "consensus" view of North American natural gas supplies is less than last year's forecasts, which resulted in a "consensus" forecast of 32.2 Tcf by 2010.

Given Canadian supply concerns, especially in the maturing WCSB, coupled with the recent uncertainty surrounding east coast gas, it is expected that LNG, CBM and MacKenzie Delta gas will help play a role in the overall North American supply picture in the years ahead.

Outlook to 2015

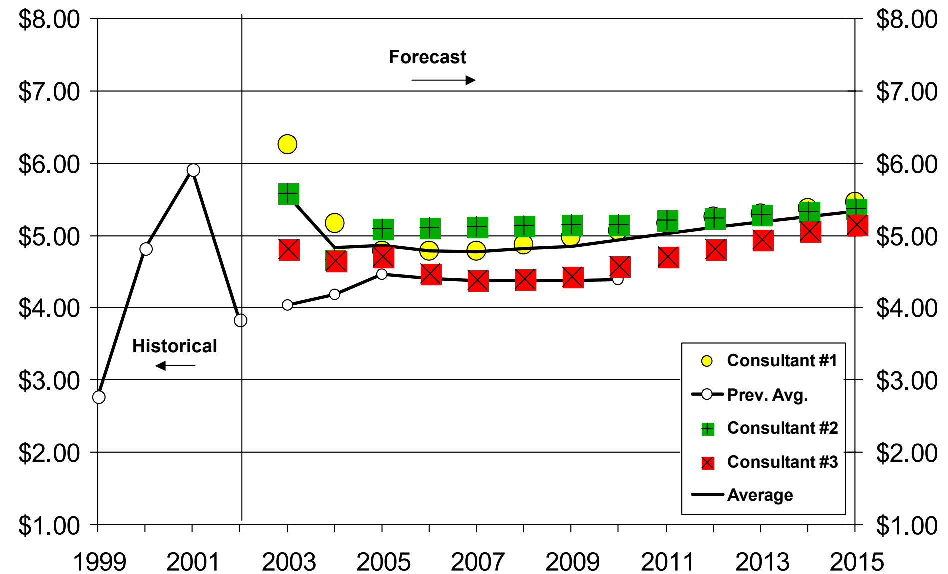
Natural Gas Prices

Figure 53
US Natural Gas Price[1] Forecasts



Sources: EIA, NEB and various consultants. **Notes:** (1) 1998-02 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 54
Canadian Natural Gas Price[1] Forecasts



Sources: Various consultants. **Notes:** (1) 1998-02 are AECO actuals from GLJ. (2) Forecast prices are Alberta. (3) Some forecasts were converted from $US. (4) Nominal dollars.

Figure 53 compares five nominal dollar forecasts of US natural gas prices. The average shows that US prices are expected to be higher than 2002 levels in the short-term, as well as over the entire forecast period.

According to the forecasters surveyed, prices are expected to average US$4.25/MMBtu in 2003. Between 2004 and 2015, US gas prices are expect to average between US$3.70 and $4.60/MMBtu.

Compared to our survey last year, US price expectations have risen again. Last year, the average price outlook for 2010 was US$3.65/MMBtu, 14% lower than the 2010 forecast price this year – US$4.15/MMBtu.

Figure 54 compares three nominal dollar forecasts of Canadian natural gas prices at the AECO-C hub in Alberta.

Prices are expected to average approximately CDN$5.50/GJ in 2003, then decline slightly to average about CDN$5/GJ over the forecast period.

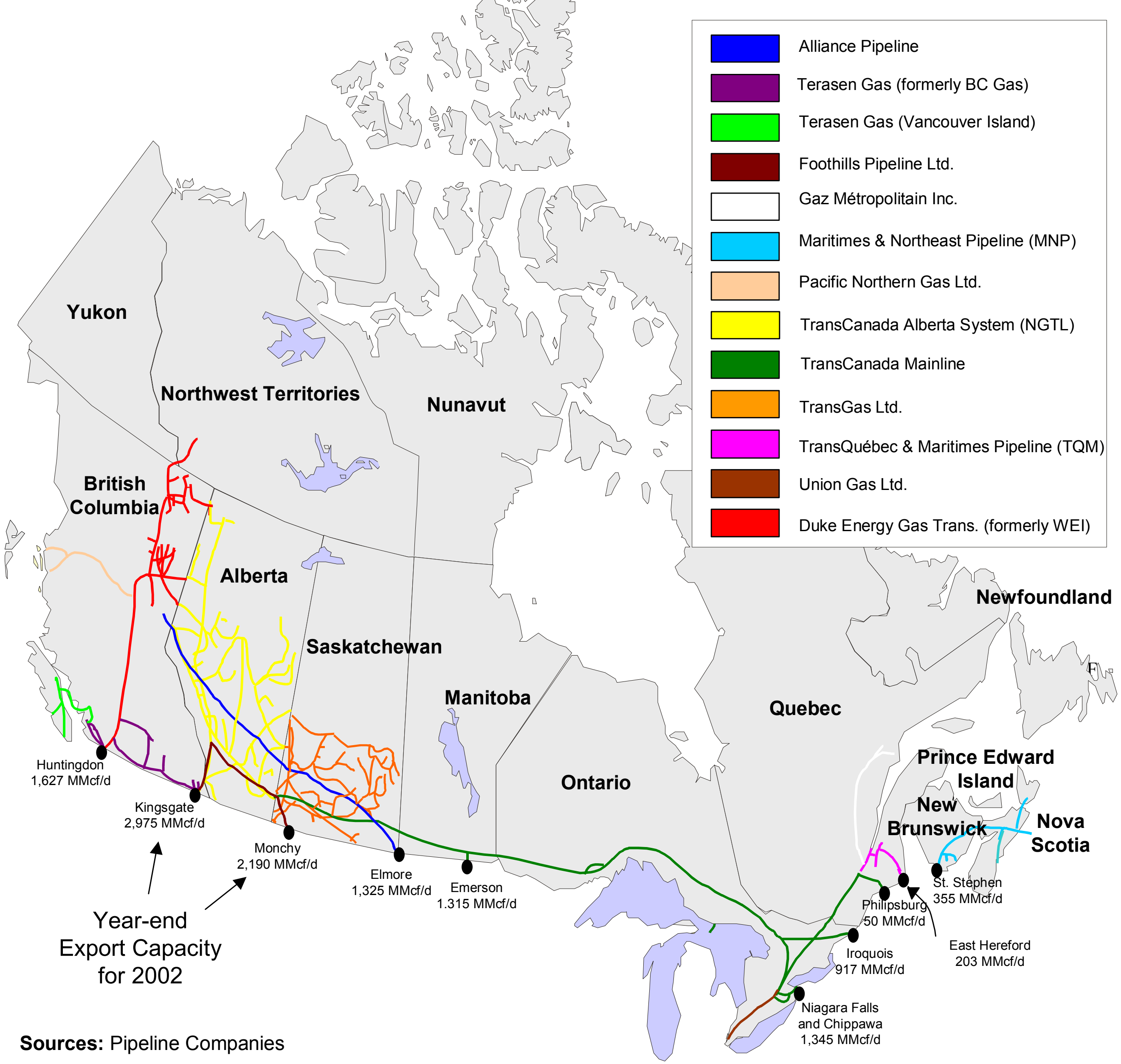
The average forecast for 2010 and 2015 sees gas prices at CDN$4.94/GJ and CDN$5.33/GJ, respectively.

Compared to our survey last year, Canadian price expectations have risen. Last year, the average price outlook over the forecast period was about CDN$4.30/GJ.

Outlook to 2015

Canadian Export & Domestic Sales

Map 7
Major Canadian Natural Gas Pipelines and Export Pipeline Capacity



Sources: Pipeline Companies

The location of Canadian natural gas pipelines (transmission and distribution), as well as year-end export capacity at major border points are presented on the map.

The Canadian gas market is served by seven major transmission pipelines (Duke Energy Gas Transmission, TCPL, 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 2002, the 'Alberta System' delivered 11.2 Bcf/d of natural gas.

Kingsgate and Monchy were the largest export points in terms of year-end 2002 capacities.

Table 14
Export Pipeline Capacity

(MMcf/d)	2001	2002		2003		2004-2015	
	Year end Capacity	Increment	Year end Capacity	Increment	Year end Capacity	Increment	Year end Capacity
Huntingdon (Westcoast)[1]	1,627		1,627	84	1,711		1,711
Kingsgate (Foothills/ANG)[2]	2,680	295	2,975		2,975		2,975
Total US West	**4,307**	**295**	**4,602**	**84**	**4,686**		**4,686**
Monchy (Foothills)	2,190		2,190		2,190		2,190
Emerson (TCPL)	1,305		1,315		1,315		1,315
Elmore (Alliance)[3]	1,325		1,325		1,325		1,325
Miscellaneous[4]	300		300		300		300
Total US Midwest	**5,120**		**5,130**		**5,130**		**5,130**
Iroquois (TCPL)	894		917		917		917
Niagara Falls (TCPL)	845		845		845		845
Chippawa (TCPL)	500		500		500		500
St. Stephen (MNP)[5]	355		355		355	400	755
E. Hereford (TCPL)	198		203		203		203
Cornwall (TCPL)	63		63		63		63
Napierville (TCPL)	61		61		61		61
Phillipsburg (TCPL)	50		50		50		50
Highwater (TCPL)[6]	0		0		0		0
Total US Northeast	**2,966**		**2,994**		**2,994**	**400**	**3,394**
Total Export Capacity	**12,393**	**295**	**12,726**	**84**	**12,810**	**400**	**13,210**

Sources: Pipeline Companies. Note that year-end MMcf/d capacity represents approximate contracted daily volumes that could be delivered on the last day of the year. Capacity additions are generally completed on November 1. **Notes:** 1 - Westcoast expansion scheduled to be completed November 1, 2003. 2 - TCPL expansion completed November 1, 2002. 3 - Alliance has authorized overrun capacity service (AOS) that is offered to firm shippers. This typically averages 212 MMcf/d. However, due to compressor problems in 2002, Alliance averaged about 145 MMcf/d of AOS. 4 - Miscellaneous Midwest includes 9 export points with over 500 MMcf/d of capacity. These export points are not intended to be used at high load factors, and so we use a lower number in the table. 5 - St.Stephen export point typically flows at 387 MMcf/d, which is greater than contract capacity. 6 - Highwater was shut down in February 2001.

Total physical export capacity reached 12,726 MMcf/d by the end of 2002, an increase of nearly 3% from the previous year.

The expansions shown in the table have all had formal applications filed with regulators.

The largest is the expansion of MNP, to handle volumes from EnCana's Deep Panuke project, which has temporarily been put on hold. Additional expansions may occur.

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 15
Export Volumes and Domestic Sales

(Bcf)	1999	2000	2001	2002	2003	2004	2005	2010	2015
Huntingdon (Duke)	402	356	324	336	-	-	-	-	-
Kingsgate (Foothills/ANG)	805	833	781	700	-	-	-	-	-
Total US West	**1,207**	**1,189**	**1,105**	**1,036**	**-**	**-**	**-**	**-**	**-**
Monchy (Foothills)	773	784	744	762	-	-	-	-	-
Emerson (TCPL)	487	491	390	389	-	-	-	-	-
Elmore (Alliance)	0	73	526	560	-	-	-	-	-
Miscellaneous	67	30	31	36	-	-	-	-	-
Total US Midwest	**1,327**	**1,378**	**1,691**	**1,747**	**-**	**-**	**-**	**-**	**-**
Iroquois (TCPL)	357	363	319	319	-	-	-	-	-
Niagara Falls (TCPL)	361	423	326	326	-	-	-	-	-
Chippawa (TCPL)	44	37	54	104	-	-	-	-	-
St. Stephen (MNP)	0	117	141	140	-	-	-	-	-
E. Hereford (TCPL)	17	34	39	47	-	-	-	-	-
Cornwall (TCPL)	9	8	9	9	-	-	-	-	-
Napierville (TCPL)	19	19	33	20	-	-	-	-	-
Phillipsburg (TCPL)	6	8	6	7	-	-	-	-	-
Highwater (TCPL)	2	15	5	0					
Total US Northeast	**815**	**1,024**	**932**	**972**	**-**	**-**	**-**	**-**	**-**
Total Gross Exports	**3,349**	**3,591**	**3,728**	**3,755**	**3,470**	**3,531**	**3,545**	**3,724**	**3,561**
Total Canadian Demand	**2,700**	**2,872**	**2,697**	**2,708**	**2,955**	**3,053**	**3,161**	**3,633**	**4,057**
Imports to Canada	**49**	**80**	**228**	**273**	**250**	**250**	**250**	**250**	**250**
Total Net Exports	**3,300**	**3,511**	**3,500**	**3,482**	**3,220**	**3,281**	**3,295**	**3,474**	**3,311**
Total Domestic Sales	**2,651**	**2,792**	**2,469**	**2,435**	**2,705**	**2,803**	**2,911**	**3,383**	**3,807**
Total Sales	**6,000**	**6,383**	**6,197**	**6,190**	**6,175**	**6,334**	**6,456**	**7,107**	**7,368**

Sources: Historical information from NEB and StatsCan. **Note:** Domestic sales equal to Canadian demand less imports. Also, gross exports plus domestic sales equal to total sales.

Table 15 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, this year, the export forecast was determined based simply on “consensus” forecasts of Canadian demand and production.

Using this approach, gross exports would remain relatively flat over the forecast period, reaching 3.72 Tcf by 2010, then falling to 3.56 Tcf by 2015. Decreased export volumes between 2010 and 2015 can be attributed to a “consensus” view that demand will grow at a faster rate than production over this 5 year time period.

Table 16

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$)
1998	3,111	$2.16	$1.92	$1.58	$4,931	$7,317
1999	3,349	$2.27	$2.19	$1.88	$6,299	$9,348
2000	3,593	$3.89	$3.85	$3.51	$12,660	$18,931
2001	3,728	$4.27	$4.30	$3.94	$14,797	$22,759
2002	3,755	$3.22	$3.06	$2.72	$10,294	$16,156
2005	3,545	$3.71	$3.61	$3.31	$11,734	$17,779
2010	3,724	$4.05	$3.95	$3.65	$13,593	$20,287
2015	3,561	$4.50	$4.40	$4.10	$14,600	$21,791

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$)**
1998	2,560	$1.36	$1.21	$3,117	$4,640	**$11,957**
1999	2,651	$1.96	$1.81	$4,820	$7,160	**$16,508**
2000	2,792	$3.40	$3.25	$9,109	$13,526	**$32,457**
2001	2,469	$4.05	$3.90	$9,700	$15,020	**$37,779**
2002	2,435	$2.58	$2.43	$5,964	$8,582	**$24,738**
2005	2,911	$3.04	$2.89	$8,417	$12,753	**$30,532**
2010	3,383	$3.14	$2.99	$10,109	$15,088	**$35,376**
2015	3,807	$3.39	$3.24	$12,321	$18,389	**$40,180**

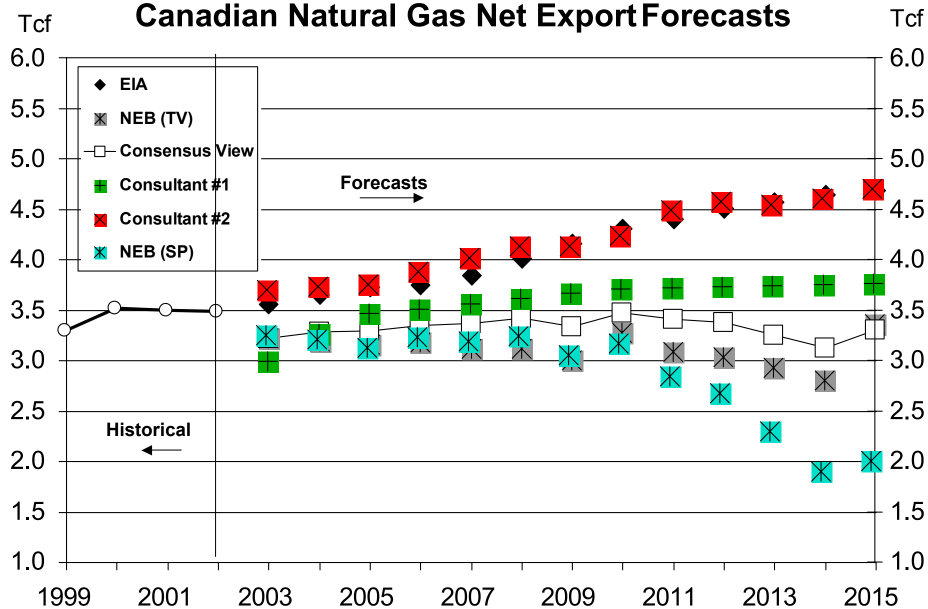
Notes: Historical export information is from NEB data. Historical domestic netbacks are estimates only, and were calculated using Alberta prices, less US $0.15/MMBtu to yield a plantgate netback, which was then multiplied by domestic sales for a revenue estimate. Future domestic netbacks and revenues 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 $US0.66 per $CDN for 2003-2005 and $US0.67 per $CDN for 2006-2015. Note that domestic sales assumed to equal Canadian demand less imports. Imports are assumed to equal 250 Bcf/year over the forecast period.

The table above provides our estimates of producer plant gate revenues to 2015, given "consensus" forecasted gas prices and NRCan's estimated export volumes and domestic sales.

Total plant gate revenues decreased by 35% in 2002. According to price and volume forecasts, producer revenues will surpass 2001 levels over the outlook period. Predictions for higher forecasted revenues are mainly the result of higher gas price outlooks.

Figure 55

Canadian Natural Gas Net Export Forecasts



Sources: EIA, NEB, and various consultants. **Note:** (1) EIA and Consultant #2 forecasts are gross export figures. (2) NEB export forecasts were deduced from Canadian production and demand projections contained in the NEB's latest supply/demand report. (3) Historical numbers from NEB.

Figure 55 shows various forecasts of Canadian natural gas exports, including the export forecast calculated in Table 15. The average of the net export forecasts shows Canadian gas net exports equaling 3 Tcf by 2015.

The "consensus" view shows Canadian gas net exports falling to 3.2 Tcf in 2003, reaching 3.3 Tcf by 2015. This forecast was generated by simply calculating the difference between the "consensus" views of Canadian gas production and demand.

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