Canadian Natural Gas

Review of 1997 & Outlook to 2005

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Natural Gas Division
Energy Resources Branch
Natural Resources Canada

CANADIAN NATURAL GAS:
REVIEW OF 1997 & OUTLOOK TO 2005

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Foreward

Canadian Natural Gas: Review of 1997 and Outlook to 2005 is an annual working paper of the Natural Gas Division of the Energy Resources Branch, Natural Resources Canada. It provides summaries of North American natural gas industry trends, including supply, demand, storage, gas flows, prices, transportation capacities, as well as Canadian gas export volumes, prices, and revenues.

Our report this year continues to focus on regional natural gas markets, as the issues of natural gas price differentials, gas market integration, and the need for large expansions of natural gas pipeline capacity between markets remain important. We have extended the outlook period to 2005. Our demand analysis this year provides considerable detail on the drivers of gas consumption, by sector, for each region in Canada and the U.S. This year's report also includes a regulatory analysis section. Some recent regulatory events will have important effects on natural gas markets.

Various sources were used in preparing this report, including private consultants, industry associations, and federal government agencies in Canada and the United States. Our main sources of statistical data were the National Energy Board (NEB), the U.S. Energy Information Administration (EIA), and Statistics Canada (StatsCan). Gas prices are generally quoted in US$/MMBtu, which is the most-used pricing unit in the North American industry. Selected prices are also given in CDN$/Gigajoule.

To obtain a copy of this report, call 613-992-9612, or fax us at 613-995-1913. Our mailing address is: Natural Gas Division, Energy Resources Branch, Natural Resources Canada, 17th floor, 580 Booth Street, Ottawa, Canada, K1A 0E4. To view other Natural Gas Division reports, visit our website at http://www.es.nrcan.gc.ca/erb/ngd/homepage/home.html. This report will also be available at the above web address.

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Executive Summary & Conclusions

In 1997, the Canadian natural gas industry maintained its role as one of the two most important supply regions in North America. The production and sale of gas makes a substantial contribution to Canadian petroleum industry revenues, and will continue to do so in the coming years.

Natural gas demand growth (+0.3%) was very weak in 1997, much lower than rates that had prevailed in the recent past, and well below the pace which is expected over the next 8 years. Last year's results are partly explained by a mild winter. Gas *supply* was surprisingly tight, given the weakness in demand. The firmness of U.S. gas prices suggests that supply growth in 1997 only just kept pace with poor demand growth.

For the future, important structural changes taking place in U.S. markets will increase demand. The shift in population to the U.S. south will increase residential demand in these areas. At the same time, gas-fired electricity generation is expanding to meet incremental power requirements, and to replace existing facilities.

U.S. and Canadian gas consumers will rely on Canada and the U.S. Gulf Coast to satisfy the bulk of incremental demand. These areas were the principal suppliers of incremental gas in 1997. However, over the last year the price of gas in the U.S. Gulf was roughly 190% of the western Canadian price. Only a lack of export pipeline capacity kept Canadian producers from delivering higher volumes to the U.S.

The disparity between Canadian domestic and export prices signaled the need for investment in additional transmission capacity. The industry has responded in both Canada and the U.S. with proposals for new and expanded pipelines. At the same time, regulators in both countries are working to design regulatory systems that will allow economic signals to encourage new capacity and allocate existing capacity efficiently.

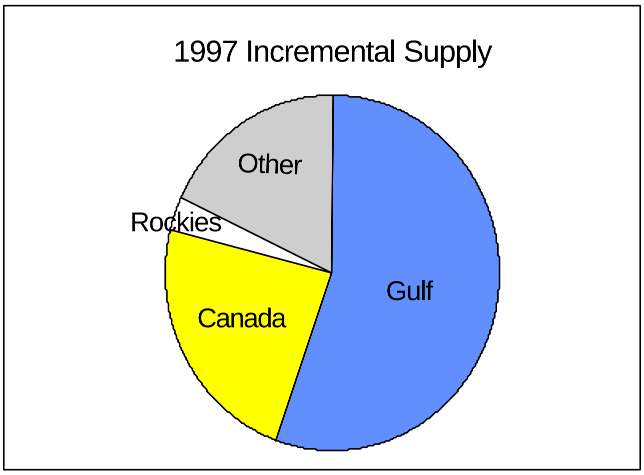
Forecasters predict strong revenue growth for Canadian natural gas sales. This is based on higher sales volumes and prices. Higher Canadian gas sales will be required to meet Canadian and export market demand growth. Higher prices are expected to result from new pipeline capacity to U.S. markets, which will cause strong linkages between Canadian and U.S. gas prices.

Review of 1997

Supply

In 1997, U.S. gas supply was tight relative to demand, and gas prices remained high. Canadian gas was restricted from capturing U.S. demand growth by a lack of pipeline capacity. Existing export pipelines are effectively full. For the second year in a row, the U.S. Gulf Coast captured most demand growth. Until recently, supplies from Canada and the U.S. Rockies had been increasing market share at the expense of the Gulf and other producing regions.

While pipeline limitations have affected Canadian supply, producers in the Rockies are facing production problems. They had been achieving volume increases of 10% per year in the past. However in 1997 production was flat

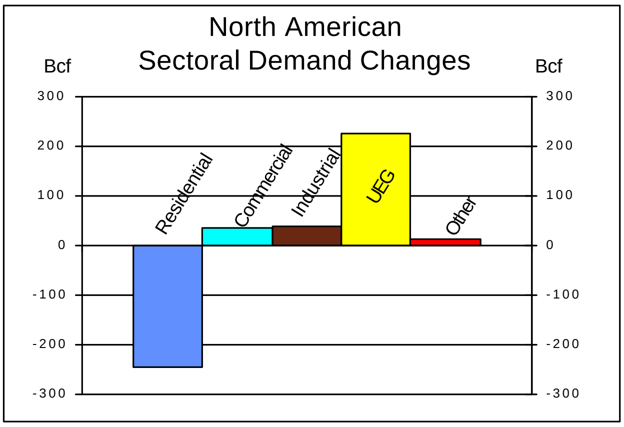


compared with 1996. The coalbed methane play in the New Mexico part of the Rockies is maturing, and New Mexico gas production has fallen for two years in a row.

Gas consumers' reliance on high cost Gulf supply to meet incremental requirements was one factor sustaining high prices in the U.S. during 1997. Gas traded on the New York Mercantile Exchange (NYMEX) averaged US$2.59/MMBtu[1], identical to 1996.

These price levels encouraged high U.S. gas drilling rates, which were 150% of 1994 levels. However, incremental U.S. production was slow in coming due to: poor drilling results in some regions; very high decline rates on existing wells; and a lack of offshore pipelines for offshore gas discoveries.

Demand
North American demand grew only 0.3% in 1997, down from 3% annual average growth over the previous five years. Demand fell in the residential sector, and was flat in the industrial and commercial sectors. An increase in Utility Electricity Generation (UEG) demand almost counterbalanced the drop in residential volumes.



A combination of short-term and long-term factors influence natural gas demand from year to year. Winter weather, measured in heating degree days (HDDs) is the critical short-term determinant of residential, commercial and industrial demand. A drop in HDDs in 1997 had a marked negative effect on gas usage. UEG demand increased more than our models predicted, suggesting that a long-term structural change in gas demand is taking place in this sector.

Storage
At the beginning of the 1997/98 heating season, some gas traders considered storage balances (held in part to meet heating season demand) to be low with respect to expected winter requirements. As a result, the NYMEX price rose to $3.35 by October. This turned out to be the high point of prices during the winter, as the El Nino weather event curtailed normal winter gas demand.

Gas Flows & Pipeline Capacity
Canadian gas flows remained stable during the past year. In both the short and medium-term, export pipeline capacity is expected to expand substantially, and gas flows from Canada into U.S. markets will increase accordingly. In 1997 Canadian gas exports increased by only 2%. However, that increase represented 57% of Canada's incremental production during the year, and clearly indicates the importance of U.S. markets for the Canadian industry.

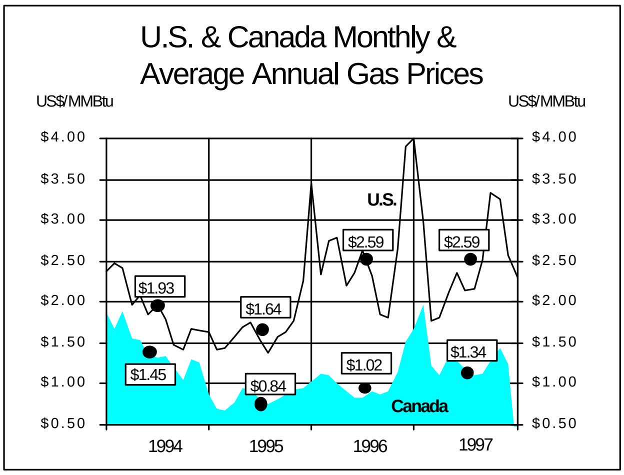
Although there were no major Canadian additions to pipeline capacity last year, 1.09 billion cubic feet per day (Bcf/d) of new capacity has been approved by regulators and is planned to be in service in 1998. Further, another 1.85 Bcf/d is either approved by regulators or under regulatory consideration for service in 1999 or 2000.

[1] U.S. dollars per million British thermal units of energy.

Within the U.S., higher demand for Gulf Coast gas led to increased use of pipeline corridors to U.S. West, Midwest, and Northeast markets. Gas flow from the Gulf increased by 5% in 1997. As a result, significant pipeline expansion from the Gulf has been proposed for the first time in many years. Discovery of new offshore Gulf supply has led to 5.2 Bcf/d of offshore pipeline capacity being proposed. In addition, supply development in the Rockies has resulted in project proposals with total capacity of 1.2 Bcf/d.

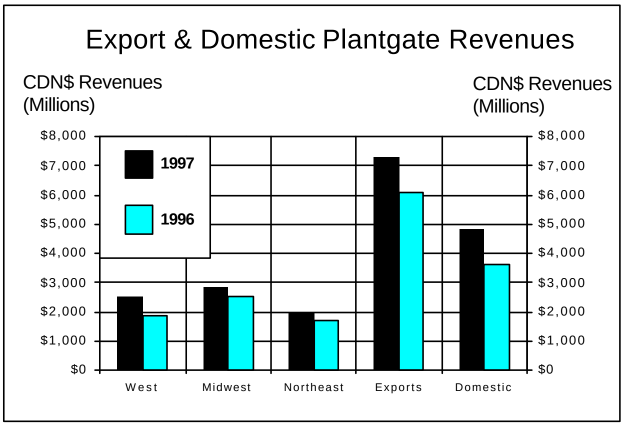
Natural Gas Prices

Average Canadian and U.S. prices remained widely separated throughout 1997. Due mainly to supply weakness in the U.S., and lack of pipeline capacity from Canada, prices remained high in U.S. markets; the NYMEX average was US$2.59/MMBtu. On the other hand, Canadian prices (Alberta) averaged only US$1.34/MMBtu (CDN$1.75/GJ). However this represented a 31% increase in Canadian prices, the result of shrinkage in the supply surplus, and the anticipation of new access to U.S. markets. Price differentials between Canadian and U.S. markets exceeded the cost of pipeline transmission to U.S. markets, indicating a lack of integration with those U.S. markets.



Sales of Canadian Gas

Producer plant gate revenues from total gas sales reached an all-time high of CDN$12.1 billion in 1997, an increase of 25% over 1996. The increase was due largely to price increases rather than greater sales volume. Canadian producers enjoyed increased prices domestically and in two of their main export markets. Prices in Canada and in the U.S. West rose by 30%, while prices in the U.S. Midwest increased by 10%, and Northeast prices were flat.



Outlook to 2005

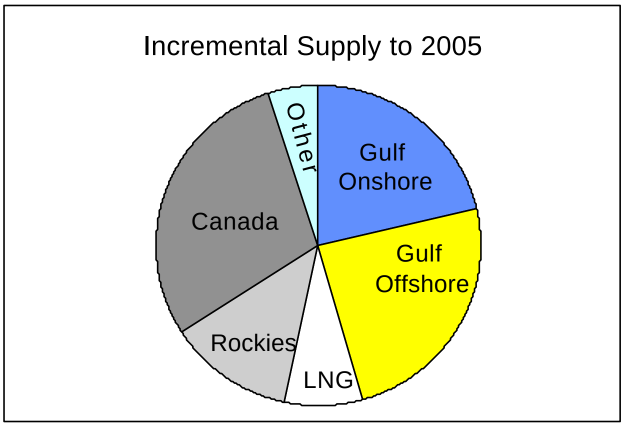
Demand

Over the next 8 years, gas demand is expected to increase by an average annual rate of 2%, down from the recent pace of 3% annually. The sectors of the economy that will lead the growth are electricity generation and industrial. The largest increments of new demand will occur in the U.S. Gulf Coast, Midwest, West, Northeast, and South Atlantic.

Supply

In order to meet demand growth, North American gas supply will have to be 4,662 Bcf more in 2005 than in 1997. The Gulf Coast would contribute 48% of that amount, while Canada would produce 31%. The remaining gas would come from the U.S. Rockies, Other U.S. regions, and LNG imports.

Supply and demand will balance in the markets, with adjustments to each determined by prevailing price levels. The above levels of supply and demand should therefore be viewed as rough guides to the future.



Gas Flows & Pipeline Capacity

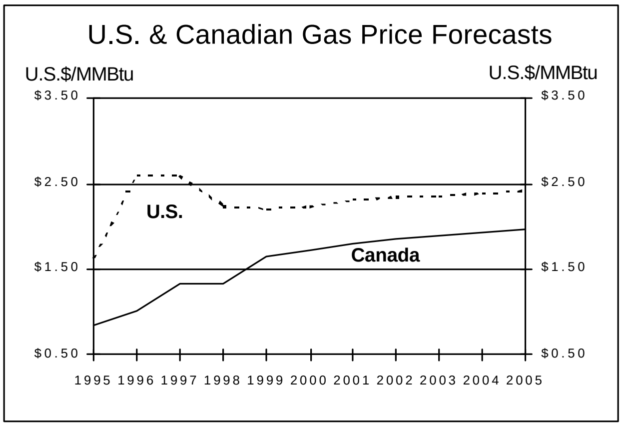
The construction of large blocks of pipeline capacity in the Gulf Offshore, as well as capacity additions from Western Canada and the U.S. Rockies to the U.S. Midwest, Northeast, and West will be necessary for incremental supply to reach markets. Most of the specific projects necessary to meet estimated requirements have at least been announced, some have been applied for, and others are well advanced in the regulatory process. It appears, however, that the U.S. West may need more capacity than is currently proposed.

Load factors on pipelines exiting the Gulf Coast should improve, as deepwater supplies begin to reach shore. Gulf producers are expected to supply all incremental market growth in the Gulf and Southwest, while the bulk of Midwest and Northeast market growth will be supplied from Canada.

Natural Gas Prices

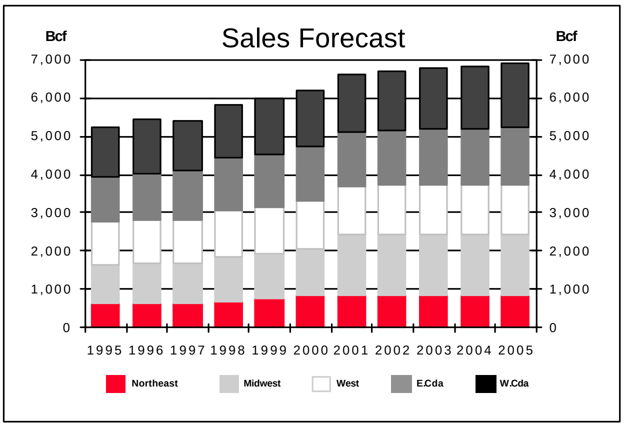
Our outlook is for continued volatility in U.S. natural gas prices, but without a return to the low prices of 1995. Supply is tighter now than at any point in the past. This is expected to keep prices close to finding and development costs. Experts see nominal U.S. gas prices remaining flat to 2005. Canadian producers are expected to benefit from stronger linkages with U.S. markets as export pipeline capacity is connected, and Canadian gas field prices are expected to increase by 5% per year to 2005.

It is important to note that the delivered price of gas to Canadian consumers contains a substantial pipeline and distribution cost component, often from 50% to 70%. The prices of these components are regulated and stable. Consequently, a 5% per year field price increase would only result in 1.5% to 2.5% per year increases in delivered prices.



Sales of Canadian Gas

Canadian producers can anticipate a combination of factors that should lead to strong revenue growth over the next 8 years. Canadian gas sales volumes are expected to increase 25% by 2005, with production reaching almost 7 trillion cubic feet (Tcf). Growth will be split between exports (61%) and domestic sales (39%).



If experts' views of gas prices are correct, producer revenues from export sales should increase in line with volume increases. Producer revenues from domestic sales should rise more dramatically. The volume increases will be combined with much stronger price increases, as Canadian producing areas are re-integrated with U.S. markets.

Regulatory Update

In Canada and the U.S., regulators are examining ways in which to make pipeline regulation a more accurate reflection of the economic forces at work in the industry.

There were a number of important developments during the year. Alberta's NOVA pipeline system is moving from a single postage stamp tolling system to a more distance-based method that more closely matches the cost of transmission with the toll. Tolls are also moving towards parity with the value of the service in the market. Under Westcoast Energy's new incentive rates settlement, tolls rise as gas prices rise. Other regulatory issues in 1997 were contract renewals on TransCanada's pipeline and intervenor funding in the regulatory process.

In the U.S., the Pacific Gas & Electric Gas Accord resolved disputes between Canadian producers and California buyers and regulators. FERC is also actively investigating ways in which it can permit pipelines to offer more differentiated services to customers through negotiated rates, terms and conditions. The Commission is also investigating ways to improve the operation of secondary markets for pipeline capacity.

An increasing share of U.S. pipeline capacity is contracted under short terms. This causes different dynamics in U.S. gas shipping decisions compared to Canadian gas shipping decisions. Where Canadian gas shippers hold long term contracts on pipelines and must pay demand charges whether gas is moved or not, there is a strong economic incentive to move the gas. This is less prevalent in the U.S., and gas tends to move only when it has significantly more value at the farther end of the pipe. This has coloured our views on future load factors for pipelines moving Canadian versus U.S. gas. We expect pipelines carrying Canadian gas to operate at higher load factors.

Introduction

Introduction

à Focus On Regional Gas Markets

In this report, we examine natural gas supply, demand, exports, prices, pipeline capacity, and other factors. In addition to looking at these factors in an overall North American context, we also examine the dynamics of several regional natural gas markets.

The North American gas market is not homogenous. It is made up of numerous geographic markets, each with different supply, demand, and price dynamics. An understanding of total U.S. supply is not sufficient information for someone to evaluate whether to purchase pipeline capacity along a certain route. Regional gas prices and their relationship to one another are of critical importance in today's gas industry.

Therefore, in addition to forecasts on overall North American trends, participants in today's gas industry require regional outlooks as well. In the past, certain gas markets have provided better gas prices to producers than others. Similarly, regional information on all features of gas supply, demand, and pricing is necessary in making many of the decisions that gas market participants and regulators routinely make.

à North American Benchmark Gas Market

The individual market which has the most influence in North America is the NYMEX Henry Hub futures market, where gas is bought and sold for delivery on the Gulf Coast of Louisiana. This market is well connected by large amounts of pipeline capacity to a large geographic area of the U.S., including the West, Midwest, Northeast, and Southeast.

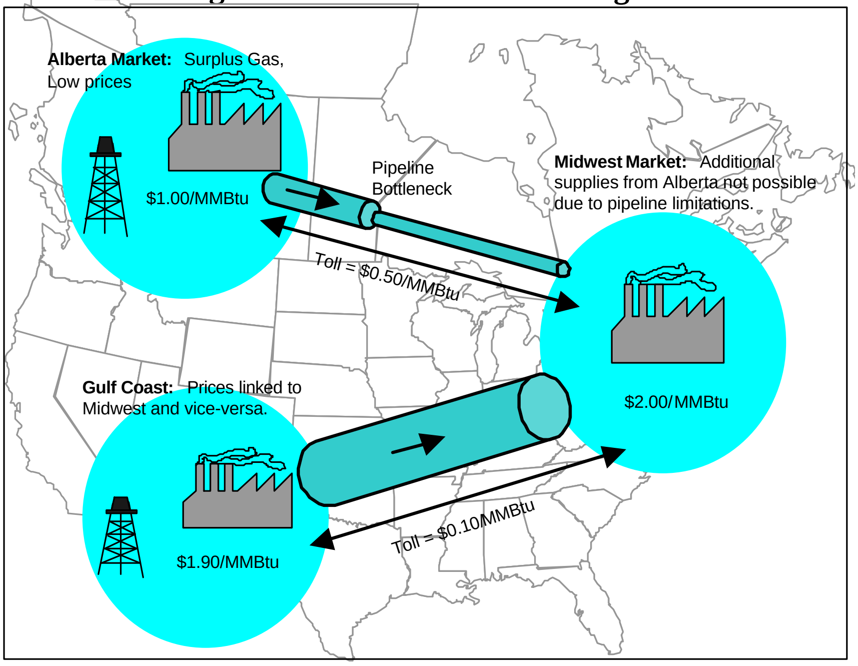
à Integration Of Gas Markets

In this large area, supply, demand, and price dynamics are able to integrate. Two gas markets are considered integrated when prices in those markets are strongly related to each other by virtue of being linked by sufficient pipeline capacity. Conversely, some gas markets are isolated from other markets due to a lack of adequate pipeline links.

This is illustrated in Figure 1. The Midwest and Gulf Coast markets are integrated, due to the large gas pipeline capacity linking them. Prices in these markets move in tandem, and balance at levels which reflect the costs of moving gas by pipeline from one market to the other.

For example, high gas demand and prices in the Midwest encourage higher gas flows northward from the Gulf Coast. Pipeline capacity to allow this is available. The additional draw on Gulf Coast supplies drives up prices in the Gulf, while the added Gulf gas moving into the Midwest drives

Figure 1: Integration Of Gas Market Pricing



Midwest prices down, until the two markets rebalance.

The last gas which must be purchased each month to satisfy Midwest demand must come from the Gulf, as pipes from other basins to the Midwest are full. The Gulf is the ***marginal supplier*** to the Midwest. To get this Gulf gas, Midwest buyers must pay Gulf prices, plus the Gulf to Midwest transportation cost. Thus, Midwest prices are typically equal to Gulf Coast prices, plus a certain transportation cost.

The Gulf has more pipeline capacity to markets than it has gas supply to fill those pipes. The Gulf can also be described as an ***overpiped supplier***.

Where pipeline capacity is inadequate, markets do not rebalance. The best example of this in recent years has been the intra-Alberta market, which is seldom in balance with NYMEX, Midwest, or Northeast markets. Alberta supply exceeds local demand plus exit pipeline capacity, which keeps the local market price low. Alberta can be said to be an ***underpiped supplier***.

Alberta prices cannot balance with those in downstream markets. Also, higher eastern market prices cannot be moderated by additional Alberta supply, since pipelines from Alberta are already full. Alberta fills its pipeline capacity to the Midwest each month. Alberta can be described as a ***baseload supplier*** to the Midwest.

Market regions can also be characterized according to their pipeline capacity situation. Markets where incoming pipeline capacity exceeds demand (i.e., the Midwest) are ***overpiped markets***. Growing gas markets, where pipeline capacity has not yet caught up to demand (i.e., South Atlantic) are ***underpiped markets***.

à Value Of Pipeline Capacity

Pipeline capacity between Alberta and the Midwest/ Northeast is very valuable. Gas can be bought at low Alberta prices and sold at high eastern prices, if pipeline capacity can be found.

The value of this capacity is equal to the price differential between the markets. In Figure 1, the value of pipeline capacity between Alberta and the Midwest is $2.00-$1.00 = $1.00/MMBtu. This is more than the regulated toll of $0.50/MMbtu in this example. As a result, there is demand for more Alberta-east pipeline capacity, and several large projects are in the works (e.g., Northern Border, Alliance, TCPL).

Obviously, changes in pipeline capacity will affect regional gas pricing and the integration between markets. However, changes in supply and demand are also important. For example, in a supply region originally well-integrated with NYMEX, growing supply could lead to pipeline capacity eventually becoming inadequate, and prices in the region becoming disconnected from NYMEX (i.e., falling well below NYMEX) as happened in Alberta.

In contrast, a region flooded with gas and out of sync with NYMEX could become relinked, if demand growth occurred within the region, or if production declined.

à Approach of This Report

Our approach is to examine supply, demand, pipeline capacity, and prices for selected North American gas market regions. We also review gas flows from one region to another. This provides insight into why certain regional gas markets provided better gas prices for Canadian exporters than others. It also gives Canadian gas buyers a better understanding of how the export gas market will affect domestic gas acquisition trends.

In the first half of this report, we examine gas market fundamentals for 1997. In the latter half of this report, we examine the outlook to the year 2005. Finally, we review important natural gas regulatory events of the past year.

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Review of 1997
North American Supply

Review of 1997 North American Supply

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à Supply Changes In 1997

North American natural gas supply grew 1.2% during 1997, as indicated in Table 1, for a total of 303 Bcf of incremental production. The bulk of the increase came from the onshore and offshore regions of the U.S. Gulf Coast. Canada, as has been typical over the past five years, also contributed significant incremental supplies (96 Bcf). In a departure from the trend of the past five years, the U.S. Rockies was not a major source of incremental supply. Rockies production increased only 12 Bcf over 1996. Midcontinent supply declined 106 Bcf, or 4%, continuing a well-established trend.

Although U.S. LNG imports increased 93%, the amounts involved are minor, as are Mexican gas imports.

à U.S. Gas Drilling

U.S. gas drilling is currently at ***very high*** levels relative to several years ago. Figure 2 examines gas prices and gas-directed drilling in the U.S. (the total U.S. rig count) and the Gulf Coast offshore since 1994. The scale for both total U.S. and Gulf offshore rig counts is the percentage of 1994 rig count levels. The Gulf offshore rig count averaged 61 rigs in 1994, while the total U.S. gas rig count was 427 rigs in 1994.

The U.S. total gas rig count at the end of 1997 was ***50% higher*** than in 1994. The Gulf offshore gas rig count was ***75% higher***.

Relatively high gas prices since late 1995 have led to higher and higher gas drilling rates, in the U.S. and the Gulf offshore. Drilling has continued to increase despite the fact that prices have remained in the same general range since late 1995. Operators obviously find recent gas prices sufficient to encourage drilling.

à U.S. Gas Production & Capacity

Figure 3 shows monthly U.S. gas production over this period of rapidly rising drilling. The rolling average production over the previous 12 months is also shown.

U.S. production is rising by only about 1% per year, in contrast to drilling, which has increased by 50-75% since 1994.

It could be argued that while production *growth* has been sluggish, production *capacity* has greatly increased. However, producers generally sell all the gas they can produce. Few producers will shut in production, because they face high fixed costs. Thus, if higher capacity existed, producers would be expected to try to market it, and this would moderate prices.

The fact that U.S. gas prices have remained consistently above $2/MMBtu suggests that gas

Table 1: North American Natural Gas Supply

	1997 (Bcf)	1996 (Bcf)	Difference (Bcf)	% Change	% of Total Increase	% N.A. Supply
Gulf Onshore	6,542	6,406	136	2.1	44.9	26.1
Gulf Offshore	5,465	5,371	94	1.8	31.0	21.9
Total Gulf	12,007	11,780	227	1.9	74.9	48.0
U.S. Midcontinent	2,415	2,521	-106	-4.2	-35.0	9.8
U.S. Rockies	2,864	2,852	12	0.4	4.0	11.7
Other U.S.	1,676	1,640	36	2.2	11.9	6.8
Total U.S. Production	18,962	18,793	169	0.9	55.8	77.2
Canadian Production	5,513	5,417	96	1.8	31.7	22.4
LNG Imports	78	40	38	93.3	12.4	0.3
Mexican Imports	15	14	1	4.3	0.2	0.1
TOTAL N.A. SUPPLY	24,567	24,264	303	1.2	100.0	100.0

supply is indeed tight.

This view is supported by a recent study by the Natural Gas Supply Association (NGSA) which surveyed 103 producers accounting for 60% of U.S. production. The sdy revealed that field capacity utilization increased from 94.1% in 1995 to 95% in 1996. NGSA estimated that due to pipeline limitations, field capacity could only be used at a maximum of 96.5%. In short, gas production is close to capacity.

There are two possible explanations for the divergence between rising U.S. drilling and flat U.S. production.

First, high drilling rates may be required simply to match declines from existing wells. Existing production is declining quickly, and drilling may be finding enough production to replace these declines, but not much more.

The second explanation is that the added drilling may be adding considerable incremental production capacity, but only *at the wellhead*. The wellhead capacity may not be able to reach markets, due to pipeline or gas plant bottlenecks.

As we will see in the regional detail on gas supply, both explanations have some merit.

à Regional Supply

The five supply regions examined in this report include the Gulf Coast Onshore and Offshore, the U.S. Midcontinent and Rockies, and Western Canada.

The boundaries of these regions are shown in Figure 4. Major sedimentary basins are also shown. The pie chart in Figure 4 shows the relative scale of regional production during 1997.

Regions were grouped into areas of similar sedimentary basins and producing characteristics. For example, gas wells in the Midcontinent region of the U.S. produce, on average, 125 Mcf per well per day. In contrast, the offshore wells of the U.S. Gulf Coast average 3.6 MMcf per well per day, or 29 times as much.

Because of these differences in producing characteristics, examining total U.S. gas wells drilled may not be useful. The effects of drilling can be more

Figure 2: U.S. Gas Drilling Trends

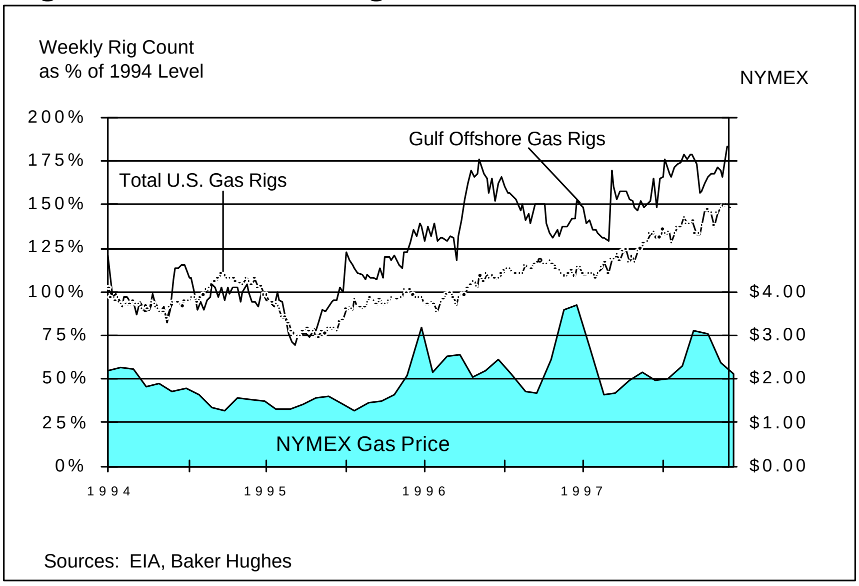
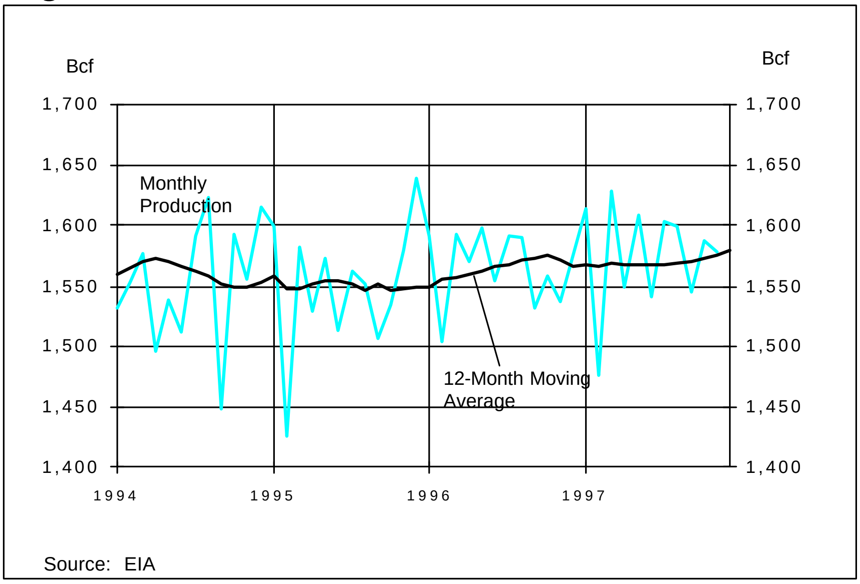


Figure 3: U.S. Gas Production Trends



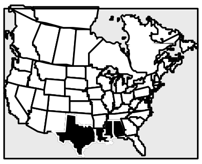
accurately assessed by using a regional approach.

à Gulf Coast

In 1997, the Gulf Coast was the most important North American supply region, accounting for 48% of total production, or 12,007 Bcf.

In a gas market sense, onshore and offshore gas from the Gulf are indistinguishable. We examine the onshore and offshore separately in the following paragraphs because their producing characteristics and production prospects are very different.

à Gulf Coast Onshore



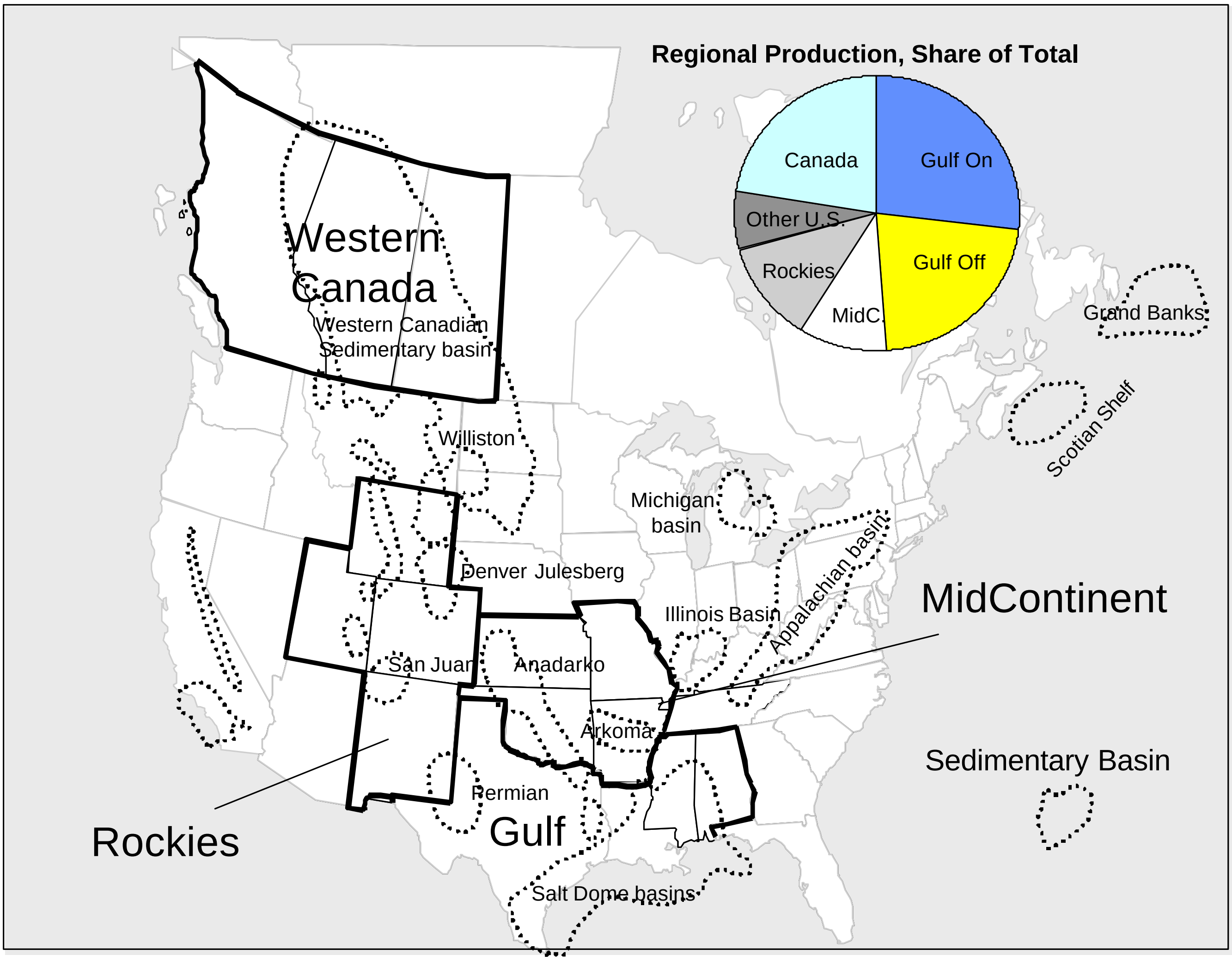
Gulf Coast Onshore production was 6,542 Bcf in 1997 (estimated), an increase of 136 Bcf over 1996. Since 1994, annual Gulf Onshore production has risen 359 Bcf, an annual rate of increase of 1.9%.

Pipeline access is not a major problem for Gulf Onshore producers. The region produced over 13,000 Bcf per year during its heyday in the early 1970s, and has adequate facilities to deliver gas to markets.

Unlike other industries, where installed capacity may remain fairly constant over time, in the natural gas industry existing production is always in a state of decline. For most gas wells, the production rate starts to deteriorate as soon as production begins. This means that a certain drilling level is required simply to maintain production at existing levels.

Decline rates differ from region to region. Decline rates in the Gulf Onshore are approximately 20% per year. In other words, Gulf Onshore gas deliverability would decline 20% in one year, if new gas wells were not

Figure 4: Supply Regions & Sedimentary Basins



connected.

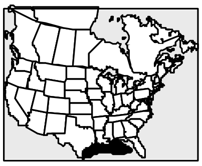
At a 20% decline rate, 1,308 Bcf of production needs to be replaced in the Gulf Onshore each year, just to maintain production at current levels. This makes production very sensitive to a period of slow drilling.

It is worthwhile to note that producers have deliberately accelerated their decline rates in recent years. Innovations such as horizontal drilling, multilateral completions, and optimizations of well locations via 3-D seismic or monitoring-while-drilling (MWD) have all led to faster recovery of gas from reservoirs. This is positive for producers, as reserves are converted to cash flows faster. However, this also leads to higher decline rates, and the requirement that more well deliverability be replaced each year.

Even with the high current drilling levels, Gulf Onshore production capacity is not rising very much. In a recent report[2], the U.S. Energy Information Agency (EIA) estimated that Gulf Onshore *capacity* increased by 3% in 1996. The base case forecast for 1997 was a further capacity increase of 10%. However, given recent high prices in the Gulf, and the observed production increase of only 2%, it seems doubtful that this capacity level was reached.

In summary, the Gulf Onshore is currently experiencing high levels of drilling primarily to maintain current production levels, given the high decline rates in the region. This drilling is also generating production gains of about 2% per year.

à Gulf Coast Offshore



Estimated 1997 Gulf Offshore production was 5,465 Bcf, an increase of 94 Bcf over 1996. Over the past three years, Gulf Offshore production has risen by 61 Bcf, for an average annual increase of 0.4%.

The Gulf offshore is the main swing producer in North America. High production rate offshore platforms can be shut in relatively easily, and offshore producers are the most likely to shut in or open up production in order to balance swings in market demand. This means that offshore Gulf Coast production is inherently difficult to monitor and predict.

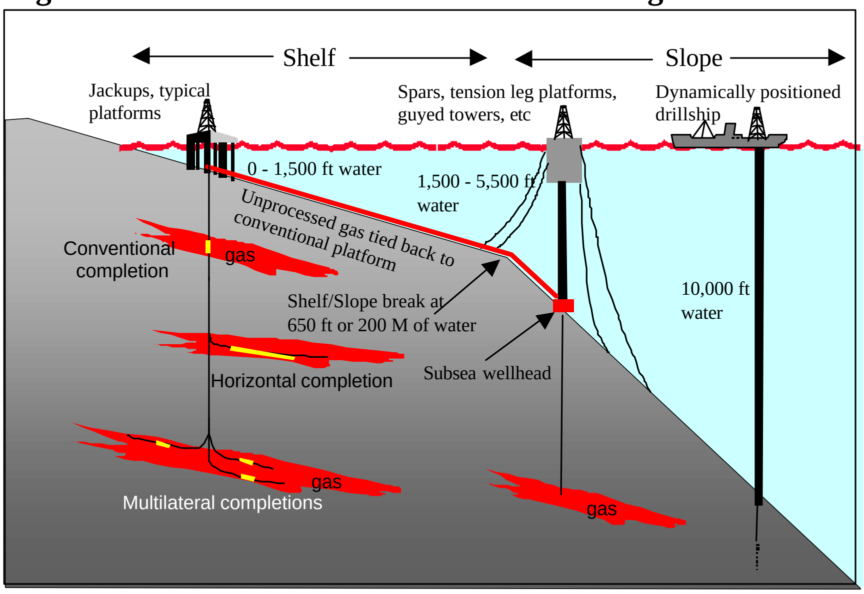
Most Gulf offshore production originates in the offshore Outer Continental Shelf (OCS), which is federal jurisdiction. Minor amounts come from state offshore acreage.

Once the gas reaches shore, there has traditionally been no lack of pipeline capacity to move it to market. However, gathering capacity to move the gas from production platforms to shore has from time to time been restricted. Unlike other regions, the Gulf Offshore is prone to disruptions from hurricanes, which periodically require platforms to shut down.

Gulf Offshore wells have the highest decline rates of any supply region, in the order of 30% per year.

Considerable new wellhead production capacity is being found in the Gulf Coast offshore, particularly in the new deepwater province (see Figure 5). Gulf Offshore fields and wells are now generally split into 2 categories,

Figure 5: Gulf Offshore Provinces & Technologies



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2 *Natural Gas Productive Capacity for the Lower 48 States 1986 Through 1998*, EIA, December 1997.

"shelf" or "deepwater" (also called the slope). The distinction between the shelf and deepwater is generally considered to be the 1,000 foot water depth, but some definitions use 650 feet as the cut-off. Figure 5 illustrates the shelf, the deepwater slope, and the drilling and production technologies used.

As shown in Table 2, most Gulf Offshore gas production continues to come from the shelf. Currently, the shelf accounts for 88% of Gulf Offshore production. Shelf production has been relatively flat in recent years. Even the relatively high drilling rates have been unable to grow production substantially.

Much of the excitement about potential production growth is in the deepwater[3]. During 1997, there were 11 deepwater discoveries announced in the Gulf of Mexico, in water depths ranging from 1,526 feet to 4,795 feet. Four deepwater projects began production in 1997, bringing the total to 21. Deepwater gas production reached 613 Bcf in 1996, according to the EIA (see Table 2).

Deepwater wells produce at very high rates (30-100 MMcf/d), so a relatively small number of wells can affect total Gulf Offshore production.

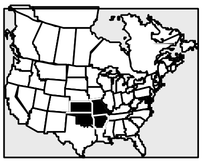
One example was Shell's Mensa project, which commenced production at 180 MMcf/d in July, 1997, from water depth of 5,300 feet, with a 68 mile flowline back to the host platform, nearer shore. Peak production of 300 MMcf/d is expected in first quarter 1998. Ultimate field recovery is estimated at 720 Bcf.

The EIA estimated that total Gulf Offshore productive capacity at the wellhead increased by 18% in 1996, and a further 19% increase is projected for 1997.

However, while this gas has been found, the offshore production, gathering, and pipeline systems necessary for deliverability will take time to install. This may explain how continued tightness in Gulf Coast gas supply currently exists despite high drilling levels and good drilling success. (Gulf pipeline capacity is examined further in the *Gas Flows & Pipeline Capacities* section, page 25.)

In summary, while Gulf Coast offshore production increased only 2% in 1997, high drilling rates are believed to have added considerable incremental production capacity at the wellhead. Most of this capacity, however, was not available to markets during 1997, due to pipeline and facilities bottlenecks.

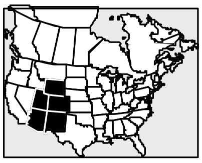
à Midcontinent



The Midcontinent region of Arkansas, Kansas, Missouri, and Oklahoma contains the Arkoma and Anadarko basins. It is a mature area in long term decline. Production has fallen steadily since 1990 (2% per year, or 463 Bcf in total). It fell again in 1997, to 2,415 Bcf, a drop of 106 Bcf from 1996.

The annual gas decline rate in the Midcontinent is 15-20%. New wells have been insufficient to offset declines in older wells. However, the EIA estimated that productive capacity rose 2% in 1996, and projected a further 6% rise in 1997. If production were to increase, it would represent a surprising turnaround from a well-established trend.

à U.S. Rockies



The U.S. Rockies producing region of New Mexico, Utah, Wyoming, and Colorado includes numerous basins. The most important is the coalbed methane dominated San Juan basin of northwest New Mexico and southwest Colorado.

Table 2: Shelf & Deepwater OCS Production

	Production Shelf (Bcf)	Change From 1992 (Bcf)	Production Deepwater (Bcf)	Change From 1992 (Bcf)
1992	4,333		243	
1993	4,335	2	316	73
1994	4,404	71	393	150
1995	4,261	-72	418	175
1996	4,432	99	613	370

Source: EIA Annual Reserves Report

[3] See *Deepwater in the Gulf of Mexico: An Update on America's New Frontier*, Minerals Management Service, January 1998.

Until recently, the Rockies had been an area of very strong supply growth. Production has risen by 750 Bcf since 1991, an annual rate of increase of 5%. However in the past 3 years this rate dropped to 0.4% per year growth.

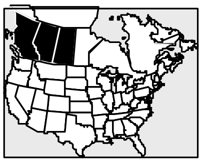
As might be imagined with the rapidly rising production during 1991-94, exit pipeline capacity additions did not keep pace. The result was a restriction of production. Rockies markets became flooded, and the local gas price was very soft by late 1995. This changed by late 1996.

After years of increasing production and growing reserves, the coalbed methane play (mostly within the San Juan basin of New Mexico) appears to have peaked. While overall Rockies production increased slightly in 1997, New Mexico production fell 56 Bcf, following a drop in 1996 of 94 Bcf. New Mexico proved gas reserves have fallen 11% over the past 3 years. San Juan supply has tightened, causing a reconnecting of San Juan and Gulf Coast gas prices. This is examined further in later sections of this report.

The decline rate in the Rockies is difficult to estimate. Unlike conventional gas wells, production from coalbed methane wells *increases* for several years after the well is put on production, and then declines slowly.

Tight formation gas production also declines very slowly. Due to the large percentage of tight gas and coalbed methane in the Rockies, the Rockies decline rate is lower than in other regions, and is estimated at 10% per year. The EIA estimated that Rockies productive capacity rose less than 1% in 1996, and projected a 3% rise in 1997.

à Western Canada



The Western Canada producing region includes British Columbia, Alberta, and Saskatchewan. Production in 1997 was 5,513 Bcf, an increase of 96 Bcf over 1996.

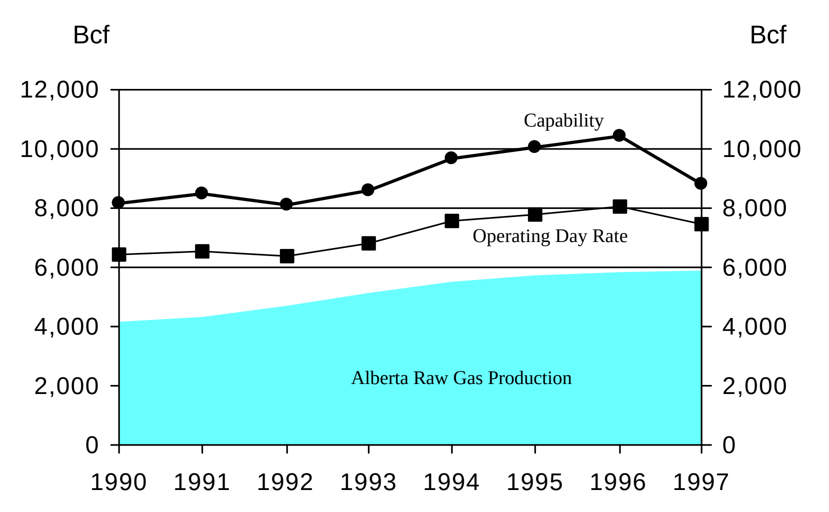
Western Canada is an area of very strong supply growth. Production has increased an average of 5% per year over the past five years. Since 1992, production has increased by 1,273 Bcf, more than in any other region.

This region has a local gas surplus, which keeps Canadian prices low, and disconnected from other North American market prices.

This is illustrated in Figure 6, which shows Alberta gas production and two measures of production capacity - the "operating day rate" and the "capability rate". Both production capacity measures illustrate that there is still a sizeable production surplus in Alberta.

Figure 6 shows, however, that the size of the Alberta surplus has diminished over the past year. Supply has tightened somewhat, and this seems to have had an effect on Alberta gas prices (discussed in a later section of this report).

Figure 6: Annual Alberta Production & Production Capacity



Source: AEUB

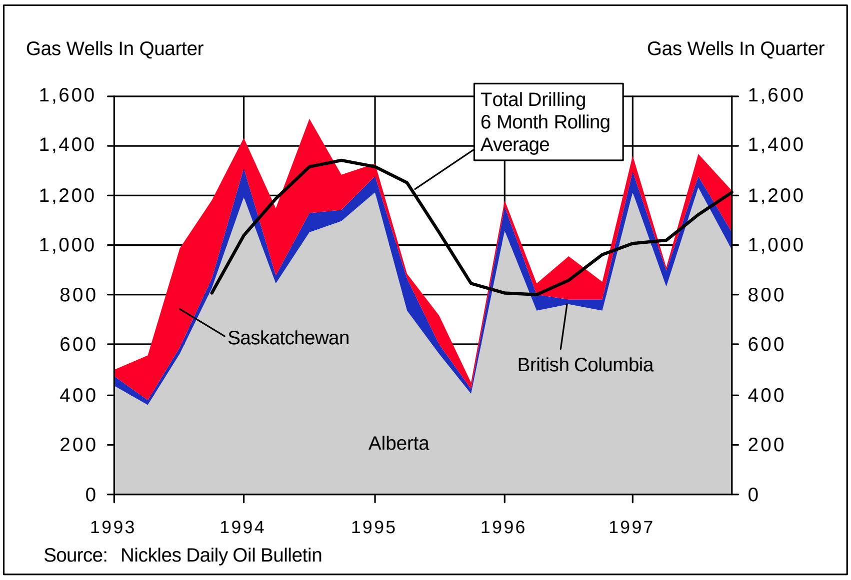
As shown in Figure 7, Canadian drilling continued to rise in 1997. Large exit pipeline capacity expansions, including the 690 MMcf/d Foothills/Northern Border expansion and the TCPL 416 MMcf/d expansion, are expected in 1998. Producers are preparing for these.

à LNG & Mexican Imports

U.S. imports of LNG during 1997 rebounded somewhat from low levels last year, as renovations of Algerian liquefaction plants were completed, and liquefaction rates returned to normal levels. LNG imports rose from 40 Bcf in 1996 to 78 Bcf in 1997.

Imports of Mexican gas were static, at 15 Bcf. Raw gas production in Mexico rose from 1,531 Bcf in 1996 to 1,626 Bcf, a 6% increase[4]. Most of this increase was used within Mexico.

Figure 7: Canadian Drilling Trends by Quarter



[4] PEMEX figures reported by El Financiero.

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à North American Demand

In 1997, North American demand for natural gas grew by less than 0.5%, to reach 24.7 Tcf. Total U.S. demand increased 0.2% to 22.0 Tcf, while Canadian demand increased by 0.7%. This low growth contrasts with the 2% increase in overall demand in 1996 (see Table 3).

While consumption grew in the UEG and commercial sectors, this growth was offset by declines in the residential and industrial sectors. Regionally, consumption increased in the U.S. Northeast, U.S. West, and Eastern Canada regions, while decreasing slightly in the Midwest, Gulf, and Western Canada regions.

à Demand by Sector

We have examined natural gas demand trends by eight geographical regions, as well as by sector.

Figure 8 indicates that the most important demand segment in North America is industrial demand in the Gulf Coast. Other large segments are residential and industrial demand in the Midwest, and UEG demand in the Gulf Coast.

Understanding what drives demand in these segments is the key to forming an overall

Figure 8: Geographic & Sectoral Gas Demand Breakdown

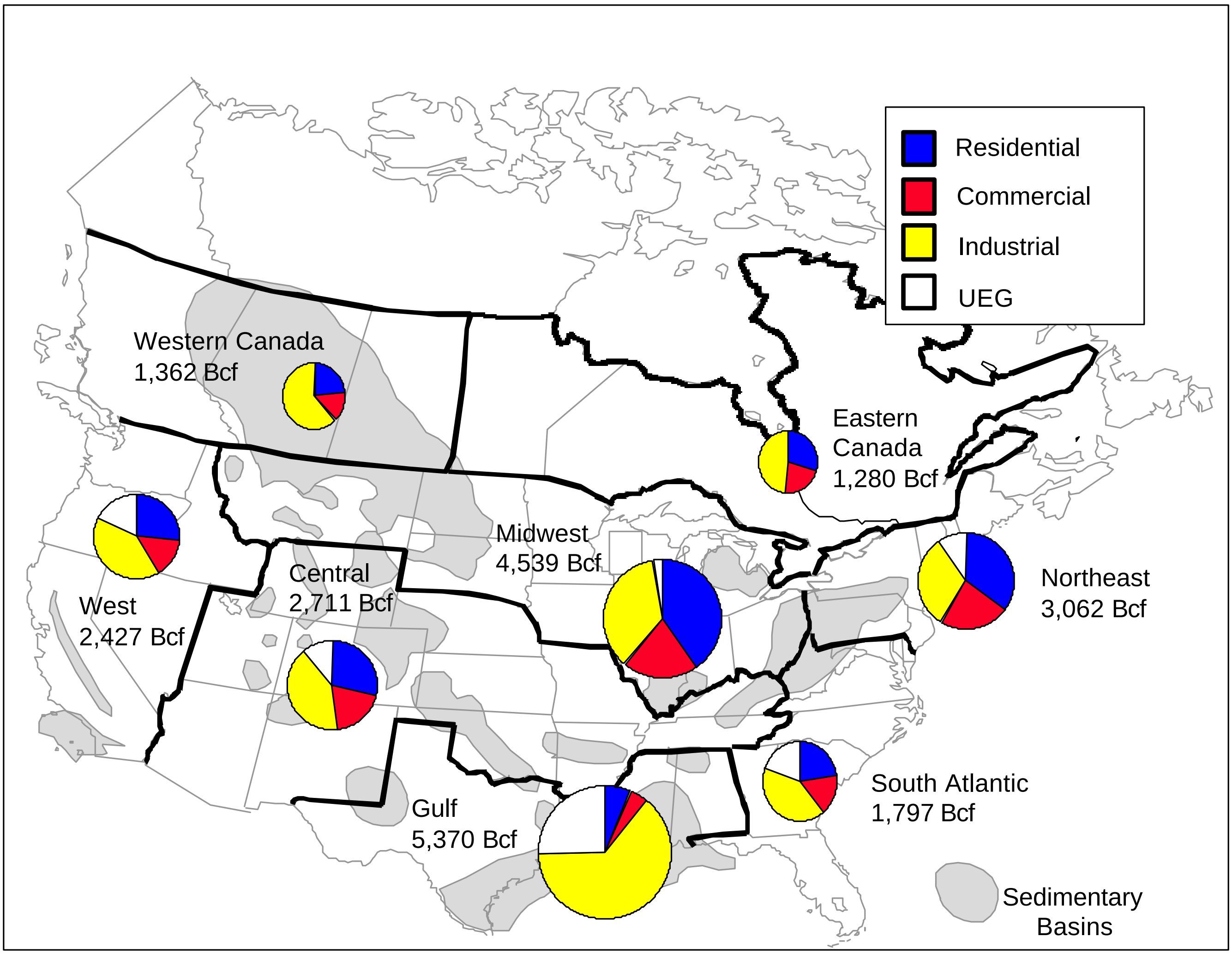


Table 3: North American Gas Demand & Disposition

	1997 (Bcf)	1996 (Bcf)	Difference (Bcf)	Change (%)	% Of Total Increase	% of N.Am. Demand
U.S. Residential	5,028	5,241	-213	-4.1	-417.6	21.3
U.S. Commercial	3,223	3,158	65	2.1	127.5	12.8
U.S. Industrial	8,844	8,870	-26	-0.3	-51.0	36.1
U.S. Electric Utility	2,958	2,732	226	8.3	443.1	11.1
U.S. Gas Used in Operations	1,965	1,966	-1	-0.1	-2.0	8.0
Domestic U.S. Demand	22,018	21,967	51	0.2	100.0	89.3
U.S. LNG Exports	62	68	-5	-7.8		0.3
U.S. Exports to Mexico	40	34	7	19.2		0.1
Total U.S. Gas Disposition	22,121	22,068	52	0.2	74.6	89.7
Cdn. Residential	585	617	-32	-5.1	-177.3	2.5
Cdn. Commercial	414	443	-29	-6.6	-164.6	1.8
Cdn. Industrial	1,373	1,309	64	4.9	361.5	5.3
Cdn. Other	270	256	14	5.6	80.5	1.0
Total Cdn. Demand	2,642	2,624	18	0.7	100.0	10.7
TOTAL N.A. DEMAND	24,660	24,591	69	0.3	98.3	100.0
TOTAL N.A. DISPOSITION	24,763	24,693	70	0.3	100.0	100.4

Sources: EIA, StatsCan. ***NOTE:*** Total North American gas disposition (24,763 Bcf) is greater than total North American supply (24,567 Bcf), due to accounting problems and/or storage changes.

demand outlook.

North American demand for natural gas is influenced by three main factors: economic growth, changes in energy market shares, and weather. Demand increases due to economic growth or increasing gas market share can be permanent, and can occur year after year. Demand increases due to weather are temporary and unpredictable in any one year.

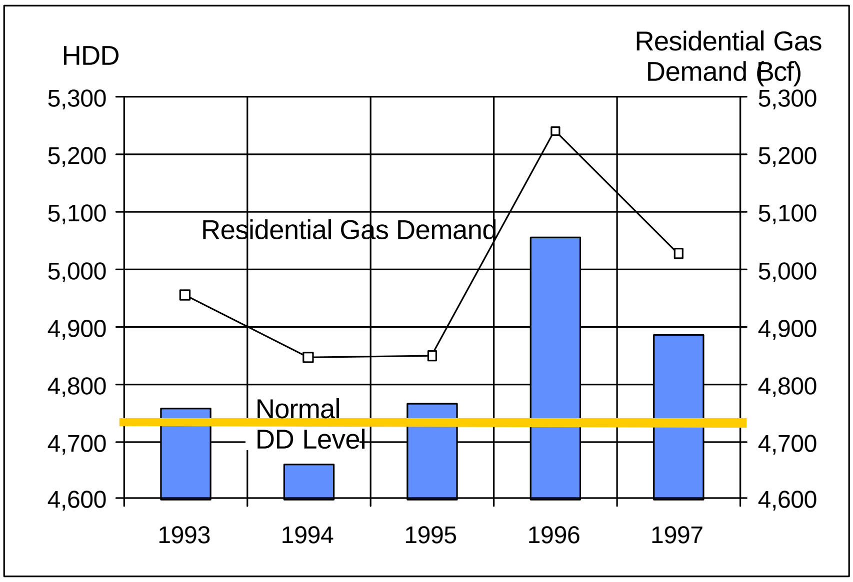
Approximately 50% of total natural gas demand, mostly in the residential and commercial sectors, is influenced by weather. Winter temperatures in northern regions influence demand for heating purposes, while summer temperatures influence electric air-conditioning requirements (i.e., gas used in generating power) throughout North America.

The demand characteristics of the sectors and regions tend to stabilize demand swings. For example, warmer winter temperatures reduce heating requirements and cause lower gas prices. However, electricity generation often increases as a result of the availability of natural gas supplies at attractive prices.

à Residential/Commercial

Figure 9 illustrates U.S. heating degree days (HDDs) and residential gas demand over the

Figure 9: U.S. Heating Degree Days



last 5 years. The residential/commercial sector represents 37% of U.S. gas demand. Warm weather in the last half of 1997, attributed to the El Niño weather event, caused U.S. residential gas demand to fall to 5,028 Bcf, a drop of 4.1% from last year. U.S. commercial demand rose 2.1% to 3,223 Bcf.

While the winters of 1996/97 and 1997/98 were both warmer than normal, *shoulder* months were colder. The net result was that temperatures were 3.3% colder than normal in 1997.

Demand in the residential and commercial sectors has increased slowly since 1990 (see Figure 10) despite robust economic growth (represented by GDP in Figure 10), which leads to new housing starts and higher commercial sector output. Demand growth does not keep pace with economic growth in these sectors because new construction is often accompanied by increased building insulation and more efficient furnace equipment.

Warmer weather in Canada also reduced sales in the residential and commercial sectors. Canadian residential sales decreased 5% to 585 Bcf, while sales in the commercial sector dropped 6.6%. Temperatures were particularly warm in western Canada, where heating degree days were 16% lower than in 1996.

à Regression Analysis

We did extensive regression analysis of U.S. sectoral and regional gas demand and HDDs to investigate the extent to which weather accounts for changes in consumption in various sectors. Regression analysis quantifies the extent to which changes in demand are explained by HDDs or other factors.

For example, the shaded area in Figure 11 shows MMcf of monthly gas demand in the U.S. Northeast residential sector since 1990. Demand is high in winter and low in summer.

The dashed line is *predicted* residential gas demand according to the formula: NE Residential Demand = Northeast HDD times 135 MMcf/HDD, plus 18,731 MMcf.

As the predicted line matches

Figure 10: U.S. GDP & Gas Demand

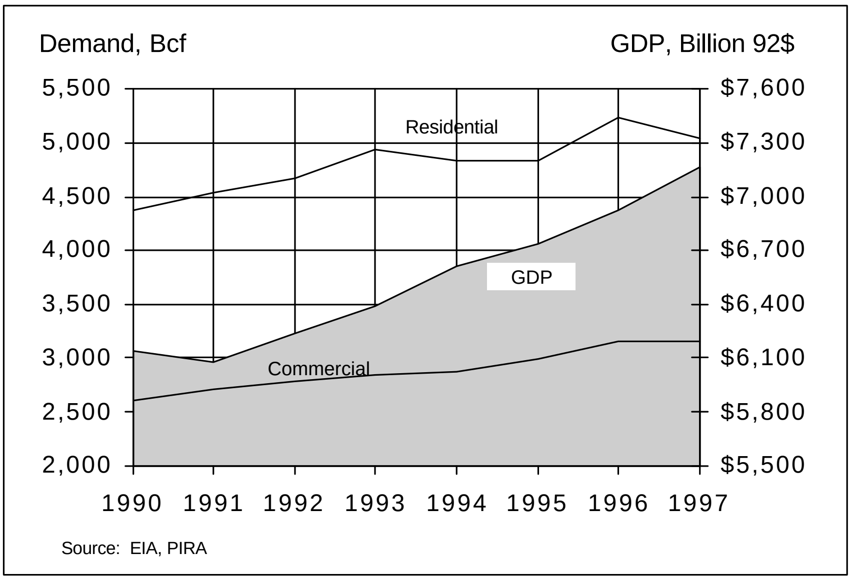
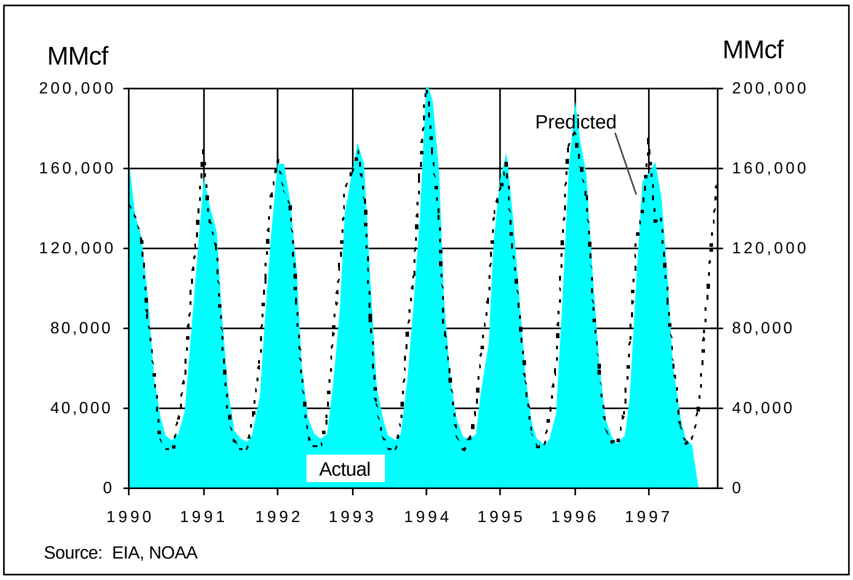


Figure 11: Monthly U.S. Northeast Residential Gas Demand



the actual, this indicates that variations in residential gas demand in the Northeast are totally driven by temperature (HDD). Changes in gas prices, the number of residential customers, the age and efficiency of gas furnaces, and other factors tend to balance each other, and have no net effect on gas demand.

à Industrial

The industrial sector represents 40% of total U.S. gas demand. In a change from the solid growth pattern registered over the last 10 years, consumption in this sector was flat at 8,844 Bcf in 1997, unchanged from 1996 levels.

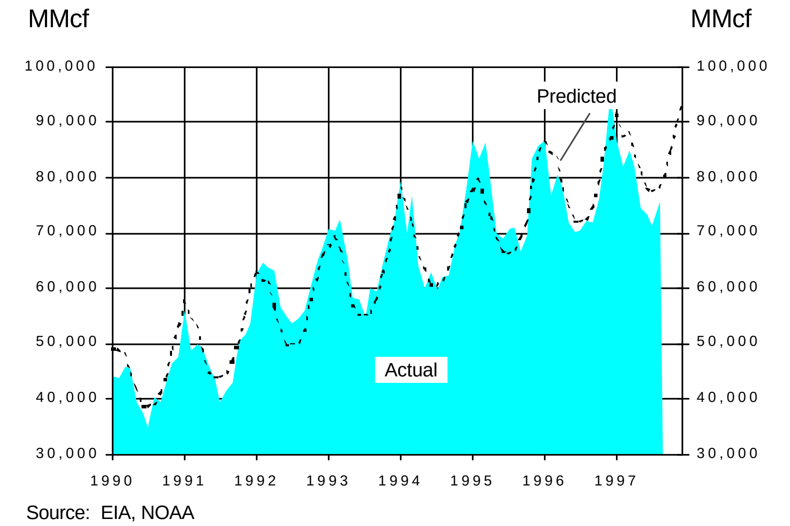
Regression analysis revealed that industrial gas demand in many regions was growing by a constant amount each month. This *structural growth* was due to rising industrial output, non-utility electric generation, and an increasing market share for gas in this sector.

The shaded area in Figure 12 shows monthly Northeast industrial gas demand since 1990. Obviously, there is constant growth occurring. The small fluctuations seen are caused by weather.

Regression analysis revealed that HDDs are important drivers of industrial gas demand in most regions, and lower HDDs in 1997 were an important factor in reducing industrial consumption during 1997.

However the lack of growth in industrial demand cannot be fully accounted for by the drop in HDDs.

Figure 12: Monthly U.S. Northeast Industrial Gas Demand



Source: EIA, NOAA

Regression analysis also indicated that gas prices and the gas/fuel oil price differential were important factors influencing industrial gas demand in some regions. High gas prices (or high gas prices relative to fuel oil) also tended to reduce gas demand in the industrial sector during 1997.

à Utility Electric Generation

The Utility Electric Generation (UEG) sector has in the past been the most price sensitive sector. Consumption rose when prices fell, and fell when prices increased. However, in 1997, UEG consumption rose despite flat gas prices and a decline in the price of competing fuels (see Figure 13).

Consumption in the UEG sector increased by 226 Bcf or 8.3% to reach 2,958 Bcf in 1997. Utilities reverted back to gas-fired units after switching to oil or coal fired units in 1996. In addition, a 7.1% reduction in nuclear generated power in 1997 led to an increased reliance on natural gas for electricity generation.

Consumption in the UEG sector is also heavily dependent on cooling degree days (CDD) during the summer. Peak summer electric demand is often supplied by natural gas fired peaking units. In 1997, demand for air-conditioning needs (as measured by CDDs) was 5% lower than 1996. The cooler summer weather tempered sales to the UEG sector.

In short, higher UEG demand in 1997 cannot be explained by gas prices (which remained steady) or air-conditioning demand (CDDs fell). Region-specific factors such as the availability of coal or nuclear power were important, as discussed below. A more fundamental shift to natural gas seems to be occurring in the UEG sector, with more gas being consumed than would have been in the past under the same CDD and price conditions.

à Geographical Demand Trends

We have divided the North American natural gas market into 8 regions for the purposes of demand analysis (as shown in Figures 8 and 14).

Two of these regions – the Gulf and Western Canada - are also important supply regions. The Central region contains the Midcontinent and Rockies supply regions.

An important determinant of consumption levels in each area is proximity to supply. This influences the cost to transport gas to the market, and thus influences the delivered-to-market price.

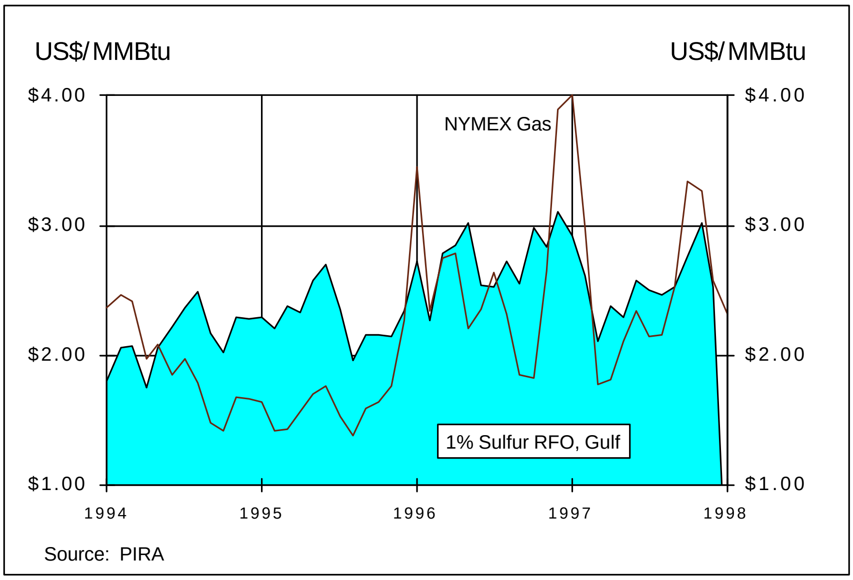
à West

Gas consumption increased in all U.S. West sectors in 1997. Total gas consumption rose by 131 Bcf, or 5.7%, to 2,427 Bcf.

Consumption in the residential and commercial sectors rose by 2.8% and 6.7% respectively, despite warmer than normal (and warmer than 1996) temperatures during the 1997 heating season. In contrast with most U.S. regions, new residential and commercial customer additions seem to be driving up gas demand.

Industrial sector growth of 3.4% is attributed to economic growth and a higher percentage of gas in the energy mix.

Figure 13: Oil Vs Gas Price Trends by Month



UEG demand increased 59 Bcf (15%), due to gas fired generation being used to replace falling nuclear capacity. Nuclear power generation fell from 30% of the region's supply in 1996 to 26% in 1997.

à Midwest

Consumption in all Midwest sectors is strongly correlated to weather patterns (HDDs and CDDs). In 1997, Midwest consumption fell by 3.2% to 4,539 Bcf.

Residential and commercial demand fell 111 and 35 Bcf, (6% and 4%) respectively, due to lower HDDs, while industrial demand fell 36 Bcf (2%), for the same reason. In the Midwest, industrial consumption varies with HDDs, and is not strongly correlated with gas prices or other factors.

The UEG sector in the Midwest saw 31 Bcf of demand growth (37%), despite a drop in fuel oil prices and CDDs.

à Northeast

Total Northeast demand rose by 49 Bcf, or 1.6%, in 1997. Residential and commercial demand fell by 34 and 16 Bcf, (3% and 2%) respectively, due to lower HDDs. Industrial sector consumption increased by 22 Bcf (2.4%), continuing steady growth.

UEG demand rose by 76 Bcf (30%). Regression analysis indicates that Northeast UEG consumption is sensitive to the ratio of the price of residual fuel oil to the price of natural gas, as well as to cooling degree days (CDD). Northeast CDDs were up 2% in 1997, but fuel oil became slightly less costly versus gas during the year.

à South Atlantic

Demand in the region was virtually identical to 1996. Both residential and commercial sector consumption decreased (-8.3% and -0.5%) as a result of mild winter weather. HDDs in 1997 were 6% lower than 1996. Industrial consumption increased 3.6% due mainly to higher than average economic growth in the region in 1997.

UEG demand increased 4.2% due to warmer than normal summer months, which led to increased air-conditioning load.

à Gulf

A combination of warmer weather and higher prices prompted a 1.9% drop in gas consumption, to 5,370 Bcf.

Residential demand fell 22 Bcf or 6%, while commercial consumption increased 17% (44 Bcf).

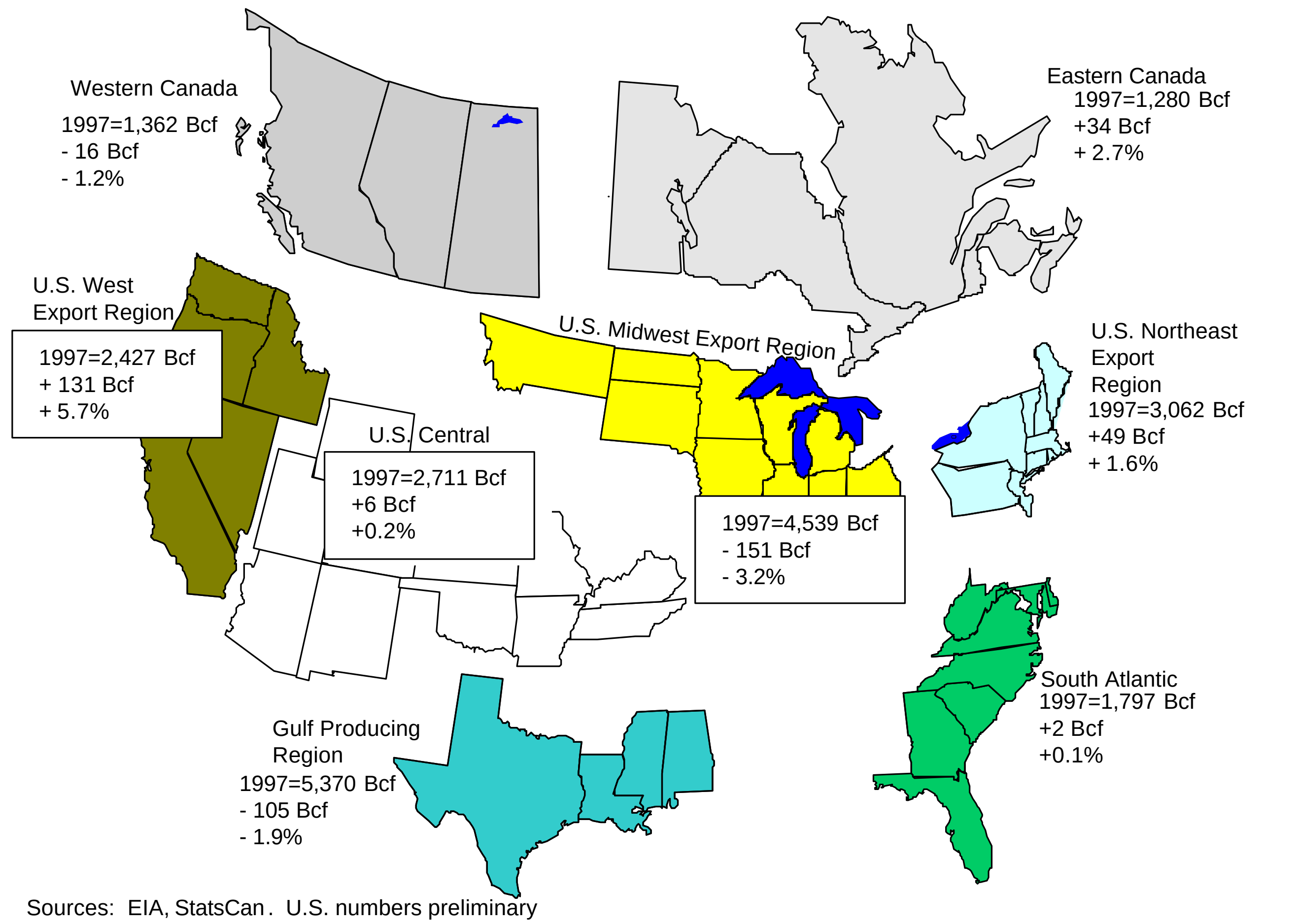
Consumption in the industrial sector, which represents over 60% of total gas sales in the region, decreased by 4.5% (156 Bcf) despite strong economic growth in 1997. This was due mainly to higher prices in the latter part of the year.

The UEG sector recorded a 2.1% increase over 1996 levels. According to our regression models, higher gas prices relative to other fuels should have prompted a decrease in UEG consumption in 1997. However, this was not the case. The limited availability of coal supplies in the region, due to railroad logistical problems, caused utilities to revert to natural gas to meet their requirements.

à Central

Demand in the Central U.S. region was virtually unchanged compared to 1996, up 0.2% to 2,711 Bcf. The largest volume change was a 26 Bcf increase in industrial consumption.

Figure 14: Demand Changes In 1997 By Region



Sources: EIA, StatsCan. U.S. numbers preliminary

à Eastern Canada

Total eastern Canadian (Manitoba, Ontario, Quebec) gas demand rose 3% or 34 Bcf during 1997, to reach 1,280 Bcf.

Eastern Canadian demand is split fairly evenly between residential (340 Bcf or 27% of total demand), commercial (253 Bcf or 20%) and industrial (611 Bcf or 48%). There is also 75 Bcf of other gas use (gas used as pipeline fuel, losses, etc.).

Residential and commercial demand fell slightly due to a 4% fall in HDDs, but this was outweighed by a 36 Bcf (6%) increase in industrial demand.

Eastern Canadian industrial gas demand growth has been strong due to strength in the economy and higher industrial output.

Over the last five years, the average rate of eastern Canadian industrial gas demand growth was 4% per year. Ontario accounts for 75% of eastern Canadian demand in this sector. The high proportion of industrial demand in eastern Canada reflects the strong industrial base there, including pulp and paper, steelmaking and other minerals industries, the auto industry, other manufacturing, and industrial gas fired cogeneration.

à Western Canada

Total western Canada (British Columbia, Alberta, Saskatchewan) gas demand fell 1% or 16 Bcf. Western Canadian gas demand was 1,362 Bcf in 1997. As in eastern Canada, the industrial sector accounts for the bulk of demand (762 Bcf or 56%). The next largest sector is residential (245 Bcf or 18%), pipeline, lease, and plant fuel (195 Bcf or 14%), and finally, commercial (161 Bcf or 12%).

Residential and commercial demand fell 10%, due to a 16% fall in HDDs. This was partly offset by a 4% increase in industrial demand.

As in eastern Canada, industrial gas demand growth in the west has been very strong, averaging 5% per year over the past five years, due to strong economic growth and higher industrial output. The industrial sector in the west includes pulp and paper, petrochemicals, in-situ and mining oilsands plants, and industrial cogeneration.

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à Role of Storage

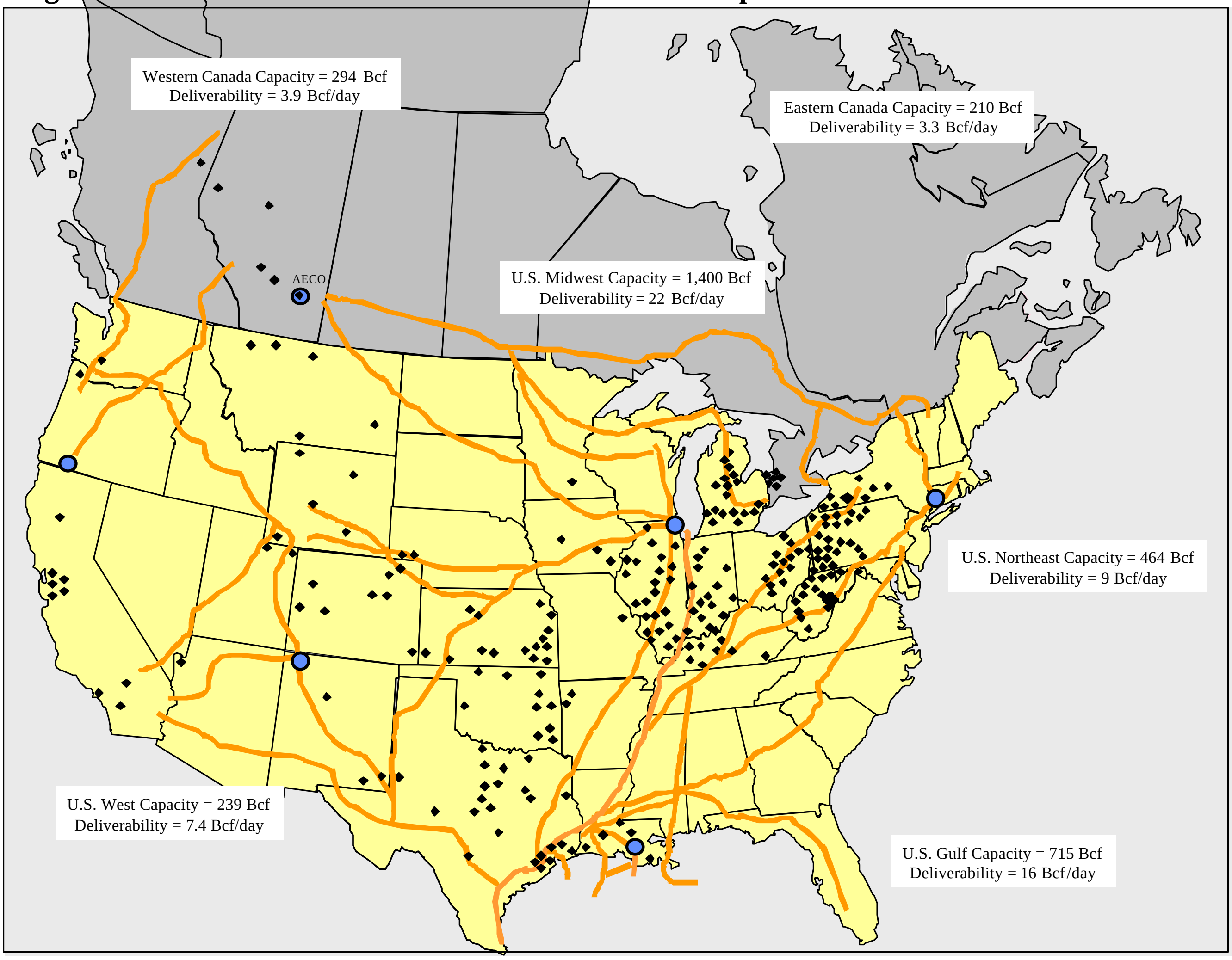
Storage plays a very large role in North American supply, demand, and price dynamics. Most storage is located in the large demand centres of eastern North America. Figure 15 is a map of storage locations.

Storage helps to balance stable production capacity with demand, which is heavily weather sensitive. The major flows are into storage during the injection season (April through October) and out during the withdrawal season (November through March).

Smaller inflows and outflows also occur hourly and daily to balance corresponding demand fluctuations with pipeline capacities, or to deal with temporary pipeline shutdowns. The amount of usable gas remaining in storage is termed *working gas*.

Storage levels, withdrawals and injections are inextricably linked to gas prices in highly complex ways. Storage decisions are based on expectations of future demand and prices. Just as storage decisions are highly dependent on price expectations, flows in and out of storage are a large component of month-to-month supply or demand, and have a significant feedback effect on natural gas prices.

Figure 15: North American Gas Storage Locations & Capacities



Flowing gas into and out of storage involves operating costs (compression fuel) and capital costs (gas inventory cost, amortization of storage facilities). Gas price savings or profits must offset these storage costs. Thus, gas is usually injected into storage when prices are low and withdrawn when prices are high.

Storage balances usually influence North American gas prices. When North American storage is low, prices strengthen. When storage is above normal, prices soften.

Storage does not lend itself to analysis by calendar year because the withdrawal season continues past the end of December. The logical end of a storage analysis period is the end of March.

In this section, we examine storage balances for the total U.S., and for Western Canada. Total U.S. storage levels have in the past been highly correlated with U.S. prices. Similarly, Western Canadian storage balances have had a large influence on Canadian gas prices.

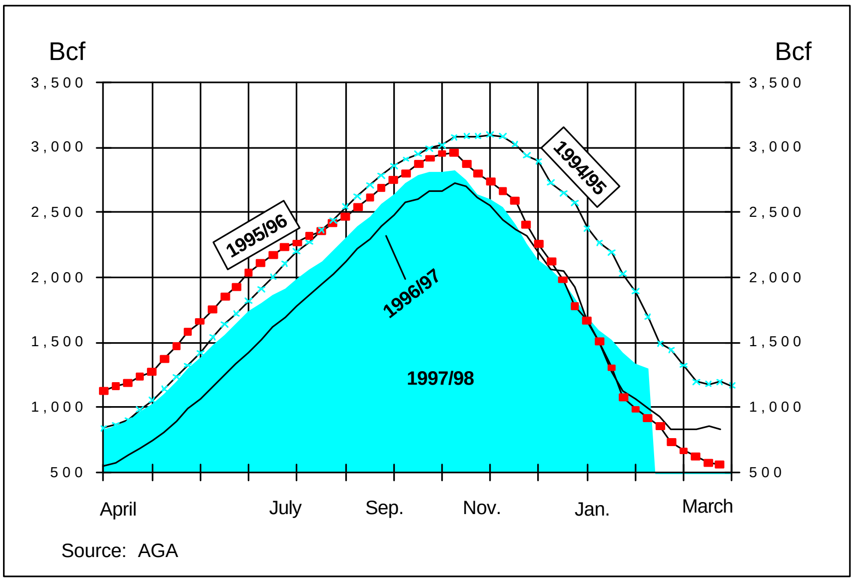
à U.S. Storage

Figure 16 shows U.S. working gas storage levels over the past four injection/withdrawal seasons.

Fill levels and withdrawal rates during 1997/98 were similar to the previous year. For the past two years, storage fill levels have been below historic levels.

U.S. heating degree days during 1997/98 were 6% lower than in the 1996/97 winter. Given lower peak winter demand this year, the relatively low storage levels were sufficient, and U.S. gas prices over the 1997/98 winter did not ramp up as dramatically as they did last year.

Figure 16: U.S. Gas Storage Balances



Recent U.S. storage levels, near the end of the withdrawal season, showed a year-on-year surplus in U.S. gas storage levels. While higher storage usually exerts downward pressure on U.S. gas prices, this year the impact of storage in gas market pricing is being overwhelmed by other factors (mainly the tightness in U.S. gas supply).

à Canadian Storage

Most Canadian storage is located in Ontario (44%) and Alberta (39%). The main market for trading gas destined for Canadian consumers is in Alberta. The pricing point is on the NOVA pipeline system at AECO C, the largest Alberta storage facility.

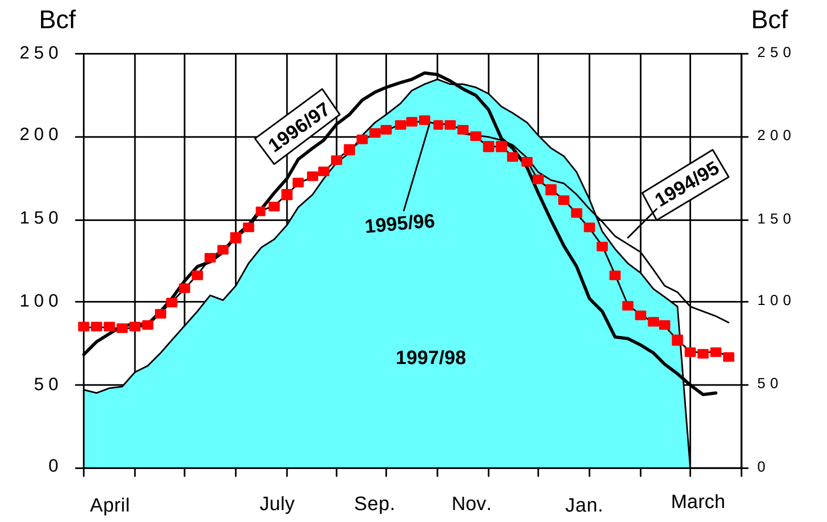
There is no large-scale eastern Canadian spot gas market. Most eastern Canadian gas users purchase their gas in Alberta and contract for pipeline capacity to transport it east. Thus, their gas is priced in Alberta, and their delivered gas cost is the Alberta price plus the regulated cost of moving the gas east.

Storage in eastern Canada is critical for seasonal balancing and maintaining a high load factor on the TransCanada PipeLines Ltd (TCPL) transmission system, which is the main transportation route for western Canadian gas moving to eastern Canadian markets. However, eastern Canadian storage has little impact on Alberta (i.e., Canadian) gas pricing. For these reasons, we examine only Western Canadian storage.

Western Canadian storage is used mainly to handle peak winter gas demand in western Canada. Flows into pipelines exiting the region remain near full capacity year-round. Thus, western Canadian storage cannot be used as "upstream storage", i.e., gas cannot be stored in Western Canada in the summer and exported to downstream markets during the winter – pipeline capacity is not available.

Figure 17 shows Western Canadian working gas storage levels over the past four injection/withdrawal seasons. Storage reached approximately the same fill level this year as last. However, Alberta heating degree days were 17% lower than last year, and the volume of gas withdrawn was reduced accordingly. More gas remained in storage at the end of the withdrawal season than during the previous two years.

Figure 17: Western Canadian Gas Storage Balances



Source: CGA

While higher storage is a downward influence on prices, the effects of storage on Canadian gas prices are being overwhelmed by other factors. For Canadian gas markets, these other factors are a narrowing of the supply/demand surplus, and the expectation of more exit pipeline capacity during 1998, which will lead to better integration of the western Canadian gas market with U.S. markets.

Review of 1997
Gas Flows & Pipeline Capacity

Review of 1997
Gas Flows & Pipeline Capacity

à Gas Flows

In this section, we examine the net gas outflows from the four main gas supply regions. Net gas outflow is the positive difference between production and consumption within a region.

Examining gas flows can aid in predicting future pipeline expansions, regional prices, and price differentials. The calculation of gas flows by region is shown in Table 4. Figure 18 (last page of this section) contains a map view of the pipeline corridors and major North American gas spot markets.

The big change in gas flows during 1997 was the 333 Bcf increase in gas flowing out of the U.S. Gulf Coast. This increase was even greater than the increase in Gulf production, as Gulf demand fell during the year.

Some of this increased Gulf outflow replaced declining outflows from the Midcontinent, which predominantly flows north to the U.S. Midwest and Northeast. Production and net outflow both fell 111 Bcf for the Midcontinent. During 1997, Gulf Coast gas also periodically flowed to U.S. West markets. In recent years, the pipeline capacity linking the Gulf and West had mainly been used to flow Rockies gas east. These lines now periodically resume westward flow.

Flows out of the Gulf or Midcontinent are not generally restricted by pipeline capacity, as large pipeline corridors to the West, Midwest and Northeast have excess capacity in all but peak periods.

In the U.S. Rockies, where production increased by only 12 Bcf, outflows increased by a similar amount. This represents a considerable change for the Rockies, which had over the past five years been supplying an ever increasing share of North American demand growth.

Finally, in Canada, a 96 Bcf increase in production was coincident with a 78 Bcf increase in net exports to the U.S. (Note: gross exports, discussed in the next section, were slightly different, due to changes in Canadian imports of U.S. gas).

Markets were largely unable to get incremental gas from the low-priced regions of the Rockies and Western Canada because no large pipeline expansions were completed. Incremental demand had to be satisfied by purchases from the Gulf, where prices are higher. This has been a factor in keeping North American gas prices relatively high during 1997.

à Pipeline Capacities
Gulf Offshore

In the Gulf Offshore, a lack of gathering facilities is limiting production. As shown in Table 5 (at the end of this section), there has been a flurry of new projects proposed to remedy this. Figure 18 shows a map view of these projects. Once these projects are in place, Gulf offshore production will increase.

For the Gulf Offshore, the projects in Table 5 were either announced or approved during 1997. Not all of these projects

Table 4: Natural Gas Flows

	1997 Prod. (Bcf)	1997 Demand (Bcf)	Net OutFlows 1997 (Bcf)	Net OutFlows 1996 (Bcf)	Difference (Bcf)	Change %
Gulf Coast	12,007	5,370	6,637	6,304	333	5.3
Midcontinent	2,415	1,280	1,135	1,246	-111	-8.9
U.S. Rockies	2,864	590	2,274	2,267	7	0.3
Canada	5,513	2,642	2,871	2,793	78	2.8

Note: U.S. demand excludes pipe, lease fuel, etc.

are likely to go ahead. However, this list provides an indication of pipeline activity in the region.

Note, however, that these projects also do not necessarily represent net incremental capacity. Existing offshore production is declining at 30% per year. Where installed offshore pipeline segments are left without supply, they are then abandoned, and new capacity must be added elsewhere.

à Gulf Onshore/Midcontinent

The Gulf Onshore and Midcontinent have in the past had enough pipeline capacity to market all their production capacity. Recently, however, anticipation of considerable incremental production from the offshore Gulf Coast has led to an increase in Gulf exit pipeline projects. Several of the projects listed in Table 5 target markets in the U.S. South Atlantic region, where Gulf Coast supply routinely captures all market growth.

The largest Gulf exit pipeline project is the 1,000 MMcf/d Tennessee Line 500 Expansion. The existing 500 line runs from Louisiana to the U.S. Midwest and Northeast. Tennessee anticipates an additional 3,000 MMcf/d of deepwater Gulf Coast production hitting landfall by 2001 (Projects 1-12 in Table 5) and is preparing to move one-third of it.

à Rockies

Currently, price differentials indicate that the San Juan market, the most widely quoted Rockies pricing point, is well served by existing pipeline capacity. Supply is fairly tight, and prices are near parity with the Gulf. However, production continues to grow in other parts of the Rockies, and in some areas producers have had difficulty getting their gas to markets. Several projects, listed in Table 5, anticipate further Rockies production growth.

The Pony Express project converted an oil pipeline to a 255 MMcf/d gas line from the Rockies to the Midwest. The line reached full capacity in late 1997.

In July 1997, El Paso Field Services Co., a San Juan basin gatherer, announced a field compression project that will increase production by 130 MMcf/d.

Transwestern's 200 MMcf/d San Juan lateral project in Table 5 is supported by five-year contracts and has an in service date of April, 1998.

à Western Canada

By the end of 1996, the price differential between Western Canada and eastern North American gas markets had become much greater than the pipeline transmission cost from AECO to eastern markets. This is driving the current push to expand pipeline capacity out of Western Canada.

There are five major natural gas pipeline projects proposed to increase Canadian gas. These are:

1) Foothills/Northern Border;

2) TransCanada PipeLines' 1998;

3) Maritimes & Northeast Pipeline;

4) Portland Natural Gas Transmission System; and

5) Alliance Pipeline.

See listing in Table 5, and the map in Figure 18.

Foothills/Northern Border

The Foothills/Northern Border expansion received all necessary approvals in 1997 and is now under construction. Regulatory approvals included a National Energy Board (NEB) certificate for the Foothills Saskatchewan expansion, and a Federal Energy Regulatory Commission (FERC) certificate for the Northern Border expansion/extension. This project is expected to meet its November 1998 startup date, adding 690 MMcf/d of new capacity.

TCPL's 1998 Expansion

In December 1997, the NEB approved TCPL's expansion plans for 1998. The $825 million of proposed facilities will permit TCPL to provide 416 MMcf/d of new Firm Transportation (FT) service on its system beginning November 1, 1998. Approximately 20% of the new capacity would be for the domestic market.

The approved facilities will also allow TCPL to convert 150 Bcf of annual Firm Service Tendered (FST) capacity to approximately 412 MMcf/d of FT, as requested by Consumers Gas and Union Gas.

Maritimes & Northeast (MNP)
The NEB issued a certificate of public convenience and necessity for the Canadian portion of the Maritimes & Northeast Pipeline project on December 17, 1997. This completed a 15-month regulatory review process which involved an extensive NEB public hearing, as part of the consolidated Sable gas projects public review. In the U.S., the FERC issued a preliminary determination on economic and technical matters in late May 1997. The issuance of a final certificate for the U.S. portion of the pipeline is pending.

TQM/Portland Natural Gas Transmission System
In April 1997, TransQuebec and Maritimes (TQM) applied to the NEB to extend its existing system from Lachenaie, north-east of Montreal, to East Hereford, near the Quebec-New Hampshire border. The extension would interconnect with the Portland Natural Gas Transmission System

Table 5: North American Gas Pipeline Projects

Map Index Number	Region/Project Name	Capacity (MMcf/d)	Timelines
	Gulf Offshore Pipeline Projects		
1	Garden Banks Pipeline	550	FERC Certificated January, 97
2	Discovery Producers Services	600	FERC Certificated February, 97
3	Williams Companies Inc	72	Announced by company, February, 97
4	TransCo S.E. Louisiana	660	FERC Approved March, 97
5	Nautilus Pipeline	600	FERC Approved March, 97
6	ANR Expansion	461	FERC Approved March, 97
7	Green Canyon Gathering Co.	300	Proposed March, 1997
8	Daupin Island (DIGP)	200	Applied to FERC April, 97
9	Trunkline Terrebonne System	50	Approved by FERC July, 97
10	TransCo Mobile Bay Lateral	350	FERC approved, In service mid 1998
11	Venice G.S. Timbalier Expansion	328	Approved by FERC November, 97
12	Destin Pipeline Project	1,000	Approved by FERC November, 97
	Total Proposed Gulf Offshore To Land Capacity	**5,171 MMcf/d**	
	Exit From Gulf Onshore & Midcontinent Pipeline Projects		
13	Southern Natural Gas	65	Applied to FERC May, 97
14	Southern Natural Gas	46	FERC Certificated May, 97
15	Southern Natural Gas	34	Applied to FERC August, 97
16	Florida Natural Gas	unknown	Announced open season August, 97
17	Columbia Gas Transmission	507	FERC Approved May, 97
18	Tennessee Line 500	1,000	Announced open season September, 97
19	Columbia Gas Transmission	218	Held open season November, 97
	Total Proposed Gulf & Midcon Exit Capacity	**1,870 MMcf/d**	
	Exit From Rockies Pipeline Projects		
20	Wyoming Interstate Co.	193	FERC Certificated February, 97
21	Pony Express Project	255	Reached full capacity late 1997
22	MIGC	45	FERC Certificated May, 97
23	TransColorado	300	Announced construction start for early 98
24	El Paso Field Services	130	Announced by company, July, 97
25	Colorado Interstate Campo lateral	110	Applied to FERC September, 97
26	Transwestern San Juan lateral	200	FERC approved November, 97
	Total Proposed Rockies Exit Capacity	**1,233 MMcf/d**	
	Exit From Canada Pipeline Projects		
27	Foothills (Northern Border)	690	Approved, In service, November 1998
28	TCPL Mainline (for export)	358	Approved, In service, November 1998
	TCPL Mainline (for domestic markets)	58	Approved, In service, November 1998
29	TQM Extension (PNGTS)	210	NEB approved, in service November 1998
30	Maritimes & Northeast Pipeline	Approx. 400	Approved, In service, November 1999
31	Alliance	1,325	NEB hearing ongoing, planned in service, 2000
	Total Proposed Canadian Exit Capacity	**2,952 MMcf/d**	*(note: total is export capacity only)*

(PNGTS) in the U.S., to serve U.S. Northeast markets. This PNGTS pipeline would replace an existing line that will eventually be re-converted to crude oil service from Portland, Maine to Montreal. The NEB held public hearings from November 17 to December 17, 1997, and approved the project in early April 1998.

PNGTS is the U.S. portion of this project. The FERC issued a final environmental impact statement for PNGTS on September 12, 1997. This completed a sixteen-month regulatory review process, and cleared the path to begin construction in the U.S.

TQM/PNGTS would increase Canadian export capacity to the U.S. Northeast by 152 MMcf/d in late 1998, increasing to 210 MMcf/d the following year. Actual incremental capacity is slightly less due to decommissioning of an older line along the same corridor.

Alliance
The U.S. portion of the proposed Alliance project received FERC approvals for non-environmental aspects of its certificate in July 1997. Environmental approvals are expected in 1998.

The NEB certificate hearing into the Canadian portion of Alliance began in November 1997. The project proponents expect the hearing to be completed by mid-1998, with a decision shortly after.

Figure 18: North American Gas Pipeline Projects

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Review of 1997
Natural Gas Prices

Review of 1997 Natural Gas Prices

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à U.S. Gas Prices
à Canadian Gas Prices
à Other Regional Prices

à U.S. Gas Prices

North American gas prices were the net result of weather, demand, supply, storage, and other factors during the year. North American gas prices are best represented by the NYMEX Henry Hub futures price.

The effects of these factors on monthly NYMEX prices during 1997 are shown in Figure 19. Storage was relatively low leading up to the heating season, prompting NYMEX prices to increase to $3.35/MMBtu by October 1997. This was followed by weak winter demand, and prices immediately began falling.

Although the month to month price pattern was quite different compared to last year, the average 1997 U.S. NYMEX gas price ($2.59/MMBtu) was identical to that of 1996.

That U.S. gas prices remain at fairly strong levels despite weak winter demand and high storage gives some indication of the degree to which the market believes gas supply is tight.

à Canadian Gas Prices

Despite the downward influence on Canadian prices of low local demand and high Western Canadian storage levels, Alberta gas prices (AECO) were much higher in 1997 compared to 1996. As shown in Figure 20, Western Canadian gas prices averaged US$1.34 per MMBtu (CDN$1.75/GJ) in 1997, 31% higher than in 1996. Prices in any market always reflect the supply/demand balance. As was reviewed in the Supply section of this report, the Alberta supply surplus has diminished somewhat

Figure 19: NYMEX Henry Hub Monthly Gas Prices

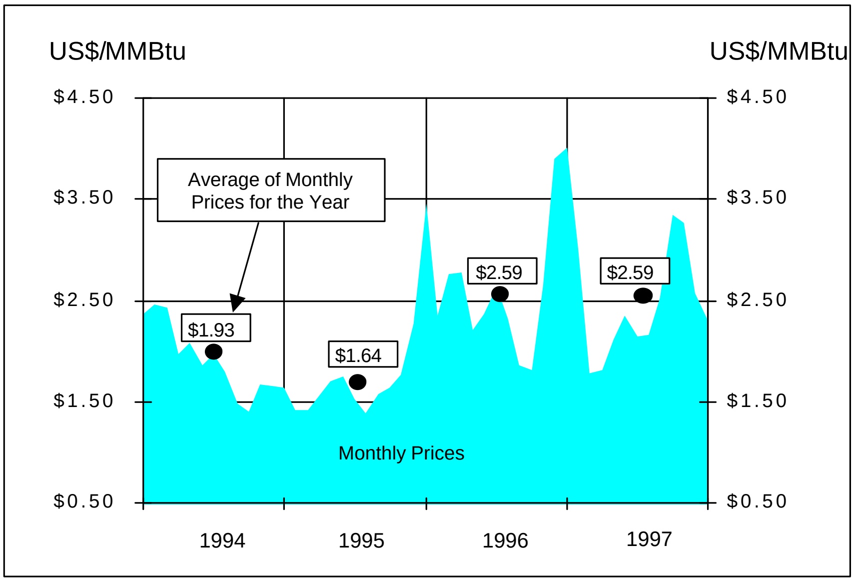
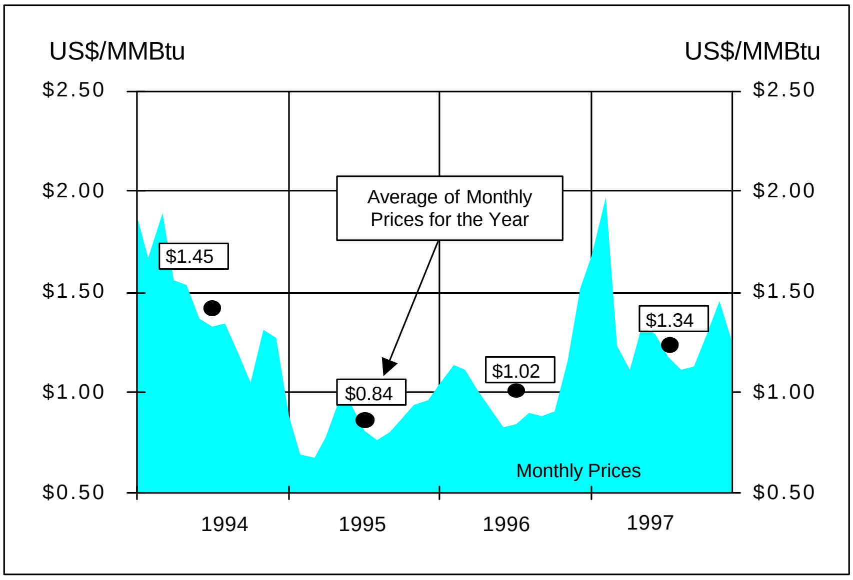


Figure 20: AECO C Canadian Monthly Gas Prices



compared to 1996, and this appears to have been reflected in Alberta gas prices. Impending pipeline expansions (Northern Border and TCPL expansions' in-service date is November, 1998) to higher priced markets may have also had an effect on 1997 gas prices in Western Canada.

à Other Regional Prices

During 1997, pipeline capacity between markets was adequate to allow most major North American gas markets to reach a balance. This is shown in Figure 21, which compares the track of monthly gas prices in several important North American gas markets: the AECO C storage hub in Alberta, the San Juan basin in New Mexico, the Henry Hub in Louisiana, Chicago, and New York City.

A review of the gas prices in Figure 21 leads to the following interpretation. In 1994, the above markets seemed to be quite well integrated. Canadian supply pipelines had just completed major expansions to U.S. markets (Iroquois, Northern Border, PGT), and all market prices moved together.

In mid-1995, eastern prices began to move up, western prices (San Juan, AECO) did not. These latter two markets had developed more production capacity than existing exit pipeline capacity. These markets were flush with gas, and prices reflected this.

In mid-1996, due to falling San Juan production and some increase in exit pipeline capacity, San Juan prices reconnected with the other prices.

San Juan prices are particularly important, as the San Juan basin is the marginal supplier to most of the U.S. West. U.S. West prices are driven by San Juan prices, and so supply tightness in the San Juan has caused higher U.S. West prices since mid 1996.

AECO is the only major gas market which continues to be isolated from the other markets. Even after a 31% increase in AECO prices in 1997, Canadian prices remained U.S.$1.25/MMBtu lower than NYMEX, on average, during 1997.

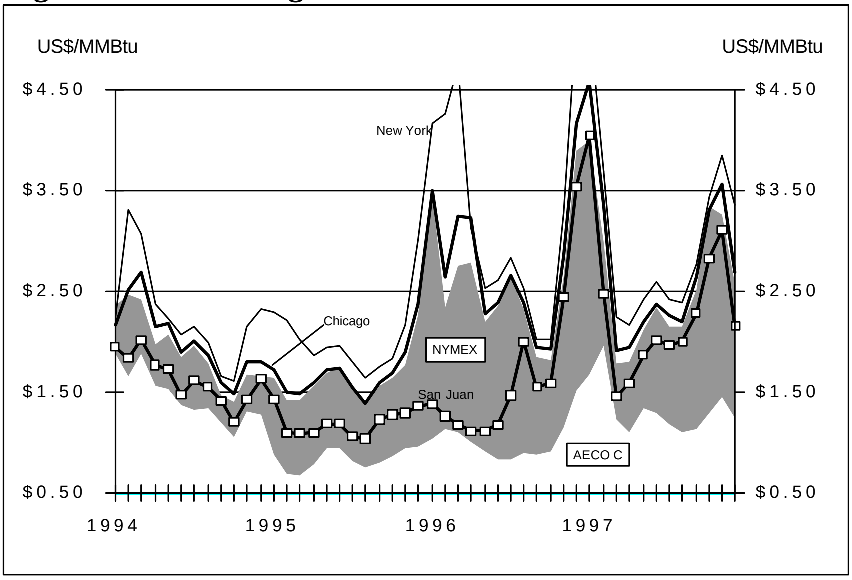
If sufficient pipeline capacity existed from Canada to U.S. markets, then Canadian prices would be more strongly influenced by U.S. prices.

In such a situation, Canadian gas prices could be expected to equal U.S. prices less a transportation differential to reflect the cost of moving gas from western Canada to the U.S.

Given that gas can be moved from western Canada to the U.S. Midwest for approximately U.S.$0.70 per MMBtu, and also considering that Midwest prices are typically higher than NYMEX prices, then with more capacity to the U.S., Canadian prices could be expected to remain in the area of NYMEX minus $0.70/ MMBtu or less.

The average Canadian gas price in 1997 ($1.34/MMBtu) was equal to NYMEX minus $1.25. NYMEX minus $0.70 would equal $1.89/MMBtu, an increase of 41% over actual Canadian prices. This illustrates why Canadian producers and marketers support more pipeline capacity to U.S. markets.

Figure 21: Other Regional Gas Prices



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Review of 1997
Canadian Export & Domestic Gas Sales

Review of 1997: Canadian Export & Domestic Gas Sales

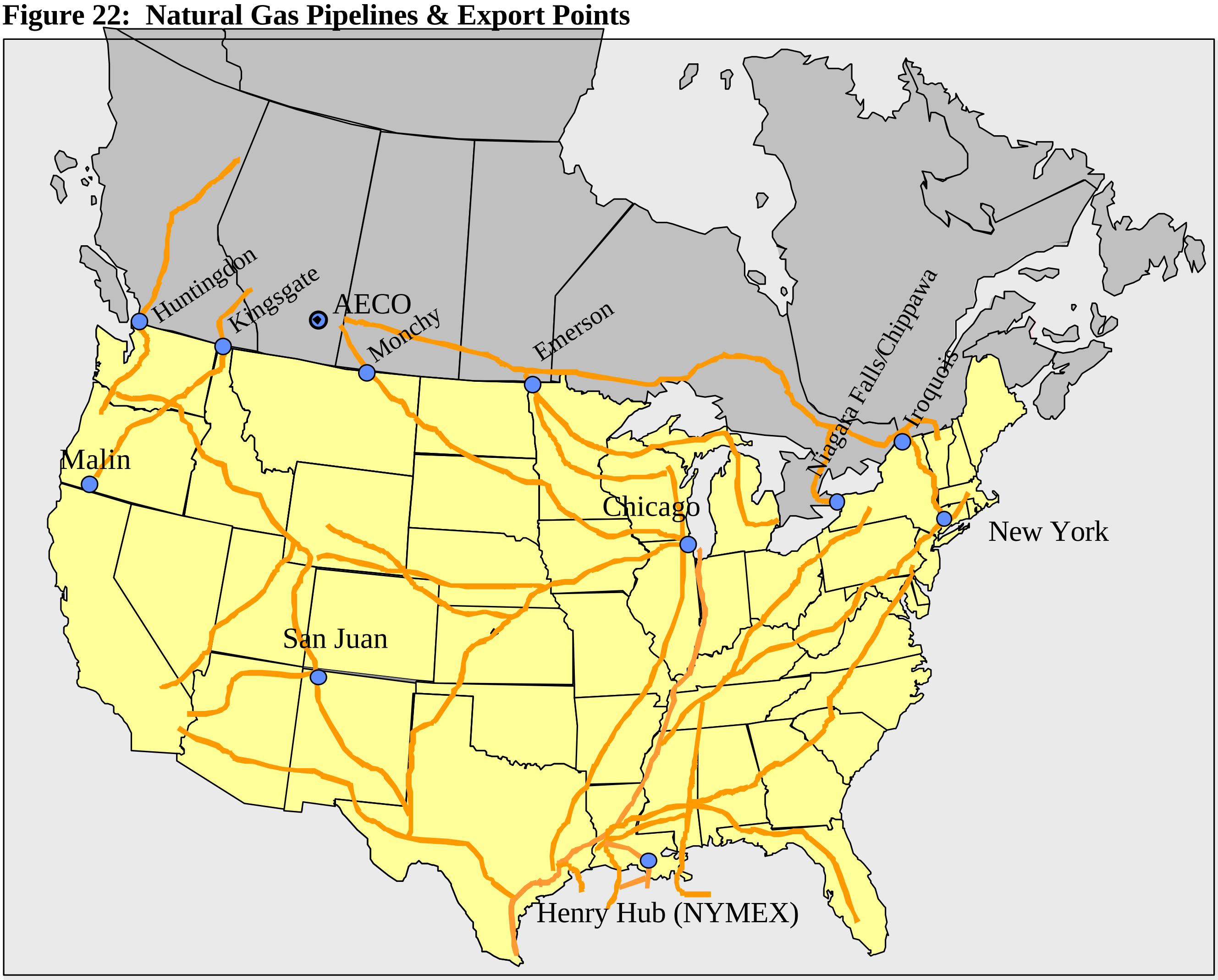
à Overview
Canadian producers achieved record revenues from natural gas sales in 1997. International border revenues were $CDN 8.7 billion in 1997, up from $CDN 7.5 billion last year. Plantgate revenues from export sales were $CDN 7.3 billion, up 20%. Domestic plantgate revenues trailed exports, at $CDN 4.8 billion, up 35% from last year.

The most important influence on revenues was higher prices. Average international border export prices rose 12% to US$2.16/MMBtu. Domestic prices (AECO) rose 31%, to $US1.34/MMBtu.

Canadian natural gas sales to the domestic market grew by only 0.5% in 1997, and exports grew by just 2%. This was the lowest volume growth rate in several years. While domestic sales were low due to warmer winter temperatures, export sales were restrained by limited export capacity.

à Pipeline Capacity
A pipeline bottleneck currently exists between Canada and U.S. markets. Pipelines serving U.S. markets have operated at full capacity for some time. A map of export points is shown in Figure 22.

Figure 22: Natural Gas Pipelines & Export Points



No major pipeline capacity additions occurred in 1997. Minor new export capacity (168 MMcf/d) was installed by TCPL to serve Midwest and Northeast markets. Growth in the domestic market was facilitated by 120 MMcf/d of new TCPL capacity to serve Eastern Canada.

à Sales Volumes

Mild weather and export pipeline restrictions curtailed the volume growth of gas sold in 1997. Figure 23 displays sales volumes by year.

Domestic sales reached 2,598 Bcf in 1997, an increase of less than 1% (13 Bcf) over 1996. Slow sales growth was due to weak demand growth (see demand review, page 19).

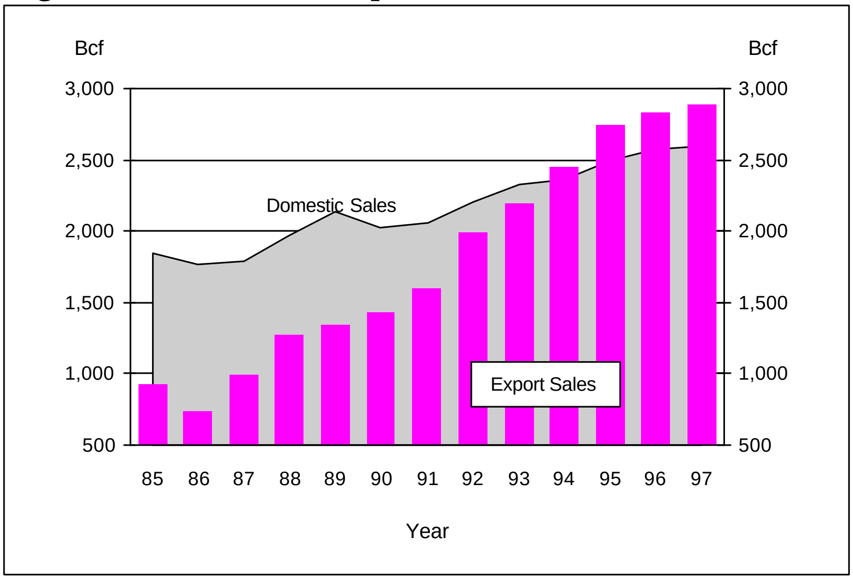
Exports reached 2,896 Bcf, up 2%. Most export growth occurred in the U.S. West market, where some under utilized pipeline capacity existed. About 50 Bcf of additional gas was exported at Kingsgate in 1997.

In the Northeast and Midwest markets, export sales were flat, reflecting only very minor capacity additions at the end of 1997.

à Load Factors

On average, export pipelines were utilized at identical load factors (89%) in 1997 as 1996. Higher load factors and volumes through the Kingsgate export point were achieved. Kingsgate was utilized at 92% load factor in 1997, compared to 86% last year.

Figure 23: Domestic & Export Gas Sales



At Huntingdon, load factors remained relatively stable and low (70%) compared to other export points. This situation reflects the fact that the Huntingdon export point includes three short user-dedicated lines, which are used at low load factors.

Again this year, Midwest and Northeast pipelines were running at essentially full capacity (Midwest 98%, Northeast 88%). As a result, Canadian producers are keenly anticipating additional capacity expected in 1988 and following years.

à Term & Class of Sales

The contractual structure of Canadian exports continued to move towards short-term contracts (defined as gas under NEB export orders of less than 2 years duration) and away from long-term sales (i.e., volumes moving under NEB export licences). In 1997, short-term sales reached 68% of total sales, compared to 62% in 1996.

A similar move toward interruptible sales occurred during the year. Interruptible sales (gas moving on interruptible rather than firm pipeline transmission contracts) accounted for 27% of total exports to the U.S., compared to 24% in 1996.

à Sales Prices

Table 6 provides an overview of natural gas prices in Canada and at the international border.

Prices for the three major export markets are drawn from information filed with the National Energy Board (NEB). Comparable price information for Canadian markets is not available from the NEB. Instead, Table 6 includes spot prices at the two most important gas pricing points for Canadian sales, the AECO-C price, (from the storage and trading hub near the Alberta-Saskatchewan border), and the Huntingdon/Sumas price (the largest British Columbia market).

Canadian gas buyers located in Alberta and points eastward typically buy their gas at the one-month AECO price. Some may buy gas at higher or lower prices, depending on the length of the gas purchase contract (hourly, daily, 1-year, etc.).

These Canadian gas buyers would then pay regulated pipeline transmission tolls to move the gas to their burners. The result is a delivered price equal to the AECO reference price plus the applicable pipeline tolls.

Prices that are determined in this way are termed *netforward prices*. Gas buyers assume the liability of paying demand charges on contracted pipeline capacity, but they purchase gas within Alberta, where prices are low.

Holding pipeline capacity has been advantageous for Canadian buyers. Netforward prices in Canadian markets have been lower than gas prices in adjacent U.S. markets.

Shippers who continue to contract for pipeline capacity between Alberta and markets are either producer/marketers, who see this as necessary to sell gas, or users who feel that, as in the past, this capacity will continue to be worth more than its regulated cost.

In contrast, U.S. gas purchasers generally rely on producers or marketers to hold pipeline capacity from Alberta to the U.S. market, and to deliver gas to the user's burner tip. The gas is then sold in the downstream market, and the price paid reflects local market conditions. While the gas buyer escapes the risk of holding pipeline capacity, the buyer loses the option of purchasing gas at the upstream end of the pipeline.

The *netback* to an Alberta producer that holds capacity to a U.S. market, and sells gas in that market, is the market price less the producer's cost of moving the gas from Alberta to the market. As netback prices are generally higher than Alberta prices, it has been advantageous for producers to hold pipeline capacity to most U.S. markets in most periods.

à Higher Prices in 1997

As shown in Table 6, natural gas prices in both the domestic and export markets were stronger in 1997. The exception was the Northeast market, which already had relatively strong prices in 1996. Northeast prices remained steady in 1997.

In Canada, the average AECO spot price continued to recover from its low of US$0.84/MMBtu in 1995. The AECO price increased by 31%,

Table 6 : Domestic & Export Gas Prices

		International Border Export Prices					Canadian Markets		
		West	MW	NE	Avg.	Avg.	AECO	AECO	Huntingd.
Year	Month	(US/MMBtu)	(US/MMBtu)	(US/MMBtu)	(US/MMBtu)	(CDN/GJ)	(CDN/GJ)	(US/MMBtu)	(US/MMBtu)
1997	January	2.77	3.58	3.85	3.32	4.24	2.15	1.68	3.92
	February	2.10	2.59	3.33	2.55	3.28	2.53	1.97	2.43
	March	1.28	1.61	2.58	1.68	2.18	1.60	1.23	1.07
	April	1.24	1.64	2.39	1.64	2.17	1.47	1.11	1.14
	May	1.43	1.76	2.49	1.78	2.33	1.75	1.34	1.36
	June	1.66	1.91	2.63	1.96	2.57	1.69	1.29	1.34
	July	1.37	1.87	2.53	1.82	2.38	1.54	1.18	1.22
	August	1.31	1.90	2.50	1.77	2.33	1.46	1.11	1.10
	September	1.42	2.18	2.68	1.96	2.57	1.49	1.13	1.19
	October	1.71	2.58	3.31	2.36	3.11	1.70	1.29	1.49
	November	2.19	2.92	3.43	2.72	3.65	1.94	1.45	2.76
	December	1.68	2.18	2.91	2.15	2.91	1.68	1.24	1.46
1997 Average		**1.69**	**2.24**	**2.90**	**2.16**	**2.83**	**1.75**	**1.34**	**1.71**
1996 Average		1.28	2.04	2.89	1.92	2.48	1.32	1.02	1.32
% change		31.7%	9.5%	0.4%	12.3%	14.1%	32.9%	30.9%	29.2%

Sources: NEB, Friedenberg

from US$1.02/MMBtu in 1996 to US$1.34/MMBtu in 1997.

Prices for Canadian gas to the U.S. West market matched the domestic price increase of 32%. Midwest prices rose 10%, while Northeast prices rose only 0.4%.

Prices paid for Canadian gas in the U.S. West market increased from US$1.28/MMBtu in 1996 to US$1.69/MMBtu in 1997. This reflected higher prices for gas in the San Juan basin, the marginal supplier to the U.S. West.

After an increase of 40% last year, export prices to the Midwest market increased by 10% this year, reaching US$2.24/MMBtu.

In the Northeast market, export prices remained flat but high (US$2.90/MMBtu) compared to the other two export markets.

à Plant Gate Netbacks

These prices resulted in higher plant gate netbacks for producers. Table 7 illustrates plant gate netbacks from U.S. sales, as well as those for gas sold at Huntingdon and AECO.[1]

In 1997, as in 1996, sales to eastern U.S. markets earned the highest netbacks for Canadian producers. Netbacks to the U.S. West remained considerably below those to the Midwest and Northeast. Producer netbacks from domestic sales were even lower, due to low Canadian market prices.

à Sales Revenue

In 1997, slight growth in gas volumes sold combined with significant price increases in both domestic and export markets translated into strong revenue growth.

Figure 24 shows a breakdown of plant gate revenues from each export region, for total exports, and for total domestic sales[1]. Revenues are expressed in Canadian dollars.

Domestic revenues are much lower than exports, reflecting slightly lower volume, and much lower prices.

Table 7: Domestic & Export Plant Gate Netbacks

		Export Plant Gate Netbacks					Domestic Plant Gate Netbacks		
		West	MW	NE	Avg.	Avg.	AECO	AECO	Huntingd.
Year	Month	(US/MMBtu)	(US/MMBtu)	(US/MMBtu)	(US/MMBtu)	(CDN/GJ)	(CDN/GJ)	(US/MMBtu)	(US/MMBtu)
1997	January	2.55	3.31	2.98	2.93	3.75	2.04	1.59	3.55
	February	1.89	2.24	2.36	2.11	2.72	2.42	1.88	2.12
	March	1.08	1.30	1.72	1.30	1.69	1.49	1.14	0.81
	April	1.04	1.38	1.59	1.29	1.70	1.35	1.02	0.88
	May	1.22	1.49	1.69	1.42	1.86	1.64	1.25	1.09
	June	1.44	1.63	1.79	1.58	2.08	1.58	1.20	1.07
	July	1.17	1.60	1.69	1.44	1.88	1.43	1.09	0.96
	August	1.10	1.63	1.69	1.41	1.86	1.35	1.02	0.84
	September	1.21	1.89	1.87	1.59	2.08	1.37	1.04	0.93
	October	1.52	2.29	2.45	2.00	2.62	1.58	1.20	1.22
	November	2.12	2.65	2.59	2.69	3.60	1.83	1.36	2.44
	December	1.50	1.90	2.14	1.80	2.43	1.56	1.15	1.19
1997 Average		**1.50**	**1.98**	**2.13**	**1.81**	**2.38**	**1.64**	**1.25**	**1.43**
1996 Average		1.17	1.77	1.96	1.56	2.02	1.20	0.93	1.06
% change		28.1%	12.0%	8.9%	15.9%	17.7%	35.9%	33.8%	35.1%

Sources: NEB, Friedenberg

1. Domestic netbacks and revenues estimated, based on published spot month prices, and assuming transmission used at 100% load factors.

In 1997, export sales revenues at the plant gate increased by 20%, reaching CDN $7.3 billion. The increases in revenues differ considerably from one region to another, ranging from 13% in the U.S. Northeast to 35% in the U.S. West market.

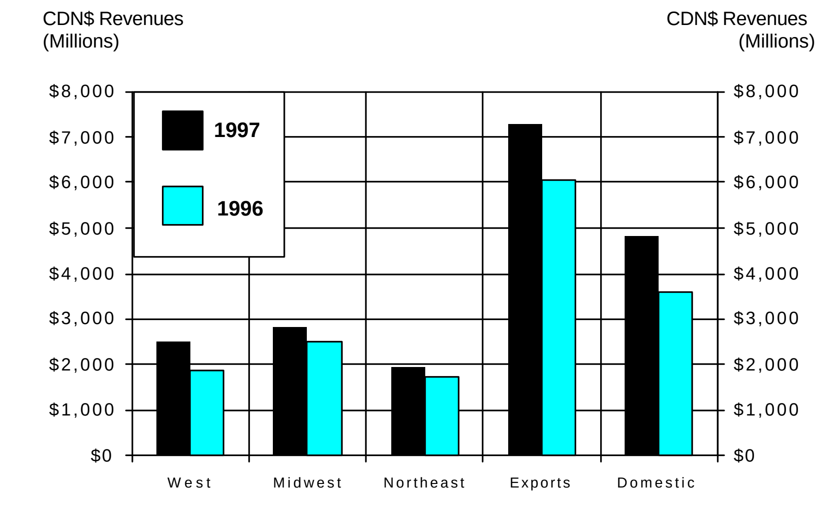
Fifty-four percent of the additional export revenues was generated in the U.S. West market, where most of the additional gas was exported in 1997, and where prices also rose by the largest percentage.

In the U.S. Midwest and Northeast markets, the increase in revenues was a more moderate 14% and 13%.

Measured at the international border, export revenues were CDN $8.7 billion in 1997, compared to CDN $7.5 billion in 1996. These prices reflect the inclusion of gas transmission costs from the plant gate to the border export point (Note Figure 24 above shows plant gate revenues, which are lower).

The Canadian dollar/US dollar exchange rate was stable versus last year, and therefore had no major impact on natural gas export revenues.

Figure 24: Plant Gate Revenues From Canadian Gas Sales



Sources: NEB, NRCan estimates

Outlook to 2005
North American Demand

Outlook to 2005
North American Demand

---SECTION CONTENTS --
à U.S. Demand
à Canadian Demand
à Regional Demand

à U.S. Demand

Figure 25 shows five forecasters' views of U.S. natural gas demand to year 2005. In 2005, U.S. gas demand is expected to be 3.3 to 4.0 Tcf higher than in 1997. The yearly average of these forecasts yields an average annual growth rate of 2.1%. U.S. demand growth over the *past* five years was 2.4%.

Each forecast assumes an important role for electricity generation (UEG) and the industrial sector in future demand growth (see Figure 26).

UEG is identified as being particularly important for future gas demand growth, with a very large change in the pattern of U.S. UEG gas demand being forecast. Projected annual UEG growth rates over the 1997-2005 period are from 4% to 10%, with the average being 7%. Over the past 5 years, annual UEG gas demand growth has averaged 1.4%. Over the next few years, it will be necessary to monitor UEG gas demand, to confirm that this growth is actually occurring.

à Canadian Demand

Figure 27 shows the Canadian Gas Association (CGA), ARC Financial, and Canadian Energy Research Institute forecasts for Canadian natural gas demand. The average expectation is for Canadian gas demand to grow at a 2.4% average annual rate. Over the *past* five years, Canadian gas demand growth has averaged 3.8% per year.

à Regional Demand

In keeping with our regional focus, Table 8 shows 1997 gas demand for supply areas and demand regions. Also shown are the historic demand growth rates in those regions, and our demand outlook.

Figure 25: U.S. Gas Demand Forecasts

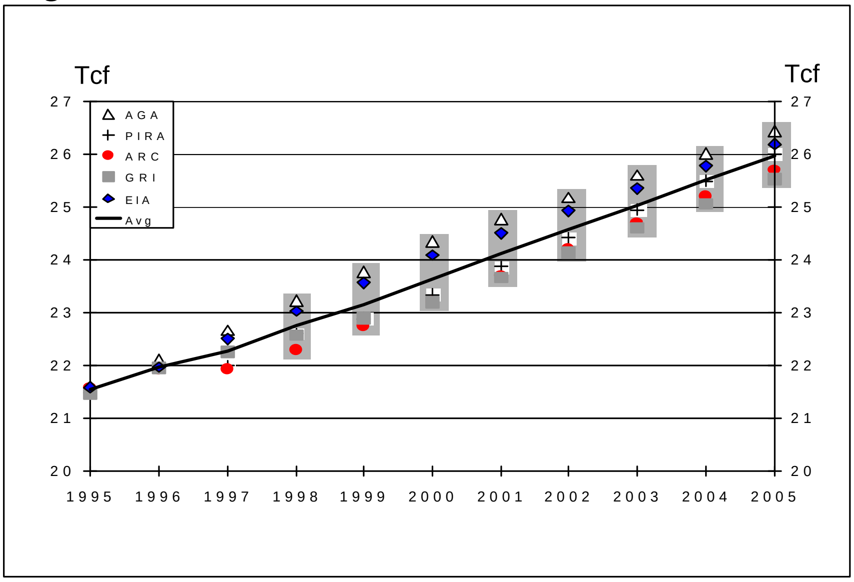
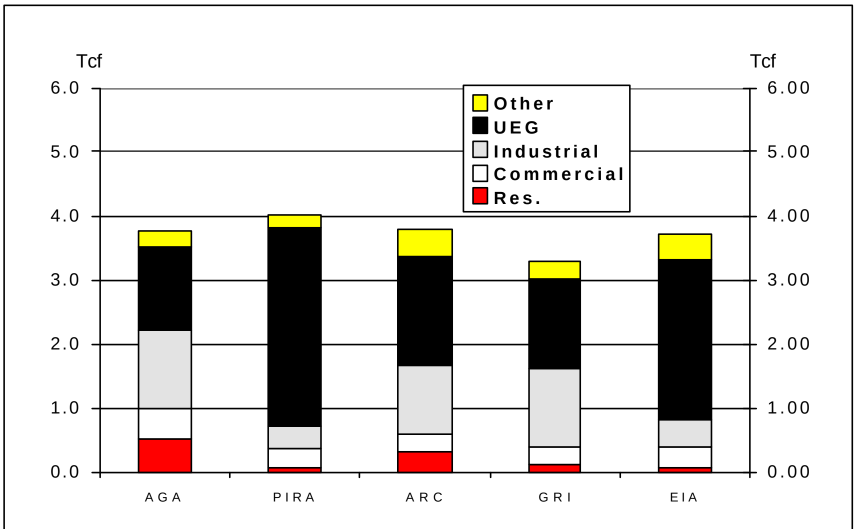


Figure 26: U.S. Incremental Demand to 2005, by Sector



Note: PIRA and GRI UEG includes all electric generation, others put NUG in Industrial

Our forecast considers historical growth in each region, and the regional demand forecasts of several organizations (PIRA, EIA, and Fosters). The highest rates of gas demand growth are projected for the South Atlantic (3.3% annually) and Western U.S. (3.2% annually) regions.

South Atlantic gas demand has grown by 3.8% per year over the past five years. The region is seeing significant population growth, driving gas demand for electric generation for home air conditioning.

In the past 5 years demand growth in the Western U.S. - only 1% per year - has not been as strong as in the South Atlantic. High hydro reservoir fill levels allowed hydropower to supply incremental electricity requirements.

However all forecasters we surveyed foresee high demand growth in the U.S. West region in the future, due to growing gas demand for newelectric generation, and minimal additions of hydropower.

In terms of absolute volumes of demand growth over the period, the largest increment of demand growth is expected for the Gulf Coast (790 Bcf), followed by the Midwest, West, Northeast, and South Atlantic (see Table 8).

We assume that U.S. and Canadian demand will follow the average forecasts of the experts surveyed. In short, U.S. and Canadian gas demand will total 29,170 Bcf in 2005.

We also assumed U.S. LNG exports of 60 Bcf per year would continue. The result is total North American gas requirements of 29,230 Bcf in 2005. This is 4,467 Bcf more than North American gas requirements in 1997.

Figure 27: Canadian Gas Demand Forecasts

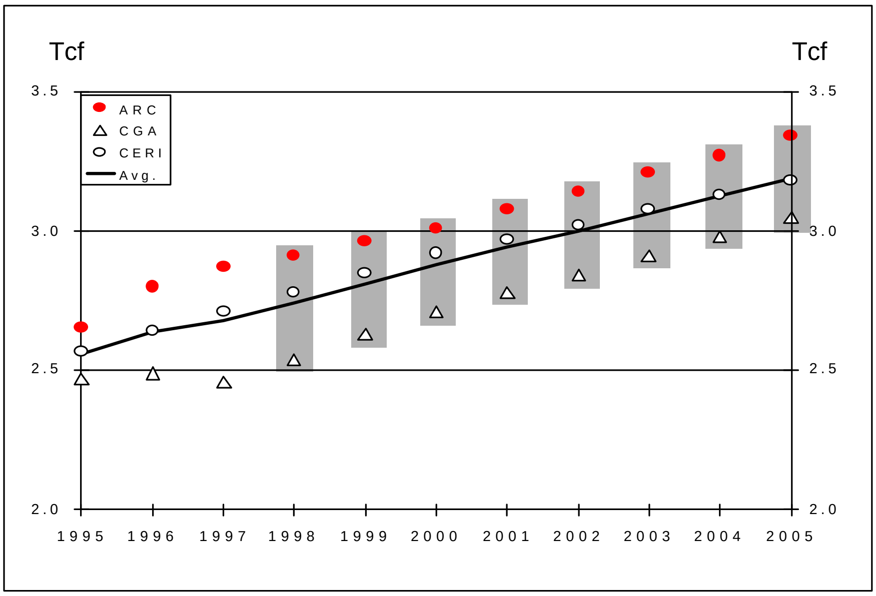


Table 8 : Regional Demand Assumptions

	Actual 1997 Demand	Historic 92-97 Annual Growth	Assumed Growth Rate to 2005	Regional Incremental Demand 97-2005	Regional Demand Forecast 2005
Gulf Coast	5,370	2.3%	1.7%	790	6,160
Midcontinent	1,280	2.3%	1.7%	182	1,462
Rockies	590	3.1%	2.2%	111	701
U.S. West	2,427	1.0%	3.2%	686	3,113
U.S. Midwest	4,539	2.5%	1.9%	732	5,271
U.S. Northeast	3,062	3.0%	2.0%	535	3,597
U.S. South Atlantic	1,797	3.8%	3.3%	538	2,335
Other U.S.	956	1.9%	0.9%	68	1,024
Total U.S. End-Use	20,021	2.4%	2.1%	3,642	23,663
U.S. Pipe fuel, etc.	1,997	2.2%	1.9%	320	2,317
Total U.S. Demand	**22,018**	**2.4%**	**2.1%**	**3,962**	**25,980**
Canadian Demand	**2,642**	**3.8%**	**2.4%**	**548**	**3,190**
Total North America	**24,660**	**2.6%**	**2.1%**	**4,510**	**29,170**

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Outlook to 2005
North American Supply

Outlook to 2005 North American Supply

------------------ SECTION CONTENTS --------------------

à Production Outlook

As indicated in the previous section, we expect the North American gas market to require 29,230 Bcf of natural gas in 2005 - 4,467 Bcf more than in 1997.

Our outlook (see Table 9 and Figure 33 at end of this section) shows U.S. producers supplying well over half of this incremental gas, and Canadian producers supplying one-third. The balance will come from LNG imports and other supplies.

Our North American supply forecast begins with the above gas requirements. We then calculate Canadian gas exports to the U.S. Our export forecast of 3,751 Bcf in 2005 is driven mainly by estimates of export pipeline capacity and our assumptions on load factors (see Canadian Gas Sales section, page 61).

We also assumed that Canadian supplies would satisfy the full 3,190 Bcf of Canadian gas demand in 2005. This yields a forecast for Canadian production of 6,941 Bcf in 2005, equal to Canadian exports to the U.S. plus Canadian demand.

Future U.S. supplies from LNG and other sources were estimated at 370 Bcf in 2005, based on the average of several expert forecasts (see paragraphs later in this section).

When supplies from Canada and LNG are subtracted from forecast North American gas use, the result is an estimate of required U.S. production. Based on this analysis, we conclude that required U.S. production will be 21,919 Bcf in 2005.

à Adequacy of U.S. Gas Supply

Given our views on U.S. gas demand and imports, the rate of U.S. production growth must increase substantially if forecast U.S. demand growth is to be met.

U.S. production grew at a rate of 1.3% annually over the last 5 years, lagging demand growth of 2.4% per year. Canadian gas made up the shortfall. If U.S. production continued at a 1.3% average annual growth from 1997 to 2005, U.S. domestic production would reach only 21,100 Bcf in 2005, 819 Bcf less than required U.S. production as calculated above.

Forecasts of U.S. Supply

Figure 28 shows various forecasters' views of U.S. production to 2005. The average expectation is for U.S. production growth to increase to 1.7% per year, allowing production to reach 21,970 Bcf by 2005.

Thus, the average expectation for U.S. production, combined with our estimates of Canadian and LNG exports to the U.S.,

Table 9: North American Gas Supply Outlook

	2005 (Bcf)	1997 (Bcf)	Difference (Bcf)	% Change	% of Total Increase	% N.A. Supply
U.S. Gulf Onshore	7,588	6,542	1,046	16.0	22.4	26.0
U.S. Gulf Offshore	6,667	5,465	1,202	22.0	25.8	22.8
U.S. Midcontinent	2,250	2,415	-165	-6.8	-3.5	7.7
U.S. Rockies&NewMex.	3,488	2,864	624	21.8	13.4	11.9
Other U.S.	1,926	1,676	250	14.9	5.4	6.6
Total U.S. Production	21,919	18,962	2,957	15.6	63.4	75.0
Canadian Production	6,941	5,513	1,428	25.9	30.6	23.7
LNG & Other	370	93	277	297.8	5.9	1.3
TOTAL N.A. SUPPLY	29,230	24,568	4,662	19.0	100.0	100.0

would be adequate to meet forecast U.S. gas demand.

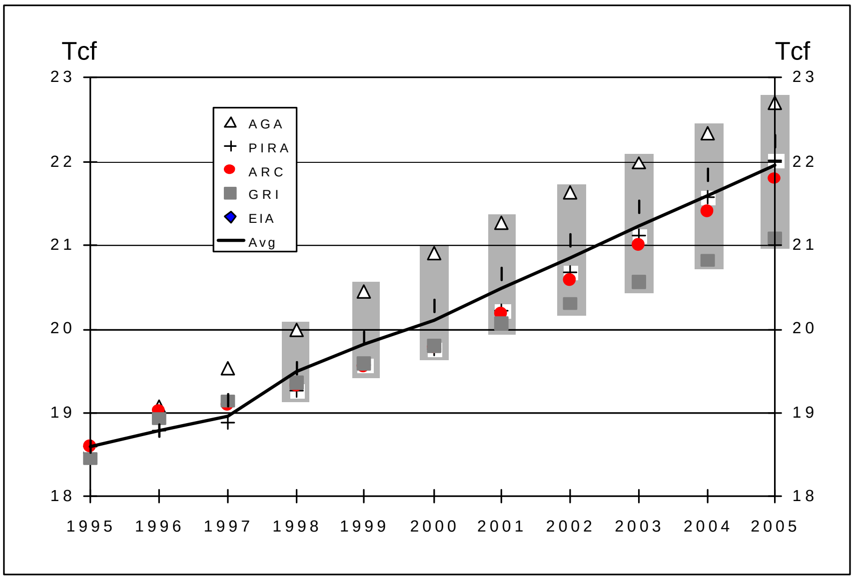
à Regional Supply Outlook
Most of the forecasters that we have used estimate aggregate supply. PIRA and EIA disaggregate U.S. production into supply regions. Our regional production outlook is based on these forecasters' predictions and the conclusions from our *Gas Supply 1997* report.

à Gulf Coast Onshore
The Gulf Coast Onshore, with 6,542 Bcf of production in 1997, is the largest U.S. supply region, accounting for 35% of U.S. production in 1997. We expect Gulf Onshore production to rise to 7,588 Bcf by 2005, for an average annual growth rate of 1.9% per year. This matches the 1.9% per year average increase over the past three years. Additions to proved reserves over the 1994-96 period were 20% higher than production, indicating good potential for supply growth.

à Gulf Coast Offshore
The Gulf Offshore currently produces 5,465 Bcf per year. Production is expected to increase by 2.5% per year, reaching 6,667 Bcf in 2005. This is much greater than the average annual growth of the past three years, which was less than 1%.

Figure 29 outlines the production forecasts from three organizations for the Gulf Offshore. All organizations expect substantial production growth.

Figure 28: U.S. Gas Production Forecasts

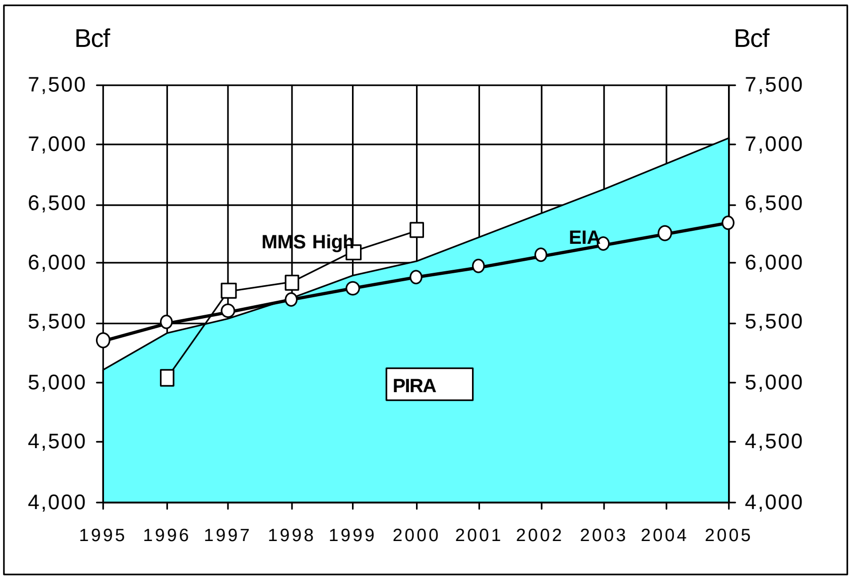


High expectations for production in this area are supported by recent upstream activity in the region. Gas drilling rates were 75% higher in 1997 than they were in 1994. Leasing activity in the offshore is also very high, as shown in Figure 30.

Most of this incremental production is expected to come from the deepwater. During 1997, 70% of the tracts bid on in Gulf Offshore land sales were in greater than 200 metres water depth.

à Midcontinent
Midcontinent production is expected to fall from 2,415 Bcf in 1997 to 2,250 Bcf in 2005, a drop of 1% per year on average. The region's production has fallen by 3.5% per year in the past 3 years. Additions to

Figure 29: Gulf Offshore Production Forecasts



proved reserves have averaged only 75% of production over the 1994-96 period. It seems doubtful that the area can maintain current production.

à U.S. Rockies

The U.S. Rockies is expected to increase production from 2,864 Bcf in 1997 to 3,488 Bcf in 2005, an average annual growth rate of 2.5%. This level of additional production will require exit pipeline capacity expansions. Most of the required capacity is either proposed or under construction.

One reason for our strong Rockies production outlook is the scale of existing proved reserves in the region. Unlike other regions, which produce 10% to 17% of their proved gas reserves each year, the Rockies currently produces only 7.5%. This indicates the potential to increase production simply by further developing already discovered reserves.

à Other U.S. Supply

We expect *other* U.S. supplies (i.e., from states with minor production such as Alaska, California, Michigan, New York, etc.) will contribute 1,926 Bcf to North American supply by 2005. This is an increase of 250 Bcf over 1997 levels.

à Canadian Production

We anticipate that Canadian production will grow from 5,513 Bcf in 1997 to 6,941 Bcf by 2005, an average annual growth rate of 3%, which was the average growth rate of the *last* three years.

Figure 30: Leasing Activity Gulf Offshore

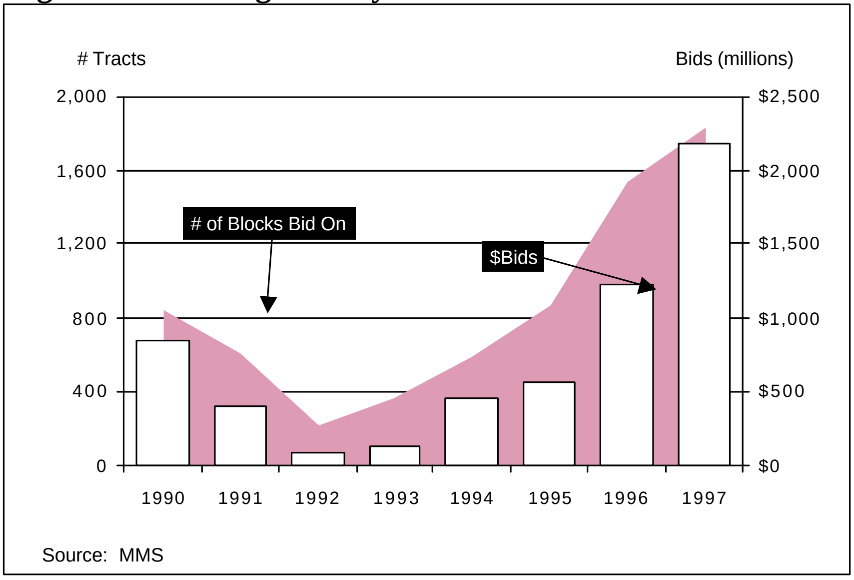
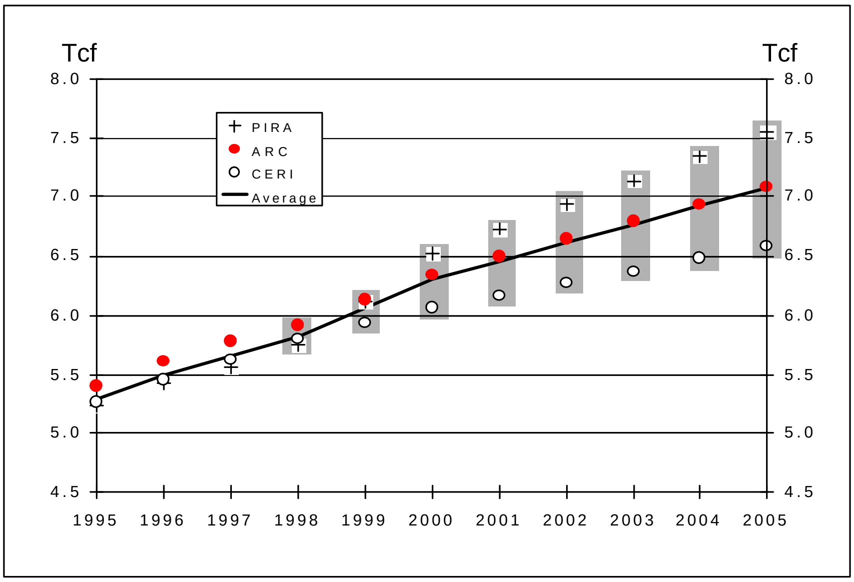


Figure 31 shows the PIRA, CERI, and ARC Financial forecasts of Canadian gas production. The average of these three forecasts approximately matches our view.

Considerable drilling will be required to reach this production level. The NEB recently estimated[5] that 3,500 to 4,000 Canadian gas wells would have to be drilled and connected each year to replace production declines and meet new demand. In 1997, there

Figure 31: Canadian Production Forecasts



[5] *Producers' Response to Changing Market Conditions*, June 1997

were 4,256 gas wells drilled in Western Canada. In short, the industry appears to be on track to achieve projected production.

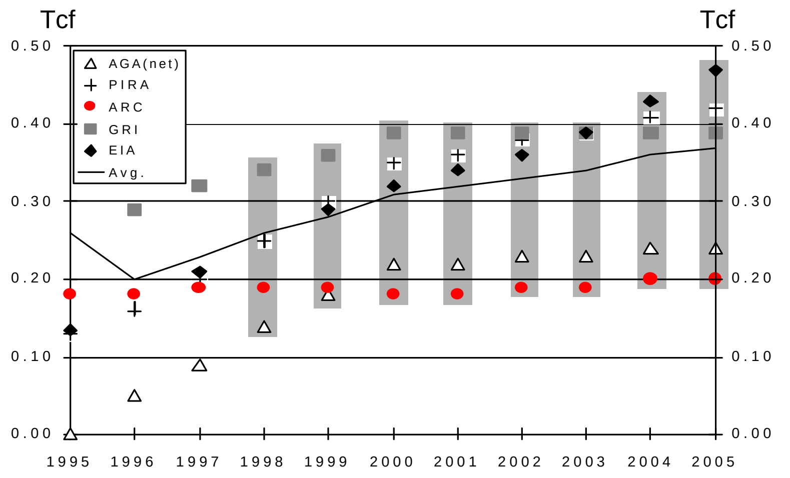
As with the U.S. Rockies, for any significant Canadian production growth to occur, pipeline expansions are necessary, as current exit pipeline capacity is effectively full. Canadian expansions are either under construction or before regulators for approval.

Over the outlook period, production is also expected to begin at the Sable Offshore Energy Project. We expect 143 Bcf per year of gas production by 2005, distributed between U.S. and Canadian markets.

à LNG & Other

Figure 32 shows various forecasts for LNG imports, supplemental gas[6], and Mexican imports into the U.S.

Figure 32: U.S. LNG* Imports



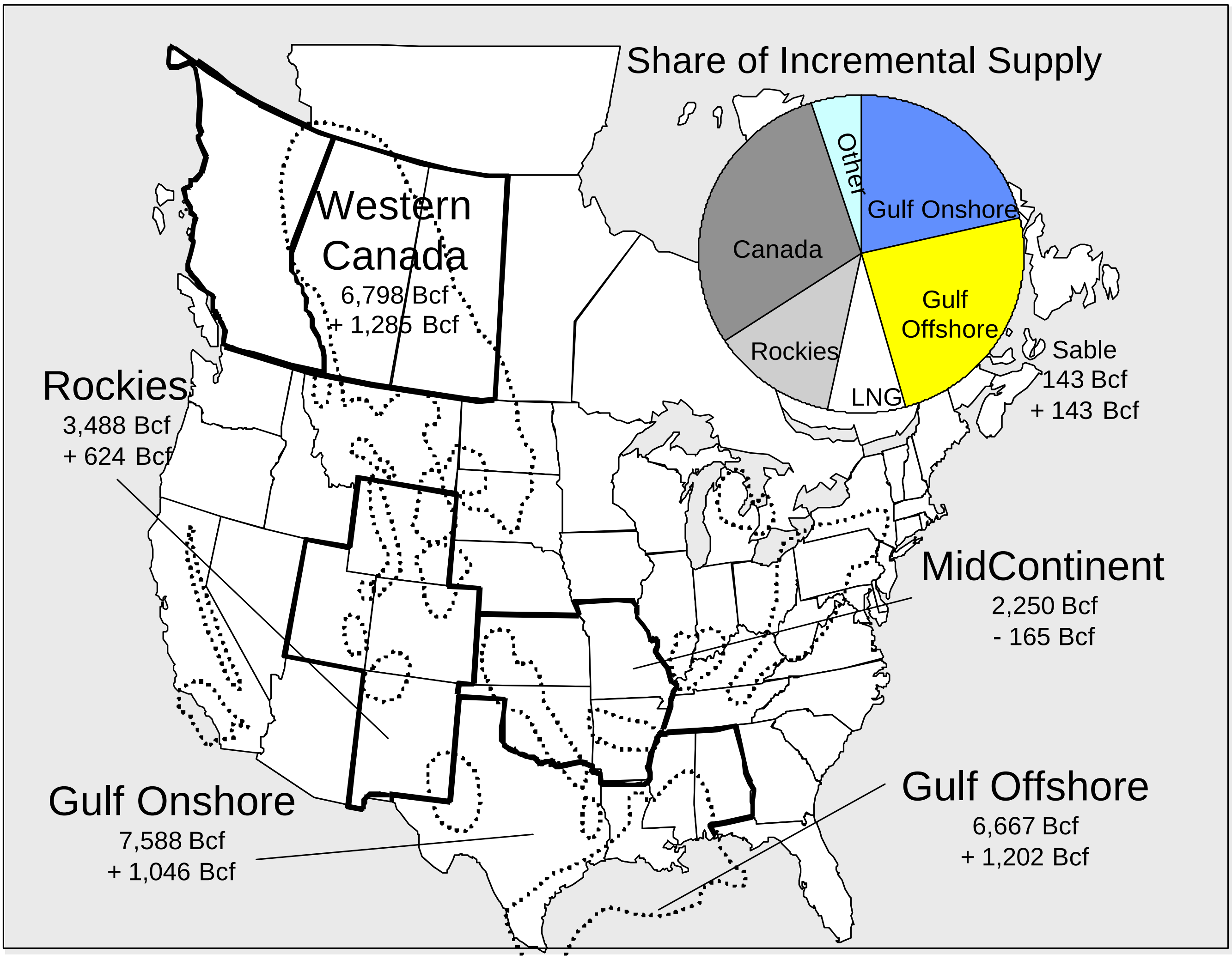
AGA = Net Basis
* includes LNG, supplementals, Mexican imports

There is a wide range of values predicted, from 200 Bcf to 470 Bcf in year 2005.

Our outlook assumes 370 Bcf of LNG and other supply to the U.S. by 2005 (i.e, the average of the forecasts). Higher Algerian LNG exports to the U.S. are widely expected, as renovations of Algerian gas liquefaction plants were completed late last year. These renovations had resulted in lower LNG exports to the U.S. in recent years.

[6] Supplemental gas includes coal gasification gas, propane/air mixtures, etc.

Figure 33: Incremental North American Gas Supply



Outlook to 2005
Gas Flows & Pipeline Capacity

Outlook to 2005
Gas Flows & Pipeline Capacity

à Outlook
Figure 34 shows our estimates of how gas flows will change by year 2005, based on our outlook for regional supply and demand changes. Detail on these flow calculations is shown in Table 10.

à Gulf Coast & Midcontinent
We expect a large increase in gas flowing out of the U.S. Gulf Coast. This forecast is based on the expected combination of strong supply growth and only a moderate expansion in demand.

We anticipate total Gulf production (onshore and offshore) will increase to 14,255 Bcf, while demand will increase to 6,160 Bcf. This will result in net flows out of the Gulf rising from 6,637 Bcf in 1997 to 8,095 Bcf in 2005, i.e., an increase of 1,458 Bcf.

The largest part of the increased Gulf outflow will satisfy demand growth in the neighbouring South Atlantic states (from Maryland south to Florida), where demand is expected to grow a total of 530 Bcf over the period. Due to its transportation cost advantage, the Gulf will continue to supply all demand in the South Atlantic. The increased Gulf outflows will also replace falling Midcontinent outflows. This will absorb a further 347 Bcf of the incremental Gulf supply.

This will still leave 581 Bcf per year of Gulf gas (1,592 MMcf/d) looking for other markets. This gas is likely to be marketed in the U.S. West, Midwest and Northeast, where it will compete with supplies from Canada and the U.S. Rockies.

Increased Gulf outflows will lead to higher utilization of pipeline capacity to the U.S. West, Midwest, and Northeast.

In general, the Gulf is well served by existing pipeline capacity. However, some new capacity out of the Gulf may be required to allow producers to target favoured markets. Several expansions from the Gulf to the South Atlantic are currently proposed, as is one large expansion to the Northeast (Tennessee's Line 500 project).

Table 10: Projected North American Gas Flows in 2005

Supply Regions:	2005 Prod. (Bcf)	2005 Demand (Bcf)	Net OutFlows 2005 (Bcf)	Net OutFlows 1997 (Bcf)	Difference (Bcf)	Change %
Gulf Coast	14,255	6,160	8,095	6,637	1,458	22
Midcontinent	2,250	1,462	788	1,135	-347	-31
U.S. Rockies	3,488	701	2,787	2,274	513	23
Western Canada	6,798	1,686	5,112	4,131	981	24
Demand Regions:			Demand 2005 (Bcf)	Demand 1997 (Bcf)	Difference (Bcf)	Change %
West			3,113	2,427	686	28.3
Midwest			5,271	4,539	732	16.1
Northeast			3,597	3,062	535	17.5
South Atlantic			2,335	1,797	538	29.9
Eastern Canada			1,503	1,280	223	17.4

à U.S. Rockies
Higher production and net exports from the U.S. Rockies are also expected, as shown in Table 10. The incremental 513 Bcf of outflows will be absorbed in the U.S. West, Midwest, and Northeast.

à Canada
A significant increase in Canadian gas exports to the U.S. is expected. We anticipate that over the 1997-2005 period, Canadian gas exports to the U.S. will increase by 855 Bcf; with an incremental 66 Bcf to the West; 606 Bcf to the Midwest; and 183 Bcf to the Northeast.

Annual gas flows from western Canada to eastern Canada will also increase, by approximately 200 Bcf.

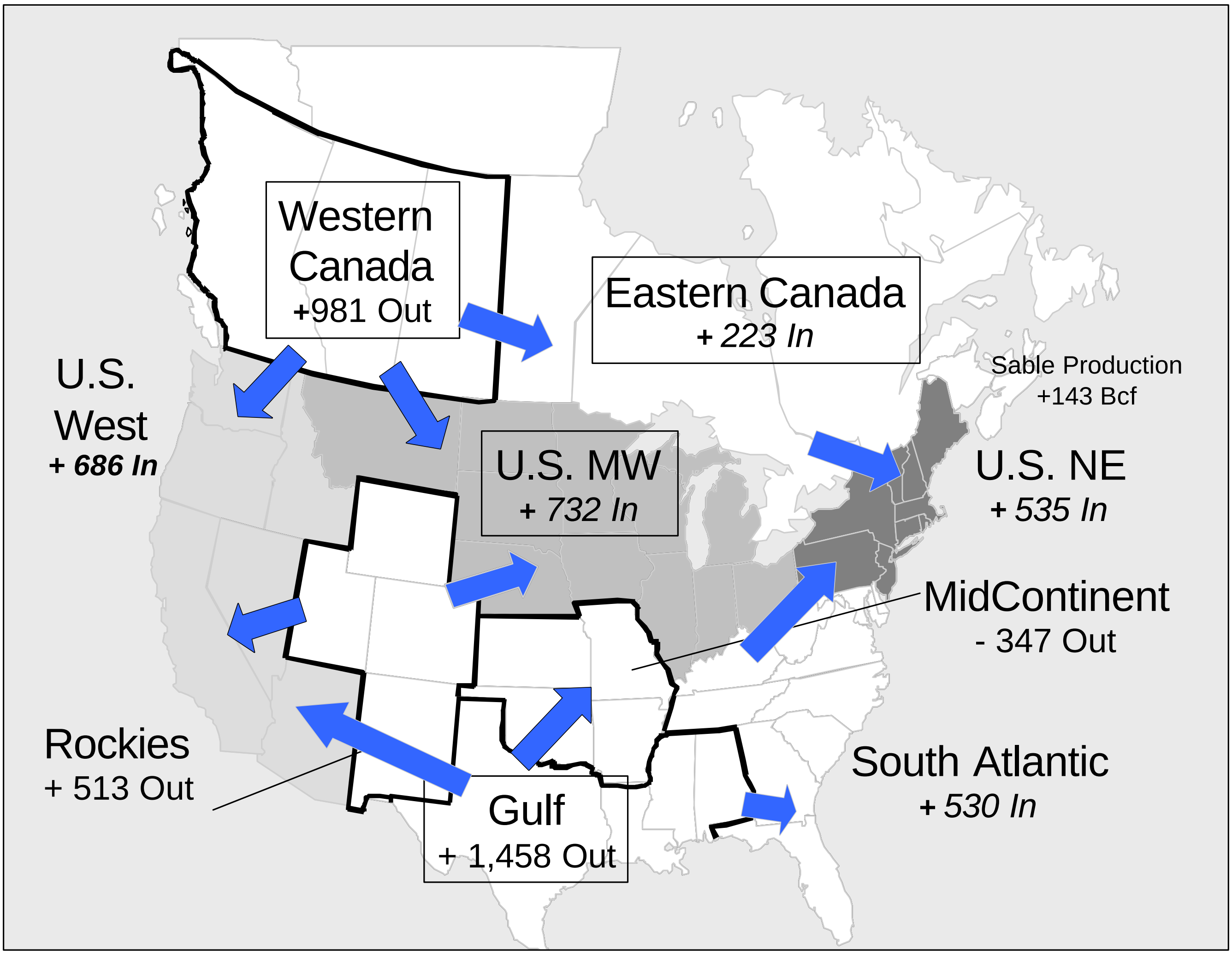
à U.S. West
Considerable demand growth (678 Bcf) is expected for the the U.S. West region.

Regarding supply of this gas, small improvements in load factors on pipelines moving Canadian and Rockies gas to the region could be attained. There is also still considerable pipeline capacity between the U.S. Gulf Coast and the West. Much of this capacity is either not being used, or is being used for west to east flow, bringing Rockies gas to the Gulf. This flow could be reversed (again).

However, given that Gulf Coast producers may decide to target markets other than the U.S. West, pipeline expansions from Western Canada and the Rockies may also be required if forecast gas demand growth does occur in the U.S. West.

à U.S. Midwest
The Midwest is currently oversupplied with pipe. As a result, the marginal supplier to the region, the Gulf, does not fill its pipes to the Midwest each month.

Figure 34: Incremental North American Gas Flows to 2005



This situation will likely intensify in the future, as the total incremental pipeline capacity proposed to the Midwest (800 Bcf per year from Canada alone) exceeds projected Midwest market growth (732 Bcf according to our outlook). Offsetting this effect, pipeline capacity from the Midwest to the Northeast will allow gas to move through the Midwest enroute to the Northeast.

Which pipeline capacity will be used will depend on: 1) prices in supply regions relative to market region prices; 2) the cost of pipeline transmission to market regions on the relevant pipeline; and 3) the nature of pipeline/shipper contracts.

For example, when the price in the Midwest exceeds the price in a supply region, plus the *marginal* cost of pipelining gas from the supply region to the Midwest, then it is profitable to move gas to the Midwest, and the pipeline capacity is used. Note that sunk costs (i.e., demand charges on pipeline capacity contracted for long terms) generally are not considered relevant to the decision on whether to use pipeline capacity.

If the Midwest price is *less* than the supply region price plus transmission cost to the Midwest, then a gas producer or marketer is better off just selling the gas in the supply region, and the pipeline capacity to the Midwest remains idle.

Thus, price differentials between various supply regions and markets are important, as are the costs of pipeline transmission along various routes.

Most pipeline capacity from Canada to the Midwest is under long term contracts with demand charges.

In short, which pipeline capacity will be used is mainly a supply question. The supply region which is able to increase production at the lowest prices will tend to fill its pipeline capacity to markets.

à U.S. Northeast

Given the number of pipeline projects proposed for the U.S. Northeast, it too is likely to become overpiped. Again, which pipes will lie idle will depend on basin-on-basin supply competition. The basins able to supply gas at the lowest delivered price will fill their pipeline capacity to the Northeast.

à South Atlantic

The South Atlantic market is growing, and pipelines will be constructed to match demand. Currently the region gets all its supply from the Gulf, and this is expected to continue.

à Eastern Canada

Eastern Canada has typically purchased most of its gas supply from western Canada. Eastern Canada imported only 44 Bcf from the U.S. in 1997.

Most pipeline capacity from western Canada to eastern Canada is held under long term contract by eastern Canadian interests. This involves payment of fixed charges to the pipelines. These high fixed costs will encourage eastern Canadian purchases of gas from western Canada to continue.

We assume all eastern Canadian demand in 2005 will be satisfied by Canadian production (including some Sable offshore project production).

Outlook to 2005
Natural Gas Prices

Outlook to 2005 Natural Gas Prices

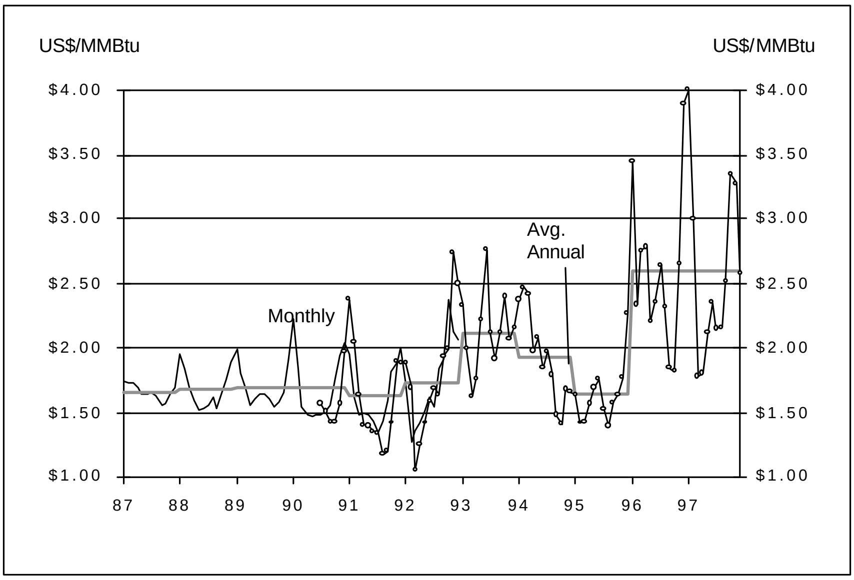
à Overall Price Framework
The Gulf, Midcontinent, Midwest, Northeast, and South Atlantic make up a large geographic area that has been well integrated by pipeline capacity over the past decade and in which prices have been linked. In this region, prices have been highest in the areas farthest from supply, and lowest in supply basins. The differentials between prices have reflected pipeline costs. As the Gulf is the largest supplier within this area, the Gulf gas price has been a benchmark.

à Historical U.S. Gas Prices
Figure 35 shows historical monthly gas prices for the U.S. (average wellhead to 1991, the Gulf Coast NYMEX price after 1991).

Gas prices have exhibited considerable volatility when viewed over the entire 1987-1997 period. The lowest monthly price was slightly more than US$1.00/MMBtu, while the maximum during the period was as high as US$4.00. However, this period can be divided into 2 distinct eras.

From 1987-1992, average annual prices varied over a relatively narrow range, from US$1.63 to $1.73/MMBtu. Excess proved reserves and productive capacity that had been built up during the regulated era were used to satisfy growing demand without causing much upward price pressure. In Canada, the excess had accumulated because export regulation required large reserves. In the U.S., the buildup was the result of incentive pricing and the Section 29 tax credit on coalbed methane and tight gas.

Figure 35: U.S. Gas Prices



The second era began in 1993, and continues to the present. Gas prices have exhibited much more volatility. This reflects the decline in reserve/ production (RP) ratios, and increased lags in supply response to changes in demand. Average annual gas prices have ranged from $1.55 in 1995 to $2.59 in 1996 and 1997 (a range of $1.04/MMBtu).

à Historical Canadian Gas Prices
Figure 36 shows past Canadian gas prices at Empress, Alberta (early years) and AECO C (1993-1997).

Canadian gas prices have been even more volatile than U.S. prices. Average annual Canadian gas prices have ranged from US$0.83 to $1.78/MMBtu, a range of $0.95/MMBtu.

Canadian prices surged in 1993 due to two factors - rising U.S. prices, and large pipeline capacity additions in late 1992 and 1993 (Northern Border, Iroquois, PGT). The new capacity allowed demand available to Canadian suppliers to equal productive capacity, reconnecting Alberta gas markets to U.S. markets. For a brief period, Canadian gas prices tracked U.S. prices.

By 1995, sufficient Canadian production had been developed for supply to once again overshoot available demand (domestic demand plus exit pipeline capacity). With gas-on-gas competition, Canadian prices dropped to about half of 1993 levels.

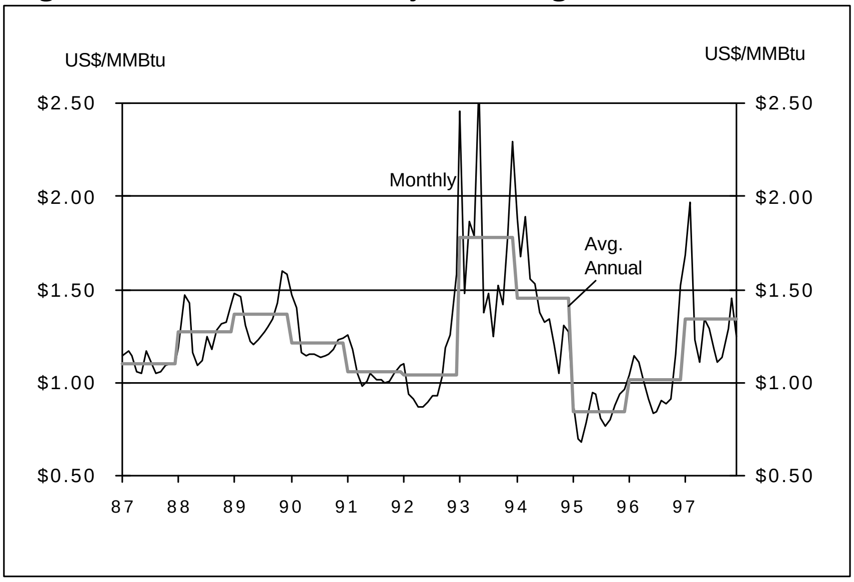
à Gas Price Outlook

We expect North American gas prices to continue to be very volatile, given the enormous influence weather has on gas demand and prices. Month-to-month price variations of more than $2/MMBtu are likely due to the seasonality of gas demand, and the high cost of meeting peak demand with storage or other means.

More important for participants in the gas industry are the trends in average annual gas prices. For consumers, higher annual gas prices may cause fuel switching to oil. For suppliers, lower annual gas prices may result in reduced exploration and development budgets.

Year-to-year price volatility is likely. Year-to-year weather variations, and the lag time between higher demand and producer ability to respond with more production leads to upside price volatility. Volatility on the downside occurs when demand falls, since producers are reluctant to shut in gas

Figure 36: Canadian Monthly & Average Annual Prices

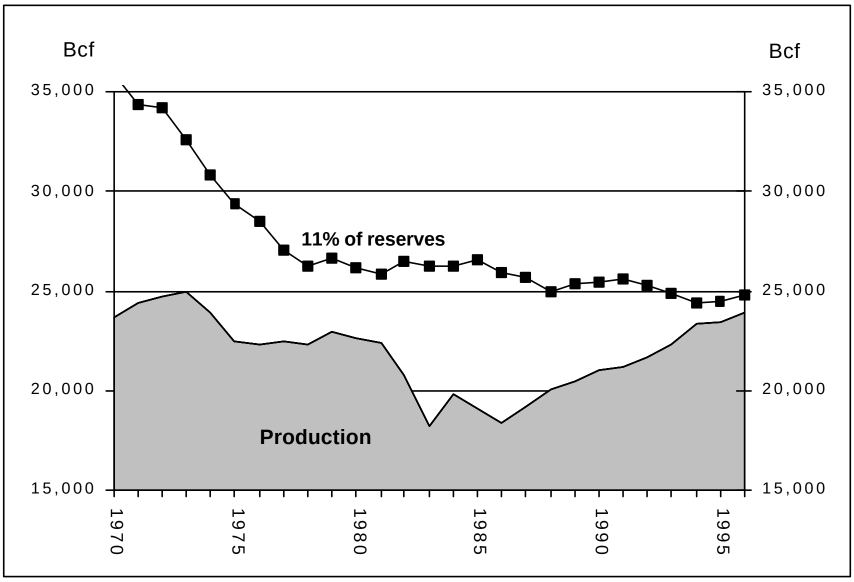


production capacity and slow to reduce drilling programs.

However, while we expect continued price volatility, we do not expect U.S. gas prices to return to the extremely low levels of 1995. The large reserves and production capacity surpluses left over from the regulated era are now exhausted. Gas demand growth has now overtaken the ability of supply areas to quickly bring on added supplies.

The tighter balance between supply and demand is illustrated by examining North American (Canada plus U.S. Lower-48) proved reserves and production. Figure 37 shows North American gas production from 1970 to 1996. Also shown is a line equal to 11% of North American proved reserves over the period.

Figure 37: Reserves Utilization, U.S. & Canada



Proved reserves are those volumes of gas in discovered reservoirs which are thought to be economically recoverable under current conditions.

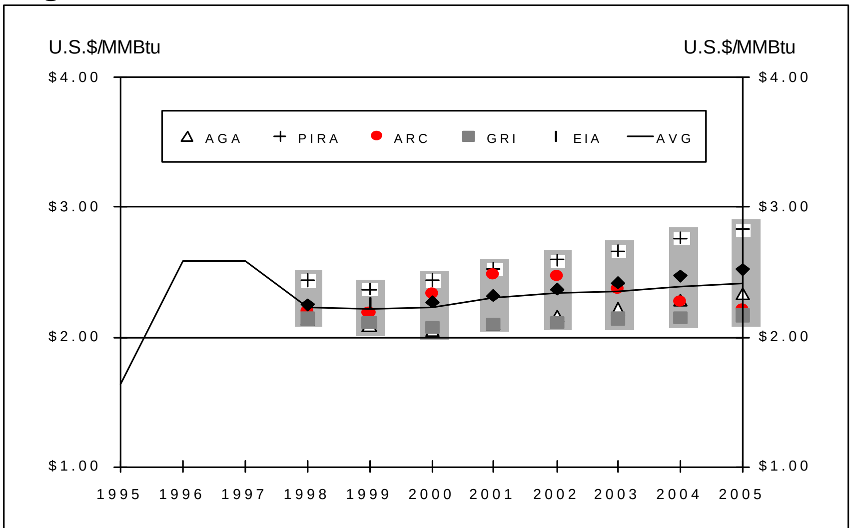
There is some question about the maximum rate at which proved reserves can be produced. We have chosen 11% for the purposes of illustration. Drilling horizontally or multilaterally into reservoirs can increase gas production rates per unit of reserves. Whatever the maximum rate is, North America is now closer to it than at any time in history. Producer strategies have also led to high well decline rates. High decline rates reduce the length of time for an oversupply situation to be worked off. There is less slack on the production side than previously, and this should keep prices from falling below producers' finding and development costs for extended periods.

à Experts Views: U.S. Gas Prices

Figure 38 shows various expert forecasts of U.S. wellhead prices, all in nominal dollars. These forecasts represent Gulf Coast prices or average U.S. wellhead prices. These forecasts are relevant to gas prices in most U.S. regions, since they are linked to Gulf prices.

The average of these forecasts shows no real growth in prices between 1997-2005. The range of prices for 2005 is $2.17 to $2.83/MMBtu, with an average of $2.41. Current U.S. gas prices are slightly higher than

Figure 38: U.S. Gas Price Forecasts



* Various field, average wellhead, or Gulf prices. Original forecasts in constant dollars, converted to nominal assuming 1.8% annual inflation. 95-97 are NYMEX actuals.

this (1997 average NYMEX price was $2.59).

Given the volatility factors inherent in today's gas markets, the range of prices displayed by these five forecasters may not capture the actual range of future prices.

A recent downward influence on gas prices is the current low oil price. Some gas demand is switchable to oil.

à Canadian Price Outlook

Given the scale of proposed pipeline expansions from Canada, the big questions are whether supply growth will be sufficient to fill the expansions, and what price dynamics in Canada will be like after the expansions.

This situation is not unprecedented. In 1992/1993, approximately 2 Bcf/d of new pipeline capacity out of Western Canada was completed. Gas supply in Western Canada relative to takeaway capacity became tight, and Canadian prices doubled, temporarily re-linking with prices in the larger North American gas market (U.S. Midwest, Northeast, & Gulf Coast). This led to high Canadian drilling levels (5,000 wells in 1994), which increased supply and drove prices back down.

We foresee another period in which Canadian and U.S. prices will be linked, due to the large pipeline capacity expansions likely in the next few years. Canadian prices (i.e., AECO) are expected to rise towards prices in U.S. markets. AECO prices are expected to be lower than U.S. prices, reflecting the costs of pipeline transmission to U.S. markets.

Whether Canadian supply will again overshoot take away capacity is another question. This time, it is likely to occur more slowly, as the Canadian basins are now operating at higher rates of take, and under higher decline rates than at any point in the past.

à Experts Views: Canadian Gas Prices

Figure 39 shows the Canadian price forecasts of several experts. These are forecasts of average Alberta plant gate prices, in nominal U.S. dollars per MMBtu.

In contrast to the U.S. gas price forecasts, 5% per year growth in Canadian gas prices is predicted, given the anticipated re-linking with U.S. markets.

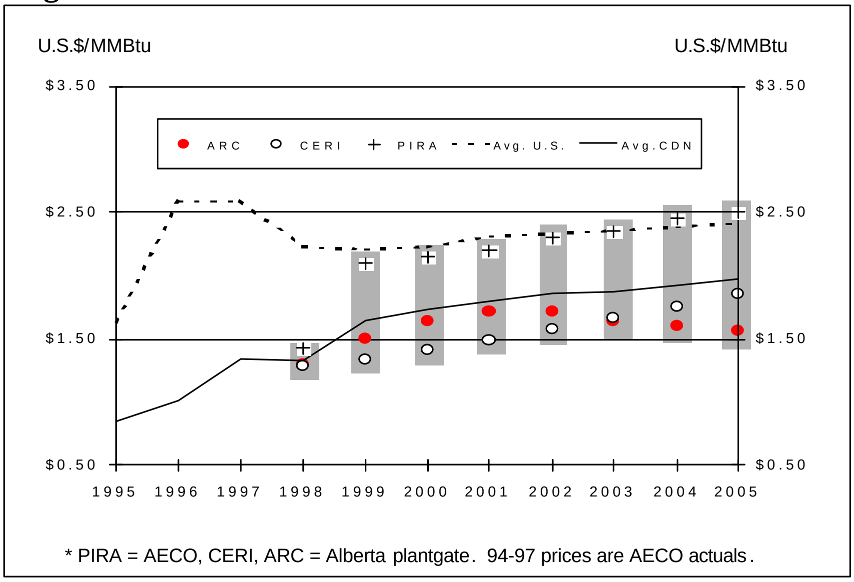
It must be noted that there are two kinds of Canadian gas prices: i) the price in the Canadian market (e.g., an AECO price), and ii) the price received for Canadian gas sold and priced in other markets. Export sale prices are dependent on U.S. prices, while domestic sale prices are driven by the Alberta (or British Columbia) market price.

About half of Canadian gas sales occur in Canadian supply areas and are priced there, while the remainder occur in downstream U.S. markets.

To make these two kinds of prices comparable, pipeline transportation charges are subtracted from the gas price received in export markets. This results in an *Alberta netback* price to producers, which can then be compared to prices for gas sold in Alberta.

According to the experts' views, Canadian prices will increase by a greater percentage than will netbacks from U.S. sales, since U.S. prices are expected to remain flat.

Figure 39: Canadian Gas Price Forecasts



à Regional Prices

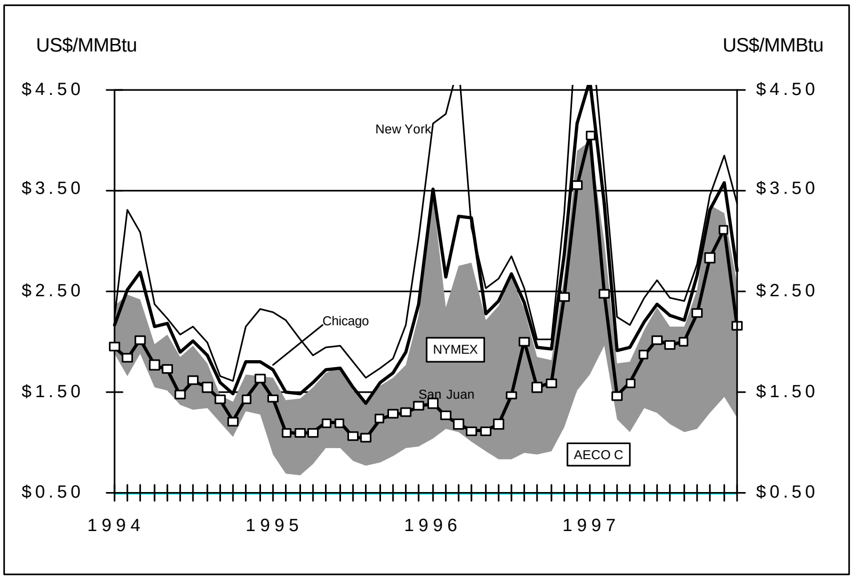
The strong past relationship of prices in regional U.S. markets can be seen in Figure 40. Only the Canadian market (AECO) does not track the others, due to the lack of pipeline capacity links. The large region that includes the Gulf, Central, Midwest, Northeast, and West is expected to remain well integrated. Prices within this large region are expected to track each other, with price differentials mainly driven by variations in the cost of pipeline transmission.

à U.S. West

Western U.S. prices are determined by prices in the San Juan basin (part of our Rockies supply region). The San Juan basin is the marginal supplier to the U.S. West demand region.

The San Juan basin had been underpiped in 1995, with prices much lower than Gulf Coast prices. Prices reconnected with Gulf prices in 1996, due to a

Figure 40: Historical Regional Gas Prices



fall in San Juan production. Currently, pipeline capacity from the San Juan to other regions is sufficient to allow all local production to flow. This keeps local prices linked to Gulf prices.

Declines in coalbed methane production from the San Juan basin will tend to keep this situation in place. However, there is the potential for higher production from other regions of the Rockies. San Juan prices could again disconnect from Gulf prices if enough of this supply reaches the San Juan basin, overwhelming pipeline exit capacity.

à U.S. Midwest

Midwest prices are correlated with Gulf Coast prices. We estimate that, on average, about 2,700 MMcf/d flows to the Midwest from the Gulf. Several large pipeline expansions from the Rockies and Western Canada to the Midwest are planned. However, the total incremental gas moved from these regions to the Midwest is unlikely to back out Gulf supplies completely, and Midwest pricing should continue to be well correlated with Gulf Coast pricing.

à U.S. Northeast

Northeast prices are also linked to Gulf Coast prices. Approximately 690 MMcf/d of incremental capacity from Canada to the Northeast is planned. However, this will not eliminate dependence by the Northeast on Gulf supplies, and pricing in the region should continue to be driven by the Gulf.

à Eastern Canada

As explained earlier, gas for eastern Canadian markets is purchased in Alberta. The eastern Canadian price is essentially the Alberta price plus a transportation charge. This practice will continue. Consequently, as the western Canadian producing region's prices rise with the reconnection to U.S. markets, the effect will be passed through to eastern Canada.

à Conclusions

Although prices in the various U.S. export regions will remain different (highest in regions farthest from supply), we expect *netbacks* from all regions (including domestic regions) to begin to equalize as more pipeline capacity is constructed.

Overall, forecasters surveyed expect little growth in U.S. prices. Due to better linkages being developed between U.S. and Canadian markets, Canadian prices are expected to rise.

Outlook to 2005
Canadian Export & Domestic Sales Forecast

Outlook to 2005: Canadian Export & Domestic Sales Forecast

à Canadian Gas Sales

Canadian gas is sold in domestic and export markets. Canadian supply satisfies essentially all domestic demand. Export sales are mainly determined by export pipeline capacity. Although exports vary monthly and annually, export flows are generally near the capacity of export pipelines.

Although substantial new export pipeline capacity has been added over the last five years, it is now fully utilized. Pipelines linking Canadian supplies with U.S. and eastern Canadian markets operated at load factors in excess of 90% during 1997. Since 1985, the pattern in the Canadian gas industry has been that production increases to fill available pipeline capacity, at which point price and netback differentials signal the need for expanded capacity.

à Export Forecast Method

Our method for estimating Canadian gas sales to export markets is based on pipeline capacity. We estimate pipeline capacity additions over the 1997-2005 period by evaluating the expansion plans of pipeline companies. This yields a forecast of pipeline capacity to each export region, as shown in Table 11.

In the past we have been able to rely on the regulatory system as a clear indicator of the likelihood of a project being realized. If sponsors had submitted an application to the NEB or FERC, we included it in our forecast. However, the NEB now permits *preliminary filings*, which do not imply the same level of commitment to a project as a full filing. In addition, recently the industry has seen multiple projects that

Table 11: Export Pipeline Capacity, MMcf/d

	1996	1997		1998		1999		2000		2001 - 2005	
	Year end Capacity	Increment	Year end Capacity	Increment	Year end Capacity	Increment	Year end Capacity	Increment	Year end Capacity	Increment	Year end Capacity
U.S. West											
Huntingdon/Westcoast:											
Northwest Pipeline	1,045		1,045		1,045		1,045		1,045		1,045
User-dedicated	380		380		380		380		380		380
Kingsgate	2,518		2,518	64	2,582		2,582		2,582		2,582
Total U.S. West	**3,943**		**3,943**	**64**	**4,007**		**4,007**		**4,007**		**4,007**
Midwest											
Monchy	1,500		1,500	690	2,190		2,190		2,190		2,190
Emerson	1,140	56	1,196	122	1,318		1,318		1,318		1,318
New Projects/Alliance								1,325	1,325		1,325
Miscellaneous	230		230	49	279		279		279		279
Total U.S. Midwest	**2,870**	**56**	**2,926**	**861**	**3,787**		**3,787**	**1,325**	**5,112**		**5,112**
Northeast											
Iroquois	819	25	844		844		844		844		844
Niagara Falls	827	39	866	39	905		905		905		905
Chippawa	200	48	248	3	251		251		251		251
St. Stephen (Sable)					0	467	467		467		467
E. Hereford (PNGTS)				152	152	58	210		210		210
Cornwall	62		62		62		62		62		62
Napierville	56		56		56		56		56		56
Phillipsburg	40		40	2	42		42		42		42
Highwater	31		31	-31	0		0		0		0
Total U.S. Northeast	2,035	112	2,147	165	2,312	525	2,837	0	2,837	0	2,837
Total Capacity (Export)	**8,848**	**168**	**9,016**	**1,090**	**10,106**	**525**	**10,631**	**1,325**	**11,956**	**0**	**11,956**

Notes: Year-end MMcf/d capacity represents approximate contracted daily volumes that could be delivered on the last day of the year.
Annual incremental capacity is generally completed at the start of the contract year (Nov. 1).

Table 12: Export & Domestic Gas Sales Outlook

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Northeast	*642*	*660*	678	760	820	835	843	843	843	843
- Niagara	*269*	*285*	291	294	287	297	297	297	297	297
- Iroquois	*283*	*293*	290	290	283	283	286	286	286	286
- PNGTS	*0*	*0*	8	65	67	68	69	69	69	69
- Sable	*0*	*0*	0	21	93	96	100	100	100	100
- Other	*90*	*81*	90	90	90	90	90	90	90	90
Midwest	*1,031*	*1,030*	1,214	1,207	1,275	1,623	1,636	1,636	1,636	1,636
- Monchy	*548*	*544*	679	687	687	687	695	695	695	695
- Emerson	*421*	*426*	471	457	457	457	457	457	457	457
- New Project(s	*0*	*0*	0	0	68	416	421	421	421	421
- Other	*62*	*61*	63	63	63	63	63	63	63	63
West	*1,164*	*1,206*	1,213	1,228	1,242	1,257	1,272	1,272	1,272	1,272
- Huntingd.	*368*	*363*	374	380	385	390	395	395	395	395
- Kingsgate	*795*	*843*	839	848	858	867	876	876	876	876
Total Exports	***2,837***	***2,896***	**3,105**	**3,195**	**3,338**	**3,716**	**3,751**	**3,751**	**3,751**	**3,751**
DOMESTIC MARKETS:										
E.Cda	***1,246***	***1,280***	1,362	1,384	1,405	1,425	1,444	1,464	1,483	1,504
W.Cda	***1,378***	***1,362***	1,382	1,428	1,474	1,516	1,559	1,601	1,643	1,686
Total Sales	***5,461***	***5,538***	**5,849**	**6,007**	**6,217**	**6,657**	**6,754**	**6,816**	**6,877**	**6,941**

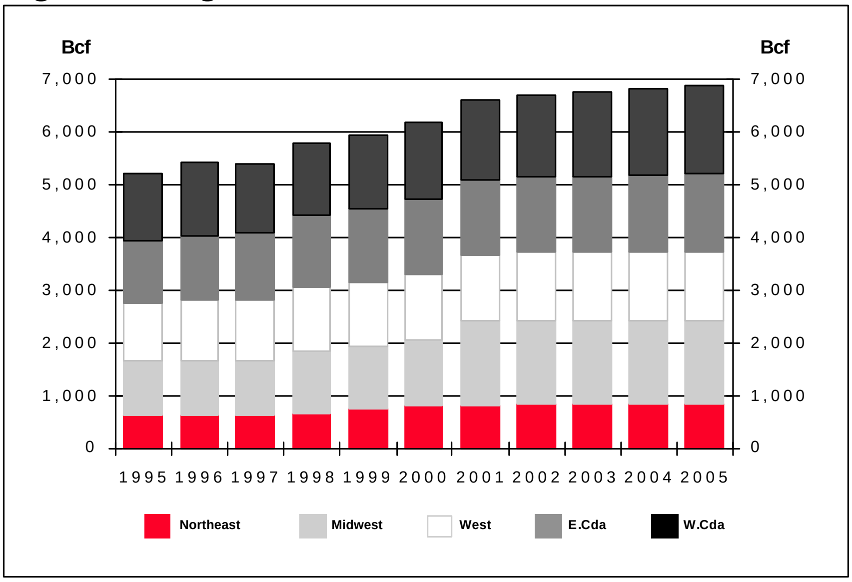
appear to be targeting the same customers. This situation also raises the level of uncertainty about the ultimate capacity that will be installed. Our approach now still relies upon the regulatory process as a reference, but a greater degree of judgement is used in developing the capacity forecast.

We then calculate exports to each region, taking into consideration various factors, including: past exports across each border point; the load factor at which each pipeline border crossing has been used; the demand outlook in the relevant export market; alternative supply sources for the target market; production outlook for these alternative supply basins; natural gas prices and price differentials between Canadian basins, the export market, and alternative supply basins; and other factors. Our forecast is shown in Table 12 and Figure 41.

Our method has worked well over the past eight years in forecasting exports. Most export pipeline capacity additions have had long lead times, and applications to regulators were made years before the capacity was built. This allowed us to predict capacity, and exports.

If anything, our forecasts of exports have been slightly low. There are two reasons for this: some pipeline expansions have occurred on short notice; and existing pipeline capacities were used at higher load factors than predicted.

Figure 41: Regional Natural Gas Sales Forecast



For Canadian pipelines serving Canadian markets, the time period between a regulatory application and construction of the capacity is not as long as for export pipelines. Also, Canadian supplies have typically captured essentially all of the Canadian market. For these reasons, we have not attempted to forecast pipeline capacity from Canadian supply regions to Canadian markets. Instead, we have assumed that Canadian gas sales to Canadian markets will be equal to forecast Canadian demand. We used an average of three expert forecasts for our Canadian demand outlook (see page 41 for details).

à Capacity Additions

For 1998, the single largest expansion of pipeline capacity from Canadian supply to markets will be the 690 MMcf/d expansion of the Foothills-Northern Border route to the U.S. Midwest. This is expected to be completed by November 1, 1998. The next largest expansion is the TCPL 1998 expansion of 416 MMcf/d, mostly for export markets.

In 1999, pipelines linking the Sable Offshore Energy Project to markets in the Canadian Maritimes and U.S. Northeast, (457 MMcf/d) are expected to be completed.

Finally, the last big slice of capacity expected is the 1,325 MMcf/d Alliance pipeline from Western Canada to the U.S. Midwest. Recently, the project sponsors have estimated the line would be in service in late 2000. We have not estimated any capacity additions beyond 2000. It will be necessary to evaluate whether western Canadian production could support additional projects in the foreseeable future.

Our pipeline capacity forecast is then used to generate our export forecast, which is shown in Table 12. We expect total natural gas exports to the U.S. to reach 3.75 Tcf by year 2005.

à Load Factor Assumptions

We assumed load factors on U.S. West export capacity would increase from 84% in 1997 to 87% in 2005. No significant capacity additions are currently applied for, but considerable new U.S. West demand is expected. We expect this to lead to higher load factors on Canada to U.S. West capacity.

Considerable new capacity is being added to the Midwest, more than forecast demand growth. We expect load factors on Canadian export capacity to fall from 98% in 1997 to 89% in 2005.

Although we are assuming lower load factors, they will remain high by North American standards. We take this view since most Canadian capacity to the Midwest is held under long term pipeline contracts, with shippers required to pay demand charges. We expect this will encourage shippers to use their capacity.

Alberta prices would have to rise to Midwest prices (almost) before shippers would stop using their capacity.

Canada’s past experience with large exit pipeline expansions during 1992/93 is also relevant. Although Alberta gas prices briefly reconnected with U.S. market prices, load factors on export pipelines remained relatively high.

In contrast, pipeline corridors from U.S. basins to the Midwest have a higher percentage of interruptible or released capacity. There is not the same incentive to flow gas in this situation. Rather, Midwest prices have to be equal to or greater than prices in the U.S. supply basin plus the cost of interruptible or released capacity.

In short, we expect pipelines from U.S. supply regions to the Midwest to be less utilized than pipelines from Canada.

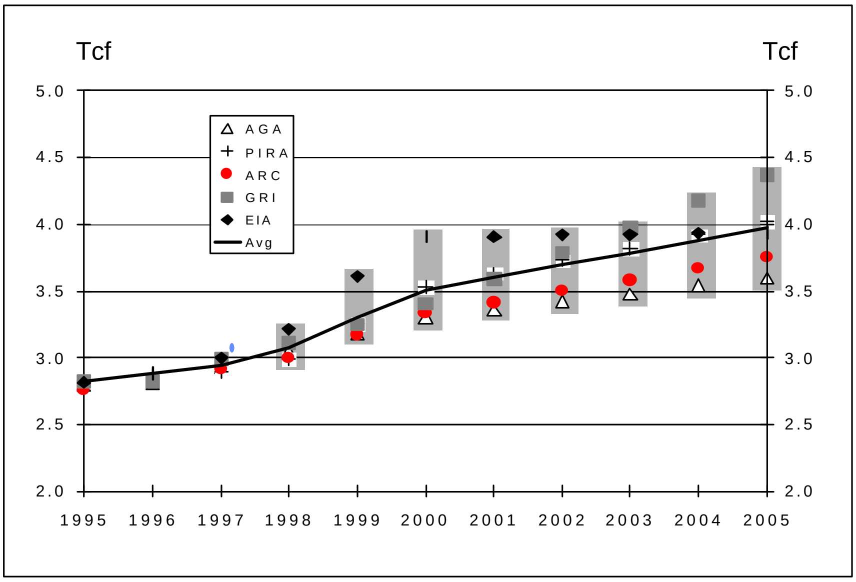
For export capacity to the Northeast, the situation will be similar. Load factors are expected to fall from 88% to 81%.

Combined with domestic sales volumes, total Canadian production should reach 6.9 Tcf by 2005.

Export Forecast Comparison

Our forecast of exports (3.75 Tcf) is comparable to forecasts made by other organizations. A sampling of such forecasts is shown in Figure 42. The average of the forecasts shown expects 3.9 Tcf of Canadian exports to the U.S. by 2005.

Figure 42: Canadian Export Forecasts



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Regulatory Update

Regulatory Update

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- *à Canadian Pipeline Regulatory Developments*
- *à U.S. Pipeline Regulatory Developments*
- *à Gas/Electricity Issues*
- *à Gas Distribution Developments*

¨ Canadian Pipeline Regulatory Developments

Pipeline Tolls In Alberta

Under NOVA's tariff structure, the NOVA toll over any distance in Alberta was one single "postage stamp" rate. This rate was relatively high (26 cents per Mcf for gas exported from the province) due to considerable production moving long distances from Northern Alberta.

In NOVA's rates case hearing held in January, 1996, some producers moving gas short distances felt they were subsidizing those moving gas long distances. The Alberta Energy and Utilities Board (AEUB) debated the issue of going to distance based tolls on NOVA, but eventually ruled to retain the postage stamp rate.

As a result, some producers developed bypass projects in order to escape the high NOVA tolls. Short bypass lines can be installed and financed using tolls much lower than NOVA's postage stamp toll.

One of these was the Palliser pipeline project. With Palliser appearing likely to proceed, NOVA opted to negotiate a lower transmission rate with Palliser sponsors, in order to keep those sponsors as customers of the NOVA system.

In January 1997, NOVA applied to the AEUB for a load retention rate for Palliser sponsors, in return for those sponsors cancelling the Palliser project. The AEUB agreed that the lower rate was necessary in order to keep Palliser sponsors on the NOVA system, and approved a rate of 15.5 cents per Mcf for Palliser sponsors. The load retention rate began January, 1998. NOVA then faced a revenue shortfall. This shortfall will be shared by NOVA (25%) and remaining postage stamp shippers (75%). As a result, the postage stamp rate rises to 26.7 cents per Mcf.

As a result, there are now two postage stamp zones in Alberta. However, future regulatory rates cases will revisit the NOVA toll redesign issue. A settlement process led by the Canadian Association of Petroleum Producers (CAPP) involved negotiations between NOVA and producers towards tolling redesign. The merger of NOVA and TransCanada PipeLines Ltd (TCPL) could involve changes to NOVA tolls. Finally, in April of 1998 NOVA applied to the AEUB for a new tolling scheme where tolls between various points in Alberta would reflect the cost of providing service between those points.

Westcoast Incentive Rates Settlement

Westcoast performs gathering, processing, and gas transmission services for producers and others in British Columbia. On May 20, 1997 Westcoast filed a tolls application relating to a multi-year incentive toll settlement with its shippers.

The National Energy Board (NEB) approved a five-year incentive-based negotiated settlement on tolls, or methodology for determining tolls, for the period from 1997 to 2001 inclusive. For gathering and processing services, shippers have the option to contract for one, three or five year predetermined tolls plus a gas price sensitive surcharge that is indexed monthly to gas prices, primarily at Sumas, Washington. Tolls will be lower for the 5-year term than for the 3-year term and lower for the 3-year term than for the 1-year term. The total amount of service contracted for the 5-year and 3-year terms is limited to 50 percent and 25 percent, respectively, of existing contracted capacity.

The base tolls for gathering and processing reflect a reduction of the allowable return on equity of five percentage points. Westcoast may recover the revenues associated with this reduction through the gas sensitive surcharge. The surcharge begins to kick in at a monthly commodity gas price of US$1.35/MMBtu and is capped at US$0.115 per MMBtu when gas prices reach US$2.00/MMBtu.

For transmission services, shippers have the option of tolls that are predetermined for five years (Option A). Alternatively, shippers can choose tolls that are adjusted to reflect the current costs of Westcoast and contract levels (Option B). The determination of Option B tolls also incorporates an incentive component that allows Westcoast and shippers to share the benefits of cost savings and encourages Westcoast to generate new revenues.

The applied-for tolls for 1997 represent an increase over 1996 tolls ranging from 4 percent to 15 percent, depending on the terms and options selected, and excluding the impact of the NEB's decisions on the recovery of expenditures for two expansion projects, and the gas price sensitive surcharge.

The May Settlement also contemplated that by the end of its term (i.e., post-2001), Westcoast and shippers would freely negotiate market-based arrangements so that light-handed, complaint-based regulation would be appropriate. In January 1998, Westcoast and its stakeholders signed an agreement, which will be subject to NEB approval, setting out the principles of this new regulatory approach.

TCPL Contracts Renewals & Expansion Policies

By letter to the NEB dated July 4, 1997, TCPL indicated a desire for changes to its Transportation Tariff regarding renewal rights, and requested that this matter be considered as part of NEB written hearing RH-1-97. On June 13, 1997, the NEB established a second phase to the proceeding to consider contract renewal rights. After a request by CAPP, the NEB also added TCPL's expansion policy to the list of issues to be considered in the hearing.

The current system encourages shippers to re-contract capacity for a one year period when their long term contracts expire. Shippers must advise TCPL of their intention to renew long term contracts 6 months in advance of expiry, while the minimum term for renewed long term contracts is 1 year. Most shippers renew for 1 year terms, and do so every six months. This is leading to shorter and shorter average contract terms between TCPL and its shippers. Meanwhile, TCPL is also receiving requests to expand capacity. TCPL's pipeline construction timeframe is up to 12 months, and its compressor construction schedule is up to 18 months. This leads to a risk that TCPL may overbuild, reduces TCPL's financing flexibility, and may also increase tolls.

TCPL has tried twice (unsuccessfully) since 1988 to revise its contracts renewal policy. In RH-1-97, TCPL proposed that the current six-month renewal notice period and the minimum one-year term for firm transportation contracts be replaced with a one-year renewal notice period and a minimum two-year term for all firm transportation contracts.

TCPL considers that the proposed renewal notice periods and contract terms would provide the company with more time to react and to manage turned-back capacity, either through adjustments to construction plans or through the remarketing of existing capacity. These changes would also reduce TCPL's risk.

With respect to TCPL's expansion policy requirements concerning the market and supply evidence to be provided by expansion shippers, TCPL favours a flexible policy, focussing specifically on the market needs. The expansion policy must ensure that there is sufficient incremental supply and market to assure a continuing need for the additional capacity.

In September 1997, the NEB postponed this hearing *sine die* until an opening occurs in its schedule.

Intervenor Funding For Canadian Pipeline Hearings

Bill C-229 (the *Intervenor Funding Act*), was a private member's bill sponsored by John Finlay in the Canadian Parliament. This bill would have required all federal departments, boards and agencies that approve projects (including the NEB) to award funding to public interest intervenors. The cost of the interventions would have been paid by the sponsors of the projects. With the calling of the federal election in April 1997, this bill died on the order paper.

In April 1997, the Canadian Energy Pipeline Association (CEPA) made recommendations to the NEB for enhancing the existing Early Public Notification (EPN) process to resolve the intervenor funding issue and eliminate the need for Bill C-229. The package included 13 voluntary enhancements including a mediation approach to resolve pipeline/landowner issues that could not be settled during an EPN process.

CEPA recommended that the NEB amend its Guidelines for Filing requirements or otherwise formulate a policy that endorsed the mediation approach. CEPA also requested that the NEB inquire into and publicly report on the effectiveness of the mediation approach after a two-year period.

In October 1997, the NEB requested public comments on the CEPA proposal. The NEB indicated it would consider the CEPA proposal following receipt of these comments. On January 22, 1998, the NEB announced that it had amended its filing requirements for pipeline applications to incorporate mediation of issues as part of the early notification process.

The NEB's decision should help resolve issues between landowners and pipeline companies. The NEB will review the effectiveness of the process in two years.

U.S. Pipeline Regulatory Developments

Pacific Gas & Electric (PG&E) Gas Accord

The California Public Utilities Commission (CPUC) approved the Pacific Gas & Electric (PG&E) Gas Accord on August 1, 1997. The Gas Accord is a settlement among Canadian and U.S. interests that resolved numerous issues relating to natural gas pricing and gas transmission tolls within California. The Gas Accord also unbundles PG&E's pipeline transmission, gas distribution, and gas merchant functions.

PG&E is the main gas pipeline and distributor in northern California, and is regulated by the CPUC. Most of its gas supply comes from Canada, via the Pacific Gas Transmission (PGT) pipeline, which PG&E owns (see Figure 43 for orientation map).

The problems which the Gas Accord addressed had developed over a long period, and were due to the restructuring of the California gas market, which began in 1991. Up to that time, Canadian gas had supplied California under one single chain of long term gas supply contracts. End-users contracted with PG&E for gas, PG&E in turn contracted with PGT, and PGT contracted with the Alberta and Southern (A&S) Canadian gas pool.

Under U.S. federal gas market deregulation in the late 1980s, pipelines (i.e., PGT) had to provide open access gas transmission, and began to move away from providing a bundled gas purchase/delivery service. The CPUC wished to encourage numerous buyers and sellers in the California gas market, with these buyers and sellers using PGT and PG&E for transmission only. To further this objective, in 1991 the CPUC attempted unsuccessfully to break the A&S supply contracts without compensating Canadian producers for contract termination. In 1993, a settlement was reached, ending the long-term contracts in return for compensation to producers. However, this left issues of fair gas pricing and tolls on PG&E unresolved.

Currently, PGT delivers Canadian gas into PG&E at the California/Oregon border. The gas is then delivered within California on twin PG&E lines

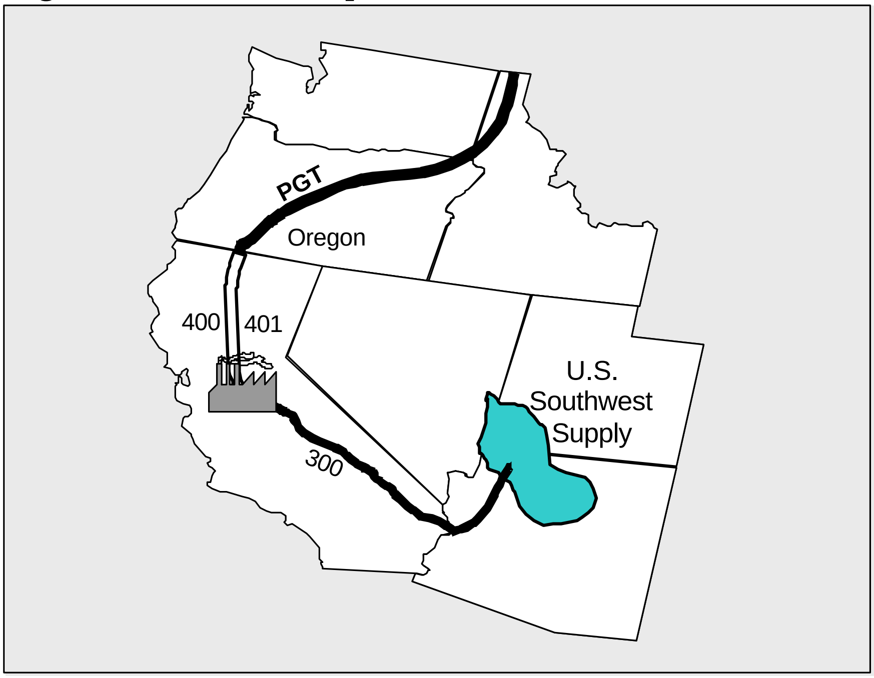
400 and 401. Line 401 was built in 1993, and charges higher tolls than the older line 400. PGT was also expanded in 1993.

PG&E also owns line 300, which brings U.S. southwest gas to California. U.S. southwest gas is the marginal gas supply, and thus sets California gas market prices. The California "market price" is the U.S. southwest price plus the cost of moving U.S. southwest gas to California on line 300.

Canadians sell gas at the terminus of PGT on the California/Oregon border as price takers. The price they can charge is equal to the California market price less transportation from the border to within California on either PG&E line 400 or 401. As PG&E owns PGT, and three California lines (400, 401, 300), there was potential for abuse of market power by PG&E.

For example, by undercharging on line 300, PG&E could reduce the California market price and lower netbacks to Canadian producers. Conversely, by keeping line 300 rates high, (this favours Canadian gas by making southwest U.S. gas more expensive), and then forcing shippers (via the "crossover ban" and other measures approved by the CPUC) to use line 401, PG&E could increase its revenues and ensure full and easy recovery of its costs for constructing the PGT expansion and line 401. The reasonableness of PG&E's

Figure 43: California Pipelines



decision to construct line 401, and whether PG&E should be allowed to recover line 401 construction costs, was also an issue at the time of negotiation of the Gas Accord.

The Gas Accord resolved all of the above issues, and had the support of most interested parties (i.e., PG&E, Canadian producers, California gas buyers, and southwest U.S. producers). The approved settlement will: 1) set rates for lines 400, 401, and 300, equalizing line 400 and 401 rates for most shippers; 2) allow shippers to use line 400 or 401 (i.e., remove the crossover ban); 3) force PG&E shareholders to absorb or be at risk for certain contested costs; 4) force PG&E to discount line 300 rates penny for penny if discounts on line 400/401 rates are made; and 5) approve PG&E's construction of line 401.

Negotiated & Market-based Rates, & Rate Innovations

Pipelines are urging FERC to do more to create a fully competitive natural gas market. The goal is to increase the flexibility of pipeline service and rate offerings, in order to satisfy changing shipper requirements. FERC's Order 636 in 1992 has led to change, and pressures for change, in the pipeline industry. The order mandated unbundled, open access transmission service and straight fixed-variable (SFV) rate design. Five years later, industry restructuring continues.

On January 31, 1996, FERC issued a Statement of Policy on alternative rate design mechanisms (RM96-6). At the same time it issued a pending rulemaking (RM96-7) and a request for comments on negotiated service terms and conditions offered by interstate pipelines. The Commission is willing to accept filings for negotiated rates to be included in pipeline tariffs, but is not yet prepared to accept negotiated terms of service.

FERC examines filings for negotiated rates on a case-by-case basis. Their acceptability is subject to a test of market power. Applicants must define the product market and demonstrate that competitive alternative products are offered. They must also demonstrate that customers have access to competitive alternatives within the geographic market in which the service is offered.

After establishing that it faces meaningful competition, the applicant must also establish that it does not exercise market power by virtue of its market share. The pipeline is also required to offer a recourse rate to any shipper who chooses not to use a negotiated rate. Shippers need only match the recourse rate to exercise a right of first refusal on contract renewal. Those shippers who use the recourse rate must not be disadvantaged relative to negotiated rate shippers (e.g., in situations where circumstances might require capacity allocation).

The FERC accepted comments on negotiated terms and conditions during 1996. On May 29-30, 1997 it held a technical conference where industry members and other interested parties put before the Commission the issues which they considered critical to the further evolution of natural gas markets. The question of negotiated terms and conditions was prominent in both written submissions to the conference, and in testimony before the Commissioners.

The Interstate Natural Gas Association of America (INGAA), whose membership includes many of the major interstate transmission companies, has established the acceptance by FERC of negotiated terms and conditions in pipeline tariffs as a priority for 1998. INGAA has argued that over the next five years pipelines may have to re-market as much as 47 percent of existing capacity. The Association believes that traditional tariffs were originally designed assuming that shippers would be predominantly local distribution companies (LDCs). Now however, pipeline customer bases have shifted dramatically and the load profiles faced by the pipelines have substantially diversified.

The debate about negotiated terms and conditions is centred on the need for flexibility in pipeline service offerings versus the danger that pipelines could exercise market power to discriminate among customer classes. FERC's rulemaking in this area remains open. The Commission's staff has prepared a comprehensive discussion paper on gas regulatory issues. Future Commission action on negotiated terms and conditions of service will likely be associated with the Commissioners' responses to this document.

Offshore pipelines in particular are devising new tolling methods for shippers, such as Sea Robin Pipeline Company's "flexible firm" service. Shippers agree to dedicate reserves to flow to the pipeline for their producible life. In return, shippers are charged a volumetric rate (no demand charge), as long as shippers maintain flows of 80% of their maximum daily contracted quantity. New deep water pipelines built by Shell, Destin Pipeline Company, Garden Banks, Nautilus, and Discovery Gas Transmission also use this system.

Capacity Turnback & Capacity Release

The effect of Order 636 has been not only to change how pipeline capacity is used but also to affect which industry members have a need for it. These changes have led to two related phenomena, *capacity turnback* and *capacity release*. Capacity turnback refers to a shipper failing to renew any or all contracted capacity, when capacity contracts expire. Capacity release is the re-sale of pipeline capacity that is still under contract. The question faced by the industry and federal regulators is how to ensure the re-allocation of capacity in an economically efficient way.

Pipelines are concerned about capacity turnback because they face the prospect of re-marketing large amounts of capacity under much shorter contract terms. Between April 1, 1997 and December 31, 2001, 40% of firm interstate capacity contracts are due to expire, while 67% will expire by 2005. In a 1995 AGA survey of 75 LDCs, 35% of respondents expected contracted capacity to remain at current levels while 45% expected reductions.

A National Regulatory Institute study[7] predicted that most expiring firm interstate capacity would be resubscribed, but at shorter contract terms (typically five years), and at discounted rates. Most LDCs would reduce their firm contracted capacity, creating excess capacity and incomplete recovery of pipeline capital investments.

Among the largest recent capacity turnbacks are the 457 MMcf/d contract capacity reduction experienced by Transwestern on November 1, 1996. Transwestern reached a settlement allocating 70% of turnback costs to the pipeline and 30% to customers. El Paso's capacity expiry totaled 1,500 MMcf/d between January 1, 1996 and January 1, 1998. El Paso first unsuccessfully tried to impose exit fees and reallocate turnback costs to remaining customers, then reached a settlement allocating 65% of costs to shareholders. Natural Gas Clearinghouse has since contracted for 1,300 MMcf/d on El Paso for a term of 2 years.

[7] *Pipeline Capacity Turnback: Problems and Options*, October 1997.

Capacity is released when a market player recognizes that the capacity no longer has sufficient economic value to that player. The change in valuation can occur because of structural change in the industry (e.g., a distributor who loses an industrial gas load), or may be due to fluctuating gas price differentials and pipeline capacity values (e.g., a gas marketer finding it more attractive to sell in one market, resulting in capacity to another market being surplus and being released). The secondary market for capacity permits valuation differences to be identified and resolved through transactions.

FERC & Secondary Markets

FERC considers the secondary market to be made up of three elements: 1) released long-term firm capacity; 2) short-term (less than one year) firm transportation contracts; and 3) interruptible transportation service. FERC has not yet resolved how to permit full capacity trading in the secondary market. There are two main outstanding issues. The Commission must establish some means of coordinating the treatment and pricing of pipeline services which could be close substitutes, such as interruptible transportation, short-term firm transportation, and released firm transportation. It must also respond to the increasing pressure to eliminate or modify the price cap which it imposed on secondary market transactions.

FERC considers the secondary market for pipeline capacity to be a regulated activity under the Natural Gas Act. A pipeline company which offers firm capacity must include a mechanism in its tariff for firm shippers to release capacity back to the company for resale on a firm basis. The pipeline must post offers to release and purchase capacity on its electronic bulletin board. The releasing shipper may simply offer its capacity for open bidding, or it may arrange a direct deal with a replacement shipper. In both cases the offer to release must be posted[8]. The pipeline must award the capacity to the highest bidder (but the highest bid can be no greater that the maximum regulated rate -- the price cap). If there are no competing bids, or they are below or equal to that of the replacement shipper, then the replacement shipper is awarded the capacity.

The pipeline effectively manages the capacity release system. Moreover, unless the pipeline agrees otherwise, the contract of the releasing shipper remains in full force. The proceeds from any capacity release agreement are simply credited to the releasing

[8]This is true provided the arrangement with the replacement shipper is for a period of more than 31 days or for any term if the released is being carried out at the maximum tariff rate. When these conditions do not apply, the pipeline need only post the details of the transaction within 48 hours after the release transaction begins.

shipper's reservation charge (also termed a demand charge).

In 1996, FERC Commissioner (now Chairman) James Hoecker noted that the secondary markets in telecommunications, airline landing slots and freight forwarding were established with considerably less regulatory involvement than has accompanied pipeline capacity. He identified the bidding and posting requirement and the price cap as FERC-imposed limitations on the market and questioned whether the cap should be removed and replaced with a revenue cap.

On July 31, 1996 FERC issued a notice of proposed rulemaking (RM96-14) that was intended to revise the capacity release system established by Order 636. It dealt with the issues of removing all bidding requirements and eliminating the price cap. FERC proposed a pilot program for capacity release without a price cap. The Commission invited prospective participants to apply by August 30. Although 11 companies originally applied to participate, by November three were approved for a pilot in the California market. However, the pilot was ultimately cancelled in February 1997 when the participants withdrew, citing the limitations which FERC had placed on the program.

Although the issues of capacity release and secondary markets were raised in FERC's May 1997 technical conference, there was little progress in 1997 on revising the regulations governing capacity release or in the secondary market generally.

In July 1997, Commissioner William Massey spoke at an American Gas Association conference about secondary markets. He indicated that the price cap was the most difficult issue to resolve. He did note, however, that the requirement for prior bidding and posting of capacity release transactions may be removed. Most transactions (90 percent) are for pre-arranged deals of less than 31 days, which do not require prior posting. He saw little benefit in continuing this requirement for the remainder.

¨ Gas/Electricity Issues

Status Of U.S. Electricity Deregulation

In the U.S., federal deregulation of the electricity industry began almost 20 years ago. It continues today at the state level and promises to have important repercussions for natural gas.

The Public Utilities Regulatory Policy Act (PURPA) of 1978 encouraged small scale hydro, wind, solar and wood chip power sources, by providing tax incentives and obliging utilities to buy the output of these generators at attractive prices. In 1992 the Energy Policy Act required utilities, which mostly own the transmission systems, to allow transmission access to other utilities and to independent power producers.

In 1996 FERC issued Order 888, to promote wholesale competition in electricity by eliminating monopoly power over the transmission of electricity. Utilities were required to unbundle the transmission function from other utility functions and establish a tariff for transmission.

The states now have the initiative for deregulation, where action is underway to restructure both wholesale and retail markets. In 14 states legislation has been enacted or a plan adopted. Legislation is under consideration, or companies have filed plans, in another 29 states.

A deregulated electricity market should allow the economic advantages of natural gas generation to be realized. Under these conditions supply and demand, rather than regulation, would determine electricity prices. Since demand fluctuates hourly, a fully deregulated market would exhibit continually fluctuating prices. During periods of low demand, the least cost generating sources would be used. As demand rises, additional requirements would be met by higher cost sources and the price demanded for incremental supply would set the market price.

Natural gas generating technology has unique advantages. It has relatively low capital costs. The U.S. Energy Information Administration (EIA) estimates that the construction costs for combined cycle generating units are 37 percent of those of coal steam plants. Natural gas units reach peak efficiency at a relatively smaller scale. Natural gas combined cycle units have conversion efficiencies on the order of 57 percent (i.e., the percent of electrical energy output as a proportion of the energy input) compared with 37 percent for coal steam units. Natural gas units can be brought on line more quickly than other types of generators. An additional advantage is the energy efficiency of natural gas transmission. The proportion of energy lost over long distances is less for natural gas than for electricity.

These characteristics provide both general and specific advantages for natural gas as an electricity source, especially for peak requirements. In addition to the efficiency advantages of natural gas, it produces relatively low levels of emissions compared to other fossil fuels. The speed with which natural gas units can be started and the relatively small capital investment required, make them ideal for meeting peak demand.

The EIA Annual Energy Outlook for 1998 (AEO98) forecasts considerable growth in natural gas demand associated with electricity generation in its reference case projections. The U.S. will require 403 gigawatts of new generating capacity to meet demand growth and the replacement of retired capacity between 1996 and 2020. It is expected that 85 percent of the additional capacity will be natural gas combined cycle or combustion turbine (using natural gas alone or in combination with oil) and will be designed for intermediate or peak supply requirements. This implies an increase in natural gas demand for electricity generation from 3 Tcf in 1996 to 10 Tcf in 2020 and represents an increase of the natural gas share of electricity generation from 9 percent to 31 percent.

Developments in the regulation of the U.S. electricity industry will have important implications for natural gas. Deregulation has already begun to have an effect on industry structure (see paragraphs below on *Gas/Electricity Convergence*). State initiatives will also influence the further penetration by natural gas into the electricity generation market.

Status of Canadian Electric Deregulation

The Canadian electricity industry is also moving from a monopoly situation to a more open, competitive marketplace. The changes taking place in the Canadian electricity industry are mainly being driven by U.S. electricity restructuring.

U.S. electric wholesale market and transmission systems are being opened to Canadian utilities as long as the Canadian utility allows U.S. utilities to have reciprocal access to the Canadian wholesale market and transmission system. With several Canadian utilities making large power sales to the U.S., the incentive to comply with U.S. initiatives is strong.

Most provincial governments and electric utilities have developed proposals to introduce competition in their respective markets, in order to comply with U.S. requirements, and position themselves in this more competitive North American electricity market. Major electric utilities in British Columbia, Alberta, and Quebec have already opened their wholesale market and transmission systems to U.S. operators. In return, FERC granted these Canadian utilities the authority to directly buy and sell electricity within the U.S., instead of being forced to use third parties.

The other provinces are still working on liberalization/ compliance plans. Some provinces are even considering opening their retail markets to competition, to allow electric companies to compete for customers.

In Ontario, a Market Design Committee (MDC) was announced on January, 20, 1998. The MDC will provide advice and recommendations on rules and structure for a competitive electricity market in Ontario, and on the governance and operation of an Independent Market Operator to manage the competitive market. The MDC will also provide recommendations related to the need for a regulatory agency to reinforce and support the operation of a viable electricity market in the province.

In addition to establishing a more open market with the U.S., the federal and provincial governments are working to implement freer internal trade for electricity in Canada by providing for more open access to interprovincial transmission power lines. Currently, there is very little interconnecting capacity across Canada.

Not all provinces agree with a more integrated inter-provincial electricity market. Some provinces would benefit from freer access to electricity markets, but provinces with high generating costs fear that competition from lower-cost electricity could strand investments in generating facilities.

Gas/Electricity Convergence

The mergers and acquisitions trend witnessed in the electric and gas industries over the last two years is motivated first and foremost by the changing electricity industry in North America. The industry is quickly moving from a vertically integrated, fully bundled (generation, transmission, distribution), geographically based, monopolistic model, to an unbundled competitive model. In this unbundled model, vertical integration is being eliminated, with separate companies providing electric generation, transmission, and distribution. This restructuring is well advanced in most U.S. states, and full unbundling of activities has been achieved in 11 states.

The changing regulatory landscape of the $200 billion-plus U.S. electricity industry has led to companies positioning themselves to profit from the evolving regulatory and business framework.

Electric utilities generally view the gas industry as a model for their own unbundling, and some have begun acquiring natural gas deregulation expertise through mergers with gas companies.

A second factor in the merger/acquisition trend is that, although the natural gas industry was nowhere near as integrated as electricity, both industries share a number of common operational and strategic elements. Thus, synergies derived from the similarities of the electric and gas industries have also driven mergers and alliances between electric and gas companies.

As restructuring evolves, electric utilities are faced with the challenge of evolving from a typical cost-of-service regulated monopoly to a competition based, marginal cost energy provider environment. For many utilities across North America, linking-up with natural gas utilities, pipelines, marketers, or producers is a way to purchase experience in operating in a deregulated market.

The widespread use of natural gas in current and future electricity generation is an additional driver for increased links between the gas and electricity sectors. Natural gas accounts for 20% of total U.S. electric generating capacity, and is expected to account for a significant proportion of new generation capacity. Increased ties between electric utilities and pipelines or natural gas producers could provide generators with lower cost access to natural gas feedstocks, translating into lower generating costs.

At the distribution level, the aggregation of a common client base is an additional driver for the integration of gas and electricity companies. Distribution mergers or alliances can lead to marketing opportunities and cost savings. New types of multi-fuel services, inter-fuel arbitrage, as well as increased operational flexibility to manage various load profiles can all provide profit opportunities in a deregulated environment.

The combination of electricity and gas delivery services could also yield economies of scale by combining various operational and marketing functions such as customer service, billing, metering, and repairs. The combination of services would ultimately yield costs savings which could contribute to lower energy costs for the customer.

The goal of the merged energy provider is to retain market share in a deregulated wholesale energy market which is rapidly moving towards full unbundling at the retail level. Energy companies will be vying to provide a wide range of energy and related products and services in a fully competitive environment. In certain cases, the sale of energy products may support the introduction of other products and services that could be offered as suites or packages.

The impact of the changing electricity industry has begun and will continue to have profound implications for the natural gas industry. The role of natural gas in electricity generation will continue to be an important link between both industries. This will be reinforced by the evolution of the current commodity-based energy market to a more integrated btu-based energy services market.

¨ Gas Distribution Developments

U.S. LDC Unbundling
Following the deregulation of interstate natural gas transmission, the next important venue for regulatory change is the state market. This has been referred to as LDC unbundling or customer choice. The AGA has defined customer choice gas volumes as those which are purchased from sources other than traditional gas utilities. They may be available as a result of full state-authorized retail market deregulation, partial de-regulation of certain market segments, or pilot programs offered by selected LDCs. In all cases the LDCs' merchant function has either been curtailed or eliminated.

The AGA reported that in 1995 (the latest year for which data are available) roughly 56% of U.S. gas volumes purchased were customer choice volumes. Non-utility gas is already widely available for large volume purchasers, such as electric utility generators (where 88% of volumes purchased are customer choice) and industrial users (86%).

Customer choice gas is attractive to large volume users with the resources to manage their own energy requirements. The AGA reports that within the industrial and commercial market segments the typical purchaser of customer choice volumes is a much larger user of gas than those which do not take advantage of customer choice.

A majority of U.S. states are either taking steps to introduce some form of residential consumer choice or studying the issue. Five states are restructuring their entire markets (Arizona, California, Massachusetts, New York and Vermont). Another five have utilities that are providing all gas customers with choice programs (Georgia, Maine, Montana, New Mexico and Ohio). There are seventeen states whose public utility commissions have authorized more limited utility pilot programs, and a further two which are studying unbundling proposals.

A change in the role of LDC's is expected to have repercussions both in end use markets as well as upstream from the citygate. As LDCs reduce or eliminate their role as gas merchants, they will have to deal with their investment in interstate pipeline capacity. The AGA has estimated that LDCs and combination utility companies currently account for 66 percent of firm transportation capacity on interstate pipelines.
In the short term, LDCs will face cost and competitive pressures from unbundling. SFV rate design for firm transportation service (FT) causes shippers' costs to increase as volumes fall. As state markets are opened up to customer choice, LDCs will be under cost pressures that will not necessarily be faced by their new competitors. Current

holders of FT can attempt to reduce their investment in excess capacity by disposing of it in the secondary market. However, under current FERC rules, it may not be sold for more than the cost of service rate. As a result, the best that an LDC could hope to do would be to break even on its investment, but would very likely suffer a loss.

In the longer term, LDC unbundling is likely to have an effect outside the citygate. The reduction in the merchant role of LDCs will cause them to curtail future investment in interstate pipeline capacity, so that expiring long term contracts will be either reduced or not renewed at all. It is estimated that between April 1, 1997 and December 31, 2001, 40 percent of FT on U.S. pipelines will expire. While natural gas demand is expected to increase, and therefore overall U.S. pipeline capacity will be required, the changes in the market for pipeline capacity arising from LDC unbundling will increase the uncertainty of future pipeline revenue streams.

Unbundling proposals must also deal with changes in the ground rules that have governed the operation of LDCs in the past. In effect, an LDC which operated with an exclusive franchise area also took on compensating responsibilities. This is often referred to as *the obligation to serve*. This obligation is composed of three elements; the requirement to extend service to new customers (based on viable economics), the requirement to maintain service to accounts in good standing, and a limitation on termination of service during the heating season of accounts not in good standing. The distribution company could also be called upon to use its position to both raise money for low income assistance programs and to effectively deliver the programs. In some cases conservation programs were also mandated.

The introduction of competition through customer choice calls these arrangements into question. Some have argued that competition may eliminate the need for some of the programs that LDCs had provided in the past. In any event, if LDCs are obliged to compete with marketers and other service providers that are not under similar obligations, they could be at a significant competitive disadvantage.

LDC unbundling is still at an early stage in the residential markets. State regulatory commissions are studying and testing approaches to expand it further.

Canadian LDCs & the OEB 10-Year Review

In 1995, with 10 years having passed since deregulation of Canadian natural gas pricing, the Ontario Energy Board (OEB) began examining the structure of the natural gas market in Ontario, to determine to what extent further deregulation could facilitate a more competitive energy market. The OEB consulted with stakeholders to explore these issues.

Most interested parties believed that Ontario legislation had created barriers to a fully deregulated natural gas market in Ontario. For example, Ontario legislation enacted when gas sales and distribution were complete monopolies, prevents title transfers of natural gas within the province. To comply with Ontario legislation, gas title transfers must be arranged to occur outside the province. This was not a problem when monopolies bought and sold all the gas distributed in Ontario, but currently approximately 70% of natural gas sold in Ontario is purchased under various types of direct purchase agreements, either by end-users or their agents, and so removal of this limitation is desired.

Most natural gas stakeholders in Ontario agreed that further benefits could be achieved with a more competitive natural gas market, and that it was necessary to revise legislation to enable the market to function more effectively and to better respond to customer needs and expectations. However, views diverged on the extent and the timing of further natural gas market deregulation.

After consulting with industry, the OEB determined that further regulatory changes were required, particularly to Ontario legislation governing title transfers of natural gas. Other issues include: i) allowing the natural gas market to operate more competitively; ii) role the OEB should take in this more competitive environment; and

iii) ensuring consumer protection.

In December 1997, the OEB submitted 14 recommendations for legislative changes to the Ministry of Energy. The OEB indicated that its recommendations outline the direction of legislative amendments which will encourage restructuring of natural gas markets towards full retail access and enhanced competition while ensuring consumer protection and system integrity.

The OEB concluded that removal of current legislative barriers to gas commodity title transfers is a necessary step to develop a more efficient and competitive gas market in Ontario. The OEB recommended that these barriers be removed as soon as possible but only when the retail gas market can be served by appropriately licensed Agents, Brokers and Marketers. Licensing would be the responsibility of the OEB.

The OEB also found that the existing OEB Act does not suit the proposed new retail market. The OEB was concerned that it may not have the necessary powers to adequately supervise the restructuring of LDC services. The OEB recommended a revised statute to provide the additional authority necessary to oversee the LDC services.

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