Canadian Gas Exports in the U.S. Market: 1995 Evaluation & Outlook

March 1996

Natural Gas Division

Natural Resources Canada

Executive Summary

Canadian natural gas exports to the United States reached 2.75 trillion cubic feet (Tcf) in 1995, marking the eighth consecutive year of strong export growth. On a regional basis, most of the growth in gas exports can be attributed to increased deliveries into the Western Region. Export volumes into the Midwest and Northeast also increased significantly.

This strong volumetric performance was in sharp contrast to the dismal price performance of gas exports. Downward price pressure persisted throughout North America during most of 1995. The average price measured at the international border dropped 20% in 1995 to $US 1.48/MMBtu. Given the steep decline in Canadian gas export prices, gas export revenues dropped 14% to $Cdn 5.6 billion.

The most significant development affecting Canadian gas exports in 1995 was the dramatic split in price differentials between the major North American producing regions. The pricing split can be attributed to a mismatch in regional supply and demand. Gas supply in Canada and the Western U.S. expanded faster than new take-away pipeline capacity, resulting in surplus gas supply and downward pressure on prices. At the same time, demand in the eastern states increased significantly. Canadian and Western U.S. suppliers have been constrained from serving this incremental demand by a lack of spare pipeline capacity. Gulf Coast and Midcontinent producers have had ample pipeline capacity but wellhead deliverability is constrained, which has led to higher prices for gas from these producing regions.

Starting in October 1995, cold weather in the eastern half of the U.S. accentuated the pricing split. Prices soared for Gulf Coast and Midcontinent gas, the main source of supply for eastern markets. In contrast, prices for Canadian and Western U.S. gas remained depressed, since most of the gas from these supply regions served the more temperate western markets.

In the short term, we expect that Canadian gas exports will continue to flow on existing export pipelines at high load factors, but they will be priced at a discount relative to Gulf Coast prices. The disconnect between Western Canadian and Gulf Coast prices will likely continue until 1998, after which new gas export capacity should provide a relief valve for the surplus gas supply within Western Canada. Canadian suppliers will be well placed to increase exports into the Midwest via the proposed Northern Border expansion project. The extent to which capacity will be expanded from the Midwest to the Northeast and other markets is uncertain.

The North American supply and demand balance will continue to evolve in response to market and supply pressures. Western U.S. producers are likely to add new take-away capacity to move gas from west to east. Gulf Coast and Midcontinent gas will continue being diverted away from U.S. Midwest markets to higher value Northeast and South Atlantic markets. The extent to

which Gulf Coast and Midcontinent suppliers are able to increase production is largely dependent on the continued successful application of new technology to offset the effects of resource depletion.

In the longer term, competitively priced Canadian gas is well placed to play a key role in bolstering U.S. domestic supply to meet growing U.S. demand. Industry forecasts predict that U.S. demand will continue to grow to reach 23 Tcf by the year 2000. Most of the growth in demand is anticipated in electricity generation. However, forecasts of bullish demand growth may be tempered as electricity deregulation unfolds and competition increases between alternate fuel sources serving the electric generation sector.

Ongoing regulatory shifts are also expected to continue to shape the competitive forces for all facets of the North American gas industry. It is still too early to assess the application of the Federal Energy Regulatory Commission's new policy on rolled-in versus incremental tolls. Also at the federal level, the unbundling of pipeline services is proceeding with market-based rates and incentive regulation. State and provincial regulatory agencies are now proceeding with the next phase of deregulation with the unbundling of services provided by local distribution companies.

Overall, the outlook for Canadian gas exports is strong. We expect that the Canadian natural gas industry will continue to respond effectively to changing market and regulatory dynamics in the North American market. Our analysis indicates that existing and proposed export capacity will be used at high load factor levels, resulting in natural gas exports of 3 Tcf by the year 2000.

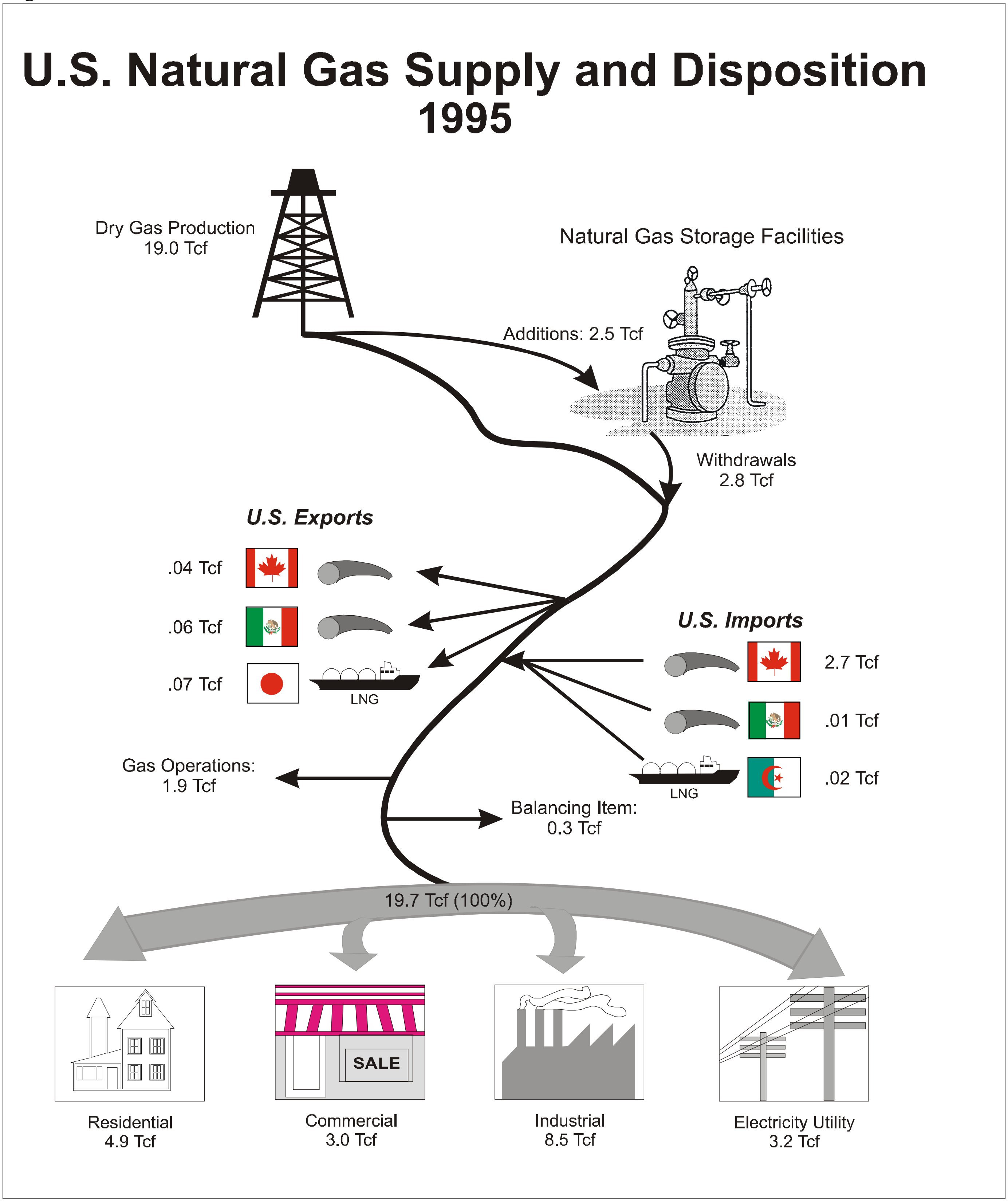
Canadian Gas Exports in the U.S. Market: 1995 Evaluation & Outlook was prepared by the staff of the Natural Gas Division, Natural Resources Canada. General information concerning this report may be obtained from Lisa Jackson at (613) 995-8921. Detailed questions on specific issues of the publication may be addressed to the following analysts:

Michel Chénier	(613) 992-8377	Volume, Capacity, Price, Northeast Region
John Foran	(613) 992-0287	Supply, Midwest Region
Chris Reid	(613) 995-0422	Demand, Western Region
Brian Troicuk	(613) 995-0177	Regulations, Electricity Restructuring

CANADIAN GAS EXPORTS IN THE U.S. MARKET:
1995 EVALUATION & OUTLOOK

TABLE OF CONTENTS

Figure 1



U.S. Natural Gas Supply and Disposition
1995
Dry Gas Production
19.0 Tcf
Natural Gas Storage Facilities
Additions: 2.5 Tcf
Withdrawals
2.8 Tcf
U.S. Exports
.04 Tcf
.06 Tcf
.07 Tcf
LNG
U.S. Imports
2.7 Tcf
.01 Tcf
.02 Tcf
LNG
Gas Operations:
1.9 Tcf
Balancing Item:
0.3 Tcf
19.7 Tcf (100%)
SALE
Residential
4.9 Tcf
Commercial
3.0 Tcf
Industrial
8.5 Tcf
Electricity Utility
3.2 Tcf

Forward

Canadian Gas Exports in the U.S. Market: 1995 Evaluation & Outlook has been prepared by the Natural Gas Division of Natural Resources Canada to provide a summary of the data and information relating to the North American natural gas industry including supply, demand, prices, transportation capacities and key regulatory events which affect current and future exports of Canadian natural gas. The report consists of three main sections: I. 1995 Year in Review; II. Outlook to the Year 2000; and, III. Regulatory Update. A review of Electricity Restructuring is included as an Appendix.

Various sources were used in compiling this report, including private consultants, industry associations and federal government agencies in Canada and the U.S. The main data sources were the National Energy Board (NEB) and the U.S. Energy Information Administration (EIA). This report is based on a calendar year as opposed to a contract year.

I. 1995 Year in Review

A. U.S. Market Dynamics

This section provides an overview of U.S. natural gas trade in 1995. A review of the trends in U.S. supply, storage, gas flows, demand, and prices is key to understanding the dynamics of the North American natural gas market for Canadian exporters.

During 1995, changing demand and supply patterns exposed the mismatch between where adequate pipeline capacity exists and where it is needed. Starting in October, eastern U.S. and Canadian demand surged due to weather. Western U.S. and Canadian supply regions could not significantly increase production, even though extra wellhead deliverability existed, because pipelines exiting these regions were already running near full capacity. The Gulf Coast and Midcontinent regions had available exit pipeline capacity, but little available incremental wellhead deliverability.

In total, the additional production delivered to eastern markets was insufficient, resulting in a heavy draw on market area storage, and price run-ups in eastern markets. In the west, wellhead deliverability bottled up by exit pipeline limitations, combined with lower demand in the area depressed local prices, leading to huge price differentials between eastern and western markets.

i) Supply

The U.S. has two main sources of natural gas supply: indigenous production (88%) and imports from Canada (13%). The gas supply sources and changes between 1994 and 1995 are shown in Table 1.

Table 1

U.S. Natural Gas Supply

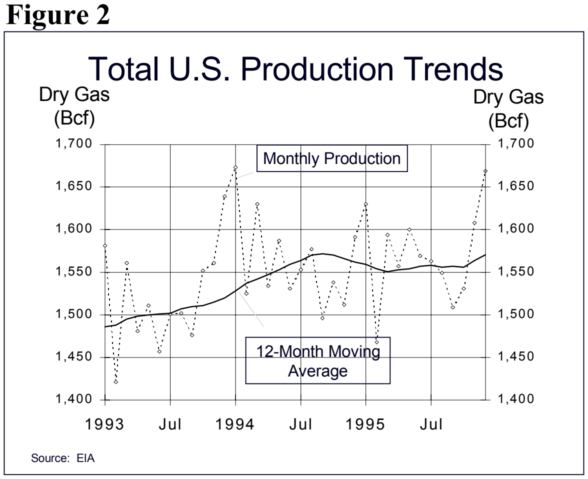
	1995 (Bcf)	1994 (Bcf)	Difference (Bcf)	Change (%)	% of U.S. Supply Increase	% of Total U.S. Gas Supply
Domestic Production	18,975	18,876	99	0.5%	43.1%	87.9%
Net Canadian Imports	2,716	2,523	193	7.6%	83.8%	12.6%
Net LNG Imports	-54	-12	-42	350.0%	-18.2%	-0.3%
Net Mexican Imports	-50	-30	-20	66.7%	-8.7%	-0.2%
Total Net U.S. Imports	2,612	2,481	131	5.3%	56.9%	12.1%
TOTAL U.S. SUPPLY	**21,587**	**21,357**	**230**	**1.1%**	**100.0%**	**100.0%**

In 1995, total U.S. gas supply was 21,587 Bcf, up 230 Bcf from the previous year. Net imports of Canadian gas accounted for 84% of the increase while U.S. production accounted for 43%. A decline in liquified natural gas (LNG) and Mexican imports tempered the overall growth in gas supply.

U.S. Domestic Natural Gas Production

U.S. indigenous production increased by 99 Bcf in 1995 to reach 18,975 Bcf. U.S. gas production appears to be flattening out, after strong growth in 1993 and 1994, a period of the highest wellhead prices in fifteen years. Figure 1 shows U.S. production by month, and the 12-month rolling average of production.

Figure 2



U.S. Regional Production and Drilling

The U.S. Gulf Coast Onshore (Texas, Louisiana, Mississippi and Alabama) supplies over 34% of total U.S. production. In 1995, Gulf Coast Onshore production was flat, at 6,544 Bcf. The U.S. Gulf Coast Offshore (state and federal waters offshore Texas, Louisiana, Mississippi and Alabama) supplied 27% of U.S. production. This year, Gulf Offshore production fell marginally to 5,030 Bcf.

From a pipeline/market perspective, the Gulf Coast Onshore and Offshore are one region, supplying over 60% of total U.S. production. The small amount of U.S. production growth in 1995 was mainly due to poor production growth in the Gulf Coast. Production in this region was 11,574 Bcf during 1995, down 13 Bcf from the previous year. This stagnation is in marked contrast to the two previous years, when Gulf Coast production increased strongly (up 197 Bcf during 1993 and up 351 Bcf in 1994).

Low drilling was the main reason for the lack of production growth in the Gulf. In 1995, it is estimated that Gulf Coast Onshore gas drilling fell to 2,961 wells, a drop of 4% versus 1994, while Offshore wells totalled 182, identical to 1994.

The next largest producing area in the U.S. is the Midcontinent (Arkansas, Kansas, Oklahoma, and Missouri), with 14% of U.S. production. In 1995, Midcontinent production fell by 25 Bcf to 2,704 Bcf. A key factor for this decline was an 8% drop in gas drilling in 1995 (to 1,318 wells).

The bulk of the remainder of U.S. production originates in New Mexico, with 8%, and the Rockies (Colorado, Wyoming, Utah), with 7%. Production in these regions rose in 1995 by a total of 88 Bcf, to reach 2,915 Bcf. In 1995, New Mexican gas drilling was flat at 181 wells, while drilling in the U.S. Rockies fell to 817 wells, a drop of 33%. In contrast to the Gulf and Midcontinent, these areas were able to increase gas production without additional gas drilling because of their excess wellhead deliverability.

U.S. Regional Gas Flows

An examination of the changes in net exportable production (regional production less internal demand) among the U.S. supply regions indicates the prospects for Canadian gas exports in regional U.S. gas markets.

Total Gulf Coast production fell by 13 Bcf in 1995, while gas consumption within the region rose by 74 Bcf, resulting in 87 Bcf less gas available to leave the region compared to last year. In the Midcontinent, production dropped by 25 Bcf, while consumption rose by 172 Bcf, leaving 197 Bcf less gas to leave the region.

The large capacity gas pipeline corridors linking the Gulf Coast and Midcontinent to the U.S. Midwest and Northeast consuming areas are important for Canadian gas. Less gas moving north from these mature U.S. supply regions has created an opportunity for increases in Canadian gas exports.

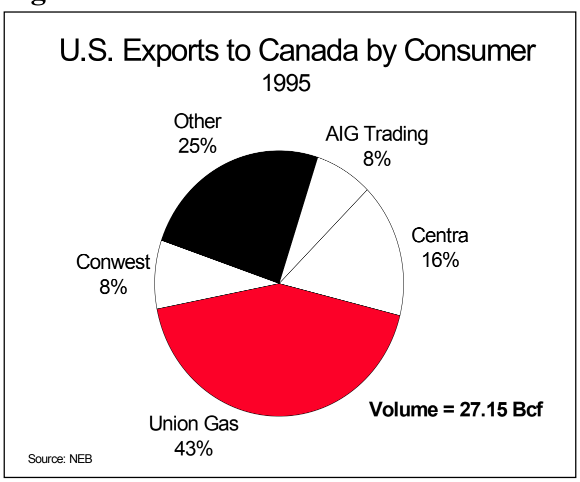
New Mexico and U.S. Rockies production rose by 88 Bcf, while demand rose by 58 Bcf, resulting in a slight increase (30 Bcf) in the exportable production from these regions. The majority of this excess gas found its way into the highly competitive California market.

Net Imports From Canada

In 1995, U.S. net imports from Canada totalled 2,721 Bcf, an increase of 203 Bcf from the previous year.

As shown in Figure 2, U.S. exports to Canada are relatively minor. The volume for 1995 decreased 38% from 1994 levels, to approximately 27 Bcf, due primarily to competitive pricing of Canadian gas.

Figure 3



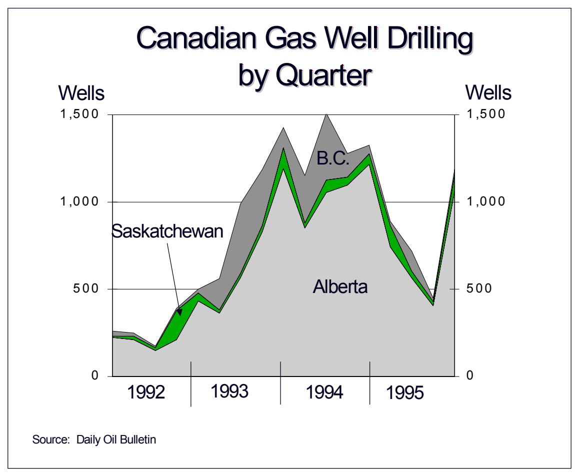
In contrast, the U.S. imported 2,748 Bcf of Canadian gas, an increase of 241 Bcf from the previous year. In 1995, Canadian gas was the largest net source (84%) of incremental gas supply to the U.S. market.

Canadian gas production increased by 339 Bcf (7%) during 1995, to reach 5,241 Bcf. In 1995, 52% of Canadian production was exported to the U.S.

Canadian wellhead deliverability is greater than the sum of local demand plus take-away pipeline capacity. As a result, the Western Canadian local gas markets are oversupplied with gas, and prices are historically low, both in absolute terms, and relative to gas prices in other North American markets.

Despite low gas prices and the existence of underutilized wellhead deliverability, drilling in Canada continues to be fairly strong, as shown in Figure 3. From a low of 908 gas wells in 1992, drilling rebounded to 3,327 gas wells in 1993, 5,300 in 1994, and 3,386 wells in 1995. The 1995 drilling level is a drop of 36% from 1994 levels, but is still high compared to most years in the past. One of the reasons that Canadian drilling reacts slower to lower price signals than U.S. drilling is the difference in equity financing.

Figure 4



As with the U.S. Rockies and New Mexico, Canadian gas production increases are not dependent on increased drilling, since unused production capacity exists. For example, gas drilling in 1992 was historically low, but Canadian production continued strong growth (10%/year) in 1992 and 1993.

Net LNG Imports

In 1995, the U.S. exported more LNG than it imported. Philips Alaska Natural Gas Corporation and Marathon Oil Company export LNG from southern Alaska to Japan. In 1995, 72 Bcf was exported, up from 63 Bcf last year. These exports involve gas that is not accessible to the Canada/U.S. gas market, and so are not particularly relevant for our purposes.

In 1995, the U.S. imported 20 Bcf of LNG from Algeria, a decline of 60% over the previous year. LNG imports represent less than 1% of total U.S. supply.

There are two operating LNG terminals in the U.S., which receive gas from Sonatrach in Algeria: Everett, Massachusetts, and Lake Charles, Louisiana. In late 1994 Sonatrach undertook a major renovation of its gas liquifaction plants in Algeria. LNG shipments to the U.S. were down over 60% as a result. Reduced LNG shipments to the U.S. are expected to continue into 1996, until Algeria's terminals get back to full capacity.

The Cove Point, Maryland, LNG terminal/ regasification facility was reopened in 1995. However, it is being used to liquify and store U.S. produced gas, for later regasification during peak demand periods. Essentially, it is being operated as a storage facility, and so will not affect U.S. LNG imports. The Elba Island, Georgia LNG terminal/regasification facility may also be reopened in 1996-97, but is also expected to be mainly used for storage.

Net Imports From Mexico

U.S. exports to Mexico continue to be higher than imports from Mexico, thereby slightly decreasing gas supply for the U.S. market.

U.S. gas exports to Mexico increased to 55 Bcf, up from 37 Bcf in 1994. Widely held expectations for rapidly growing Mexican gas demand and significant (over 200 Bcf) imports from the U.S. have not yet materialized. Increased U.S. export expectations were based on Mexico converting oil-fired electrical generating plants to gas service, and PEMEX not being able to supply incremental gas. Plant conversions are far behind schedule, and so the Mexican demand increase has not yet been seen.

In 1995, the U.S. imported 5 Bcf of Mexican gas. Mexican gas supply balances are managed by PEMEX, the state oil and gas company. Since there is negligible gas storage in Mexico, exports to the U.S. are used as a "relief valve", when PEMEX has excess gas production over domestic demand.

In the last months of 1995, PEMEX had excess gas and exported about 150 MMcf/d into Texas. This slight surplus within Mexico is due to PEMEX gearing up for a surge in Mexican natural gas demand in 1998. Mexican regulations restricting emissions are scheduled to be in effect in 1998, and are expected to cause much higher Mexican gas demand, as industrials and power generators will be forced to switch from fuel oil to gas.

U.S. Storage Considerations

Storage has large impacts on North American gas supply, demand, and prices. In the U.S., huge volumes of natural gas, roughly 3 Tcf, are injected into underground storage over the April to October period, and withdrawn during the November to March period.

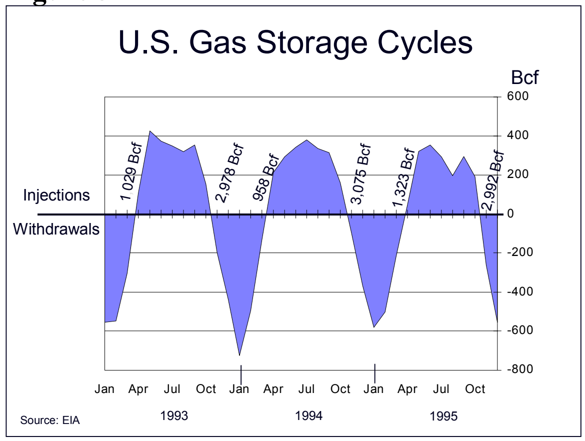
Roughly similar amounts of gas are injected to storage each year. Depending mainly on weather, this volume will be either insufficient, excessive, or appropriate. Storage balances thus represent the memory of the gas market, and a very obvious price signal. Storage balances are low if injections were low or demand was heavy, and low storage tends to support price increases.

The U.S. storage cycle over the past several years is shown in Figure 4 below. The area above the horizontal line represents injections, and the area below represents withdrawals. Also shown on the figure are working gas levels at the beginning and end of each storage cycle.

The November 1994 - March 1995 storage withdrawal cycle ended with 1,323 Bcf of gas remaining in storage. This volume was relatively high compared to previous years (over 300 Bcf higher). Because the storage injection cycle began relatively full, storage demand during 1995 was low, and this contributed to weak gas prices over most of 1995. The injection cycle ended with 2,992 Bcf in storage, 83 Bcf less than last year.

With the strong gas demand seen in November and December 1995, heavy withdrawals occurred, leaving U.S. storage balances much lower going into 1996 than last year. This should result in strong U.S. demand for gas to refill storage in early 1996, and should consequently support gas prices.

Figure 5



ii) Demand

This section concentrates on U.S. end-use natural gas demand for 1995 (see Table 2). Data for this section is primarily sourced from the EIA. Because of the time lag in EIA reporting, estimates were made for the last month of the year. To stay concise, regional explanations are provided only where there were dramatic changes from the previous year.

U.S. end-use gas demand increased to approximately 19.7 Tcf in 1995. The 17% growth in consumption since 1990 has pushed 1995 consumption levels to within half a percentage point of the all-time consumption record reached in 1972. In total, end-use gas demand grew by 750 Bcf in 1995, a 4% increase over the previous year.

Table 2

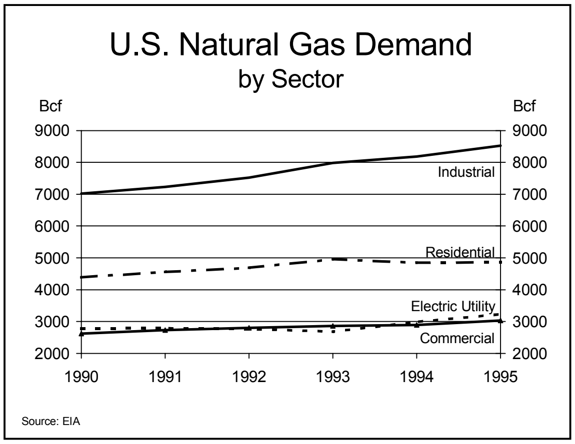
U.S. Natural Gas Demand

	1995 (Bcf)	1994 (Bcf)	Difference (Bcf)	Change (%)
End-use U.S. Demand				
Residential	4,860	4,848	12	0.2%
Commercial	3,038	2,895	143	4.9%
Industrial	8,526	8,179	347	4.2%
Electric Utility	3,232	2,987	245	8.2%
Sub-Total	19,656	18,909	747	4.0%
Gas Used in Operations*	1,915	1,845	70	3.8%
TOTAL U.S. DEMAND	**21,571**	**20,754**	**817**	**3.9%**

* Plant lease and pipeline fuel

Residential/Commercial
In 1995, residential gas demand was basically unchanged from 1994, remaining at 4.9 Tcf (see Figure 5). This was the second year that residential gas demand was flat. This is not all that unusual as gas demand in the residential sector is largely a function of heating degree days. Sustained growth only occurs when new customer demand is greater than efficiency improvements.

Figure 6



In 1995, commercial gas demand increased by 143 Bcf or 4.9%, with annual consumption totalling 3.0 Tcf. This year demand growth is largely attributable to gains made during the second and third quarters. This is partly explained by the changing components of the commercial sector.

The majority of commercial demand is for space heating and is therefore greatly influenced by heating degree days. However, commercial demand during the non-heating season is increasingly influenced by non-utility generation and gas cooling applications. These emerging uses have helped commercial gas demand achieve steady growth over the last few years and will help flatten out the seasonal demand curve.

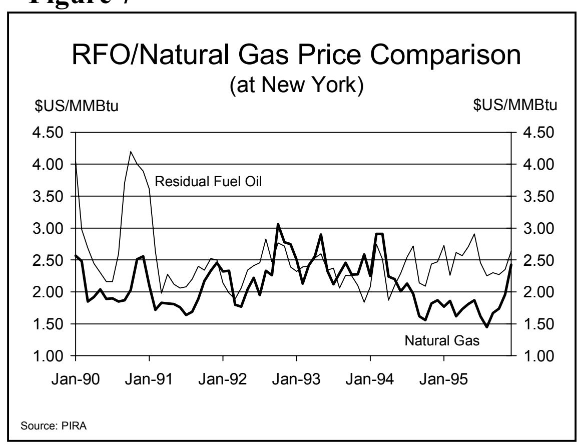
Industrial
In 1995, annual industrial gas demand increased by 347 Bcf or 4.2% and now stands at 8.5 Tcf.

This sector is responsible for much of the recent gains in U.S. gas demand. Between 1990 and 1995, industrial gas demand increased by 1.5 Tcf. This growth is attributed to the following three factors.

First, there has been notable real economic growth in the U.S. over this period, with a corresponding increase in industrial energy consumption. The gas-weighted manufacturing index experienced healthy growth in 1995, close to 4%. Key industrial gas customers include chemical, iron and steel, petroleum refining, and paper companies.

Second, and most important for 1995, is the price advantage natural gas experienced over alternative fuels. Figure 7 compares gas and residual fuel oil prices measured in the New York area. Industrial consumers used more gas during 1995, as a result of the largest price differential in several years.

Figure 7



The third factor is the inclusion of natural gas consumed in non-utility electric generation, currently estimated at 2 Tcf. Favourable regulations encouraged the emergence of this demand component. A significant amount of recent industrial demand growth is due to non-utility generation.

On a regional basis, much of the growth in industrial gas demand has occurred in the eastern part of the U.S. Of particular significance this year is the tremendous surge in New York consumption (25% of U.S. increase). This is largely due to the start-up of the 1000 MW Sithe Energy "Independence" project which can consume 200 MMcf/d of natural gas (see Northeast Regional Analysis section for more details).

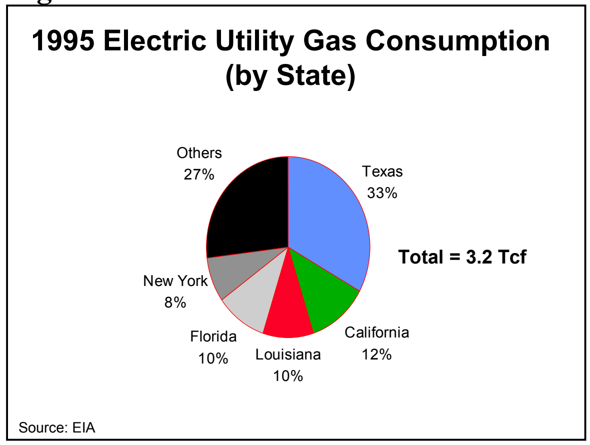
Electric Utility

In 1995, natural gas demand in the electric utility market increased by 245 Bcf or 8.2%, to total 3.2 Tcf. As in the industrial sector, the key reason for this year's increase was low natural gas prices. The electric utility sector is unique in that five states account for almost 75% of its consumption (see Figure 8).

The largest gains were made in Florida and New York, two states that have historically consumed considerable fuel oil to generate electricity. The completion of the Florida Gas Transmission expansion (over 500 MMcf/d) in March 1995 enabled almost 200 Bcf of incremental gas to serve mostly electricity demand. In Florida, the market share of gas in electric generation rose from 14% in 1994 to 23% in 1995. This is a result of the pipeline expansion and low gas prices which displaced considerable fuel oil demand (43% decline).

In New York State's electric utility sector, competitively priced natural gas captured much

Figure 8



of the dual-fuel power generation load from oil. A 50% increase in gas consumption indicates that gas is the fuel of choice. Natural gas now generates about 25% of all utility generation in New York, while fuel oil's market share has shrunk from 13% to 8%.

Low gas prices have taken market share away from oil and coal in several other states as well. Mississippi, Massachusetts, Michigan, Connecticut, and Pennsylvania have experienced gas demand doubling or tripling from levels of only two years ago.

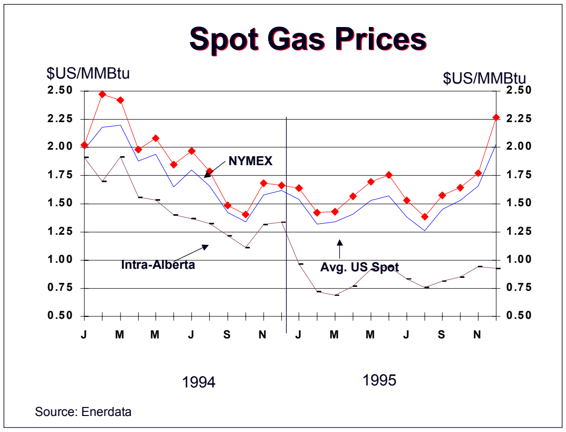
Finally, the overall growth in the electric utility sector is especially notable given the dramatic fall in consumption in California. California electric utility gas demand fell 32% from abnormally high 1994 levels, due to a resurgence of hydro-electric generation and cooler summer temperatures.

iii) Price

This section focuses on two main developments that occurred over the past year: volatile overall U.S. spot prices and divergent east-west continental prices. Figure 9 shows the average U.S. spot gas price, the NYMEX price, and the intra-Alberta spot price (at AECO C) over 1994 and 1995.

The weak U.S. spot price of 1994 carried over into 1995. For most of 1995, prices hovered around $US 1.50/MMBtu until the November/December surge that returned prices into the $US 2.00/MMBtu range.

Figure 9



The downward price pressure over most of 1995 was largely a result of the interaction of supply, demand and storage during the 1994/95 heating season demand was lower than the previous year, storage was not drawn down as far as expected. This held the heating season price spike down and exerted downward pressure on prices for the following months.

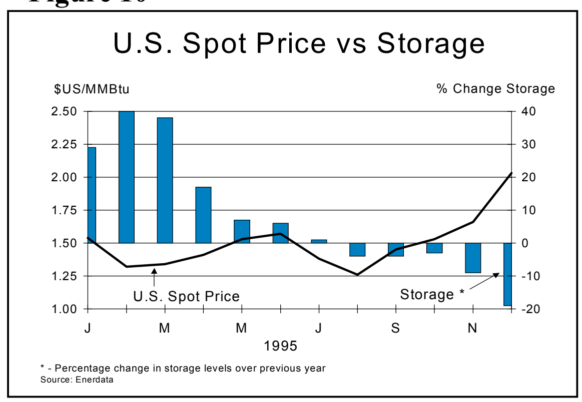
By late 1995 (the start of the heating season), conditions changed dramatically. Although U.S. supply (including domestic production and Canadian gas imports) increased throughout the year, demand growth (weather-induced) outpaced increased supply.

The unseasonably cold temperatures in November 1995, set the stage for higher prices for the rest of the heating season. Supplies from storage were consumed earlier than expected, and as a result, buyers looked to the spot market for incremental supply. As shown in Figure 9, this exerted upward pressure on spot prices as well as on the current winter's remaining NYMEX contracts.

Figure 9 also indicates the price divergence that has occurred between the intra-Alberta market and NYMEX. Similar price differences developed between western U.S. basins and NYMEX. Intra-Alberta spot prices were isolated from the run-up in eastern U.S. prices, leading to unusually high pricing differentials in the latter part of the year.

The pricing split or widening of basis differentials between western producing regions and the Gulf Coast is attributed to a combination of factors: In 1994, productive capacity in western basins (U.S. and Canada) grew faster than demand (due to very high drilling rates), leading to a growing surplus of supply. However, a lack of spare pipeline capacity meant that western producers were unable to move incremental gas to eastern markets where demand was strong. This resulted in intense gas-on-gas competition in western producing markets and contributed to steadily falling intra-Alberta prices.

Figure 10



At the same time, demand for U.S. Gulf Coast and Midcontinent gas production exceeded wellhead deliverability, driving up prices in those supply regions, and in markets served by them. Gulf Coast and Midcontinent producers had ample pipeline access to the higher valued eastern markets, but wellhead deliverability was limited.

Another key factor to depressed western prices was the significant decline in western demand; particularly in California. Higher hydro-electric generation for the entire year came at the expense of natural gas. In addition, mild winter temperatures in California significantly lowered residential demand in the fourth quarter of 1995. Combined with significant excess of pipeline capacity into the Western region and ample deliverability, prices plummeted.

B. Canadian Gas Exports

i) Price

U.S. price trends were directly reflected in Canadian export prices for 1995. Average Canadian export prices (measured at the international border) declined by 23% from 1994 to reach $1.43/MMBtu in 1995. Overall export prices were at their lowest level since deregulation in 1986.

On an annual basis, long-term export prices fell by 15% in 1995 to $US 1.73/MMBtu, while short-term export prices decreased by 42% to $US 1.19/MMBtu (see Table 3). This reflected the overall decline in spot market prices throughout North America.

Table 3

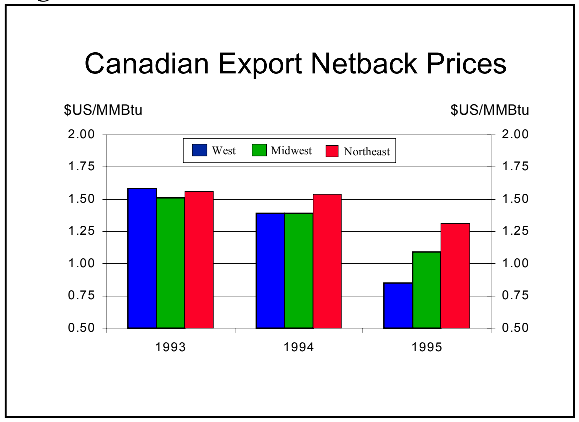
Overall Canadian Gas Prices

		$US/MMBtu, International Border		
Year	**Month**	**LT**	**ST**	**Avg**
1995	January	1.85	1.39	1.60
	February	1.77	1.13	1.42
	March	1.65	1.09	1.35
	April	1.68	1.11	1.38
	May	1.77	1.23	1.49
	June	1.75	1.20	1.47
	July	1.65	1.15	1.39
	August	1.56	1.06	1.31
	September	1.72	1.15	1.44
	October	1.77	1.19	1.49
	November	1.79	1.45	1.59
	December	1.92	1.67	1.77
Total 1995		**1.74**	**1.25**	**1.48**
Total 1994		2.03	1.68	1.86
% Change		-14.3	-25.6	-20.4

LT (Long-term licences) - more than 2 years
ST (Short-term orders) - less than 2 years

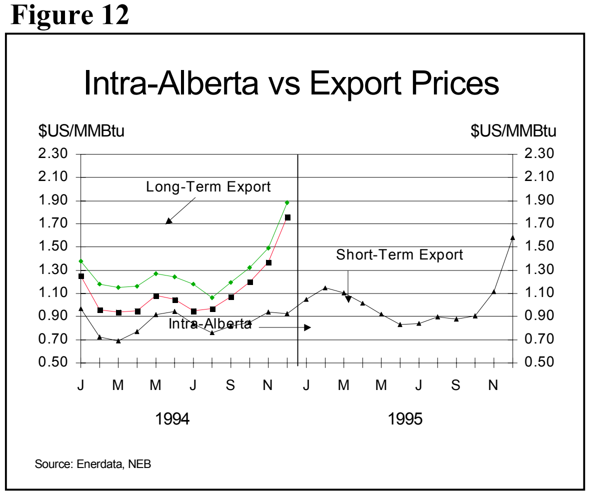
The east/west pricing split can be seen when comparing Canadian plant-gate netbacks across the different export regions. As shown in Figure 11, the price parity of 1993 and 1994 has turned into a staircase effect in 1995. Excess pipeline capacity resulting from expansions, tolling decisions, and lower than expected demand have significantly reduced netbacks to the Western region. In contrast, Northeast export netbacks were the strongest due to the high proportion of long-term contracts and being able to participate in the region's late year price run-up.

Figure 11



Although exporters experienced a price decrease in 1995, it was much less pronounced than the drop in intra-Alberta prices. The impact of intense gas-on-gas competition and limited alternative market outlets increased the between intra-Alberta and export prices. This differential, which hovered around $US 0.12/MMBtu in 1994, began to increase in the last quarter of 1995 to finally end at over $US 0.90/MMBtu in December (see Figure 12).

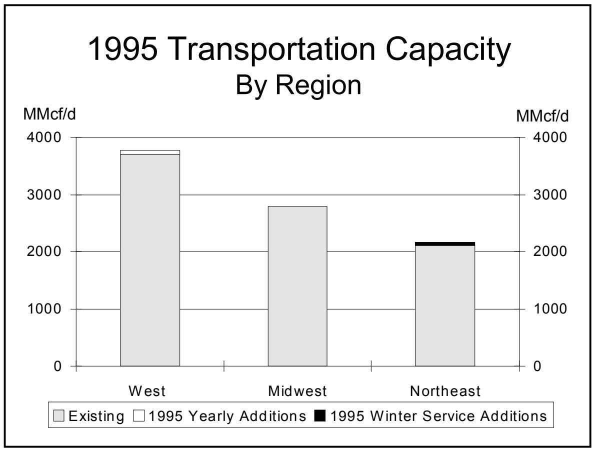
Figure 12



ii) Capacity/Volume

Pipeline capacity grew marginally in 1995. Export capacity to the Northeast and Western regions increased as a result of expansions at the Iroquois, Niagara Falls, and Huntingdon export points. Capacity serving the Midwestern region remained at the 1994 level (see figure 13).

Figure 13



Capacity at the Iroquois export point was increased by 50 MMcf/d for the winter period. The capacity was added to accommodate incremental exports to the Northeast during the winter months. This expansion brings the total export capacity at Iroquois to 825 MMcf/d for 151 days during the winter heating season. A minor expansion (7.5 MMcf/d) was also completed at the Niagara Falls export point to serve markets in the Northeast.

Total export capacity to the Western region increased by 80 MMcf/d. Westcoast expanded its export capacity to enable increased deliveries to customers via the Northwest pipeline's system. As a result total export capacity at the Huntingdon export point is now 1045 MMcf/d. A 113 MMcf/d pipeline was also constructed to serve new customers in Nevada. Capacity at the international border was not increased as a result of this project. Upstream capacity for this project was obtained from PG&E's capacity release program.

In 1995, Canadian gas export volumes increased by 9% over the previous year, to 2,744 Bcf (see Table 4). Gas exports to all regions were up in 1995 and is discussed in the following section.

In this report, exports with underlying firm transportation capacity are classified as firm, while all other exports are recorded as interruptible. The share of firm and interruptible sales remained unchanged from last year. Firm sales, representing 78% of total export volumes, rose by 9% to about 2,149 Bcf. Interruptible exports increased by 11%, ending the year at 597 Bcf.

Although 9% growth in exports is substantial, Canadian gas exports to the U.S. grew an average of 15% per year over the 1990-94 period. Reduced export growth was due to a lack of pipeline construction, and existing pipeline capacity to the U.S. approaching full utilization.

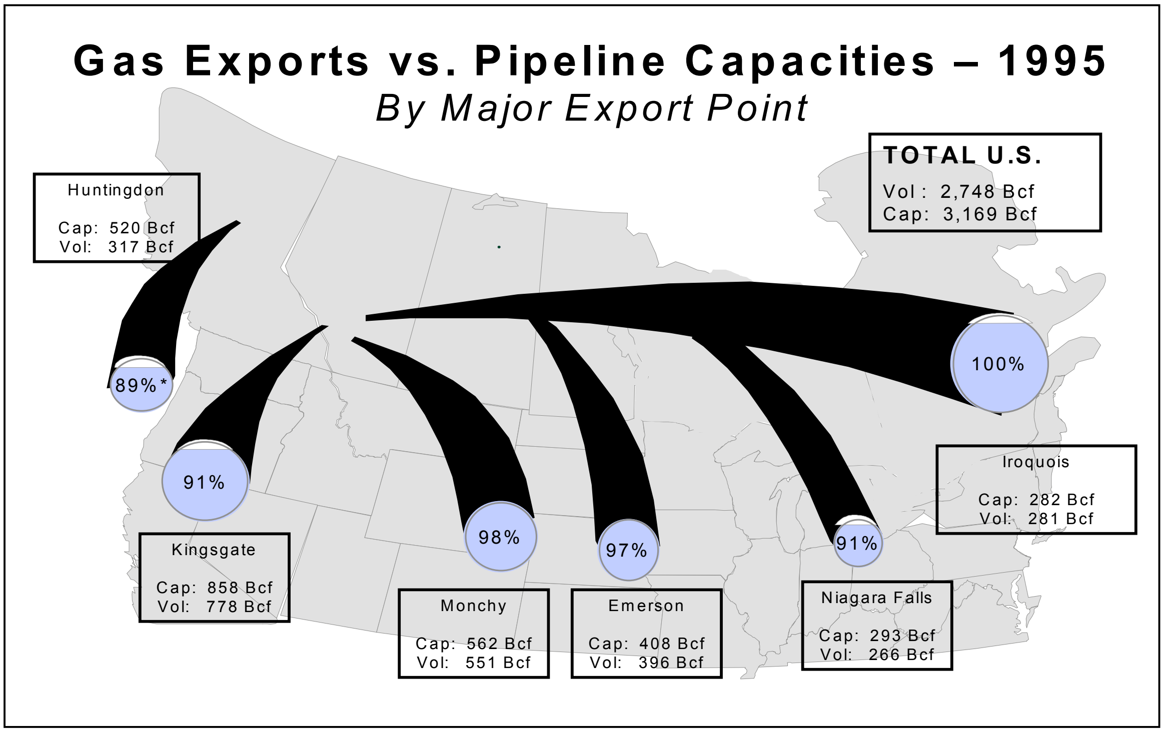
The overall utilization factor for pipelines capable of exporting gas to the U.S. was 86%. On a regional basis, the load factors were as follows: Western region, 89%, Midwest region, 98%, and Eastern region, 95%. Figure 14 shows total capacity by export point and the corresponding utilization factors.

Table 4

Overall Canadian Gas Export Volumes (Bcf)

Year	Month	Firm	Interruptible	Total
1995	January	184.1	64.0	248.2
	February	167.1	58.0	225.1
	March	187.4	60.2	247.6
	April	173.9	46.7	220.6
	May	172.7	42.2	214.9
	June	172.6	44.5	217.1
	July	173.9	49.1	223.1
	August	183.9	43.5	227.3
	September	181.9	39.7	221.5
	October	190.8	41.6	232.3
	November	185.6	36.8	222.4
	December	200.4	47.9	248.4
Total 1995		**2,174.2**	**574.2**	**2,748.4**
Total 1994		1,971.0	536.7	2,507.7
% Change		10.3	7.0	9.6

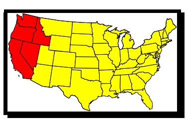
Figure 14



iii) Regional Analysis

The Western Region

The Western Region, A Statistical Snapshot



California
Idaho
Nevada
Oregon
Washington

	1995	1994	% Change
Canadian Exports to the Western Region (Bcf)	1,095	992	10%
Average International Border Price (US/MMBtu)	1.03	1.63	-37%
Average Plant Gate Price (US/MMBtu)	0.85	1.45	-41%
Revenue ($Cdn)	1,576	2,245	-30%
Gas Consumption in the Western Region (Bcf)			
• Residential	606	636	-5%
• Commercial	374	359	4%
• Industrial	928	892	4%
• Electric Utility	477	662	-28%
Total Natural Gas Consumption	2,385	2,549	-6%

The Western Region is a newly defined region for our analysis, which combines the California and Pacific Northwest markets. The main reasons for this change relate to the restructuring of the Alberta and Southern export arrangement and the expansion of the Pacific Gas Transmission (PGT) and Northwest Pipeline (NWPL) systems into the region. In addition, the construction of the new Tuscarora pipeline requires the inclusion of Nevada in the market region.

Total natural gas demand in the Western Region was 2,385 Bcf in 1995. This was a decline of 164 Bcf, or 6%, from 1994, but this demand still exceeded 1993 levels. Recall that 1994 consumption was abnormally high due to depressed hydro-electric generation and warmer than normal summer temperatures.

By state, California is dominant, accounting for approximately 80% of gas demand in the region. Thus, changes in this state drive the entire region. This year, California demand fell by 184 Bcf. Gains made in the commercial and industrial sectors were dwarfed by the 192 Bcf decline in electric utility generation, which were 410 Bcf in 1995. The decrease is attributed to high precipitation levels in 1995 compared with relatively low levels in 1994.

For the region as a whole, milder than normal weather in the fourth quarter resulted in a 4.7% overall decline in residential demand to 606 Bcf. Gains were made in the commercial and industrial sectors, with increases of 2.6% to 374 Bcf and 4.0% to 928 Bcf, respectively. Electric utility demand declined by 28%, to 477 Bcf in 1995.

Canadian exports to the Western Region reached 1,095 Bcf in 1995, a 10% increase over 1994. Competitive prices and the absorption of spare capacity from the November 1993 PGT expansion led to the rise.

The combination of higher exports and lower gas demand resulted in a higher Canadian share of the Western gas market. Canada's market share reached 46%, up from 39% in 1994, and 33% in 1993.

Westcoast expanded its export capacity to the Huntingdon hub in November 1995 by 80 MMcf/d. Accordingly, NWPL's capacity now totals 1,045 MMcf/d. Load factors for 1995 on Kingsgate and Huntingdon averaged 92% and 61%, respectively.

The 61% load factor reported at the Huntingdon export point could lead to the mistaken conclusion that export volumes could be increased easily. This is not the case. Westcoast deliveries into the Huntingdon hub averaged 89% during 1995 (98% over the winter months). Deliveries at the hub are made to NWPL for export, three user-dedicated pipelines for export, and to BC Gas for domestic and export markets. During many winter months, higher domestic deliveries downstream of Huntingdon restrict the amount of physical gas that can be exported (even though the contractual obligations are met with U.S. supplies via NWPL). Further depressing load factors are the three user-dedicated pipeline which consistently run at 20% load factors due to their over-capacity design.

The ratio of Canadian gas exported under firm versus interruptible transportation arrangements remained unchanged. Firm exports accounted for 70% of total exports, with the remainder exported as interruptible.

For 1995, the international border price of gas exported to the Western Region fell by 37%, to $US 1.03/MMBtu. Average Canadian plant gate netbacks fell by 41% to $US 0.85/MMBtu. The decrease in prices dwarfed the higher volumes, resulting in a 30% decline in export revenues at the international border: a $US 498 million loss.

Other Noteworthy Events

Numerous events occurred during 1995 in the Western Region. Although the following issues are mutually exclusive, they affect current or future Canadian exports.

The Tuscarora pipeline was completed in November 1995 with a capacity of 113 MMcf/d. This pipeline taps into PGT's mainline at Malin, Oregon, and runs through California to Reno, Nevada. The main consumer is Sierra Power's Tracy Power plant (95 MMcf/d).

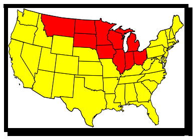
A pipeline expansion that did not get off the ground was a PGT expansion proposal. In the spring of 1995, PGT held an open season to determine the demand for new capacity commencing in 1997. Given the lack of interest in committing to long-term demand charges for the over-piped California market, the expansion did not proceed.

Optimism regarding incremental power generation demand was deflated with the Bonneville Power Authority's (BPA) cancellation of its contract with Tenaska. In May 1995, BPA announced it will not be purchasing power from the 248 MW facility, which was under construction. Tenaska has filed a $US 1 billion lawsuit for damages. Shell and Husky Canada hold long-term gas export licences for 21 and 14 MMcf/d, respectively, to serve this facility. The facility may still be built, but its fate awaits the outcome of litigation over the contractual cancellations.

Certain environmental organizations were quite active in the Pacific Northwest states in 1994. Attempts to solicit opposition to natural gas-fired generation in 1995 were unsuccessful. Combined with the erosion of gas demand projections, this issue has been put on the back burner.

The Midwest

The Midwest



Illinois
Iowa
Indiana
Michigan
Minnesota
Montana
North Dakota
Ohio
South Dakota
Wisconsin

A Statistical Snapshot

	1995	1994	% Change
Canadian Exports to the U.S. Midwest (Bcf)	1,006	942	7%
Average International Border Price ($US/MMBtu)	1.45	1.73	-19%
Average Plant Gate Price ($US/MMBtu)	1.13	1.39	-23%
Revenue ($Cdn)	1,996	2,274	-12%
Gas Consumption in the U.S. Midwest (Bcf)			
• Residential	1,756	1,710	3%
• Commercial	865	865	0%
• Industrial	1,661	1,577	5%
• Electric Utility	114	78	47%
Total Natural Gas Consumption	4,396	4,230	4%

Overall demand in the Midwest market grew by 4% over the previous year to reach 4,396 Bcf in 1995. On a sectoral basis over the past year, residential demand, which accounts for 40% of overall gas demand in the region, increased by 2.7% to reach 1,756 Bcf in 1995. Commercial demand for natural gas was flat at 865 Bcf. Industrial demand increased by 5.3% to 1,661 Bcf, while electric utility demand soared by 47% to reach 114 Bcf in 1995.

Storage is particularly important in the Midwest, which has roughly 40% of total U.S. underground storage capacity. During peak winter demand months, over 40% of gas demand in the region is met by local storage withdrawals, while in summer months 40% of gas delivered to the region is used to fill storage. These storage operations moderate price volatility in the region.

Total Canadian natural gas exports to the Midwest during 1995 were 1,006 Bcf, up 7% from last year's level of 942 Bcf. The Canadian share of the Midwest natural gas market rose to 23%, compared to 22% last year.

The Monchy (Foothills) and Emerson (TCPL) export points together accounted for 94% of Canada's exports to the Midwest. Midwest export capacity through Emerson was estimated at 1,117 MMcf/d during 1995, and was used at a 97% load factor, up from 95% last year. At Monchy, capacity of 1,540 MMcf/d was used at 98% load factor, up from 92% last year.

Capacity at other smaller export points serving the Midwest total over 300 MMcf/d, but this capacity is not exclusively dedicated to exporting gas; it is used for imports at certain times. However, assuming capacity dedicated to exports at 297 MMcf/d, the load factor for these other Midwest export points was 56% in 1995.

For 1995, the international border price of gas exported to the Midwest fell by 19% to $US 1.45/MMBtu. This was mainly due to a general weakness in North American gas prices. For example, NYMEX prices fell by 14%, dragging Midwest prices with them. Average Canadian plant gate netbacks for the Midwest fell by 23% to $US 1.13/MMBtu.

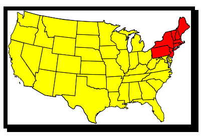
The decrease in prices offset higher volumes, resulting in a 12% decline in export revenues at the international border. Revenues at the international border totaled $US 1.5 billion, while plant gate revenues totaled $US1.0 billion.

Other Noteworthy Events

From November 14-17, 1995, Foothills pipeline in Saskatchewan shut down completely for maintenance work. Gas exports to the Midwest via Monchy were therefore zero for these four days, and November was the lowest volume month for exports to the Midwest. The work was done in response to the February 1994 pipeline rupture, which was identified as being caused by hydrogen-induced cracking due to pipe reactions with sulfur in cement weights on the line. All sulfurous concrete weights were replaced; this appears to have resolved the problem.

The Northeast

The Northeast



Connecticut
Maine
Massachusetts
New Hampshire
New Jersey
New York
Pennsylvania
Rhode Island
Vermont

A Statistical Snapshot

	1995	1994	% Change
Canadian Exports to the U.S. Northeast (Bcf)	**647**	**569**	**14%**
Average International Border Price ($US/MMBtu)	**2.28**	**2.46**	**-8%**
Average Plant Gate Price ($US/MMBtu)	**1.36**	**1.54**	**-13%**
Revenue ($Cdn)	**2,020**	**1,932**	**5%**
Gas Consumption in the Northeast (Bcf)			
• Residential	**997**	**1,056**	**-6%**
• Commercial	**648**	**638**	**2%**
• Industrial	**970**	**798**	**22%**
• Electric Utility	**433**	**286**	**51%**
Total Natural Gas Consumption	**3,048**	**2,778**	**10%**

Overall demand in the Northeast grew by 9.7% over the previous year to reach 3,048 Bcf in 1995. This was a significant increase compared with the 2% demand growth rate of the two previous years.

On a sectoral basis, over the past year, residential demand, which accounts for over 30% of overall gas demand for the region, declined by 5.6% to 997 Bcf in 1995. While unseasonable weather conditions prevailed during both the first (warmer than normal) and fourth quarters (colder than normal) of 1995, the net effect was a decline in residential demand. Commercial demand for natural gas increased by 1.6% to reach 648 Bcf. The difference between residential and commercial consumption trends can be explained by the increased use of gas in cooling and non-utility generation applications, which are not a factor in residential consumption.

Demand in the industrial sector increased by 22% in 1995 to 970 Bcf. This represents the bulk of the increase in overall consumption levels for the region. The strong demand in this sector since 1990 is attributed to the growth in gas demand by the non-utility generation (NUG) sector. Most of the increase in 1995 was due to the start-up of the Sithe Energies cogeneration facility near Oswego, New York. Sithe began its operations in November 1994 and consumes 200 MMcf/d of gas to produce 1,004 MW of electrical power. However, the impact on Canadian gas exports is minimal, since only a small portion of the total gas supply originates in Canada.

The competitive pricing of natural gas in 1995 also contributed to increased gas consumption by industrial users in the U.S. Northeast. Natural gas prices were well below residual fuel oil prices throughout 1995.

Demand in the electric utility sector soared by 51% to 433 Bcf in 1995. As in the industrial sector, low natural gas prices compared with residual fuel oil prompted utilities to favour natural gas in dual-fuel generation facilities in 1995.

Total Canadian natural gas exports to the Northeast during 1995 were 647 Bcf, up 13.8% from last year's level of 569 Bcf. However, export growth kept pace with incremental demand in the region, and the Canadian market share remained stable at 20%.

Unlike the past several years, no new major export capacity was added to the Northeast in 1995. The exception was a minor expansion at the Niagara export point which will allow incremental volumes of 7.5 MMcf/d via the Tennessee pipeline in the U.S.

In an effort to optimize existing pipeline capacity, Winter Firm Service (WFS) was introduced on the Iroquois Transmission System in 1995. This new service enables shippers to take advantage of favorable technical conditions present in the winter to export more gas during the winter months. Although these conditions have always existed, the firm allotment of this space is a new type of service being offered by Iroquois. To date, Iroquois has marketed 50 MMcf/d of WFS to CNG Energy Services to serve various customers in the Northeast. The overall load factor on pipelines serving the Northeast remains high this year, averaging 96%.

The ratio of Canadian gas exported under long-term contractual arrangements remained high this past year. Long-term exports accounted for 87% represented over of exports, with the remainder exported as interruptible.

For 1995, the international border price of gas exported to the Northeast decreased by 18 to $US 2.28/MMBtu. This decrease reflects the overall decline of U.S. prices through the first ten months of the year. Prices for exports to the Northeast recovered somewhat in the last two months, buoyed by cold temperatures and higher U.S. spot prices.

Prices for exports to the Northeast mirror pricing trends in the market, since most contracts use pricing formulas which are indexed to local spot prices as well as oil prices. Export prices at both the Iroquois and Niagara export points decreased by 10 and 25 cents respectively over the previous year.

The growth in volumetric sales to the region during the year offset the decline in prices. Revenue at the international border was $US 1,471 million, while plant gate revenue totalled $US 875 million.

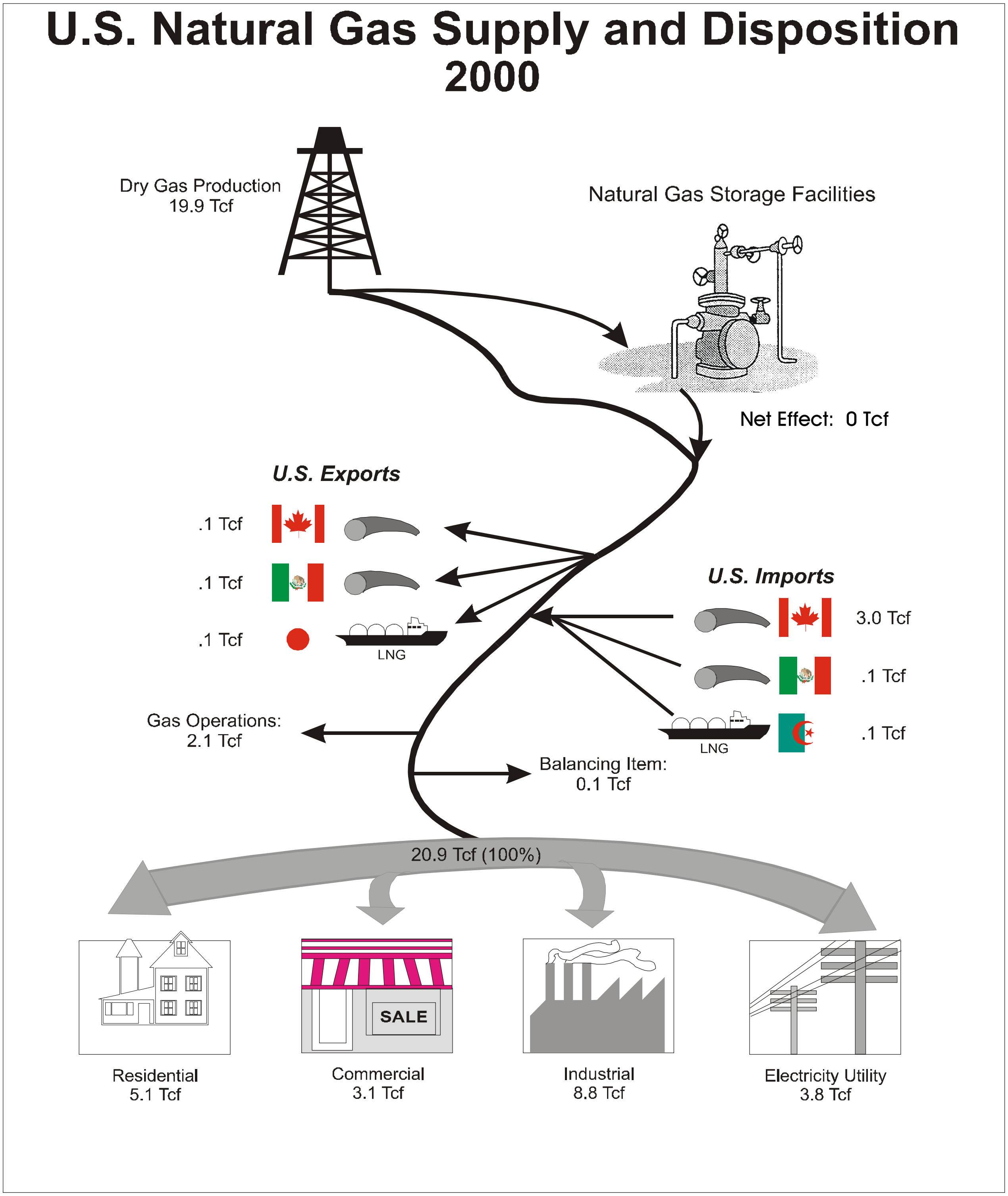
Other Noteworthy Events

Ongoing deregulation initiatives in the U.S. contributed to the reduced growth rate in Canadian exports to the Northeast. The Northeast gas market is currently in a transition period. As was the case with deregulation initiatives at the interstate level (Order 636), existing infrastructure will be used more efficiently as LDC unbundling progresses in most northeastern states.

Throughout the year, most utilities in the Northeast have responded to calls from state regulators and have submitted restructuring proposals. The programs all address issues relating to direct purchase options by residential and commercial customers. The main impact of these programs will be elimination of the traditional linear relationship between users and utilities. Gradually, all customers will be given the opportunity to contract for gas services from third parties (marketers or producers).

Of particular significance to Canadian exporters is the generalized shortening of contractual arrangements associated with gas sales which will accompany unbundling. This is important for increased exports to the region, as they rely on new infrastructure which require long-term commitments. New infrastructure will require new types of contractual arrangements where the risk is shared among different segments of the industry.

Figure 15


U.S. Natural Gas Supply and Disposition
2000
Dry Gas Production
19.9 Tcf
Natural Gas Storage Facilities
Net Effect: 0 Tcf
U.S. Exports
.1 Tcf
.1 Tcf
.1 Tcf
LNG
U.S. Imports
3.0 Tcf
.1 Tcf
.1 Tcf
LNG
Gas Operations:
2.1 Tcf
Balancing Item:
0.1 Tcf
20.9 Tcf (100%)
SALE
Residential
5.1 Tcf
Commercial
3.1 Tcf
Industrial
8.8 Tcf
Electricity Utility
3.8 Tcf

II. Outlook to the Year 2000

A. U.S. Market Dynamics

i) Supply

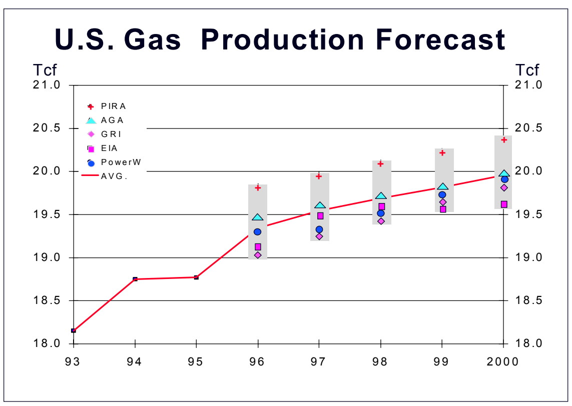
U.S. demand increased at a 2.8% average annual rate over 1990-95, while production increased at 1.3%. The shortfall of U.S. production compared with demand growth has driven the growing need for Canadian natural gas. This section examines the prospects for U.S. gas supply to the year 2000.

U.S. Domestic Production

To aid in estimating future U.S. domestic supply, the following expert forecasts were surveyed: ARC Financial (formerly PowerWest), PIRA, EIA, the American Gas Association (AGA), and the Gas Research Institute (GRI). These are shown in Figure 16.

The average of the forecasts surveyed expect U.S. production at 19.9 Tcf by 2000. The range of production volumes for the year 2000 is 19.6 Tcf (EIA) to 20.4 Tcf (PIRA).

Figure 16



The average forecast (year 2000) represents a gain of 857 Bcf over 1995 production levels. The trend line shows a 0.8% average annual growth, an indication that most forecasts anticipate U.S. production growth will slow.

This compares to the 1.3% annual pace of the past five years. This slowdown appears to be primarily driven by future expectations for gas demand, and the assumption that increased Canadian gas imports will make up any shortfall.

To complement these forecasts, a qualitative analysis of U.S. production on a regional basis is provided. A regional approach is useful for understanding regional market dynamics, regional gas export prospects, and the probabilities of various U.S. production growth scenarios.

Gulf Coast and Midcontinent

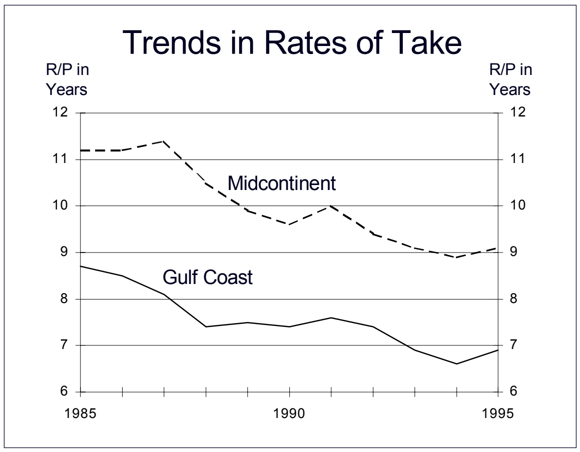
Because of its dominant role, a key question is whether the Gulf Coast can increase production enough to satisfy incremental demand. Recent reports contend that the Gulf Coast can meet this challenge. One of the key assumptions underpinning this notion is the impact of technology improvements, notably in deep offshore drilling.

The other crucial component is the excess pipeline capacity that exists from both the Gulf Coast and Midcontinent to the major consuming regions of the Midwest and Northeast. Therefore, increased supply only requires wellhead deliverability, which can be brought on-stream quickly. This gives Gulf Coast and Midcontinent producers an advantage over other regions which must construct new pipeline capacity.

However, there are also several factors that question the ability of these producing regions to significantly increase production over the forecast horizon.

Due to the high rates of take from these reserves, wellhead deliverability declines faster than in other areas, and more production must be replaced each year. Over the past 10 years, all North American producers have gone to higher rates of take for their reserves. This is indicated by lower and lower reserves to production ratios, as shown for the Gulf Coast and Midcontinent in Figure 17.

Figure 17



However, there is now little scope for this to continue in these regions. Thus, in order to increase or even maintain production, large amounts of new reserves and new wellhead deliverability (at relatively high marginal costs) must be developed each year; consequently high gas drilling levels are required.

For these areas, strong drilling levels are mostly determined by gas prices. Prices will probably have to exceed the average of 1990-94 (since prices over this period resulted in falling reserves on average). As prices are difficult to predict, the production outlook for the mature areas is also uncertain.

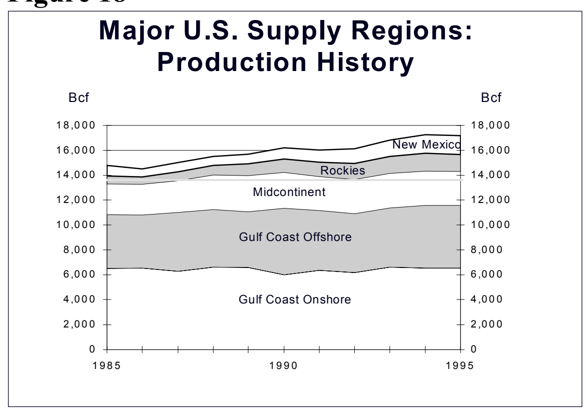
Rockies and New Mexico

On a regional basis, the bulk of U.S. production growth over the past ten years has been from the U.S. Rockies and New Mexico (the western areas), as shown in Figure 18. In contrast, the mature areas have increased production only marginally.

Unlike the Gulf Coast and Midcontinent, the western supply basins do not have excess pipeline capacity. Most pipelines exiting these regions are running near full capacity, and transportation rates are not discounted.

In contrast to the Gulf Coast and Midcontinent, the cost of incremental production at the wellhead in these areas is low. Because of the lack of adequate pipeline capacity, western wellhead deliverability is not used at high load factors, and proved reserves are not developed as quickly. This means that considerable incremental gas production can be obtained by accelerating production from proved reserves, which is inexpensive. As an indication of the scale of this, the reserves to production ratio in these areas is close to 13 years, compared to 7-9 years in the Gulf Coast and Midcontinent.

Figure 18



Increased production from the Rockies and New Mexico will require additional pipeline construction, with gas prices having less influence. Two of the pipeline projects currently proposed are the Wyoming Interstate Company 812 MMcf/d expansion from southwest Wyoming to central Nebraska and the conversion of an oil line to gas, which would add 200 MMcf/d of Rockies production to Midwest capacity. However, unless the slow pace of new pipeline construction in the U.S. can be overcome, it is questionable whether significantly higher western U.S. gas production will be possible until near the end of the decade.

Net Imports from Canada

Net imports from Canada are expected to continue to grow over the forecast period. Since U.S. exports to Canada are expected to remain minor (under 50 Bcf), this section focuses on Canadian exports to the U.S.

The U.S. is a critical market for Canadian producers, as 80% of the production increase between 1990-95 was exported to the U.S.

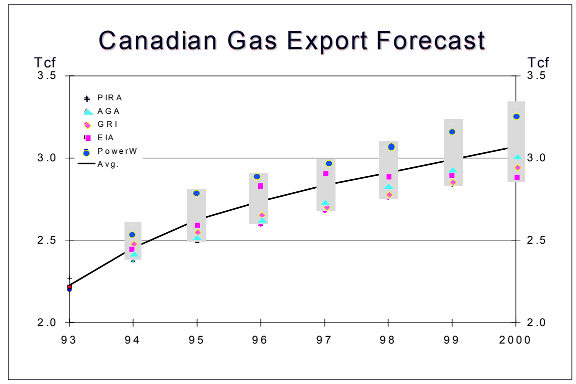
Currently, Canada has excess gas wellhead deliverability. Various analysts estimate that effective Canadian wellhead deliverability (deliverable to pipelines) is up to 17% greater than production rates. The current constraint to increased Canadian gas exports to the U.S. is gas pipeline capacity. The nearest significant export pipeline capacity addition (Northern Border) will not be ready until spring of 1998. Thus, significant increases in Canadian exports to the U.S. are not possible until that time.

To aid in developing our longer-term outlook for Canadian gas exports (in Section B), we have examined the export forecasts of several organizations: ARC, PIRA, EIA, AGA, and GRI. As shown in Figure 19, the average of the forecasts surveyed is for Canadian gas exports of 3.0 Tcf by 2000. The range of forecasts for the year 2000 is 2.7 Tcf (EIA) to 3.4 Tcf (PIRA).

The average forecast for 2000 represents a gain of 300 Bcf over 1995 production levels, or growth of 2.5% per year. Canadian gas exports to the U.S. have grown an average of 13% per year over 1990-95. The period of rapid growth in Canadian gas exports is now over, unless major pipeline projects are constructed.

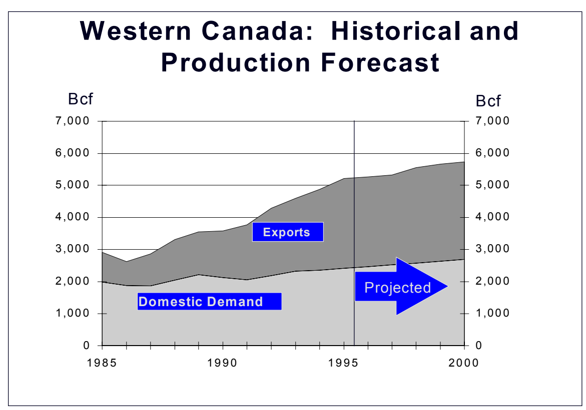
Currently, at least one large pipeline project, the Northern Area Transportation Study (NATS) project, is being discussed at preliminary stages. Since it is not at the stage of having applied to regulatory bodies for leave to construct, we have not yet included it in our forecast export capacities. The pipeline would add 800-1,200 MMcf/d of Canadian gas export capacity to the U.S. Midwest market.

Figure 19



For the longer term, Canada has large volumes of undiscovered resources and is less developed and explored compared to most supply regions in the U.S. Given its capture of gas market volumes from other regions, and despite the pipeline disadvantages Western Canada has vis-à-vis certain other basins, it appears to be one of the low-cost gas areas in North America. Over the medium term, the large volumes of proved reserves currently existing in Canada should allow production to increase to roughly 5.7 Tcf by the end of the decade, as shown in Figure 20.

Figure 20



Lastly, preliminary proposals are being discussed to bring gas from offshore Nova Scotia, near Sable Island, to the U.S. Northeast.

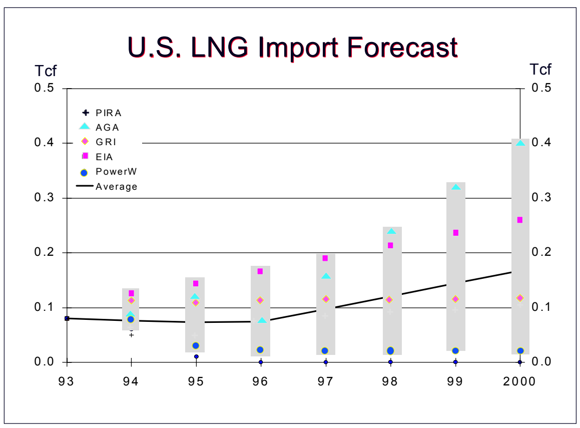
This is not at the stage of having applied to regulators, so it is not included in any of our capacity analyses.

Net LNG Imports

There are two operating LNG terminals in the U.S. A review of forecasts by EIA, PIRA, AGA, GRI and ARC (Figure 21) shows a wide range of expectations for LNG imports. Expectations range from the U.S. importing no LNG in the year 2000 (ARC) to importing 400 Bcf in that year (AGA). Obviously, the level of LNG imports to the end of the decade is very uncertain, but it is unlikely to be significantly above historical levels.

LNG exports from Alaska are expected to remain at about 70 Bcf per year. However, these volumes represent a leakage of supply, since it is not accessible to the U.S. or Canadian market.

Figure 21



Net Imports from Mexico

Current U.S. imports from Mexico through the Hidalgo border point are minor (5 Bcf in 1995, with a capacity of 150 MMcf/d or 55 Bcf annualized). On a net basis, these volumes are even lower, since U.S. exports to Mexico continue to occur at the Eagle Pass, El Paso, and Douglas U.S. border points. From month to month, the U.S. switches from being a net importer to being a net exporter with Mexico. During 1995, the U.S. was a net exporter of gas to Mexico, totalling approximately 50 Bcf.

The question of whether the U.S. will be a net importer or exporter with Mexico (through the year 2000) remains unclear. Net trade will be relatively minor and will range between 55 Bcf of imports and 200 Bcf of exports. In the longer term, it should be remembered that Mexican reserves are among the lowest cost supplies in the world. This is why some analysts see Mexico as the "sleeping giant" of North American gas supply.

Aside from the trade aspect with Mexico, there are other developments which bear mention. Equity investment in all aspects of Mexican natural gas was until recently the exclusive right of Petroleos Mexicanos (PEMEX), the state energy company. Mexico, by law, cannot grant equity ownership of oil or gas reserves to foreign investors but must rely on internal cash flows and debt financing for capital projects.

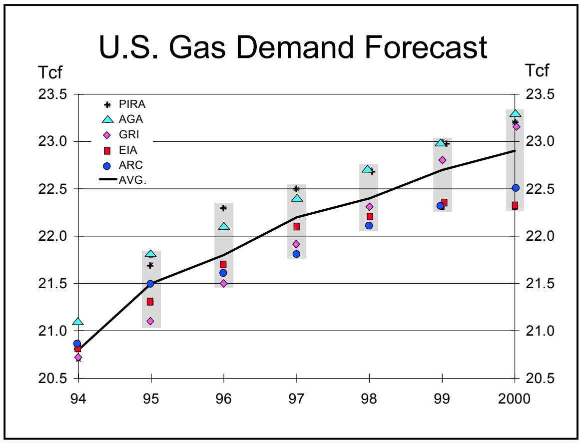
However, Mexican policy-makers improved the availability of capital with the new "natural gas law" and related regulations. These allow 100% foreign ownership and operation of natural gas distribution systems, gas pipelines, and storage facilities. Now, PEMEX can leave much of that investment to foreign or private investors and perhaps retain more capital for upstream gas investments.

Lastly, new environmental regulations in Mexico, due to come into effect in 1998, are expected to cause large volumes of new gas demand. This is because industrial and electric utility generators will be forced to switch from fuel oil to gas. Certain new Mexican gas markets (Juarez, Mexicali, Tijuana, Rosarito) are isolated from Mexican gas pipelines and supply, but, are close to the U.S. pipeline grid; gas demand growth in these areas could be supplied by the U.S.

ii) Demand

As shown in Figure 22, a survey of five natural gas demand forecasts predicts continued growth. By the year 2000, most of the forecasts anticipate demand in the range of 23 Tcf.

Figure 22



Many of the positive aspects of natural gas are reflected in the forecasts. Lower burner-tip emissions from natural gas, compared to coal and oil, favour continued growth in gas consumption, especially in those states that are adopting more stringent air quality standards. Furthermore, the displacement of U.S. offshore oil import requirements offers national security benefits. Increased Canadian gas exports contribute to all of these aspects.

It is worthwhile to define the source of incremental growth. Sectoral demand growth is addressed first, followed by an examination of regional demand growth.

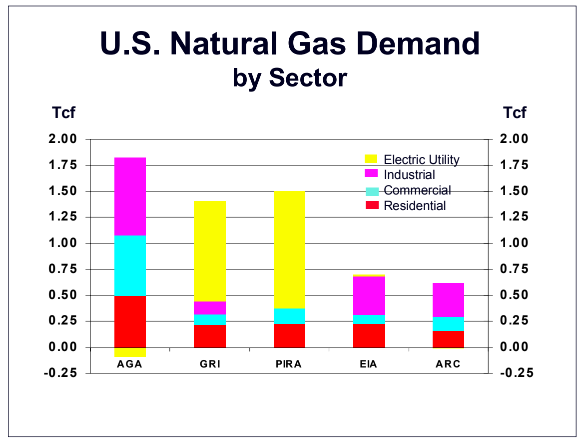
Figure 22 shows the range of demand forecasts to the year 2000. PIRA, the AGA and the GRI believe that past growth trends will continue, resulting in overall demand of about 23.25 Tcf. On the other hand, ARC and the EIA expect demand growth rates to level off, resulting in overall demand of about 22.5 Tcf.

As illustrated in Figure 23, the key difference between the forecasts is found in electricity demand projections.

Residential/Commercial

Four of the five forecasts (all but AGA) agree that incremental residential gas demand will total approximately 0.2 Tcf. This moderate growth would place the consensus view of residential gas demand (year 2000) at 5.1 Tcf. Increased efficiencies are expected to offset any increase in gas demand for space heating. However, growth is expected to come from greater penetration of traditional appliances (cooking, water heating, clothes drying) and new applications (cooling and fireplaces).

Figure 23



In terms of incremental commercial demand, four of the five forecasts agree that demand will total just over 0.1 Tcf (3.1 Tcf total demand for 2000). Efficiency improvements and conservation will likely moderate increases from demographic changes. Recent gains have been made in cogeneration (for own use) and space cooling. However, cogeneration growth in the commercial sector is unlikely to keep growing, given the expected downward pressure on electricity prices resulting from electricity restructuring. Commercial gas demand growth is expected to be driven by greater penetration of the gas cooling appliance market.

The AGA's residential/commercial growth forecast is three times the average of the others for the combined sector, projecting growth of over 1 Tcf. The AGA predicts increases in both space heating and new applications (e.g., cooling) and disagrees that efficiencies will offset customer growth. When evaluating which forecast is more accurate, recall that residential gas demand fell for the second consecutive year in 1995.

Industrial/Electric Utility

As in past years, the majority of incremental gas demand is expected to come from electricity generation. The development of highly efficient gas-fired combustion turbines has given gas a preferred position in the market for new power generation equipment. Gas demand growth is captured in both the industrial sector (where most non-utility generation is included) and the electricity sector (traditionally generated by utilities).

Most forecasters anticipate relatively flat traditional industrial demand while industrial self-generation of electricity (and some sales to third parties) will increase. In total, industrial gas demand is expected to increase between 0.1 Tcf and 0.4 Tcf, averaging 8.75 Tcf by 2000. Again, the AGA is more bullish on demand growth, forecasting industrial demand of 9.3 Tcf by 2000. AGA predicts that both cogeneration and traditional demand will increase.

Electricity generation forecasts show the widest divergence, with growth expectations ranging from 0 to 1 Tcf. This would put total electricity generation by the year 2000 at either 3.3 Tcf or 4.3 Tcf. ARC, the EIA, and the AGA see no growth by electric utilities, while PIRA and the GRI see 1 Tcf growth in power generation outside their industrial sector projections.

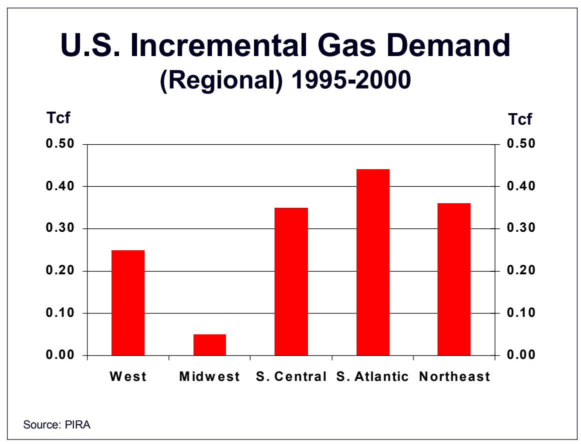
The progression of electricity restructuring efforts appears to be having a dramatic effect on gas demand forecasts. One has to wonder if it is merely a coincidence that the two most recent forecasts (EIA - Jan/96 and ARC - Jan/96) predict the lowest gas demand growth. For more analysis of the impact of electricity restructuring on gas demand, see the Appendix.

Sectoral analysis is often complicated by the inclusion of power generation in both the industrial and electric utility components. PIRA no longer includes non-utility generation in its industrial gas sector. With electric restructuring, other agencies are likely to follow PIRA's lead, resulting in a traditional industrial sector and an electricity sector (which will encompass all forms of electricity generation).

Regional

A firm understanding of demand growth on a regional basis is especially important for Canadian exporters who are faced with decisions on whether to sign up for long-term commitments on specific export pipelines. Figure 24 shows a regional representation of incremental gas demand between 1995 and 2000 (PIRA forecast).

Figure 24

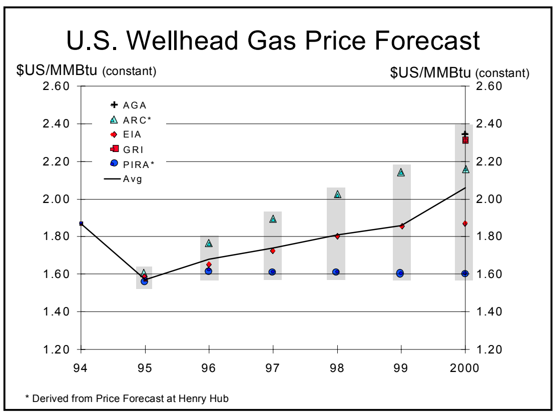


Clearly, a large proportion of this prospective growth is in regions that are not traditionally served by Canadian exporters (South Atlantic and South Central). These markets are expected to be met by increased deliveries from the Gulf Coast. If the Gulf Coast cannot increase production to capture this incremental market, it will have to divert deliveries from its more traditional markets. This may open the door for increased Canadian exports to regions such as the Midwest. A more detailed analysis of regional demand can be found in the regional export forecast sections.

iii) Price

As shown in Figure 25, a survey of five natural gas price forecasts predicts limited growth in U.S. natural gas prices in the medium term. By the year 2000, U.S. wellhead gas prices are expected to reach $US 2.06/MMBtu in inflation-free dollars. At the high end of the spectrum, the AGA, in its forecast of January 1995, predicts gas prices to reach $US 2.35/MMBtu. PIRA represents the bearish view to future gas prices, with gas prices expected to remain flat at approximately $US 1.60/MMBtu through 2000.

Figure 25



The overall consensus amongst forecasters is that gas prices will remain near current levels.

The main factors influencing these forecasts are: relatively low world oil prices, increased efficiencies in the exploration, development and production of natural gas, and moderate growth in overall North American gas demand.

The differences between gas price forecasts by the various experts relate to their assumptions for the variables mentioned above. PIRA for example, predicts falling oil prices through 2000. This is mirrored in a low gas price outlook for the forecast period. On the other hand, AGA predicts gas demand growth to continue at the current pace, which in turn, puts upward pressure on prices.

Electricity deregulation initiatives are expected to play an important role in determining the future market share of gas in the electricity generation market. The competitive pricing of natural gas vis-à-vis coal and residual fuel oil will dictate the future role of gas in this market. The dynamics of the interaction between future gas prices and gas demand in the electricity generation market will ultimately impact all gas sectors and, consequently, the overall realized price.

B. Canadian Export Forecast

i) Price

The delinking of Western Canadian prices from NYMEX has increased the complexities associated with price projections. The methodology used in our previous reports was largely based on the assumption that differentials between Canadian and U.S. prices would remain stable. Since this assumption is no longer valid, the previous approach cannot be used. Surveying experts' views was deemed more appropriate for this report.

1996 Outlook

The demand to replenish supplies depleted from storage during the 1995-96 heating season is expected to have a significant impact on prices through 1996. Therefore, Canadian prices are expected to be higher than those experienced in 1994 and 1995. However, the significant gap in basis differentials is expected to continue, as no significant pipeline capacity will be added in 1996. ARC Financial expects Alberta prices (wellhead) to hover around $Cdn 1.50/Mcf for the remainder of the year. This is moderately higher than the realized price of approximately $Cdn 1.34/Mcf in 1995.

Medium-Term Outlook

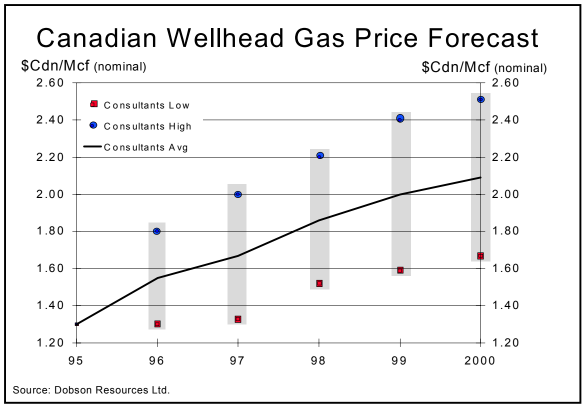
A survey of 16 independent oil and gas consultants, conducted by Dobson Resources Management Ltd., in January 1996, yielded an average wellhead price of $Cdn 2.07/Mcf in the year 2000 (see Figure 26).

Dobson's price survey is similar to those by other consultants cited in this report. For example, PIRA expects Canadian export prices to reach $Cdn 1.97/Mcf in 2000, while ARC Financial is more optimistic and expects the average price to reach $Cdn 2.33/Mcf in 2000.

In real terms, natural gas prices are expected to remain stable at current levels through the forecast period. Constrained pipeline capacity to certain key markets negatively affected prices in Alberta during 1995. This situation is not expected to improve significantly, until new export capacity is constructed. Until Northern Border's expansion becomes available in the spring of 1998, differentials between Gulf Coast and Western Canadian prices are expected to remain large.

However, the positive effect of new pipeline capacity on Western Canadian prices could be reduced significantly if production originating in the U.S. Rockies and Midcontinent is connected to eastern markets before 1998. To date, two pipeline projects have been proposed to enhance the flow of gas from the U.S. Rockies to the Midwest.

Figure 26



Additionally, the increased pipeline capacity to the Chicago city-gate from the Western basins could reduce prices in the Midwest market. The current downward pressure on prices stemming from gas-on-gas competition in the Western production areas could be transferred to the Midwest market.

The evolution of the overall energy market into a commodity market is also expected to continue to put downward pressure on natural gas prices. As the electricity market is deregulated in Canada and the U.S., energy commodity markets are expected to become even more integrated. Arbitrage opportunities are expected to eliminate pricing discrepancies between fuels used to generate electricity.

ii) Capacity/Volume

The following capacity and volume forecast represents our views to the year 2000. The forecast assumes relatively stable oil and gas prices. Canadian natural gas exports are expected to capture growth in U.S. gas demand throughout the forecast period. Canada's ample natural gas reserves will not constrain further increases in export volumes.

Existing and planned pipeline capacity is key to projecting Canadian natural gas export volumes. Since physical pipeline capacity represents a ceiling for gas export levels, existing and future pipeline capacity is first examined in the context of regulatory and market developments. Next, load factors are estimated for each export point using a number of variables, which include regional economic growth forecasts, competing fuel prices, and various industry sources.

Rationalization of existing pipeline capacity has been a key feature of the North American pipeline grid over the past year. Competitive forces are driving the natural gas industry to seek greater efficiencies. Load management tools such as storage, capacity release, and market hubs have become more prevalent. Deregulation initiatives such as unbundling and incentive ratemaking are expected to further increase overall efficiencies.

However, the current differential between prices in the western and eastern regions of the continent could prompt the next round of infrastructure development. Increased productive capacity in the West, combined with insufficient supplies in certain eastern markets could provide expansion opportunities.

These new potential capacity expansions face challenges of rapidly changing market dynamics and the shift away from long-term contracting practices. In the past, the risk associated with pipeline projects was reduced by the endorsements provided by long-term contracts. In an era of shorter contracts, shippers must now bear long-term risk without the comfort of long-term contracts.

Although new projects are currently in the early planning stages, the only sign of significant increased pipeline capacity over the forecast period is the expansion planned by Northern Border. It is currently awaiting regulatory approvals and is expected to be completed in 1998. This expansion is expected to provide 700 MMcf/d of additional capacity to the Midwest market.

TransCanada PipeLines will expand its system in 1996 to accommodate a number of new contractual arrangements to the U.S. Northeast. Facilities will be built to accommodate continued or new exports to the Brooklyn Navy Yard Cogeneration facility (26.5 MMcf/d), Enron Capital and Trade Resources Corp. (15 MMcf/d), Coastal Gas Marketing Company (10 MMcf/d), Altresco Pittsfield, L.P. (21.5 MMcf/d), and Delmarva Light and Power (2.8 MMcf/d).

Table 5 gives a detailed view of existing and expected future pipeline export capacity over the next three years (1998 levels will prevail to the year 2000). The Midwest and the Northeast will experience growth in export capacity, while capacity to the Western Region will remain at current levels.

Based on these assumptions, total natural gas exports to the U.S. are expected to reach 3,055 Bcf by the year 2000. Table 6 provides a detailed breakdown of exports by region and major export point. Export pipelines are expected to continue to be utilized at near full capacity through the forecast period.

Table 5

Estimated Exit Pipeline Capacity

	1995		1996				1997				1998			
	Year End Capacity		Annual Increment		Year End Capacity		Annual Increment		Year End Capacity		Annual Increment		Year End Capacity	
	MMcf/d	Bcf	MMcf/d	Bcf	MMcf/d	Bcf	MMcf/d	Bcf	MMcf/d	Bcf	MMcf/d	Bcf	MMcf/d	Bcf
Western Region														
Huntingdon/Westcoast														
Northwest Pipeline	1,045.0	381.4	0.0	0.0	1,045.0	381.4	0.0	0.0	1,045.0	381.4	0.0	0.0	1,045.0	381.4
User-dedicated	380.0	138.7	0.0	0.0	380.0	138.7	0.0	0.0	380.0	138.7	0.0	0.0	380.0	138.7
Kingsgate/ANG,Foothills														
PGT	2,350.0	857.8			2,350.0	857.8	0.0	0.0	2,350.0	857.8				
Total Western Region	3,775.0	1,377.9	0.0	0.0	3,775.0	1,377.9	0.0	0.0	3,775.0	1,377.9	0.0	0.0	3,775.0	1,377.9
Midwest Region														
Monchy/Foothills														
Northern Border	1,540.0	562.1	0.0	0.0	1,540.0	562.1	0.0	0.0	1,540.0	562.1	700.0	255.5	2,240.0	617.8
Emerson/TCPL														
Viking/GLGT	1,117.0	407.7	0.0	0.0	1,117.0	407.7	0.0	0.0	1,117.0	407.7	0.0	0.0	1,117.0	407.7
Others														
Miscellaneous	139.0	50.7	0.0	0.0	139.0	50.7	0.0	0.0	139.0	50.7	0.0	0.0	139.0	50.7
Total Midwest	2,796.0	1,020.5	0.0	0.0	2,796.0	1,020.5	0.0	0.0	2,796.0	1,020.5	700.0	255.5	3,496.0	1,276.0
Northeast Region														
Iroquois/TCPL														
Iroquois Gas	776.6	283.5	41.5	15.1	818.1	298.6	0.0	0.0	818.1	298.6	0.0	0.0	818.1	298.6
Niagara Falls/TCPL														
Tennessee Gas	803.0	293.1	24.3	8.9	827.3	302.0	0.0	0.0	827.3	302.0	0.0	0.0	827.3	302.0
Others														
Miscellaneous (est)	270.5	98.7	0.0	0.0	270.5	98.7	0.0	0.0	270.5	98.7	0.0	0.0	270.5	98.7
Total Northeast	1,850.1	675.3	65.8	24.0	1,915.9	699.3	0.0	0.0	1,915.9	699.3	0.0	0.0	1,915.9	699.3
Total Capacity	**8,421.1**	**3,073.7**	**65.8**	**24.0**	**8,486.9**	**3,097.7**	**0.0**	**0.0**	**8,486.9**	**3,097.7**	**700.0**	**255.5**	**9,186.9**	**3,353.2**

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).
Exculdes Winter Firm and Short-Haul Service to the International Border

Table 6

Regional Natural Gas Export Forecast by Major Point (Bcf)

Year	1996	1997	1998	1999	2000
Western Region					
Huntingdon - NWPL	296	304	308	312	316
Huntingdon - Other	28	28	28	28	28
Kingsgate	798	806	815	815	815
Total Western Region	1,122	1,138	1,151	1155	1159
Midwest Region					
Monchy	551	551	678	752	777
Emerson	395	395	395	345	395
Other	61	61	61	61	61
Total Midwest	1,007	1,007	1,134	1,158	1,233
Northeast Region					
Niagara	270	272	275	278	281
Iroquois	282	296	296	296	296
Other	86	86	86	86	86
Total Northeast	638	654	657	660	663
Total	2,767	2,799	2,942	2,973	3,055

iii) Regional Analysis
Western Region
Demand Outlook

PIRA estimates that between 1995 and 2000 Western gas demand will grow by approximately 250 Bcf (10%) to 2,690 Bcf. Residential and commercial demand growth will account for under 30% of this increase. As traditional industrial demand is expected to remain flat, the remaining growth would result from additional electric generation requirements.

The next five years is one of the most challenging periods to forecast gas demand for the electricity market, particularly in the Western Region. As in previous years, forecasters must establish an accurate estimate for total electricity generation. This has been relatively straightforward, given the close relationship between GNP and electricity. Next, an estimate for precipitation levels is necessary to determine the availability of hydro-electricity. These assumptions must be considered first, because gas competes for electric generation after both hydro and nuclear availability.

The uncertainty associated with these assumptions pale in comparison to the number of variables raised by electricity restructuring. The one area of consensus is that both short-term and long-term gas demand face immense change.

California is expected to be a front-runner, charting a new course for the electricity industry. Unbundling may result in a restructuring that may mirror the gas industry, with generation companies, a transmission company, and distribution companies. The net effect will be increased competition. It is unknown if natural gas can capitalize in the short term, let alone keep its existing market share.

Favouring gas in the short term is its relatively low price, environmental superiority over alternative fuels, and available pipeline capacity. However, gas will be up against large generation facilities with minimal incremental operating costs and idle capacity, combined with heightened incentives to maximize generation. In the longer term, gas will likely be a big winner once new facilities need to be built.

In the Pacific Northwest salmon-related issues are exerting downward pressure on hydro-electric generation, at a time of expected load growth. However, the anticipated effects of electricity restructuring have moderated previous expectations for a significant increase in natural gas-fired generation facilities.

Some electric utilities have delayed plans until restructuring, and the need for new power plants, is clarified. Almost all of the proposed power plants in Northwest Natural Gas' service area have been cancelled or are in litigation.

Transportation Capacity Additions

There are currently no plans to expand Canadian export pipeline capacity through either Huntingdon or Kingsgate. The Western Region, California in particular, has been the focus of major pipeline expansion activity since 1990 (e.g., PGT, NWPL, Kern River, El Paso, Transwestern). The resultant large capacity overhang has depressed prices and severed the region's connection to NYMEX price trends.

Two possible remedies to alleviate downward price pressure include demand growth and pipeline re-direction. Transwestern and El Paso are considering building more capacity which will allow some of their gas to flow eastward. This would also reduce the amount of California border capacity.

Sponsors of the proposed Altamont/Wild Horse pipeline project indicated in February 1996 that expansion into the Western market would not be viable for another seven to ten years. Accordingly, Altamont is considering re-working its project and accessing the Midwest or other more eastern markets.

Other Regulatory Events

Two major regulatory events under way in California could have a significant impact on the market and Canadian exporters. The first is the ongoing PGT rate case and the second is the PG&E Gas Accord.

In November 1993, the PGT expansion project came on-stream, increasing Canada's export capacity to California by 755 MMcf/d. The project was originally certificated by the FERC in 1991, with incremental tolls pending the outcome of the first transportation rate case. This process began in February 1994, when PGT filed an application with the FERC to implement rolled-in tolls. The submission of evidence and cross-examination began in April 1995.

Most Canadian natural gas interests support rolled-in tolls on PGT or, at least, do not oppose them, on the basis that incremental tolling on PGT has created an inequitable and inefficient commercial environment. The CPUC opposes rolled-in tolls and is intervening to protect California core ratepayers, served via PGT's pre-expansion pipeline facilities, from a rate increase.

For the past several months, PGT has been trying to achieve a settlement among its old and new shippers and the CPUC. If approved by the FERC, a settlement would preclude continuation of the rate case. On February 1, 1996, the FERC extended deadlines for filing briefs (in the rate case) with the news that many of the parties have agreed to a settlement in principal.

The final outcome will have a direct impact on Canadian producer netbacks (which are at historic lows in California) as it will likely be a compromise between the pre-expansion/incremental toll of $US 0.24/Mcf and the expansion/incremental toll of $US 0.43/Mcf.

The PG&E Gas Accord is another important regulatory issue. There are three key components of the plan, mostly dealing with unbundling of gas sales and transmission.

First, PG&E proposes to provide residential and commercial (core) customers a choice to buy from suppliers other than itself. This is an extension of PG&E’s non-core direct purchase policy initiated in 1988. For Canadian exporters, this will drastically increase the number of buyers (and administrative burden), although most of these are small buyers. Some marketers may see the opportunity to capture market share. However, increased exports could be constrained by pipeline capacity.

To offset PG&E load losses due to direct sales, PG&E plans to incrementally release pipeline capacity which is presently held for the core market. Pipeline capacity held on PGT, ANG, and NOVA would be reduced from the current level of 600 MMcf/d to 150 MMcf/d by the year 2000. Capacity relinquishments would reduce core commitments on El Paso and Transwestern to zero and 150 MMcf/d, respectively.

Second, PG&E proposes to unbundle its gas transmission and distribution functions and services. This would eliminate cross-subsidization and make the “crossover ban” unnecessary. This has the possibility of improving Canadian netbacks, but it will depend on how the rates are re-packaged.

Lastly, the Accord seeks to resolve outstanding regulatory cases pending before the CPUC, including rate proceedings involving capacity held on Transwestern and Order 636 transition costs, and PGT’s Pipeline Expansion Project Reasonableness review of excess capacity costs. If discriminatory treatment facing Canadian shippers is addressed, it could result in improved netbacks for Canadian exporters

PG&E first proposed the Gas Accord in August 1995. As of March 1, 1996, a settlement has not been reached. Diverse stakeholder interests and a complexity of issues have dragged this process out. It is possible that a new settlement proposal will be forwarded soon.

Load Factors

In 1995, export pipelines to the Western Region averaged 80% utilization. Recall that the main export pipelines are essentially full and that three user-dedicated pipelines which run at 20% load factors significantly distort the region's average. Canadian gas is expected to remain competitive; therefore, load factors are expected to remain high throughout the forecast period. Deliveries on PGT (Kingsgate) are expected to increase marginally from 91% to 95%. Exports via NWPL (Huntingdon) could rise from 78% to a maximum of 83%, based on the physical dynamics of the Huntingdon delivery hub. The result would be an average load factor of 84% in the year 2000.

The load factors on competing pipelines into California, El Paso and Transwestern, also warrant discussion. High load factors on PGT and Kern River have come at the expense of El Paso and Transwestern. For many months in 1995, the two southern pipelines experienced load factors between 30% and 50%. The future also appears bleak, since both pipelines are facing serious capacity turnback problems. Approximately 2 Bcf/d of capacity is likely to be released in the next few years by SoCalGas and PG&E. These sobering facts will entice the re-direction of capacity eastward, in search of higher prices.

Export Volumes

Demand for Canadian natural gas in the Western Region is expected to grow from 1,100 Bcf in 1995 to 1,160 Bcf by the year 2000. Minimal growth is a result of no new transportation capacity expansions. The result of growing regional demand and limited export growth, will mean a decline in market share, from 45% in 1995 to 43% in the year 2000.

Midwest

Demand Outlook

PIRA uses a slightly different definition for the Midwest compared to NRCan. However, using PIRA's projected 1995-2000 growth rate of 0.2%, Midwest demand would reach 4,440 Bcf by the year 2000.

This growth pales in comparison to the 4% annual growth experienced in 1995. Further, Midwest gas demand has increased by 625 Bcf since 1990, an average annual growth rate of 3%. Of this increase, the residential sector has accounted for 33%, while the commercial, industrial and utility electric generation sectors accounted for 12%, 45% and 10%, respectively.

Given these recent growth trends in Midwest demand, the PIRA forecast may be somewhat pessimistic.

Transportation Capacity Additions

A 700 MMcf/d capacity expansion has been proposed for the Monchy export point (1998). This involves adding compression and looping to both the Foothills pipeline in Canada and the Northern Border pipeline in the U.S. Northern Border is also planning to extend its line, to allow Canadian exporters greater access to markets further downstream in the Midwest, particularly in the Chicago area.

There is another major pipeline expansion to the Midwest being proposed. The Northern Area Transportation Study (NATS) project contemplates an 800-1,200 MMcf/d pipeline from Northeastern British Columbia, through Alberta, to the Chicago area. This project is in very preliminary stages. It does indicate the degree to which Western Canadian producers need more pipeline space to the U.S. It also indicates a certain optimism about the U.S. Midwest as a market for incremental Canadian gas exports.

NATS will not be incorporated into our forecast until regulatory approvals have been applied for in Canada and the U.S.

A number of new pipeline expansions have also been proposed (no applications to-date) from the U.S. Rockies to the Midwest. One of these proposed expansions is the Wyoming Interstate Company proposal to expand from southwest Wyoming to central Nebraska by 812 MMcf/d. These types of projects would provide additional competition for Canadian gas in the Midwest market.

The flurry of pipeline expansion proposals may seem contradictory to demand growth pessimism. However, an important point to keep in mind is that these proposals come from regions with excess wellhead deliverability. Furthermore, the alternative market (i.e., the Western Region) is simply not an option due to the existing pipeline over-capacity and depressed prices.

Another question this raises is what happens to the existing supply source for the Midwest. About 65% of Midwest gas currently comes from the Gulf Coast and Midcontinent. However, if production continues to be flat in these regions, while demand increases, they will have less gas to ship to other regions, including the Midwest. In addition, Gulf Coast and Midcontinent producers may see higher netbacks in the U.S. South Atlantic region.

These two factors should create room for additional Canadian gas in the Midwest market.

Even with further penetration of Western Canadian and U.S. supply into the Midwest market to the end of the decade, the Midwest will continue to rely on the Gulf Coast and Midcontinent for the largest part of its supply.

Load Factors

Given that export capacity on Northern Border has been used at very high load factors for several years, we are assuming that the Northern Border expansion will also be operated at high load factors. Our forecast assumes existing Midwest export capacity will be used at roughly a 93% load factor until 1998. Load factors that year are assumed to drop to 89% overall with the addition of new capacity and then rebound to 92% in subsequent years.

Export Volumes

Canadian natural gas exports to the Midwest were 1,006 Bcf in 1995. We project that Canadian exports to the Midwest will increase to 1,233 Bcf by the year 2000. Most of this growth will occur during 1998, with the Northern Border expansion.

Northeast

Demand Outlook

PIRA estimates that natural gas demand should reach 3,430 Bcf by the year 2000 (3,048 Bcf in 1995). This represents an average growth rate of 1.6% per year over the 1995-2000 period. This is substantially lower than the 6% annual growth rate between 1990-1995.

Natural gas demand growth in the industrial, commercial, and residential sectors is tied to economic growth in the region, which is expected to be moderate. Future demand in the industrial sector will likely benefit from the relative price advantage over oil, given the current flat outlook for gas prices.

Previous expectations of significant increases in gas sales related to power generation have been significantly reduced. According to PIRA, demand increases in this sector originally forecasted to be around 10% per year have been cut in half to around 5% per year over the forecast period. The possible changes to the Public Utilities Regulatory Policies Act (PURPA), which could reduce electricity generated by gas-fired facilities, combined with electricity generation capacity surpluses have dampened the enthusiasm for new ds gas-fired electricity generation facilities.

Efficiency gains in existing generation facilities stemming from electricity deregulation initiatives are expected to absorb most incremental needs for electricity through the year 2000. Gas is still expected to be the fuel of choice for new generating facilities, but new facilities are not expected to be required until the next century.

Transportation Capacity Additions

Export capacity is not expected to increase significantly over the forecast period. TransCanada PipeLines Limited will expand its system in 1996 to accommodate four new export arrangements to the Northeast. These include 25.0 MMcf/d of incremental capacity to serve the Iroquois export point as well as 24.5 MMcf/d to serve the Niagara export point. Given the applications for pipeline expansions filed with regulatory agencies at the end of 1995, export capacity to the Northeast Region is not expected to increase significantly over the forecast period.

At this time, a number of new gas pipeline projects involving Canadian gas are gathering momentum in the Northeast marketplace, although none have filed applications for regulatory approvals at this time. These include the Portland Natural Gas Transmission System and the Maritimes Northeast Pipeline which would transport natural gas reserves offshore Nova Scotia to markets in the Northeast.

However, uncertainties with respect to electricity deregulation and further deregulation of natural gas activities at the state level have left the market unwilling to commit to large investments at this time. Furthermore, the market is in a position to choose between a number of supply options to meet its supply requirements. These include just-in-time types of expansions from the Gulf Coast, peaking LNG storage, as well as additional salt cavern storage.

Load Factors

Since the outlook for large increments in export capacity is limited, the overall load factor on pipelines serving the Northeast are expected to remain very high through the forecast period. The 95% load factor registered this year is expected to continue to increase gradually as existing facilities are further optimized to reach a point near 100% by the end of the decade.

Export Volumes

Canadian gas exports to the Northeast are expected to continue to increase, matching available gas pipeline capacity to the region. New export opportunities created by minor expansions over the next two years lead us to project that Canadian exports to the Northeast will reach 654 Bcf by 1997 and flatten out to 663 Bcf by the year 2000.

III. Regulatory Update

Introduction

To date, a substantial portion of the natural gas industry has been deregulated, particularly in the upstream sector. Nevertheless, U.S. regulatory agencies and stakeholders continue to seek increased competition at the transportation and distribution levels, pursuing such options as LDC unbundling, market-based rates, and incentive regulation. Traditional ratemaking principles have come under closer scrutiny, and in some cases, such as pipeline expansion tolling methodology, changes have already been implemented.

As these regulatory developments unfold in the U.S., the potential arises for an impact on Canada/U.S. natural gas trade. In today's market environment, Canadian exporters are keenly interested in U.S. regulatory decisions that could affect commercial undertakings to increase Canada's export pipeline capacity, as well as marketing activities in the U.S.

A. Rolled-In vs Incremental Tolling

On May 31, 1995, the U.S. Federal Energy Regulatory Commission (FERC) issued a policy statement that established guidelines on whether interstate pipeline expansion costs should be recovered on a rolled-in or incremental basis.

The FERC's policy statement concluded a generic review process in which comments were submitted by numerous parties, including producers, pipeline companies, utilities, marketers, and large industrial and power generation users. The review process was precipitated in July 1994 by a U.S. Court of Appeals remand of the FERC's 1991 incremental toll ruling on the expansion of Great Lakes Gas Transmission.

i) Policy Components

The FERC's policy statement basically consists of three elements: 1) consideration of rates during certificate proceedings; 2) criteria for determining the appropriate tolling method; and 3) rate impact mitigation measures.

The FERC intends to provide greater rate certainty by making a predetermination of rate design during the certificate proceeding of a pipeline expansion project. In the first ensuing Section 4 rate case, the FERC will issue a final decision on tolling, consistent with its findings in the certificate hearing, unless parties demonstrate that circumstances have changed significantly. Previously, the FERC did not address cost allocation issues until the Section 4 rate case phase, well after the expansion project was constructed and in operation. The resultant uncertainty of not knowing which tolls would be ultimately adopted for a new pipeline project frustrated market development.

According to its new policy, the FERC will establish a presumption for rolled-in rates if expansion facilities are integrated into a pipeline's existing facilities, the existing customers derive operational and financial benefits from the new facilities, and the rate increase to existing customers from rolling-in the new facilities is 5% or less. If the rate impact exceeds 5%, the pipeline must demonstrate that benefits to existing customers are proportionate to the rate impact. In addition, the FERC stated that pipelines should present measures that would mitigate the effects of rate shock on existing customers.

ii) Policy Implications

During the generic review process, many Canadian interests supported a generic approach to toll design that would allow the roll-in of expansion costs on an integrated pipeline system that provides the same level of service to the same market destination. Instead, the FERC is proceeding on a case-by-case basis, which would not appear to provide the level of rate design certainty many had hoped for. Only after a number of FERC rate predeterminations in certificate proceedings have been addressed in subsequent Section 4 rate cases will it be possible to truly assess the level of upfront rate assurance provided by the FERC's new policy.

There are also concerns with the threshold level chosen by the FERC. The 5% benchmark would seem to imply that large expansion projects would not qualify for a presumption of rolled-in rates, particularly for a relatively depreciated system. This suggests continued rate design uncertainty, or as some have characterized it, a counter presumption for incremental rates. In addition, the FERC did not indicate in its policy the weight it would attach to operational and financial benefits, nor how it would balance benefits that are quantifiable with those that are qualitative in nature.

The FERC's requirement for mitigation measures has also raised questions. If system-wide benefits are proportionate to a significant rate increase, it is arguable that these benefits themselves represent sufficient mitigation, and further measures would be unjustified. However, if the benefits are not proportionate, it remains unclear whether the FERC would approve rolled-in tolls on the basis of proposed mitigation measures.

iii) Policy Application

Subsequent to the release of its policy statement, the FERC has issued a number of certificate decisions in which it made a predetermination of rolled-in rates. However, the rulings do not clarify how stringently the FERC will apply its 5% threshold. Most of the approvals of rolled-in rates dealt with minor expansion projects.
All but one of the projects proposed a rate impact of less than 5%. In the case of the exception, Northwest Pipeline's rates will increase by 7.12% as a result of the Jackson Prairie Storage Project expansion. However, this rate increase is only marginally greater than the FERC's threshold level, and the project was not opposed by existing customers.

As to system-wide benefits, the FERC, for the most part, treated operational and financial benefits in a qualitative and general nature (see Table 1). However, it remains unclear to what extent the FERC would weigh system-wide benefits in face of a rolled-in rate impact significantly greater than 5%.

Table 1

Sample of FERC Rolled-In Approvals

Docket	Expansion Details	Rate Impact	Operational Benefits	Financial Benefits
Northwest CP95-576 Oct 4/95	- increase withdrawal at Jackson Prairie - $1.8 million	7.12%	- increased flexibility and peak shaving capability - remove transport imbalances	
Southern Nat. CP95-500 Oct 16/95	- 2 compressors - $14.7 million	0% 10yr 1% aft.	- additional sources of supply - eliminate capacity constraint	- lower off-system costs - reduction in cost of gas - new shipper contribution
Northwest CP93-613 et al Dec 20/95	- pipeline looping - compression - $116.2 million	2.63%	- reduction of system constraints - flexible receipt & delivery pts - attach new markets	- avoid loss of contract demand - replace lost contract demand - reduce future expansion costs
K N Interstate CP95-113 Jan 18/96	- 52 mi. - 16" looping - 1 compressor - $14.9 million	-2.2% to +0.6%	- greater reliability & flexibility - elimination of bottleneck - increased supply access	
CNG CP95-109 Jan 31/96	- 5 mi. - 30" looping - $8 million	0.5%	- increase system pressure and thus reliability	- shippers can use new facilities on a secondary receipt and delivery point basis

FERC Chair Moler's dissenting opinion in the Great Lakes Decision, issued July 26, 1995 (RP91-143-027), may represent the strongest indication of which direction the FERC is heading. Chair Moler placed a great deal of emphasis on the effects of rate shock, arguing that the rate impact on existing customers must be commensurate to benefits received. On this basis, expansion proponents proposing rolled-in tolls where the rate impact significantly exceeds the 5% threshold would face an uphill battle. This would be unfortunate, given the recent events this past winter, which underscore the need for further integration and expansion of the North American pipeline network to facilitate greater access between supply and markets.

iv) Old vs. New Policy Application

The FERC's decision to approve rolled-in tolls for the Great Lakes 1990 expansion project does not establish precedence for its new policy. The FERC stated that it erred in its original decision and should not have applied the "commensurate benefits test" which led to the adoption of incremental tolls. Instead, the FERC concluded that it should have applied its previous policy, known as the "Battle Creek test," in which rolled-in tolls are allowed if expansion facilities are integral to the mainline system and are able to confer some positive benefit on all customers. In addition, the FERC clearly indicated that its new 1995 policy should not be retroactively applied to the Great Lakes case.

This judgment was further clarified in the FERC's December 20, 1995 decision concerning the expansion of Northwest Pipeline (CP93-613 et. al.). The FERC concluded that, even though it had already issued a final certificate order and approved initial rates, it was appropriate to apply its new policy in the Northwest case because, unlike the Great Lakes situation, rates for the Northwest expansion had not been placed into effect and the expansion facilities were still under consideration in an amendment proceeding.

Based on this reasoning, one could argue that the FERC should also apply the "Battle Creek test" to determine the appropriate tolling methodology for the 1993 expansion of Pacific Gas Transmission (PGT). This would appear to be an academic question, however, since PGT's settlement negotiations in its pipeline rate case (RP94-145) have led to an agreement in principle.

v) Northern Border

At this stage, it is uncertain if FERC's treatment of Northern Border's expansion/extension project (CP95-194) will shed any light on how rate shock will be treated either. As filed in its application, Northern Border stated that rolled-in rates would translate into a 12.6% reduction in the unit cost of service mileage rate. However, Natural Gas Pipeline disputes the depreciation rate schedule used by Northern Border in its calculations. Furthermore, the issue of depreciation rates is up for review in a parallel proceeding, Northern Border's upcoming rate hearing (RP96-45).

vi) Conclusion

Tolling methodology should promote a dynamic North American pipeline network, adaptable to changing market and supply developments. A regulatory regime should facilitate the abandonment and addition of new pipelines as required by the market and not create a static infrastructure. This is particularly relevant in today's environment, characterized by increasing natural gas demand in eastern markets, the occurrence of regional transmission bottlenecks, and the restructuring of the electricity sector and LDC services.

In closing, an incremental tolling approach would not facilitate the continued expansion and integration of the North American natural gas pipeline system. Furthermore, in a deregulated and competitive environment, tolling methodology should treat shippers on a transmission pipeline system indiscriminately, without distinguishing between those seeking markets and those seeking supply.

B. LDC Unbundling

Following the implementation of FERC Order 636, which completed the unbundling of services in the interstate pipeline sector, the next phase of natural gas deregulation in the U.S. appears to be targeted at the LDC level. LDCs and state regulators are responding to changing market dynamics. LDCs view unbundling as a means to maintain competitiveness with non-regulated entities, and state regulators are seeking to enhance competition and economic efficiency.

Direct sales represent the simplest form of unbundling. End-use customers typically execute buy/sell arrangements by purchasing natural gas from upstream suppliers and reselling it to the LDC, either at the city-gate or further upstream, at the distributor's weighted average cost of gas. The gas is then delivered to the end-user via the LDC's sales service, and the consumer pays the bundled sales rate. The end-user realizes a discount based on the differential between the price of its contracted third-party supply and the LDC's weighted average cost of gas.

In recent years, virtually all LDCs have gone a step further and separated commodity and distribution services, although access to distribution capacity has been generally limited to large, and medium-sized industrial, commercial, and cogeneration customers. The next stage of LDC unbundling concerns two issues: whether LDC distribution and commodity services should be separated for the core market and whether LDC distribution services should be fully unbundled (e.g., balancing, loaning, parking, standby, storage, peaking, billing, metering, financial, etc.).

Numerous LDCs and state regulatory agencies are establishing guidelines or experimental programs to unbundle distribution services. Considerations range from the extent of services to be unbundled to which customer classes will have access to the new services. At the moment, regulators, LDCs, and stakeholders are grappling with many issues, including the role of the LDC with respect to the obligation to serve, the preservation of operational integrity (load aggregation, daily metering, etc.), cost shifting among customer classes, the treatment of stranded costs, the effect of electricity restructuring on inter-fuel competition, and the growing trend of total energy package marketing.

LDC unbundling should not have a large impact on the upstream sector of the natural gas industry, from an overall supply perspective. Further unbundling is not expected to lead to incremental natural gas demand growth. Most large-volume natural gas consumers already have access to diversified supply.

However, LDC unbundling could significantly affect producer marketing strategies. At the very least, there will be increased competition behind the city-gate, with the potential to affect all aspects of the value chain, including wellhead price. Customer needs will shift as small-volume buyers with a wide diversity of competitive elements enter the marketplace. This aspect will be particularly important if distribution services are fully unbundled. Those which are innovative and quick to act will benefit from new business opportunities. Potential strategies range from end-use aggregation to the development of strategic alliances between producers and downstream companies, including marketers, pipelines, and LDCs.

Nevertheless, with many state regulators acting independently, the forces for change will not be uniform. For instance, a number of experimental programs and pilot tests within the residential sector have had mixed results, ranging from limited interest to customer sign-ups with marketers.

In Canada, both core and non-core customers have access to direct sales mechanisms, providing diversification of supply. However, provincial regulators are only now examining whether to separate the LDC's merchant function from its distribution function, some more actively than others. The Ontario Energy Board held workshops in December 1995 and January 1996, but it has yet to indicate which direction it will take. In Manitoba, the Public Utilities Board, will initiate its process by holding a public hearing on LDC unbundling on April 22, 1996.

C. Market-Based Rates

On January 31, 1996, the FERC issued a policy statement which created a framework for the consideration of market-based rates. In essence, the FERC will not authorize market-based rates unless it finds that there is either a lack of market power or that the market power will be sufficiently mitigated. The FERC defined market power as the ability of a pipeline to profitably maintain prices above competitive levels for a significant period of time.

The FERC established specific criteria that it would consider on a case-by-case basis. First, it would define the relevant markets by identifying specific products or services, as well as substitutes. The FERC would examine the availability of substitutes within a reasonable time frame and compare the price level and quality of service of substitutes with the applicant's services. The FERC would also examine the number of sellers of a product or service on a geographic basis, based on pipeline receipt and delivery points.

The second step would involve measurement of the applicant's market share and market concentration. To determine an applicant's level of market power, the FERC will use the Hirschman-Herfindahl Index (HHI), an economic measure of industrial concentration based on the sum of the squared shares of sales of all firms in the industry. Instead of adopting a rigid threshold, the FERC will apply closer scrutiny to an applicant if the HHI is above 0.18, and less scrutiny if it is below.

The third step would consist of an examination of other relevant factors, including the ease of entry into the market, the presence of buyer power, and potential mitigation measures which would prevent exercise of market power.

In establishing its authorization process, the FERC indicated that it would continue its current policy of using declaratory orders to rule on requests for market-based rates on a case-by-case basis. Upon a positive ruling, the applicant would make the appropriate tariff filing to set the market-based rates into effect.

It is expected that market-based rates would have limited application to primary firm pipeline transportation because of existing market power characteristics. However, market-based rates may play a significant role with respect to other transportation services, such as capacity release, interruptible service, short-term firm transportation, and hub services.

In addition, included in the policy statement on market-based rates was a decision to establish a separate proceeding to review possible negotiated rates programs (with traditional cost-of-service rates available as a recourse) as a viable way of achieving flexible and efficient tolls when market-based rates would not be appropriate.

D. Incentive Regulation

Incentive regulation generally refers to rate structures designed to promote efficiency within a regulated utility's operations. Savings that accrue from increased efficiency are typically split between ratepayers and utility shareholders on the basis of a predetermined formula and standards, often developed by the utility and its stakeholders, but approved by the respective regulator. The typical objective of incentive regulation is to foster competitive-type behaviour in an environment characterized by market power.

As part of its policy statement on alternative ratemaking, issued January 31, 1996, the FERC also modified its 1992 incentive regulation policy. There is no longer a requirement to quantify benefits, and incentive rates can exceed traditional cost of service rates. However, the pipeline company proposing an incentive program is required to share efficiency gains with its ratepayers. The revisions were presumably due to lack of response to its 1992 policy statement.

To date, the vast majority of incentive ratemaking in the U.S. has been initiated at the state level. Many state regulatory agencies have adopted some form of performance-based rates for utilities. The key distinction from interstate pipeline programs is that LDC performance-based rates tend to focus on procurement activities and not transportation.

In Canada, the National Energy Board approved an incentive cost recovery and revenue sharing settlement for TransCanada PipeLines (TCPL) in February 1996. The settlement followed negotiations among TCPL, its shippers, and other stakeholders. Under the settlement, close to 40% of TCPL's total revenue requirement ($1.8 billion) will be subject to incentive regulation over a four-year period from 1996 to 1999. Included in the incentive envelope are controllable costs, such as operating, maintenance, and administration costs. Return on equity, income tax and depreciation costs were excluded and will continue to flow through on a cost-recoverable basis. Savings resulting from this agreement will be shared equally by TCPL and its shippers.

Other natural gas pipeline companies in Canada have closely followed TCPL's settlement proceedings and are examining the possibility of implementing similar programs in the near future.

Appendix:
U.S. Electricity Restructuring

The electric industry in the U.S. is in a period of deregulation and rapid restructuring. The process will undoubtedly transform electricity markets and industry structure. The subsequent impact of electricity restructuring on the North American natural gas industry, however, is presently unclear.

This section presents a summary of the current electric restructuring process. It includes a short review of past legislation, followed by an analysis of current initiatives and their impact on electric markets. Lastly, an outlook presents the positive and negative factors that would impact the natural gas industry.

I. Current Situation

The U.S. electric industry is dominated by vertically integrated utilities which generate, transmit and distribute electricity to consumers in a highly regulated monopolistic market. Wholesale electricity sales and inter-state transmission are regulated by the FERC. Retail sales and intra-state transmission are under state jurisdiction. Restructuring has been under way at the federal level since 1978. Individual states are also undertaking restructuring initiatives.

A. Key Regulations and Initiatives

i) Public Utilities Regulatory Policies Act (PURPA 1978)

Purpose: Encouraged cogeneration and the use of renewable resources in electricity generation.

Requirement: Utilities required to buy power from qualifying NUGs at utility's avoided cost.

Result: Demonstrated that NUGs can compete successfully with utility generation. As a result of PURPA, NUGs accounted for 10% of total generating capacity in the U.S. by 1992.

Status: Recent House and Senate Bills seek to amend PURPA to end the requirement that utilities buy power from NUGs. Existing contracts between utilities and NUGs would be upheld.

ii) National Energy Policy Act (NEPA 1992)

Purpose: Eliminated market power held by vertically integrated utilities over transmission.

Requirement: Gave the FERC the power to order utilities to allow competitors to transmit power across their systems for wholesale transactions (wholesale wheeling).

Result: Improved third-party access to transmission.

Status: Transmission owners still hold an advantage over electricity wholesalers that do not own transmission, in terms of immediate access to the full-range of transmission services.

iii) FERC Notice of Proposed Rulemaking on Open-Access Transmission (NOPR 1995)

Purpose: To provide all wholesale buyers and sellers of electricity with equal access to electricity transmission.

Requirements: Utilities that own or control transmission facilities used for interstate transactions must file tariffs for transmission and ancillary services (wheeling tariffs), and offer wholesale transmission services under the filed tariffs. Utilities must provide information about available transmission capacity to potential customers. Utilities can recover stranded costs from departing customers.

Status: A final rule is expected in spring 1996

Key Issues Raised by the FERC NOPR

The FERC received over 300 submissions in response to its request for comments. The Commission must resolve several key issues before it can proceed with a final rule.

- Does the FERC have jurisdiction to order utilities to file open access transmission tariffs? These tariffs are the foundation of the proposed rule. Some argue that the FERC's authority is limited to ordering utilities to wheel power.

- FERC's proposal for the recovery of stranded costs associated with wholesale transmission access is contentious. Opponents to the proposal argue that the recovery of stranded costs from departing customers will create a barrier to competition by effectively holding those customers captive to the utility.

- How effective is the proposed rule in promoting competition in the wholesale generation market? Divestiture of utility generation assets from transmission and distribution may be necessary to eliminate vertically integrated utilities' market power. Utilities that own and control both generation and transmission may have an incentive to favour their own generation over that of other market entrants.

- How transmission service will be priced under open access has not been determined. Pricing is problematic because electricity does not follow a predetermined path when transmitted from one location to another. Current pricing is based on the contract path. Alternative options include zone and distance-based rates.

iv) State Restructuring Initiatives

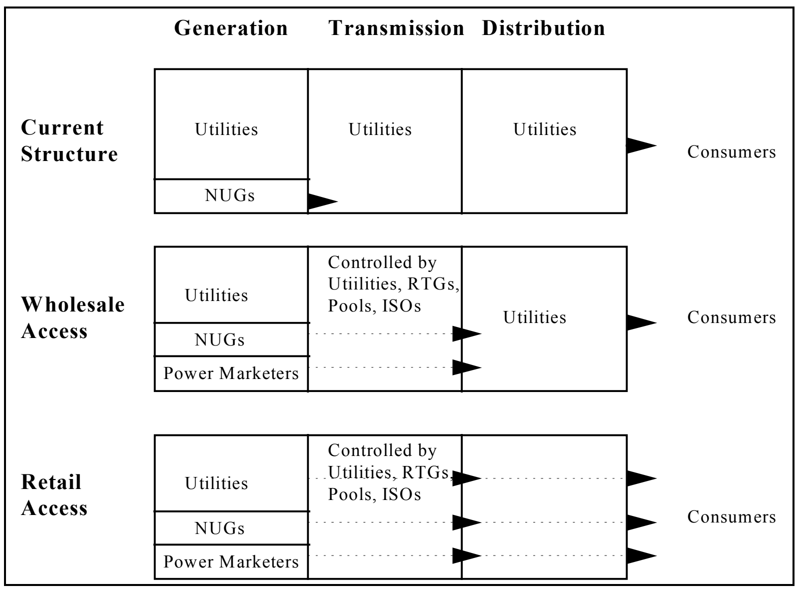
Most states are investigating a range of restructuring options, and several have initiated proposals to restructure electric services. These proposals include unbundling generation, transmission and distribution functions; alternatives to cost-based rate setting; and retail wheeling legislation. Many market analysts believe that the key to a competitive generation market is either direct access for power marketers to consumers of electricity, or full retail wheeling.

California is the most advanced state in restructuring the electricity market. The California Public Utilities Commission (CPUC) issued a final decision in December 1995 on electricity restructuring. The plan proposed a voluntary wholesale power pool with an independent transmission system operator. Retail access would be phased in over five years, beginning January 1, 1998. Distribution would remain with the utilities, but regulated under performance-based rates.

B. Impact on Electric Industry Structure

Pending federal and state legislation will change both the players and their roles in the electric industry. Utilities are positioning themselves for a more competitive environment. Many vertically integrated utilities are voluntarily separating their generation, transmission, and distribution components into business units, as proposed by the FERC in March 1995. Regional transmission groups (RTGs), which emerged following the transmission access provisions of the NEPA, continue to develop. RTGs provide a means for regional transmission planning and a transition toward more open transmission access. Figure A1 illustrates potential frameworks for the electric industry under three scenarios: the current regulated structure; wholesale wheeling as proposed by the FERC; and retail wheeling.

Figure A1



Alliances between electric and natural gas companies, and electric company mergers have been established, as firms seek to reduce costs and increase the range of services that they can provide. Electricity marketers and brokers have entered the electric market to take advantage of the opportunities expected under more competitive conditions.

As restructuring unfolds, vertically integrated utilities will continue to unbundle their services. The resulting generation, transmission, and distribution companies may in turn re-integrate to gain efficiency. Re-integration may include partnerships between electric companies, or between electric and gas companies.

Additionally, electric distribution companies that divest their generation assets may focus on selling energy services rather than simply electricity. Energy distributors and marketers would seek the best technology for a given energy need. In this respect, consolidation of the two industries would intensify the competition between electricity and natural gas for end-uses.

II. Outlook

In the short term, from 1996 to 2000, most forecasters agree that no new electricity generating capacity will be needed as utilities rationalize and take advantage of existing excess capacity for low cost incremental generation. Improved access to generation under more open transmission access would reduce the reserve requirements.

In the longer term, out to 2010, the need for electric capacity additions is uncertain. The need for incremental facilities will depend on the retirement schedule of existing coal and nuclear capacity, changing market dynamics resulting from competition, and technological advances.

Natural gas is well poised to capture an increasing share of the evolving electric industry. Gas-fired generation holds many advantages over competing fuels. The low capital cost, operating flexibility, short construction period, ability to add capacity in small increments, and substantially lower emissions make natural gas a favourable choice for electricity generation.

Initially, many forecasts predicted that natural gas would capture a large share of incremental electricity generation. However, as restructuring proceeds, expectations have been tempered. The following two lists show factors for and against the consumption of gas in the electricity generation market.

Factors Leading to Decreased Natural Gas Consumption

- Competition based on marginal cost would tend to favour existing facilities with excess generating capacity;
- Increased access to low-cost power from other regions could displace local gas-fired power;
- Utilities might seek to cancel or re-negotiate NUG contracts, many of which are fueled by natural gas;
- Increased output from underutilized coal and nuclear plants through rationalization;
- Further development of clean-coal technology; and,
- Full recovery of stranded costs would slow the transition to competition and the construction of new low-cost facilities.

Factors Leading to Increased Natural Gas Consumption

- Competitive natural gas prices relative to coal and residual fuel oil;
- Reduced coal-fired generation in compliance with Clean Air Act emission reduction requirements;
- Poor performance and early retirement of some existing nuclear facilities;
- Decline in hydroelectric generation due to fish flow requirements for endangered salmon species;
- Growth in the non-utility industry to fill incremental demand under more open transmission;
- Any uncertainty causing utilities to delay construction of new facilities would favour gas-fired generation which requires a relatively short lead time; and,
- Gas-fired generation is favoured in areas where problems arise with expanding transmission facilities.

Bibliography

1. American Gas Association, Gas Energy Review.
2. Ibid., 1995 AGA/TERA Base Case, January, 1995.
3. American Petroleum Institute, Quarterly Completions Report, 1995
4. ARC Financial Corporation, Energy Update, January 1996.
5. California Gas and Electric Utilities, California Gas Report, 1995.
6. Department of Energy, Natural Gas Imports and Exports Quarterly.
7. Energy Information Administration, Annual Energy Outlook: 1996, January 1996.
8. Ibid., Electric Power Monthly.
9. Ibid., Monthly Energy Review.
10. Ibid., Natural Gas Productive Capacity for the Lower 48 States. 1984 through 1996, February 1996
11. Ibid., Natural Gas 1994: Issues and Trends, November 1995.
12. Ibid., Natural Gas Monthly.
13. Gas Research Institute, GRI Baseline Projection of U.S. Energy Supply and Demand, August 1995.
14. National Energy Board, Canadian Energy Supply and Demand 1993-2000, December 1994.
15. Petroleum Information Research Associates, Annual Retainer Client Seminar, October 1995.