

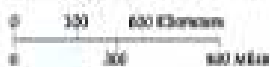
North American Natural Gas Vision

January 2005



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North American Natural Gas Vision

**North American Energy Working Group
Experts Group on Natural Gas Trade and Interconnections**

January 2005

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Introduction

This report, the North American Natural Gas Vision, is a deliverable for the North American Energy Working Group (NAEWG) and was produced by the NAEWG Natural Gas Experts Group. It is representative of the interest Canada, the United States of America, and Mexico share toward enhancing collaboration on North American energy issues.

In early 2001, U.S. President George W. Bush, then Canadian Prime Minister Jean Chrétien, and Mexican President Vicente Fox recognized that, as neighbors, their energy issues merited regional attention and agreed there would be great benefit to all three nations from enhanced cooperation in this area.

Given that interest by the three leaders, at a meeting on March 8, 2001, then Energy Ministers Ralph Goodale (Canada), Ernesto Martens (Mexico), and Spencer Abraham (United States) formally committed to work more collaboratively on North America's energy issues. To achieve this goal, the three cabinet-level officials agreed to establish a group of national representatives that would focus specifically on the region. The concept of the NAEWG was announced by the three Heads of State at the Summit of the Americas in April 2001. Natural Resources Canada, the Mexican Secretariat of Energy, and the U.S. Department of Energy jointly chair the Working Group.

The goals of NAEWG are to foster communication among the Governments and energy sectors of the three countries on energy related matters of common interest, and to enhance North American energy trade and interconnections. To achieve these goals, the Working Group exchanges views and shares information on factors affecting North American energy and identifies issues that need to be addressed.

The work of NAEWG is implemented through six expert groups, in the areas of Science and Technology, Natural Gas, Energy Picture, Electricity, Energy Efficiency, and Critical Infrastructure Protection.

The NAEWG Natural Gas Trade and Interconnections' Experts Group was established in December 2001 by Canada, Mexico and the U.S., at the second meeting of the North American Energy Working Group. Mexico serves as chair for the Group. The Experts Group has the goal of ensuring that the three governments carry on close dialog on energy policies and regulations to ensure an efficient, reliable, and integrated North American system of natural gas production and delivery. To that end, the Group meets regularly to exchange views and share information on factors affecting the North American natural gas sector, including policies and programs, market developments and anticipated demand and sources of supply. The Group identifies issues that need to be addressed for an optimally functioning market, such as regulatory structures, interconnections, technology research and development, technical specifications, and production incentives.

The scope of the Natural Gas Experts Group's discussions includes the full range of issues related to natural gas development, production, transportation and transmission, distribution and consumption in North America. This report is unique because it presents the views of the three governments, working in close cooperation, on the gas market now and in the future. Further, this report recognizes private sector views. In preparing this report, the NAEWG Gas Experts Group held a workshop in December 2003 to gain views on issues related to the future of the North American gas market.

The report examines the increasingly important role that natural gas has played over time in the energy sectors of three countries of North

Introduction

America -- Canada, Mexico and the United States -- by discussing supply and demand. According to the joint statistics prepared by Canada, Mexico and the United States reported in **North America: The Energy Picture** in 2000, natural gas production was 19.4 trillion cubic feet (Tcf) in the United States, 5.9 Tcf in Canada and 1.7 Tcf in Mexico. Natural gas production in all three countries is predicted to grow significantly through the period discussed here to 2012. Mexican production is forecasted to reach 2.5 Tcf by 2012, while Canadian production is expected to grow to 7 Tcf and U.S. production is expected to reach 23 to 24 Tcf. Together, North America consumed about 26.8 Tcf of gas in 2003, nearly one-third of the world's gas consumption. Canada consumed 2.9 Tcf, Mexico consumed 1.9 Tcf and the United States consumed 22.0 Tcf.

The report presents the restructuring and regulatory changes in all three countries that have accompanied the increase in natural gas demand and have had impacts on infrastructure development. Pipelines carry gas in both directions between Canada and the United States and between the United States and Mexico. The report discusses progress on meeting the goals of a more environmentally aware, yet transparent and streamlined, natural gas industry in which permits and pipeline construction are more feasible, and markets achieve maximum efficiency.

The report details the amount of trade among the three countries. Trade in natural gas is highly developed and functions extremely efficiently in the North American market. Canada exports about half of its gas production to the United States. The United States imports about 16 percent of its gas consumption from Canada, and Mexico imports approximately 19 percent of its gas consumption from the United States. The report looks at how provisions of the Canada-U.S. Free Trade Agreement (FTA) and the North American Free Trade Agreement

(NAFTA), along with the General Agreement on Tariffs and Trade (GATT) govern energy trade in North America. Both the FTA and NAFTA resulted in some important changes in the rules governing energy trade. The inclusion of energy in these agreements ensured that trade in this increasingly significant sector would be based on internationally-recognized, non-discriminatory market access principles that were already applied in most sectors of economic activity. The NAFTA has provided the building block for the emergence of a cooperative North American market for energy goods.

The report builds on the idea, recognized by the three governments, that growth in natural gas use has been fueled by three key factors: sustainable energy policies, technological advancement and private sector investment. All three nations pursue policies of sustainable energy development. Natural gas, a clean burning fuel, is recognized as a key component of meeting sustainable development goals. Further, the development of highly efficient combined cycle electricity generation technology has dramatically increased demand for natural gas for electricity generation. Private sector investment in natural gas is allowed to varying degrees in all three nations and has eased issues resulting from the effect that lack of capital has on resource development. Lack of capital remains an issue where private investment is constrained.

“The North American Natural Gas Vision” is a key effort by the three nations, with input from the energy industry, to look at how North America can achieve its goals for natural gas. The document explores what we have done in each nation to assure the optimal development of natural gas and what we will need to do in the future to assure that our projected gas demand will be met.

Summary of Key Findings

OVERVIEW

Canada, Mexico and the United States recognize that they have important interrelationships in the natural gas sector. This report demonstrates the commitment of the three governments, through the North American Energy Working Group, to encourage a secure, competitive, efficient, and growing North American gas market, that will help fuel the economies and environmental objectives of the three countries.

Based on data from the three countries' energy ministries, natural gas demand in North America will continue to increase significantly. Demand is expected to rise from 72.6 Bcf per day in 2001 (U.S. accounting for 82 percent of total, Canada 11 percent of total, Mexico 7 percent of total) to 93.8 Bcf per day in 2012 (U.S. accounting for 79 percent of total, Canada 11 percent of total, Mexico 10 percent total). North America will require an additional 21.2 Bcf per day of natural gas supply by 2012.

In particular, natural gas will be required for incremental electric power generation in all three countries, and for crude oil and bitumen recovery from Canada's oil sands.

The maturity of conventional natural gas supply areas and sources in the United States and Canada, and the lack of capital to develop gas supplies in Mexico, will mean that increasing supply to meet this North American demand growth will be challenging. This will also create a significant opportunity for unconventional gas supplies and sources, such as gas from shale, coalbed methane, gas from Alaska and Arctic Canada, and gas imports via ship-borne liquefied natural gas (LNG).

These challenges currently face the natural gas industry:

- Bottlenecks in production, transportation and storage infrastructure need to be remedied. Feedback from a three country industry workshop held by NAEWG highlighted an unprecedented level of landowner concerns to pipeline projects, and difficulties in pipeline permitting, as well as difficulty in finding credit-worthy shippers to sign long-term contracts and underpin expansions, particularly given gas market volatility.
- Significant siting and regulatory hurdles must be overcome to create LNG facilities, build new pipelines and storage facilities, and develop Arctic Gas. More efficient regulation is needed to allow markets to freely function so that natural gas supply and infrastructure can be developed in a timely manner.
- Government policies on energy, the environment and land use need to be clear. Compatible guidelines and strategies among the three countries would enhance transparency and encourage a cooperative North American region, while respecting divisions of jurisdictional authority of each country.
- Issues have been raised regarding the lack of smoothness in the regulatory interface among the three countries. Experts stress that regulatory structures need to be flexible enough to change as markets evolve.

The three nations agree that greater interaction among governments and with the private sector would lead to a better understanding of energy policies; endowing the industry with more effective strategies to assure that supply meets demand and that there exists sufficient

Summary of Key Findings

infrastructure to achieve this goal at the most efficient price.

SUPPLY DEVELOPMENT AND DELIVERABILITY

Gas prices are at high levels primarily because growth in demand has outstripped growth in North American gas production. For the future, increases in conventional natural gas supplies appear unlikely – production from conventional Canadian and U.S. gas basins in recent years has been flat or declining, despite historically high levels of natural gas drilling. Mexican gas production, while potentially significant, has faced some challenges because of a lack of financing and impediments of the legal framework to utilizing private investment for resource development.

Additional gas supplies for North America will come from LNG imports, additional development in Mexico, unconventional gas sources in the lower 48 U.S. states and western Canada, and frontier gas from Alaska, Arctic Canada, and the Canadian offshore.

LNG imports to North America will grow significantly, from about 1.1 Bcf per day to almost 12.5 Bcf per day by 2025 according to the recent National Petroleum Council (NPC) study. In its Annual Energy Outlook 2004, the U.S. Energy Information Administration (EIA) forecasts that LNG imports could average 13.1 Bcf per day by 2025. Over 45 new LNG import projects have been announced for North America. The actual siting of a new LNG receiving terminal is not a foregone conclusion, however, given the significant investment necessary and environmental problems already plaguing early proposals. Thus far, four LNG projects have been approved for construction in the U.S. (Cameron, Port Pelican, Energy Bridge, Freeport), but it is far from certain how many will eventually be built. The Altamira project

in Mexico is also underway. Furthermore, the Comisión Reguladora de Energía (CRE) has authorized some LNG storage projects for the Baja California region. These permits were awarded, in 2003, to: Gas Natural de Baja California (Marathon Oil Company) RES/136/ALM/03, LNG Terminal of Baja California (Shell) RES/146/ALM/03, and Energía Costa Azul (Sempra Energy) RES/147/ALM/03. In addition, two projects in eastern Canada - Canaport in New Brunswick and Bear Head in Nova Scotia - have received provincial regulatory approvals.

Multiple service contracts offered by Mexico open the door to new strategies for gaining the capital necessary to develop greater supplies of Mexican gas. With these contracts, the Mexican state oil company, Petróleos Mexicanos (Pemex) expects to increase natural gas production by 440 million cubic feet per day starting from 2006, attracting investments to the country for \$U.S. 4.4 billion, further representing savings for Pemex of \$U.S. 800 million. However, significantly more investment will be necessary to fully realize Mexico's gas potential.

With technological improvements and rising natural gas prices, natural gas production from unconventional sources (tight sands, shale, and coalbed methane) is projected to increase more rapidly than conventional production. However, some industry observers believe that development of non-conventional sources may require incentives. Coalbed methane production in Western Canada is projected by the National Energy Board (NEB) to grow from current levels of less than 0.5 Bcf per day to 1.4 Bcf per day by 2015, and 2.2 Bcf per day by 2025¹. U.S. coalbed methane production totaled 4.1 Bcf per day in 2002 and is projected to rise to 4.7 Bcf per day in 2010, rising to 5.6 Bcf per day in 2020 and 5.5 Bcf per day in 2025.

¹ Canada's Energy Future, June 2003.

Mexico does not project production of its unconventional gas resources or its offshore, frontier supplies. Frontier supplies from Canada's east coast offshore are expected to increase from 0.5 Bcf per day in 2003 to the 2 – 2.4 Bcf per day range by 2015.² U.S. Shale gas production was 1.6 Bcf per day in 2002 and is projected to rise to 2.8 Bcf per day in 2015 and 3.1 Bcf per day in 2025.

A great deal of preliminary work has been undertaken on Alaskan and Arctic Canada supplies. Canada's National Energy Board (NEB) projects that gas from Canada's Mackenzie Delta will become available to gas markets in 2010³, initially at 1.5 Bcf per day, and ramping up to 2.1 Bcf per day by 2015.

In EIA's Annual Energy Outlook 2004 analysis, the North Slope Alaska natural gas pipeline is assumed to begin transporting Alaskan gas to the lower 48 United States in 2018 at a rate of 2.2 Bcf per day, but ramping up to 5.6 Bcf per day by 2025.

Also, policies regarding exploration and development in areas currently off limits, such as parts of the arctic and areas in the outer continental shelf of both Canada and the U.S., are being re-examined, particularly given concerns about scarcity of gas supply. These revisions could result in additional sources of gas supply being available in the future.

DEMAND AND MARKET DEVELOPMENT

North America consumes⁴ approximately 73 Bcf of natural gas per day, or 29 percent of global gas demand⁵. Gas demand is expected to grow significantly in North America. The 2003 U.S. National Petroleum Council (NPC)

² Ibid.

³ Ibid.

⁴ As of 2003.

⁵ BP Statistical Review of World Energy, 2001.

Study emphasized that gas, due to its ease of use and low environmental footprint, is the fuel of choice for the industrial sector and for electric power generation.⁶ As gas-fired generation capacity is overbuilt, and as building additional coal, nuclear, or other generation capacity in the short to medium term is extremely difficult, gas demand by power generators is expected to be very strong even if natural gas prices are high.

Canada

Canada currently consumes 8.7 Bcf of natural gas per day, split approximately equally between three sectors: residential/commercial, industrial, and other. By 2015, Canadian gas demand is expected to reach the 9.5 – 11 Bcf per day range; by 2025, Canadian gas demand is expected to be in the 8.8 – 12.7 Bcf per day range⁷. The industrial (includes oil sands) and power generation sectors are expected to account for the bulk of natural gas demand growth.

The NEB projects that natural gas use for oil sands development will grow from 0.6 Bcf per day in 2003 to the 1.4 – 1.8 Bcf per day range by 2015. The net increase in demand over the period would be in the 0.8 – 1.2 Bcf per day range. The Canadian oil sands industry currently uses 1 thousand cubic feet (1 Mcf) of gas for each barrel of oil produced from oil sands via in-situ thermal recovery, 0.25 Mcf/barrel for oil sands mining, and 0.5 Mcf/barrel for upgrading of oil sands into synthetic crude oil⁸. However, oil sands developers are sensitive to input costs, and are particularly concerned about natural gas prices. In response to higher and more volatile gas prices, producers are seeking alternatives

⁶ "Balancing Natural Gas Supply." National Petroleum Council, Sept, 2003.

⁷ Canada's Energy Future, June 2003.

⁸ National Energy Board, Canada's Oil Sands: Opportunities and Challenges to 2015, May 2004.

Summary of Key Findings

to reduce their dependence on natural gas as the major source of energy for their operations. A number of alternatives have been suggested, with gasification of bitumen likely to be the first implemented on a commercial scale.⁹

Canadian gas-fired electric power generation currently consumes 0.6 Bcf of natural gas per day; by 2015 this is expected to reach the 1.5 – 2.2 Bcf per day range; by 2025, the 2 – 2.9 Bcf per day range¹⁰.

Mexico

Mexico is currently a net importer of natural gas from the U.S., importing one Bcf per day, and Mexico is expected to be increasing its imports from the U.S. for the foreseeable future. Mexico's gas demand is five percent of total North American demand. Over the next ten years, Mexican power sector will need capacity additions of 25,757 MW; of this total, around 21,658 MW would require close to four Bcf per day of natural gas for power generation, in 2012. Since all the new generation capacity will not be gas-fired, the incremental demand is expected to be closer to three Bcf per day. Gas is expected to come from domestic sources via Pemex, U.S. imports by pipeline, or from LNG imports.

United States

The U.S. Energy Information Administration's AEO 2004 says annual natural gas use is projected to grow. In EIA's reference case, end use gas consumption is projected to grow by 1.4 percent per year from 2002 to 2025. Total gas consumption by 2010 is projected to average 24.15 Tcf. Total consumption is further projected to be between 29.1 and 34.2 Tcf by 2025. Some industry observers, present at the 2003

⁹ Ibid.

¹⁰ Ibid.

NAEWG Gas Private Sector Roundtable, noted that they see electric power demand for gas in the United States growing to 7 Bcf over the next ten years. They further predicted that industrial demand could decrease by 3.4 Bcf per day, for a net demand increase of 3.6 Bcf per day. Electrical appliances are cited as the real drivers of electric demand. Residential consumption of natural gas in the U.S. is also growing rapidly.

NATURAL GAS PIPELINES AND INFRASTRUCTURE

The demand for natural gas is expected to increase in all three countries. Even where the physical infrastructure is considered adequate for current markets, substantial infrastructure investment will be needed to meet domestic demand and demand for trade among the three nations.

The LNG shipments to North America are expected to require the construction of considerable infrastructure: docking facilities, LNG storage and regasification facilities, and associated pipelines. There are currently four U.S. terminals importing LNG, three of which are being, or are under consideration to be, expanded. There are currently eight proposed terminals for Canada's east and west coasts, and five proposed terminals for Mexico (including Altamira). LNG proposals will require access to existing pipeline capacity or the construction of the capacity necessary to take the regasified LNG into the existing pipeline grid. However, building the necessary pipeline capacity increases investment costs and risk.

Canada

Given a lack of production growth, Canada currently has excess pipeline capacity along several pipeline corridors leading away from Western Canada. However, other corridors

will require expansion. For example, increases in natural gas production expected from the east coast offshore will require pipeline expansions to reach markets. If LNG projects on Canada's east coast do come to fruition, they will also require new pipeline capacity for the regasified product to reach markets. Totally new capacity will have to be built to transport Mackenzie Delta gas to the existing Canadian pipeline grid, which begins in northern British Columbia and Alberta.

Mexico

Although private investors can participate in natural gas transmission, Pemex continues to be the principal owner and developer of these systems (84 per cent of open access gas pipelines that operate in Mexico). Mexico needs private participation to realize its pipeline network expansion goals.

United States

Increasingly, there is opposition to new pipeline projects that cross through states, but do not service markets in those states – “if you don't serve me, go around me.” There are also concerns regarding post- FERC certificate delays, especially with respect to the issuance of Federal clearances that have been delegated to state agencies.¹¹ In addition, necessary infrastructure enhancements downstream to LNG terminals will be needed which are likely to raise landowner and cost allocation issues.

REGULATORY ISSUES: SITING AND PERMITTING

Regulatory certainty and compatibility were cited by industry at the NAEWG Gas Private Sector Roundtable as key factors in creating an attractive investment environment for

developing projects with long lead times and high capital costs.

Canada

In Canada, the siting and permitting of natural gas infrastructure has historically seen limited opposition. More recently, however, as a result of several new projects being proposed, concerns have been expressed with LNG import terminal projects and coalbed methane (CBM) development projects.

Increased CBM concern has prompted governments to increase public awareness and education. For example, the Alberta government formed a CBM multi-stakeholder advisory committee (MAC), with representation from environmental organizations, landowners, agriculture groups, local governments, the energy industry and various provincial departments. The MAC was formed to review the existing legislative and regulatory framework in Alberta surrounding landowners potentially affected by CBM development. This is seen as one option for mitigating future siting and permitting issues in Canada.

As LNG import terminal projects arrive in Canada, so do local concerns with such projects, similar to the U.S. and Mexican experiences. In Quebec, locals have expressed concerns about safety and a loss of property values. Project proponents are working with stakeholders to familiarize people with their projects and to allow identification of issues that need to be addressed in subsequent project phases.

Mexico

Siting and permitting for LNG terminals is also an issue in Mexico. Local authorities have an important role in the process and “not in my backyard” problems can grow to the

¹¹ This concern relates only to interstate transport.

Summary of Key Findings

point of project cancellations. Moreover, reluctance to grant soil use permits and the awarding of environmental permits, are also issues requiring attention.

United States

In the United States, one viewpoint is that there are many regulations that hinder the development of gas supply: the National Environmental Policy Act (NEPA), state laws and regulations, safety/security, environment, land use and others. The criticism, as addressed in the NPC report, is that while government policy encourages the use of natural gas (e.g., the preference for a clean-burning fuel, especially in electric generation), it does not address the corresponding need for additional gas supplies. Also in the U.S., state and local authorities can impede the permitting of pipeline projects and this permitting problem is magnified for LNG facilities. The proposed U.S. energy bill has provisions to mitigate this problem. Experts stress that regulatory structures need to be flexible enough to change as markets evolve. The Federal Energy Regulatory Commission's Hackberry decision regarding LNG terminals (where open access regulations were lifted and the operators were allowed to charge market-based rates rather than regulated rates) is a prime example of this regulatory flexibility.¹²

To limit the time and expense for regulatory approval processes, industry has requested that divergent agency or government department requirements be met concurrently and at one window as much as possible. Greater coordination between different government levels, and more public education

¹² The Federal Energy Regulatory Commission (FERC) decided in Hackberry to essentially treat LNG terminals as production facilities, meaning that the FERC, other than siting terminals under Section 3 of the Natural Gas Act, only takes rate and service jurisdiction at the outlet of the terminal.

on LNG and its benefits are needed if local support is to be gained.

GOVERNMENT POLICIES

Government laws, treaties, regulations, and policies can have synergistic or antagonistic effects with respect to achieving a fully competitive North American natural gas market. Governments can address the following:

- Environmental laws and regulations can provide incentives for the use of gas in industrial and commercial processes relative to coal or oil. Tax incentives can promote investment in natural gas.
- Removing restrictions on foreign investment can foster the development of gas supplies and the growth of natural gas infrastructure.
- Permitting and licensing policies are important factors conditioning the difficulty and time needed to site and construct natural gas infrastructure used in trade among the three countries.
- Government policies that affect energy efficiency and exploration and development can also be influential in determining the volume of natural gas available to export to other North American countries.

CONCLUSIONS

The ability of North America to sustain a competitive, efficient, reasonably priced, and growing gas market seems to hinge on the issue of natural gas supply. There is considerable uncertainty around the timing and availability of various indigenous North American gas supplies and LNG imports. In addition, there are problems with assuring that

infrastructure will be in place when demand requires more supply.

The governments of Canada, Mexico and the United States should work together and with stakeholders to find the answers that will ensure abundant natural gas supplies for the continent, supported by a comprehensive infrastructure.

Review Section

MARKET STRUCTURE

Industry Structure

The natural gas industries of Canada, Mexico, and the United States can be separated into three sections or streams: the upstream, midstream, and downstream. These streams account for all of the industry activities including exploration, extraction, production, transportation, storage, distribution, marketing and consumption. The upstream represents the initial stages of natural gas production and the discovery of the raw gas, the midstream represents the processing of gas, and the downstream represents the transportation and use of the marketable gas product.

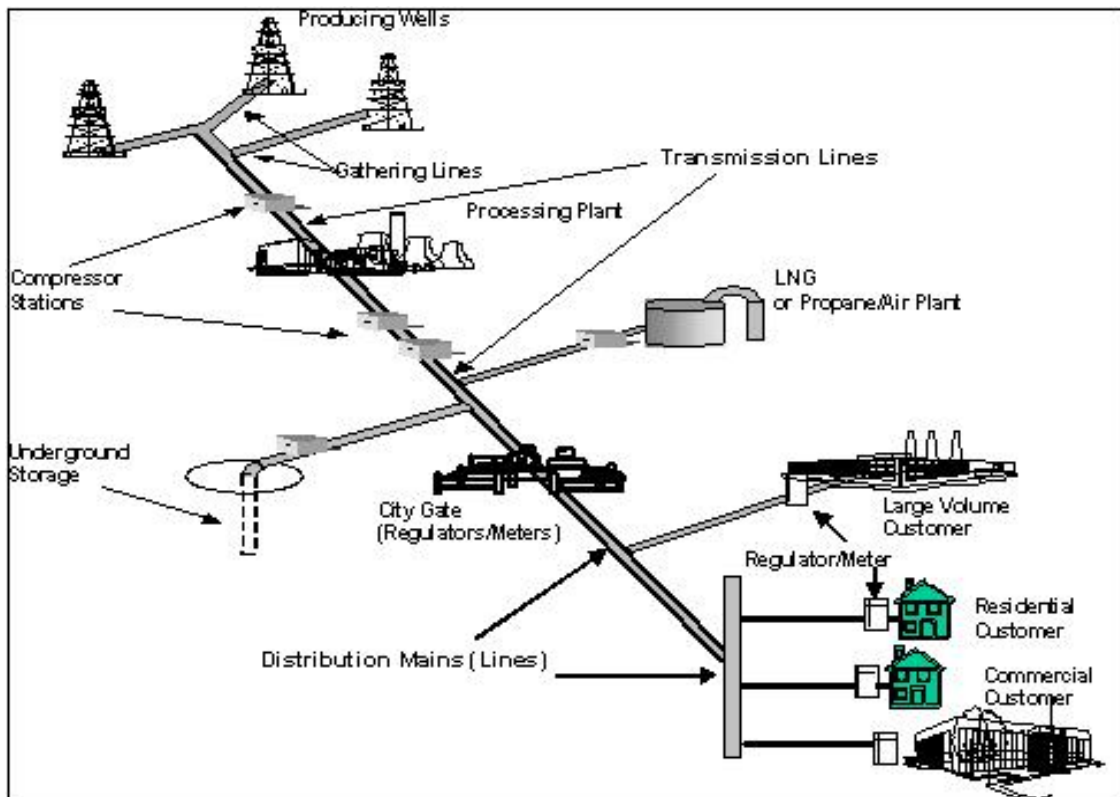
Although the individual countries place different emphasis on each of these aspects, together they have developed an efficient and largely seamless method for providing natural gas to the residential, commercial, industrial and electric generation sectors, as well as recognizing and implementing the import and export of natural gas across national borders to meet demand. Figure 1 provides a schematic detailing the typical path of natural gas from wellhead to burner tip.

Canada

Upstream

In Canada, the upstream sector begins with exploratory and development wells as well as the gathering pipelines that bring the gas to

Figure 1. North American Natural Gas Schematic



Source: U.S. DOE, Office of Fossil Energy

Review Section

the midstream sector. Hundreds of companies comprise the upstream sector and they can vary in size from tiny companies employing a handful of people to multinationals employing thousands.

Midstream

The midstream sector is primarily made up of larger processing facilities and the pipelines that tie these fields and processing facilities together. Due to the expense involved in constructing this processing infrastructure, there are fewer players in the midstream than in the upstream.

Most gas in Canada requires some level of processing after it has been extracted from the well. One function of processing is to remove contaminants such as moisture, hydrogen sulfide and carbon dioxide, all of which can corrode pipelines.

Natural gas containing hydrogen sulfide is called sour gas. About one-third of Western Canada's raw gas production is sour and requires special processing at gas plants. These plants convert most of the hydrogen sulfide into sulfur. Because Canada is a large natural gas producer, and much of its production is sour, Canada leads the world in sulfur exports.

Besides removing contaminants, processing extracts other commercially valuable substances from the gas stream. Natural gas reservoirs typically contain other hydrocarbons such as ethane, propane, butane, and heavier condensates (e.g., natural gas liquids). These natural gas liquids are drawn off at the processing plants and sold to consumers in order to create a huge array of products such as plastics, solvents, and adhesives.

Most midstream processing takes place in the field near producing reservoirs. However, Western Canada's midstream sector also includes processing facilities known as straddle plants because they straddle large natural gas pipelines. These plants extract natural gas liquids – essentially ethane, propane, and butane – from the natural gas before re-injecting the gas into the pipeline. The world's largest natural gas straddle plant processing facility is located on the Alberta-Saskatchewan border at Empress, Alberta, which is the main export point for Alberta's natural gas.

Transportation and Downstream

While the small pipelines needed for natural gas production and processing are part of the upstream and the midstream sectors, large long-distance natural gas transmission pipelines and the local distribution pipelines that take gas directly to consumers comprise an industrial sector of their own.

This sector is known as the downstream. In Canada, almost 80,000 km of transmission pipelines carry natural gas from processing plants to consuming regions and export points. At the end of these lines, local distribution companies (LDCs) deliver natural gas to residential, commercial, and industrial users.

Mexico

Upstream

In Mexico, the upstream consists of the exploration, development and production activities as well as all fields and gathering pipelines facilities. The exploration and production of natural gas has been exclusively entrusted to Pemex Exploración y Producción (PEP), the most important subsidiary of Pemex. However, all activities related to exploration and production of natural gas in

Mexico are performed either by (1) PEP itself, or (2) private parties specifically contracted by PEP to carry out such activity, under the control and supervision of the former, and subject to government procurement laws and regulations and international treaties.

Pemex is looking to increase natural gas production through the execution of new contracts with private companies (known as multiple service contracts or MSC) in the Burgos Basin.

Midstream

The midstream activity consists of processing natural gas in Pemex Gas y Petroquímica Básica (PGPB) facilities. At the moment of extraction, natural gas contains impurities such as water, hydrogen sulfide (H₂S), carbon dioxide and nitrogen that have to be removed before it is transported and commercialized.

The processing necessary to bring this gas to suitable pipeline quality dictates that approximately 70 percent of raw gas must be processed because it is associated natural gas. The processing takes place in ten main natural gas processing facilities operated by PGPB. The current natural gas processing capacity is concentrated in southern Mexico.

Transportation and Downstream

Most of the gas transportation pipelines in Mexico are owned and controlled by Pemex. The national pipeline system is comprised of 8,704 km of trunklines that are fully interconnected. Additionally, there are isolated systems in the Northwestern part of Mexico. Most of the distribution transportation systems are interconnected with PGPB's pipeline system. Furthermore, there are pipelines operated by the private sector under the open access or own use modality.

In Mexico, natural gas is transported and distributed to the final users by steel pipelines of various diameters. Compression stations provide the necessary energy to push the natural gas across the national territory. Given the lack of storage facilities in Mexico, compression facilities are a key part of the transport infrastructure, allowing Mexican pipelines to be utilized as storage as well as transport, and assuring that gas is able to travel to where the demand is.

There are 21 local distribution companies operating in Mexico. These companies provide services to residential and industrial consumers.

All gas to be injected into a Mexican pipeline (transportation and distribution) is subject to a Gas Quality Norm published by the Comisión Reguladora de Energía (CRE), the Mexican Energy Regulatory Agency.

United States

Upstream

In the United States, the upstream sector includes exploration, development, production, and gathering activities. The exploration process refers to the practice of locating natural gas and petroleum deposits, usually done by teams of geologists and geophysicists. Potential locations of pools are typically delineated by seismic surveying, while the actual discovery of a pool requires drilling. Development refers to further drilling of discovered deposits, and the installation of production infrastructure at discovered pools, which involves geoscientists and engineers. Gathering pipelines are constructed to bring raw gas to processing plants.

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Midstream

Natural gas, as consumed by households or the industry sector, is almost entirely methane. Natural gas as found underground contains a variety of other compounds and gases as well as oil and water that must be removed. In the United States, natural gas must meet purity and heat values specifications prior to being transported by pipelines. These safety regulatory restrictions are enforced by the U.S. Department of Transportation. Most of the natural gas processing occurs near the well.

Natural gas comes from two types of wells: oil wells, and gas and condensate wells. Natural gas that comes from oil wells is typically termed 'associated gas'. This gas can exist separately from oil in the formation, or dissolved in the crude oil. Natural gas from gas and condensate wells, in which there is little or no crude oil, is termed 'non-associated gas'. Gas wells typically produce mostly natural gas, with some natural gas liquids, like ethane, butane, propane, etc. Whatever the source of the natural gas, once separated from crude oil (if present) it commonly exists in mixtures with other hydrocarbons; principally ethane, propane, butane, and pentanes. In addition, the raw natural gas stream contains water vapor, hydrogen sulfide (H₂S), carbon dioxide, helium, nitrogen, and other compounds.

Natural gas processing consists of separating all of the various hydrocarbons and fluids from the methane, to produce what is known as 'pipeline quality' dry natural gas. Major transportation pipelines usually impose restrictions on the composition of the natural gas stream that is allowed into the pipeline, which is one of the reasons for processing the gas before it is transported by pipelines.

Transportation and Downstream

FERC order 636, issued by the U.S. on April 9, 1992 (with re-hearings issued on August 3 and November 27, 1993), led to significant changes in the downstream gas sector. Order 636 unbundled the link between wellhead and end-user by requiring pipeline companies to separate their gas sales services from their transportation services. Besides unbundling sales and transportation services, this order led to significant restructuring of the interstate natural gas pipeline industry, including moves towards diversification into other energy sectors and the consolidation of individual pipeline companies into large pipeline systems.

At the close of 2002, the 85 companies that make up the U.S. interstate natural gas mainline transportation network operated about 212,000 miles of pipeline and had the capability to deliver more than 133 Bcf per day of gas. This represented a 2 percent increase in mileage from the 2001 level and an 11 percent increase in interstate pipeline capacity.

In the U.S., local distribution companies typically transport natural gas from delivery points along interstate and intrastate pipelines through thousands of miles of small-diameter distribution pipe. Delivery points to local distribution companies, especially for large municipal areas, are often termed 'city gates', and are important market centers for the pricing of natural gas. Either local distribution companies take ownership of the natural gas at the city gate, and deliver it to each individual customer through an extensive network of small-diameter distribution pipe or, as is now the case in many states, distribution companies are permitted to transport gas for customers without taking ownership.

Energy Policy

The North American energy policy environment is characterized by a balance between attention to market driven indicators and concern for sustainable, long-term energy needs. Canada, Mexico and the United States have natural gas policies that follow the spirit of each country's overall energy priorities. While each country places specific emphasis on certain aspects of their energy policy, all three agree on the general principles needed to guide the creation of reliable energy for today and the future. Overall, North American energy policies seek to fulfill short-term supply and demand needs while considering the long-term economic, environmental, and social consequences of those decisions. Each country recognizes the interdependence of the North American energy market and works to promote greater cooperation between Canada, Mexico, and the United States. The global trend towards developing new technologies to increase energy efficiency and decrease environmental impact is reflected in the energy policies of all three countries. The countries of North America recognize that natural gas plays a key role in meeting the goals of developing new energy markets, attracting investment, diversifying sources of energy, and meeting environmental standards.

Canada

Canadian natural gas policy falls under the more general Canadian energy policy framework. Since 1993, Canadian energy policy has been guided by the principles of sustainable development. Sustainable development is development that meets the needs of the present without compromising the ability of future generations to meet their own needs. For the natural resources sector, sustainable development requires that social, environmental and economic considerations

are integrated into resource development decisions.

For energy, sustainable development is further defined as ensuring that future generations will have available the services energy provides. Canada's energy policy is no longer narrowly concerned with production and supply issues.

A basic premise of Canada's strategy of sustainable development is: economic growth provides the conditions in which protection of the environment can best be achieved, and environmental protection, balanced with other human goals, is necessary to achieve growth that is sustainable.

Canada's sustainable energy policy framework consists of the following main objectives:

1. *To develop a competitive and innovative energy sector* - by implementing a framework that promotes the long-term development of Canadian energy resources, encourages the wise use of energy resources and maximizes economic opportunity in the energy sector for Canadians (which reflects the government's goal of promoting jobs and growth).
2. *To encourage environmental stewardship* - by addressing the environmental impacts of energy development, transportation, and use and by integrating environmental objectives into all policies and programs.
3. *To establish secure access* - by ensuring that current and future generations of Canadians have enough competitively priced energy and by taking measures that make efficient use of existing resources and provide reliable energy services to Canadians.

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Key to all of these objectives is a market orientation in which prices are established and investments are made in a competitive and freely functioning energy market. As well, long-term security is provided by a robust energy sector that has open access to both product and capital markets.

For example, the commodity price of natural gas is determined by the market forces of supply and demand. Investment in the natural gas sector is open to private and foreign capital.

Canada does intervene in areas where the market does not adequately serve its policy objectives. Canada's government agency with federal jurisdiction over energy matters, Natural Resources Canada (NRCan), for example, educates Canadians to use energy more efficiently and conducts research on new energy technologies.

A key Canadian commitment regarding climate change was made at Kyoto in 1997 to reduce Canada's greenhouse gas (GHG) emissions to six percent below 1990 levels by 2008 to 2012. The Government of Canada released the Climate Change Plan for Canada on November 21, 2002. The Plan sets out a three-step approach for achieving Canada's climate change objective of reducing annual greenhouse gas (GHG) emissions. The Plan identifies action in five broad areas: transportation, housing and commercial /institutional buildings, large industrial emitters, small and medium-sized enterprises, and the international market. Some of the tools specified in the plan, such as emissions reductions for large emitters, and information for consumers, may result in end-users switching from higher-carbon fuels to natural gas.

Trade Agreements

The Canadian natural gas industry is affected by Canada's international commitments. The North American Free Trade Agreement (NAFTA), and the Free Trade Agreement (FTA) that preceded it, set rules for Canada-U.S. natural gas trade. Under these agreements, Canada-U.S. natural gas trade is open, with no import or export taxes or tariffs. However, exporters and importers of natural gas do require a short-term export or import order or a long term license from the NEB, depending on the expected duration.

Mexico

The Mexican energy sector plays a key role within the Federal Government economic strategy to foster economic growth and improve the living standard of the population.

Mexico's energy policy is based on a sustainable development agenda which aims at three policy goals:

1. *Economic Development*: developing the energy sector to enhance its contribution to the country's economic growth, international competitiveness and job creation.
2. *Environmental Commitment*: ensuring that energy development is conducted in a manner which minimizes the damage to the environment and increases natural resources efficiency.
3. *Social Commitment*: guaranteeing that current and future generations have access to competitively priced energy and enhancing socio-economic development in remote areas of the country.

The Energy Sector Program 2001-2006, encapsulates the main policies and driving

principles of President Fox's energy portfolio, as well as the strategic goals and measurable targets set for this dynamic sector.

The main driving principles of Mexico's energy policy are:

- **Guaranteed energy supply.** Economic development requires energy inputs with high quality standards and competitive prices.
- **Clean and Competitive Energy.** Enhance the competitiveness of domestic industry through the availability of a sufficient, timely and competitive supply of a cost effective fuel such as natural gas; and contribute to a better environment by offering a cleaner fuel.
- **Social commitment.** Energy is a key driver not only for economic growth, but also for assuring higher living standards for the population.
- **Modernization of the energy sector.** Current infrastructure needs to incorporate the new technology trends in order to be able to compete within the world energy markets.
- **Increasing participation of the private sector.** The Federal Government is committed to guarantee the long-run sustainability of the energy sector. Therefore, the Federal Government is encouraging a higher participation of the private sector in some areas of the oil, gas, and power industries.
- **Commitment to sustainable development.** The energy sector is aware of its impact on the environment; therefore it is aiming to fit its policies in a sustainable development framework.

- **Commitment to future generations of Mexicans.** Mexico's energy endowment is considered as wealth of the Nation; therefore, its exploitation must bring returns not only for the current generation, but also for the oncoming ones.

These policies complement and reinforce the efforts to foster the development of natural gas, and underline the commitment of the Mexican Government to guarantee the supply of energy and to work for a long term strategy of sustainable development for future generations.

Evolution of the Natural Gas Policy

Within Mexico's national energy strategy, natural gas plays an increasingly important role. Some events in the last decade have influenced the development of the domestic natural gas market, such as the technological shift in power generation, the reforms that opened some areas of the industry to the private sector and the actions taken towards promoting sustainable development.

On the demand side there have been other drivers for the development of the natural gas market, such as the increasing use of this fuel to expand power capacity based on combined cycle technology; the commitment to burn cleaner fuels as a result of the introduction of stringent environmental standards that limit the emissions of air pollutants; and finally, the promotion of private participation in the development of infrastructure for transportation, storage and distribution of natural gas.

Commitment to Sustainable Development

Mexico is committed to a long-term strategy of sustainable development. Therefore, its energy policy considers the socioeconomic and environmental impacts of its actions, with

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special attention to protecting the environment.

In December 1994, two new environmental standards¹³ were introduced. The first one (NOM 085) set the maximum emission levels of particulates of SO₂ and NO_x for non-mobile sources. This standard has had a significant impact on the industrial sector and on the fuel consumption bundles of power utilities. The second environmental standard (NOM 086), which entered into effect in 1998, specifies quality characteristics of fuels regarding emission limits.

The introduction of new environmental standards represented a serious challenge for the Mexican energy sector, considering that fuel oil with high sulfur content was the most commonly used fuel by the industrial and power sectors. In order to meet these standards, Pemex had to change its production portfolio, increasing the share of clean products like natural gas, low sulfur diesel and gasoline. This shift required the development of infrastructure projects.

Technological Changes

The introduction of combined cycle electric generation plants in Mexico (which are more profitable, more efficient and cleaner than traditional plants) was a driving force to foster the rapid development of the natural gas industry. This technology was used by private participants in the power sector once reforms on private participation were approved (in 1992 for power generation and in 1995 for some limited natural gas activities), therefore increasing the expected and observed demand for natural gas.

The 1995 Mexican Natural Gas Reform Law followed the amendment in 1992 of the Electric Energy Public Service Law, originally

enacted in 1975. This amendment opened up power generation to limited private participation. Although Comisión Federal de Electricidad (CFE —the national State-owned utility—) remained the only entity to supply electric power for public service, domestic and foreign investors were allowed to invest in the sector through different modalities, the most important of which are self-suppliers and independent power producers (IPPs).

Technology changes indicated that natural gas was going to gain weight in the energy balance. Therefore, domestic production had to be increased to avoid the dependency on foreign sources. By the mid 90's, it was evident that the natural gas market needed a major restructuring to satisfy the new market requirements.

Deregulation and Restructuring of the Industry

In addition to the demand drivers, there are other elements fostering the rapid development of the Mexican natural gas industry. Following a corporate restructuring in 1992, Pemex was split in four subsidiaries according to the main business units: oil and gas E&P activities are carried out by Pemex Exploración y Producción (PEP), while natural gas processing, transmission and marketing are the responsibility of Pemex Gas y Petroquímica Básica (Pemex Gas and Basic Petrochemicals). Additional affiliates include: Pemex Refinación (Pemex Refining), in charge of refining, distribution and trading of oil products; Pemex Petroquímica (Pemex Petrochemicals), responsible for production and distribution of secondary petrochemical products; and Pemex Comercio Internacional (Pemex International), responsible for international trade.

¹³ NOM-085-ECOL-1994 and NOM-086-ECOL-1994.

In 1995, the Mexican government introduced far-reaching reforms in the natural gas sector, with the following aims:

- Attract private investment to this industry.
- Enhance the competitiveness of domestic industry through the availability of a reliable fuel.
- Contribute to a better environment by offering a cleaner fuel, in compliance with newly established environmental regulations for the industry.
- Facilitate the development of new private projects of power generation in the modalities allowed under the legal framework.

As the legal reform was established, the industry structure was redefined along the following lines:

- Natural gas exploration and production, processing and first hand sales were considered strategic activities reserved to Pemex.
- Natural gas transportation, distribution, storage and marketing, including foreign trade, became non-strategic activities in which the private sector could participate.

Thus, the private sector became a prime developer of natural gas infrastructure in Mexico.

The reforms included the following elements:

- **Policy Decisions:** Design and implement policies on which reforms would be based. This guaranteed that all government institutions and offices involved in the process had a common final objective and based their activities on a clear and pre-

established framework, avoiding contradictory behaviors that could jeopardize the success of the reform.

- **Legal Reform:** Undertake the necessary legal reforms to establish a clear and predictable regulatory framework that will give certainty to private participation and clear rules for competition.
- **Institutional Building:** Develop a clear definition of the government's role as owner (Ministry of Energy), operator (Pemex) and regulator (Energy Regulatory Commission). This was done in order to define the objectives for each entity, eliminate conflicts of interest and avoid controversies resulting from concurrent roles.

Additionally, a new price policy was introduced to reflect the opportunity cost of natural gas. Thus, the price of natural gas in Mexico started taking into account the price of the international market as a reference, specifically the price in southern Texas. By doing this, domestic prices reflect the conditions of a competitive market instead of Pemex's costs.¹⁴

International Energy Policy

The National Development Plan (PND) points out the importance of Mexico's participation in the global energy markets. Likewise, it determines that international cooperation should be strengthened.

On the other hand, international collaboration should be an efficient support instrument for the energy sector's development and modernization.

¹⁴ Mexican users of natural gas have always received a volumetric service, even though under the new regulation they should reserve capacity in Pemex pipeline system. This has not been possible since final rules for first hand sales have not been approved yet.

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Furthermore, bilateral energy trade with the United States should be improved, starting from an increase both in the capacity and in the number of border interconnections.

Additionally, working through the NAEWG, Mexico seeks the broadening of energy trade and interconnections taking into consideration the three countries' mutual interest in sustainable development. In order to reach these objectives, Mexico supports the goal of NAEWG to share and discuss several points of view and information about energy related matters in North America, including different programs and policies, market developments, anticipated demand and supply sources. NAEWG will also consider alternative energy sources and the efficient use and production of energy.

United States

U.S. energy policy has long been based on the belief that competitive markets, based on the private ownership of energy capital and resources, best ensure optimal supplies and consumption of energy. An integral part of this policy includes encouraging the development and utilization of natural gas, especially during the time period studied here. The U.S. government recognizes, however, that competitive markets inherently focus on the here and now. Therefore, the government has a role in promoting the development of technologies that provide the most efficient use of energy today as well as to assure that there are affordable, reliable and environmentally compatible energy supplies to meet the energy needs of the future. Also, from an energy security point of view, U.S. government energy policy has an important role to play in making sure that energy supplies represent a diverse set of energy resources from a diverse set of energy suppliers.

The National Energy Policy (NEP), adopted by President Bush in May 2001, builds on these principles and embodies U.S. energy policy. The NEP examines the nation's increasing reliance on natural gas and seeks to achieve more balance among the many energy sources. This more balanced portfolio is attained by enlarging the role of renewable energy as well as maintaining the role of traditional sources like hydropower and nuclear energy. By using technology to increase the efficiency and the role of those sources, the United States balances reliance on natural gas, while achieving greater overall energy supplies and more economic productivity with less impact on the environment and on communities.

U.S. policy supports the development of Alaskan natural gas. As U.S. demand for natural gas has increased, interest has been renewed in tapping into Alaska's natural gas supplies. These proven gas resources of about 35 trillion cubic feet could make a significant long-term contribution to U.S. energy supplies if delivered to the lower 48 states. These supplies would be transported through Canada. There also may be an additional 100 trillion cubic feet of gas resources on the North Slope that, although currently more speculative, could potentially be a source of new energy supplies in the future. While the private sector will lead the way, governmental agencies in both the United States and Canada will be prepared to expedite permit applications. The U.S. Government maintains its route neutral policy and will respond appropriately when companies make their decisions.

On October 22, 2004, President Bush signed legislation containing two key financial incentives for the Alaska North Slope natural gas pipeline that producers have said are necessary to make that gas line viable. One tax

provision allows the North Slope gas owners to amortize the cost of Alaska-built segments of a pipeline in their taxes over seven years instead of 15 years, a change that will save line owners an estimated \$U.S. 441 million over the life of the line, \$U.S. 150 million in the first 10 years. The second incentive allows an enhanced oil recovery tax credit for the cost of a gas conditioning plant on the North Slope. That provision is expected to save companies \$U.S. 295 million more in taxes in the first decade of the project. Earlier in October, 2004 President Bush signed the first part of the gas line legislation package into law, approving an \$U.S. 18 billion loan guarantee. That legislation also streamlined permitting and expedited court review, created the Office of the Federal Coordinator for Alaska Natural Gas Transportation Projects, to be responsible for speeding construction of an Alaska gas line, and established a \$U.S. 20 million worker training program and other provisions to help Alaska benefit from development of the project.

The U.S. recognizes that it has an aging energy infrastructure and seeks to remedy this through the development of new technologies that allow for more and more energy to travel through smaller, more efficient lines. The NEP recommends steps that will ensure greater reliability by relieving bottlenecks that act as choke points when moving power from region to region.

The NEP also calls for revamping research and development by increasing the movement of technologies like solar, wind, and geothermal energy to the market, while concentrating more R&D resources on technologies and ideas that represent the next wave, such as distributed energy systems, fuel cells, hydrogen-generated energy, and fusion.

The United States supports programs like LIHEAP, the Low Income Home Energy

Assistance Program to lower energy costs for low income consumers. Tax incentives are needed for research and development in areas such as distributed generation technologies. The Bush Administration supports legislation to improve the safety of natural gas pipelines, as well as additional interagency efforts to expedite the permitting of natural gas pipelines in an environmentally compatible manner. In the NEP, the Bush administration details its goals of supporting initiatives to encourage energy conservation, increasing supply, and lessening U.S. dependence on natural gas for electricity generation.

The United States is striving to increase domestic production and to diversify sources of energy. The NEP emphasizes the importance of improving U.S. energy infrastructure, both within the United States and at U.S. borders with Canada and Mexico.

International Energy Policy

A key part of U.S. energy policy is the recognition by the United States that it cannot address its energy concerns alone. Energy security is intricately linked to the international market. The United States is committed to working with Canada, Mexico, and other countries, particularly in the Western hemisphere, to strengthen and create energy partnerships. U.S. energy security will continue to depend on supplies from outside its borders. The United States recognizes that it is fortunate to have reliable North American partners that supply a significant part of U.S. energy requirements.

The U.S. National Energy Policy includes several recommendations to improve the efficiency of the broader North American energy sector, including one to improve the U.S. project permitting process and another requiring that Energy Impact Statements be prepared when any significant government

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action is proposed that would affect U.S. energy supply.

Internationally, U.S. policy calls for strengthening global alliances through such important mechanisms as existing bilateral relationships with Canada, Mexico and other countries in the Hemisphere, as well as with other key countries around the world. The United States supports the work being done under the Summit of Americas Hemispheric Energy Initiative process, which involves the U.S., Canada, and Mexico as major players.

The United States views the formation of the North American Energy Working Group as a key international policy accomplishment. U.S. President Bush, then-Canadian Prime Minister Chrétien and Mexican President Fox directed their Energy Departments to work together to develop ways to facilitate the development of a true North American energy market that will deliver reliable, affordable energy to the citizens of all three countries. An overarching goal of the Working Group is to foster communication and cooperation among the three governments on matters of common interest.

U.S. policy supports the energy integration of North America, with oil and natural gas pipelines and electric transmission lines as fully integrated energy systems. Today, there are 35 cross-border natural gas pipelines, 22 oil and petroleum product pipelines, and 51 cross-border electric transmission lines that already bind the three nations together and increase the energy security of the nations of North America.

Regulation

The regulatory environment for natural gas in Canada, the United States and Mexico has undergone many changes as it has adapted to changing energy policy. Canada has reformed

regulatory codes and tax regimes in order to encourage the private sector to participate in the energy sector and to create a secure continental energy market for the future. Mexico has taken steps to introduce a new regulatory framework that will create a competitive market with private participation in addition to economic efficiency. In the United States, regulations depend on competitive market forces more than they have in the past.

The benefits of an independent regulator are recognized in North America. Canada has the National Energy Board (NEB), which regulates natural gas trade and pipelines in view of safety, environmental protection and economic efficiency. Mexico's Energy Regulatory Commission (CRE) serves as an administrative unit of Mexico's Ministry of Energy (SENER) and has become an empowered, independent regulator. The United States Federal Energy Regulation Commission (FERC) regulates the interstate transportation of natural gas and the construction of new facilities to effect such services, and monitors the day to day operations of the U.S. pipeline industry. These regulators of each country function as reliable sources of improving interrelations among the three countries' gas markets, as well as with other energy resources. Regulations in the three countries share the goal of optimal, environmentally sensitive development of natural gas.

In recognition of the importance of coordinated regulatory policies, regulators in Canada, Mexico and the United States meet three times a year to discuss regulatory schemes and issues. Canada's NEB and the U.S. FERC have signed a cooperative agreement and FERC and Mexico's CRE have also signed a similar agreement.

Canada

In Canada's constitution, jurisdiction over energy is divided between the federal and provincial governments. Provincial and Territorial governments have jurisdiction in the areas of:

- Resources management within provincial boundaries;
- Intra-provincial trade and commerce, and;
- Intra-provincial environmental impacts.

Given this, provincial authorities regulate the upstream or producing end of the natural gas sector, including land access, exploration, drilling permits, natural gas production regulation, environmental regulations regarding natural gas exploration, drilling, production, processing, gathering pipelines, roads, etc. Provinces also lease subsurface land rights to the Exploration and Production industry, and charge land rental fees and royalties on natural gas production.

Provinces regulate natural gas markets within their borders. Intra-provincial pipeline transportation of gas, and distribution of gas, are natural monopolies, for which provinces typically regulate rates, on a cost of service basis.

The Canadian Federal Government has jurisdiction over:

- Resource management on frontier lands;
- Inter-provincial and/or international trade and commerce;
- Trans-boundary environmental impacts, and;

- Policies of national interest such as economic development, energy security, and federal energy science and technology.

Federal powers in natural gas are primarily associated with the interprovincial and international movements of natural gas, and with works extending beyond a province's boundaries. This permits the federal government to develop policies and regulate interprovincial and international natural gas trade and pipelines. For example, federal powers govern the energy efficiency standards of equipment that crosses provincial or international borders.

On Canada's frontier lands (north and offshore) the federal government has ownership of oil and gas resources. In the offshore areas of Nova Scotia and Newfoundland, the federal government and the province jointly manage the oil and natural gas industry. In each of these areas, an independent offshore petroleum board regulates oil and gas exploration, development and production on behalf of both levels of government.

The National Energy Board (NEB), an independent federal agency, regulates interprovincial and international natural gas trade and pipelines. The NEB's purpose is to promote safety, environmental protection and economic efficiency in the Canadian public interest while respecting individuals' rights within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The NEB regulates:

- The construction and operation of interprovincial and international pipelines;
- The tolls and tariffs of interprovincial and international pipelines;

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- The construction and the operation of international power lines;
- The exports of oil and electricity;
- The exports and imports of natural gas, and;
- The exploration and development of oil and gas resources in non-Accord frontier areas.

In November 1998, the federal government devolved the responsibility for jurisdiction for onshore oil and gas resources to the Yukon Territorial Government. In addition, exploration around St. Pierre et Miquelon dictates that there be some form of agreement with France regarding trans-boundary issues. This is under negotiation between the two governments.

Mexico

SENER

The Mexican Secretariat of Energy (SENER) has jurisdiction over the entire energy sector. SENER is in charge of conducting Mexico's energy policy, according to the National Development Plan, and surveying the operations of industry related agencies.

Petróleos Mexicanos (Pemex)

In Mexico, natural gas exploration and production activities are exclusively reserved to the Mexican State through the state company, Pemex. Pemex is also involved in exploration, production, processing, transmission and marketing. Except for exploration and production activities (which are carried out by Pemex Exploración y Producción, PEP) Pemex Gas y Petroquímica Básica (PGPB) took over all activities related

to natural gas, LPG and those products considered as basic petrochemicals by law¹⁵.

First Hand Sales and Rates:

Pemex has exclusive control over first-hand sales and owns the main pipeline system in the country, which is operated under an open access criteria. With the exception of gas used for upstream activities, first hand sales of supply generally refers to supplies used in Pemex's transmission system, but not necessarily those supplies used in third-party distribution systems. Figure 2 reveals the structure of the Mexican natural gas market.

As defined by the Natural Gas Regulation (NGR), first hand sales are all sales of natural gas produced and delivered in Mexico to end users other than Pemex. Given Pemex's monopolistic condition as exclusive producer of gas in Mexico, the CRE (Mexico's Regulatory Commission) regulates first-hand sales using an international reference and a netback methodology in order to reflect the opportunity cost of Mexican gas with respect to the North American market. However, it should be noted that the NGR opens the possibility to lift first-hand sales regulation if the Federal Competition Commission (*Comisión Federal de Competencia- CFC*) determines that there are effective competitive conditions in the marketplace. In principle, a reason for determining this situation could be a significant inflow of gas imports made by agents other than Pemex in a certain region.

Current legislation states that gas production is a strategic area reserved to the State through Pemex. For this reason, first-hand sales are

¹⁵ According to the RLCA27, (Regulatory Law of Constitutional Article 27 on Petroleum and Natural Gas) basic petrochemicals are: ethane, propane, butane, pentane, hexane, heptane, naphtha, and methane used as input for petrochemicals. In turn, secondary petrochemicals are the by-products derived from basic petrochemicals.

subject to price and conditions of service regulation. However, supply is potentially competitive, as consumers can buy gas from either Pemex or third parties, including importers. Natural gas imports are not subject to price regulation (except for Pemex's imports) because they come from a competitive market.¹⁶

Transportation and distribution rates are regulated under an incentive-type methodology, and particularly under an average revenue formula, which includes some elements of cost of service regulation. This method aims to offer permit holders the necessary flexibility in developing new markets while allowing them the opportunity to achieve an appropriate return on their assets and encouraging the expansion of gas supply to a wide customer base. Additionally, the method is designed to provide transporters and distributors with an incentive to improve efficiency.

Every five years the CRE and the permittee will undertake a global review of rates. Based on this review, the CRE may determine new rates, which cannot have retroactive effects. These tariff changes are a result of an adjustment factor determined through a comparative efficiency analysis. This adjustment factor is used so that the permittee has the incentive to provide services for the lowest possible cost while assuring security and maintaining quality standards.

¹⁶ Pemex requested that its imports of gas mixed with its own production be treated as regulated gas.

Energy Regulatory Commission (CRE):

The CRE is a decentralized administrative unit of SENER established by decree in November 1993.¹⁷

The CRE was founded in January 1994 as a decentralized technical and consultative body of the SENER. The decree that created the Commission limited the scope of its authority to an analysis and consultative role applicable only to the electric industry.

The CRE Act of 1995 transformed the role of the CRE to that of an empowered, independent regulator with technical and operational autonomy and provided the CRE with a legislative mandate to regulate the activities of both public and private operators in the electricity and gas industries. The CRE grants permits, authorizes prices and rates, approves terms and conditions for the provision of services, issues directives, resolves disputes, requests information and imposes sanctions when regulations are violated.

The CRE Act defines the following activities as being subject to regulation:

- Supply and sale of electricity to public service customers.
- Private sector generation, import and export of electricity.
- Acquisition of electricity used in public service.
- Transmission services between agencies that provide public service and generation, export and import permit holders.
- First-hand sales of natural gas and LPG.

¹⁷ Decreto Legal, Diario Oficial, Noviembre 25, 1993.

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- Transportation and storage of natural gas that is not related to exploration or production.
- Natural gas distribution.
- Transportation and distribution of LPG through pipelines.

The CRE has based its regulatory activities on five basic operation principles:

1. *Clear and predictable rules.* The CRE established clear and precise rules with respect to its regulatory duties.
2. *Stability.* The rules are designed to promote long-term investment in the energy industry.
3. *Transparency.* Decisions are made by a five-member collegial body and kept in public record.
4. *General Applicability.* The law makes no distinction between public and private entities; all participants are required to

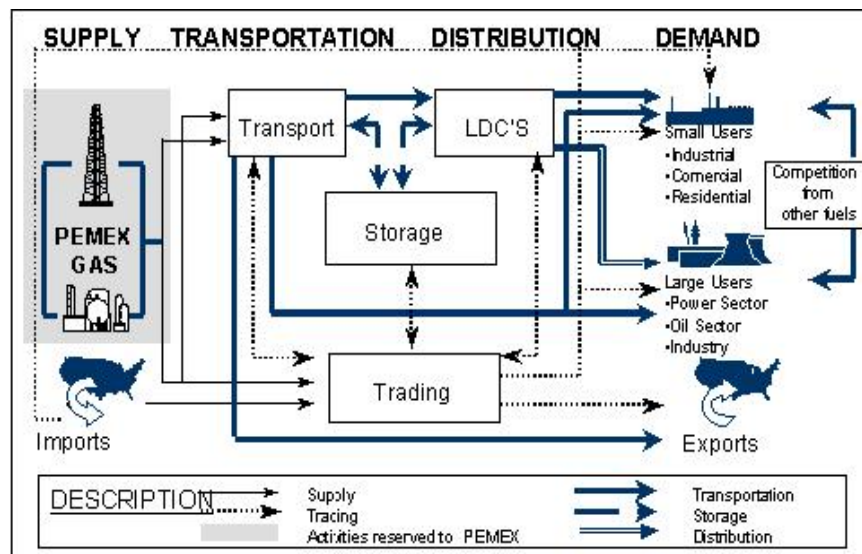
comply with regulatory provisions. Uniform analysis criteria are applied in a consistent and predictable manner.

5. *Autonomy.* Decisions are taken by the CRE based on a long-term vision of the industry, established in legal provisions not subject to political considerations.

Permit Regime

Three types of activities require a permit: transportation, storage, and distribution. The CRE grants permits for these activities upon application or by a competitive bidding procedure. Permits have an initial term of 30 years and may be renewed for additional 15 year periods. The same person may hold permits for all three activities, but transportation permits to serve a particular geographic zone shall not be granted to a person holding also the distribution permit for the same zone. An exception to this restriction may be granted whenever the CRE deems such vertical interrelation would result in efficiency gains and more cost-effective rates to customers.

Figure 2. Mexican Natural Gas Market Structure



Source: SENER

Transportation and storage permits are granted upon application and do not confer exclusivity.

The first permit for distribution in each geographic zone is granted by a bidding procedure and confers exclusivity. After the exclusivity period ends, other distribution permits may be granted upon application and shall not confer exclusivity. The first distribution permit for each geographic zone confers exclusivity on the construction of the distribution system and on the transmission of natural gas in the zone. The period of exclusivity allows the distributor to develop a network with a long term plan.

It is important to notice that granting of a permit implies an obligation to comply with the regulatory provisions and all the terms and conditions of the permit.

Key governing legislation:

The Mexican Constitution (Article 27) establishes the direct, inalienable and imprescriptible ownership of all hydrocarbons in the national territory - including the continental plateau - in oil fields or strata, whatever their physical state, including intermediate states, that make up crude mineral oil, go with it or derive there from; all these are retained by the Nation.

The Regulatory Law of Constitutional Article 27 on Petroleum and Natural Gas (RLCA27, 11/05/95), redefines the structure of the natural gas industry, distinguishing between strategic and non-strategic activities.

The Law of the Energy Regulatory Commission (LCRE, 31/10/95), establishes the purpose, jurisdiction and powers of the regulator of the energy sector. In May of 1995 the Congress approved amendments to this Regulatory Law to authorize the private sector

to construct, operate, and own natural gas transportation, storage, and distribution systems (activities previously reserved to the State).

The goals of the reform were to:

- Promote competition.
- Reach supply reliability at competitive prices.
- Introduce a new regulatory framework to achieve economic efficiency and market competition.
- Introduce mandatory non-discriminatory open access in pipelines, beginning with Pemex transportation system as well as unbundled sales.
- Allow private participation in transport, distribution, storage and trade, including international trade.
- Strengthen the regulatory body powers of the Energy Regulatory Commission and transform it into an independent entity.
- Allow Pemex to concentrate its resources and efforts in exploration, production and processing of natural gas.
- Develop Mexico's natural gas reserves.
- Privatize Pemex distribution assets.

While fostering open, efficient gas markets, the CRE grants permits, authorizes tariffs and first hand sales prices for Pemex, approves terms and conditions for the provision of services, issues directives, resolves disputes, requests information and imposes penalties, among other activities. The regulatory activities carried out by the CRE must not obstruct nor limit private participation.

Review Section

Regarding natural gas, the key directives and regulations are:

The Natural Gas Regulation (08/11/95), implements the Regulatory Law of the Constitutional Article 27 on Petroleum (RLCA27), which establishes the primary regulation for natural gas, first hand sales, transportation, distribution and storage activities.

The Directive on the Determination of Prices and Rates for Natural Gas Regulated Activities (20/03/96), contains the methodologies which must be used by regulated businesses when setting prices and rates in the natural gas industry.

The Accounting Directive for Natural Gas (03/06/96), establishes the criteria and accounting guidelines to be used by regulated firms.

The Directive on the Determination of Geographic Zones for Natural Gas Distribution (27/09/96), establishes the criteria and guidelines that will be used by the CRE to determine geographic zones for natural gas distribution.

In order to complement these reforms and to implement the legislative mandate of the Regulatory Law on Petroleum, the Natural Gas Regulation (Reglamento de Gas Natural) was issued in November 1995. The law establishes general principles of regulation, while the regulation develops the regulatory provisions necessary for participation of Pemex and private parties in the new natural gas industry.

United States

The U.S. Federal Energy Regulatory Commission (FERC) regulates the interstate

transportation of natural gas as well as the construction of facilities necessary to perform such services. In addition, FERC approval is required to abandon facility use and services, as well as to set rates and tariff provisions for these services. The FERC also authorizes the construction of facilities for the import and export of natural gas.

Specific Regulation

The Natural Gas Act (NGA) of 1938, the Natural Gas Policy Act (NGPA) of 1978, and the Outer Continental Shelf Lands Act (OCSLA), are the primary laws that the FERC administers to oversee the U.S. natural gas pipeline industry.

Under Section 7 of the NGA, the FERC regulates both the construction of pipeline facilities and the transportation of natural gas in interstate commerce. Companies providing services and constructing and operating interstate pipelines must first obtain certificates of public convenience and necessity from the Commission. Commission approval under Section 7 is also required to set rates and tariff provisions initially. Subsequent changes to existing rates and tariff provisions are subject to Section 4 of the NGA. In addition, Commission approval under Section 7 of the NGA is required to abandon facility use and services. The Commission also regulates the transportation of natural gas as authorized by the NGPA and the OCSLA.

The FERC, under Section 3 of the NGA, also authorizes the siting and construction of facilities (pipelines and LNG terminals), operations, and place of entry and exit for imports and exports of natural gas. If the facilities for the import and export of natural gas connect facilities at the borders of the United States and Canada or Mexico, the FERC, in consultation with the Secretaries of

Defense and State, also issues a Presidential Permit for these facilities.

In November 2002, the U.S. Congress amended the Deepwater Port Act of 1974 in the Maritime Security Act of 2002. This legislation transferred the jurisdiction of offshore natural gas facilities (i.e. offshore LNG terminals) from FERC to the U.S. Department of Transportation's Maritimes Administration and the U.S. Coast Guard.

Regulatory Policy

All aspects of the natural gas market were regulated prior to 1985. In 1985, the FERC adopted Order No. 436 that established rules for pipelines to offer open access transportation service independent of pipelines' sales service. In 1989, Congress passed the Natural Gas Wellhead Decontrol Act that removed all price regulation from the gas commodity by 1993. In Order No. 636, the FERC found that the pipelines' provision of a bundled gas and transportation service had anticompetitive effects that limited the benefits of open access service and wellhead decontrol. The FERC, therefore, required pipelines to cease their merchant function and act only as a transporter of natural gas, indifferent to the shipper. (The pipeline or its holding company could form a marketing affiliate to sell gas, but such marketer must compete with other shippers for capacity on its affiliated pipeline.)

The combination of wellhead decontrol, open access transportation, and the unbundling of pipeline gas sales from the pipelines' transportation function created more efficient and competitive gas commodity and transportation markets.

Import/Export Regulations

Natural gas imported into the United States and exported from the United States has required U.S. federal approval since the passage of the NGA in 1938. The NGA vested authority to approve such transactions with the Federal Power Commission. The Department of Energy Organization Act of 1977 transferred the economic authority to the Department of Energy (DOE) and the siting and construction authority remained with the FPC's successor agency, the FERC. Gas is imported and exported by pipeline or as liquefied natural gas (LNG).

Provisions of the Energy Policy Act of 1992, together with the restructuring of the U.S. natural gas market and changes in the regulatory process implemented by the DOE, have resulted in a streamlined process for approving international natural gas transactions. With the passage of the North American Free Trade Agreement, the authorizations for trade within North America have become routine and have been issued within a matter of days. Future free trade agreements could extend such streamlined approval to other nations.

RESOURCE BASE

North America has a significant natural gas resource base. Canada, Mexico, and the U.S. combined have proved natural gas reserves of 282.8 Trillion Cubic Feet (Tcf), with 186.9 Tcf in the U.S. as of year end 2002, 57 Tcf in Canada, and 38.9 Tcf in Mexico. In addition to proved reserves totaling 282.8 Tcf, the three countries are currently estimated to have even larger volumes (1,107 Tcf) of other natural gas resources which are either not yet discovered, not currently economic, or for other reasons do not yet qualify as proved reserves. However, these undiscovered

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resources of natural gas could contribute to supply in the future.

Proved Reserves

For proved reserves, definitions are fairly similar across North America. Within the working group, it was agreed that proved reserves would be defined as:

Proved Reserves: Proved Reserves of natural gas are the estimated quantities of gas in known drilled reservoirs, which are producible and are connected to pipelines and markets, or which can easily be connected. Through analysis of geological and engineering data these gas volumes are determined, with considerable certainty, to be recoverable in future years under existing technology and economic conditions. It is important for all the necessary components of gas extraction, production and transportation to market to be in place or reasonably easy to put in place before reserves can be classified as proved reserves. Definitions of proved reserves used by securities commissions for companies reporting reserves are similar to this definition.

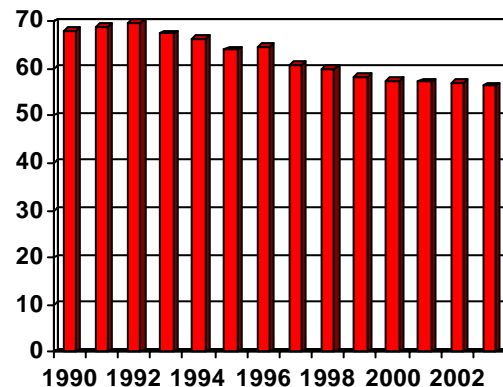
Other Resources

For other categories of natural gas resources, the Working Group noted that there are a plethora of natural gas resource terminologies in use today, such as probable reserves, possible reserves, discovered resources, undiscovered resources, ultimate potential, unproved reserves, nonproven resources, inferred reserves or resources, and others. Further, it was noted that terminologies used typically differ from nation to nation.

For these reasons, the working group felt it would be worthwhile to provide simplified and comparable estimates of those “other” natural gas resources in all three countries

which are not yet proved, but which could contribute to natural gas supply in the future. These are given within each country section below.

Figure 3. Canadian Natural Gas Proved Reserves, Tcf



Source: NEB, 2003 data estimated

Canada

Proved Reserves

Canadian natural gas proved reserves as of year-end 2001 were 57 Tcf. Most Canadian proved reserves (53.9 Tcf) are in the Western Canada Sedimentary Basin (WCSB) of Alberta, Saskatchewan, and British Columbia. As of year-end 2001, there was also 2.7 Tcf of proved reserves offshore Nova Scotia, in the basin known as the Scotian Shelf.

Canadian proved reserves have varied over time, as shown (Figure 3). Over the 1990 – 1999 period, reserves were generally falling. This reflected a situation where gas well production capacity exceeded production, excess reserves existed (this had been a regulatory requirement), and gas drilling was not particularly high. For example, over the 1990 – 2000 period, on average there were only 4,140 gas wells drilled per year in Canada. With deregulation initiatives

removing the requirement of holding large reserves, reserves levels were allowed to fall as production increased. Despite relatively low drilling, Canadian production increased dramatically, almost doubling over the 1990-2000 period.

By 2000, production had reached a level such that reserves were fully utilized. At this time it became necessary to ramp up drilling to maintain production and reserves. Drilling in 2000 was 8,950 gas wells, and exceeded 11,000 gas wells in 2001. With this increase in gas drilling, reserves and production have stabilized, but have not increased. This inability to increase reserves (or production) since 2000 is mainly a reflection of the increased maturity of the Western Canada Sedimentary Basin.

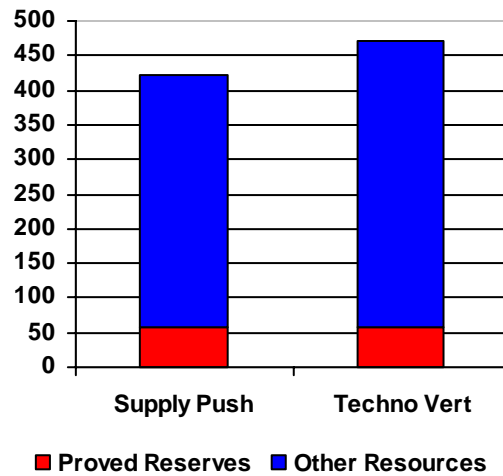
In that basin, the relatively small number of larger gas pools have already been found, and industry is now forced to drill a large number of wells, mainly targeting small pools, of which there are a very large number. By drilling a large number of gas wells, industry has been able to keep reserves (and production) roughly level since 2000.

Other Resources

Canada's Other Resources for natural gas are much larger than current proved reserves of natural gas. Some of these other resources will be developed in the future and contribute to gas supply.

These Other Resources include large drilled and discovered gas pools in Canada's Mackenzie Delta/Beaufort Sea area. These are not yet classed as proved reserves since there is no pipeline to bring the gas to markets. However, once constructed, the Mackenzie Valley Pipeline project will connect some of this resource to markets. At that time these resources will become proved reserves. The

Figure 4. Canadian Natural Gas: Other Resources, Tcf



Source: NEB

Mackenzie Delta/Beaufort Sea area has a total of 9 Tcf of such discovered gas.

An identical amount of discovered gas (9 Tcf) is known to be located in offshore Newfoundland. Due to prohibitive costs, at this time there are no known plans for pipeline projects to tap this gas. The use of compressed natural gas ships to realize these resources is being discussed.

There is also an additional 17 Tcf of other known, already discovered gas resources in other regions of Canada, none of which are currently slated for development due to high anticipated costs of development.

Besides proved reserves, the National Energy Board has estimated there is an additional 366 to 414 Tcf of natural gas remaining in Canada (i.e. other resources) which could contribute to future production.

Figure 4 compares Canada's proved reserves to other resources. Note that the NEB has two cases for Canadian natural gas other resources. The Supply Push (SP) scenario envisions a relatively low pace of technological

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improvement, but societal choices which allow producers to access land for drilling. The Techno-Vert (TV) case assumes sensitivity to the environment, less land access, but much higher technological improvement and gas recovery factors.

Mexico

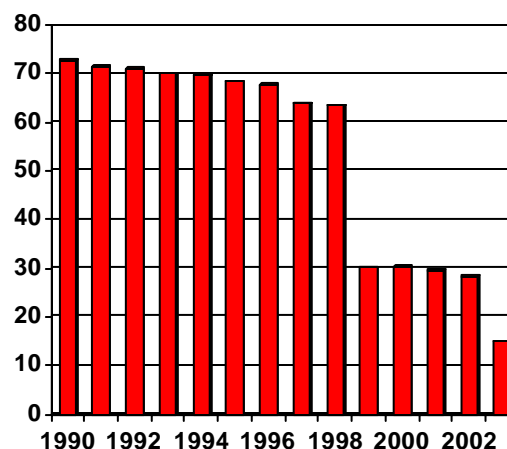
Mexican natural gas proved reserves as of year-end 2003 were 15.0 Tcf. Most Mexican proved reserves are contained within oil fields (e.g., associated gas), while the rest arise from nonassociated gas reserves. Geographically, the bulk of Mexican proved reserves are in the southern part of the country, including the offshore Gulf of Campeche area.

Mexican proved reserves have varied over time, as shown in Figure 5. Over the 1990 – 1998 period, reserves generally fell. This is due to several factors. First, Pemex has continued to focus the bulk of its exploration activities on crude oil. Secondly, there has been insufficient investment for the incorporation and recovery of reserves, and finally, proved reserves levels have been revised downwards over time.

The Mexican reserve estimate's evolution has been affected by changes within the estimation methodology, due to the fact that Mexico updates it year after year according to definitions used internationally and accepted by the financial community.

In 1998, Pemex revised the reserves of hydrocarbons of the country, applying definitions, methods and procedures accepted by the world petroleum industry. That year, the studies of the fields of the North region were finalized and the reserves of the fields of the South and Marine regions were brought up to date, according to those criteria.

Figure 5. Mexican Natural Gas Proved Resources, Tcf



Source: Sener

The reserves were audited by two consultancy firms of recognized world prestige: Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton, and the reserves were released on April 1999. Thus, Pemex moved to fulfill its 1996 decision calling for an ordered statistical transition of the estimated reserves.

Since the beginning of 2003, proved reserves have been estimated based upon definitions issued by the Securities and Exchange Commission (SEC), a U.S. government agency that regulates the financial and stock markets in the United States. Meanwhile, the quantification of probable and possible reserves continues to be undertaken according to The Society of Petroleum Engineers (SPE), American Association of Petroleum Geologists (AAPG) and The World Petroleum Congresses (WPC)¹⁸. This decision to follow the SEC definitions resulted in a significant part of the reserves from Chicontepec, originally classified as proven, being moved to the probable category on January 1, 2003. This reclassification decreased the proven

¹⁸ *Memoria de Labores 2003*, Pemex, p. 21 (online version) and *Las reservas de hidrocarburos de México*, Pemex Exploración y Producción, January 1st, 2004.

reserves, while it increased the probable reserves in the same amount.

These standardizations are advantageous because they are used around the world. Beyond creating the ability to make natural comparisons, these standards allow for the establishment of auditable work processes which generate magnitudes and reserve assortments that are also auditable. This procedure guarantees certainty and transparency both in the reported reserve volume and in the procedure employed to reach the estimation. Additionally, Pemex certifies its reserves periodically through an external subsoil consultant, which adds certainty to the data.

Proved Reserves

These are hydrocarbon volumes evaluated under atmospheric conditions, and under economic and existing working conditions, up to a specific date, which are estimated to be commercially recoverable with reasonable certainty, whose extraction complies with the established government norms, and that have been identified through the analysis of geological and engineering information. Proved reserves can be classified as developed and undeveloped.

In general terms, reserves are considered as proved if the deposit's commercial productivity is supported with real pressure and production data. In this context, the term proved refers to the quantity of recoverable hydrocarbons and not to the wells or deposits productivity. An important requirement to be taken into consideration when classifying reserves as proved is the assurance that the infrastructure for their commercialisation exists, or the certainty that it will be established.

Probable Reserves

These reserves are those in which the deposits' geological information and engineering analysis suggests that they are more feasible to be commercially recovered. If probabilistic methods are used for their evaluation, there will be a probability of at least 50 per cent that the quantities to be recovered are equal or greater than the sum of the most probable proved reserves.

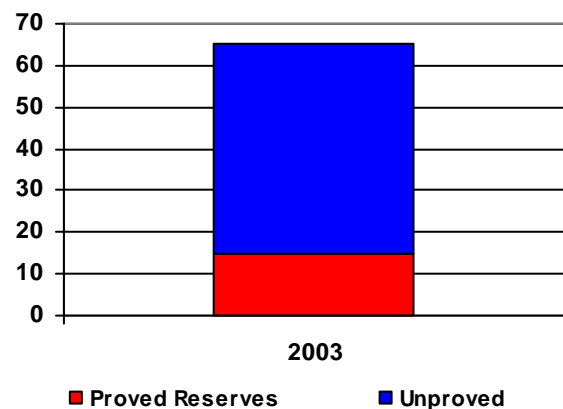
Probable reserves include those reserves beyond the proved volume, and those where the knowledge of the productive horizon is insufficient to classify these reserves as proved. Moreover, those reserves in formation which appear to be productive inferred through geophysical registers are included.

Possible Reserves

Possible reserves are those hydrocarbon volumes whose geological and engineering information suggest that their commercial utilization is less probable than probable reserves.

According to this definition, when probabilistic methods are used, the sum of

Figure 6. Mexican Natural Gas: Other Resources, Tcf



Source: Sener

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proved reserves, probable plus possible will have a probability of at least 10 per cent that the quantities truly recovered are equal or greater.

Other Resources

The total of possible and probable reserves is classified as unproved reserves. These reserves are equal to more than double the amount of proved reserves; reaching 43.8 Tcf. These consist of those reserves for which the geological information and engineering analysis of the deposits suggests the feasibility of commercial recovery.

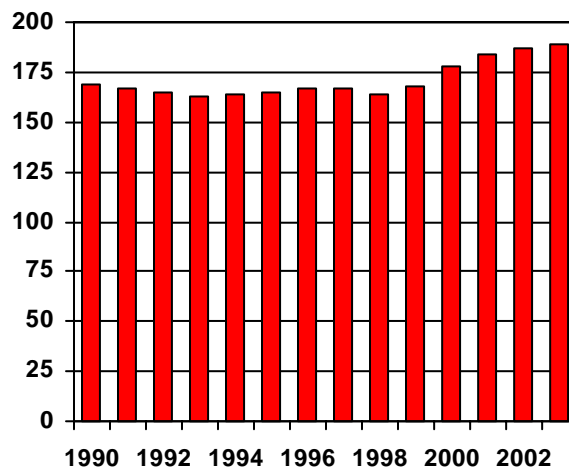
Figure 6 shows a comparison of Mexican proved reserves levels to nonproven gas resources. Compared to Canadian and U.S. sedimentary basins, the basins of Mexico have not yet been extensively drilled. As more information becomes known about Mexico's natural gas basins, the estimates of nonproven resources could be revised considerably.

United States

Proved Reserves

As of December 31, 2002, the United States had estimated proven natural gas reserves of 187 trillion cubic feet (Tcf), or 3.1 percent of world reserves (6th in the world). U.S. natural gas proved reserves are divided between numerous basins and producing areas. In 2002, the Rocky Mountain States and Texas dominated gas reserves additions. These additions highlight a shift from conventional gas fields to unconventional gas fields. Six areas accounted for 72 percent of the nation's dry natural gas proved reserves: Texas, 24 percent; Gulf of Mexico Federal Offshore, 13 percent; Wyoming, 11 percent, New Mexico, 9 percent; Oklahoma, 8 percent; Colorado, 7 percent. Dry gas reserves increased significantly in 2002 in Wyoming, Colorado,

Figure 7. U.S. Natural Gas Proved Reserves, Tcf

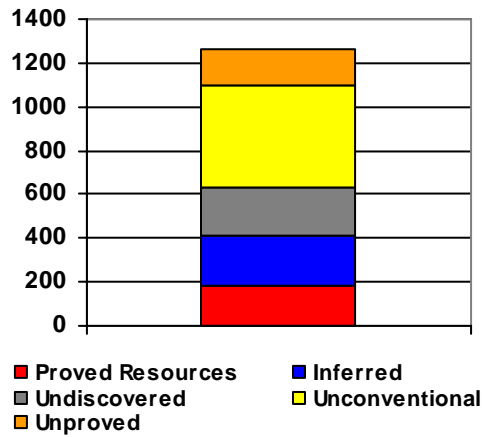


Source: EIA, 2003 data estimated

Oklahoma, and Texas. Although the Gulf of Mexico remains one of the leading areas in dry gas reserves, its reserves declined sharply in 2002.

U.S. proved reserves have varied over time, as shown in figure 7. Over the 1990 – 1999 period, reserves were generally stable. Since 1998, U.S. proved reserves have risen somewhat. U.S. proved reserves at year-end 2002 were 14 percent higher than 1998 levels. However, U.S. gas drilling, as in Canada, has increased dramatically, while proved reserves have not. The 12 percent increase in proved reserves between 1998 and 2002 was accompanied by a 66 percent increase in the number of gas wells drilled during that same time period. Over the 1990 – 1998 period, there were on average 9,847 gas wells drilled in the U.S. per year, compared to a 1999-2002 average of 16,341. By drilling a large number of gas wells, industry has been able to increase proved reserves somewhat and keep production stable.

Figure 8. U.S. Natural Gas: Other Resources, Tcf



Source: EIA

Other Resources

U.S. Other Resources for natural gas are much larger than current proved reserves of natural gas. Some of these other resources will be developed in the future and contribute to gas supply and others will not for a myriad of reasons.

These Other Resources include the very large drilled and discovered gas pools in the Alaska North Slope. Some of this gas is produced, with oil, and is reinjected to enhance crude oil recovery. According to EIA’s Annual Energy Outlook 2004, the North Slope Alaska natural gas pipeline is projected to begin transporting Alaskan gas to the lower 48 States in 2018. In 2025, total Alaskan gas production is projected to be 2.7 trillion cubic feet in the reference case.

Besides proved reserves, the U.S. Geological Survey and the U.S. Minerals Management Service have estimated there are large amounts of technically recoverable gas resources which could contribute to U.S. supply in the future. Total U.S. Other Resources are estimated at 1,154 Tcf as of year-end 2001. The EIA Annual Energy Outlook 2004 projects that, as a result of

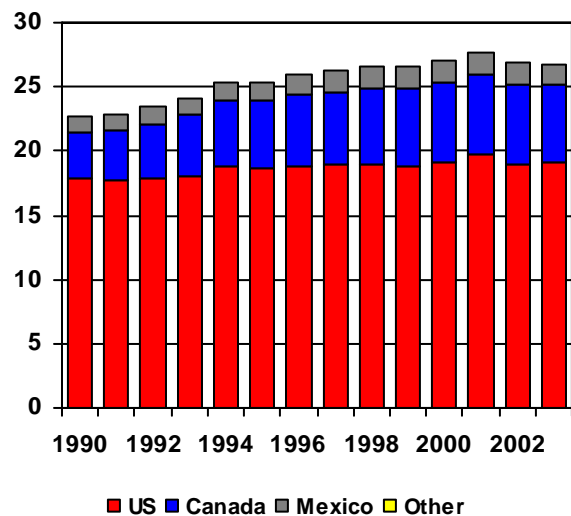
technological improvements and rising natural gas prices, natural gas production from unconventional sources (tight sands, shale, and coalbed methane) is projected to increase more rapidly than conventional production.

SUPPLY

North America produces and consumes approximately 28 Trillion Cubic Feet (Tcf) of natural gas per year. Seventy-three percent of production originates in the U.S., 21 percent in Canada and 6 percent in Mexico. North America is essentially self-sufficient in natural gas, with only 1 percent of supply coming in from other continents, via ship-borne imports of Liquefied Natural Gas (LNG). All LNG imports currently flow into the U.S. Figure 9a shows the breakdown of North American natural gas supply, as well as the trends in supply over the 1990 – 2003 period.

North American natural gas production has increased from 22.7 Tcf in 1990 to 27.3 Tcf in 2003, for a total increase of 4.6 Tcf or 20

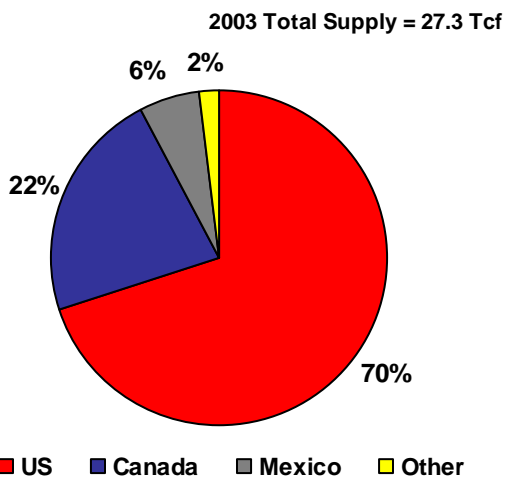
Figure 9a. North American Natural Gas Production and Supply, Tcf



Sources: Sener, Canadian Association of Petroleum Producers, EIA

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Figure 9b. North American Natural Gas Production and Supply %



Sources: Sener, Canadian Association of Petroleum Producers, EIA, NRCAn

percent, or an average annual production growth rate of 1.4 percent per year. Canadian production provided the bulk of incremental gas over this period, growing by 2.5 Tcf, while the U.S. increased by 1.2 Tcf, and Mexico by 0.8 Tcf.

Canada

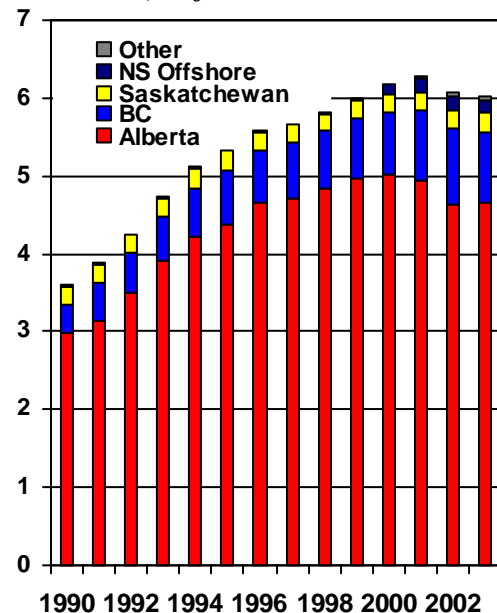
Canadian natural gas production in 2003 was 6 Tcf, accounting for 21 percent of total North American production. Current Canadian natural gas production is concentrated in the provinces of Alberta (77 percent of 2003 production), British Columbia (15 percent), Saskatchewan (4 percent), offshore Nova Scotia (3 percent), and other (1 percent). Alberta, Saskatchewan, and British Columbia are underlain by the Western Canada Sedimentary Basin (WCSB), which provides the bulk of Canadian gas production.

A graph of Canadian natural gas production over the 1990 – 2003 period is given in figure 10.

Overall, Canadian natural gas production grew from 3.6 Tcf in 1990 to 6 Tcf in 2003. This was a total production increase of 2.4 Tcf (67 percent), or an average annual increase of about 4.8 percent per year.

Gas production from the Western Canada Sedimentary Basin (WCSB) grew quickly in the 1990s as large new export pipeline projects were constructed. Production was able to grow quickly because of the availability of large volumes of unused production capacity. Excess production capacity was available in part because of the immaturity of the WCSB, and partly the result of the regulated era of the late 1970s and early 1980s. During this regulated era, producers were required to prove natural gas reserves before export sales would be permitted. As a result, in order to make export sales, producers proved up large volumes of reserves. This had the side effect of also developing an excess of production capacity.

Figure 10. Canadian Natural Gas Production, Tcf



Source: Canadian Association of Petroleum Producers, NRCAn estimates.

When regulations were amended removing the requirement of holding large volumes of proved reserves, WCSB production was able to increase rapidly. Thus, WCSB production was able to grow quickly in the early 1990s to meet rapid Canadian demand growth, as well as a portion of U.S. demand growth.

However, by 1996, Canadian production growth began to slow as the Western Canada Sedimentary Basin (WCSB) matured. While Canadian production grew an average of 8 percent per year over the 1990 - 1996 period, over the 1996 - 2001 period production growth slowed to 2 percent per year, and more recently Canadian natural gas production has declined, falling 1 percent in 2002 and 4 percent in 2003.

Canadian gas production has slowed despite a much heavier drilling effort. Canadian natural gas well completions were only 2,200 in 1990. In 2003, there were nearly 14,000 gas wells completed. Due to the increasing maturity of the Western Canada Sedimentary Basin (WCSB), (reflected in the much lower initial productivity of new wells compared to 10 years ago), and the fact that existing wells are flowed near capacity and deplete fairly rapidly, high rates of gas drilling are necessary to grow production or even maintain it.

In 2000, gas production began from the Canadian east coast offshore. In 2003, east coast offshore production was 153 Billion cubic feet (Bcf), or 2 percent of total Canadian gas production. East coast production fell 14 percent from 2002 levels.

Coalbed methane production is also beginning in the WCSB, which has very large coal deposits. It has been estimated by the Canadian Energy Research Institute that the WCSB may have up to 568 Tcf of coalbed methane gas in-place. Only a portion would be recoverable. Recently, several coalbed

methane pilot production projects have begun in the WCSB. Production is currently estimated at approximately 55 MMcf per day.

Mexico

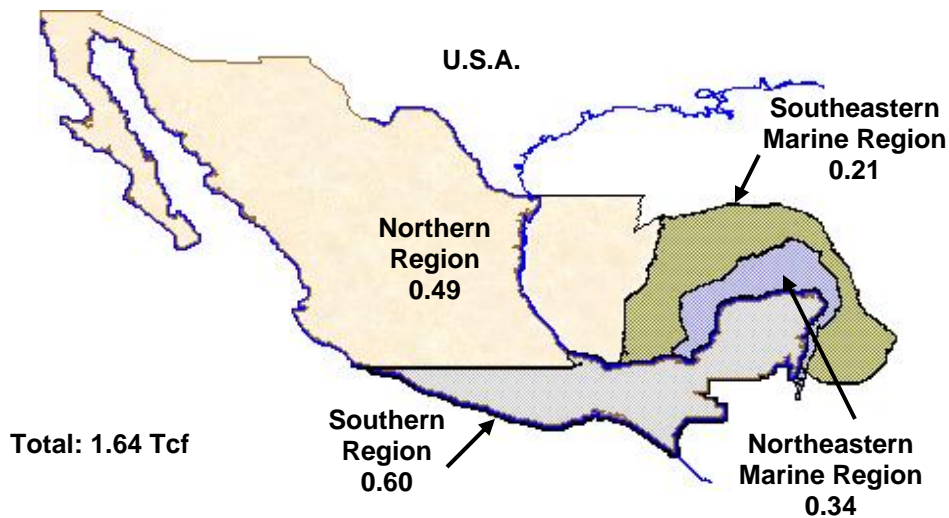
Mexican natural gas production is currently 1.6 Tcf per year, representing 6 percent of North American natural gas production. Mexican natural gas production is concentrated in the south of the country, in the states of Veracruz, Tabasco, Campeche, and Chiapas. About 70 percent of Mexican natural gas production comes from the southern producing areas, which include onshore and offshore production. Figure 11 shows the distribution of natural gas production in Mexico.

Most of the natural gas production in the south is associated with crude oil production. Overall, about 70 percent of Mexican natural gas production is associated with oil production. This is in dramatic contrast to U.S. and Canadian situation. In the U.S. and Canada, less than 15 percent of natural gas is produced in association with oil production. Petróleos Mexicanos (Pemex) performs all exploration and production of natural gas in Mexico.

Mexico's northern region is mainly nonassociated gas production, in contrast with the south. Among the nonassociated natural gas basins in Mexico, the Burgos Basin is the most prominent one. This basin is located in the Northeast of the country in the states of Tamaulipas, Nuevo Leon and Coahuila.

Burgos production reached almost 23 percent of total Mexican gas production in 2002 and 2003. Burgos production represents almost 75 percent of nonassociated gas production. Production in Burgos went from 110 Bcf in 1995 to 376 Bcf in year 2003, with a slight decline in 2001. Mexican natural gas

Figure 11. Mexican Natural Gas Production by Region, 2003, Tcf



Source: SENER

production trends over 1990 – 2003 are shown in figure 12.

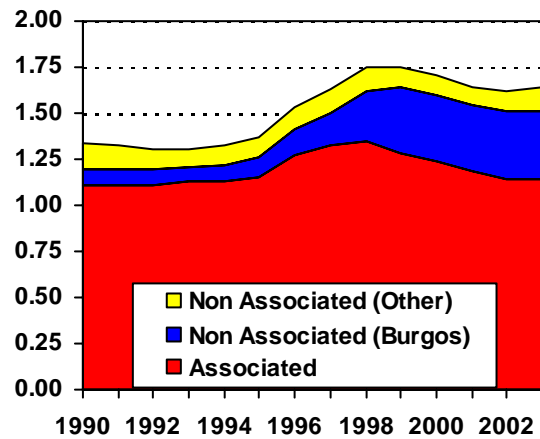
Mexican annual natural gas production has increased by a total of 0.3 Tcf over the 1990 – 2003 period. This represented a total increase of 23 percent over the period, or an average annual increase of 2.3 percent per year.

However, there are several distinct phases within this overall trend: from 1990 – 1995, production stagnated; from 1995 – 1998, production grew rapidly; and from 1998 – 2003, production has again stalled.

In the mid 1990’s gas production became a priority for Mexico, and Pemex undertook several initiatives to increase Mexican gas supply, particularly nonassociated gas production. The Burgos Project was developed. In 2000, Pemex announced the “Strategic Gas Program” with the aim of increasing nonassociated natural gas production in five different areas: Macuspana, Veracruz, Misantla, Tampico and Burgos. In addition, the plan intended to increase the production of light marine crude oil in the

Gulf of Mexico, which has a higher gas content.

Figure 12. Mexican Natural Gas Production, Tcf



Source: Sener

These initiatives had considerable success, with discoveries such as the Kopo field in Sonda de Campeche (offshore Campeche) and new nonassociated pools in the Lankahuasa area (offshore Veracruz). However, the biggest impact has been increased production

from the Burgos basin. Burgos production increased by 420 percent over 1990 – 2003.

United States

The U.S. is the largest natural gas producer in North America, accounting for 19.0 Tcf of annual North American gas production in 2002. U.S. natural gas production comes primarily from the Gulf of Mexico region, both onshore and offshore. Figure 13 shows the breakdown of U.S. production over the 1992 – 2002 period.

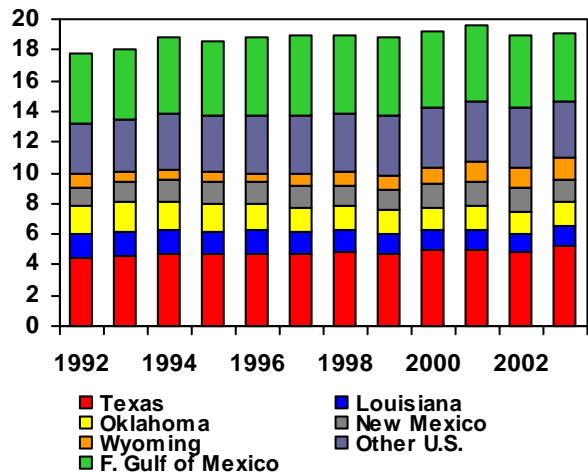
Post 1992 offshore Gulf of Mexico natural gas production is listed separately from the state total for Louisiana and Texas. In 2002, total offshore Gulf of Mexico natural gas production was about 25 percent of total U.S. gas production. In 2002, the three contiguous States of Texas, Louisiana, and Oklahoma accounted for approximately 39.4 percent of total U.S. gas production. In 1992, these States provided 44.1 percent of total U.S. gas production. In 2002, other significant producing States were: Colorado with 810 Bcf, Kansas with 416 Bcf, Alaska with 429 Bcf, Utah with 271 Bcf, and Michigan with 270 Bcf.

Overall, U.S. natural gas production grew from 17.8 Tcf in 1990 to 19.0 Tcf in 2002. This was a total production increase of 1.2 Tcf (7 percent), or an average annual increase of about 0.5 percent per year.

Texas and Louisiana gas production has declined slightly over the period, while Oklahoma production has declined more dramatically. Most of the growth in U.S. production has occurred within New Mexico, Wyoming, and other states.

A significant portion of the 1990 through 2002 increase in U.S. natural gas production can be attributed to rapidly growing coalbed methane

Figure 13. U.S. Natural Gas Production, Tcf



Source: EIA, 2003 data is preliminary

production. In 1990, U.S. coalbed methane production was approximately 200 billion cubic feet. By 2002, total U.S. coalbed methane production was 1.6 Tcf, with 1.3 Tcf of that produced in the Rocky Mountain States of New Mexico, Wyoming, and Colorado.

LNG

The final component of U.S. natural gas supply comes from LNG imports, which are currently relatively minor. LNG imports accounted for over 2 percent of U.S. supply in 2003.

While LNG supplies to the U.S. represent a minor component of overall gas supplies today, there is increasing diversity in LNG supply options, and significant movement toward a global LNG commodity market.

In the United States gas consuming markets on the coastline are typically highly populated areas at the extreme ends of pipeline systems. While siting new pipeline capacity in these markets is increasingly difficult, the rapid decline in delivered LNG costs makes LNG an attractive, cost competitive, baseload natural

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gas option in those gas consuming markets. LNG terminals planned in the Gulf of Mexico will bring LNG to East, West and Midwest U.S. gas consuming markets through existing pipeline infrastructure. Thus, LNG deliveries to the U.S. are expected to increase in the future.

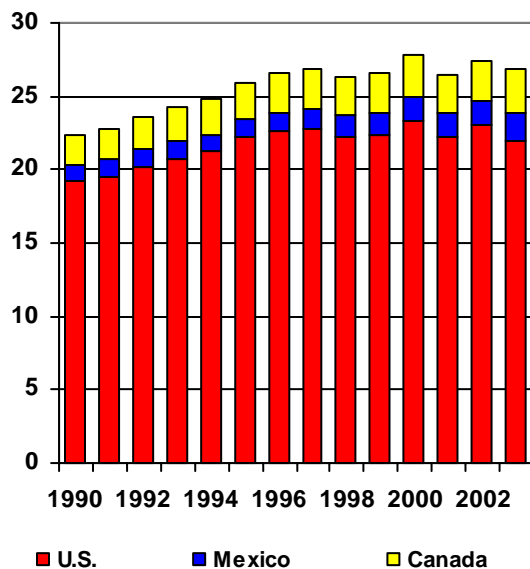
DEMAND

North American natural gas demand during 2003 was 26.5 Tcf.¹⁹ The U.S. accounted for 82 percent of demand, Canada for 11 percent, and Mexico for 7 percent.

Figures 14 and 15 show the breakdown of North American natural gas demand, as well as the trends in demand over the 1990 – 2003 period.

North American natural gas demand has increased from 22.3 Tcf in 1990 to 26.5 Tcf in

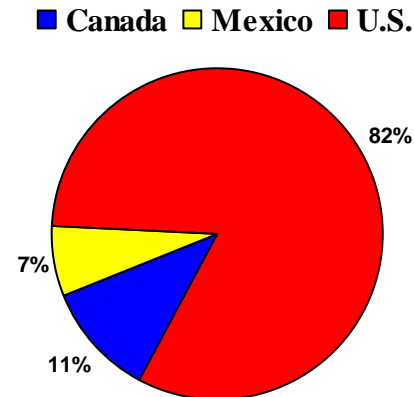
Figure 14. North American Natural Gas Demand, Tcf



Source: Sener, Statistics Canada, EIA, NRCan

¹⁹ Total North American demand of 26.5 Tcf in 2003 does not equal total North American supply of 27.3 Tcf due to storage movements and accounting differences.

Figure 15. North American Natural Gas Demand, by National Percentage of Demand



Total Demand in 2003 = 26.5 Tcf

Sources: Sener, Statistics Canada, EIA, NRCan

2003, for a total increase of 4.2 Tcf or 19 percent, or an average annual demand growth rate of 1.6 percent per year. U.S. demand has increased by 3.1 Tcf, while Canada increased by 0.7 Tcf, and Mexico by 0.5 Tcf.

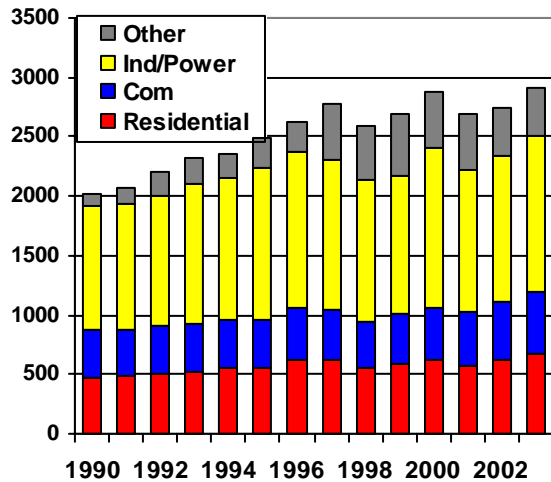
Natural gas demand is more variable than natural gas production, mainly due to year-to-year differences in weather and use of gas for heating.

Canada

Total natural gas consumption in Canada rose from 2.0 Tcf in 1990 to 2.9 Tcf in 2003, for an annual average growth rate of 3.2 percent. Demand trends by sector are shown in figure 16. Demand growth was particularly strong from 1990-97, lead by growth in industrial demand. Since 1997, Canadian natural gas demand has been relatively flat.

Regionally, the centers of Canadian natural gas demand are the provinces of Alberta and Ontario. In Alberta, where most Canadian gas is produced, the largest demand sector is industry, including petrochemicals, refining, oilsands mining, in-situ extraction and

Figure 16. Canadian Natural Gas Demand, Bcf

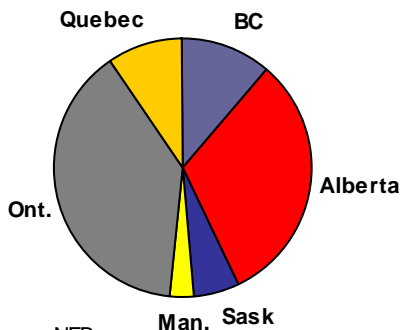


Sources: StatsCan, NRCan

upgrading. Oilsands operations consumed approximately 219 Bcf of natural gas in 2003.

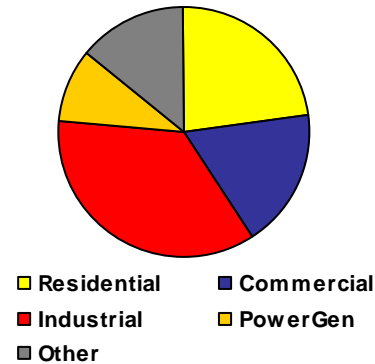
In Ontario, demand is essentially divided between residential, commercial and industrial demand. For Canada in total, the sectoral split of natural gas demand in 2003 was 35 percent industrial, 23 percent residential, 14 percent other (mostly natural gas pipeline compressor fuel and producer use), 18 percent commercial, and 10 percent power generation.

Figure 17a. Canadian Natural Gas Demand, Breakdown by Province, 2003, Bcf



Source: NEB

Figure 17b. Breakdown by Sector, 2003

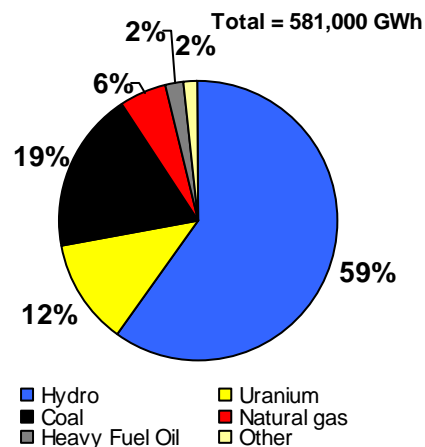


Source: NEB

Natural gas represented only 6 percent of total power generation in Canada in 2002²⁰. Power generation in Canada is dominated by Hydro, Nuclear (Uranium), and Coal Generation. Generation using orimulsion is minor but is grouped with heavy fuel oil statistics. Together, both orimulsion and heavy fuel oil accounted for only 2% of electric generation in 2002.

Statistics on Canadian natural gas consumption for power generation are only

Figure 18. Canadian Electricity Generation by Fuel, 2002



Source: NRCan - OEE

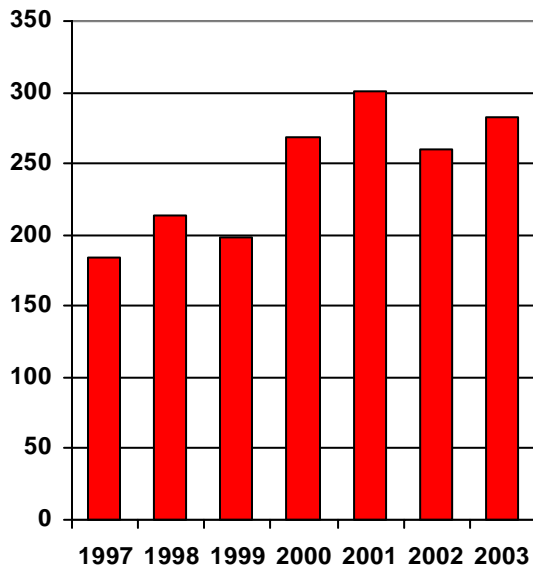
Note: Orimulsion included with heavy fuel oil.

²⁰ 2003 numbers are not yet available.

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available beginning in 1997. Over the 1997-2003 period, Canadian natural gas demand for power generation increased by 53 percent, or by an average of 7.6 percent per year.

Figure 19. Canadian Natural Gas Consumed in Power Generation, Bcf



Source: NRCan

Mexico

Total natural gas consumption in Mexico rose from 1.1 Tcf in 1990 to 1.9 Tcf in 2003, for an annual average growth rate of 4.3 percent. Consumption trends by sector are shown in figure 20.

Over this period, consumption growth was driven by state owned petroleum and power companies²¹ both under the direct control of the Federal Government. By 2003 they accounted for almost 80 percent of total consumption, 10 percentage points greater

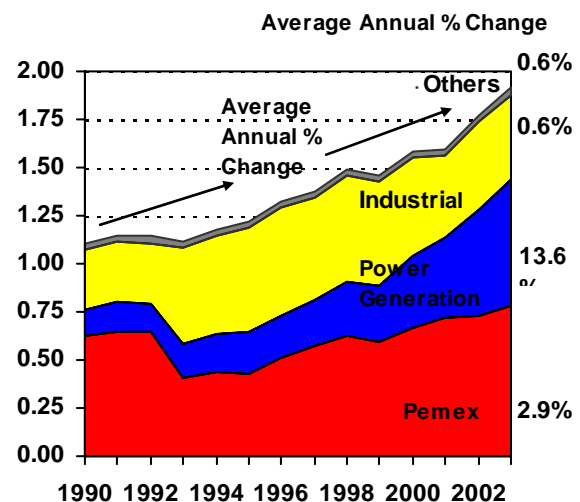
²¹ There are two utility companies in Mexico: Comision Federal de Electricidad (CFE) and Luz y Fuerza del Centro (LFC). The first one is in charge of all power generation along the country, while LFC handles the biggest distribution network in the central states, which includes Mexico City's metropolitan area.

than in 1990. The electric sector's consumption also accounts for Independent Power Producers' (IPP's); which, in 2003, represented one third of the power sector

Pemex's consumption of natural gas increased from 627 Bcf in 1990 to 780 Bcf in 2003, with an average growth rate of 1.7 percent. Pemex Exploración y Producción (PEP) is the subsidiary with the highest consumption level of natural gas: it uses gas primarily in oil fields to enhance oil production. Therefore, as production of oil increased, so did the consumption of natural gas in support of the new production levels.

Natural gas is also used in other Pemex subsidiaries, in different kinds of industrial facilities such as refineries, processing gas plants, compressor stations and petrochemical plants. However, in the last case, there was a drastic reduction in its consumption levels, from 256 Bcf to 104 Bcf over the period from 1990 - 2003. This decline, averaging 6.7 percent per year, helped compensate for incremental demand increases for other uses inside Pemex.

Figure 20. Total Mexican Natural Gas Consumption by Sector, Tcf



Source: Sener * Category includes residential, transport and service sectors.

Pemex has represented more than a 50 percent share of national natural gas consumption. Pemex's share declined from 57 percent in 1990 to 47 percent in 2003 and this volume is traded between Pemex divisions at market prices. Pemex subsidiaries are now receiving the right price signals, which are being incorporated into their economic decisions.²²

Pemex²³ remains the largest consumer of natural gas, but the power generation sector is the most dynamic one as well, with an average growth rate of 13.0 percent. This is explained by the growing use of combined cycle technology for electric generation which, given its efficiency, has resulted in greater substitution away from fuel oil consumption; basically in environmentally critical zones.

Between 1990-2003 private industrial consumption grew on average 0.6 percent annually. Natural gas consumption in the industrial sector showed a sustained growth tendency between 1990-1999 passing from 0.312 Bcf to 0.373 Bcf. In 2000, there was a reduction in natural gas consumption due to a consumption decrease in the chemical, iron and steel industries. The principal natural gas consumers were affected by the 2001 rise in prices, reaching levels of 0.306 Bcf that year. In 2003, the effects of the North American economic activity's slowdown and price volatility in March decreased the industrial sector's productive capacity in Mexico,

²² A good example is the initiative taken by Pemex Exploración y Producción to build a nitrogen plant to use nitrogen instead of natural gas in order to enhance oil production. This plant, which started operations in May 2000, has a total capacity of 1200 MMcf per day and it delivers nitrogen to the Cantarell oil field. At current natural gas prices it seems clear that this was a wise choice.

²³ Including the consumption of Pemex's four subsidiaries.

registering a demand of 0.440 Bcf during that year.

The decline in consumption at Pemex Petroquímica's²⁴ plants is explained by a combination of several factors, among them: the elimination of subsidies in natural gas prices, in recognition of the opportunity cost of gas; the crisis in the international ammonia markets in the second half of the 90's (which brought a dramatic fall in ammonia prices and left Pemex's plants in a noncompetitive position); the uncertainty of unsuccessful petrochemical industry privatization attempts; and the lack of private investment. In addition, petrochemicals is the only Pemex business line that really faces direct market competition both from domestic and foreign competitors. Pemex Petrochemicals' market share in all of its products has drastically fallen.

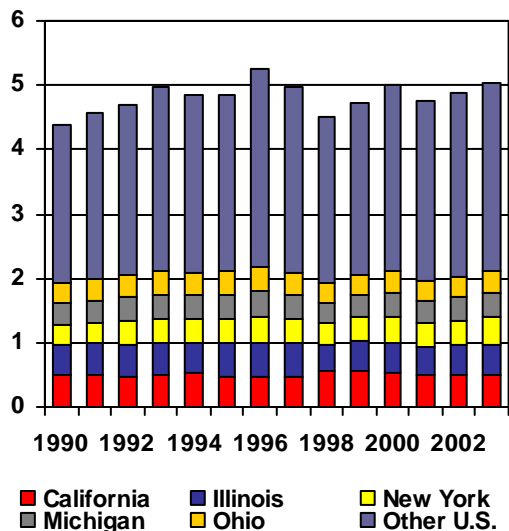
The residential and services sectors represent a small portion of the national market with an average of only 2 percent due to the lack of development within the distribution network. Between 1990 and 2003 these sectors reached an annual average growth rate of 1.0 percent.

In 1999, the transport sector started registering small amounts of compressed natural gas (CNG) consumption. Presently, there are four CNG service stations in the valley of Mexico City's metropolitan area and one more in the north eastern part of the country. Furthermore, the technology's cost for converting vehicles is still high. Compressed natural gas consumption in this sector went from 0.007 Bcf in 1999 to 0.83 Bcf in 2003.

²⁴ Pemex Petroquímica's consumptions are included within the industrial sector.

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Figure 21. U.S. Residential Natural Gas Consumption (Tcf, Dry)

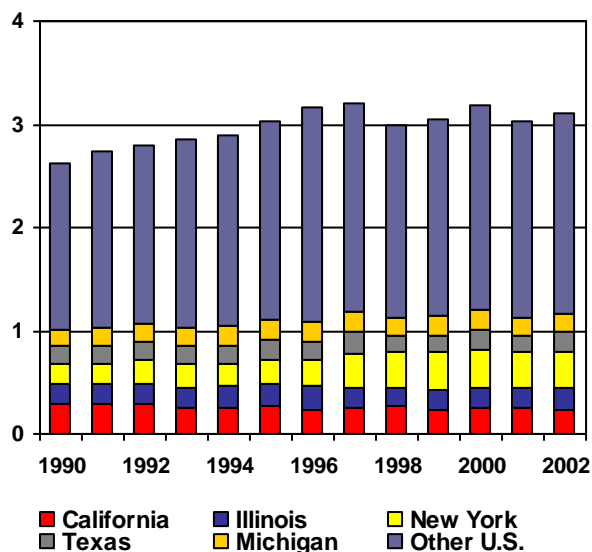


Source: EIA, *2003 data is preliminary

United States

Total U.S. natural gas consumption has increased from 19.2 Tcf in 1990 to 23.0 Tcf in 2002, for a total increase of 3.8 Tcf or 20 percent, or an average annual demand growth rate of 1.5 percent per year. About 64 percent

Figure 22. U.S. Commercial Natural Gas Consumption, Tcf



Source: EIA

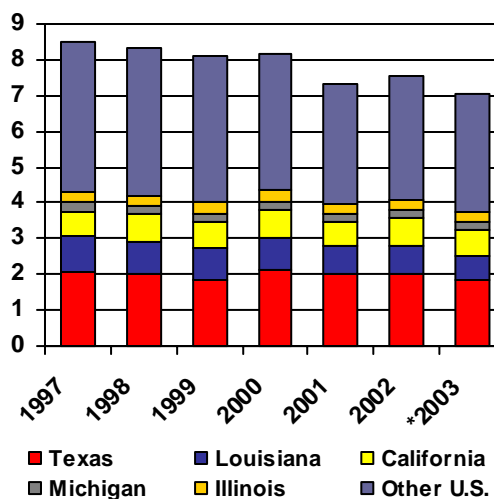
of this 3.8 Tcf growth in consumption came from the electric power sector. Trends in sectoral consumption of U.S. natural gas are shown (Figures 21 - 24).

End-use gas consumption equals the gas consumed in the residential, commercial, industrial and electric power sectors. Pipeline and field gas consumption are not included in these figures.

Unlike natural gas production, which is largely concentrated in a few U.S. states, natural gas consumption is much more geographically dispersed. The geographic dispersion of U.S. gas demand is also illustrated. (Figures 21 - 24).

In 2002, the top five gas consumption states accounted for only 45 percent of total end-use gas consumption. In 2002, other significant gas consumption states were: Michigan with 926 Bcf, Ohio with 815 Bcf, Florida with 691 Bcf, Pennsylvania with 631 Bcf, and New Jersey with 597 Bcf.

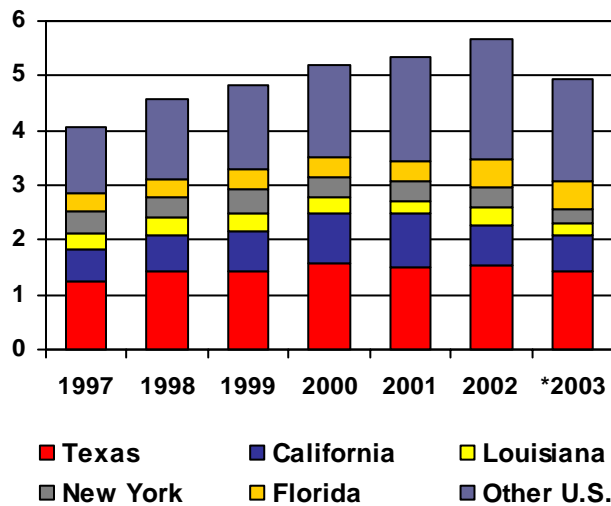
Figure 23. U.S. Industrial Natural Gas Consumption, Tcf



Source: EIA

*2003 data is preliminary.

Figure 24. U.S. Electric Power Natural Gas Consumption, Tcf



Source: EIA

*2003 data is preliminary.

Because U.S. residential natural gas consumption is primarily used for space heating, winter weather conditions largely determine the regional volumes of gas consumed. Consequently, there is considerable year-to-year variation in the state consumption patterns for this end-use sector. The states with the largest amounts of residential gas consumption were: California, Illinois, New York, Michigan and Ohio. In 2002, other significant residential gas consumption states were: Pennsylvania with 239 Bcf, New Jersey with 210 Bcf, Texas with 210 Bcf, Wisconsin with 137 Bcf, and Minnesota with 135 Bcf.

For the four end-use consumption sectors, the geographic dispersion is the greatest in the commercial gas consumption sector. The largest 5 gas consuming states in this sector – California, Illinois, New York, Texas and Michigan - only accounted for about 38 percent of the total U.S. commercial sector gas consumption. In 2002, other significant commercial gas consumption states were: Ohio with 163 Bcf, New Jersey with 146 Bcf,

Pennsylvania with 136 Bcf, Minnesota with 104 Bcf, and Indiana with 82 Bcf.

Much of the United States' industrial gas consumption occurs near the gas production fields. Because gas transportation involves a cost, industrial facilities located near the point of production can obtain the gas more cheaply than manufacturing facilities located at a greater distance from the point of production. Another advantage is that the extensive gas pipeline network in the production area gives large industrial consumers considerable flexibility as to their source of gas supply. As a result of low gas transportation costs and other factors, the largest proportion of total U.S. industrial consumption is located in Texas and Louisiana, which accounted for 37 percent of total U.S. industrial gas consumption in 2002.

In 2002, high natural gas prices and an economic recession reduced industrial gas consumption. As a result, 2002 industrial gas consumption was only 7.6 trillion cubic feet (Tcf), which is 12 percent lower than the 1995 industrial gas consumption level of 8.6 Tcf. In 2002, other significant industrial gas consumption states were: Ohio with 308 Bcf, Indiana with 259 Bcf, Pennsylvania with 205 Bcf, Alabama with 157 Bcf, and Oklahoma with 126 Bcf.

Like industrial gas consumption, much of the gas consumed in the production of electricity occurs near the point of production, particularly in Texas and Louisiana. In 2002, these two states accounted for 33 percent of the gas consumed in the production of electricity. Between 1990 and 2002, the largest increase in gas consumed in electric power generation occurred outside of the top five states shown in the graph as "other U.S."

The electricity sector posted the largest growth in gas consumption between 1990 and

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2002. During this period, gas consumption increased by 75 percent, going from 3.2 Tcf in 1990 to 5.7 Tcf in 2002. The rapid growth in the amount of gas consumed for electricity generation during 1990 through 2002 reflects the fact that most of the new electricity generation capacity built in the United States during this period was fueled by natural gas.

PRICES

North American natural gas prices, which were already somewhat linked, began to converge in 1999 due to increasing market interrelation and since then have tracked each other. This trend has largely continued despite regional market pressures. Unfortunately, this market interrelation has not helped to reduce the price volatility that has emerged since the mid-nineties. This volatility, caused by a tightening between supply and demand, has seen prices surge to as high as \$U.S. 10 per MMBtu and fall back to below \$U.S. 2 per MMBtu.

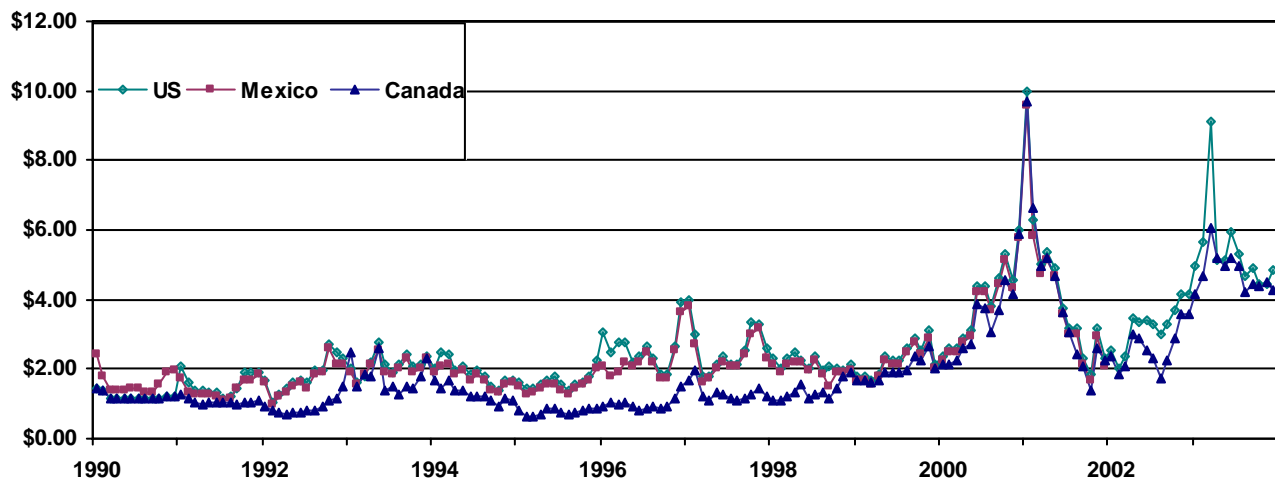
The increase in prices in late 2000 was due to a combination of factors, including slow growth in gas supply, strong weather-related

demand, high crude oil prices, and a lack of natural gas in storage. These high prices had two effects: they spurred producers to drill more wells and caused consumers to look to other fuels for their needs. These conflicting actions created an increase in supply and a decrease in demand which brought prices back towards historical levels during 2002. However, in 2003 and since, prices have risen again, once more due to a combination of factors, including strong demand, slow supply growth, high world crude oil prices, and other factors.

Main Pricing Points

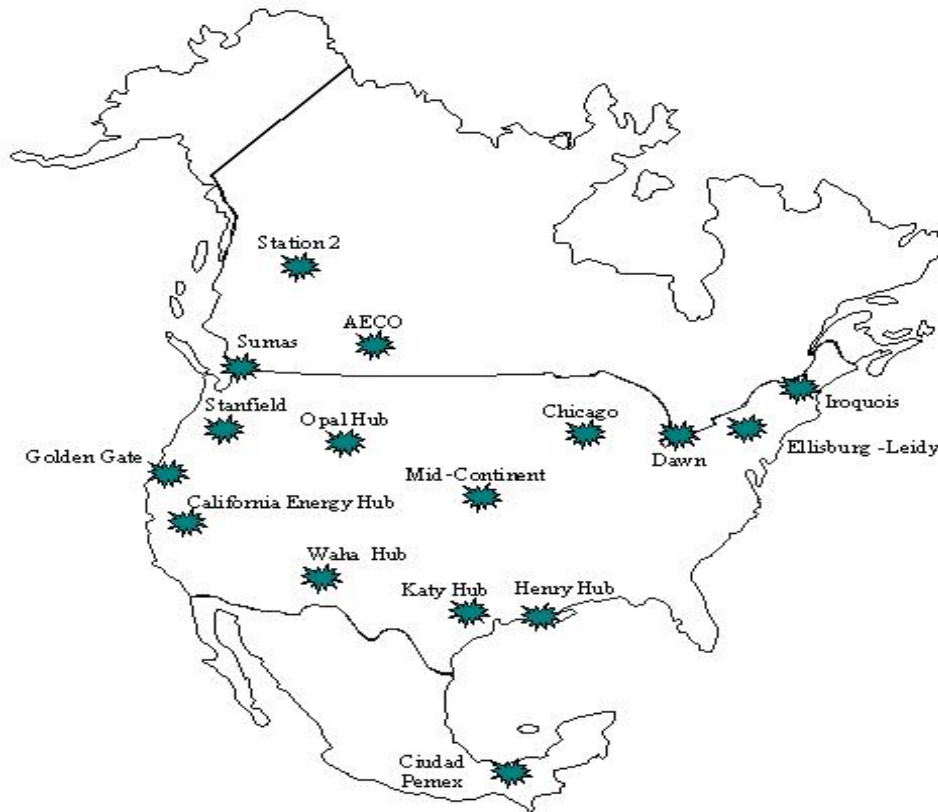
The establishment of market centers and hubs is a rather recent development in the natural gas marketplace. They evolved, beginning in the late 1980s, as an outgrowth of gas market restructuring. These centers also developed new and unique services that helped expedite and improve the gas transportation process overall. For instance, many centers developed Internet-based access to gas trading platforms and capacity release programs, and provided title transfer services between parties that buy, sell, or move their gas through the center. Some of the major market centers and hubs are shown in Figure 26.

Figure 25. North American Natural Gas Prices



Source: NRCan

Figure 26. North American Market Centers and Hubs



Source: Petroleum Encyclopedia, Oil and Gas Journal

Canada

Main Pricing Points

It is important to define the point at which natural gas prices are being quoted. Common points for natural gas price information are the natural gas processing plant gate or at certain points on the pipeline system. In Canada, the largest natural gas pricing point is the intra-Alberta market, which is also called the NIT or AECO market.²⁵ Once producers place

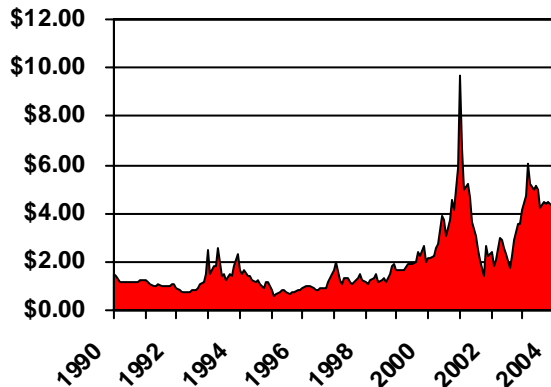
natural gas into the TransCanada PipeLines Alberta system, it is available to a large pool of buyers. The price for gas delivered to this intra-Alberta market is the most widely quoted Canadian natural gas price. Natural gas can be purchased for one day, one month, or for other periods. Besides the intra-Alberta market, other important natural gas pricing points in Canada include Station 2, on the Westcoast pipeline in British Columbia, Sumas/Huntingdon (also on the Westcoast system), and the Dawn Hub in Ontario.

²⁵ The Alberta System is also known as Nova Gas Transmission Ltd or NGTL. NIT refers to Nova Inventory transfer. AECO refers to a storage facility in southeast Alberta, located on the Alberta System. Intra-Alberta, NIT, or AECO prices refer to the same thing --

the market for natural gas delivered to the Alberta system.

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Figure 27. Canadian Natural Gas Prices (\$US/MMBtu)



Source: Canadian Natural Gas Focus

Note: Canadian prices after December 1991 are intra Alberta prices. Pre-1992 prices are at Empress, Alberta.

Price Determination

Natural gas commodity prices at any of the above pricing points are not regulated. Prices are determined daily, hourly and monthly by supply and demand fundamentals. In Canada, natural gas commodity prices were last regulated in 1985; they have been market-determined since then. End-user prices in Canada are the sum of a commodity gas price (such as the intra-Alberta price), plus natural gas pipeline transmission costs, plus natural gas distribution costs. The latter two components of end-user prices are regulated. Interprovincial pipeline rates are regulated by the National Energy Board, while distribution rates are regulated by provincial authorities.

Pricing Dynamics 1990-2001

During the regulated era prior to 1985, Canadian natural gas exports were limited by the surplus test. This forced exporters to demonstrate that Canada had reserves equal to 25 times annual Canadian demand²⁶ (later this

²⁶ The formula required that Canada have reserves equal to 25 times annual Canadian demand plus the

was changed to 15 times annual Canadian production) before export licenses would be granted. In the early 1990s, the effects of deregulation were still working through natural gas markets in Canada. The removal of the surplus test meant that producers could export more natural gas, and attain higher production. The existence of large proved reserves also meant that production could be increased rapidly. However, higher natural gas production led to an excess of natural gas in Western Canadian producing areas. Excess gas could not be exported, because existing export pipeline capacity was already full. As a result, excess gas production swamped local natural gas markets, leading to low natural gas prices in the Cdn\$1 per gigajoule²⁷ range.

Low prices in Canada were occurring at the same time that prices in adjacent U.S. gas markets were considerably higher, resulting in large Canada to U.S. natural gas price differentials. Canadian and U.S. natural gas markets were not completely integrated, due to the lack of adequate pipeline capacity between the two.

The large price differentials were an incentive for market participants to expand pipeline capacity. Several large natural gas pipeline projects were completed in the 1990s, including a large TransCanada Pipelines expansion, and the Alliance pipeline project was completed in 2000.

By 1998 enough pipeline capacity had been built to eliminate the local natural gas surplus in Western Canada. This linked Canadian and U.S. natural gas markets. Since 1998, Canadian and U.S. natural gas prices have generally moved together.

maximum quantity of gas exportable under existing National Energy Board export licenses.

²⁷ 1 gigajoule = .28 MWH.

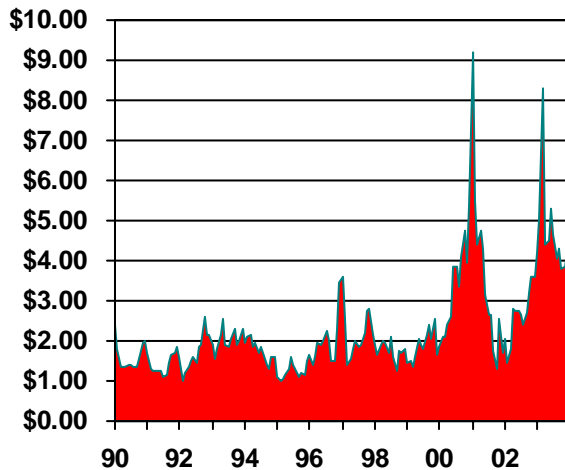
Mexico

Since the beginning of the 1990s, Mexican prices have typically followed the American NYMEX price very closely because Mexican prices are indexed to U.S. prices by regulation.

Main Pricing Points

The primary pricing point in Mexico is in the producing region of *Ciudad Pemex*, located in southern Mexico on the Gulf of Mexico.

Figure 28. Mexican Natural Gas Prices (\$US/MMBtu)



Source: Sener

Note: Mexican prices from 1990-95 are an average of TETCO and PG&E. Post-1995, the Ciudad Pemex price is used.

Price Determination

In 1991, the Price Committee of Oil Products and Natural Gas established a methodology to determine domestic natural gas prices using a "netback" concept. Essentially, the netback concept benchmarks Mexican gas prices with prices in southern Texas, U.S.

The netback methodology used in Mexico takes the price in south Texas as a reference and adds the net transport costs from this

region to *Ciudad Pemex*, in southeast Mexico, where the vast majority of associated gas is produced within the country.

In the netback methodology, the point where the flow of northern imported and domestically produced gas coincides with southern gas production is known as the arbitrage point. The price of natural gas in Mexico is therefore the sum of the reference price in Texas, plus the transport cost from the border to the arbitrage point, minus the transport cost from this point to *Ciudad Pemex*. Higher prices experienced in Mexico during the 1995-2003 period were largely caused by trends in U.S. markets.

Price Dynamics: 1990 – 2003

Between 1990 and 2000 natural gas prices were relatively stable with some increments in the winter of 1997. However, average prices were always less than \$U.S. 3.8/MMBtu.

During 2001, prices reached their highest level in years. In the middle of 2001, the Mexican government implemented a mechanism to avoid future price volatility. Under this mechanism, the price was fixed at \$U.S. 4.00/MMBtu for three years. Transportation and distribution companies were able to buy natural gas at this price, avoiding the volatility experienced by U.S. markets.

The volatile behavior in prices in the U.S. natural gas market continued in 2002 and 2003. In December 2002, the spot prices experienced a rising trend that continued into the following months. As a result of this behavior, the basket of monthly indexes in south Texas for March reached \$U.S. 8.71/MMBtu.²⁸

The natural gas behavior in the market was motivated in part by the adverse weather

²⁸ (CRE's resolution 012/2001, 020/2001)

Figure 29. The Netback Mechanism



Source: SENER

conditions that affected various regions in the U.S. These weather conditions translated into a substantial increase in the demand for natural gas for heating, which reduced the inventory of gas in the storage facilities to below the average levels of prior years. At the same time it generated instability and distrust in the market, which motivated speculation in both the physical market and in the futures market; causing an increase in price volatility. Additionally, international energy markets were affected by the conflict in the Middle East.

In December 2003 the hedging scheme known as 4x3 ended. This scheme allowed the stabilization of natural gas prices during three years at around \$U.S. 4.00/MMBtu. Currently, a resolution issued by CRE is being applied, which allows natural gas distributors to incorporate into their maximum acquisition price the adjustments derived from the employment of financial covering instruments.

These adjustments will be in effect until at least December 2006.

Further, due to the uncertainty in the future natural gas price level, Pemex and the Ministry of Energy decided on November 2003 to offer its clients two forms of additional hedging aside from the others normally offered.

By doing this, Pemex currently has 50 percent of its industrial and distribution customers covered for the 2004-2006 period. Additionally, there are other gas buyers that have chosen other companies to carry out their hedging transactions.

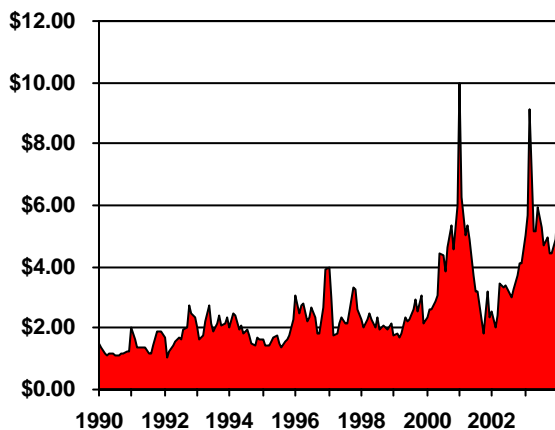
These measures are intended to protect residential, commercial and distribution services and industrial users against natural gas fluctuations, particularly those users that do not have access to financial instruments to mitigate such volatility.

United States

Main Pricing Points

In the United States, the gas industry trade press is responsible for reporting natural gas prices for spot transactions, which occur at gas market centers. Natural gas market centers usually occur where two or more major pipelines interconnect. The transfer of gas ownership between buyers and sellers takes place at these market centers as the gas moves from one pipeline system to another. Extensive gas trading at these market centers has caused the reported transaction prices to become benchmarks for the value of gas produced and consumed in the surrounding region.

Figure 30. U.S. Natural Gas Prices (\$US/MMBtu)



Source: Canadian Natural Gas Focus

The Henry Hub market center in Louisiana has become the premier industry benchmark for gas prices. The New York Mercantile Exchange (NYMEX) uses the Henry Hub as the physical delivery point for the NYMEX traded gas futures. Natural gas bought and sold at the Henry Hub can be transferred to almost 30 pipelines, which provide access to all the major gas consumption markets in the eastern United States.

Price Determination

Since the U.S. Wellhead Decontrol Act of 1989, the market forces of supply and demand determine wellhead gas prices. Intrastate and interstate gas pipeline tariffs for firm transportation services are regulated by State and Federal agencies, respectively. These regulatory agencies set the maximum tariff rate, which these pipelines can charge, based on the cost of providing gas transportation services.²⁹ Similarly, the individual states regulate local distribution company service rates. As a result, the price paid by gas consumers is a combination of unregulated wellhead prices and regulated transportation and distribution rates.

Price Dynamics 1990 - 2002

Prevailing natural gas market prices largely reflect transitory supply and consumption conditions, such as weather severity and storage inventory levels. Because natural gas supply and consumption are relatively price inelastic in the short-term, large price changes are sometimes required to bring natural gas supply and demand into balance. Consequently, gas prices can be quite volatile, as demonstrated by more recent price behavior.

INFRASTRUCTURE

Delivery and storage systems are key to making natural gas an economical source of fuel for energy consumption. The increasingly competitive global natural gas market has resulted in a need for countries to increase natural gas storage capacity, both to ensure secure supplies of the fuel and to increase market efficiency and, subsequently, market

²⁹ These regulatory agencies can also permit pipelines to charge market-based rates, based on a determination that their markets are sufficiently competitive to not require rate regulation.

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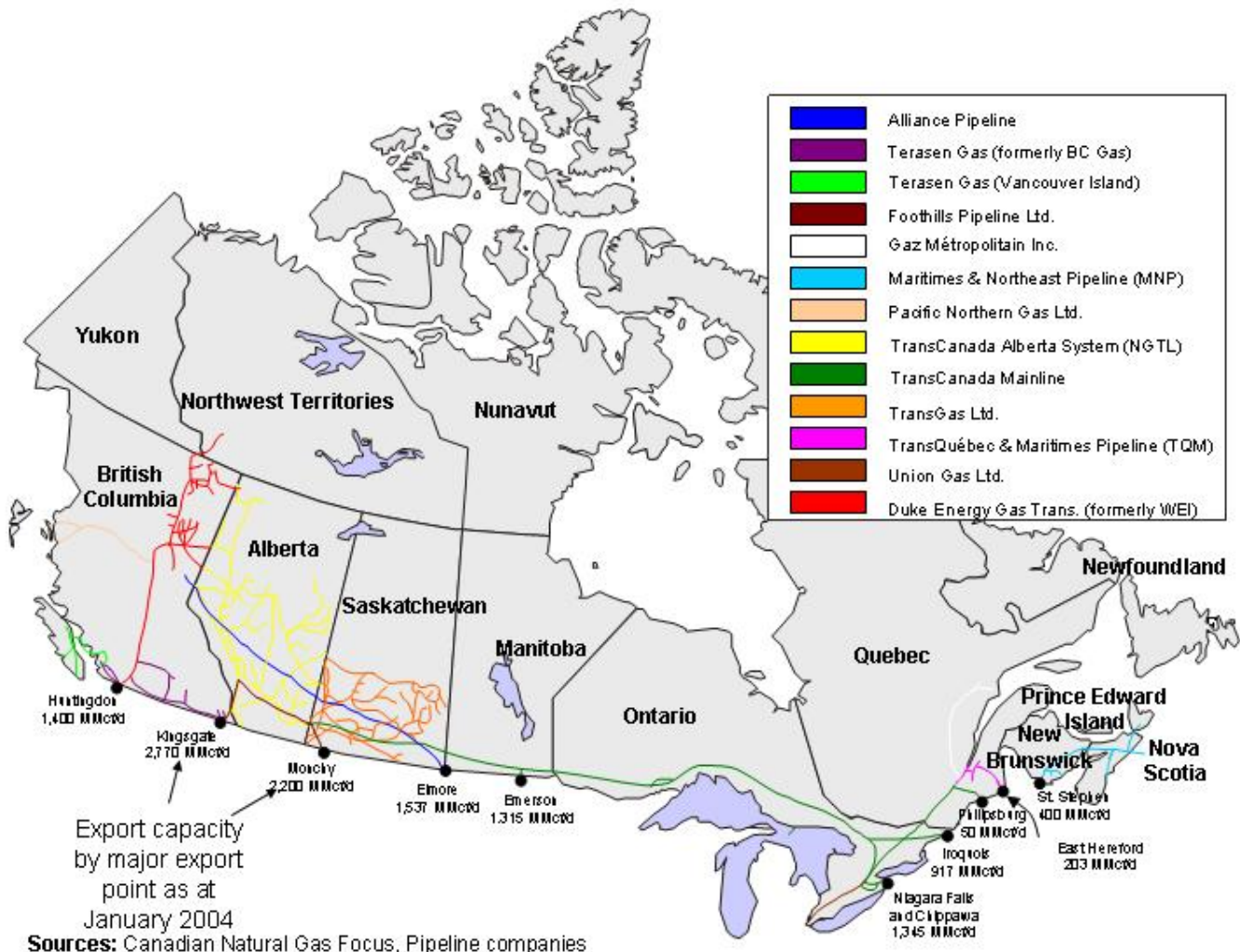
growth. This has been particularly evident in countries in North America, where imports, deregulation and competition have increased the demand for flexible mechanisms to transmit gas to customers.

During the last decade, a great deal of construction activity to develop gas distribution and transmission systems took place world-wide. The North American natural gas market has developed into an industry that operates in a more open market environment. Trade liberalization, pursuant to the North American Free Trade Agreement (NAFTA), and the integration of Mexico into a continental natural gas market has created an increasingly interrelated and competitive North American natural gas market.

Canada

The natural gas market in Canada is served by several major transmission pipelines that also interconnect with the U.S. pipeline grid. TransCanada Pipelines Limited (TCPL or TransCanada) is one of the largest carriers of natural gas in North America. The largest pipeline system in terms of gas moved is TransCanada's 'Alberta System', which transported more than 10.6 Billion cubic feet (Bcf) per day of natural gas in 2003. The largest pipeline system in terms of total distance is the TransCanada system, which includes approximately 37,580-km of pipeline in Canada.

Figure 31. Primary Canadian Natural Gas Pipelines and Export Pipeline Capacity



Ownership

All transmission pipelines, both inter- and intra-provincial, are owned and operated by widely held public companies, except the gas transmission system in Saskatchewan. This company, TransGas Limited, is a provincial Crown corporation under the authority of the *SaskEnergy Act*.

Pipeline System

In Canada, approximately 80,000 km of transmission pipeline carries natural gas from processing plants to the consuming regions and export points at the international border.

There are nine major natural gas transmission pipeline companies in Canada (located from west to east), which include:

1. Duke Energy Gas Transmission (DEGT)
2. Trans-Canada Pipelines Limited (Trans-Canada)
 - a. The 'BC System'
 - b. The 'Alberta System'
 - c. The 'Canadian Mainline'
3. Foothills Pipe Lines Limited (Foothills)
 - a. Foothills South BC
 - b. Foothills Alberta
 - c. Foothills Saskatchewan
4. Alliance Pipeline Limited (Alliance)
5. TransGas Limited (TransGas)
6. Vector Pipeline (Vector)
7. Union Gas Limited (Dawn/Trafalgar Pipeline)
8. Trans Québec and Maritimes Pipeline Incorporated (TQM)
9. Maritimes and Northeast Pipeline (MNP)

The Canadian Energy Pipeline Association (CEPA) represents Canada's transmission pipeline companies. CEPA represents the interests of seven of the nine major Canadian natural gas transmission pipeline companies: DEGT, Trans-Canada, Foothills, Alliance, Trans-Gas, TQM and MNP. Some of Canada's transmission pipelines are also active members of the Canadian Gas Association (CGA), which also represents their interests when needed.

Capacity

Pipeline capacity is defined as, "the maximum throughput of natural gas over a specified period of time for which a pipeline system or portion thereof is designed or constructed, not limited by existing service conditions." Canadian natural gas pipelines transport an average of 16.5 Billion cubic feet (Bcf) of natural gas per day to markets in Canada and the United States. Actual pipeline capacity is somewhat greater.

Pipeline Throughput

Canada's transmission system transports nearly all of Canada's natural gas production from producing regions to markets throughout Canada and the U.S. In 2003, about 6,024 Bcf (an average of 16.5 Bcf per day) of natural gas was produced and distributed through Canada's natural gas transmission pipeline system. More than half of Canada's gas production was exported to the U.S.

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Mexico

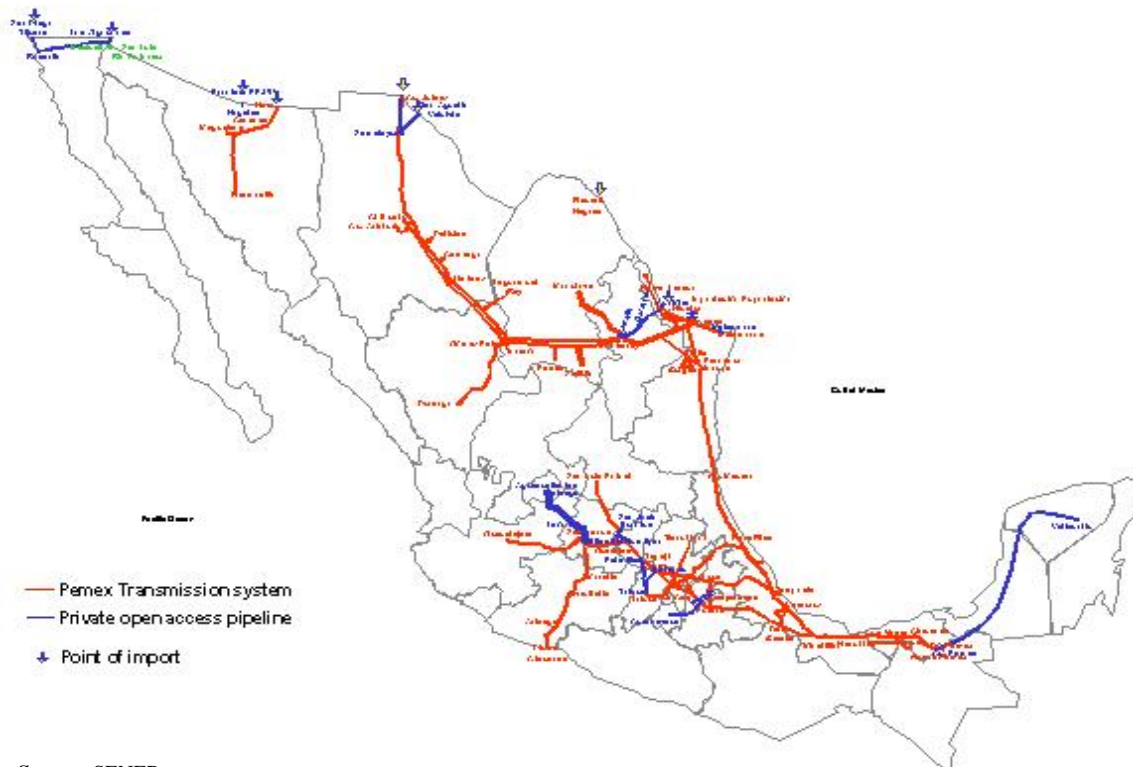
Mexico has made rapid progress in opening natural gas distribution, transport, storage and commercialization to private participation. The effort began in May 1995 with legislation that opened natural gas transmission, distribution and storage to private investment and allowed private companies to import and export natural gas. Considerable expansion of the existing infrastructure was needed both to provide gas to fuel electricity generation and to provide access to the residential market. Much of the expansion has been accomplished by the private sector. Proposed projects to expand pipeline capacity on the U.S.-Mexican border also reflect the growing interest of U.S. firms in expanding their trade with Mexico.

Most of the transmission network is owned and operated by Pemex, which held a monopoly on transmission service until 1995. During the period from 1995 - 2003, the CRE

granted 100 operative permits for gas transmission that represent over 11,481 km of high-pressure pipeline, with annual capacity of 5,568 Bcf (15,255 million cubic feet per day (Mcf per day)). Of these, 16 permits were for 10,864 km of pipelines operated under an open access regime, with an annual capacity 3,929 Bcf (10,765 Mcf per day) or 71 percent of the total transmission capacity, and 84 permits were for 617 km of short pipelines operated by industrial firms for their own use, with an annual capacity of 1,639 Bcf (4,490 Mcf per day) or 29 percent of the total transmission capacity.

Of the portion of the pipeline network under the open access regime, Pemex accounted for 2 of the 16 permits, 9,043 km of pipeline or 83 percent of the network by length, and 1, 904 Bcf (5,217 Mcf per day) or 48 percent of the network by capacity.

Figure 32. Main Mexican Natural Gas Pipelines



Source: SENER

PGPB Pipeline Systems

Prior to the 1995 reform, Pemex was a vertically integrated firm that had control over transmission and over the commercial aspects of the main distribution systems. However, over the past few years it has completely withdrawn from distribution, selling its assets to private investors. In addition to its upstream exclusivity, Pemex owns the main pipeline system in the country, as well as one other relatively small local pipeline on the northwest border: Naco-Hermosillo. It has 9 compression stations, 4 in the south and 5 in the north of the country. Currently, its compression capacity is 324,860 hp and total transport capacity is 1,860 Bcf (5,096 MMcf per day).

Private Pipeline Infrastructure

Since 1995, when private participation in pipelines was made possible, new pipelines have started operations. These pipelines do not compete directly with PGPB pipelines. However, they help to eliminate bottlenecks in the PGPB system. The Energia Mayakan pipeline is the most important, running for 710 km from *Ciudad Pemex* to Mérida in the Yucatan Peninsula. It was built to provide natural gas to the Mérida III combined cycle IPP power plant. Moreover there is the Tamaulipas' pipeline with a capacity of 1,000 Mcf per day; the Kinder Morgan Monterrey pipeline has a capacity of 424 Mcf per day; and the Gasoductos del Río pipeline with a capacity of 330 Mcf per day.

Cross Border Pipelines

Before 1995, seven interconnections across the U.S./Mexico border existed. The natural gas commerce was small, but created an important way to balance demand and supply. Since then eight new interconnections have been developed to increase the capacity

available for imports from the U.S. The 15 interconnections currently can provide 3.387 Bcf per day of capacity.

Local Distribution Networks

In the last decade, distribution systems have been constructed and operated by world class companies, experts in the development of energy infrastructure. The total investment commitments up to the fifth year of operation were \$U.S. 921 million. Since 1996, Mexican regulator CRE began organizing public bids to grant distribution permits in the main urban areas of the country. Private companies showed interest in participating in this market, leading to the grant of 21 distribution permits. According to the business plans of the LDC's during the first years of the permit, they plan to build 28,041 km of pipelines to serve 2.3 million users. The largest distribution company is Gas Natural México, with seven permits and 450 per day or 30 percent of the distribution capacity. The second largest distribution company is Tractebel with three permits and 387 Mcf per day or 26 percent of the distribution capacity.

Gaz de France has three permits and 384 Mcf per day or 25 percent of the distribution capacity. Sempra Energy has three permits and 117 Mcf per day or 8 percent of the distribution capacity, and Compañía Mexicana de Gas has 115 Mcf per day or 8 percent of the distribution capacity commitments. The remaining distribution permits are held by 4 different firms, holding the remaining three percent of capacity.

In December 2003, distributing companies in Mexico had 1.4 million users connected to the distribution net. Moreover, companies have invested more than \$U.S. 1.13 billion in installation, operation, and expansion of more than 25,000 kilometers of pipelines.

Table 1. U.S. - Mexico, Natural Gas Interconnections

Interconnection	Location	Capacity MMcf per day
Northwest		
San Diego - Rosarito	Baja California	300
Los Algodones - Tijuana	Baja California	500
Mexicali	Baja California	29
Naco - Hermosillo	Sonora	130
Nacozari de Garcia	Sonora	85
Agua Prieta	Sonora	173
Northeast		
Ciudad Juárez	Chihuahua	80
San Augustin Valdivia - Samalayuca	Chihuahua	312
Piedras Negras	Coahuila	38
Ciudad Mier Monterrey	Nuevo León	425
Kinder Morgan (Arguelles)	Reynosa	300
Gulf Terra	Reynosa	200
Río Bravo	Reynosa	330
Tennessee	Reynosa	235
Tetco	Reynosa	250
Total		3,387

Source: Sener

Gas is distributed in only a few of Mexico's major metropolitan areas, so just 12 percent of the population can access gas from existing transportation networks. However, there are plans to improve access to gas for small residential and commercial consumers by extending distribution grids to include several towns and cities.

United States

The existing U.S. interstate natural gas pipeline grid consists of more than 212,000³⁰ miles of mainline transmission lines with an estimated daily deliverability capacity of approximately 138³¹ billion cubic feet (Bcf). Between 80 and 90 pipeline systems make up the interstate network—about 50-55 are

³⁰ As of 2003.

³¹ As of 2003.

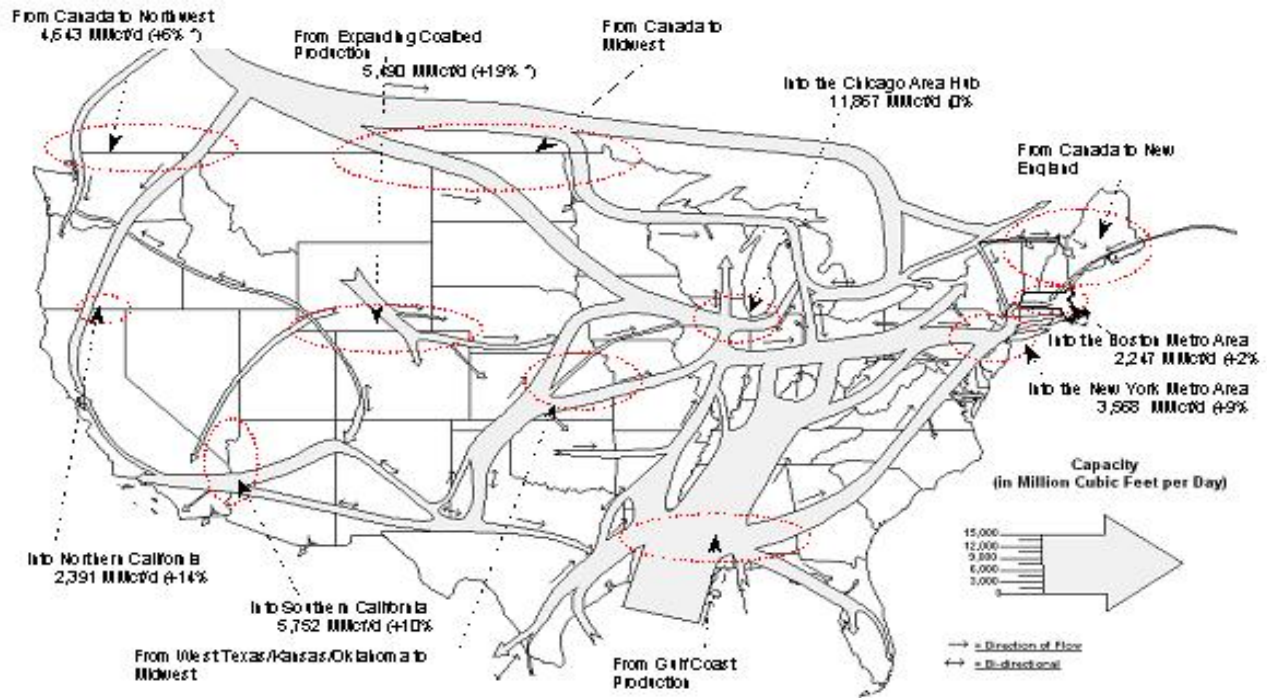
categorized as major by the Federal Energy Regulatory Commission (FERC). Another 60 pipelines operate strictly within the borders of individual states in the intrastate market. The intrastate portion of the grid (excluding gathering lines and local gas distribution systems) accounts for at least another 73,000³² miles of pipeline.

Pipelines and Interconnections Used for International Trade

Canada and the U.S. share twenty-one active export/import points of varying sizes along the border and Canada's international natural gas trade is currently conducted with only the United States. (For a map of the most significant import/export points, see Figure 31.)

³² As of year-end 2003.

Figure 33. Major Natural Gas Pipeline Corridors and Capacity at Key Locations



Source: EIA

In order to keep up with increasing production and demand, Canada’s export capacity to the U.S. has grown significantly since 1990. Between 1990 and 2003, Canadian export capacity has grown by 2,533 Bcf. The most significant capacity increases have occurred at the Kingsgate point in British Columbia and the Elmore point in Saskatchewan. The largest export points in Canada by capacity are at Kingsgate and Monchy. These two are joined by Elmore to comprise the three largest export points in Canada by gas volumes exported to the U.S.

Major U.S. Pipeline Systems with Canadian Interconnects

The Canadian and U.S. gas markets have increasingly evolved into an integrated market. Natural gas can be bought from many supply sources and delivered to any market area via a highly integrated pipeline grid. There are twelve major U.S. natural gas transmission pipeline systems that import gas

supply from Canada for delivery to markets in the Lower 48:

1. Northwest Pipeline Corporation (NWP)
2. PG&E Gas Transmission Northwest (PG&E GT-NW)
3. Northern Border Pipeline Company (NBPL)
4. Alliance Pipeline Limited (Alliance)
5. Viking Gas Transmission Company (Viking)
6. Great Lakes Gas Transmission Company (GLGT)
7. Panhandle Eastern Pipeline (Panhandle Eastern)
8. Tennessee Gas Pipeline Company (Tennessee)

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9. Empire State Pipeline (Empire)
10. Iroquois Gas Transmission System (Iroquois)
11. Portland Natural Gas Transmission System (PNGTS)
12. Maritimes and Northeast Pipeline (MNP)

U.S. exports to Canada

The U.S. exports natural gas to Canada at Courtright, Ontario. While a significant proportion of these exports are merely the

2003 had increased by nearly a factor of ten, when they reached 371 Bcf.

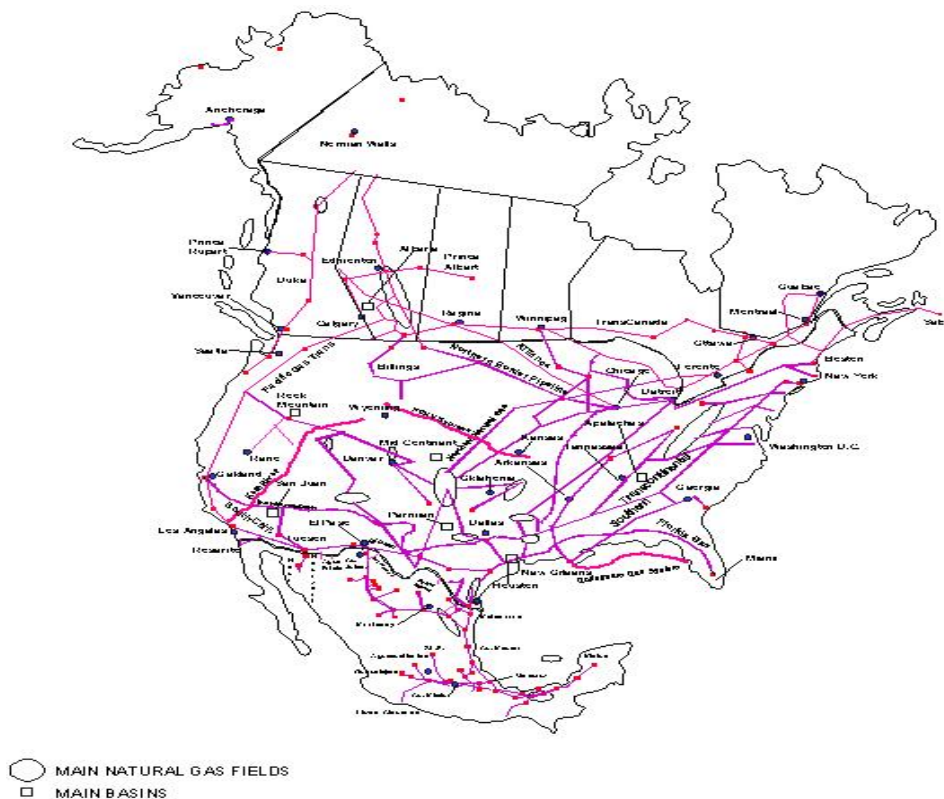
Mexico/United States

Interconnections between Mexico and the U.S.

Mexico has 15 natural gas interconnections with the southern United States which add up to an import capacity of 3.387³³ Bcf per day.

From these, six pipelines with a total capacity of 1.410 Bcf per day are connected to Pemex Gas' National Pipeline System between the states of Tamaulipas and Nuevo León. The

Figure 34. Main Pipeline Network in Canada, Mexico and the U.S.

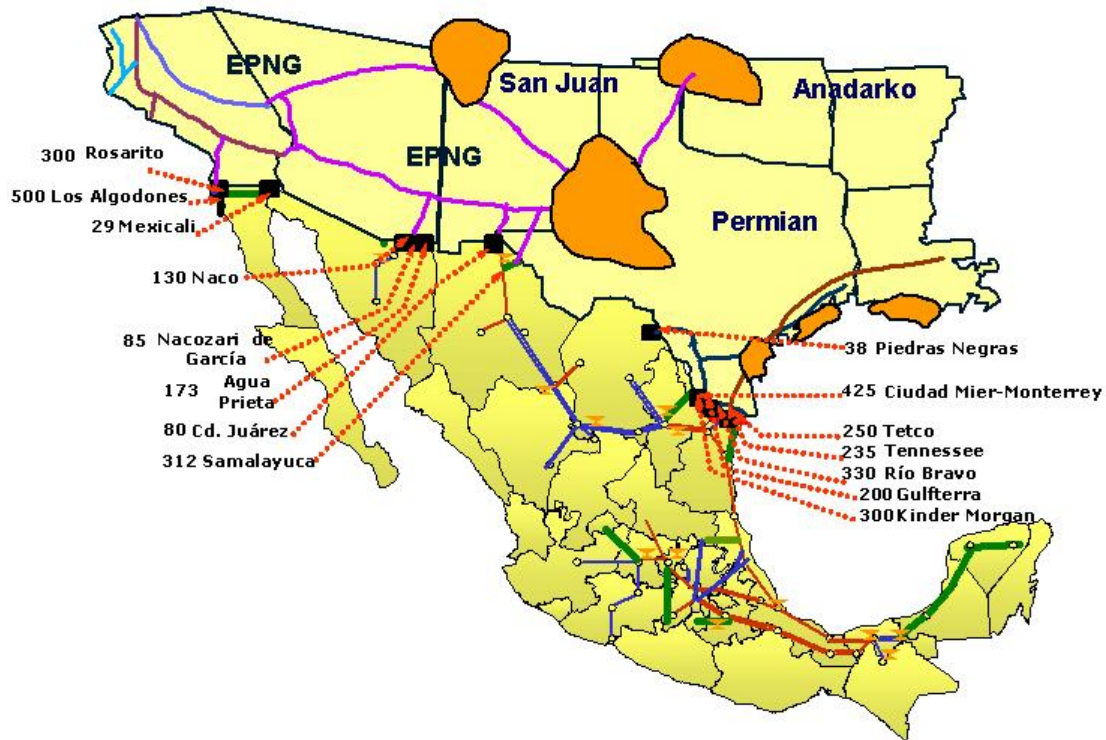


SOURCE: *Petroleum encyclopedia and Oil and Gas Journal*, 1996.

export of already imported Canadian gas, these exports have been growing very strongly recently. Exports first began in 1998 and by

³³ As of year-end 2003. It is important to mention that all capacity data refers to interconnection capacity with the maximum flow not happening through all the interconnections at the same time.

Figure 35. Mexican Natural Gas Pipelines and Interconnections with the U.S.



Source: Sener

rest of the interconnections (1.977 Bcf per day of capacity) are associated to the isolated system of Pemex Gas (in the state of Sonora) and to other natural gas companies in Mexico (Sempra in Baja California and Gasoductos de Chihuahua in Chihuahua).

Most of the interconnections in Tamaulipas have a two directional flow capacity and allow gas transportation in both for imports and for exports.

Existing Storage Facilities

Underground natural gas storage facilities serve peak winter gas consumption requirements, and also smooth out volatility in natural gas supply and demand, in order to reduce natural gas price volatility. Natural gas storage in market areas is used to allow pipelines serving a market area to be built

with capacities closer to average daily demand levels rather than peak daily demand levels. Gas storage facilities in the gas production areas are used to smooth out production variations caused by weather and maintenance.

Storage is also used to maximize load factors on natural gas pipeline systems, moderate price swings, and ensure that market areas have sufficient natural gas supply during periods of peak winter demand.

Most underground storage reservoirs are depleted natural gas production fields. However, some storage has been developed in salt beds or aquifers. The bulk of North American natural gas storage is underground reservoir storage. However, some gas is stored as liquefied natural gas. Gas is liquefied by cooling methane to minus 260 degrees

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Fahrenheit. In this liquefied form the gas is stored in insulated tanks. This liquefied gas is regasified when desired. Gas storage facilities are generally filled during the summer and drained during the winter, although considerable gas volumes are injected into storage during warm winter periods. Most of the gas storage capacity is located near gas consumption centers. This permits both gas wells and the pipeline system to operate at relatively high capacity factors, even though gas consumption varies on a daily, weekly and seasonal basis.

The total useable North American natural gas storage capacity is over 3,600 Bcf, and is located in Canada and the U.S. In both Canada and the U.S., gas storage facilities are owned

by a variety of owners: pipeline companies, local distribution companies, producing companies, and pure storage companies. The rights to use storage capacity are held under contract by pipelines, local distribution companies, marketers, and end-users. The rates charged by pipeline or distribution companies for the use of storage they own are typically regulated, and are considered as part of the regulated monopoly's rate base. In contrast, so called 'third party storage' is owned by investors, and the rates charged by these facilities are typically not regulated.

Canada

Canada has total natural gas storage working capacity of 605.6 Bcf. This represents about

Province	Company	Facility Name	Type	Storage Capacity (Bcf)
British Columbia	Unocal Gas B.C. Gas	Aitken Creek	Depleted Gas	80
		Tilbury	LNG Tanks	0.6
Alberta	ATCO	Carbon	Depleted Gas	40
	Midstream	Fort Saskatchewan	Salt Cavern	3.5
	ATCO Gas	Suffield	Depleted Gas	85
	AEC	Hythe	Depleted Gas	10
	AEC	Countess	Depleted Gas	10
	BP Canada	CrossAlta	Depleted Gas	40
	Alberta Hub	Sabine Hub Services	Depleted Gas	35
	Husky	Severn Creek	Depleted Gas	15
Saskatchewan	Trans Gas	Several	Various	32
Total Western Canada				351.1
Ontario	Union Gas Enbridge Union Gas	Dawn	Depleted	150
		Tecumseh	Reef	96
		Hagar	Depleted	0.6
			Reef LNG Tanks	
Quebec	Gas Metro Gas Metro	Point-du-Lac/St.	Depleted Gas	2.9
		Flavien	LNG Tanks	2
		Montreal LNG		
Total Eastern Canada				251.5
Total Canada				602.6
Source: NRCan				

40 percent of typical winter Canadian natural gas demand over the November - March heating period. In Canada, most third-party storage is in Western Canada. Distributors own most of the storage capacity in Eastern Canada. Distributors use storage to park gas during summer, and withdraw it to meet peak demand in their franchise area in winter. Storage costs are embedded in rates charged to distribution company users, and these rates are regulated by provincial authorities.

Mexico

Mexico has not fully developed its natural gas storage capacity. Currently it uses the main pipeline to store gas and is evaluating the possibility of gas storage.

United States

Most North American storage is located in the U.S., which has over 3,000 Bcf of working

gas storage capacity. This represents about 85 percent of total North American storage working gas capacity.

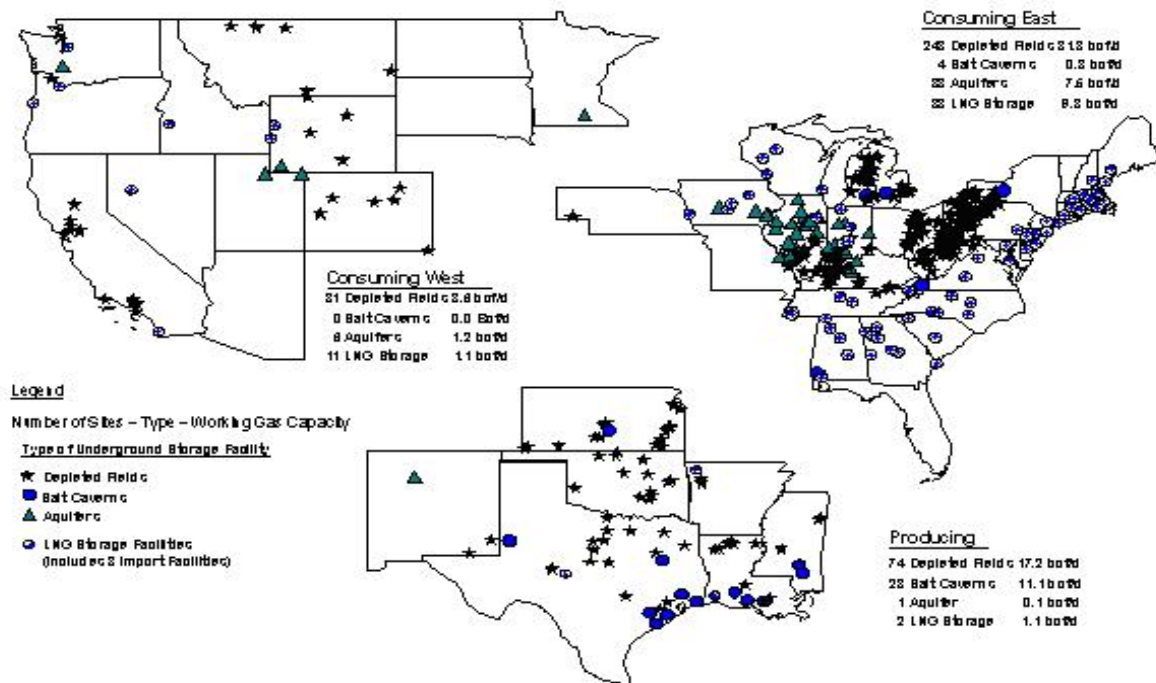
As shown in figure 36, U.S. natural gas storage can be divided into storage regions: the Consuming East; the Consuming West and the storage in the Producing region.

In the Consuming East, there are 235 depleted fields which can be used for storage. In this region there are also 4 salt caverns, 32 aquifers, and 83 LNG storage facilities.

In the Consuming West, there are 37 depleted fields. In this region there are no salt caverns, but there are 5 aquifers and 12 LNG storage facilities.

In the Producing region, there are 74 depleted fields which can be used for storage. There are also 23 salt caverns, 1 aquifer and 2 LNG storage facilities.

Figure 36. U.S. Underground Gas Storage Sites



Note: Bcf/d = billion cubic feet per day. Regions are those used by the EIA in its Weekly Underground Storage Survey.

Source: U.S. DOE, Office of Fossil Energy

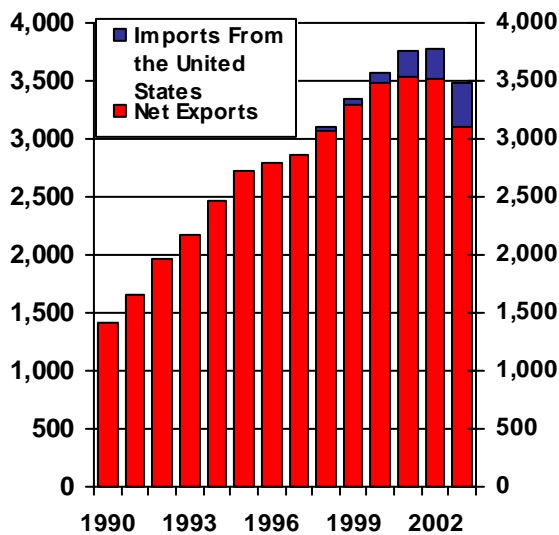
TRADE

Canada/U.S. Trade Balance

Deregulation of natural gas markets in Canada and the United States has had a major influence on Canada-U.S. trade patterns. Prior to deregulation, Canadian and U.S. gas transmission networks were more or less independent of each other, with the exception of points of export between the two countries. The deregulation of natural gas markets – supported by the Free Trade agreements – has resulted in the emergence of a more integrated market between the two countries. Buyers and sellers on both sides of the border can negotiate for gas supplies and pipeline space on transmission systems in both countries, thereby arriving at the most cost effective method of arranging for gas supplies in each country.

Canada has traditionally exported a great deal of domestic natural gas production to the U.S. In fact, since 1990, the percentage of Canadian production that has been exported has increased from 39 percent to 57 percent.

Figure 37. Canadian Natural Gas Exports to the U.S., Bcf



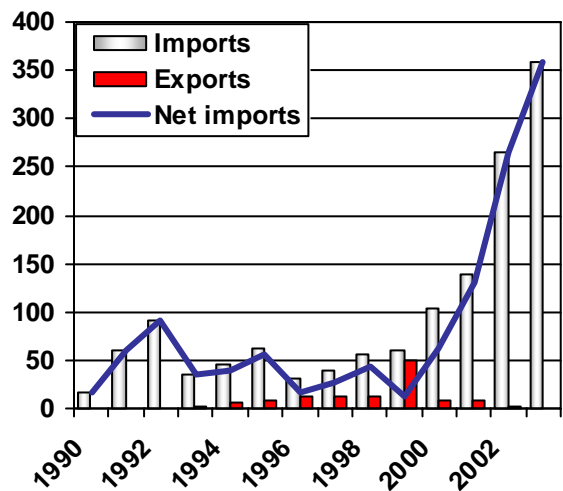
Sources: NEB, Canadian Association of Petroleum

Also, every year from 1990 to 2002, exports of natural gas to the U.S. increased. However, this trend ended in 2003 when net exports decreased by 400 Bcf. This decrease was due to several factors, including flat to declining Canadian natural gas production, increasing Canadian natural gas demand, and a myriad of purchase decisions by customers in both Canada and the U.S. Canada to U.S. export levels have not been this low since 1998, and it seems likely that Canadian exports will remain below 2002 levels for the medium term.

Mexico/U.S. Trade Balance

The natural gas market is one in which Mexico has kept an important commercial relationship with the United States. Until 2002, Mexico exported several surpluses to the United States, registering the greatest volume in 1999 when it exported 55 Bcf. However, since 1997 through 2003, Mexico has been increasing its natural gas imports and is now a net importer from the United States.

Figure 38. Mexican Natural Gas Foreign Trade, Bcf



Source: Sener

In 1996, in compliance with the North American Free Trade Agreement's framework, natural gas imports were free from the previous import permit; however, a tariff of 6 percent was applied for commercial and services imports on the border. This tariff was originally scheduled to decrease 1 percent every year until it reached 0 percent on December 31, 2002. However, in August 1999, the import tariff was suspended, facilitating market trade openness and the opportunity for new investments for infrastructure development at the border with the United States.

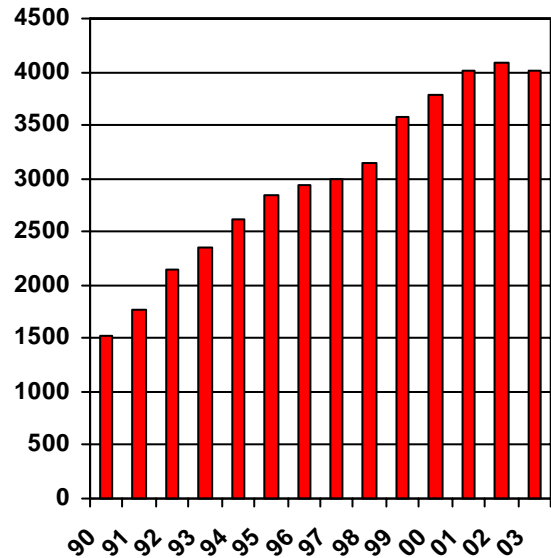
As noted in the chapter on infrastructure, in the presence of a growing natural gas demand, Mexico has increased its interconnection points through diverse pipelines at the border with the United States in order to satisfy its growing demand.

During 2003, Mexico imported 365 Bcf for national consumption from diverse interconnections located in the southern and western United States. From this total, 55 percent was imported through the state of Tamaulipas via the National Pipeline System, and the rest through Mexico's isolated systems.

United States

As the U.S. demand for natural gas increases, the U.S. has relied more heavily on imports, primarily from Canada. Over the past several years, the United States has experienced a widening gap between production and consumption. In 1990 U.S. domestic production satisfied 95 percent of the total consumption, compared to 85 percent of total U.S. gas consumption in 2003. Pipeline imports from Canada accounted for 87 percent of total U.S. natural gas imports in 2003, with liquefied natural gas (LNG) imports comprising the remaining 13 percent.

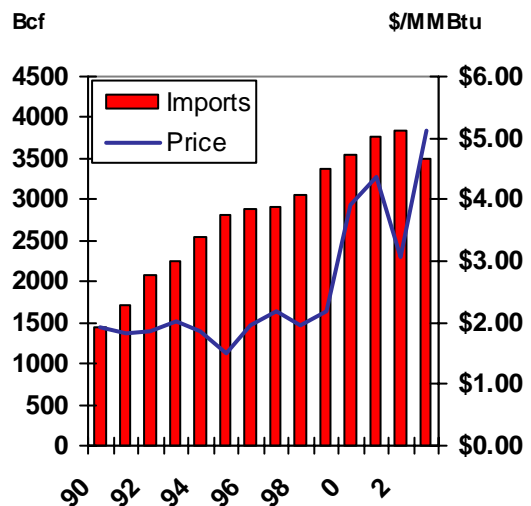
Figure 39. U.S. Natural Gas Imports, 1999 - 2003, (Bcf)



Source: U.S. DOE, Office of Fossil Energy

From 1990 through 2002, natural gas imports continued on a steady upward trend, reaching a peak of 4,015 Bcf. In 2003 they fell slightly to 3,996 Bcf. A 9-percent decline in imports from Canada was somewhat offset as LNG imports more than doubled. Net imports in 2003 were 3,304 Bcf.

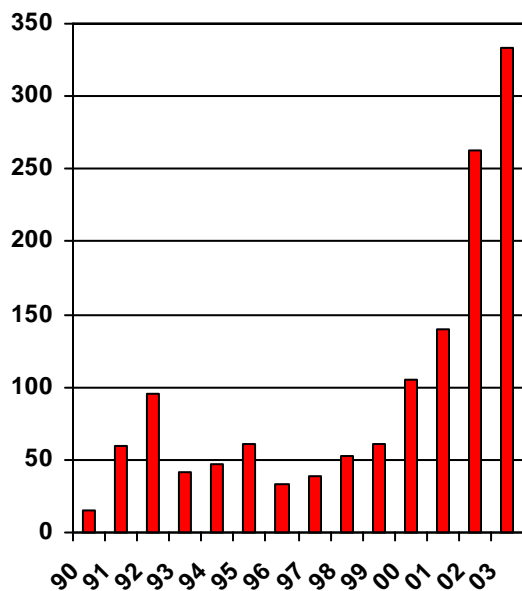
Figure 40. U.S. Imports of Canadian Natural Gas (1990 - 2003)



Sources: NEB, U.S. DOE, Office of Fossil Energy

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Figure 41. U.S. Natural Gas Exports to Mexico, 1999 - 2003, Bcf



Source: U.S. DOE, Office of Fossil Energy

Canada continues to be the main supplier of natural gas to the United States. Although Canadian imports declined in 2003 from the previous year, they still reached 3,490 Bcf, more than double their level in 1990. From 1990 through 1999 the annual price of Canadian imports remained near a level of \$U.S. 2.00/MMBtu. In the year 2000, the price rose sharply to \$U.S. 3.90/MMBtu and remained above \$U.S. 3.97/MMBtu, reaching \$U.S. 5.13/MMBtu in 2003.

Exports from the United States to Mexico have been growing. In 1990 they were 16 Bcf. They rose sharply in 2002, reaching 263 Bcf, and climbed again to 333 Bcf in 2003. The average price of exports to Mexico was \$U.S. 5.36 per MMBtu in 2003. Mexico has been a net importer of natural gas in recent years. There were no natural gas imports from Mexico into the United States in 2003.

Table 3. Pipeline Trade to the United States, Bcf

	U.S. Imports			U.S. Exports			Net Imports
	Canada	Mexico	Total	Canada	Mexico	Total	
1990	1,448	0	1,448	17	16	33	1,415
1991	1,710	0	1,710	15	60	75	1,635
1992	2,094	0	2,094	68	96	164	1,930
1993	2,267	2	2,269	45	40	85	2,184
1994	2,566	7	2,573	53	47	100	2,473
1995	2,816	7	2,823	28	61	89	2,734
1996	2,883	14	2,897	52	34	86	2,811
1997	2,899	17	2,916	56	38	94	2,822
1998	3,052	15	3,067	40	53	93	2,974
1999	3,368	55	3,423	39	61	100	3,323
2000	3,544	12	3,556	73	106	179	3,377
2001	3,729	10	3,739	167	141	308	3,431
2002	3,785	2	3,787	189	263	452	3,335
2003	3,421	0	3,421	294	333	627	2,794

Source: Annual Energy Review, 2003, Energy Information Administration

LNG

Canada and Mexico

Although Canada and Mexico currently have no LNG terminals, there are several projects proposed for both countries.

United States

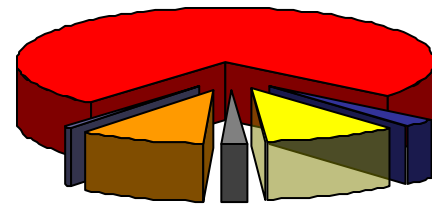
The United States has four active LNG import terminals. Three are located on the East Coast: Everett, Massachusetts; Cove Point, Maryland; and Elba Island, Georgia; and one is located in the Gulf of Mexico: Lake Charles, Louisiana. (There is also an import terminal located in Puerto Rico which supplies a gas-fired cogeneration plant.) The Cove Point and Elba Island facilities were shut down for many years but reopened recently: Elba Inland in 2001 and Cove Point in 2003.

In 2003, the United States imported 507 Bcf of LNG at an average price of \$U.S. 4.50 per MMBtu. Historically, LNG imports represented a small amount of natural gas imports, about 3 percent. From 2000 to 2002 they accounted for about 6 percent of gas imports. LNG imports more than doubled in 2003 from the prior year and now represent 13 percent of the total gas imports. During the past 22 years, the United States has imported LNG from nine different countries. These countries are: Algeria, Australia, Indonesia, Malaysia, Nigeria, Oman, Qatar, Trinidad and Tobago, and the United Arab Emirates.

However, these countries accounted for only about 2 percent of total U.S. gas demand. The Republic of Trinidad and Tobago began supplying LNG to the United States in 1999, and by 2003 more than 75 percent of total LNG imports came from Trinidad.

The Lake Charles facility received almost half of the 2003 LNG imports. Imports into Everett

Figure 42. U.S. LNG Imports by Country of Origin, 2003, Bcf



■ Trinidad -- 378.1	■ Qatar -- 13.6
■ Algeria -- 53.4	■ Oman -- 8.6
■ Nigeria -- 50.1	■ Malaysia -- 2.7

Source: U.S. Office of Fossil Energy, U.S. Dept. of Energy

are an important component of local gas supplies; they were 31 percent of total LNG imports, and 44 percent greater than the 2002 level of imports at this facility. Although the Cove Point facility was operational for only the last four months of 2003, it received more than 13 percent of all LNG imports for that year.

The four U.S. LNG import terminals have a maximum storage capacity of 18.7 Bcf and a peak daily deliverability of 3.1 Bcf. On an annual basis, these terminals can deliver a maximum of 1,131.5 Bcf.

Bcf. Expansions at Elba Island and Lake Charles are under construction. When completed, the four terminals will have storage capacity of 24.7 Bcf and a daily deliverability of just over 4 Bcf per day.

FERC has approved two LNG terminals, in Hackberry, Louisiana and in Freeport, Texas, respectively. The Hackberry³⁴ terminal will have a storage capacity of 10.4 Bcf and a daily deliverability of 1.5 Bcf. The Freeport terminal will have a storage capacity of 7 Bcf and daily deliverability of 1.5 Bcf.

³⁴ Named the "Cameron" terminal, the name "Hackberry" refers only to its location in Hackberry Louisiana.

Figure 43. U.S. Natural Gas, Import and Export Points - Pipeline and LNG



The Coast Guard has approved two offshore LNG terminals in the Gulf of Mexico – Energy Bridge and Port Pelican. Energy Bridge will be able to deliver 0.5 Bcf per day and Port Pelican will be able to deliver 1.6 Bcf per day.

There is a LNG terminal located in Kenai, Alaska which exports LNG to Japan. In 1990, 53 Bcf were exported to Japan. In recent years these exports have ranged from 63 Bcf to 66 Bcf, with a level of 64 Bcf in 2003.

In total, there are 19 LNG facilities subject to FERC jurisdiction, including the four terminals in the continental U.S. and the terminals in Puerto Rico and Alaska. The other jurisdictional LNG facilities are used for storage.

In addition to the FERC jurisdictional LNG storage facilities, local utilities have constructed LNG storage facilities primarily for storage in order to meet peak demand. The estimated capacity of these LNG storage facilities is 86 Bcf.

Outlook Section

OVERVIEW

Continued North American cooperation in natural gas production, storage, and delivery will be even more important over the next decade. For all three countries, the demand for natural gas is expected to increase, at a faster rate than production growth. The increased demand for natural gas will be driven by many factors, including population growth, industry consumption, and the environmental benefits of natural gas (compared to other fuels). This increased demand is expected to be between 15 and 25 percent for Canada and the U.S. and over 90 percent for Mexico during the ten-year period (2002 to 2012).

To adapt to these demand increases, there are plans in all three countries to build or expand LNG import capabilities. LNG is the primary form of intercontinental natural gas trading, as natural gas can be transported by ship as LNG over long distances more cheaply than by long sub-sea pipelines. However, whether planned LNG expansions will occur is anything but certain as there are significant regulatory and public perception hurdles to be overcome.

There are also plans for a few large production or pipeline projects over the period to 2012, most notably the Mackenzie Valley Pipeline project, projected by the NEB to begin moving natural gas from northern Canada to markets in 2010.

The price of natural gas is expected to decline slightly over the next several years followed by a gentle climb.

SUPPLY TO 2012

The three countries of North America expect natural gas supplies to increase. North American gas supplies currently total 73.5 Bcf per day. By 2012, this is expected to reach 79 Bcf per day, and 91.4 Bcf per day by 2025.

For the future, significant increases in gas supply from the traditional North American natural gas supply areas appear unlikely—production from traditional Canadian and U.S. gas basins³⁵ in recent years has been flat or declining, despite historically high levels of natural gas drilling. Mexican gas production has also been stagnant, due to a lack of capital spending by Pemex on resource development. Overall, we expect production from these traditional areas of North America to decline³⁶, even as unconventional gas production in these areas increases. However, the traditional areas of Canada, the U.S., and Mexico will remain by far the largest sources of natural gas supply to North America for the foreseeable future. In 2002 these areas supplied 98 percent of North America's gas, and by 2012, they are still expected to provide 87 percent of North American supply.

This report finds that the largest single source of additional gas supplies for North America will come from LNG imports. All three countries expect to import considerable LNG volumes in the future. Overall, North American imports of LNG could reach 7.9 Bcf per day by 2012.

Other new supplies, in rough order of importance, will include: increased development of unconventional gas (coalbed methane, shale gas, tight gas); U.S. Rocky Mountain development (which includes much unconventional gas); U.S. Midcontinent development; additional development in Mexico (particularly via Multiple Services Contracts); the onset of production from northern Canada's Mackenzie Delta; and

³⁵ Traditional basins are those of the U.S. Lower-48, the U.S. Gulf of Mexico offshore, Western Canada, onshore Mexico, and the Mexican Gulf of Campeche.

³⁶ Mexican production is expected to increase somewhat. However, this increase cannot compensate for the declines in conventional Canadian and U.S. areas.

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increased frontier Canadian offshore gas development.

Canada

Canadian natural gas production in 2002 was 17 Bcf per day. Of that amount, 97 percent originated in the conventional gas reservoirs of Western Canada, and 3 percent came from the eastern Canadian offshore frontier (the Sable Offshore Energy Project offshore Nova Scotia). Canadian supply is currently much larger than Canadian demand, and 60 percent of production is exported to the U.S.

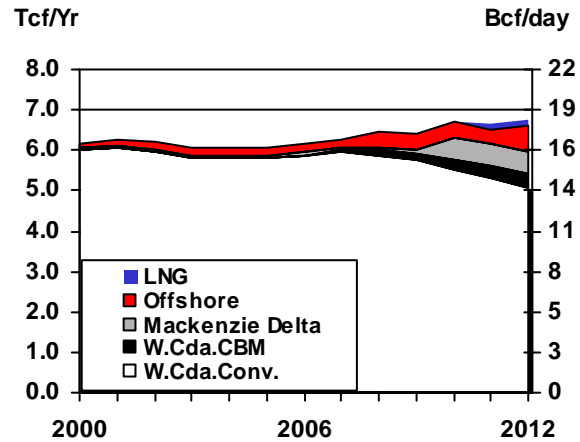
Figure 44 shows the Canadian natural gas supply outlook of the National Energy Board (NEB). This outlook was developed in 2003 after rigorous analysis and extensive consultation with industry. The NEB developed two scenarios: The Supply Push (SP) scenario envisions a relatively low pace of technological improvement, but societal choices which allow producers to access land for drilling. The Techno-Vert (TV) case assumes sensitivity to the environment, less land access, but much higher technological improvement and gas recovery factors.

In both the SP and TV cases, Canadian gas supply grows slowly to 2012, reaching about 18.5 Bcf per day.

In both cases, conventional production from Western Canada is expected to remain stable until 2008 at about 6 Tcf per year (16.4 Bcf per day), and then begin to decline fairly dramatically, falling to the 13.9 – 14.3 Bcf per day range by 2012.

Coalbed methane production in Western Canada is projected to grow slowly, from current levels of less than 0.5 Bcf per day to 1.0 Bcf per day by 2012.

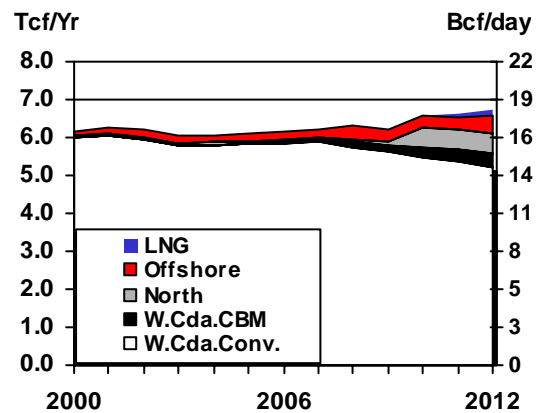
Figure 44a. Canadian Natural Gas Supply Outlook, Supply Push Case



Source: NEB, 2003

The Mackenzie Valley Project includes a pipeline from Inuvik, Northwest Territories, to a tie-in with the existing pipeline grid in northern Alberta. The regulatory approval process for this project has begun, with a preliminary information package having been filed with the National Energy Board. The NEB, in its 2003 Canada's Energy Future Report, projected this project to be on line and producing 1.2 Bcf per day by 2010.

Figure 44b. Techno-Vert Case



Source: NEB, 2003

Frontier supplies from Canada's east coast offshore are expected to increase from 0.5 Bcf per day in 2003 to the 1.3 - 1.7 Bcf per day range by 2012. Several specific projects have been identified. The first is an expansion of

the Sable Offshore Energy Project. This is currently the only natural gas production area in Canada's offshore. Within the Sable project are several producing fields, and several fields not yet connected. As the new fields are connected, production is expected to increase.

It is expected that the Deep Panuke project, a discrete field within 5 km of Sable, will be developed. In addition, the NEB projects one other undetermined project in offshore Nova Scotia to be found and developed within the period to 2012.

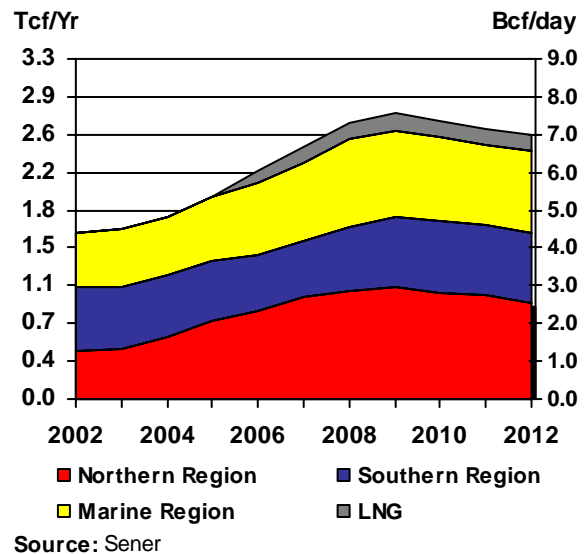
Finally, the NEB projects that supply from domestic Canadian production is expected to be augmented by LNG imports beginning in 2011. However, project proponents are now targeting LNG imports as early as the end of 2007. As of October 2004, there were eight proposals to construct LNG import facilities in Canada, six of which had completed or were then undergoing a regulatory review process. This included three projects in the Maritimes, two of which were well advanced, two projects in Quebec, that were in the early stages of the regulatory review process, and one project in BC, which had just begun the review process. Two additional projects (one in British Columbia and one in Nova Scotia) had been announced but had not yet begun any regulatory reviews.

Mexico

Currently, Mexican natural gas production is 4.5 Bcf per day. Of that amount, 1.2 Bcf per day originates in the Northern region (mainly nonassociated gas from the Burgos Basin), while 3.3 Bcf per day originates in the southern and offshore regions (mostly associated gas).

Figure 45 shows the Medium Case, Risk-adjusted Scenario of SENER. This outlook was developed by SENER at the end of 2003

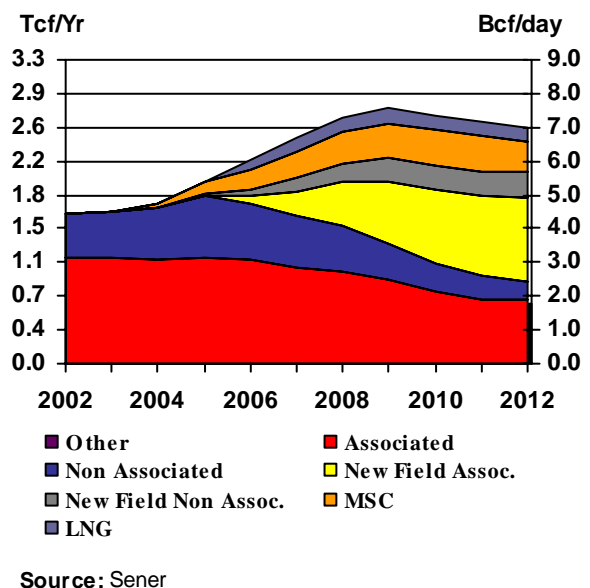
Figure 45a. Mexican Natural Gas Supply Outlook, Supply by Region



with input from Pemex. This figure shows the production increases by geographic area and also by activity or type.

Total Mexican natural gas production is expected to increase from the current 4.5 Bcf per day level to 7 Bcf per day by 2009, and then to decline slowly to 6.5 Bcf per day by 2012.

Figure 45b. Supply by Type



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Production increases will be driven by a Mexican/Pemex initiative to raise production – the Gas Strategic Program. This plan has four principal elements: a) reactivation of exploration in areas of greater potential; b) special focus on nonassociated gas reserves, c) reaching production in levels comparable with international practices, and d) the implementation of the Multiple Services Contracts.

The plan anticipates a focus on the Burgos Basin for the exploitation of gas, but also a renewed focus on the areas of Veracruz, Macuspana and the continental platform of the Gulf of Mexico.

Part of the net gas production increase will be achieved via the use of Multiple Services Contracts (MSCs). The Multiple Services Contract is a public work contract based upon unitary prices, in which the property of hydrocarbons and the executed work is always kept by Mexico's Federal Government and Pemex. Regardless of the production level, the contractor receives a cash payment based on unitary prices for the execution of the work. Consequently, this contractual scheme is neither a concession, nor a risk-sharing contract of production or of shared profit. It simply groups together, in a single contract, different services that Pemex has always hired. In 2004, gas production resulting from MSCs is expected to be 0.14 Bcf per day; by 2010, this is expected to reach 1.1 Bcf per day. The Appendix of this document provides more background on the Multiple Services Contract programs.

Most of Mexican production growth is expected to be from the Northern region, where production is expected to increase from 1.2 Bcf per day in 2002 to 2 Bcf per day by 2012. The Marine region's production is forecast to grow from 1.5 Bcf per day in 2002

to 2.1 Bcf per day by 2012. Southern region production is expected to remain flat at 1.8 Bcf per day.

Liquefied Natural Gas (LNG)

On July 31 2003, Mexico approved³⁷ the construction of an LNG import terminal at Altamira, Tamaulipas. This terminal is expected to begin operations in the fourth quarter of 2006, with output of 300 MMcf per day by 2010 and 500 MMcf per day by 2011. Gas output will be used to supply Comisión Federal de Electricidad (CFE) gas-fired combined cycle power plants Altamira V, Tuxpan V, and Tamazunchale, adjacent to the states of Tamaulipas, Veracruz and San Luis Potosí.

Terminals are also being considered for the municipalities of Ensenada, Baja California, Lázaro Cárdenas Michoacán, Manzanillo and Colima on the Pacific Coast, and Topolobampo, in Sinaloa, and Puerto Libertad in the state of Sonora.

Furthermore, there is an offshore project proposed by Chevron Texaco which is currently under the CRE's inspection. The project is to be located 13 kilometers from the Tijuana's coast, in Baja California, just beside the Islas Coronado. The terminal will have a peak re-gasification capacity of 1 Bcf per day.

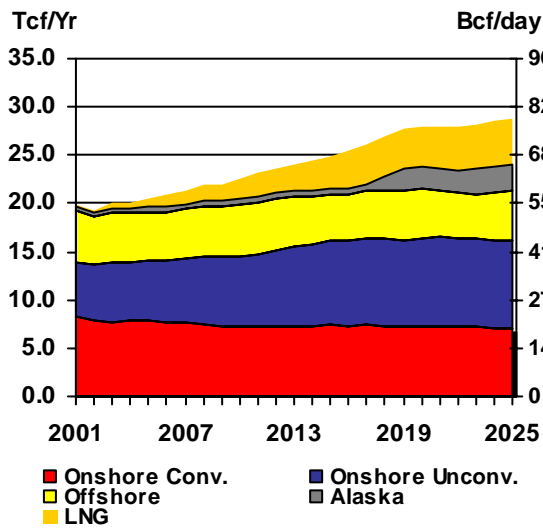
SENER is forecasting total LNG imports to Mexico reaching 0.075 Bcf per day in 2006, climbing to 0.500 Bcf per day by 2012.

United States

The U.S. natural gas production in 2002 was 52 Bcf per day. Of that amount, 41 percent was from conventional onshore Lower-48 reservoirs, 31 percent from unconventional

³⁷ CRE. RES/145/2003.

Figure 46a. U.S. Natural Gas Supply Outlook, Reference Case



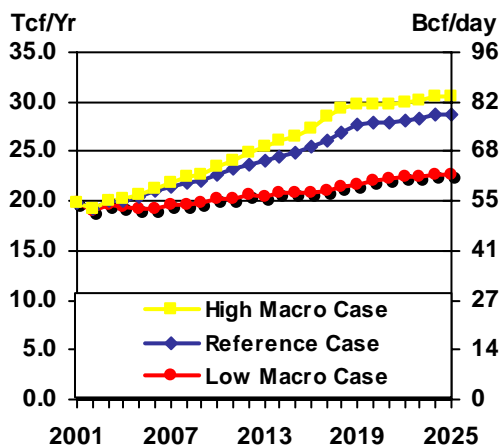
Source: EIA, 2004

Note: Associated Gas Included in Conventional

onshore reservoirs, 26 percent from the offshore, and 2 percent from Alaska.

Figure 46 shows the reference case, U.S. natural gas production plus LNG imports outlook of the U.S. Energy Information Administration’s Annual Energy Outlook 2004 (AEO 2004). The figure also shows a comparison of supply under the high and low macroeconomic cases. Total U.S. gas production is expected to rise from 52 Bcf per day in 2002 to 57.9 Bcf per day in 2012 and 65.7 Bcf per day by 2025.

Figure 46b. A Comparison of Cases

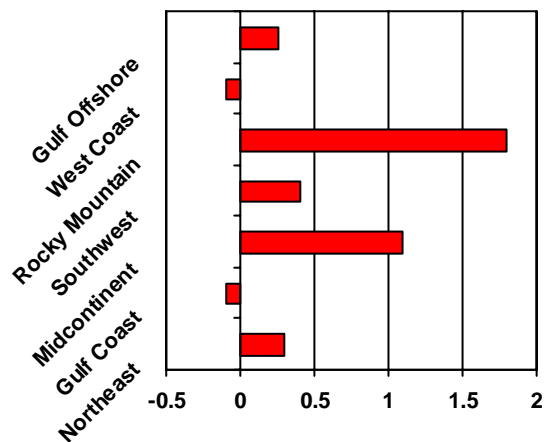


Source: EIA, 2004

U.S. onshore Lower-48 conventional gas supplies are expected to remain relatively stable over the period to 2025, at about 19.4 Bcf per day. Although projected drilling levels are projected to increase because of higher prices, declining rates of production per well mean that more and more wells are needed just to maintain current levels of production. The drilling of deeper wells in conventional reservoirs is expected to slow the overall decline in conventional onshore gas production. The number of new Lower-48 natural gas wells is expected to increase throughout the projection period, from 16,155 wells in 2002 to 15,665 wells in 2010 and 17,160 wells in 2025.

As a result of technological improvements and rising natural gas prices, natural gas production from unconventional sources (tight sands, shale, and coalbed methane) is expected to increase at a faster growth rate than conventional production. Under the Reference Case, U.S. onshore unconventional gas supply (coalbed methane, tight gas, shale

Figure 47. Projected U.S. Natural Gas Production Growth by Region, in the Reference Case, 2000 - 2012. Incremental Change in Production, Tcf



Source: EIA

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gas) is expected to increase from about 16.2 Bcf per day in 2002 to 21.5 Bcf per day by 2012, and 25.1 Bcf per day by 2025.

In the Reference Case, Lower-48 offshore natural gas production is projected to decline slightly through 2006, when the offshore is projected to produce 13.7 Bcf per day of natural gas. After 2006, offshore gas production is projected to increase slightly, reaching 14.5 Bcf per day in 2012, and then decline to 13.8 Bcf per day in 2025. In the Reference Case, the offshore's share of total U.S. gas production declines from 26 percent in 2002 to 25 percent in 2012.

An Alaskan natural gas pipeline is not projected to be built and in operation by 2012. Consequently, Alaskan gas production is projected to grow only slightly during the period to 2012, reflecting the expected growth in gas consumption and production around the Cook Inlet in Southern Alaska. Alaskan production in 2012 is projected to be 1.7 Bcf per day. The reference case projects an Alaska pipeline by 2018. In that year, Alaskan production jumps to 4 Bcf per day, and then climbs to 7.4 Bcf per day by 2025.

The natural gas production profiles for the Low and High Macroeconomic Cases are

fundamentally similar to those expected for the Reference Case. The main difference between the three scenarios is the relative proportion of unconventional gas production. In the Low Macroeconomic Case, unconventional gas production accounts for 36.5 percent of total U.S. production in 2012, compared to 37.2 percent for the Reference Case. In the High Macroeconomic Case, unconventional gas production is expected to account for 37.9 percent of total U.S. production in 2012.

Regionally, onshore natural gas production is expected to increase in Northeast, Midcontinent, and Rocky Mountain gas production regions, while Gulf Coast, Southwest, and West Coast gas production is projected to decline. U.S. regions are shown in Figure 48.

The largest increase in U.S. natural gas production through 2012 is projected to come from the Rocky Mountain region, predominantly from unconventional resources. Rocky Mountain natural gas production is expected to increase by 4.6 Bcf per day between 2002 and 2012. The next largest increase in U.S. gas production is expected from the offshore Gulf of Mexico region, which is projected to increase production by

Figure 48. U.S. Natural Gas Production Regions



Source: U.S. FERC

about 1.2 Bcf per day between 2002 and 2012. Other production increases are projected for the Northeast and Midcontinent regions, which are expected to increase gas production by about 0.3 Bcf per day and 0.4 Bcf per day, respectively.

From 2002 through 2012, onshore gas production in the Gulf Coast, Southwest, and West Coast is projected to collectively decline by about 0.1 Bcf per day. Offshore Pacific gas production is projected to decline by 0.1 Bcf per day between 2002 and 2012.

LNG

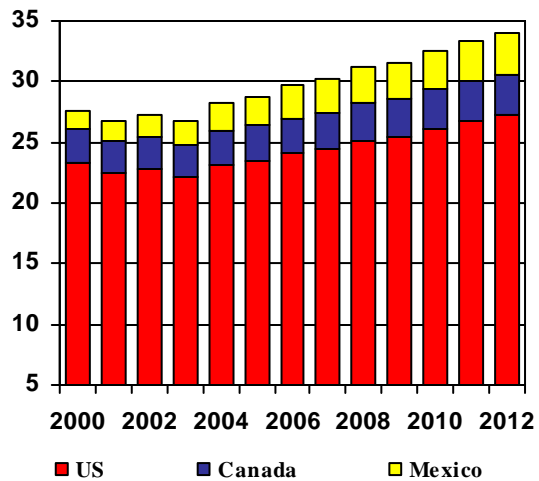
The most significant change in U.S. gas supply is projected to be the increased importation of LNG. In the AEO2004 Reference Case, net LNG imports are expected to increase from 0.5 Bcf per day in 2002 to 7.1 Bcf per day 2012, and 13.2 Bcf per day by 2025.

In contrast, during the 2002 – 2012 period, domestic gas production is projected to grow by only 1.1 percent per year from 52 Bcf per day in 2002 to 57.8 Bcf per day in 2012. Of the 11.2 Bcf per day increase in total U.S. gas supplies from 2002-2012, about 60 percent is projected to be satisfied by LNG imports, while the remainder will be provided by increased domestic production.

DEMAND TO 2012

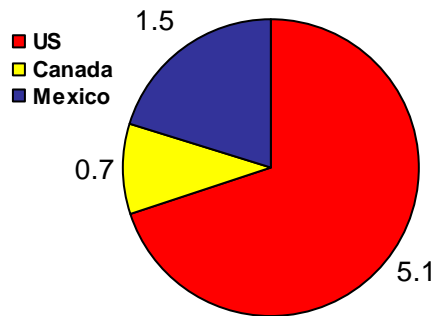
North American natural gas demand is expected to consistently grow as we move towards 2012. This is due to many reasons, including stricter environmental standards encouraging the use of natural gas, the construction of relatively cheap and efficient combined cycle natural gas power plants, and the continued penetration of natural gas infrastructure into the furthest corners of North America.

Figure 49a. North American Natural Gas Demand Outlook, Tcf



Sources: Sener, NEB (avg of TV and SP cases), EIA reference case

Figure 49b. Share of Total Demand Growth, Tcf



Total 2003 - 12 Demand Growth = 7.3 Tcf

Source: See Figure 49a.

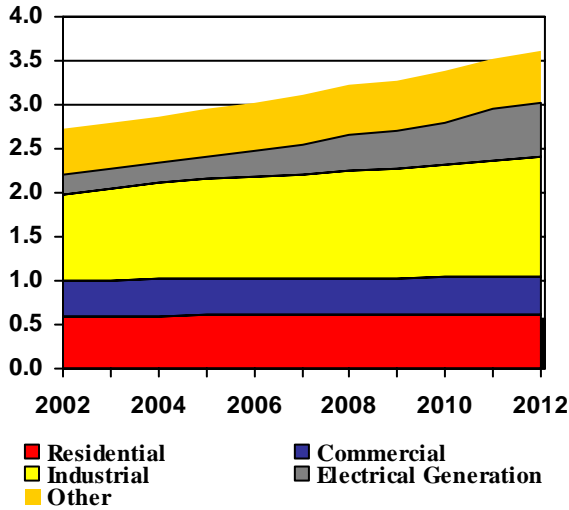
All sectors are expected to at least maintain current levels of consumption and most expect increases. Natural gas consumption for electricity generation is expected to boom and this sector is projected to more than double by 2012.

Canada

The NEB predicts continued growth of natural gas demand to 2012. In the Techno-Vert scenario, Canadian gas demand increases from

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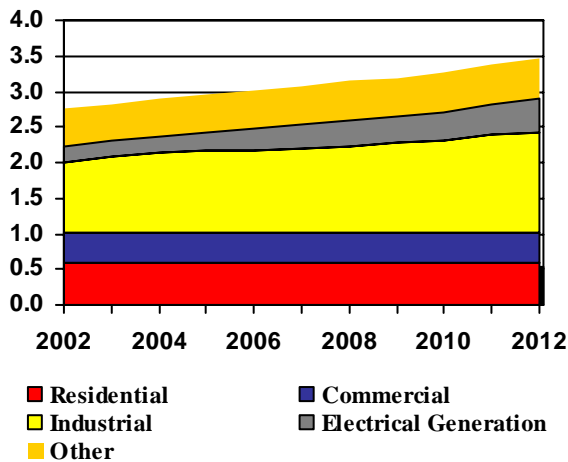
Figure 50a. Canadian Natural Gas Demand Outlook, by Sector, Supply Push Case, Tcf/Year



Source: NEB

2.75 Tcf to 3.46 Tcf in 2012, an increase of 26 percent. In the Supply Push scenario, demand increases from 2.75 Tcf to 3.62 Tcf, an increase of 33 percent. Under both scenarios, gas for electrical generation is the largest engine of demand growth - more than doubling between 2002 and 2012. However,

Figure 50b. Canadian Natural Gas Demand Outlook, by Sector, Techno-Vert Case Tcf/Year



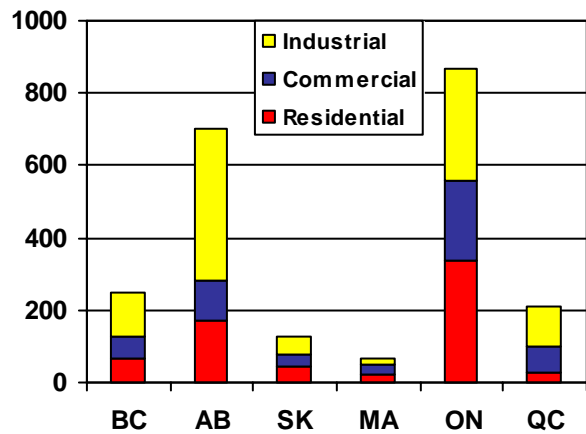
Source: NEB

the industrial sector remains the largest sector in 2012, capturing 41 percent of Canadian natural gas demand in the Techno-Vert scenario, and 37 percent in the Supply Push scenario.

Currently, Canadian natural gas consumption is split exactly in half between eastern and western Canada. However, the split between residential and commercial demand and industrial demand is not even. The majority of residential and commercial gas demand is found in the east, where the majority of Canadians reside, and the majority of industrial gas demand is found in the west, where the natural gas-related industrial sector has congregated around the production area of the Western Canada Sedimentary Basin (WCSB).

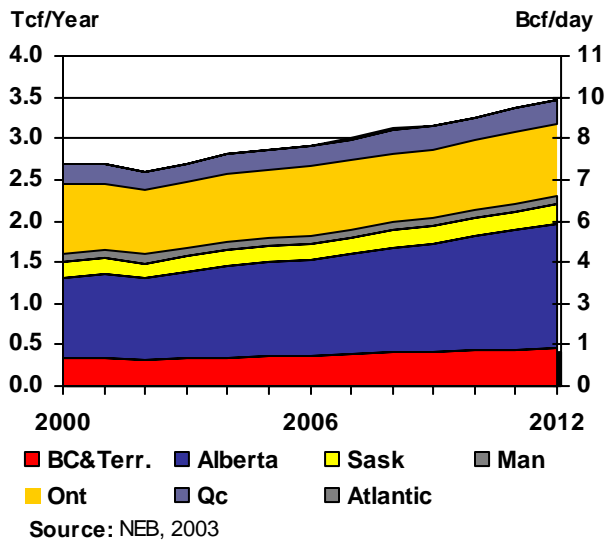
Over the next ten years, Canadian gas demand is expected to move towards the west, with industrial gas demand increasing substantially. This is primarily due to increased use of gas in Alberta power generation and the growth in demand for natural gas by oil sands projects in northern Alberta.

Figure 51. Canadian Regional and Sectoral Demand, Bcf



Sources: StatsCan, NRCan Estimates

Figure 52a. Canadian Natural Gas Demand Outlook, by Region, Supply Push Case



Alberta natural gas consumption is expected to increase considerably, driven by increases in gas used for power generation and for extraction and processing of oilsands. Over the 2003 - 2012 period, gas use for oil sands extraction or processing is expected to increase by 66% - 101%, or from 220 Bcf in 2003 to the 365 - 442 Bcf range in 2012.

Figure 52b. Canadian Natural Gas Demand Outlook, by Region, Techno-Vert Case

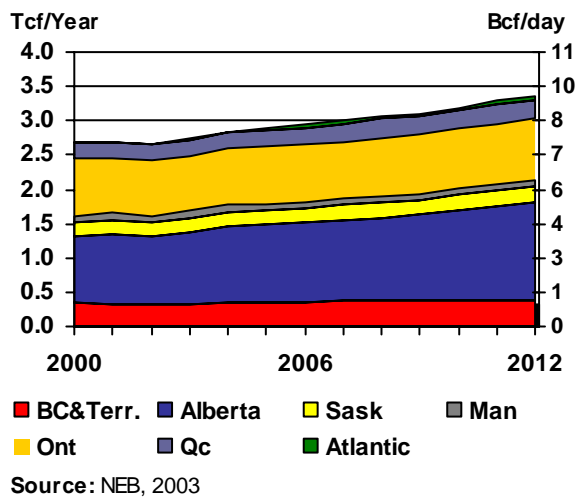


Figure 53a. Historical and projected Alberta Gas Demand, Supply Push Case, Bcf

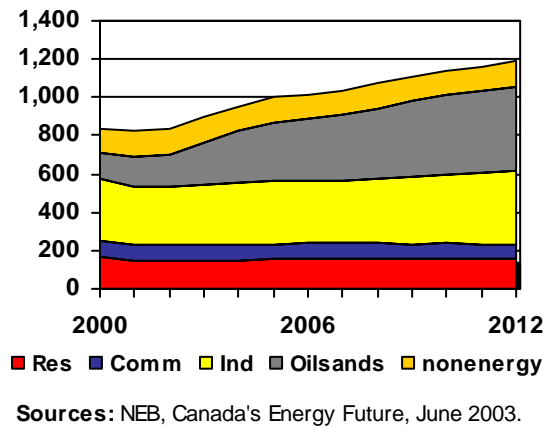
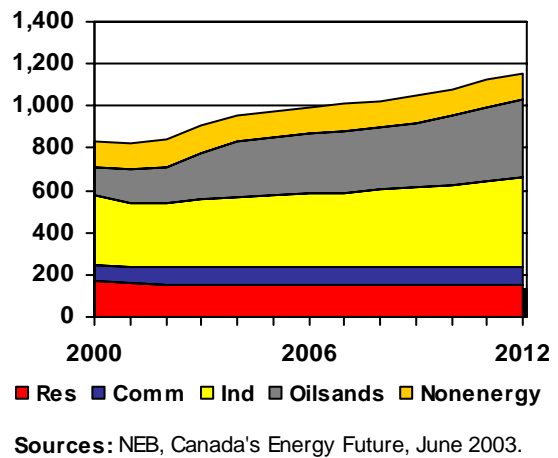


Figure 53b. Techno-Vert Case, Bcf



Mexico

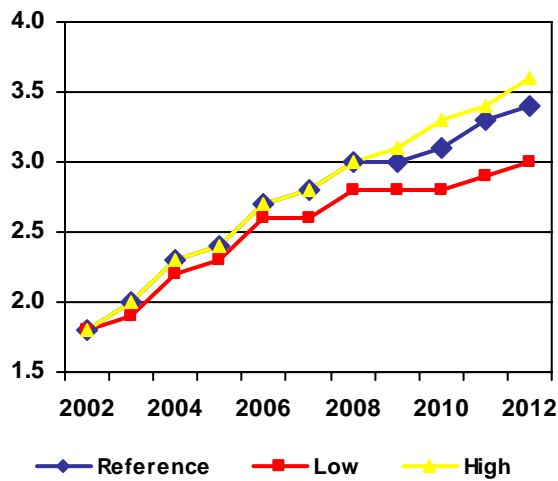
During the next 10 years, the national demand for natural gas is expected to reach an average annual growth rate (aggregate) of 6.8 percent, growing from 1.8 Tcf in 2002 to 3.4 Tcf in 2012 (See figure 54).

Electric Sector

In order to produce the necessary energy for Mexico to maintain its development path, the electric sector sustains a great part of its expansion in the combined cycle technology which embodies technical efficiency and

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Figure 54. Total Projected Mexican Natural Gas Consumption, Tcf



Source: Sener

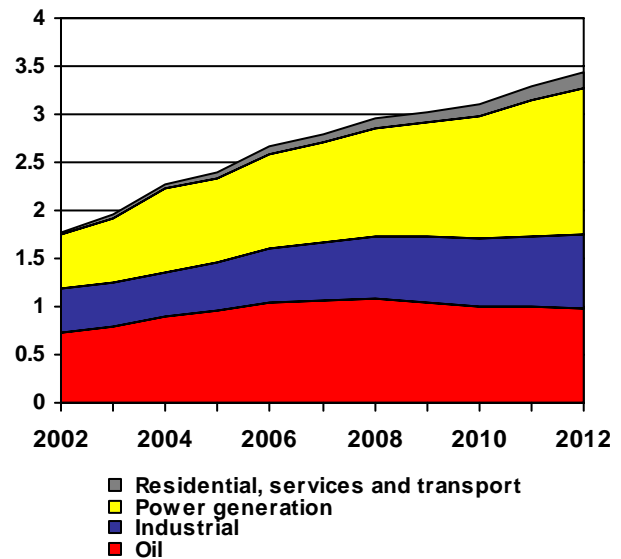
productivity. The Comisión Federal de Electricidad (CFE) and the Independent Power Producers (IPP) will drive regional development and environmental protection with this technology.

The national electric sector will be the biggest consumer of natural gas. Its natural gas requirements will increase from 0.5 Tcf consumed in 2002, to 1.5 Tcf in 2012, which represents an annual average growth rate of 10.8 percent.

The expected evolution of natural gas consumption considers population growth, total consumption intensity within large industries, observation of environmental norms and the evolution of the expected relative prices of gas and fuel oil, among others. For this reason requirements for this fuel will almost triple in the next 10 years and will represent 44.5 percent of total demand in 2012.

Natural gas demand in the electric sector considers the gradual displacement of fuel oil consumption as a consequence of the

Figure 55. Mexican Natural Gas Demand by Sector, Tcf



Source: Sener

observation of environmental rules. In 2004, the effect of fuel oil substitution for natural gas will represent 12.5 percent of total consumption. During 2003-2012, the substitution will represent 5.8 percent of total demand.

Industrial and Oil Sectors

The industrial sector will absorb 22.5 percent of total national market consumption towards the end of 2012. These projections include the petrochemical project Fénix whose start up date is expected in 2008.

Currently, 41 percent of natural gas consumption takes place in the oil sector. Pemex uses this hydrocarbon as fuel in refineries for gas lift and to generate electric power. In accordance with the estimates of each Pemex subsidiary, without including Pemex Petroquímica (PPQ), it is expected that the total consumption of natural gas will grow at an annual average rate of 3 percent, from 0.7 Tcf in 2002 to 1 Tcf in 2012. Towards the

end of the period, Pemex will account for 28.6 percent of total national consumption.

Residential and Services Sector

The introduction of natural gas in the residential and services sectors has been slower than expected due to the difficulties distributors have faced fulfilling their pipeline installation programs. It is expected that consumption in these sectors will reach 0.1 Tcf in 2012, and account for 5.4 percent of national demand.

The services sector will show a similar trend to that of the residential sector. The demand is estimated to rise from 22.4 MMcf per day in 2002 to 92.6 MMcf per day in 2012. The different growth rates by region will depend on the population level. The same occurs in the residential sector.

Transport Sector

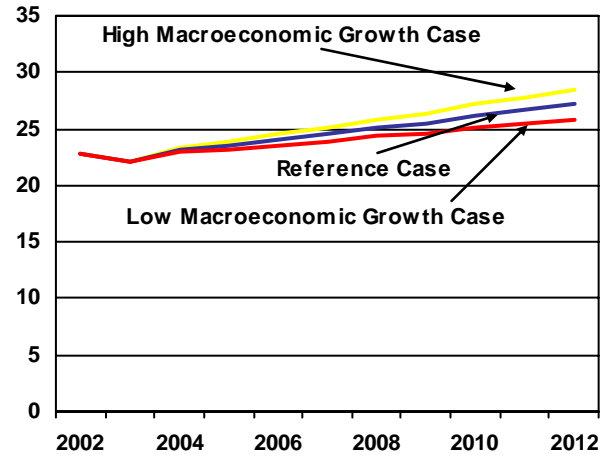
The transport sector represents a very weak market with several factors that have limited its development. In 2002 its consumption was 1.9 MMcf per day, which will increase to 54 MMcf per day by the year 2012. Consequently, its share of gas demand in 2012 will be approximately one percent.

The estimated consumption of natural gas by this sector is based mainly on the expectations expressed by the sector’s key players and by natural gas distribution companies involved in the business. These players believe that, while a wide market exists which follows to the growing dynamics of the vehicular market, the main investment opportunities are only for intensive use transport vehicles.

United States

Future economic growth rates largely determine the level of future natural gas

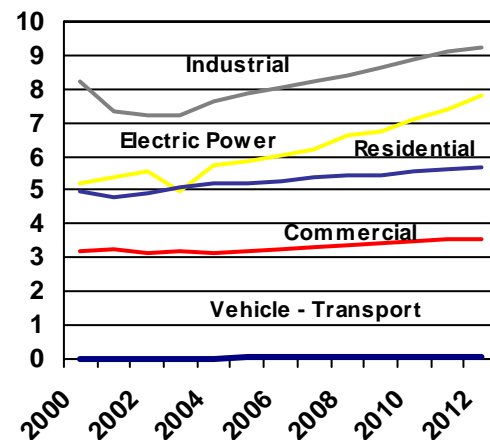
Figure 56. Projected Total U.S. Natural Gas Consumption for Three Cases, 2002 - 2012.



Source: EIA

consumption in the United States. Higher rates of future economic growth result in higher gas consumption levels. For the period encompassing 2002 through 2012, the average annual growth in Gross Domestic Product (GDP) is 3.2 percent per year for the Reference Case, 2.7 percent per year for the

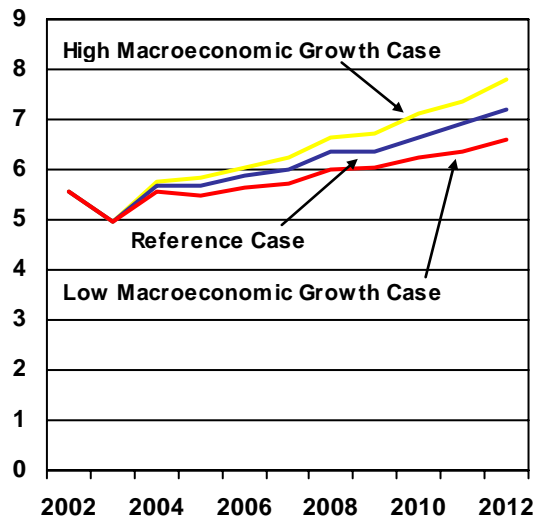
Figure 57. Projected U.S. Natural Gas Consumption by Sector, for the Reference Case, 2000 - 2012, Tcf per year



Source: EIA

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Figure 58. Projected U.S. Natural Gas Consumption - Electric Sector, in Three Cases, 2002 - 2012, Tcf/Yr



Source: EIA

Low Macroeconomic Growth Case, and 3.8 percent per year for the High Macroeconomic Growth Case. The Low and High Macroeconomic Growth Case project 2012 total gas consumption levels of 25.8 and 28.5 trillion cubic feet, respectively. The Reference Case projection for total U.S. consumption in

2012 is 27.2 trillion cubic feet.

Natural gas consumption is expected to increase in all five end-use sectors in the Reference Case. The greatest growth in gas consumption is expected to occur in the electric power sector, which increases from 5.7 trillion cubic feet in 2002 to 7.2 trillion cubic feet in 2012. Most new electricity generation capacity is expected to be fueled by natural gas. Although average coal prices are expected to decline, natural gas-fired generators are expected to have advantages over coal-fired generators, including lower capital costs, higher fuel efficiencies, shorter construction lead times, and lower emissions.

Industrial sector gas consumption is projected to increase from 7.6 trillion cubic feet in 2002 to 8.7 trillion cubic feet in 2012. Gas consumption in the residential and commercial end-use sectors is projected to collectively increase by 1.2 trillion cubic feet from 2002 through 2012. Vehicular transportation gas consumption is also expected to grow, but this sector's consumption reaches only 70 billion cubic feet per year in 2012.

Figure 59. United States Census Divisions



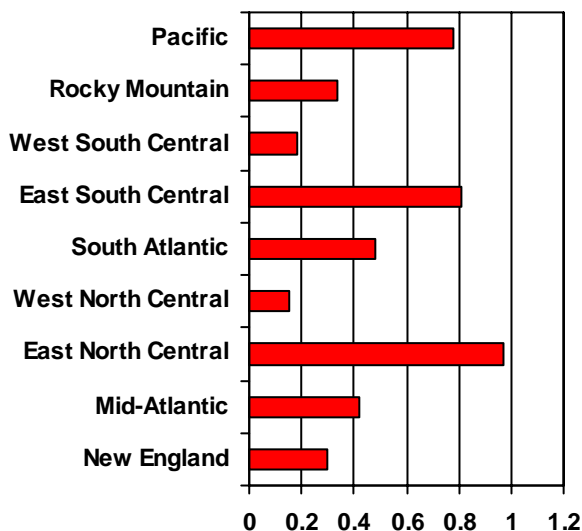
Source: EIA

Electric Power Natural Gas Consumption

Electric power gas consumption is expected to show the greatest growth in gas consumption. Because electricity consumption growth rates are largely determined by the rate of economic growth, electric power gas consumption is expected to show the greatest variance between the three cases. The Reference Case projects 2012 electric power gas consumption to be 7.2 trillion cubic feet per year. In comparison, the Low and High Macroeconomic Growth Cases project electric power gas consumption to be 6.6 and 7.8 trillion cubic feet per year in 2012, respectively.

Natural gas consumption is projected to increase in all nine U.S. Census regions. The gas consumption projections by region largely reflect the projected trends for economic, demographic, and industrial activity. Consequently, most of the growth in U.S. gas consumption occurs east of the Mississippi and along the Pacific Coast.

Figure 60. Projected U.S. Natural Gas Consumption Growth, Incremental Consumption, Tcf



Source: EIA

In 2002, 48 percent or 11.0 trillion cubic feet of the U.S. natural gas end-use consumption is east of the Mississippi River. By 2012, this percentage is projected to remain at 48 percent or 12.3 trillion cubic feet of total U.S. natural gas consumption. The greatest gas consumption growth occurs in the East North Central census region, which increases by 1.0 trillion cubic feet between 2002 and 2012.

In contrast, western natural gas consumption is projected to increase by 2.0 trillion cubic feet per year during the forecast period. About 780 billion cubic feet per year of this increase is projected to occur in the West South Central census region.

TRADE TO 2012

Canada, Mexico and the United States have a strong trading relationship in natural gas that is expected to continue into the future. As the North American economy continues to grow and expand, so will its energy supply needs. Natural gas demand is increasing throughout North America and the rest of the world. This will put greater focus on trade, both inside North America and with outside suppliers of LNG, and on the need for this trade to be carried out in safe, environmentally sound, efficient and affordable ways.

All three nations recognize the growing need for natural gas and are taking measures to work toward a fully cooperative market in order to best be able to produce, import and export, transport, and distribute natural gas to meet demand. Currently, while gas trade is significant, there are some remaining economic, infrastructure and regulatory barriers to the expansion of natural Gas trade and the development of supply in Canada, Mexico and the United States.

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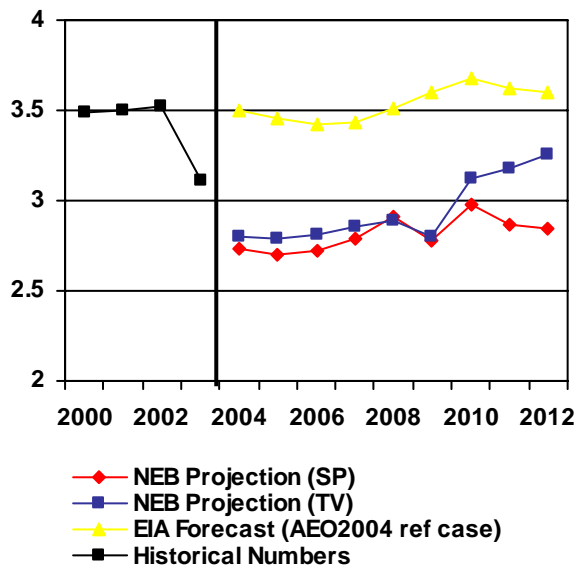
Growing demand as well as the inability to develop all indigenous supplies at cost-competitive rates is making LNG a likely possibility to fill the gap between natural gas production and consumption. In order to meet consumption needs in North America, it is projected that North American markets will need to develop LNG receiving capability in Canada and Mexico, and expand it in the United States, therefore enhancing the region's ability to access suppliers outside of the region. The global LNG market will be increasing and maturing in the future and it is important to maintain North America's ability to access and efficiently trade the necessary amounts of this important source of energy.

Canada

Pipeline Trade with the U.S.

Canada is involved in two-way natural gas trade with the U.S. Canada to U.S. exports are much larger than U.S. to Canada exports, and Canada is a large net exporter to the US. In 2003, Canada to U.S. natural gas exports were

Figure 61. Canadian Natural Gas Exports to the U.S., Tcf



Source: NEB, EIA

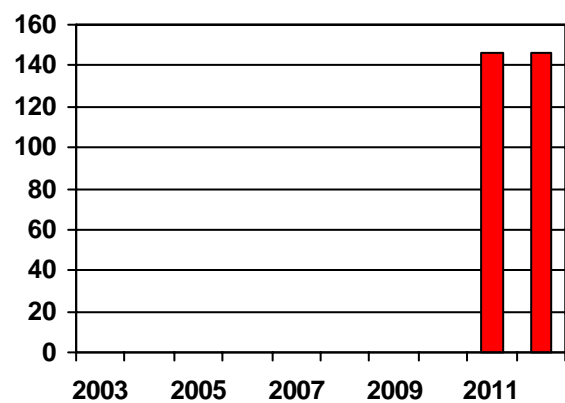
3.5 Tcf, while imports were 0.3 Tcf. This resulted in net exports in 2003 of 3.1 Tcf. Imports from the U.S. have grown dramatically over the past 4 years, rising from 50 Bcf in 1999, to over 370 Bcf in 2003. Canadian natural gas net exports to the U.S. are expected to remain relatively stable through 2012. Over the forecast period, pipeline trade with the United States will remain very large.

Current Canada to U.S. pipeline capacity should be roughly sufficient to meet the needs of natural gas exporters and importers. However, some additional natural gas pipeline capacity may be necessary, particularly given the potential for LNG imports to eastern Canada, and expanded production offshore eastern Canada.

Trade via LNG

As of 2004, there were no LNG import terminals in Canada. However, the NEB projects that there will be one LNG import terminal in operation by 2011, which would import approximately 146 Bcf of natural gas per year.

Figure 62. Canadian Liquefied Natural Gas Imports, Bcf

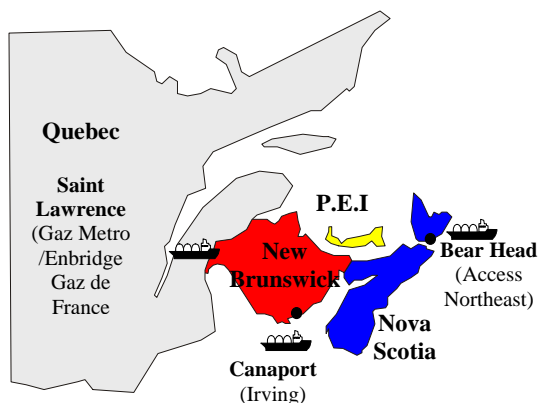


Source: NEB

However, it is possible that this level of LNG imports will be exceeded. As of October 2004, three of the eight Canadian LNG import terminal projects had been proposed by operators. Of these, six projects had completed or were then undergoing a regulatory review process, while the other two had not yet begun regulatory review. Two projects in the Maritimes were well advanced -- the Anadarko project in Nova Scotia, and the Irving project in New Brunswick. These two projects were expecting to receive all required regulatory approvals by year-end 2004. If these two projects proceeded at their announced capacity levels, by 2008 they would be importing a total of 730 Bcf per year. Regasified natural gas from Canadian LNG imports would target domestic Canadian markets as well as US export customers.

If all three projects are constructed and they meet the design and construction goals, by 2008 they will be importing a combined 1.75 Bcf of LNG per day, or 639 Bcf per year. This is much more optimistic than the NEB projection and would equal approximately 22 percent of Canadian demand in 2008. Thus far, none of the projects have been approved for construction.

Figure 63. Canadian Liquefied Natural Gas Proposals



Source: NEB

Mexico

While Mexico currently projects that it will continue to import U.S. gas through 2012, growth in demand will also be met by many strategies. Aside from pipeline imports, another of the strategies to guarantee natural gas supply and to diversify the supply sources has been to promote re-gasification terminals to import liquefied natural gas (LNG). Under this policy, in September 2003, a decision was made on the construction of an LNG terminal for the electric sector's supply in the area of Altamira, Tamaulipas, which will supply the combined cycle plants Altamira V, Tuxpan V and Tamazunchale, adjacent to the states of Tamaulipas, Veracruz and San Luis Potosí.

This plant is programmed to begin operations in the fourth trimester of 2006 with a demand from CFE of 300 MMcf per day by 2010 and of 500 MMcf per day by 2011. In this way, the power stations of Tuxpan V, Altamira V and Tamazunchale will be supplied.

One project which is currently being considered is a proposal by Chevron - Texaco to develop and operate an inshore regasification LNG terminal, located beside the Islas Coronado, in the state of Baja California.

In the municipality of Ensenada, Baja California, three companies plan to build three LNG terminals in order to supply the electric sector; opening the possibility of export to the North American market. Even though the three projects already have all of their permits, it is expected that only one of them will be developed and begin operations in 2008.

CFE has also been promoting the possibility of carrying out another bidding process for a similar re-gasification plant on the Pacific Coast. Also, Topolobampo, in Sinaloa, is considered a potential area for the future

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installation of a micro LNG terminal, and will be associated with Lázaro Cárdenas as a support terminal. Finally, there is one potential LNG reception project in Puerto Libertad, in the state of Sonora.

United States

U.S. domestic natural gas production is expected to rise more slowly than consumption during the forecast period. The growing gap between U.S. gas consumption and production is projected to be filled by increased gas imports. All of this increase in U.S. natural gas imports is projected to be imported as liquefied natural gas (LNG), because foreign LNG is expected to be cost competitive with North American gas production, and overall North American gas production is expected to decline.

Until recently, net LNG imports accounted for less than 1 percent of total gas supply. In 2003, LNG imports more than doubled and constituted about 2 percent of the total gas supply. LNG imports in the United States are expected to increase in all 3 AEO2004 cases. In the Reference Case, net LNG imports are projected to be 2.6 trillion cubic feet per year in 2012. In the Low and High Macroeconomic Cases, net LNG imports are expected to be 2.0 and 2.8 trillion cubic feet, respectively. This projection is based on the expectation that all four operating LNG import terminals (i.e., Cove Point, MD; Everett, MA; Lake Charles, LA; and Elba Island, GA) will be expanded, and that several new LNG facilities will be operational by 2012, with most of the new LNG terminal capacity being built along the Gulf of Mexico.

While LNG supply to the United States is likely to be from foreign sources, there is increasing diversity in supply options and significant movement toward a global LNG commodity market. In general, natural gas is

not so heavily traded as oil, and international gas markets are relatively young and immature. While more than 50 percent of the world's oil crosses an international border before it is consumed, only about 20-25 percent of natural gas is traded internationally and most of this moves by pipeline. LNG accounts for about 25 percent of world gas trade, which translates to about 6 percent of global gas consumption.

LNG relies on ship-borne delivery that makes it an attractive natural gas source for coastal markets. In the United States those markets are generally in highly populated areas at the extreme end of the pipeline system. LNG imports are, and will continue to be, particularly important in providing gas to meet the needs of supply-constrained U.S. east coast markets. LNG can account for over 30 percent of gas supply in New England during peak winter demand periods. The rapid decline in delivered LNG costs makes LNG an attractive, cost-competitive, baseload natural gas option in these markets. However, siting new pipeline capacity in these markets is increasingly difficult. Therefore, even though LNG terminals are best sited near large urban gas consumption markets, most of the U.S. LNG terminals are projected to be built in the Gulf of Mexico where permitting and licensing is expected to be less difficult. These terminals would be located within a well developed pipeline infrastructure system, subsequently allowing the LNG gas to flow to every major U.S. consumption market.

The construction of new LNG terminals could entail lengthy and difficult regulatory delays. However, two recent developments – the FERC's "Hackberry" decision and the amendment of the Deepwater Port Act – are expected to reduce the regulatory delays associated with constructing new U.S. LNG terminals. FERC's December 2002 Hackberry decision permits LNG regasification terminals

to negotiate market-based rates, and not be subject to FERC's open-access transportation and cost-of-service rate regulations. The Hackberry decision essentially treats LNG regasification terminals as non-jurisdictional production facilities. In making this decision, the FERC has reduced the regulatory burden and delays imposed by the legal "due process" requirements associated with its open-access transportation and cost-of-service rate regulations.

Many offshore LNG regasification terminals have been proposed, because it is thought that these facilities potentially will not face the degree of opposition anticipated for siting new land-based LNG terminals. In November 2002, the U.S. Congress passed and the President signed the Maritime Transportation Security Act of 2002, which amended the Deepwater Port Act. This legislation establishes that the Maritime Administration (of the Department of Transportation) and the U.S. Coast Guard (of the Department of Homeland Security) have jurisdiction over the construction of offshore LNG terminals. This lowered the regulatory hurdles faced by developers of offshore LNG regasification terminals by not requiring the terminal capacity to be open access (similar to the Hackberry decision for onshore LNG terminals discussed above). It also required that a decision be rendered within a year of the filing of an application for the construction of an offshore LNG terminal.

PRICES TO 2012

Future natural gas prices in North America will be influenced by a variety of factors: the size and quality of the North American natural gas resource, drilling rates, economic growth, weather, world crude oil prices, access to imported LNG, interest and inflation rates, and many other factors.

In particular regional natural gas market areas, local prices will also be affected by local factors, such as the adequacy of pipeline connections to the broader North American pipeline grid, local demand and supply characteristics, and the availability of local storage.

Growing awareness of the limited size and quality of the North American natural gas resource endowment has been playing a determinative role in North American natural gas prices over the past few years. The major gas producing regions of the U.S. Gulf Coast and Western Canada have seen production and reserve discovery rates flatten, calling into question their ability to keep supplying markets with ever-increasing volumes of natural gas. A general difficulty in growing North American gas supply, combined with strength in gas demand, has led to higher natural gas prices since 2000, and higher expectations for future natural gas prices.

On the demand side, future rates of economic growth across North America will be an important determinant of the growth in future natural gas consumption. Generally, higher rates of economic growth cause higher levels of future gas consumption, which in turn, cause higher gas price levels. Similarly, lower rates of economic growth cause lower wellhead gas prices.

World crude oil prices also impact natural gas demand and prices, via fuel switching between natural gas and oil. The degree to which oil remains a substitute for natural gas, and the price of oil, will influence gas prices in the future.

Access to imported gas will play an increasing role in the price of gas in the future for North America. With the assumption that the bulk of North American increases in gas demand will be met by imported LNG, different dynamics

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will begin to play on North American natural gas prices, such as the availability of infrastructure to allow LNG imports, and the price for LNG in world markets.

Finally, the development of remote and unconventional North American gas resources, and the timing and cost of needed infrastructure additions for development of those resources, could also affect prices. The cost of developing and transporting gas over longer distances from frontier areas, and the cost of environmental and regulatory compliance in such remote or potentially sensitive areas could have important implications for North American natural gas prices.

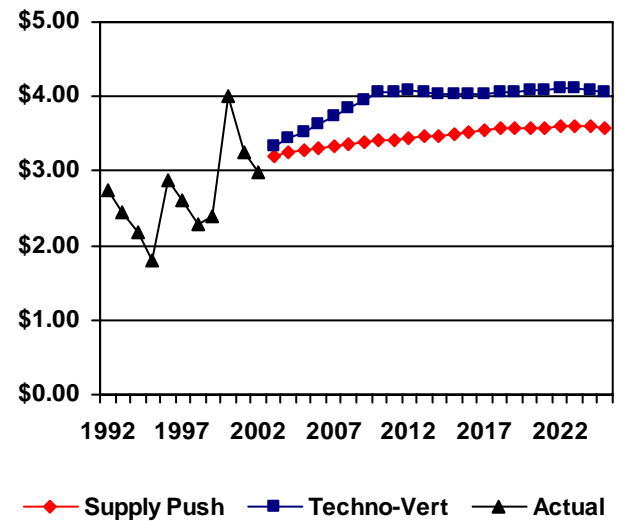
Canada

The NEB's price assumptions are shown in figure 64. The NEB's price assumptions, provided in *Canada's Energy Future*, quoted prices at the Henry Hub, in Louisiana. This was done in recognition of the inter-related nature of U.S. and Canadian natural gas markets, and the fact that Henry Hub is the largest North American gas market and the most often quoted price point.

There will always be price differentials between U.S. and Canadian natural gas markets. Generally Canadian gas prices are somewhat less than U.S. prices. This reflects the differences in the supply/demand balances in the two countries. The U.S. has more demand than indigenous supply, imports approximately 17 percent of its natural gas needs, and generally has higher prices. In contrast, Canada exports over half of its gas production, and generally has lower prices.

Canadian prices tend to track U.S. prices, but at a lower level. The difference in Canadian and U.S. prices tends to be roughly equal to the cost of pipeline transmission from the

Figure 64. Nymex Natural Gas Prices at Henry Hub, \$US 2001/MMBtu



Source: NEB

relevant Canadian to U.S. market point. Figure 65 shows historical monthly differentials between Henry Hub and two major Canadian natural gas market points (AECO, the intra-Alberta market, and Dawn, the Dawn, Ontario market hub). As shown, typically Alberta prices are somewhat lower than Henry Hub, while Dawn prices are somewhat higher than Henry Hub.

The NEB's fundamental assumption on future North American natural gas prices is that oil and oil products will be good substitutes for natural gas in North America in the future, and this will mean a strong linkage between world crude oil prices and North American natural gas prices.

In particular, the NEB expects world crude oil prices will average 2001 \$U.S. 22 per barrel (West Texas Intermediate) to 2012, and this will result in Henry Hub natural gas prices at the following levels:

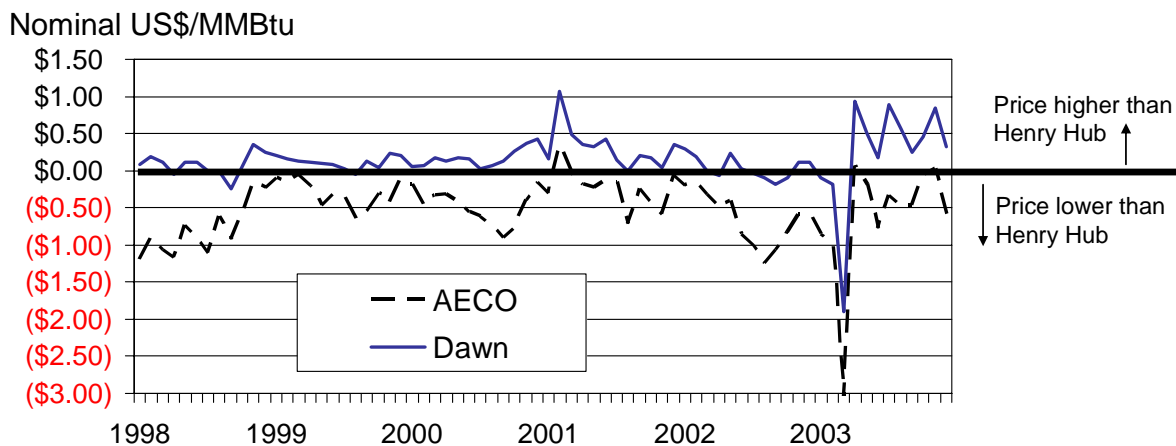
- Henry Hub prices at \$U.S. 3.50/MMBtu by 2012 under the Supply Push Scenario.

- Henry Hub prices at \$U.S. 4.09/MMBtu by 2012 under the Techno-Vert scenario.

The primary reason that the Techno-Vert price is expected to be higher is that the TV case assumes a stronger preference for natural gas over other non-renewable fuels (e.g. crude oil, coal) in the future due to the environmental benefits of gas. This means that although natural gas prices remain linked to crude oil prices, users are prepared to pay a premium for gas, due to its environmental benefits.

come solely from the U.S. Therefore, Mexico decided that making the Southeastern U.S. natural gas market the price reference for the Mexican system was the natural choice. For these reasons, Mexico does not forecast prices at Mexican market points, but rather references U.S. market point price projections instead.

Figure 65. Historical Canadian Price Relationships with Henry Hub



Source: NEB

Mexico

Mexican projections recognize that Canadian, Mexican and U.S. natural gas prices are strongly linked. Mexican natural gas prices are indexed to U.S. prices by regulation. Consumers in Mexico have few alternative sources of natural gas. Therefore, there is not a competitive market in place. The objective is to get the right price signals for consumers in the Mexican market, trying to reflect the opportunity cost of the fuel.

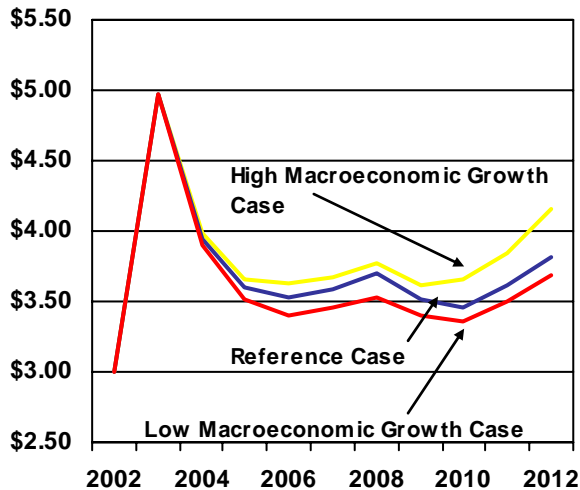
The domestic natural gas balance for Mexico shows a deficit which Pemex has to solve by importing natural gas. Currently, these imports

United States

In the AEO2004 Reference Case, average wellhead natural gas prices are expected to increase to \$U.S. 3.75 per thousand cubic feet (2002 U.S. dollars) in 2012. Technically recoverable resources are expected to be adequate to support the gas production increases in the three scenarios. As United States gas resources are depleted, however, wellhead natural gas prices are expected to increase, causing net gas imports to increase their share of total U.S. gas consumption from 15 percent in 2002 to 22 percent in 2012.

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Figure 66. Projected Average U.S. Wellhead Natural Gas Prices, in Three Cases, 2002 - 2012. 2003 \$US per Mcf



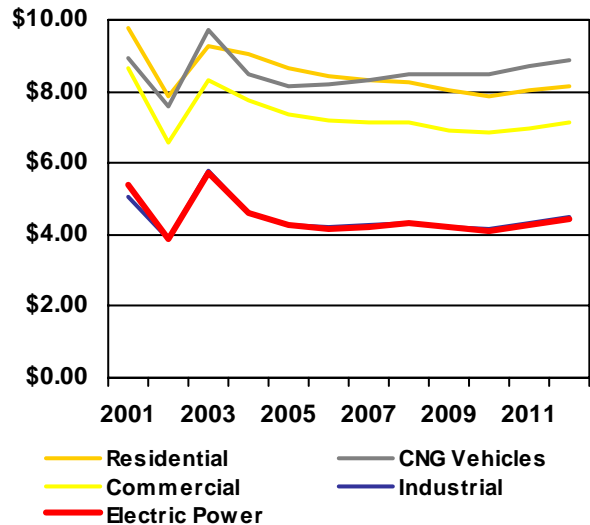
Source: EIA

Under the Low Macroeconomic Growth Case, wellhead gas prices are expected to reach \$U.S. 3.62 per thousand cubic feet (2002 U.S. dollars) in 2012, while the High Macroeconomic Growth Case projects 2012 wellhead prices to be \$U.S. 4.10 per thousand cubic feet (2002 U.S. dollars).

End-use natural gas prices are expected to decline in the early part of the forecast, from their relatively high levels in 2002, followed by a gradual increase starting in 2005 as a result of increasing wellhead prices. A portion of the increase in wellhead prices is expected to be offset by a projected decline in the average transmission and distribution margins as a larger proportion of the natural gas delivery infrastructure becomes fully depreciated.

The relative magnitude of the natural gas transmission and distribution margin reflects both the volume of gas delivered and the infrastructure requirements of the particular sector. For example, the margin associated with compressed natural gas vehicles is

Figure 67. Projected U.S. Delivered End Use Prices, in The Reference Case, 2000 - 2012. 2003 \$US per Mcf



Source: EIA, AEO 2004

expected to increase, because the cost of refueling infrastructure must be added to serve non-fleet vehicles. Conversely, the industrial and electric power sectors have the lowest end-use prices, in part because they receive most of their natural gas directly from interstate pipelines, thereby avoiding local distribution charges. Summer-peaking electricity generators reduce their transmission costs by using lower cost interruptible transportation rates during the summer when spare pipeline capacity is available. However, as electric generators take an increasing share of the gas market, they are expected to rely more on higher cost firm transportation to a greater extent.

ISSUES BEYOND 2012

North America's natural gas issues beyond 2012 will be similar to the issues that are present today, such as reconciling demand growth with continental production stagnation or even decline; facilitating more LNG imports when there is local opposition to

terminals in many places; building infrastructure such as pipelines, storage, and wells when there is local opposition to such development; the size and quality of remaining natural gas resources; investment capital for the development required by market demand for gas; and the conflict between public desire for preserving certain lands or resources and natural gas producers' desire for access to those lands for drilling.

LNG looks to be a key additional source of gas beyond 2012, with imports possibly reaching 14.8 Bcf per day by 2025. However, to realize that vision, facilities will need to be built in North America, including receiving terminals and additional pipelines to assure this resource can get to market.

Unfortunately, many potential LNG supply sources lack sufficient liquefaction and export facilities, and in many cases the natural gas resources and production capacities are undeveloped. Subsequently, considerable investment will be required before this gas can reach North America as LNG.

At this point, more LNG facilities have been proposed in North America than need to be built under the rosier demand scenarios. It is expected that competition between proponents for limited LNG supply and financing will result in most proposals being shelved.

Arctic gas supplies from Canada's Mackenzie Delta, and from Alaska in the U.S., are also expected to play a significant role in meeting demand in the out years. Again significant investment is required.

Canada

Supply

The availability of future natural gas supplies has become the major issue facing the

Canadian natural gas market for the long term. According to the NEB's projections, Canadian natural gas supply will begin to decline after 2012, while domestic Canadian demand continues to increase. This will mean adjustments for exports, for throughput on major pipeline corridors, and for gas consumers.

In such an environment, accessing and developing existing conventional, unconventional and frontier sources of natural gas will be important. As production levels from conventional sources in western Canada mature, unconventional supplies such as coalbed methane (CBM), frontier gas and LNG will be encouraged. The NEB projects that these three sources of natural gas supply will account for over 50 percent of Canadian supply by 2025, in comparison to less than 1 percent in 2003.

The size of Canada's natural gas resource base continues to be a significant uncertainty, especially the frontier regions and unconventional sources, such as CBM. Through exploration drilling and development, industry's knowledge of the Western Canada Sedimentary Basin (WCSB) has improved, and successive estimates over time are now beginning to stabilize.

In contrast, very little development of unconventional natural gas has occurred to date; consequently, the uncertainty associated with estimates of unconventional natural gas resources, or for projections of future production, is high.

Similarly, estimates of resources for most of the frontier regions have a much greater degree of uncertainty than estimates for the WCSB, reflecting the limited state of exploration in those areas. Some of these regions, such as the Arctic Islands, may have discovered resources but are not expected to

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produce any natural gas pre-2025 due to the high cost of developing production and transportation facilities in remote areas.

Another supply uncertainty is LNG. The NEB projects that imports of LNG will reach 438 Bcf by 2018, or 7 percent of total Canadian natural gas supply. However, with new announcements of Canadian LNG import terminal projects occurring regularly, LNG imports in the future could be even larger.

Demand

The NEB projects that Canadian natural gas demand will continue to increase past 2012. However, the impact of falling Canadian supply past 2012 will mean significant market adjustments will be necessary, primarily in the industrial sector. These will likely take the form of fuel switching from gas to other fuels. Developers of oil sands projects and electric power generators may be pressured to reconsider their reliance on natural gas. Impacts on residential and commercial consumers would also be felt, especially in the form of higher and more volatile prices.

Canada/U.S. Natural Gas Trade

As Canadian natural gas production declines after 2012, while demand increases, changes to export and import patterns with the U.S. will result. These changes will be driven by regional natural gas supply and demand balances, prices, transportation costs between regions, and other factors. Gas buyers will act rationally, seeking out the lowest delivered natural gas costs, while sellers will pursue the highest netback prices. This could result in lower Canada-to-U.S. gas exports, and higher U.S.-to-Canada exports.

Infrastructure

Given its flat supply, Canada currently has more excess pipeline capacity than deliverability along several pipeline corridors leading away from Western Canada. In the future, development of Alaska and Mackenzie Delta gas could change this dynamic. For other corridors, as new supply is developed, pipelines will require expansion.

For example, increases in natural gas production expected for the east coast offshore will require pipeline expansions to reach markets. As LNG projects on Canada's east coast are built, these will also require new pipeline capacity for the regasified product to reach markets.

Totally new capacity will have to be built to transport Mackenzie Delta Arctic gas to the existing Canadian pipeline grid, which begins in northern British Columbia and Alberta.

Mexico

Supply

In the long term, the Mexican energy sector has as a fundamental challenge to continue supplying the country with the energy it requires and to support the sustained development through the use of fuels that protect the environment.

Without important changes in current technological conditions, and assuming that, to a certain extent, the use of combined cycle dominates the electric generation sector, it is foreseen that meeting the demand for natural gas will be one of the main issues for the Mexican energy sector. In order to meet this demand and to diversify imports, the fundamental strategies will continue being the increase of natural gas domestic production

and the development of LNG regasification terminals.

However, under the current legal framework, supply growth will depend principally upon the federal government's budgetary resources, the success of exploratory activities and the incremental growth in reserves. Furthermore, priority should be given to exploratory and exploitation programs of non associated natural gas and light crude oils. In a complementary manner, Pemex will have to continue developing new trading schemes to increase its capacity.

The increase of domestic natural gas production levels would translate, first of all, into important savings through a reduction of the southern Texas natural gas market price as well as possible northward movement of the price formula arbitrage point. Secondly, it would have a positive impact on the country's trade balance and would strongly favour the natural gas industry since residential as well as industrial consumption of this cleaner fuel would be fostered.

The need for new technologies for natural gas extraction is also a key issue for the coming years. As the need to develop natural gas reserves grows, Pemex will need to develop or acquire new technologies to rapidly-and-efficiently produce increasing amounts of the much needed fuel.

Trade and LNG

A fundamental element of an efficient natural gas industry is to have an adequate supply system. In the medium and long run, it is expected that the expansion of private investment in infrastructure will continue. Of great importance will be to continue promoting the construction of natural gas interconnection projects with the southwestern United States. The goal is to have a

transport system that allows access to the U.S. market from different demand points. If these interconnections are not increased, the development of the different economic sectors that use the fuel in their processes will slow down.

Even though trade via pipeline between the United States and Mexico is expected to continue to play a fundamental role, there is some concern with the ability of the southern United States to continue supplying gas to Mexico. Because of these concerns, and in consideration of the federal government's limited financial resources to increase natural gas production, a policy aimed at guaranteeing the supply of natural gas, diversifying sources and promoting market flexibility, has been designed. This policy requires the utilization of LNG as an alternative supply source.

This market segment offers investment opportunities in ports on the Mexican Pacific shoreline, where the lack of an interconnected infrastructure with the National Pipeline System is both a challenge and an investment opportunity.

The development of these terminals will depend mainly on the linkage of each project to anchor demand points, the procurement of the required permits for their construction, and assurances from supply sources available in world markets. It is important to notice that these investment opportunities for LNG are open to private participants as well as to the CFE and Pemex.

Demand

In the long term, it is expected that the greatest natural gas consumer will continue to be the electric sector. Expansion and modernization plans are based on combined cycle power. These projects have either just begun or will begin in the coming years and

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are considered to have an expected life of at least 30 years. For that reason, the use of natural gas will continue to be fundamental within the power sector.

It is estimated that within the industrial sector, the industries with intensive natural gas utilization, such as the steel industry, will decrease their consumption as new inputs improve efficiency, implying shorter productive processes. However, it is estimated that the low consumption industries such as the food, beer or paper industries, would increase their natural gas consumption, thus contributing to a growing dependency on this fuel.

In the residential sector, a greater penetration of natural gas is expected, in substitution for liquefied petroleum gas (LPG) due to the broadening of local distribution networks.

Fuel Substitution

Within some co-generation projects, primarily in the oil industry, the use of residual fuels, such as vacuum residuals, is foreseeable in order to achieve savings in natural gas usage.

The oil sector is one of the main consumers of natural gas in Mexico, especially in oil production activities. Nitrogen injection in wells for the extraction of crude oil is feasible, because it is cheaper than the use of natural gas. Currently, nitrogen is injected in some fields in the Marine Regions, and there are also some projects under study in the Southern Region where nitrogen or CO₂ are scheduled to be injected depending upon the condition of the deposits.

Prices

A determining factor in the demand for natural gas in some sectors will be the price behaviour. Prices will also influence

investment decisions and can be a key factor for the development of LNG projects. Mexico's ability to have an impact on North American natural gas markets will increase if both domestic production is increased and LNG projects move forward.

United States

Supply

Substantially higher natural gas prices in recent years has led to a reevaluation of expectations about future trends in natural gas markets, the economics of exploration and production, and the size of the natural gas resource. The EIA's Annual Energy Outlook 2004 (AEO2004) forecast reflects these revised expectations, projecting greater dependence on alternative supplies of natural gas, such as imports of liquefied natural gas (LNG), with expansion of existing terminals and development of new facilities, and remote resources from Alaska and from the Mackenzie Delta in Canada, with completion of the Alaska Natural Gas Transportation System and the Mackenzie Delta pipeline. All of these assumptions of where the gas is going to come from have with them uncertainties on how the gas will be developed and whether the facilities will be in place to bring the gas to market.

Demand

Based on EIA long-term forecasts, U.S. natural gas consumption is projected to increase from 23.0 Tcf in 2002 to 26.2 Tcf in 2010 and 31.4 Tcf by 2025. Domestic gas production is expected to increase more slowly than consumption over the forecast period, rising from 19.0 Tcf in 2002 to 20.5 Tcf in 2010 and 24.0 Tcf by 2025. The difference between consumption and production will be made up by imports, which

are projected to rise from net imports of 3.5 Tcf in 2002 to 7.2 Tcf by 2025.

Trade

U.S. projections call for LNG to become the largest source of net U.S. imports by 2015. Net pipeline imports from Canada are expected to reach 3.7 Tcf in 2010, before declining as Canadian fields mature and Canadian demand increases. Mexico is expected to continue to be a net importer throughout 2025, although U.S. imports are expected to be used mainly to supply industry located on the United States–Mexico border. EIA projects that overall U.S. exports to Mexico will decline after 2005 as LNG terminals in Baja California, Mexico come online, which are expected to supply both the Mexican market and nearby U.S. markets.

The economics of a fully integrated North American market would assure that gas would move across borders between the U.S. and Mexico and Canada, finding the most efficiently accessed demand.

CONTINUING CONCERNS

Any restraints to the free flow of trade across borders would hamper the efficiency of the North American market. Further, significant investment needs to be made to realize the development of LNG and remote gas supplies. Environmental requirements and concerns regarding the development of supplies and facilities must also be addressed in order to realize the projected sources of gas for North America beyond 2025.

List of Acronyms

AEO	Annual Energy Outlook (U.S.EIA)	NGR	Natural Gas Regulation
AGA	American Gas Association	NPC	U.S. National Petroleum Council
Bcf	Billion cubic feet	NRCan	Natural Resources Canada (Canadian Energy Dept.)
CBM	Coalbed methane	OCSLA	U.S. Outer Continental Shelf Lands Act
CRE	Comisión Regulatoria de Energia (Mexican Energy Regulatory Commission)	Pemex	Petróleos Mexicanos (Mexican State Owned Oil and Gas Company)
CFE	Comisión Federal de Electricidad (Mexican State Owned Electric Utility)	PND	Mexican National Energy Development Plan
DOE	U.S. Department of Energy	SENER	Secretara de Energia (Mexican Energy Secretariat)
EIA	U.S. Energy Information Administration	Tcf	Trillion cubic feet
FERC	U.S. Federal Energy Regulatory Commission	U.S.	United States
FTA	Canada-U.S. Free Trade Agreement	\$U.S.	United States Dollars
GATT	General Agreement on Tariffs and Trade	WCSB	Western Canada Sedimentary Basin
IMP	Instituto Mexicano del Petróleo		
LDC	Local Distribution Company		
LNG	Liquefied Natural Gas		
LPG	Liquefied Petroleum Gas		
Mcf	Thousand cubic feet		
MMBtu	Million British thermal units		
MMcf	Million cubic feet		
MAC	Multi-stakeholder Advisory Committee		
MW	Mega Watts		
NAEWG	North American Energy Working Group		
NAFTA	North American Free Trade Agreement		
NEB	Canadian National Energy Board (Regulatory Agency)		
NEPA	U.S. National Environmental Policy Act		
NGA	U.S. Natural Gas Act of 1938		
NGPA	U.S. Natural Gas Policy Act of 1978		

CENTRAL PLAYERS

Canada

Natural Resources Canada (NRCan)

Regulators:

Natural Resources Canada (NRCan) has responsibility for developing federal energy policies, and for advising the Minister of NRCan and the Government of Canada on energy matters. The National Energy Board (NEB), which is responsible for regulation of interprovincial and export pipelines, and for regulation of natural gas imports and exports, reports to the Canadian Parliament through the Minister of Natural Resources Canada.

Producers:

There are hundreds of natural gas producing companies in Canada.

Marketers:

Marketers act as sellers of natural gas for producing companies, or as buying agents for natural gas consumers.

Pipeline Companies:

Pipeline companies move natural gas long distances in high-pressure pipelines. Major Canadian pipeline companies include TransCanada Pipelines (operating in Alberta, British Columbia, Saskatchewan, Manitoba, Ontario, and Quebec); Duke Energy Gas Transmission (Formerly known as Westcoast Energy, operating in British Columbia); Alliance Pipeline (operating in British Columbia, Alberta, and Saskatchewan); TransQuébec and Maritimes (operating in Québec); Maritimes and Northeast Pipeline (operating in Nova Scotia and New

Brunswick); and Enbridge (part owner of the Alliance Pipeline and owner of Union Gas).

Local Distribution Companies:

Local distribution companies in Canada typically own a franchise right to distribute all natural gas in a certain geographic area. The largest Canadian distributors are BC Gas, Centra Gas BC, (both of British Columbia); Atco Gas (Alberta); SaskEnergy (Saskatchewan); Centra Gas Manitoba (Manitoba); Union Gas and Enbridge Distribution (both of Ontario); Gaz Métropolitain (Quebec); and Enbridge Gas New Brunswick (New Brunswick).

Local Regulation:

The local distribution rates are regulated by provincial regulatory boards or commissions or directly by a provincial government as shown below:

- Newfoundland and Labrador - Board of Commissioners of Public Utilities.
- Prince Edward Island – Island Regulatory and Appeals Commission.
- Nova Scotia - Nova Scotia Petroleum Directorate.
- New Brunswick - New Brunswick Board of Commissioners of Public Utilities.
- Québec - Régie de l'énergie.
- Ontario - Ontario Energy Board.
- Manitoba - Public Utilities Board.
- Saskatchewan - Department of Industry and Resources.

Appendix

- Alberta - Alberta Energy and Utilities Board (AEUB).
- British Columbia - British Columbia Utilities Commission.
- Northwest Territories - Public Utilities Board of the NWT.
- Nunavut - Department of Public Works and Services.
- Yukon - Department of Energy, Mines and Resources.

A number of other federal departments and groups contribute to the regulation of natural gas in Canada. For example, the Canada - Nova Scotia Offshore Petroleum Board is the independent joint agency of the Governments of Canada and Nova Scotia responsible for the regulation of petroleum activities in the Nova Scotia Offshore Area. Federal departments such as Environment Canada administer the Canadian Environmental Assessment Act. Other key players include Transport Canada and Department of Fisheries and Oceans.

Mexico

Ministry of Energy (SENER), which defines national energy policy.

Petróleos Mexicanos (Pemex), which is formed by subsidiary organisms: Pemex Exploración y Producción, which is in charge of exploration and production of oil and gas; Pemex Gas y Petroquímica Básica, which carries out natural gas processing, transmission and marketing; Pemex Refinación, which is responsible for the refining, distribution and trading of oil products; Pemex Petroquímica, is responsible for the production and distribution of secondary petrochemical products; and Pemex

Internacional, which is in charge of international trade.

Comisión Reguladora de Energía (CRE), is in charge of regulating permits for transmission, distribution and storage of natural gas, monitoring the open access regime in gas transmission and distribution, and verifying that there is no cross-subsidization among market functions.

Pipeline Companies

The enterprises that own the pipelines and facilities for the transmission of gas. Major pipeline companies are Petróleos Mexicanos – Pemex Gas y Petroquímica Básica, Kinder Morgan Gas Natural México, Gasoductos de Chihuahua, Igasamex Bajío, Energía Mayakan, Tejas Gas de Toluca, FINSA Energéticos, Transportadora de Gas Zapata, Gasoductos del Bajío, Transportadora de Gas Natural de Baja California, Ductos de Nogales, Gasoducto de Tamaulipas and Gasoducto del Río.

Local Distribution Companies

These are enterprises responsible for the receiving, transmitting, delivering and, if applicable, marketing of gas through pipelines within a geographic zone. Major Mexican distribution companies are Gas Natural México, Tractebel, Gaz de France, Sempra Energy, Compañía Nacional de Gas, Gas Natural del Noroeste, Compañía Mexicana de Gas, Gas Natural de Juárez and Distribuidora de Gas de Occidente.

Power Utilities

In Mexico, Comisión Federal de Electricidad (CFE) is the national State-owned utility that provides these services. This organism is responsible for the generation of electricity and its transmission/distribution for public

service for the entire country excepting Mexico City and its surrounding area; including the states of Mexico Puebla, Morelos and Hidalgo, which fall under the responsibility of Luz y Fuerza del Centro. Domestic and foreign investors are allowed to invest in the generation sector through different modalities. The most important schemes are self supply, cogeneration and independent power producers (IPPs).

United States

FEDERAL:

Federal Energy Regulatory Commission (FERC)

Regulation of facility construction (including environmental review and compliance) and transportation in interstate commerce; regulation of facilities for import and export of natural gas.

Department of Energy

Office of Fossil Energy – Regulation of import and export of natural gas.

Department of Transportation

Office of Pipeline Safety – Administration of national pipeline safety program.

Coast Guard – Authority for siting offshore liquefied natural gas (LNG) facilities.

Department of Agriculture

United States Forest Service – Federal lands stewardship.

Department of Interior - Wildlife conservation, historic preservation and protection of endangered species.

Bureau of Land Management – Federal lands stewardship.

United States Fish and Wildlife Service – Federal lands stewardship.

Minerals Management Service – Federal lands stewardship (Outer Continental Shelf); royalty management (onshore and offshore).

National Park Service – Federal lands stewardship.

Environmental Protection Agency - Management of Federal environmental statutes and regulations.

Department of Commerce

National Oceanic and Atmospheric Administration – Management of coastal zones.

STATE:

State Public Utilities and Services Commissions

Regulation of intrastate pipelines, local distribution companies and the price of natural gas to end-users. Some states regulate the environmental impact of natural gas whether by state laws or by administering Federal statutes by delegation

PRIVATE SECTOR:

Pipeline Companies

Responsible for construction of facilities and transportation services in interstate commerce.

Gas Producers

Gas Gatherers

Appendix

Local Distribution Companies

Industrial Gas Users

Electric Utilities

*Landowners, Environmental Groups,
Consumer Advocate Groups*

Along with those with a direct role in producing and/or transporting natural gas, these groups participate in proceedings at the Federal Energy Regulatory Commission or before state-regulatory bodies as formal interveners or as commenters.

Sources and Notes

Canada

The National Energy Board (NEB) in Canada periodically publishes a long-term outlook for energy supply and demand in Canada as part of its ongoing mandate to monitor energy markets. For this publication, Canada's natural gas projections for supply, demand, and prices are taken from the NEB's recent report, **Canada's Energy Future: Scenarios for Supply and Demand to 2025**, released in early 2003.

This report uses two major scenarios in its supply-demand estimates. The "Supply Push" scenario envisions a low pace of technological development and limited new environmental regulations. In contrast, a high pace of technological development and growing concern for the environment characterizes their "Techno-Vert" scenario.

Mexico

Demand

The natural gas projections are taken from the Natural gas market outlook 2003-2012 that the Ministry of Energy publishes annually in cooperation with Petróleos Mexicanos, Comisión Federal de Electricidad and the Instituto Mexicano del Petróleo.

This document describes and analyzes the country's needs related to the natural gas industry for the next 10 years. Although three demand scenarios and two of supply are presented, this report discusses the reference case demand scenario and the medium supply scenario.

The study contemplates natural gas demand in a regional and sectoral scale based on the estimated growth in the economy for the

following 10 years; as well as a supply analysis.

The Natural gas market outlook is based on research on the end uses of fuels by making inquiries of distributors of fuels, pipeline owners and private industrial companies including private electricity generators. Most data are monthly.

Power sector

The power demand scenario is a result of the coordinated application of econometric sectoral models and of regional estimations sustained in the analysis of historical trends and of the behavior of the sectors in the different zones.

Industrial sector

Main driver:

- Growth of regional Gross Internal Product (GIP) of each group of industries.
- Calculation of Unit Energy Consumption (UEC) by industry.
- Technology Possibility Curves (TPC) as calculated by the National Energy Modeling System.
- Trend forecasts use scenarios of regional growth of industries, taking into account UECs and TPCs.
- Substitution of fuels for cost reasons.
- Substitution of fuels motivated by enforcement of laws for environmental protection in certain so-called *critical zones*.

Sources and Notes

- Substitution of fuels as a consequence of the establishment of new zones of distribution of natural gas.

Residential and Commercial Sectors

- Regional panel regressions for the sum of the consumption of the two main fuels are used in these sectors (LPG and Natural Gas).
- Regressors: population, regional Gross Internal Product, average weighted price of LPG and natural gas.
- Estimation of the share of natural gas in the total demand using a kind of logistic growth curve of market penetration for each of the 21 zones of exclusivity of natural gas distribution, and for three additional zones probably being put up for public concourse in the near future.

The logistic curve presents a maximum percentage of ten years ahead market penetration of natural gas in these sectors for each zone. It is determined by expert opinion of the CRE and the Instituto Mexicano del Petróleo (IMP) and the estimations of the distributing companies themselves.

Transport Sector

Estimation of the per capita road vehicle ownership uses the results of the Dargay & Gately model (2001) in which this variable depends on per capita income in the form of the Gompertz curve.

Price, income and density elasticities of the demand of fuels of vehicles using gasoline, LPG and CNG are based on regression analysis.

Supply

On the supply side, the medium case, risk-adjusted scenario contemplates Pemex Exploración y Producción's (PEP) projects that have authorization to be financed in the coming years and whose development will depend on the existence of budgetary sufficiency, Pemex financing capacity and success in exploratory activities.

The production scenario includes the Gas Strategic Program (PEG) and the development of the Burgos Basin Multiple Services Contracts (MSCs). Besides, the integral strategy for the increase in natural gas supply in the medium and long terms is based on the following elements: a) reactivation of exploration in areas of greater potential; b) preferential focus on non associated gas reserves, and c) reaching production in levels comparable with international practices.

This scenario considers the development of new important projects with great potential for incorporating reserves and diversifying the regions from where the production will be obtained. This means that besides the Burgos Basin for the exploitation of gas, the areas of Veracruz, Macuspana and the continental platform of the Gulf of Mexico are contemplated.

Multiple Services Contracts

The Multiple Services Contracts are public works contracts bid by Pemex for the execution of development works. The Generic Model of Multiple Services Contracts guarantees the permanent control of Pemex during the execution of the contracts and stipulates that all of the fixed assets constructed by the private companies are Pemex's property. The contractor only gets a fixed payment for the realized work and given services. They have no participation in the

production process, or in utilities. Natural gas belongs to and is commercialized by Pemex. Under the MSC, hydrocarbons' property and authority belong to the nation. Pemex keeps control of exploration and distribution activities. The contractor only gets a fixed payment for the realized work and services rendered.

which represents between 8 and 12 percent of national production.

The expected investment within these 5 contracts will be of \$U.S. 4.3 billion.

Besides the Burgos Basin, the possibility of awarding new MSCs for the development of the Coatzacoalcos, Tertiary Gas and Cuichapa

Table 4. MSC Blocks Awarded

Block	Awarded to:	Estimated investment (billion \$U.S.)
Reynosa-Monterrey	Repsol	2.437
Cuervito	Petrobras, Teikoku Oil Co., Ltd. y D&S Petroleum	0.260
Misión	Industrial Perforadora de Campeche y Tecpetrol	1.036
Fronterizo	Petrobras, Teikoku Oil Co., Ltd. y D&S Petroleum	0.265
Olmos	Lewis Energy Group	0.344
TOTAL		4.342

Source: Pemex

The MSC includes several different services such as seismic studies, perforation and development, pipeline construction and maintenance. Previously, these services were hired in an individual manner.

The MSC generates a series of benefits for Pemex's modernization and contributes to the strengthening of the country's oil industry. With the MSC, natural gas production will be increased and, therefore, net gas imports will be reduced.

Five out of the seven services contracts offered in the Burgos Basin were assigned. It is expected that for 2006, the above-mentioned contracts will be generating between 467 and 667 MMcf of natural gas,

projects, in the states of Veracruz and Tabasco, is being carefully analyzed, both onshore and offshore. This will give a boost to non associated gas production in Mexico, through national and international participation.

United States

The United States' natural gas projections presented in this report come from the U.S. Energy Information Administration's (EIA's) publication entitled: "*Annual Energy Outlook 2004*" (AEO2004), which was published in January 2004. Although over 30 different scenarios are discussed in the AEO2004, this presentation reviews the AEO2004 projections for three scenarios,

Sources and Notes

which are labeled in the AEO2004 as: the Reference Case, the Low Macroeconomic Growth Case, and the High Macroeconomic Growth Case.

The projections in AEO2004 are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The AEO2004 projections are based on the laws and regulations that were in effect on September 1, 2003. The projections are business-as-usual trend forecasts, based on current technological, economic and demographic trends.

The AEO2004 provides comprehensive projections for all major energy sources and for all major categories of energy consumption. This discussion will highlight the AEO2004 projections for natural gas. Because energy supply and demand for the various energy forms are interrelated, this discussion will not attempt to discuss all the facets associated with the natural gas projections.

The projections are calculated from the EIA's National Energy Modeling System (NEMS). The National Energy Modeling System (NEMS) is a computer-based, energy-

conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. NEMS was designed and implemented by the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE). Readers interested in obtaining additional information on the NEMS structure or the specific scenario assumptions associated with the projections discussed herein can obtain further information at the EIA internet web site at <http://www.eia.doe.gov/>.

AEO2004 Scenario Assumptions and Natural Gas Model Structure

Although a host of external inputs determine NEMS projections, the two primary drivers are economic growth and world oil prices. For the period encompassing 2002 through 2012, the average annual growth in Gross Domestic Product is 3.2 percent per year for the Reference Case, 2.7 percent per year for the Low Macroeconomic Growth Case, and 3.8 percent per year for the High Macroeconomic Growth Case. World oil prices are expected to be at the following levels for the 3 scenarios:

Table 5. Expected World Oil Prices, 2004 (2002 \$U.S.)

	Reference Case	Low Macroeconomic Growth Case	High Macroeconomic Growth Case
2005	23.30	23.15	23.38
2010	24.17	23.64	24.67
2012	24.53	23.84	25.17

Source: EIA, AEO2004

economy modeling system of U.S. energy markets for the time period through 2025. NEMS projects the production, imports,

The natural gas supply portion of NEMS represents domestic natural gas supply within

an integrated framework that captures the interrelationships between the various sources of supply: onshore, offshore, and Alaska, by both conventional and non-conventional techniques, including gas recovery from coalbeds and low-permeability formations of sandstone and shale. This framework analyzes cash flow and profitability to compute domestic natural gas investment and drilling, subject to prices, technology, and the recoverable resource base. Future natural gas production is computed for 12 supply regions, including offshore and Alaska. The NEMS gas module also represents foreign sources of natural gas, including pipeline imports to and exports from Canada and Mexico, and

liquefied natural gas (LNG) imports and exports.

Future natural gas consumption requirements are calculated in a set of end-use consumption modules representing residential, commercial, industrial, and transportation energy requirements. These end-use consumption modules project energy requirements for each of the nine Census regions. Using the North American Electric Reliability Council regions and sub-regions, the electric power module projects electricity consumption and fuels requirements at a regional level.