BALANCING NATURAL GAS POLICY

FUELING THE DEMANDS OF A GROWING ECONOMY

VOLUME II

INTEGRATED REPORT

NATIONAL PETROLEUM COUNCIL

SEPTEMBER 2003

National Petroleum Council
An Oil and Natural Gas Advisory Committee to the Secretary of Energy

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September 25, 2003

The Honorable
E. Spencer Abraham
Secretary of Energy
Washington, D.C. 20585

Dear Mr. Secretary:

On behalf of the members of the National Petroleum Council, I am pleased to submit to you the Council's report on natural gas: *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy*. This report was prepared at your request to provide insights on energy market dynamics as well as advice on actions that can be taken by industry and government to ensure adequate and reliable supplies of energy for American consumers. We further recognize the importance of your request and the urgency of our recommendations, given the heightened sensitivity among consumers to energy costs and reliability.

Natural gas continues to be a vital source of energy and raw material, and will play an important role in achieving the nation's economic and environmental quality goals. The Council finds that recent fundamental shifts in North American natural gas markets have led to the current market conditions of higher gas prices and increased price volatility. This situation will likely persist and could deteriorate unless public policy makers act now to reduce the conflicts that are inherent in current public policies.

Clearly, the recent tightening of the natural gas supply/demand balance places greater urgency on addressing the future of this important energy source and resolving conflicting policies that favor natural gas usage, but hinder its supply. The Council has reached out to hundreds of experts in the public and private sectors, representing both suppliers and consumers, to analyze future supply, demand, and infrastructure requirements, in order to advance recommendations that we believe will equip local, state, and national policy makers to make sound and balanced decisions for the future.

The Council recommends a balanced portfolio of actions by industry and government that includes:

- Encouraging conservation and efficiency
- Improving demand flexibility and efficiency
- Increasing supply diversity
- Sustaining and enhancing infrastructure
- Promoting efficiency of markets.

Policies most likely to have an immediate impact are actions to promote consumer conservation and energy efficiency. Actions to increase supply diversity and demand flexibility should also be taken immediately because several years will elapse before their full impacts will be felt. The Council's recommended approach includes action in all of these interdependent areas, because neither increasing supplies nor improving the efficiency of gas consumption would alone be sufficient to achieve the country's goals. It is vital to accomplish both.

The Council further recommends that the Department of Energy schedule a series of workshops designed to review steps taken to implement the report's recommendations, and to monitor the implications of ongoing changes in market conditions.

The Council is available to discuss further the results of this report and to aid in the implementation of its recommendations.

Respectfully submitted,

Bobby S. Shackouls
Chair

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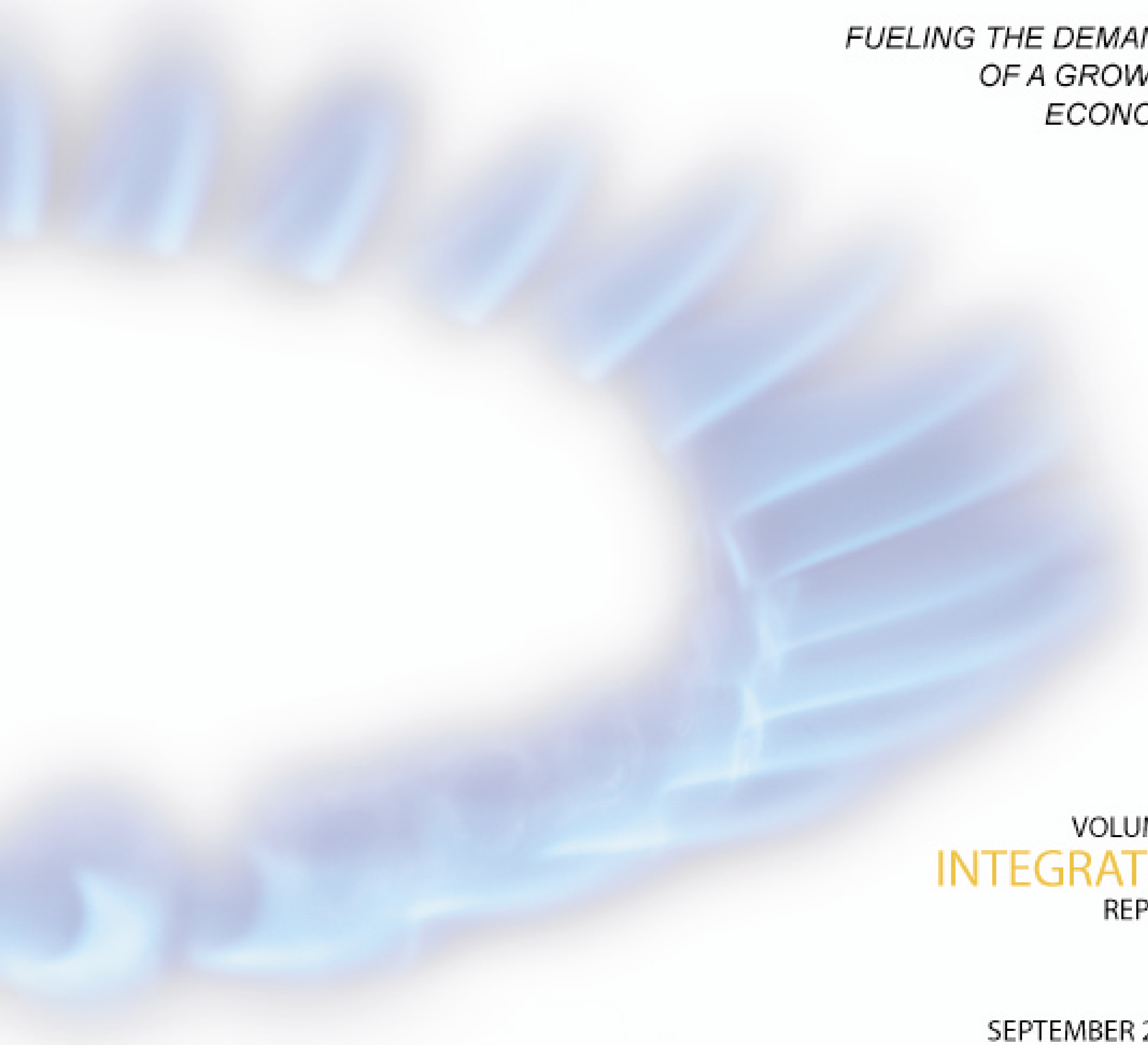

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NATIONAL PETROLEUM COUNCIL
COMMITTEE ON NATURAL GAS
BOBBY S. SHACKOULS, CHAIR

NATIONAL PETROLEUM COUNCIL

Bobby S. Shackouls, *Chair*
Lee R. Raymond, *Vice Chair*
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U.S. DEPARTMENT OF ENERGY

Spencer Abraham, *Secretary*

The National Petroleum Council is a federal advisory committee to the Secretary of Energy.

The sole purpose of the National Petroleum Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to oil and natural gas or to the oil and gas industries.

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PREFACE

Study Request

By letter dated March 13, 2002, Secretary of Energy Spencer Abraham requested the National Petroleum Council (NPC) to undertake a new study on natural gas in the United States in the 21st Century. Specifically, the Secretary stated:

> Such a study should examine the potential implications of new supplies, new technologies, new perceptions of risk, and other evolving market conditions that may affect the potential for natural gas demand, supplies, and delivery through 2025. It should also provide insights on energy market dynamics, including price volatility and future fuel choice, and an outlook on the longer-term sustainability of natural gas supplies. Of particular interest is the Council's advice on actions that can be taken by industry and Government to increase the productivity and efficiency of North American natural gas markets and to ensure adequate and reliable supplies of energy for consumers.

In making his request, the Secretary made reference to the 1992 and 1999 NPC natural gas studies, and noted the considerable changes in natural gas markets since 1999. These included "new concerns over national security, a changed near-term outlook for the economy, and turbulence in energy markets based on perceived risk, price volatility, fuel-switching capabilities, and the availability of other fuels." Further, the Secretary pointed to the projected growth in the nation's reliance on natural gas and noted that the future availability of gas supplies could be affected by "the availability of investment capital and infrastructure, the pace of technology progress, access to the Nation's resource base, and new sources of supplies from Alaska, Canada, liquefied natural gas imports, and unconventional resources." (Appendix A contains the complete text of the Secretary's request letter and a description of the NPC.)

Study Organization

In response to the Secretary's request, the Council established a Committee on Natural Gas to undertake a new study on this topic and to supervise the preparation of a draft report for the Council's consideration. The Council also established a Coordinating Subcommittee and three Task Groups – on Demand, Supply, and Transmission & Distribution – to assist the Committee in conducting the study.

Bobby S. Shackouls, Chairman, President and Chief Executive Officer, Burlington Resources Inc., chaired the Committee[1], and Robert G. Card, Under Secretary of Energy, served as the Committee's Government Cochair. Robert B. Catell, Chairman and Chief Executive Officer, KeySpan Corporation; Lee R. Raymond, Chairman and Chief Executive Officer, Exxon Mobil Corporation; and Richard D. Kinder, Chairman and Chief Executive Officer, Kinder Morgan Energy Partners, L.P., served as the Committee's Vice Chairs of Demand, Supply, and Transmission & Distribution, respectively. Jerry J. Langdon, Executive Vice President and Chief Administrative Officer,

[1] William A. Wise, Retired President and Chief Executive Officer, El Paso Energy Corp., served as Chair of the Committee until May 16, 2003.

Reliant Resources, Inc., chaired the Coordinating Subcommittee, and Carl Michael Smith, Assistant Secretary, Fossil Energy, U.S. Department of Energy, served as Government Cochair.

The members of the various study groups were drawn from the NPC members' organizations as well as from many other industries, non-governmental organizations, and government organizations. These study participants represented broad and diverse interests including large and small producers, transporters, service providers, financers, regulators, local distribution companies, power generators, and industrial consumers of natural gas. Appendix B contains rosters of the study's Committee, Coordinating Subcommittee, three Task Groups and their subgroups. In addition to the participants listed in Appendix B, many more people were involved in regional and sector-specific workshops in the United States and Canada.

Study Approach

The study benefited from an unprecedented degree of support, involvement, and commitment from the gas industry. The breadth of support was based on growing concerns about the adequacy of natural gas supplies to meet the continuing strong demand for gas, particularly in view of the role of gas as an environmentally preferred fuel. The study addresses both the short-term and long-term outlooks (through 2025) for North America, defined in this study as consisting of Canada, Mexico, and the United States. The reader should recognize that this is a natural gas study, and not a comprehensive analysis of all energy sources such as oil, coal, nuclear, and renewables. However, this study does address and make assumptions regarding these competing energy sources in order to assess the factors that may influence the future of natural gas use in North America. The analytical portion of this study was conducted over a 12-month period beginning in August 2002 under the auspices of the Coordinating Subcommittee and three primary Task Groups.

The Demand Task Group developed a comprehensive sector-by-sector demand outlook. This analysis was done by four subgroups (Power Generation, Industrial Utilization, Residential and Commercial, and Economics and Demographics). The task of each group was to try to understand the economic and environmental determinants of gas consumption and to analyze how the various sectors might respond to different gas price regimes. The Demand Task Group was composed of representatives from a broad cross-section of the power industry as well as industrial consumers from gas-intensive industries. It drew on expertise from the power industry to develop a broad understanding of the role of alternative sources for generating electric power based on renewables, nuclear, coal-fired, oil-fired, or hydroelectric generating technology. It also conducted an outreach program to draw upon the expertise of power generators and industrial consumers in both the United States and Canada.

The Supply Task Group developed a basin-by-basin supply picture, and analyzed potential new sources of supply such as liquefied natural gas (LNG) and Arctic gas. The Supply Task Group worked through five subgroups: Resource, Technology, LNG, Arctic, and Environmental/Regulatory/Access. Over 100 people participated. These people were drawn from major and independent producers, service companies, consultants, and government agencies. These working groups conducted 13 workshops across the United States and Canada to assess the potential resources available for exploration and development. Workshops were also held to examine the potential impact on gas production from advancing technology. Particular emphasis was placed on the commercial potential of the technical resource base and the knowledge gained from analysis of North American production performance history.

The Transmission & Distribution Task Group analyzed existing and potential new infrastructure. Their analysis was based on the work of three subgroups (Transmission, Distribution, and Storage). Industry participants undertook an extensive review of existing and planned infrastructure capacity in North America. Their review emphasized, among other things, the need to maintain the current infrastructure and to ensure its reliability. Participants in the Transmission & Distribution Task Group included representatives from U.S. and Canadian pipeline, storage, marketing, and local distribution companies as well as from the producing community, the Federal Energy Regulatory Commission, and the Energy Information Administration.

Separately, two other groups also provided guidance on key issues that crossed the boundaries of the primary task groups. An ad hoc financial team looked at capital requirements and capital formation. Another team examined the issue of increased gas price volatility.

Due to similarities between the Canadian and U.S. economies and, especially, the highly interdependent character of trade in natural gas, the evaluation of natural gas supply and demand in Canada and the United States were completely integrated. The study included Canadian participants, and many other participating companies have operations in both the United States and Canada. For Mexico, the evaluation of natural gas supply and demand for the internal market was less detailed, mainly due to time limitations. Instead, the analysis focused on the net gas trade balances and their impact on North American markets.

As in the 1992 and 1999 studies, econometric models of North American energy markets and other analytical tools were used to support the analyses. Significant computer modeling and data support were obtained from outside contractors; and an internal NPC study modeling team was established to take direct responsibility for some of the modeling work. The Coordinating Subcommittee and its Task Groups made all decisions on model input data and assumptions, directed or implemented appropriate modifications to model architecture, and reviewed all output. Energy and Environmental Analysis, Inc. (EEA) of Arlington, Virginia, supplied the principal energy market models used in this study, and supplemental analyses were conducted with models from Altos Management of Los Altos, California.

The use of these models was designed to give quantified estimates of potential outcomes of natural gas demand, supply, price and investment over the study time horizon, with a particular emphasis on illustrating the impacts of policy choices on natural gas markets. The results produced by the models are critically dependent on many factors, including the structure and architecture of the models, the level of detail of the markets portrayed in the models, the mathematical algorithms used, and the input assumptions specified by the NPC Study Task Groups. As such, the results produced by the models and portrayed in the NPC report should not be viewed as forecasts or as precise point estimates of any future level of supply, demand, or price. Rather, they should be used as indicators of trends and ranges of likely outcomes stemming from the particular assumptions made. In particular, the model results are indicative of the likely directional impacts of pursuing particular public policy choices relative to North American natural gas markets.

This study built on the knowledge gained and processes developed in previous NPC studies, enhanced those processes, created new analytical approaches and tools, and identified opportunities for improvement in future studies. Specific improvements included the following elements developed by the Supply Task Group:

- A detailed play-based approach to assessment of the North American natural gas resource base, using regional workshops to bring together industry experts to update existing assessments. This was used in two detailed descriptive models, one based on 72 producing regions in the United States and Canada, and the other based on 230 supply points in the United States, Canada, and Mexico. Both models distinguished between conventional and nonconventional gas and between proved reserves, reserve growth, and undiscovered resource.
- Cost of supply curves, including discovery process models, were used to determine the economically optimal pace of development of North American natural gas resources.
- An extensive analysis of recent production performance history, including virtually every gas well drilled in the United States and Canada between 1990 and 2002. This analysis clearly identified basins that are maturing and those where production growth potential remains, and helped establish forward-looking assumptions in the models.
- A model to assess the impact of permitting in areas currently subject to conditions of approval.
- A first-ever detailed NPC view and analysis of LNG and Arctic gas potential.

The Demand Task Group also achieved significant improvements over previous study methods. These improvements include the following:

- Regional power workshops and sector-specific industrial workshops to obtain direct input on consuming trends and the likely impact of changing gas prices.
- Ongoing detailed support from the power industry for technology and cost factors associated with current and future electric power generation.
- Development of a model of industrial demand focusing on the most gas-intensive industries and processes.

Study Report

Results of this 2003 NPC study are presented in a multi-volume report as follows:

- Volume I, *Summary of Findings and Recommendations*, provides insights on energy market dynamics as well as advice on actions that can be taken by industry and government to ensure adequate and reliable supplies of energy for American consumers. It includes an Executive Summary of the report and an overview of the study's analyses and recommendations.

- Volume II, *Integrated Report*, contains discussions of the results of the analyses conducted by the three Task Groups: Demand, Supply, and Transmission & Distribution. This volume provides further supporting data and analyses for the findings and recommendations presented in Volume I. It addresses the potential implications of new supplies, new technologies, new perceptions of risk, and other evolving market conditions that may affect the potential for natural gas demand, supplies, and delivery through 2025. It provides insights on energy market dynamics, including price volatility and future fuel choice, and an outlook on the longer-term sustainability of natural gas supplies. It also expands on the study's recommended policy actions. This volume presents an integrated outlook for natural gas demand, supply, and transmission in the United States, Canada, and Mexico under two primary scenarios and a number of sensitivity cases.

  The demand analysis provides an understanding of the economic and environmental determinants of natural gas consumption to estimate how the industrial, residential/commercial, and electric power sectors may respond under different conditions. The supply analysis develops basin-by-basin resource and cost estimates, presents an analysis of recent production performance, examines potential technology improvements, addresses resource access issues, and examines potential supplies from traditional areas as well as potential new sources of supply such as liquefied natural gas and Arctic gas. The transmission, distribution, and storage analysis provides an extensive review of existing and planned infrastructure in North America emphasizing, among other things, the need to maintain the current infrastructure and to ensure its reliability.

- *Task Group Report Volumes and Appendices* include the detailed data and analyses prepared by the Demand, Supply, and Transmission & Distribution Task Groups and their Subgroups, which formed the basis for the development of Volumes I and II. The output of the study's computer modeling activities is also included. The Council believes that these materials will be of interest to the readers of the report and will help them better understand the results. The members of the National Petroleum Council were not asked to endorse or approve all of the statements and conclusions contained in these documents but, rather, to approve the publication of these materials as part of the study process.

  Included with the Task Group Reports is a CD-ROM containing further model output on a regional basis. The CD also contains digitized maps, which were used in assessing the potential impact of conditions of approval for access to key Rocky Mountain resource areas.

A form for ordering additional copies of the report volumes can be downloaded from the NPC website, http://www.npc.org. Pdf copies of Volumes I and II also can be viewed and downloaded from the NPC website.

Retrospectives on 1999 Study

In requesting the current study, the Secretary noted that natural gas markets had changed substantially since the Council's 1999 study. These changes were the reasons why the 2003 study needed to be a comprehensive analysis of natural gas supply, demand, and infrastructure issues. By way of background, the 1999 study was designed to test the capability of the supply and delivery systems to meet the then-public forecasts of an annual U.S. market demand of 30+ trillion cubic feet early in this century. The approach taken in 1999 was to review the resource base estimates of the 1992 study and make any needed modifications based on performance since the publication of that study. This assessment of the natural gas industry's ability to convert the nation's resource base into available supply also included the first major analytical attempt to quantify the effects of access restrictions in the United States, and specifically the Rocky Mountain area. Numerous government agencies used this work as a starting point to attempt to inventory various restrictions to development. This access work has been further expanded upon in the current study. Further discussions of the 1999 analyses are contained in the Task Group reports.

The 1999 report stated that growing future demands could be met if government would address several critical factors. The report envisioned an impending tension between supply and demand that has since become reality in spite of lower economic growth over the intervening time period. On the demand side, government policy at all levels continues to encourage use of natural gas. In particular, this has led to large increases in natural gas-fired power generation capacity. The 1999 study assumed 144 gigawatts of new capacity through 2015, while the actual new capacity is expected to exceed 200 gigawatts by 2005. On the supply side, limits on access to resources and other restrictive policies continue to discourage the development of natural gas supplies. Examples of this are the 75% reduction in the Minerals Management Service's Eastern Gulf Lease Sale 181 and the federal government's "buying back" of the Destin Dome leases off the coast of Florida.

The maturity of the resource base in the traditional supply basins in North America is another significant consideration. In the four years leading up to the publication of this study, North America has experienced two periods of sustained high natural gas prices. Although the gas-directed rig count did increase significantly between 1999 and 2001, the result was only minor increases in production. Even more sobering is the fact that the late 1990s was a time when weather conditions were milder than normal, masking the growing tension between supply and demand.

In looking forward, the Council believes that the findings and recommendations of this study are amply supported by the analyses conducted by the study groups. Further, the Council wishes to emphasize the significant challenges facing natural gas markets and to stress the need for all market participants (consumers, industry, and government) to work cooperatively to develop the natural gas resources, infrastructure, energy efficiency, and demand flexibility necessary to sustain the nation's economic growth and meet environmental goals.

CHAPTER 1

INTEGRATED OUTLOOK

Natural gas is a critical source of energy and raw material, and will play a vital role in achieving the nation's economic and environmental goals. Current higher gas prices are the result of a fundamental shift in the supply and demand balance. North America is moving to a period in its history in which it will no longer be self-reliant in meeting its growing natural gas needs; production from traditional U.S. and Canadian basins has plateaued. Government policy encourages the use of natural gas but does not address the corresponding need for additional natural gas supplies. A status quo approach to these conflicting policies will result in undesirable impacts to consumers and the economy, if not addressed. Further, a continuation of incremental policy reactions to market events will likely lead to higher energy costs and increase the potential for economic dislocations of North American industries. The solution is a balanced portfolio of actions that includes increased energy efficiency and conservation; alternate energy sources for industrial consumers and power generators, including renewables; gas resources from previously inaccessible areas of the United States; liquefied natural gas (LNG) imports; and gas from the Arctic.

While there is considerable uncertainty in any projection, the NPC arrived at this view through fundamental analysis of the basic components that make up the balance of supply and demand. Thorough study was conducted of the North American indigenous natural gas resource base, the production history of mature North American basins, and likely advances in upstream technology, to arrive at an overall view of indigenous supply. This was complemented by a comprehensive review of the potential for LNG imports and Arctic gas to supplement that supply. Analyses of demand were similarly undertaken with particular attention paid to the potential for demand growth for power generation, and for demand impacts on key industrial, residential, and commercial sectors in response to higher gas prices. The capability of existing transmission, distribution, and storage infrastructure as well as requirements for new infrastructure were also projected based on the outlooks for supply and demand.

Scenarios

The current policy direction – unaltered – will likely lead to difficult conditions for natural gas, but industries, government, and consumers will react. Therefore, this study assumes action by all these parties beyond the status quo.

A status quo approach to natural gas policy yields undesirable outcomes because it discourages economic fuel choice, new supplies from traditional basins and Alaska, and new LNG terminal capacity. The NPC developed two scenarios of future supply and demand that move beyond the status quo. Both require significant actions by policy makers and industry stakeholders to effect change. These scenarios, "Reactive Path" and "Balanced Future," are discussed below.

These scenarios were developed by a range of market participants, including representatives of producers, pipelines, local distribution companies, industrial consumers, power companies, and government agencies. These scenarios bring together the data and analyses of North American supply, demand, and infrastructure in internally consistent frameworks for analyzing choices open to the principal stakeholders in North American gas over the study time period. Thus, they are not forecasts, per se, and reflect in some areas the offsetting and/or complementary effects of actions by suppliers and consumers. For example, certain combinations of actions may lead to lower demand in a lower-price environment; conversely, the lack of those actions could foster higher natural gas demand, despite a higher-price environment.

Each of the two scenarios has different assumptions regarding key variables related to supply and demand in response to public policy choices. These key variables included degrees of access to gas resources, greater energy efficiency and conservation, and increased flexibility to use fuels other than gas for industry and power generation. The two scenarios result in contrasting demand, supply, infrastructure, and price profiles. Each scenario assumes a continuation of current standards for environmental compliance.

Reactive Path Scenario

- Public policies remain in conflict, with actions taken in a reactive mode
- Siting industrial facilities and powerplants continues to favor natural gas due to investment and regulatory uncertainties
- No additional alternative fuel backup to existing facilities
- Significant new generation capacity including coal with firm environmental control, and renewables
- Access/permitting restrictions to lower-48 production persist
- Two-year LNG regasification plant permitting; seven new terminals during the study period
- Arctic pipelines built

"Reactive Path" assumes continued conflict between natural gas supply and demand policies that support natural gas use, but tend to discourage supply development. However, in addition to these broad policies, the assumptions built into this case acknowledge that resultant higher natural gas prices will likely be reflected in significant societal pressure to allow reasonable, economically driven choices to occur on both the consuming and producing segments of the natural gas industry. In essence, market participants, including public policy makers, "react" to the current situation while inherent conflicts continue. The supply response assumes a considerable amount of success and deviation from past trends, evidenced by a major expansion of LNG facilities, construction of Arctic pipelines, and a significant response in lower-48 production from accessible areas. The resulting demand level is lower than other outlooks including the EIA, with less upward pressure on the supply/demand balance. Even with uncertainty surrounding air quality regulations, there is potential for construction of new, state of the art, fully compliant coal-based generation plants at levels that approach the prior coal boom years in the 1970s. Together, this scenario implies a degree of success in supply and demand responses significantly beyond what has been demonstrated over recent years.

The Reactive Path scenario results in continued tightness in supply and demand leading to higher natural gas prices and price volatility over the study period. Federal Reserve Board Chairman Alan Greenspan provided the best characterization of the conflict between policy choices in his testimony to the United States Senate Committee on Energy and Natural Resources: "*We have been struggling to reach an agreeable tradeoff between environmental and energy concerns for decades. I do not doubt we will continue to fine-tune our areas of consensus. But it is essential that*

Balanced Future Scenario

- Public policy more symmetrical, proactive
- Siting new plants is emission performance oriented, and more fuel neutral
- Clean air goals met with time, technology, and market-based mechanisms; emissions trading and fuel-switching ability expanded
- Additional new generation capacity including coal with firm environmental control, and renewables
- Access to lower-48 supplies enhanced
- LNG permit timing improved; nine new terminals
- Arctic pipelines built

our policies be consistent. For example, we cannot, on the one hand, encourage the use of environmentally desirable natural gas in this country while being conflicted on larger imports of LNG. Such contradictions are resolved only by debilitating spikes in price."

Alternatively, "Balanced Future" is a scenario in which government policies are focused on eliminating barriers to market efficiencies. This scenario enables natural gas markets to develop in a manner in which improved economic and environmental choices can be made by both producers and consumers. On the demand side, opportunities for conservation, energy efficiency, and fuel flexibility are both authorized and encouraged while adhering to current environmental standards. On the supply side, barriers to development of new natural gas sources are progressively lowered, both for domestic and imported natural gas. The result is a market with lower gas prices and volatility due to enhanced supply and more flexible demand. This scenario results in a better outcome for North American consumers than the "Reactive Path."

It would be possible to construct many different scenarios or visions of the future to illustrate the NPC analysis. For example, neither the Reactive Path nor the Balanced Future scenario reflects the effect of *not* developing major new LNG import facilities or the Arctic gas pipelines; neither scenario reflects actions that might severely limit CO_2 emissions or the permitted carbon content of fuels; and neither scenario attempts to speculate on ground-breaking new technology that could

Findings

There has been a fundamental shift in the natural gas supply/demand balance that has resulted in higher prices and volatility in recent years. This situation is expected to continue, but can be moderated.

Demand

Greater energy efficiency and conservation are vital near-term and long-term mechanisms for moderating price levels and reducing volatility.

Power generators and industrial consumers are more dependent on gas-fired equipment and less able to respond to higher gas prices by utilizing alternate sources of energy.

Gas consumption will grow, but such growth will be moderated as the most price-sensitive industries become less competitive, causing some industries and associated jobs to relocate outside North America.

Infrastructure

Pipeline and distribution investments will average $8 billion per year, with an increasing share required to sustain the reliability of existing infrastructure

Regulatory barriers to long-term contracts for transportation and storage impair infrastructure investment.

Supply

Traditional North American producing areas will provide 75% of long-term U.S. gas needs, but will be unable to meet projected demand.

Increased access to U.S. resources (excluding designated wilderness areas and national parks) could save consumers $300 billion in natural gas costs over the next 20 years.

New, large-scale resources such as LNG and Arctic gas are available and could meet 20-25% of demand, but are higher-cost, have longer lead times, and face major barriers to development.

Markets

Price volatility is a fundamental aspect of a free market, reflecting the variable nature of demand and supply; physical and risk management tools allow many market participants to moderate the effects of volatility.

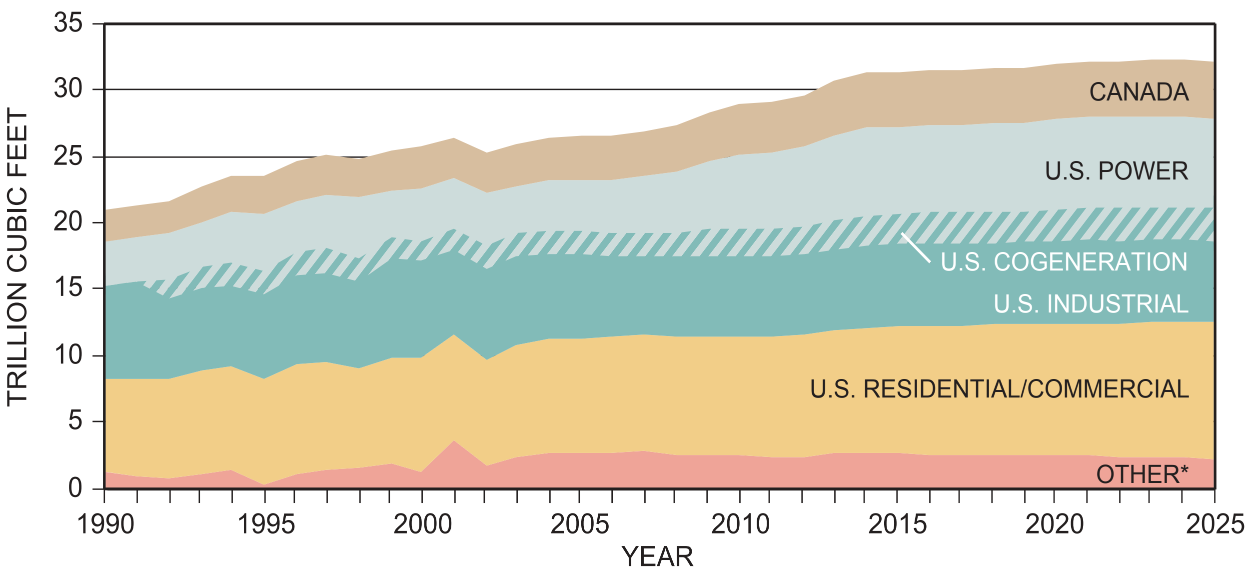
A balanced future that includes increased energy efficiency, immediate development of new resources, and flexibility in fuel choice, could save $1 trillion in U.S. natural gas costs over the next 20 years. Public policy must support these objectives.

fundamentally alter demand patterns or supply potential. The NPC did not consider such possibilities as being likely enough to be integrated into the base scenarios. However, each scenario was tested against variabilities in these and other major underlying assumptions through the use of sensitivity analyses. Major assumptions tested included weather patterns, economic growth, the price of competing fuels, the size of the domestic gas resource base, timing of infrastructure implementation, and the role of other electric generation technologies such as nuclear and hydroelectric plants. These sensitivity analyses provide additional insight to the conclusions reached from the base scenarios and reinforce the study findings and recommendations.

In either scenario, it is clear that North American natural gas supplies from traditional basins will be insufficient to meet projected demand; choices must be made immediately to determine how the nation's natural gas needs will be met in the future. The best solution to these issues requires actions on multiple paths. Flexibility in fuel use must be encouraged, diverse supply sources must be developed, and infrastructure must be made to be as reliable as possible. Policy choices must consider domestic and foreign sources of supply, large and small increments of production, and the use of other fuels as well as gas for power generation. All choices face obstacles, but all must be supported if we are to achieve robust competition among energy alternatives and the lowest cost for consumers and the nation. The benefits of the Balanced Future scenario to the economy and environment unfold over time; but it is important that these policy changes be implemented now; otherwise their benefits will be pushed that much farther into the future, and the uneasy supply/demand balance we are experiencing will continue.

Findings

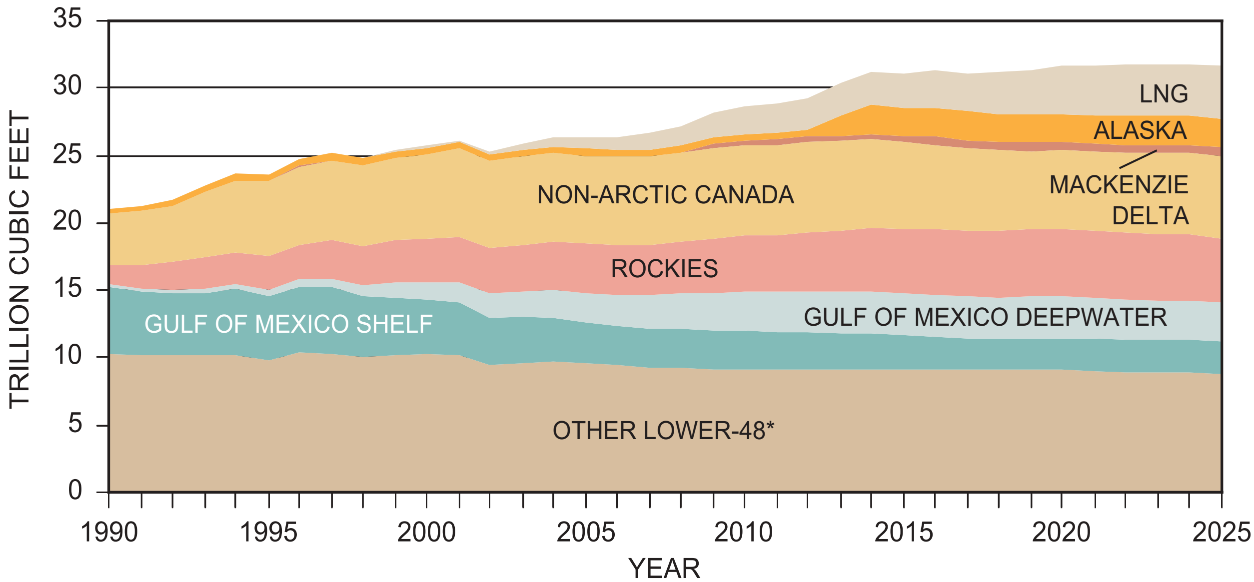
National Petroleum Council projections of future demand and supply are illustrated in Figures 1-1 and 1-2.



*Includes net Mexico exports, lease/plant/pipeline fuel, and net storage.

- Natural gas demand for power generation increases, reflecting future utilization of recent, significant additions of natural gas-fired generation.
- Natural gas use in the industrial sector erodes, illustrating projected losses in industrial capacity in the most gas-intensive industries.

Figure 1-1. Natural Gas Demand History and Outlook



* Includes lower-48 production, ethane rejection, and supplemental gas.

- Production from traditional basins remains strong but has plateaued; Rockies and deepwater Gulf of Mexico offset declines in other areas.
- Growth is driven by LNG imports and Arctic supply.

Figure 1-2. Natural Gas Supply History and Outlook

Natural Gas Supply

Abundant natural gas resources exist in North America and worldwide. Historically, the producing regions of the Gulf Coast and Gulf of Mexico, the Midcontinent, and West Texas have provided the majority of the U.S. natural gas supply as shown in Figure 1-3. In recent years, the Rockies have become a significant source of supply, primarily from nonconventional tight gas and coal bed methane production. Natural gas imports via pipeline from Canada have also played an expanding role in the U.S. supply picture and now account for 14% of U.S. consumption. Of the other sources of imports, LNG currently accounts for only one percent of U.S. supply and Mexico is a small net importer of gas from the United States.

A thorough study was conducted to assess the remaining potential of traditional North American natural gas producing basins, as well as the potential for growth from new supply sources. The resulting outlook is that indigenous North American production will remain relatively flat, as increasing production from the Rockies and deepwater Gulf of Mexico offsets declining production from the maturing traditional basins. Supply growth will be met by LNG imports and new Arctic developments.

Natural Gas Demand

Government policies have encouraged industrial consumers and power generators to become increasingly reliant upon natural gas-based technologies to meet their energy requirements and to satisfy more-stringent air quality standards. Recent major growth in natural gas-fired generation capacity and continued residential customer connections create the potential for even greater natural gas consumption. Continued energy conservation and more efficient use of existing equipment can ease short-term market pressures, and will continue to have a significant impact on future energy consumption. However, this alone will not solve the problem; additional supplies are required. Figure 1-4 shows regional demand growth patterns for North America.

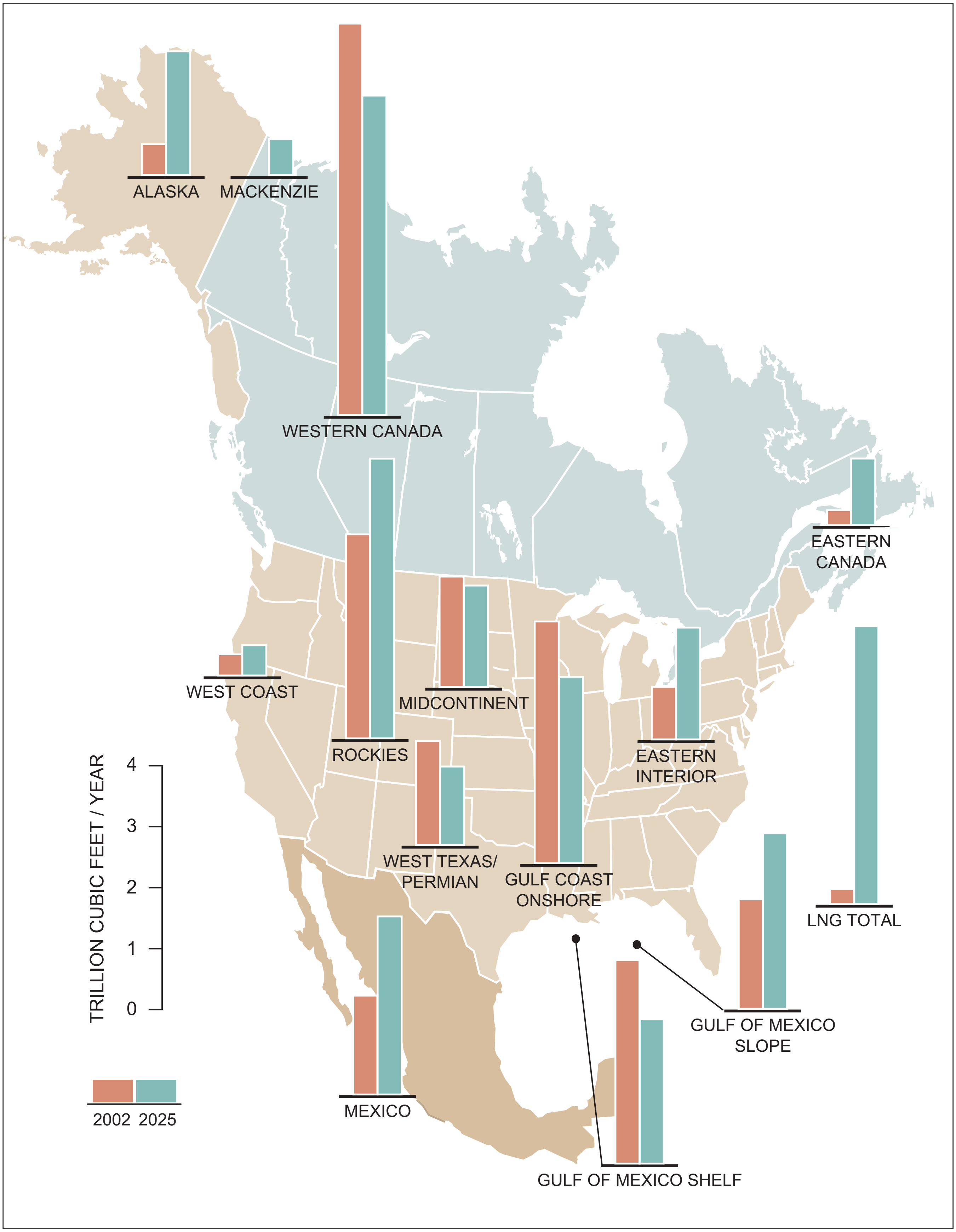


Figure 1-3. Regional Natural Gas Supply

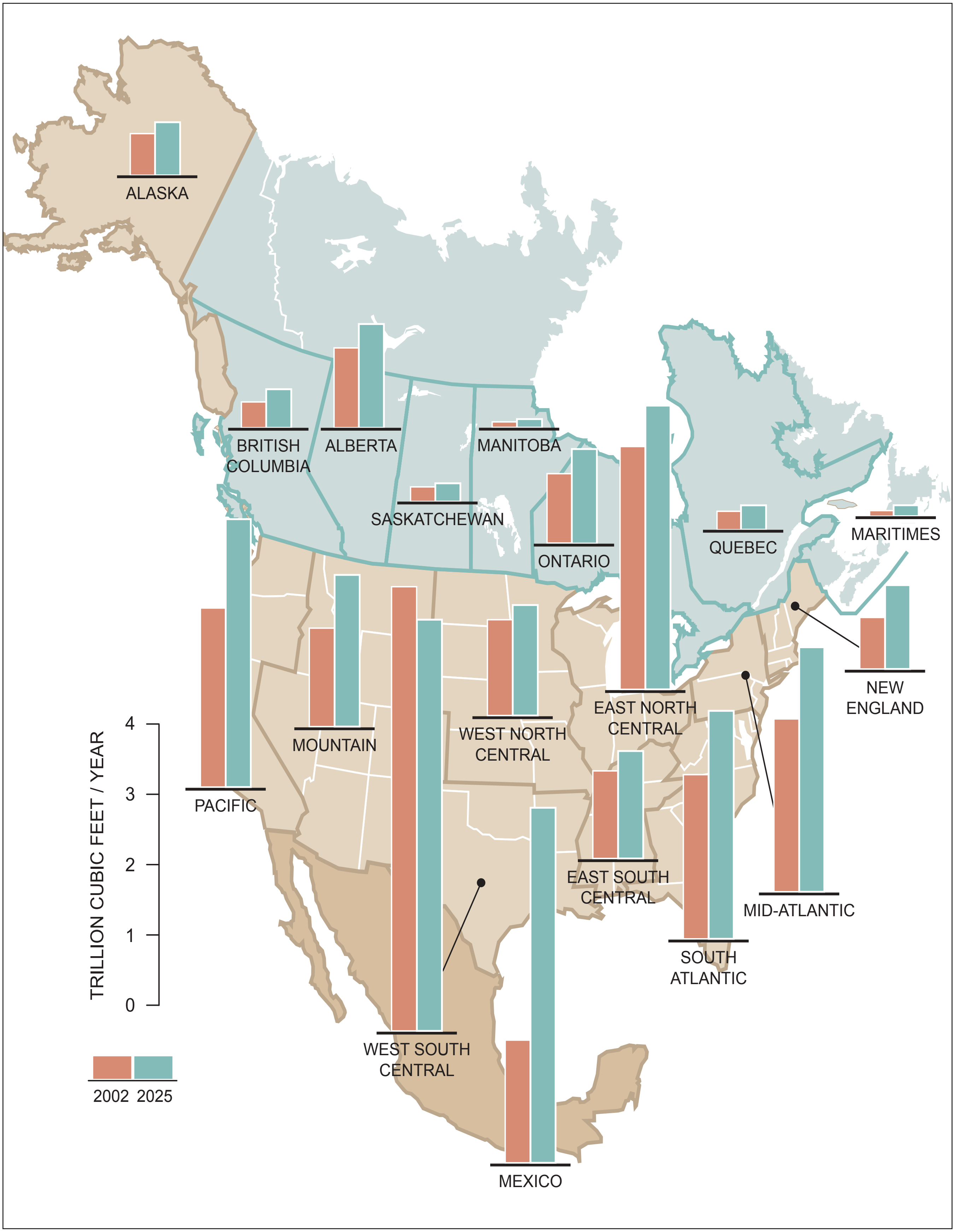


Figure 1-4. Regional Natural Gas Demand

Infrastructure Expansions

Significant new infrastructure will be needed through 2013, then the projected need for capital for new infrastructure will decrease while sustaining capital becomes an increasing percentage of total capital requirements. Regulatory policy that supports long-term contracts and regulatory certainty will be required to develop new infrastructure and maintain the same level of reliability.

Potential Price Ranges

The NPC-projected price ranges for the alternate scenarios are illustrated in Figure 1-5. Supply and demand are projected to balance at higher price ranges than historical levels. The price ranges will be primarily determined by demand response through increased efficiency, conservation, and alternate fuel use, the ability to increase conventional and nonconventional supplies from North America including the Arctic, and increasing access to world resources through LNG imports. As has previously been described, the scenarios that drive these outlooks move beyond the status quo. They require significant initiative by policy makers and industry stakeholders to implement the recommendations of this report and take market-driven actions. Each scenario has potential additional price variability due to external factors including weather, lower-48 supply response to higher prices, timing of infrastructure development, potential breakthrough technologies, and use of competing fuels. These projected ranges are not intended to be precise estimates of future prices but are provided to provide insights to the effects of government policy. Additionally, sensitivity analyses (detailed later in this report) were performed to test the effects of changes in key assumptions.

Capital Expenditures

Over $1.4 trillion (2002 dollars) in capital expenditures will be required to fund the U.S. and Canadian gas upstream and infrastructure industry from 2003 to 2025. Eighty-five percent will be spent in the exploration and production sector ($1.2 trillion), with the remaining 15% ($0.2 trillion) spent on pipelines, storage, and distribution, as shown in Figures 1-6 and 1-7. These expenditures represent a significant increase over the 1990-2000 period for the exploration and production sector. Expenditures for the pipeline, storage, and distribution sector are expected to remain relatively constant, considering increasing needs for "sustaining capital" to meet reliability requirements.

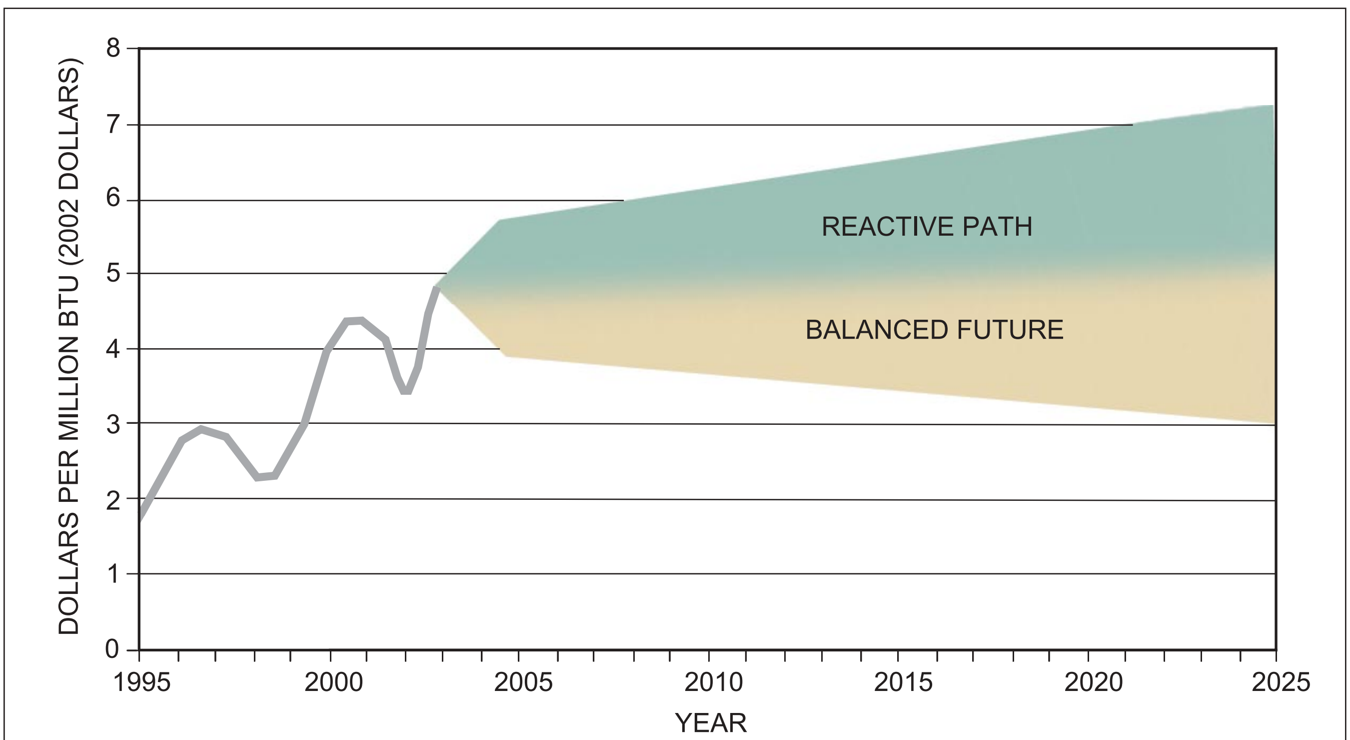


Figure 1-5. Average Annual Henry Hub Prices

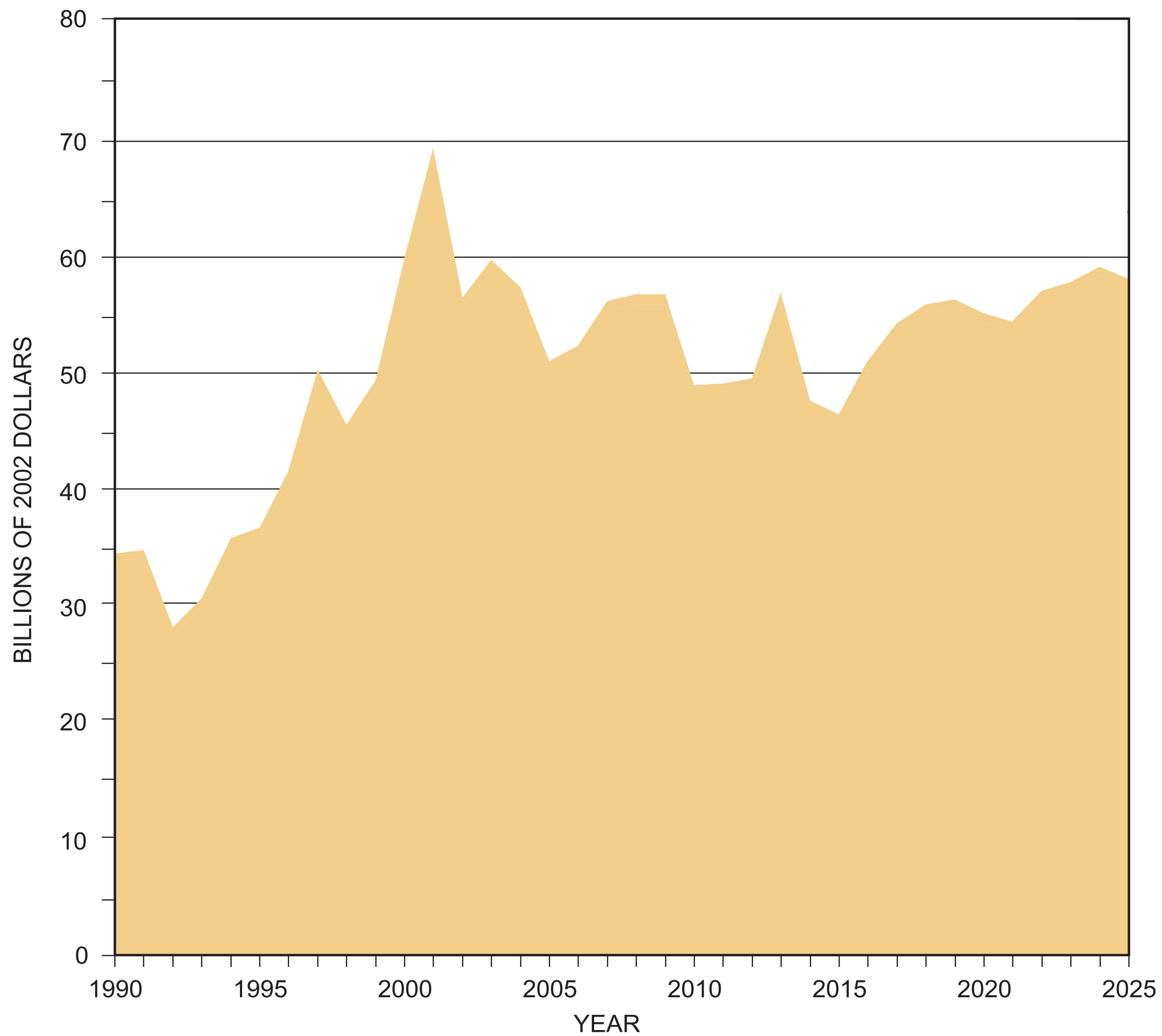
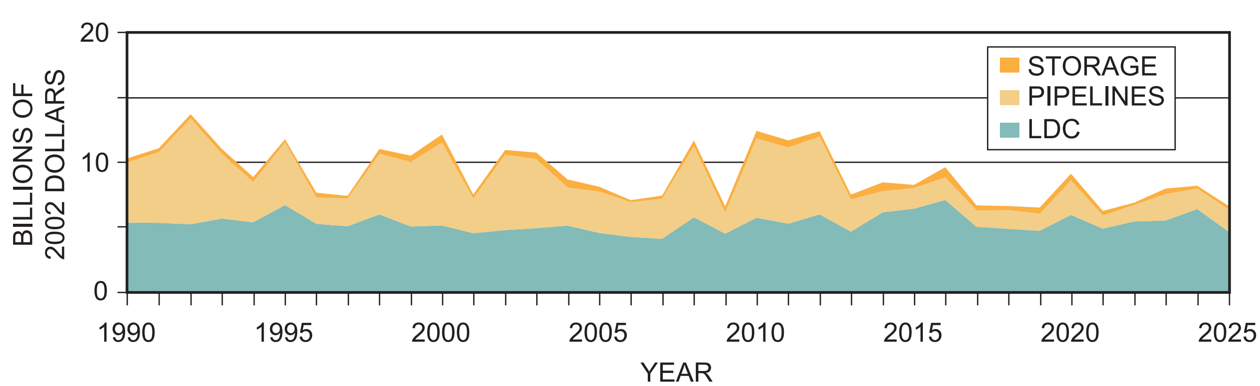


Figure 1-6. North American Upstream Expenditures – Balanced Future Scenario



Note: This figure is a revision of Figure 53 in Volume I of this report.

Figure 1-7. North American Infrastructure Expenditures – Balanced Future Scenario

Sensitivities

There are many factors that will affect future gas markets in North America. The NPC considered these factors and created base assumptions for the Balanced Future and Reactive Path scenarios. Because of the uncertainty inherent in making such assumptions for 20+ years into the future, the NPC often developed alternative sets of assumptions to test how the natural gas market might evolve under different circumstances. Those alternative assumptions addressed the effects of a different economic environment, government policies, natural resource size, upstream technological trends, weather, end-use efficiency improvements, and other factors. Figure 1-8 shows the price and volume effect of differing assumptions. Table 1-1 lists the assumption change for each case. The factors have widely varying probabilities.

Recommendations

The findings of the National Petroleum Council described in this report represent the conclusions of the Council from the detailed analysis undertaken over the course of this study. They provide the clear motivation for the recommendations that follow. Collectively and individually, policy makers will make decisions affecting the future of natural gas in the economy. These choices will have significant effects on resource availability, on natural gas production, on the cost-effective use of natural gas, on the capacity of infrastructure to serve markets, and on prices and price volatility. Prompt implementation of the NPC's recommendations will reduce the conflicts in current public policy and benefit both consumers and the environment. Further details on the recommendations can be found later in this report.

Sensitivity	Assumption
High Resource Base (10% probability)	+35% of base, +570 TCF
Fuel Flexibility	Industrial switching increased from 5% to 28% by 2025, fuel backup included in 25% of new gas-fired generation
High Supply Technology	Increase exploration success, cost reduction, well recoveries from ~ 1% to 1.5%/year
Low Economic Growth	2.7%/year GDP growth (vs. 3%/year base)
Increased Access to Resources	10%/year improvement in access to new resources for five years
High LNG Imports	15 BCF/D imports (vs. 12.5 BCF/D Reactive Path)
Less Access	Continued trend toward more restrictive permitting, higher costs to develop resources
No Alaska Pipeline	4 BCF/D pipeline not built
High Electricity Growth	Limited energy efficiency; GDP-to-electricity elasticity fixed at 72%
High Economic Growth	3.3%/year GDP growth (vs. 3%/year base)
West Texas Intermediate $28 Oil Price	+$8/bbl vs. Reactive Path and Balanced Future Scenarios
Low LNG Import	6 BCF/D (vs. 12.5 BCF/D Reactive Path)
Static Supply Technology	No improvement in exploration success, costs, recoveries
Low Resource Base (90% probability)	-30% of base; -490 TCF

Table 1-1. Sensitivity Analysis

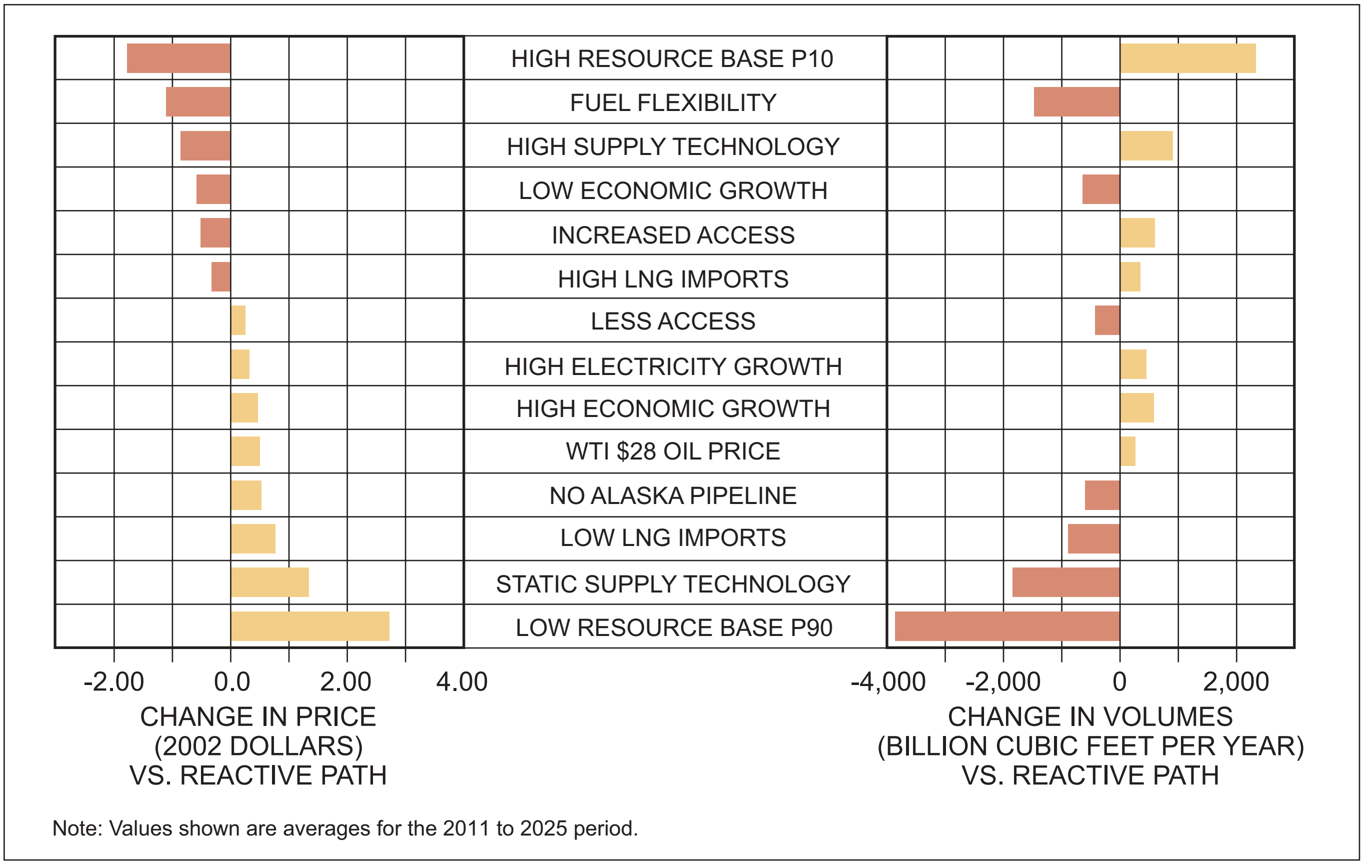


Figure 1-8. Price and Volume Impacts of Selected Sensitivities

Recommendations

Improve Demand Flexibility and Efficiency

Encourage increased efficiency and conservation through market-oriented initiatives and consumer education.

Increase industrial and power generation capability to utilize alternate fuels.

Sustain and Enhance Infrastructure

Provide regulatory certainty by maintaining a consistent cost-recovery and contracting environment and removing regulatory barriers to long-term capacity contracting and cost recovery of collaborative research.

Permit projects within a one-year period utilizing a Joint Agency Review Process.

Increase Supply Diversity

Increase access and reduce permitting impediments to development of lower-48 natural gas resources.

Enact enabling legislation in 2003 for an Alaska gas pipeline.

Process LNG project permit applications within one year.

Promote Efficiency of Markets

Improve transparency of price reporting.

Expand and enhance natural gas market data collection and reporting.

CHAPTER 2
BACKGROUND

Role of Natural Gas in the Economy

Natural gas is a critical source of energy and raw material, permeating virtually all sectors of the economy. Today natural gas provides nearly one-quarter of U.S. energy requirements[1] and is an environmentally superior fuel, thereby contributing significantly to reduced levels of air pollutants. It provides about 19% of electric power generation and is a clean fuel for heating and cooking in over 60 million U.S. households. U.S. industries get over 40% of all primary energy from natural gas. Figure 2-1 illustrates the contribution of natural gas to U.S. energy needs, and Figure 2-2 shows gas use by sector.

North America's natural gas exploration and production industry has been successful in efficiently finding and developing the continent's indigenous resources, and an extensive infrastructure has been developed to efficiently transport natural gas from its diverse sources to its multiple markets. Technology advances throughout the supply chain have increased supply, reduced costs, and minimized environmental effects. Effective mechanisms for the sale, purchase, and pricing of natural gas have evolved, and there has been a progressive reliance in recent years on competition and open markets at each point along the natural gas supply value chain.

Today, many regulations and policies affecting natural gas are in conflict. Public policies promote the use of natural gas as an efficient and environmentally attractive fuel. These policies have led to restrictions on fuels other than natural gas for the siting of power generation and industrial facilities, restrictions on fuel switching, and fuel choice limitations. Other laws and regulations have been enacted that limit access to gas-prone areas – areas where gas can be explored for and produced in an efficient and environmentally friendly manner – and there are outright bans to drilling in certain regions. There are laws and regulations that unnecessarily hinder pipeline and infrastructure siting or interfere with the functionality of the market in ways that lead to inefficiencies. Overall, these conflicting policies have contributed to today's tight

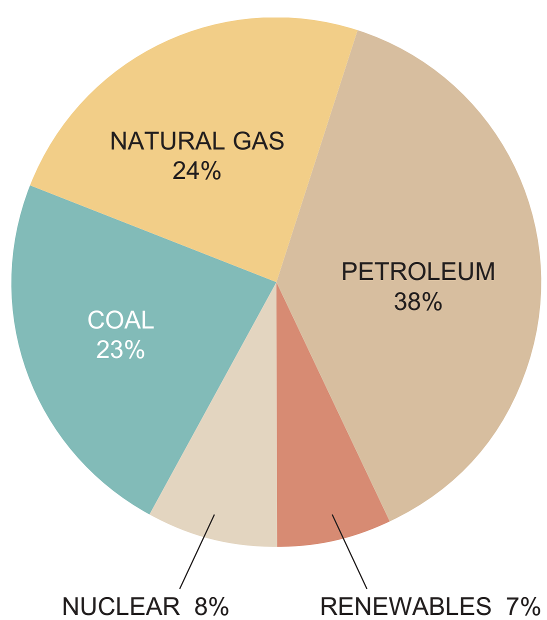


Figure 2-1. Average Annual Energy Use, 1997-2001
97 Trillion Cubic Feet per Year (Equivalent)

[1] Data from Energy Information Administration, Monthly Energy Review, April 2003.

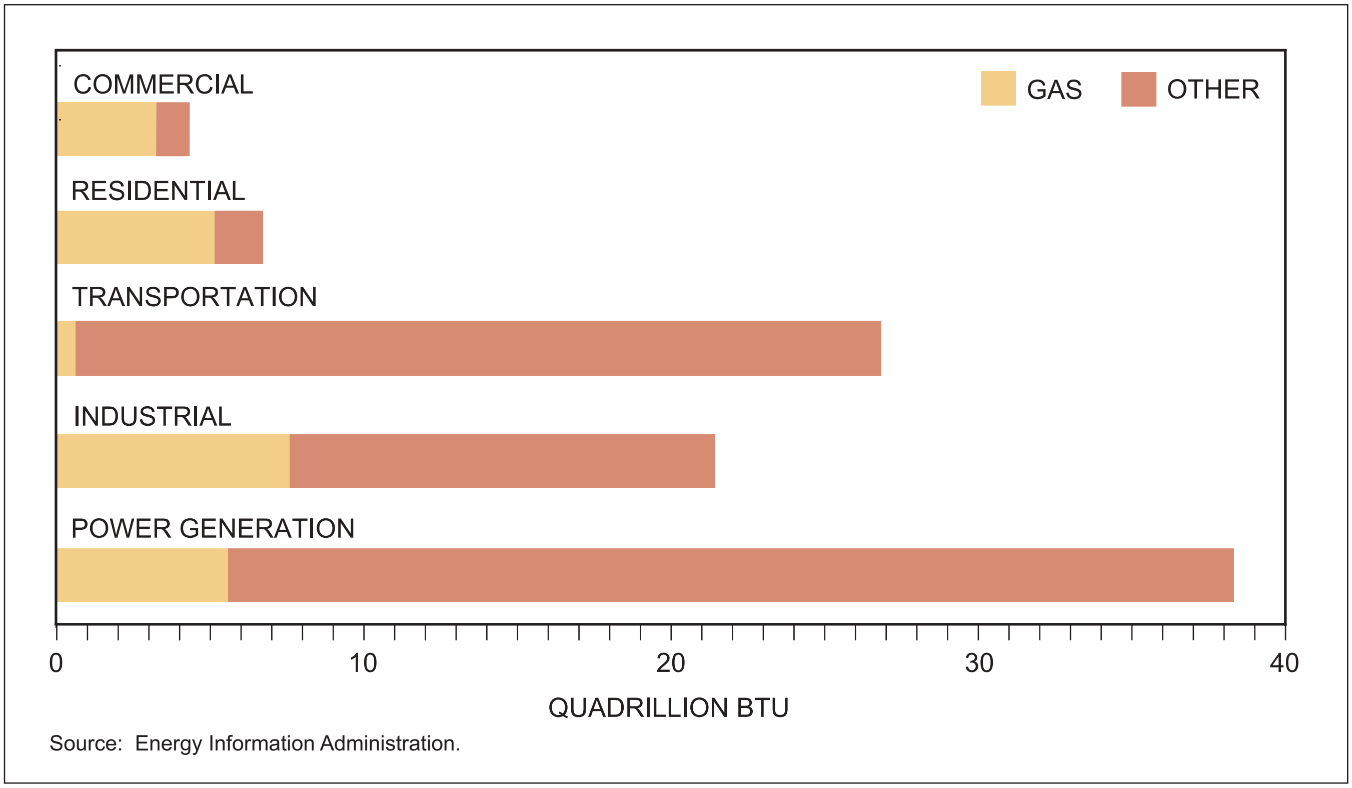


Figure 2-2. U.S. Energy Use by Sector, Year 2002

supply/demand balance, with higher and volatile gas prices. The beneficial effects of additional gas use can be achieved more efficiently and at a lower cost with policies that eliminate the current conflicts.

Natural Gas Market History

Natural gas use in the United States has reflected changes in the economy, in natural gas infrastructure, in natural gas-based technologies, in the regulation of natural gas, and in environmental initiatives. Regulation of the natural gas industry in the United States has had profound effects on natural gas supply and demand and has at times led to stresses on the economy, including the natural gas shortages experienced in the 1970s. In 1938, Congress passed the Natural Gas Act, representing the first major federal involvement in natural gas sales and distribution, and gave the Federal Power Commission (the forerunner of the Federal Energy Regulatory Commission) jurisdiction over interstate natural gas sales and the rates charged for interstate natural gas delivery. The Supreme Court later determined that the FPC also should regulate the prices of natural gas sold in the interstate market. This decision had a complicated and far-reaching effect on the natural gas industry and created significant administrative difficulties for the FPC in trying to set prices for a large number of natural gas producers.

Ultimately, the regulated prices were lower than the market value of the natural gas. These relatively low prices prompted a surge in demand, but failed to encourage additional production, thus leading to a shortage of supply. In addition, since the intrastate market was unregulated, producers sold as much of their production as possible into the intrastate market, thereby exacerbating the shortage in the interstate market. In turn, the natural gas shortages led the FPC to impose priority systems whereby scarce natural gas was allocated to certain customers, with deliveries curtailed to certain customers, such as industrial consumers, who were deemed "low priority."

U.S. gas consumption grew for many years before peaking at 23 trillion cubic feet (TCF) per year in 1972 as shown in Figure 2-3. Post-1972 declines in gas consumption and production were the result of both economic and regulatory forces. For example, gas utilization by industrial consumers and power generators was severely limited by the Power Plant and Industrial Fuel Use Act; gas demand was further dampened by the attendant effects of two economic reces-

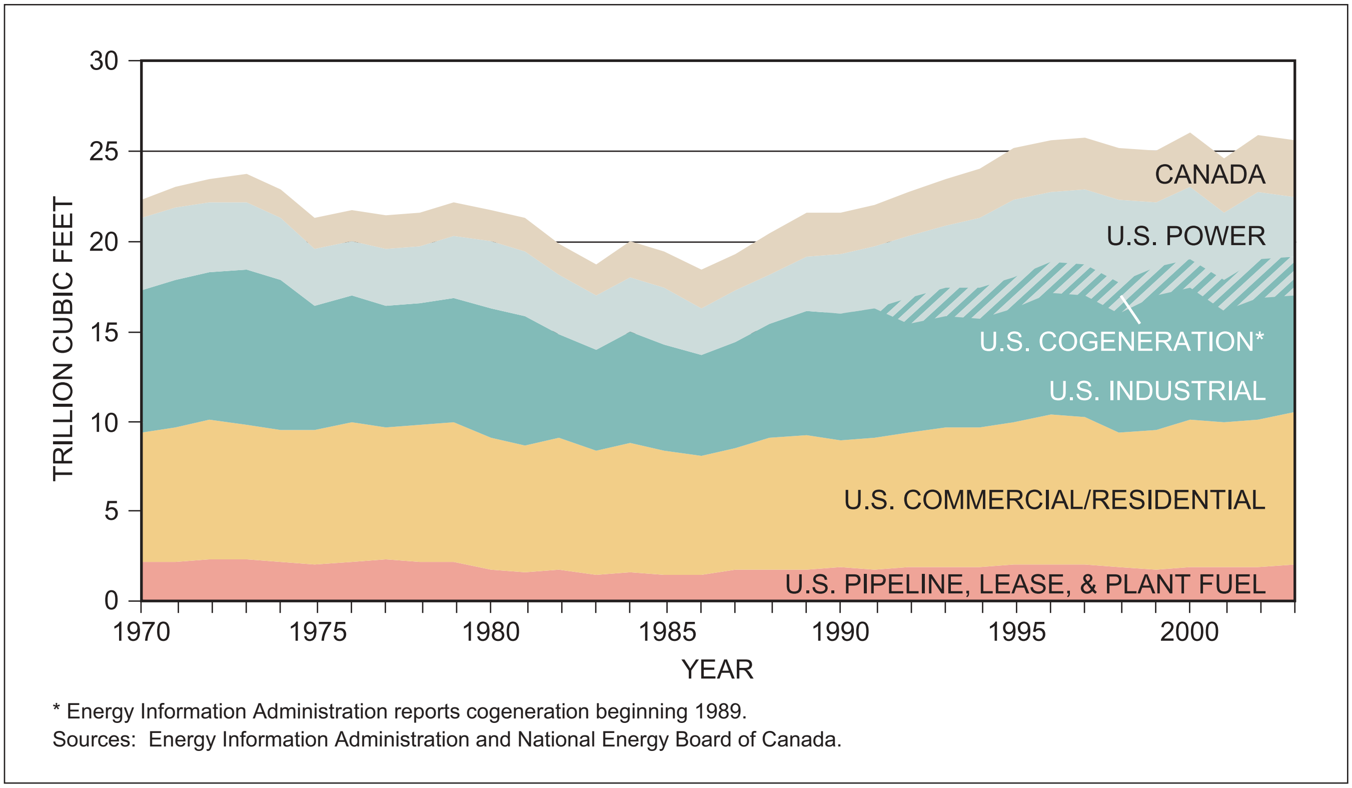


Figure 2-3. U.S. and Canadian Natural Gas Demand

sions. During this period, price-induced conservation reduced residential gas use by 16%. At the low point in 1986, both gas consumption and production had fallen in excess of 25% from the 1972 peak.

Factors that contributed to a rebound in gas consumption and production in the second half of the 1980s continue to shape today's natural gas marketplace. These factors include repeal of the Power Plant and Industrial Fuel Use Act in 1987, the elimination of gas price controls (1989), a restructuring of interstate pipeline contracts, implementation of FERC Orders 436 and 636, passage of the Clean Air Act Amendments (1990), and robust economic growth. Generally falling gas prices after the mid-1980s also stimulated gas demand. Gas became a commodity, one where there was a competitive market and a financial framework for gas buyers and sellers to make short- and longer-term decisions.

U.S. gas consumption increased from 16.2 TCF in 1986 to 23.5 TCF in 2000, surpassing the 1972 peak. Residential and commercial gas growth returned as limits on new hook-ups were lifted, and continued as gas was competitively priced and environmentally preferred. Industrial consumers found gas an attractively priced fuel for process heat, feedstock, and cogeneration, as well as an effective method to meet air quality standards. Electric generators also found gas prices attractive; especially with new, highly efficient, low-emission and low-cost gas-fired turbines providing an environmentally acceptable and economically efficient way to satisfy electricity demand growth. Falling real gas prices during the 1990s made gas attractive as a fuel and feedstock.

In response to demand growth, U.S. gas production rose after 1986, utilizing excess well deliverability and applying advances in production technology. Much of this gain was a result of the industry's transition from a regulated market where most gas was sold by pipelines and was bundled with transmission to one where gas was sold in a competitive market. This transition resulted in a temporary "gas bubble" where both productive capacity (supply) and deliverability (transmission and distribution) exceeded gas demand. By the mid-1990s this excess capacity dissipated due to demand growth and limited increases in productive capacity, as illustrated in Figure 2-4.

Canadian gas imports increased five-fold between 1986 and 1999, filling a growing gap between U.S. consumption and lower-48 production. Canadian production growth occurred from increased drilling

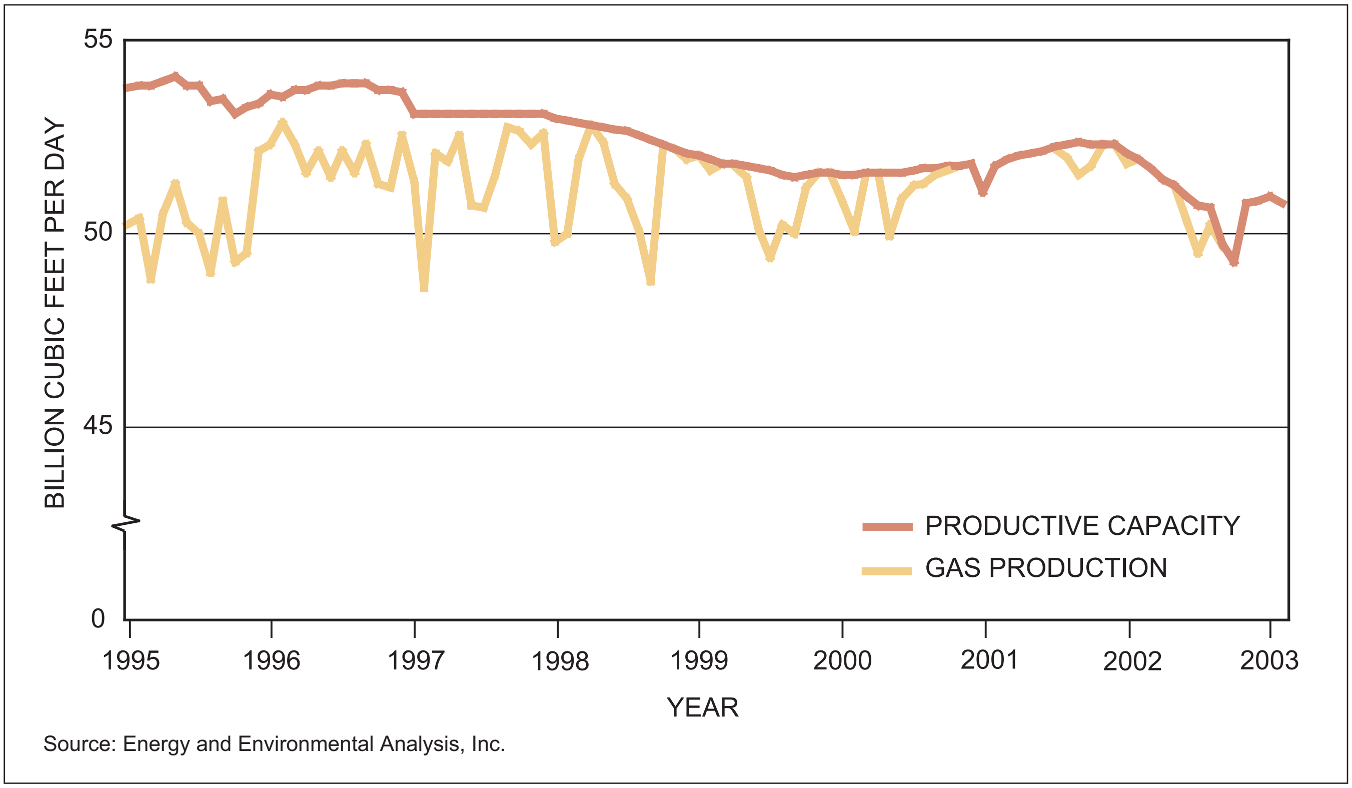


Figure 2-4. Lower-48 Dry Gas Production vs. Dry Gas Productive Capacity

activity and pipeline capacity expansions to U.S. markets. In addition, small volumes of liquefied natural gas (LNG) were imported to terminals in Massachusetts and Louisiana.

During the 1990s, gas prices were generally flat to declining. Although gas supply and demand were more closely balanced, mild weather and new Canadian import projects masked any pronounced tightness. However, by the late 1990s, gas prices began to reflect the value of natural gas in its more diverse applications where gas was becoming a competitive alternative. These applications were often electric generating plants or industrial boilers capable of burning oil or oil-derivative fuels. Increasingly, gas prices were becoming correlated with oil prices.

Another driving factor in gas demand growth during the 1990s was environmental regulations. The Clean Air Act Amendments of 1990 were primarily focused on reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions from electric powerplants and, to a lesser extent, from other industrial and transportation sources. To comply with the mandates of both the first (1995-1999) and second (2000+) phase of the Act, generators and industry turned increasingly to natural gas, either in the form of fuel-switching or investments in new, gas-only equipment. While this strategy has been highly effective in reducing emissions, it has limited the ability to switch to other fuels when the natural gas market becomes stressed.

Finding: There has been a fundamental shift in the natural gas supply/demand balance that has resulted in higher prices and volatility in recent years. This trend is expected to continue, but can be moderated through policy actions.

Natural Gas Prices

Natural gas prices remained in the $1.50 to $3.00 per million Btu (MMBtu) range through the 1990s. With the tightening supply demand balance in the late 1990s, prices have risen and become more volatile, as shown in Figure 2-5. In late 2000, gas prices rose significantly with a short peak at nearly $10.00/MMBtu. Low gas storage levels at the start of the 2000-2001

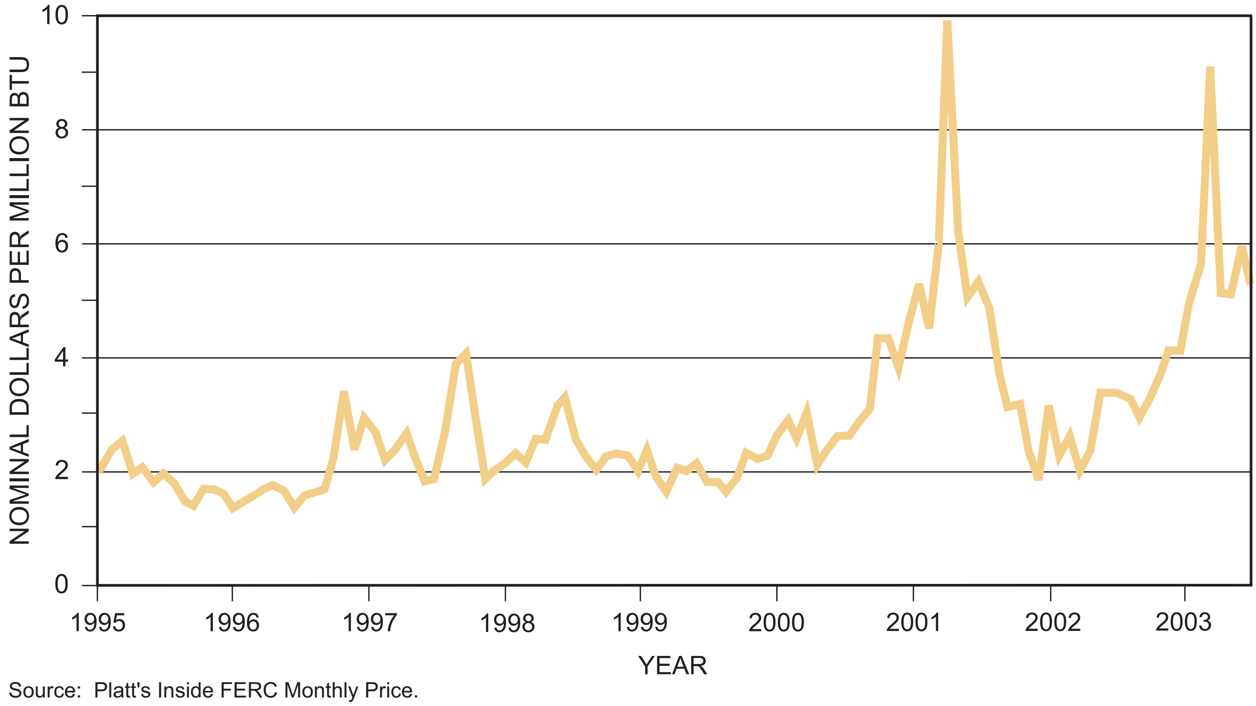


Figure 2-5. Henry Hub Monthly Index Prices

winter, record cold temperatures in November and December, and record storage withdrawals prompted fears of gas shortages. Gas consumers responded to these price signals by reducing gas consumption through a variety of measures that included fuel switching, factory closings, and conservation.

Producers responded to these record prices in late 2000-2001 by embarking on an intensive drilling program. Gas production rose moderately in 2001 as drilling peaked. With rising prices, producers pursued their available inventory of higher-cost, lower-productivity prospects. Supply available to U.S. markets reached its highest level in 20 years as a result of these transitory factors

Gas prices on the New York Mercantile Exchange (NYMEX) fell from $9.00/MMBtu at the start of January 2001 to under $2.00/MMBtu in October 2001. The transitory factors that contributed to this price variability were: mild weather from late winter of 2000 through the summer of 2001; reduced gas demand due to weak GDP growth and falling industrial output; and declining oil prices (West Texas Intermediate (WTI) crude oil falling from $30/bbl in January 2001 to under $20/bbl by year-end).

In 2002, another mild winter and stagnant manufacturing activity depressed gas demand. Gas storage levels were at record-high levels throughout most of 2002. Gas prices fell significantly from the 2000-2001 peaks. The early onset of cold temperatures in the 2002-2003 winter and falling natural gas production depleted North American storage inventories, which fell to record lows in early spring contributing to the run-up in prices in 2003.

Major Assumptions/Methodologies

Macroeconomic Assumptions

Throughout history, economic growth has been associated with higher energy consumption. In the past 25 years, energy use grew 1.0% annually while gross domestic product (GDP) increased at a 3.0% annual rate. While energy use is pervasive in the U.S. economy, there have been steady gains in efficiency with a downward trend in the amount of energy necessary to produce one dollar of GDP. U.S. GDP growth was assumed to average 3.0% per year from 2005 to 2025, similar to the historical trend. The impact of changes in natural gas prices on GDP growth was analyzed, but analysis conducted for the NPC by Global

Insight suggests that GDP growth rates would not be significantly impacted by higher natural gas prices.

U.S. industrial production was assumed to grow at a rate of 3% per year, which is below the 1995-2002 historical growth rate of 3.4% per year. The lower-than-historical growth rate was chosen to reflect the effect of higher-than-historical natural gas prices on gas-intensive industries.

Prices for alternative fossil fuels were assumed within historical ranges. WTI crude oil was assumed to follow the forward curve for the first few years and then settle at a long-term equilibrium price of $20/bbl in constant 2002 dollars. This is similar to the average real price in the 1990s and consistent with the financial community view. Coal prices were assumed to follow the historical trend of decline from a level of $1.25/MMBtu in real terms. This decline reflects continued productivity improvements and competition.

Macroeconomic and other assumptions used in the Reactive Path and Balanced Future scenarios are summarized in Table 2-1. Additional assumptions used in the Reactive Path scenario are highlighted below.

Residential and Commercial Demand

- Residential and commercial demand for natural gas is driven primarily by population growth and demographic patterns.
- Trends in conservation/efficiency improvements continue.
- Natural gas demand in this sector is fairly insensitive to natural gas prices.

Industrial Gas Demand

- This NPC study included more detailed modeling of the gas-intensive industries than the 1992 and 1999 studies because of the recent higher-than-historical gas price environment. This study also incorporates feedback obtained from gas-intensive industry representatives in several workshops.
- Natural gas-intensive industrial production is assumed to grow at a 1.0% to 1.5% average annual rate.
- The chemical and refining sectors represent 50% of the total output from gas-intensive industries. The sectors most impacted by higher natural gas prices are chemicals, ammonia, methanol, and metals.
- Capacity idled for at least two years is assumed to shut down permanently.
- Local, state, and federal government environmental regulations are assumed to continue to limit fuel switching from natural gas to oil.

Macroeconomic Assumptions	**Average Annual Growth Rate**
U.S. GDP Growth	2.8% 2002-2005; 3.0% thereafter
Canadian GDP Growth	2.4% 2002-2005; 2.6% thereafter
Inflation Rate (GDP Deflator)	2.5%
Other Assumptions	
Weather	Historical averages
Oil Price	WTI at $20/bbl (2002$) 2005-2025
Refiner Acquisition Cost of Crude Oil (RACC)	90% of WTI
Residual Fuel Oil Price	84% of RACC by 2004
Distillate	140% of RACC
Coal Price	$1.25/MMBtu and declining in real terms at 1.0%/year to $1/MMBtu by 2025

Table 2-1. Macroeconomic and Other Assumptions

Electric Power

- Electricity Demand Growth – Growth rates were based on income elasticity that declines from 0.72 in 2003 to 0.62 in 2025 to reflect a continued shift in the U.S. economy away from energy-intensive industries, and some power conservation as a result of an extended period of higher-than-historical natural gas prices.

- Technology – Power generation technology is assumed to continue to improve incrementally.

- Coal – Mercury emission regulations are assumed to result in the closure of approximately 20 gigawatts of coal capacity by 2015, although the financial structure of the industry is assumed to support some environmental retrofits of existing coal-fired powerplants. A limited number of new coal plants are built in selected locations.

- Nuclear – Nuclear powerplant utilization is assumed to rise to 90-92% after 2006. No episodic or permanent nuclear plant shutdowns are assumed. However, no new nuclear plants are built due to the long lead-time and high capital costs.

- Oil and Gas Steam – Some existing oil and oil/gas steam units are retired before 2010 and regional/local government limitations on oil usage are maintained.

- Renewables – Renewable capacity will be aggressively constructed, such that over 70 gigawatts of renewable generation will be constructed by 2025.

- The remainder of new generation capacity required is assumed to be gas fired.

Supply

- The study used U.S. Geological Survey, Minerals Management Service, and Canadian Gas Potential Committee play-level assessments and conducted industry/government workshops to review the North American resource base.

- A detailed 72-region supply model was used to evaluate supply, with detailed finding rates and costs.

- Production performance was analyzed over the past ten years, with assessments of initial production rates, production decline rates, and total well recoveries for each major producing basin.

- Cost-of-supply curves were used to estimate market clearing prices that satisfy demand.

- Mackenzie Delta gas was assumed to start up in 2009 at a production rate of 1 billion cubic feet per day (BCF/D) and then ramp up to 1.5 BCF/D beyond 2015. The Alaskan gas pipeline was assumed to start up at 2.5 BCF/D in 2013 and then rise to 4 BCF/D in 2014 and thereafter.

- LNG imports were evaluated and growth to 12.5 BCF/D is projected by 2025 in the Reactive Path scenario; 15 BCF/D in the Balanced Future scenario.

- Annual improvement factors were applied to reflect advancing technologies that will lower drilling and infrastructure costs, improve exploration success, and increase well recoveries over the model timeframe.

Transportation and Storage Infrastructure

- A detailed 115-node model with 317 different pipeline corridors was used to determine the pipeline and storage infrastructure.

- Known or expected pipeline and storage projects coming on stream during the next five years were specified. Beyond the first five years pipeline capacity was assumed to come on stream two and a half years after justified by price basis differential, with some capacity added more quickly in areas with significant supply development.

- For large projects such as Arctic, LNG, and deep offshore, infrastructure was assumed to be built just in time.

- Working gas capacity of storage was increased over the study period by about 700 BCF from the 2003 level, based on the daily load analysis.

- Substantial additions to transmission capacity are projected to link new storage capacity to markets in the Northeast.

- The historical storage injection seasonal pattern was changed to reflect the emerging July-August peak use of gas-fired generation.

- Distribution facilities are demographically driven, based on growth in customers.

CHAPTER 3

NATURAL GAS DEMAND

This chapter describes the methods used by the Demand Task Group to develop an outlook for natural gas demand and describes the results of these analyses. The demand-related aspects of this study's findings and recommendations are based on these analyses. The demand outlook is discussed below, along with additional details for each of the major areas driving the demand for natural gas. The full demand study documentation is found in the Demand Task Group Report and its appendices.

Study Approach

The analysis of natural gas demand focused on the primary factors affecting current natural gas consumption and evaluated variables that are likely to affect long-term usage. This analysis consisted of the following elements:

- An assessment of historical and expected macroeconomic and demographic factors affecting the demand for natural gas.
- A detailed evaluation of installed and likely additions to future power generation capacity within the regions and sub-regions of the North American Electric Reliability Council, including the manner in which this capacity will likely be used. This analysis also assessed the recent, massive buildup in natural gas-based generation.
- An assessment of natural gas utilization in the most energy-intensive industries, including estimates of short-term demand elasticity and the potential for short and longer term demand destruction.
- An assessment of future trends for residential and commercial gas consumption.
- Assessments of the effects of energy efficiency and technology advancement on natural gas demand.

The study of demand was undertaken by four working groups: Economics and Demographics, led by Shell Trading Gas and Power; Power Generation, led by American Electric Power; Industrial Utilization, led by Process Gas Consumers; and Residential and Commercial, led by KeySpan Corporation. KeySpan provided overall coordination of the Demand Task Group.

The Economics and Demographics Subgroup developed critical assumptions necessary to run econometric and other analyses for the Demand, Supply, and Transmission & Distribution Task Groups. These assumptions included major North American economic growth parameters and alternate fuel prices, mainly U.S. coal and oil prices. Model outputs were additionally vetted to see if key assumptions needed to be altered.

The Power Generation Subgroup focused its efforts on understanding the factors that are likely to drive capacity and utilization decisions of existing and new gas-fired generation. A variety of electric power generators from various regions was represented or consulted in this analysis, and workshops were held in New Orleans, Phoenix, and Baltimore. A suite of cost factors were developed for the construction and utilization, or dispatch, of generation capacity by fuel type. The team performed extensive analysis on investment criteria; likely technology advances; outlooks for coal, nuclear, and hydroelectric capacity; the potential effects of Regional Transmission Organizations; the effects of state, provincial, and local regulations and standards; and practices governing the flexibility of power generators to substitute fuels.

The Industrial Utilization Subgroup attempted to analyze the recent changes observed in industrial natural gas demand. Emphasis was focused on critical gas-intensive industries such as chemicals, primary metals, and paper. The subgroup received considerable support and information from these and other key energy-intensive industries. A series of outreach sessions was held to evaluate trends and to analyze factors influencing gas demand by sector and process within the sectors.

To analyze future trends in residential and commercial gas consumption, the Residential and Commercial Subgroup used econometric models and capital stock models. These models included the effects of weather, demographic trends, population growth, residential housing stock, capital stock efficiency, commercial floor space, penetration of gas-based technology, and gas prices as determinants of gas consumption.

All of the subgroups placed particular emphasis on understanding the historical and potential role of energy efficiency. Similarly, the impact of environmental laws and regulations was modeled to ascertain past and anticipated effects on natural gas demand. Finally, the role of energy market mechanisms – which either facilitate or impede efficient natural gas utilization – was assessed within each demand sector.

Demand Outlook

The Demand Task Group analyzed the demand-related aspects of scenarios on natural gas supply, demand, and infrastructure through 2025. This analysis was largely performed using a series of econometric and other models developed by Energy and Environmental Analysis, Inc. (EEA). Although the use of EEA's models was similar to the 1992 and 1999 NPC studies, the EEA models were augmented by extensive work on the industrial segment to create a greater degree of granularity in the price elasticity and switching behavior of this demand segment.

Natural gas demand in 2002, by major consuming and geographic segment, is depicted in Figure 3-1. Industrial demand and gas for electric power have been historically concentrated in the primary gas-producing regions, while the large population centers in colder climates show larger residential and commercial demands.

Figure 3-2 depicts the results of the Reactive Path scenario for North American demand. In this scenario, North American natural gas demand grows at an approximate 1% annual average rate through 2025. Today's largest consuming sector, industrial gas, shows relatively little growth, while gas for power generation grows at a faster pace than any of the other sectors. Residential and commercial gas consumption growth slows to less than 1% per year.

Energy, Natural Gas, and the Economy

Natural gas has played a critical role in the United States' energy picture during the last 50 years. Natural gas was about 16% of the total energy consumption in the early 1950s. As it became a widespread fuel for home heating, and a significant fuel and feedstock in industrial applications, its share of total energy grew to nearly 32% in the early 1970s.

During the early 1980s, however, natural gas use as a percentage of total energy consumption dropped to about 23%. Gas consumption declined due, in part, to a period of relatively high gas prices, gas shortages, and curtailments that led to government policies discouraging the use of gas for certain applications. Since the mid-1980s, natural gas has maintained approximately a 25% share of total energy consumption while its use has grown by about 2.1% per year. Figure 3-3 shows natural gas in relation to the other primary sources of energy for the United States.

Gas is a major source of energy in every sector of the economy except the transportation sector, as depicted in Figure 3-4. It has become a highly desirable fuel in each of the sectors where it enjoys significant market share due to its ease of use, historical competitive costs, and most recently its desirable environmental impact characteristics of low emissions.

Gas Demand for Electric Power Generation

Over the past decade, power generation has been increasing its demand for natural gas. The drivers for this growth include increasing electricity demand, the rapid buildup of gas-fired generating capacity, and more stringent environmental policies. Figure 3-5 shows historical and projected power generation capacity. The large quantity of natural gas-fired generation capacity installed between 1998 and 2005 underpins the outlook for significant gas demand growth over much of the 2005-2025 period, as depicted in Figure 3-6.

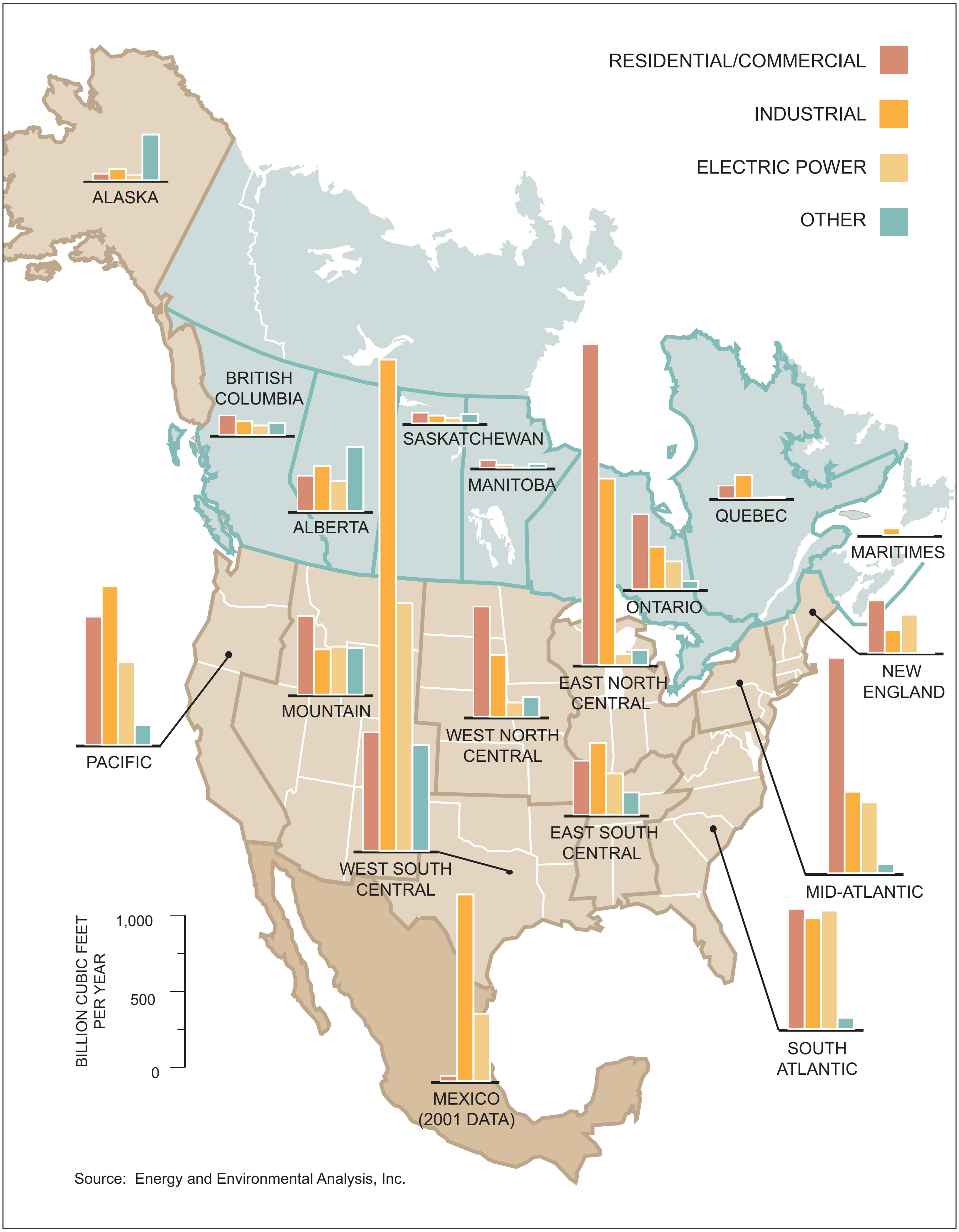


Figure 3-1. North American Natural Gas Demand by Sector and Region, 2002

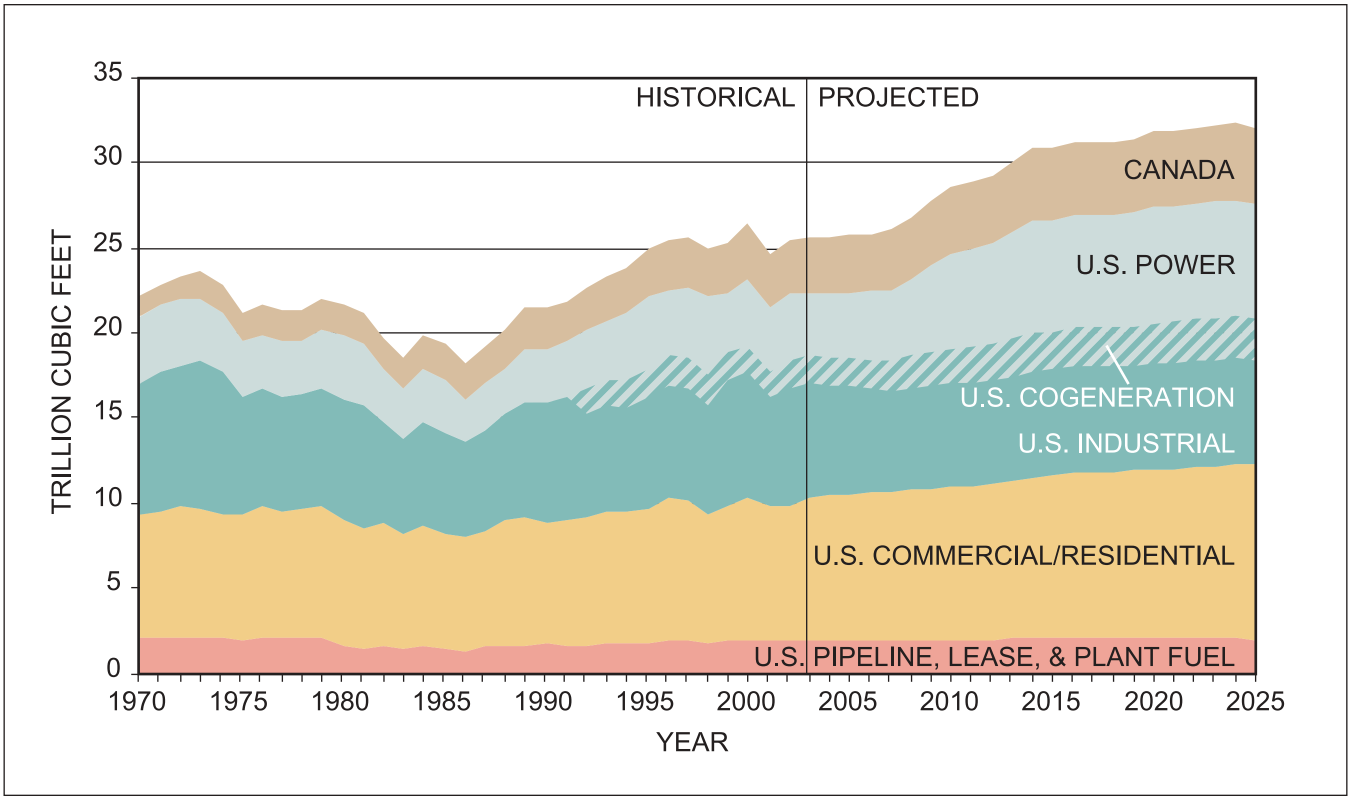


Figure 3-2. Historical Gas Demand and Reactive Path Projection

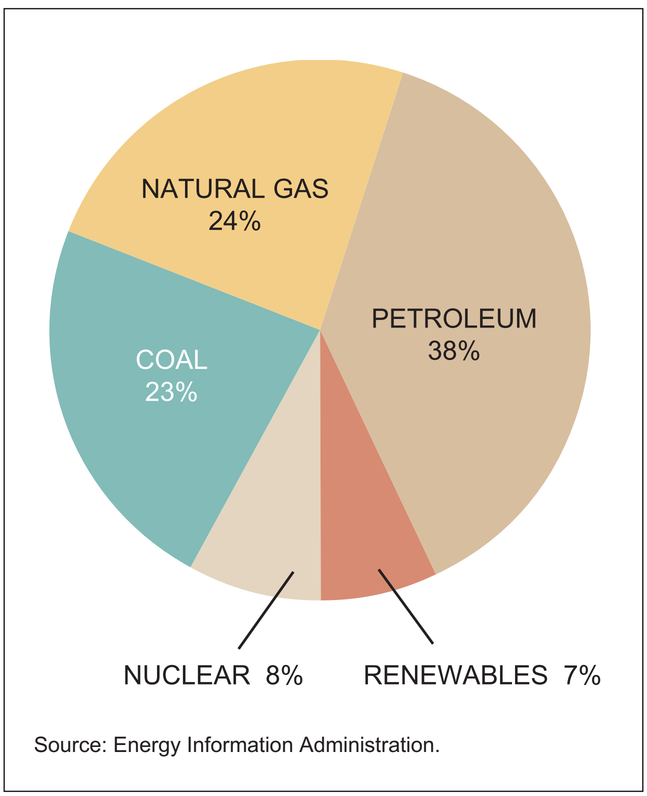


Figure 3-3. Average Annual Energy Use, 1997-2001
97 Trillion Cubic Feet per Year (Equivalent)

Figures 3-5 and 3-6 also suggest that coal will continue to provide a significant share of total power generation. However, permitting and siting a new coal facility will remain a formidable challenge. The analysis expects that new technologies for lowering air emissions of sulfur oxides (SOx) and nitrogen oxides (NOx) will make it possible to build coal-fired powerplants in the regions that traditionally have the highest percentage of coal-fired capacity. It was assumed that no coal plant would be successfully sited in the non-attainment areas of the U.S. east or west coasts during the period of this study. Figure 3-7 shows the non-attainment areas and provides a geographic distribution of the new gas-fired capacity that is included in the NPC's outlook. Except in the Pacific Northwest and upper Midwest, over 50% of the ultimate projected gas-fired capacity is in place or under construction.

Industrial Natural Gas Demand

The industrial sector is currently the largest demand segment for natural gas. It fueled much of the growth in demand from the mid-1980s until late in the 1990s. As shown in Figure 3-2, an important element of that growth was the use of natural gas in cogeneration applications producing combined heat and power for

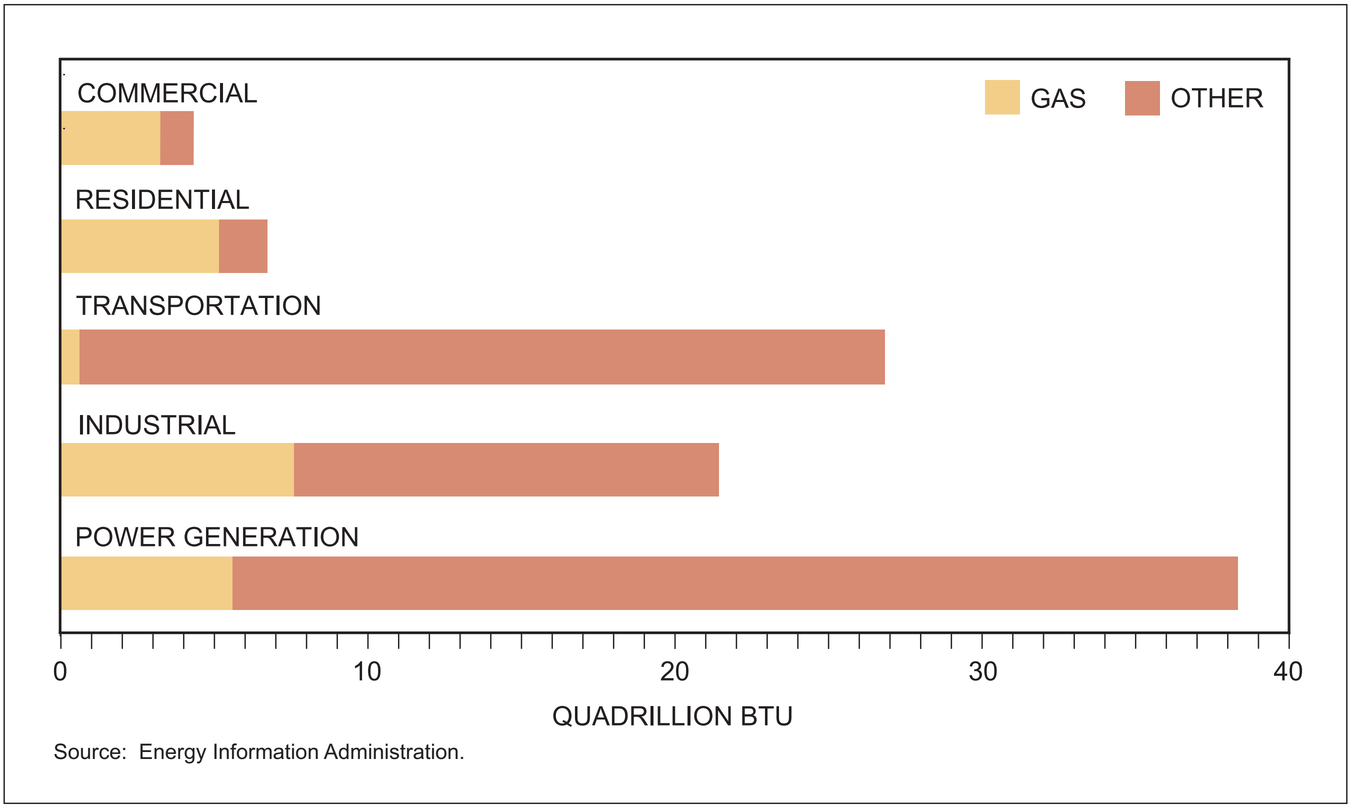


Figure 3-4. U.S. Energy Use by Sector, 2002

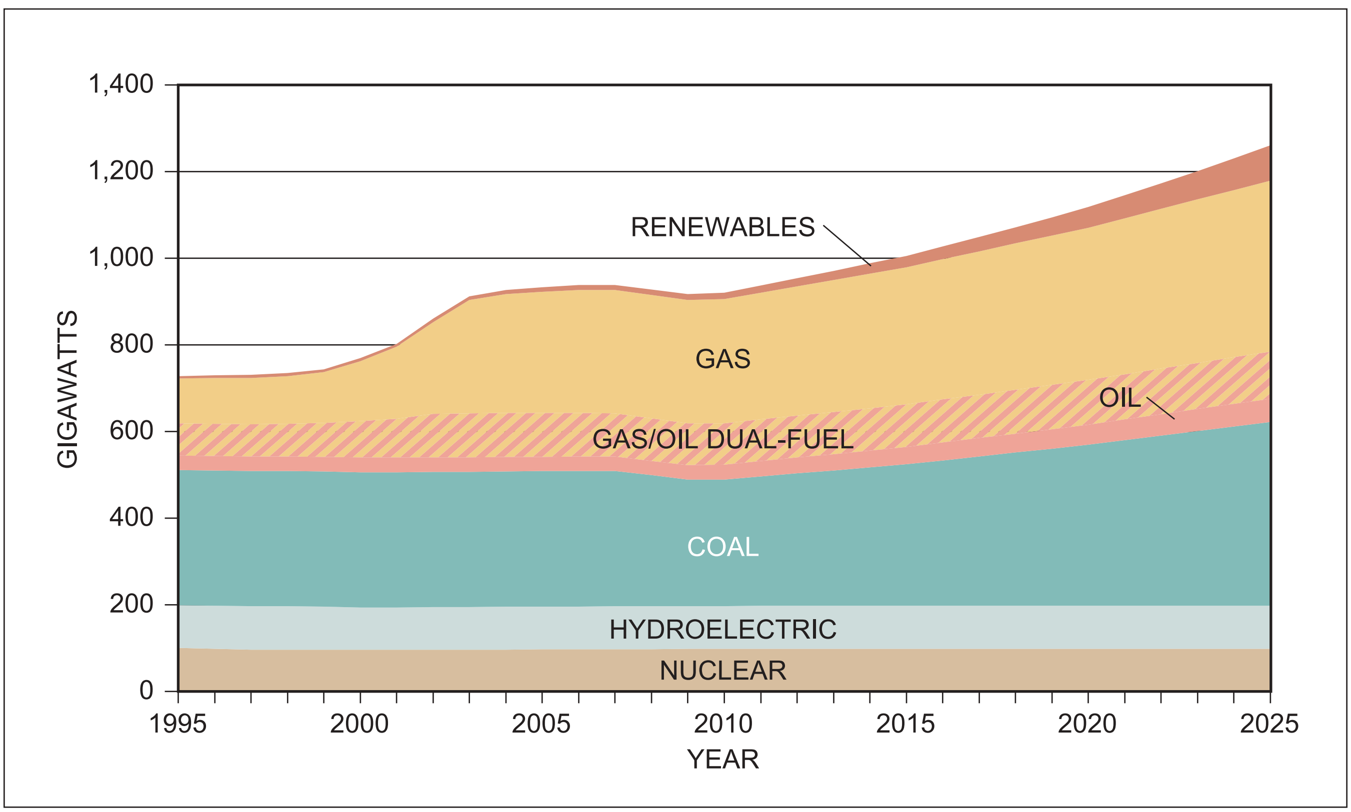


Figure 3-5. U.S. Electric Power Generation Capacity by Fuel Type

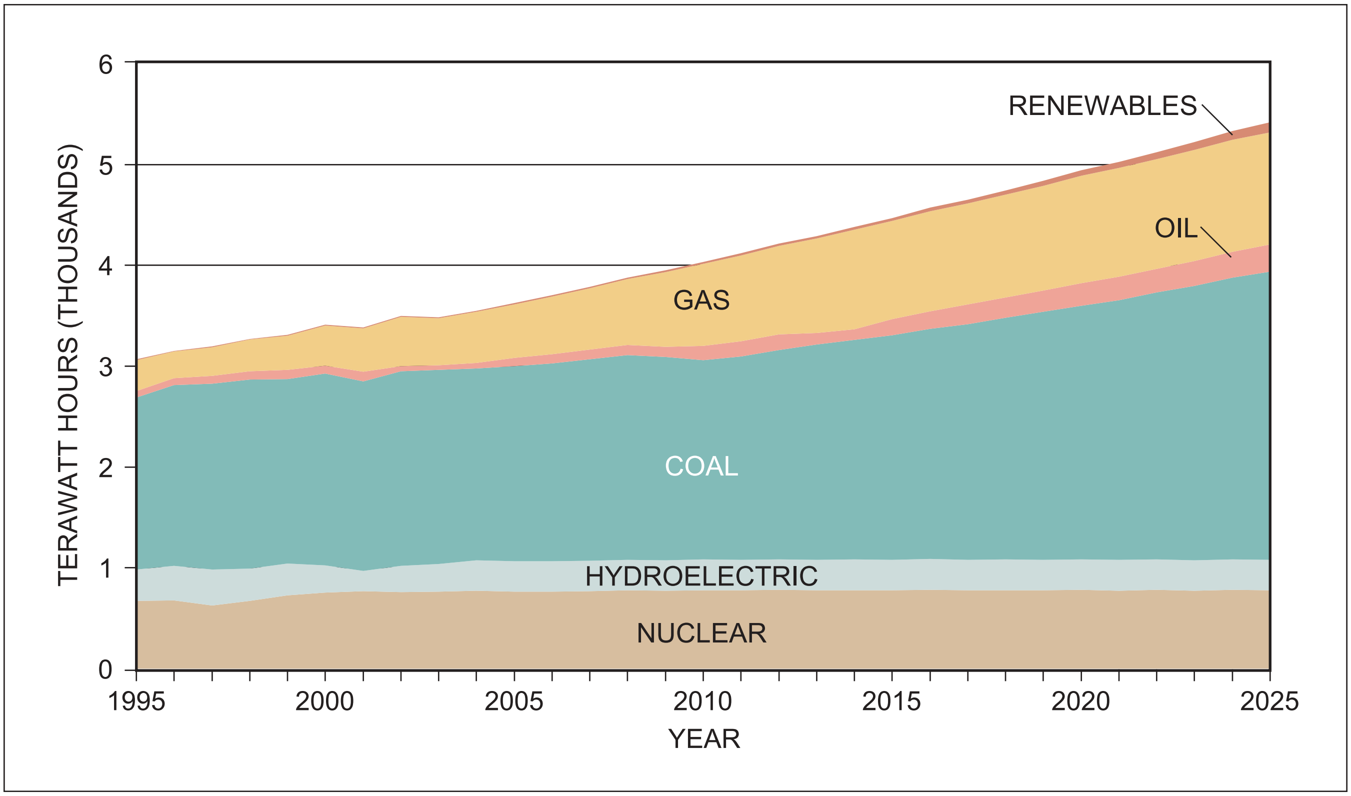


Figure 3-6. U.S. Electricity Generated by Fuel Type

the industrial facilities and optimizing the efficiency of producing steam and electricity. The six most gas-intensive industrial groups are:

- Chemicals
- Petroleum Refining
- Primary Metals
- Food and Beverage
- Paper
- Stone, Clay, and Glass.

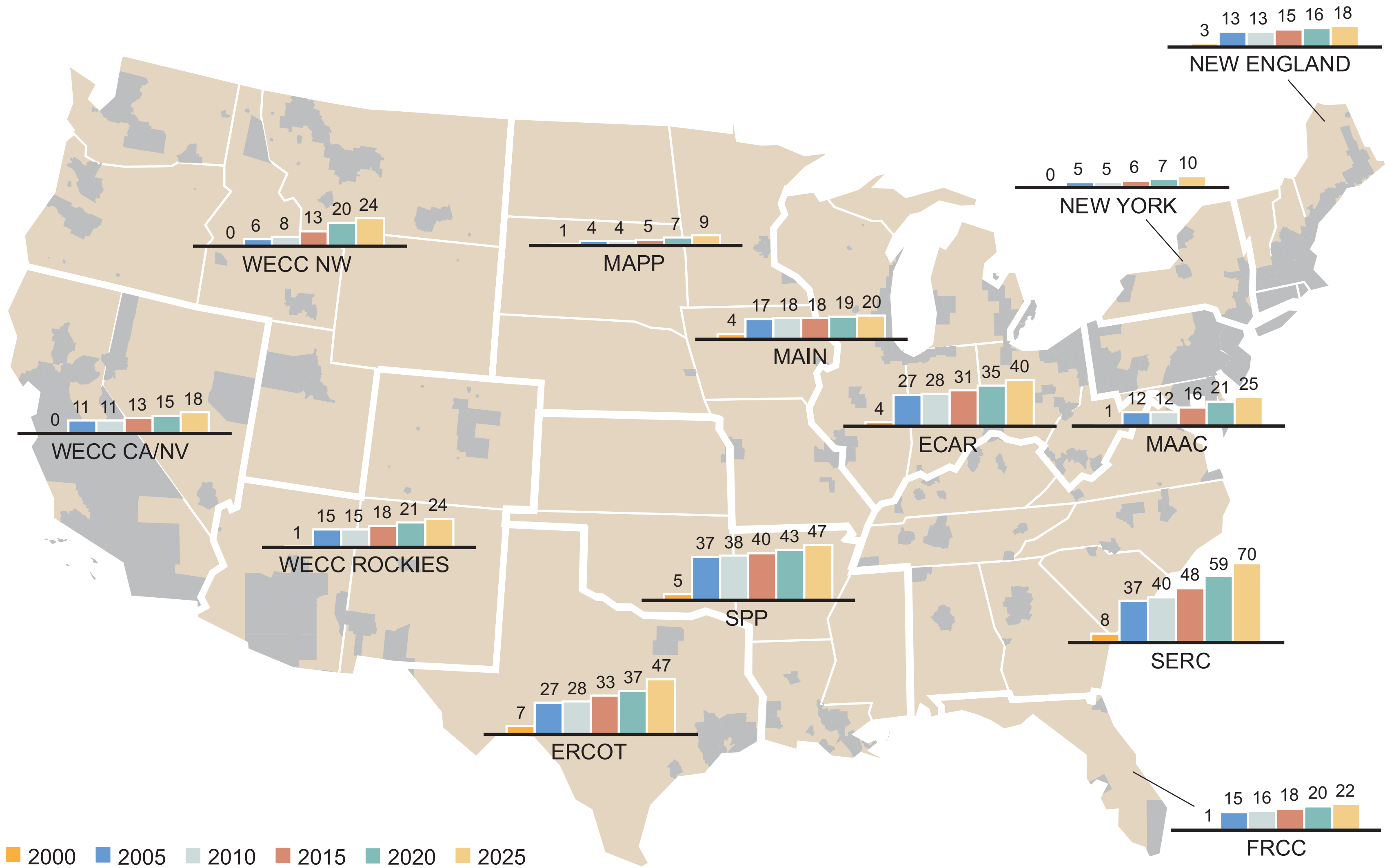
Figure 3-8 shows the outlook for natural gas demand by energy-intensive industrial segments. Higher natural gas prices for feedstock and fuel combined with global competition results in a more subdued outlook for demand growth in the industrial sector. The chemical industry, in particular, is projected to reduce gas demand through 2025. Figure 3-9 shows the outlook for gas demand by type of end-use application within the industrial sector. Environmental emission characteristics, ease of use, and continued efficiency gains may allow natural gas to maintain its share of these end-use applications energy requirements.

The NPC found that industrial consumers are under more severe pressure from higher natural gas prices than other demand sectors. Further, the investment decisions of industrial gas consumers are predicated on a wide range of factors, many of which pertain to international competition and geopolitical considerations. Therefore, the potential for additional demand destruction exists in all gas-intensive manufacturing

Residential and Commercial Natural Gas Demand

Residential and commercial customers primarily use natural gas for space heating, water heating, and cooking. Over 60 million households in the United States use natural gas for some application. Natural gas has a high saturation rate for space heating, particularly in the population centers in the northern climates. This extensive use as a heating fuel contributes to the seasonal nature of the natural gas industry. Consumption of natural gas in the United States has a distinct annual cycle. Average monthly gas demand in the winter peaks at 35-40% above the annual average.

Residential and commercial natural gas demand is expected to increase more slowly over the 2005-2025



Notes: Units are measured in gigawatts. Regions are based on North American Electric Reliability Council (NERC) regions.
Shaded areas are the EPA non-attainment areas.

Figure 3-7. EPA Non-attainment Areas and New Gas-Fired Capacity

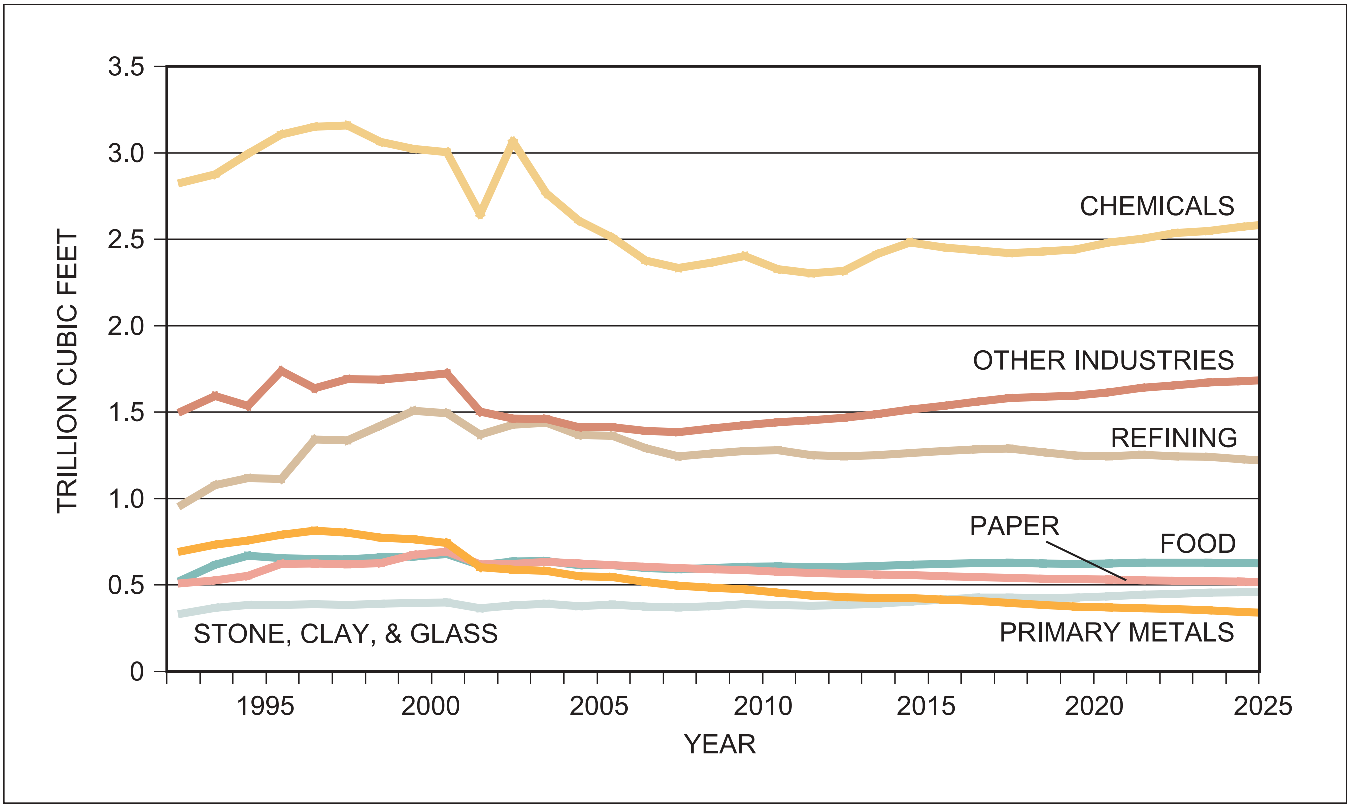


Figure 3-8. U.S. Industrial Gas Consumption by Industry

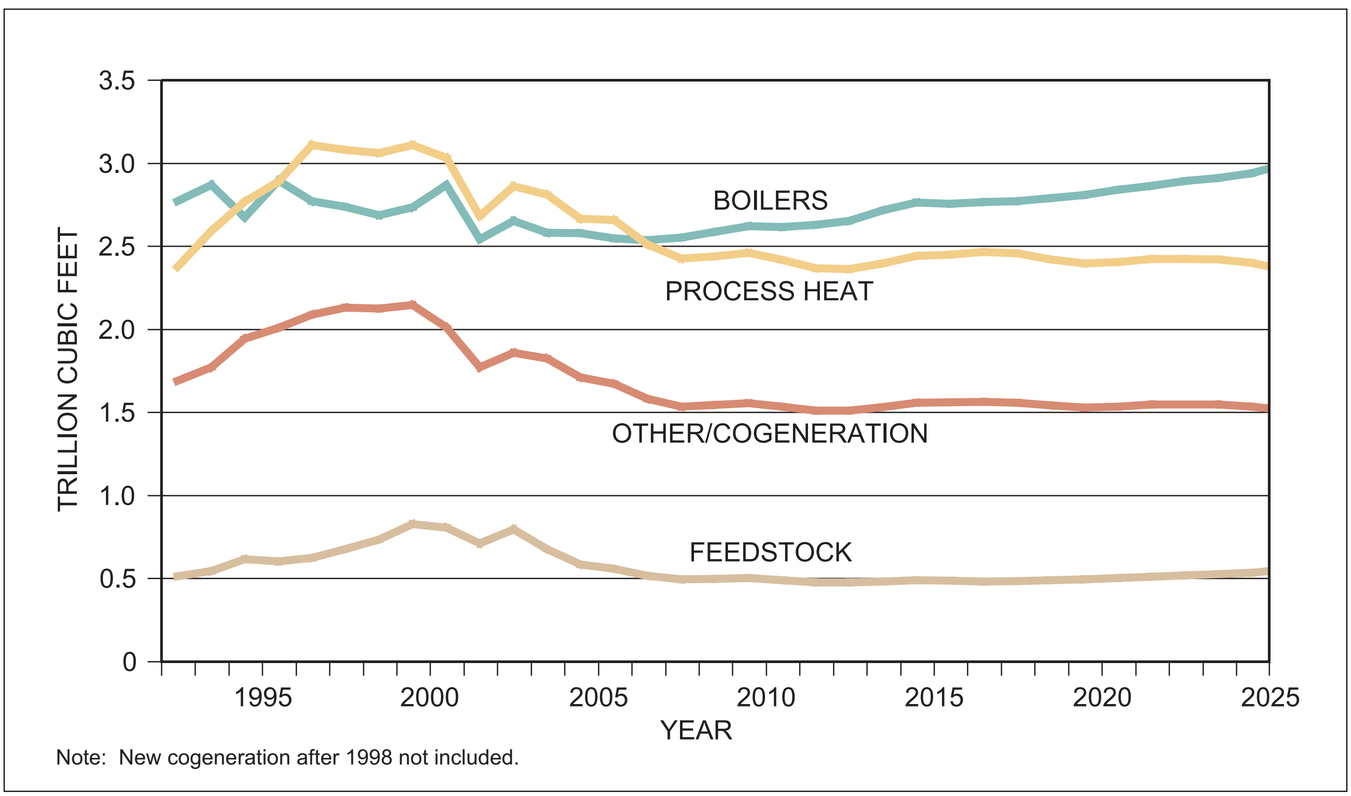


Figure 3-9. U.S. Industrial Gas Demand Breakdown

period. Efficiency gains and demographic shifts are the primary factors in this decline. In the Reactive Path scenario, growth in this sector is slightly less than 1.0% annually.

Macroeconomic Factors

The primary macroeconomic and exogenous price assumptions that were used in the demand projections are listed in Table 3-1. The same primary macroeconomic assumptions were used in both the Reactive Path and Balanced Future cases.

Natural Gas Price and Oil Substitution

The reduction in fuel substitution capability recently observed in both the industrial and electric power sectors is due primarily to actions taken by consumers in response to environmental requirements. In the Reactive Path scenario, this trend continues through 2025. However, this trend has implications for the relationship between natural gas and competing fuels and/or feedstocks. Natural gas has historically tended to sell at a discount to crude oil on an annual average basis. In general, this pricing relationship reflected the extent to which petroleum products could be substituted for natural gas, including relative costs of transportation and storage. Figure 3-10 shows that natural gas has approached price parity with crude oil in recent years, reflecting the increasing investment in either gas-only facilities or facilities that are restricted to using cleaner petroleum products.

In both the Reactive Path and Balanced Future scenarios, the price of crude oil is assumed to decline from

U.S. GDP Annual Growth	3.0%
U.S. Industrial Production Annual Growth	3.0%
U.S. GDP Deflator Annual Change	2.5%
Canadian GDP Annual Growth	2.6%
Crude Oil, WTI (2002$)	$20.00
U.S. Coal Price Annual Changes (2002$)	-1.0%

Table 3-1. Primary Macroeconomic Assumptions, 2005-2025

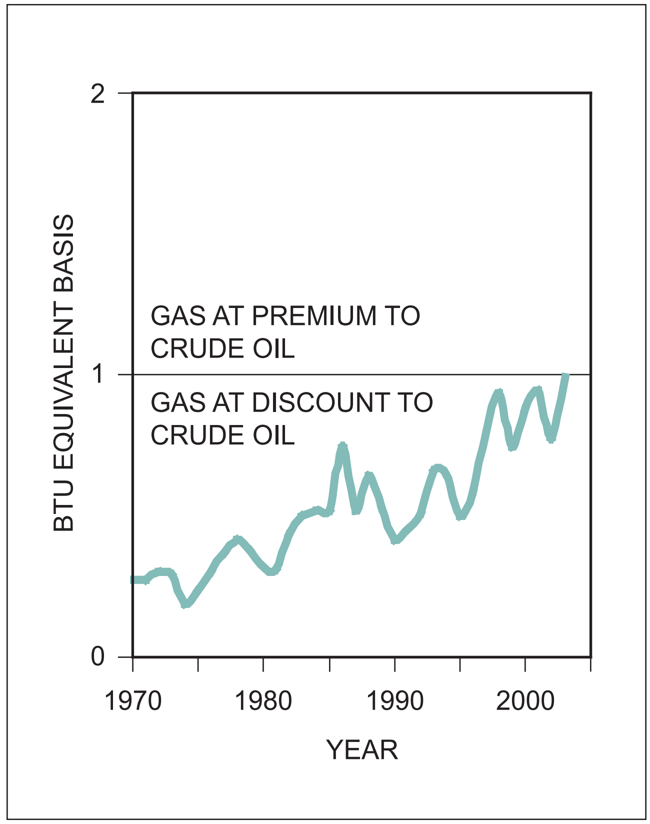


Figure 3-10. Ratio of Wellhead Natural Gas Price to West Texas Intermediate Crude Oil Price

year 2003 levels to its historical average of approximately $20/bbl for West Texas Intermediate crude oil in the 2005-2025 period. The results of each scenario suggest that natural gas would tend to sell at a premium to crude oil in the future using this oil price assumption because of the limited ability of market participants to substitute oil and its derivative products for natural gas. However, the Balanced Future scenario projects natural gas to be priced closer to crude oil parity.

Conclusions

This NPC analysis suggests that natural gas demand is likely to remain at recent levels for several years, with power generation demand continuing to grow while industrial demand continues to erode. Demand is then likely to increase slowly due to increasing needs for power generation, the energy requirements of a growing economy, and the environmental imperatives in both the United States and Canada. This analysis also suggests considerably higher natural gas prices will be necessary to balance supply and demand, resulting in lower demand levels than projected in the 1999 NPC study, as well as in other U.S. government forecasts.

Industrial Demand

This section provides details of natural gas use in the industrial sector. The historical determinants of industrial gas use and the factors that will affect its future use are reviewed and analyzed. Finally, projections of industrial gas use through 2025 are summarized.

Industrial consumers used 7.2 trillion cubic feet (TCF) or about 32% of total U.S. gas consumption in 2002. Industrial businesses use natural gas for energy and as a raw material or feedstock. Figure 3-11 illustrates regional energy use for U.S. industrial consumers in 2002. Figure 3-12 provides a basic description of the use of natural gas as a raw material. Natural gas use in the industrial sector has developed over many years. Over the last 60 years, industrial consumers have made considerable investment in capital equipment for preferential use of natural gas. Except for a few periods, natural gas has been a widely available, cost-effective fuel and feedstock. Since 2000, however, the price of natural gas has risen significantly, attendant with new concerns about its availability. The high price for natural gas alone changes the competitive environment for many industrial consumers.

The price of natural gas relative to other fuels is a key variable in future industrial gas demand. A key variable to project the future use of natural gas in this study is industrial production. Industrial production measures changes in the output of production versus a baseline year. In contrast to past NPC studies, emphasis was placed in this analysis on relating gas price forecasts to future industrial production.

Value of Gas to Industrial Consumers

Natural gas has become an increasingly important fuel for industrial consumers. Natural gas in industrial applications offers flexibility, controllability, and low emissions; relative to other fuels, it has been cost-competitive. Table 3-2 summarizes the characteristics of natural gas and competing fuels. Historically, natural gas on a heat content (dollars per Btu) basis has been less expensive than all other fuels except for coal. The operational characteristics of natural gas are as good or better than more-expensive energy sources (e.g., distillate or electricity). Natural gas is widely available, easy to transport, and requires no on-site storage. Natural gas can be used in a wide variety of applications to provide a high degree of control without negatively affecting product quality; for example, in contact heating and drying processes.

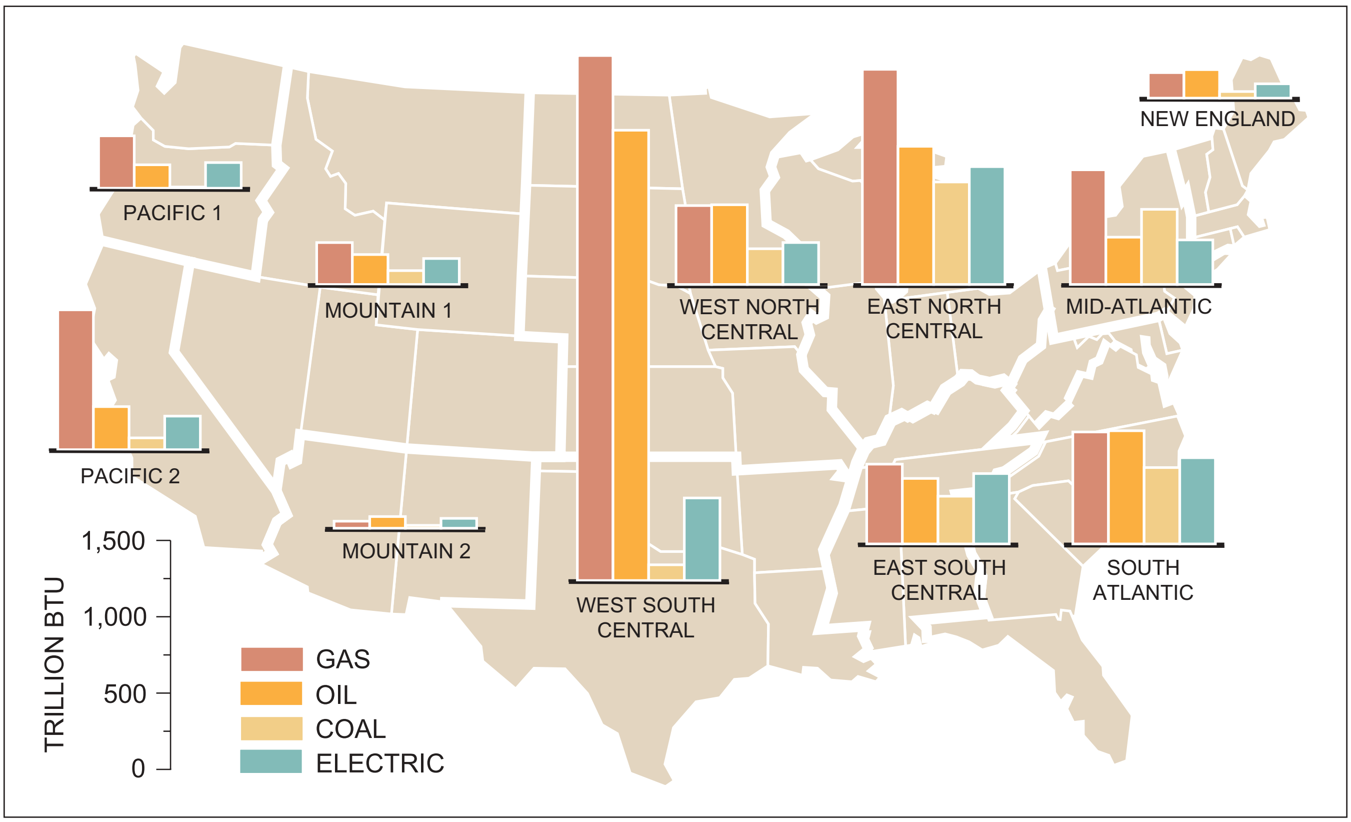
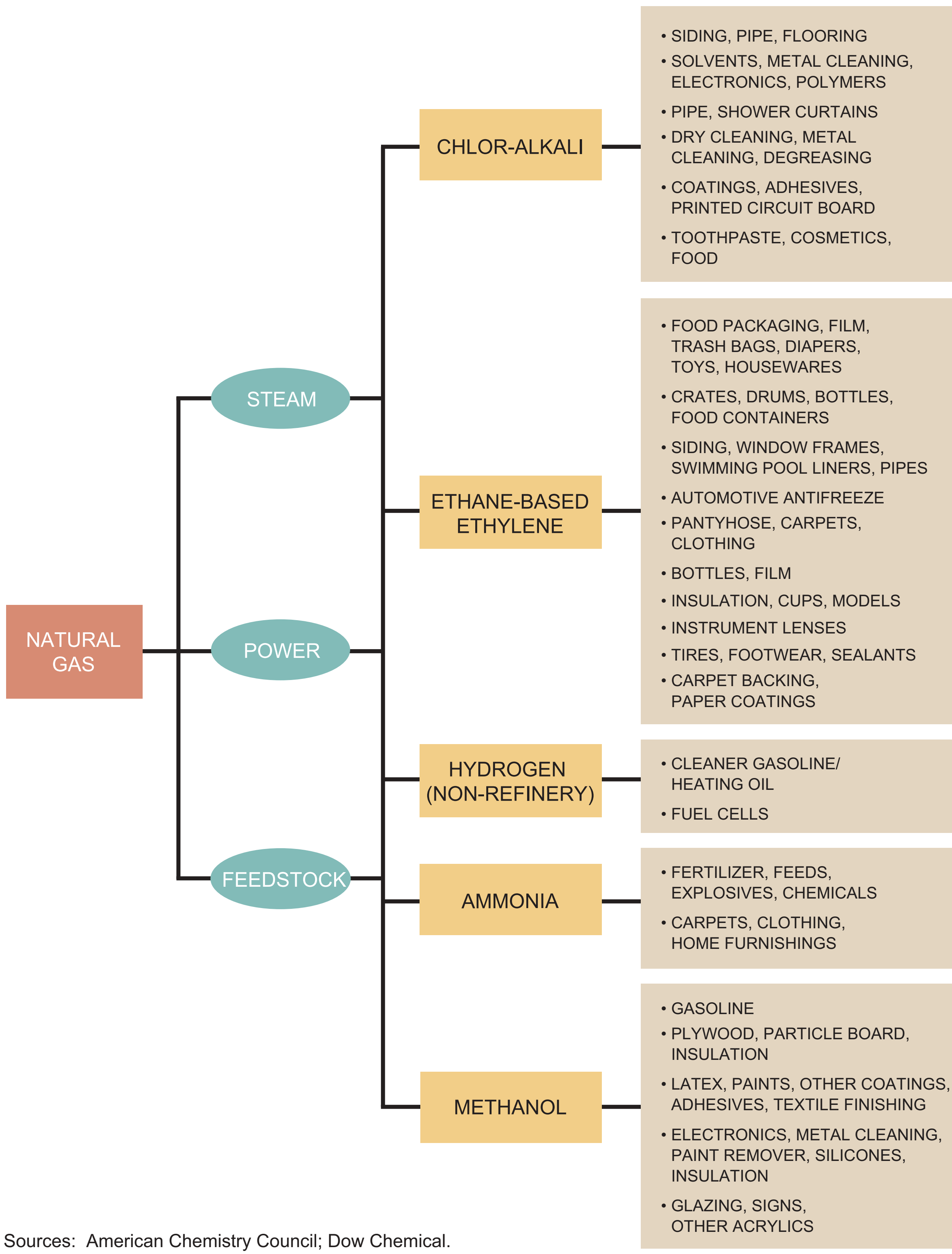


Figure 3-11. U.S. Industrial Energy Use in 2002



Sources: American Chemistry Council; Dow Chemical.

Figure 3-12. Simplified Diagram of Natural Gas Use as a Raw Material

	Coal	Residual Oil	Distillate Oil	Electricity	Natural Gas
Cost	Low	Low	High Mid	High	Low Mid
Transportation	Difficult	Difficult	Medium	Easy	Easy
Storage	Difficult	Difficult	Medium	NA	NA
Combustion	Difficult	Difficult	Medium	Easy	Easy
Controllability	Poor	Poor	Good	Very good	Very Good
Direct Contact	No	No	Many	Yes	Yes
Emissions	High	High	Medium	"Zero"	Low
Historical Price	$1-2/MMBtu	$3-5/MMBtu	$4-5/MMBtu	$12-14/MMBtu	$2-4/MMBtu
Major Uses	Large boilers, boiler cogeneration, cement calcining	Large boilers, refinery heaters, lime calcining	Diesel fuel for transportation. Backup fuel for many small- and mid-sized boilers, many process heat applications, primary fuel for only a few	Electric Arc Furnace, lighting, machine drive, many drying, heating, melting, and curing applications	Boilers, cogeneration (boiler and turbine), all kinds of process heat, largest include chemical, refining, primary metals, glass melting

Table 3-2. Characteristics of Industrial Fuels

The importance of gas in the industrial sector relative to other energy sources is shown in Figure 3-13. Gas is the primary fuel for boilers, cogeneration, and process heating. Gas is also an important feedstock. However, gas is not the primary fuel in electric applications (e.g., lighting and motors) and transportation, where diesel fuel predominates.

The use of alternate fuels has been important for industrial consumers. For example, periodically when gas prices were high relative to alternate fuels, facilities capable of switching to another less-expensive fuel had important competitive advantages. That role has diminished during the last decade, however, as fuel-switching capability has dwindled due to the combination of regulatory and operational factors. Government data on alternate fuel use and capability are not current. The NPC modeling was based upon information from extensive outreach efforts among the industrial community.

Natural gas is used in practically every part of the industrial sector. Figure 3-14 shows that 72% of industrial energy and 80% of industrial natural gas is consumed in six of the most gas-intensive industries: Chemicals; Petroleum Refining; Primary Metals; Food and Beverage; Paper; and Stone, Clay, and Glass. The performance of these key industries has been used to determine the overall industrial demand for gas.

Industrial Natural Gas Use Drivers and Trends

Key drivers for industrial energy and gas uses are:

- **Production Growth.** "Industrial Production" is a key factor in describing the driving forces for total U.S. energy and gas demand. Many factors determine production growth, including growth in the U.S. and global economies and the competitiveness of U.S. industry in global markets. High relative energy prices reduce industry competitiveness, potentially lowering the demand for energy and gas.
- **Industry Mix.** Long-term trends in industry mix impact energy demand. Over the last 30 years, many traditional manufacturing industries have declined in the United States due to foreign competition or other factors. The United States has evolved to more technology and service industries, which consume less energy per gross domestic product (GDP) dollar. Some basic energy-intensive industries, such as primary metals and fertilizer, have experienced temporary and permanent declines.

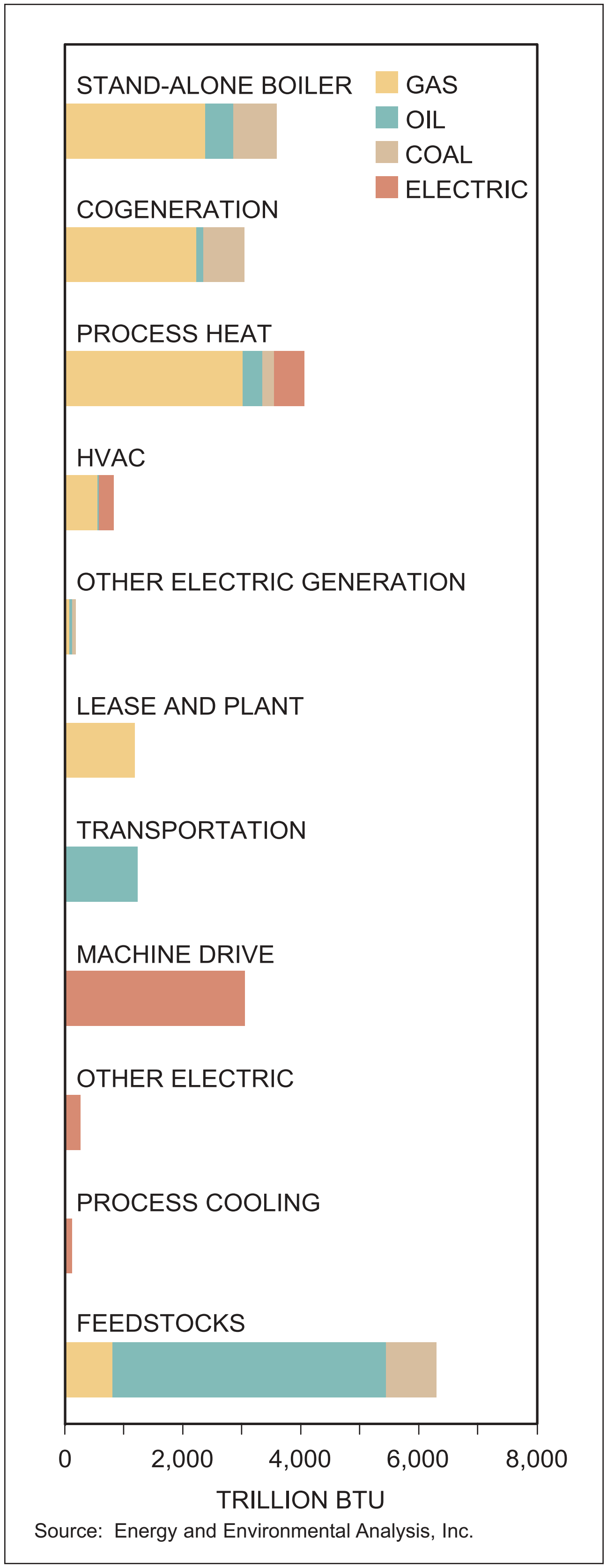
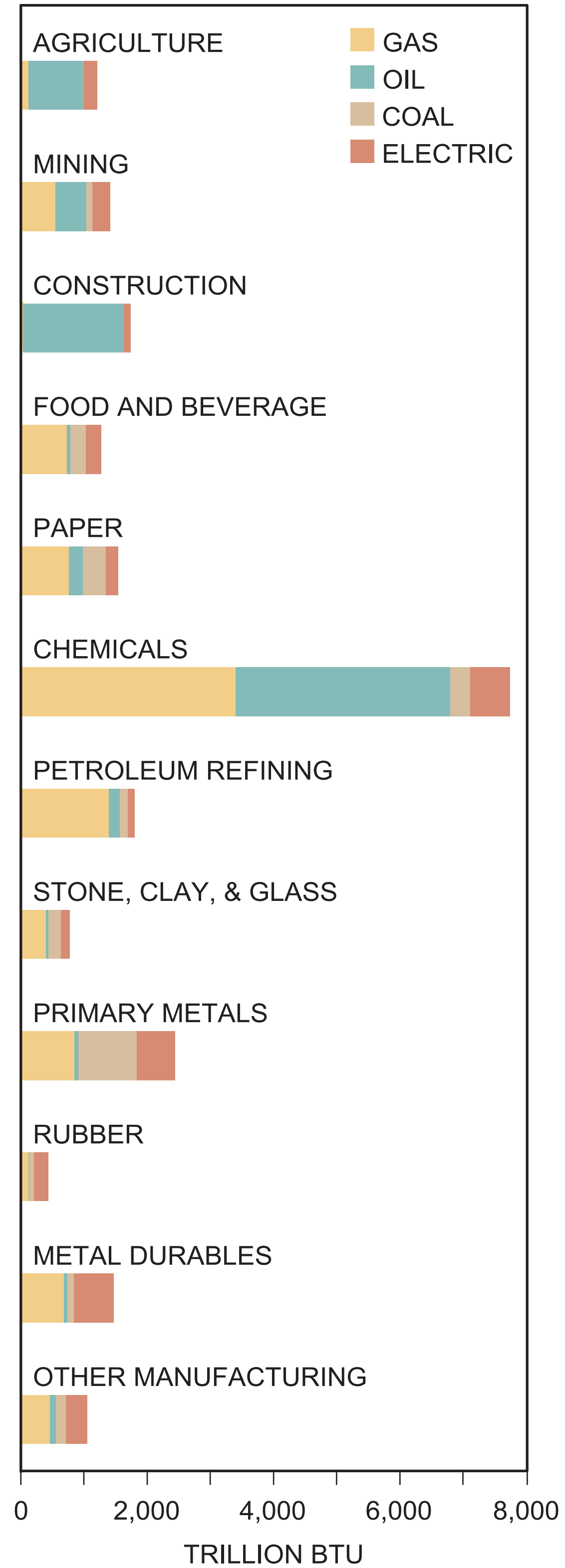


Figure 3-13. U.S. Industrial Energy Consumption by End Use in 2001



Source: Energy and Environmental Analysis, Inc.

Figure 3-14. U.S. Industrial Energy Consumption by Sector in 2001

- **Energy Efficiency and Process Change.** In a continuous effort to improve their cost structures, most industries focus on energy efficiency. As old equipment is replaced and upgraded, the industry stays competitive. Process changes and technology improvements create major reductions in energy use. Specifically, the increased use of recycled materials, increased recovery of waste heat and fuels, development of more efficient processes and technologies, and increased penetration of cogeneration systems have resulted in greater energy efficiency and increased industrial productivity.

- **Fuel Switching.** Some industrial applications are designed to substitute fuels depending on economics. Short-term fuel switching facilitates alternate fuel use for periods of hours to weeks. For example, gas boilers may switch to residual fuel oil as a secondary fuel when gas prices exceed fuel oil prices on a dollars-per-Btu basis. The total consumption of the secondary fuel may not be large, but this switching capability serves an important role in industry competitiveness and in temporarily reducing gas demand. Long-term fuel switching stems from a process change to use alternate fuels in response to economics or supply concerns, and usually entails a large capital investment.

- **Price Response and Demand Curtailment.** The prospect of a protracted price increase can stimulate investments in higher efficiency equipment, fuel-switching equipment, or facility shutdowns. A facility shutdown reduces energy demand but it also reduces production capacity, and may lead to loss of jobs and other negative economic outcomes.

- **Changes in Raw Materials.** Some changes in raw material actually increase energy consumption. In petroleum refining, the crude oil quality has been declining, increasing the need for more processing. More complex operations increase energy and natural gas use. New requirements for low-sulfur transportation fuels are expected to increase these effects.

- **Environmental and Other Regulation.** More stringent emissions requirements have increased industrial natural gas use. Gas is preferred because it lowers emissions more than other fossil fuels and can meet emission limits at a lower cost. Other regulation has encouraged gas use. For example, the Public Utility Regulatory Policies Act of 1978 encouraged new gas-fired industrial cogeneration facilities during the 1980s and 1990s because they greatly increased industrial cost efficiencies.

As shown in Figure 3-15, industrial natural gas consumption grew steadily up to the early 1970s and peaked at 8.7 TCF in 1973. After the "oil shock" of that year, industrial gas demand dropped more or less continuously to a low of 5.6 TCF in 1983.

Many factors contributed to the decline in natural gas demand beginning in the early 1970s, as listed here:

- General economic downturns during the period
- Foreign competition
- Evolution toward technology and service industries
- Major increases in efficiency and implementation of new technologies.

As the overall economy improved in the late 1980s, industrial production grew. Many industries became more competitive and increased production. Adapting to new environmental regulations, companies became more efficient by employing gas technologies. Cogeneration grew very rapidly during this period. As a result of these trends, industrial gas consumption rebounded to 8.9 TCF by 1996.

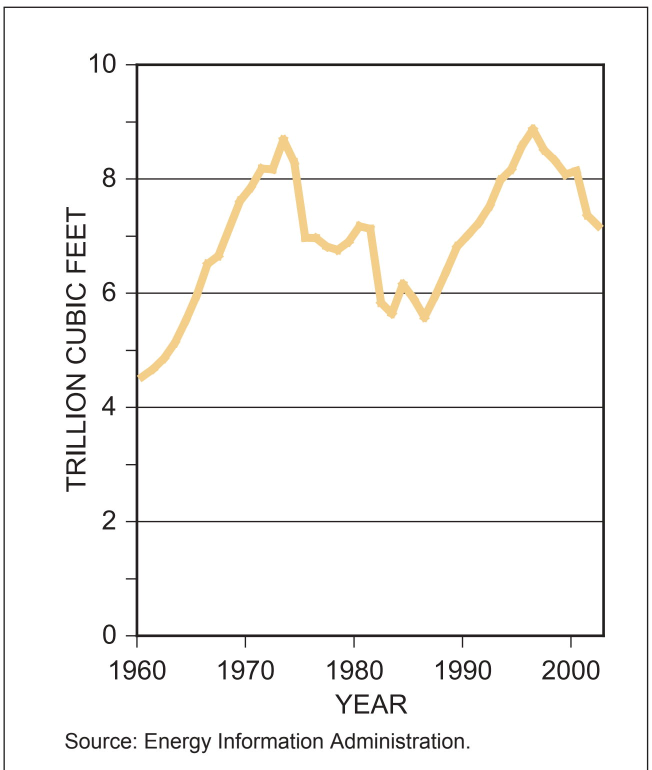


Figure 3-15. Industrial Natural Gas Consumption

Industrial gas demand started to decline again in 1997. Overall industrial production since 1997 has been much slower than earlier in the 1990s. More importantly, the energy-intensive industries have been impacted particularly and reported lower production levels relative to the non-energy-intensive industries. Weak economic performance by these industries coupled with higher gas prices has resulted in the recent declining use of natural gas in the sector.

Overview of the Modeling Approach

The industrial sector comprises a diverse mix of customers, many of which have different gas consumption needs, drivers, fuel-switching capability, and price elasticity dynamics. An accurate representation of the sector required a "bottom-up" approach to modeling for the NPC study. The model was developed to forecast U.S. industrial demand for 26 industries, 11 regions, and 4 end-use categories (boilers, process heat, feedstocks, and other) reflecting economic growth assumptions and a range of natural gas prices. Because of its size, complexity, and importance to gas-consumption trends, the modeling of the chemical industry was further disaggregated into ammonia, methanol, hydrogen, and other chemical industry products.

The model was designed to explicitly capture changes and improvements in technology including improvements in energy efficiency, short- and long-term fuel switching, and global competition. In order to develop input parameters and to validate the results, outreach seminars were conducted with representatives of key gas intensive industries to capture emerging trends and key drivers.

The model was used also to test various demand sensitivities and policy choices. Adjustments for competitive and price elasticity effects were made to fine tune demand in each sector. Particular focus was placed on gas price elasticity dynamics because model price outputs were on the upper end of historical norms, and there was little data to calibrate sustained demand response to higher prices and greater global competition.

Figures 3-16 and 3-17 illustrate the analysis process for non-chemical and chemical industry demand, respectively. These figures show that the projection of gas demand for each sector is made in a multi-step process. Historical energy consumption and industrial production data are used to calculate historical "gas

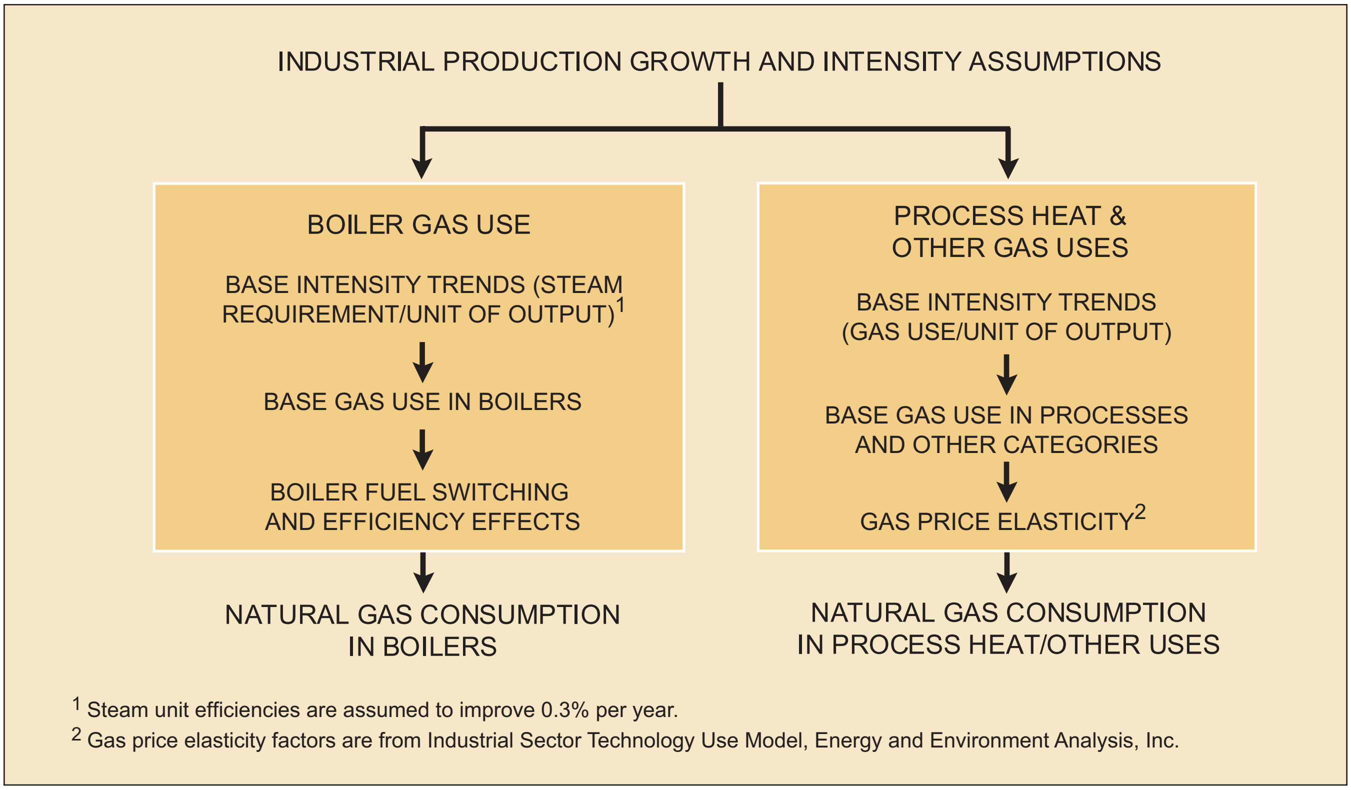


Figure 3-16. Industrial Demand Analysis – Non-Chemical Uses

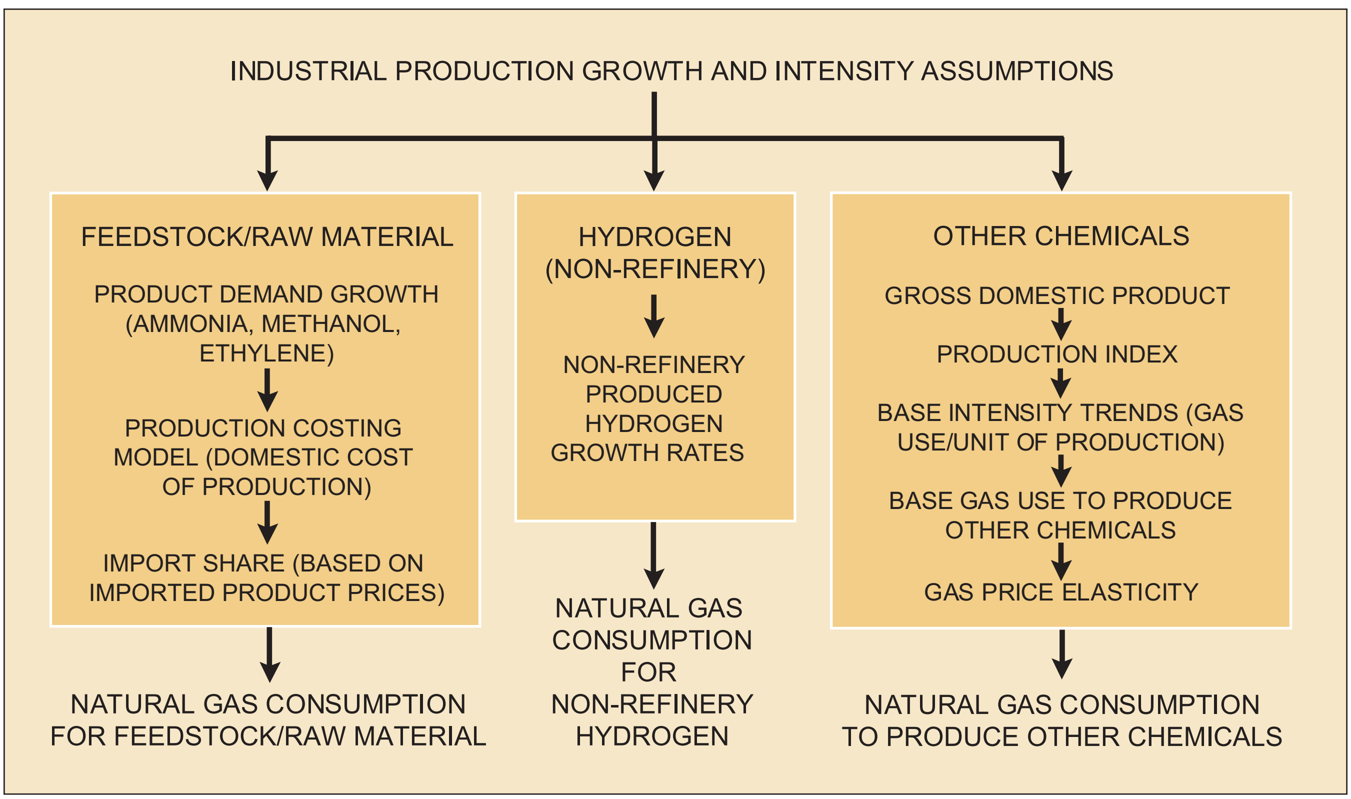


Figure 3-17. Industrial Demand Analysis – Chemical Uses

energy intensity" values for each sector. Future gas energy intensity values are projected reflecting:

- Trends in long-term technology and efficiency effects
- Fuel-switching effects for alternate fuels (subject to known limits)
- Price elasticity that results in additional fuel-switching capability or investment in efficiency improvements.

The forecasted values of gas energy intensity in each sector are applied to projected industrial production. The model outputs reflect recent trends in the composition of the industrial sector of the economy and the assumptions of overall economic growth. In addition, the projected industrial production reflects global competition from countries that have lower natural gas and energy costs and where energy cost differentials constitute a significant competitive advantage relative to product transportation costs.

Projection of Future Demand

The NPC projection of industrial gas demand addressed key factors affecting gas-intensive industries. These include:

- Industrial production growth
- Overall efficiency trends
- Fuel switching, both short- and long-term
- Demand elasticity
- Effects of global competition on commodity chemicals.

The EEA model employed by the NPC study forecast 26 industries in 11 North American regions with 4 end-use categories (boilers, process heat, feedstocks, and other). The model incorporated economic growth assumptions and a range of future natural gas prices. Because of its size, complexity, and importance to gas consumption trends, the modeling of the chemical industry was further disaggregated into ammonia, methanol, hydrogen, and other chemical products.

The model was designed to explicitly capture technology improvements in energy efficiency, short- and long-term fuel switching, and global competition. In order to develop input parameters and to validate the results, outreach seminars were conducted with representatives of key industry segments to capture emerging trends and key drivers.

Industrial production growth is the key driver of gas consumption. Table 3-3 lists the growth factors used in the projections compared to recent historical data (1992-1998). Industrial production for gas-intensive industries grew at a slower rate than for other industries. Often, energy consumption grew at a slower rate than production due to better energy efficiency. During the 1992-1998 period, overall energy consumption grew at only 1.3% per year.

Compared to other fuels, gas consumption grew at a faster rate, particularly from growth in gas-intensive processes. New cogeneration during this period also contributed to the increase. Gas consumption grew by 2.4% per year when cogeneration was excluded.

Industrial production growth was strong during the 1990s. This high growth rate is not forecast in this study. During the forecast period of 2001-2025, industrial production is projected to increase by only 1.1% per year and gas consumption is expected to decrease by 0.4% per year. The decline in gas consumption is due to the overall lower projection of industrial production, continued efficiency improvements, process change, and the overall effects of higher natural gas prices. Some increased fuel switching away from gas is projected towards the end of the forecast, as gas prices trend higher.

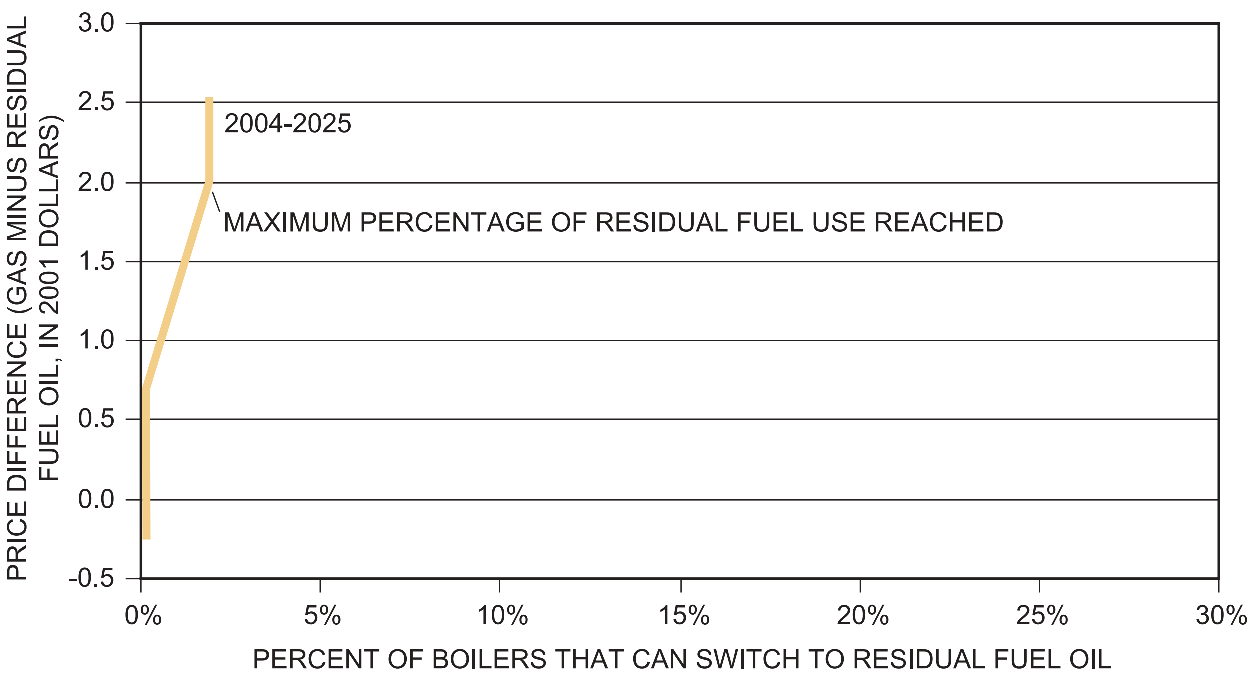
The principal differences between the Reactive Path and the Balanced Future scenarios with regard to industrial consumers are assumptions for fuel-switching capability, both short-term and long-term, and greater efficiency improvement in the Balanced Future scenario.

To model fuel-switching behavior of industrial consumers, boiler-switching relationships were developed for each region of the United States and Canada; these are contained in the Demand Task Group Report. An example of these relationships is shown by Figures 3-18 and 3-19, the boiler-switching capability modeled in the Reactive Path and Balanced Future scenarios, respectively, for the West South Central region of the United States. In the Balanced Future scenario, the percentage of industrial boilers that would be able to fuel switch was increased from a low in 2003 of 2% to 8%, depending on the region, to a high of 28% in all

	1992-1998			2001-2030	
	Industrial Production	Gas Use	Gas No Cogen	Industrial Production	Gas Use
Gas-Intensive Industries	2.4	2.9	4.3	1.1	-0.6
Food and Beverage	1.8	3.8	4.0	1.1	-0.4
Paper	0.4	3.5	4.6	0.0	-1.3
Petroleum Refining	1.2	6.7	8.2	1.0	-1.2
Chemicals*	0.6	1.3	0.4	0.8	-0.1
Stone, Clay, and Glass	3.8	2.8	2.8	2.8	0.8
Primary Metals	3.5	1.8	0.3	-0.2	-2.7
Other Industries	5.2	1.9	2.0	2.6	0.1

*Industrial production growth rate for 1992 to 1998 is for the Organic Chemicals industry, overall industry growth was much higher but includes less gas-intensive processes. Industrial production growth rate for 2001 to 2030 uses the model results' average of the growth rates of gas feedstocks and non-gas-intensive chemical industry production.

Table 3-3. Growth Factors (Percent)



Note: Switching curve is constant throughout forecast.

Figure 3-18. Industrial Boiler Switching Curve Used for West South Central Region of United States in Reactive Path Scenario regions by 2025. Since the switchable boilers cannot operate 100% on oil due to operational constraints, the maximum oil percentage for the switching curves was varied to account for the differences in boiler capabilities by region.

The aggregate results modeled for industrial boiler switching and the attendant fuel utilization are illustrated in Figures 3-20 and 3-21 for the Reactive Path scenario, and in Figures 3-22 and 3-23 for the Balanced Future scenario.

To further apply the process described by Figures 3-16 and 3-17 ("Industrial Demand Analysis"), the NPC developed price elasticity relationships. Base elasticity trends were taken from the Industrial Sector Technology Use Model, developed by EEA; these were modified to reflect the major industry groupings analyzed by the NPC Study group, and are shown in Table 3-4. Further, energy intensity price elasticity factors were taken from the Industrial Sector Technology Use Model, and modified to reflect the major industry groupings, and then developed for both the Reactive Path and Balanced Future scenarios; Tables 3-5 and 3-6 contain these factors. The Demand Task Group Report provides details of energy intensity price elasticity for each industry sector. An example of these relationships is shown by Figures 3-24 and 3-25 for the Petroleum Refining industry, as modeled in the Reactive Path and Balanced Future scenarios, respectively.

The resulting industrial gas demand projected for the Reactive Path scenario is shown in Figure 3-26. This suggests a continuation of the current decline in gas demand from the 1997 high down to about 7 TCF per year in about 2007. Industrial gas demand in both scenarios is forecast to be relatively flat to 2013, after which a small increase begins.

Figure 3-27 shows the historical and projected gas demand by industry, illustrating both the trajectory and overall magnitude of gas consumption in each industry. The chemicals industry is projected to remain the largest industrial gas consumer, although its consumption drops significantly from recent levels. This decline is largely due to loss of market share to global competition at the projected gas prices. Natural gas feedstock is projected to drop for ammonia as is ethane used for ethylene production.

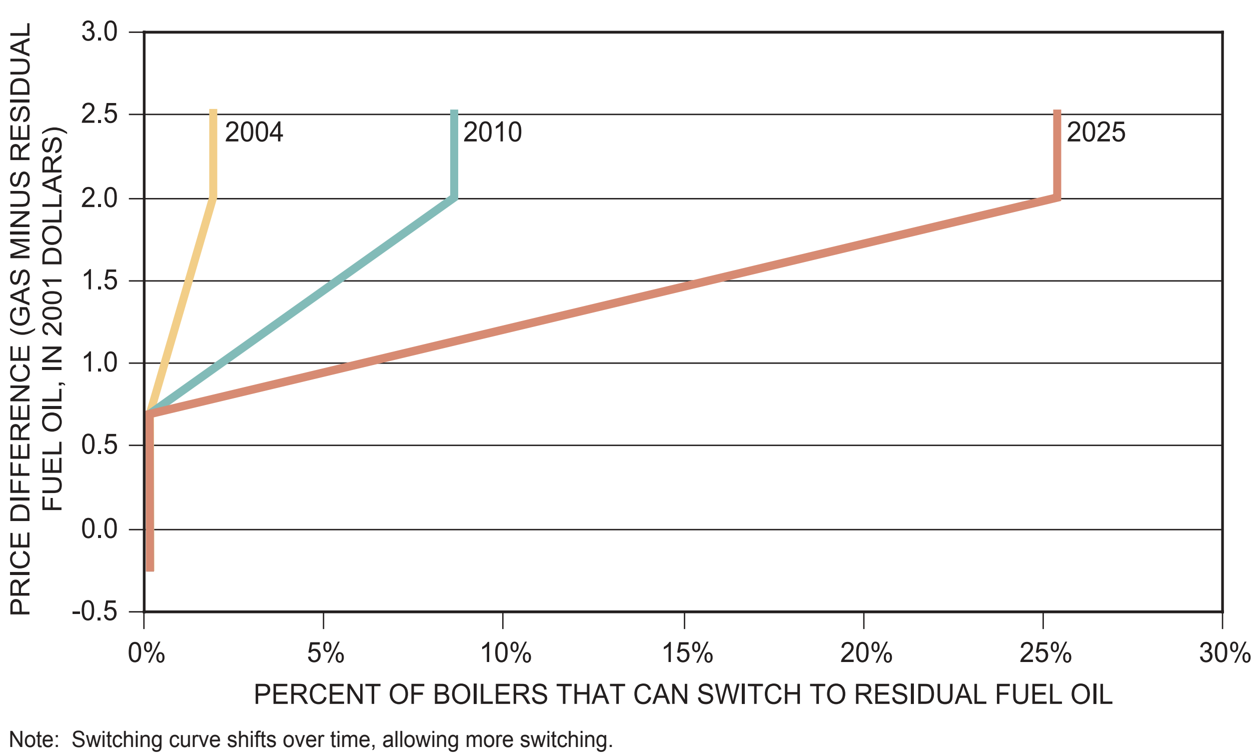


Figure 3-19. Industrial Boiler Switching Curve Used for West South Central Region of United States in Balanced Future Scenario

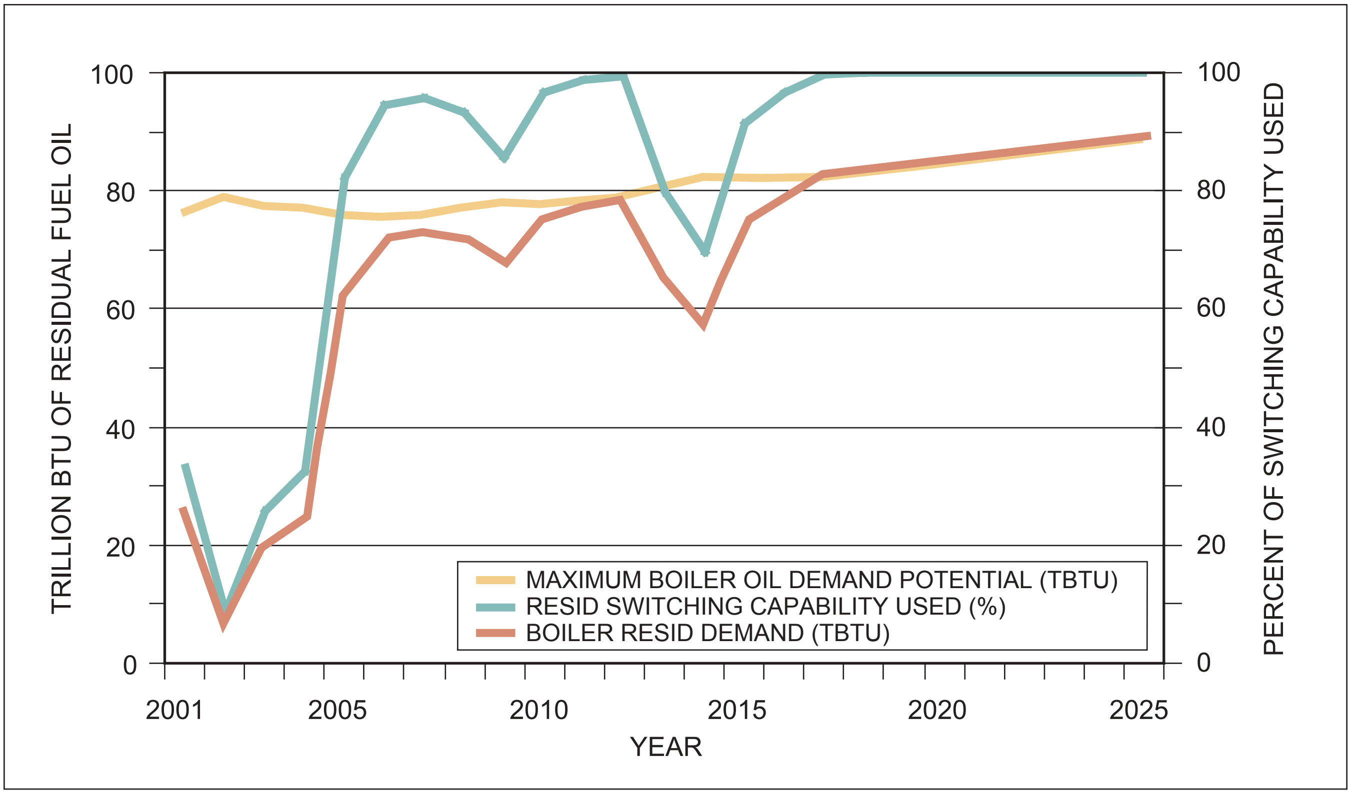


Figure 3-20. Industrial Boiler Switching in Reactive Path Scenario

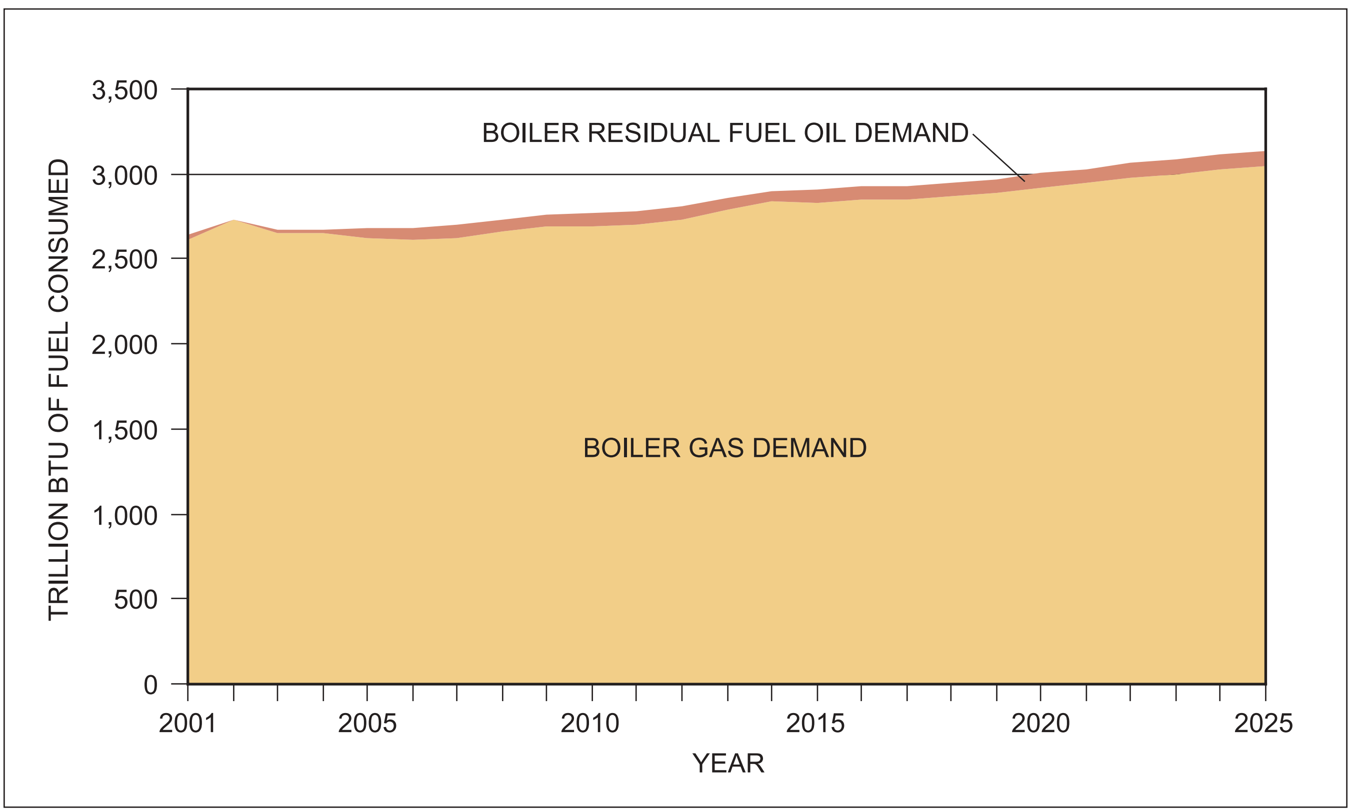


Figure 3-21. Industrial Boiler Fuel Use in Reactive Path Scenario

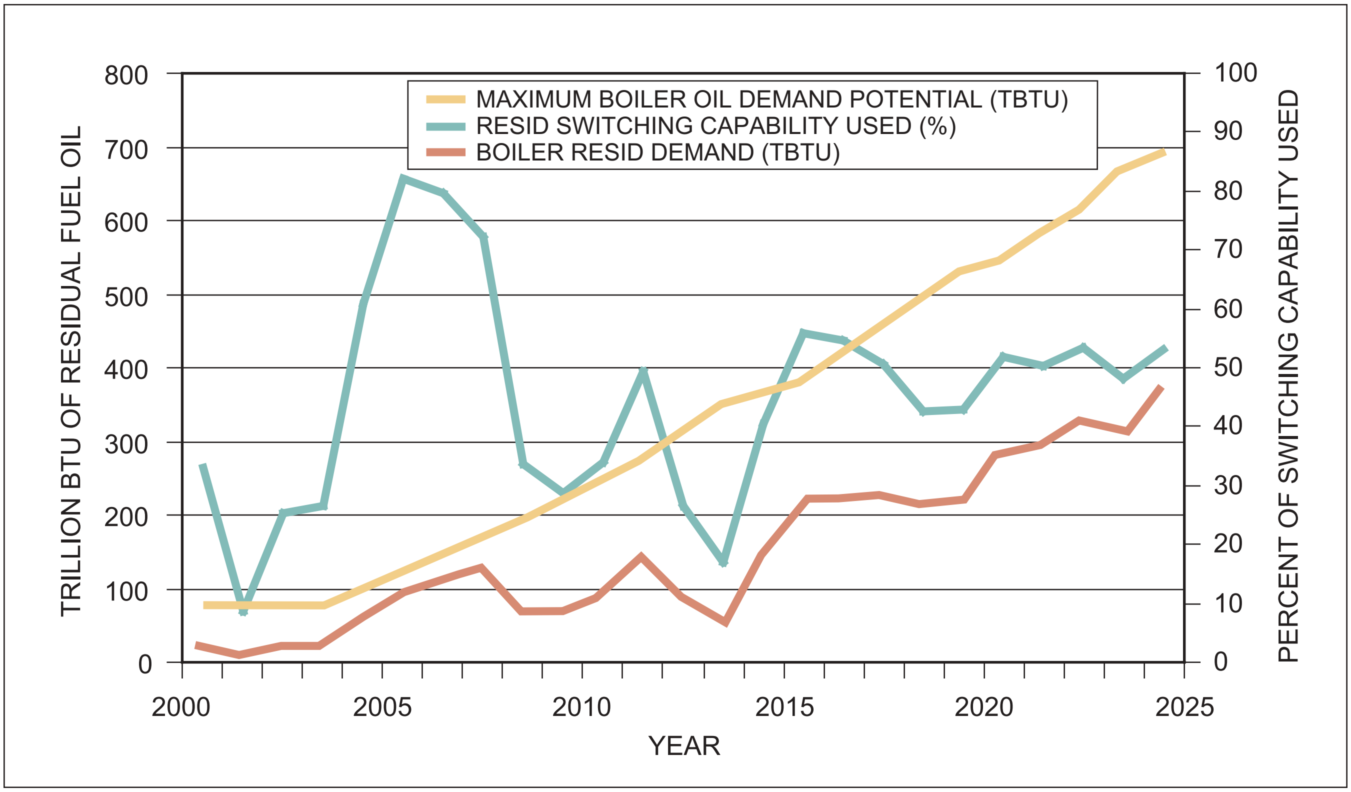


Figure 3-22. Industrial Boiler Switching in Balanced Future Scenario

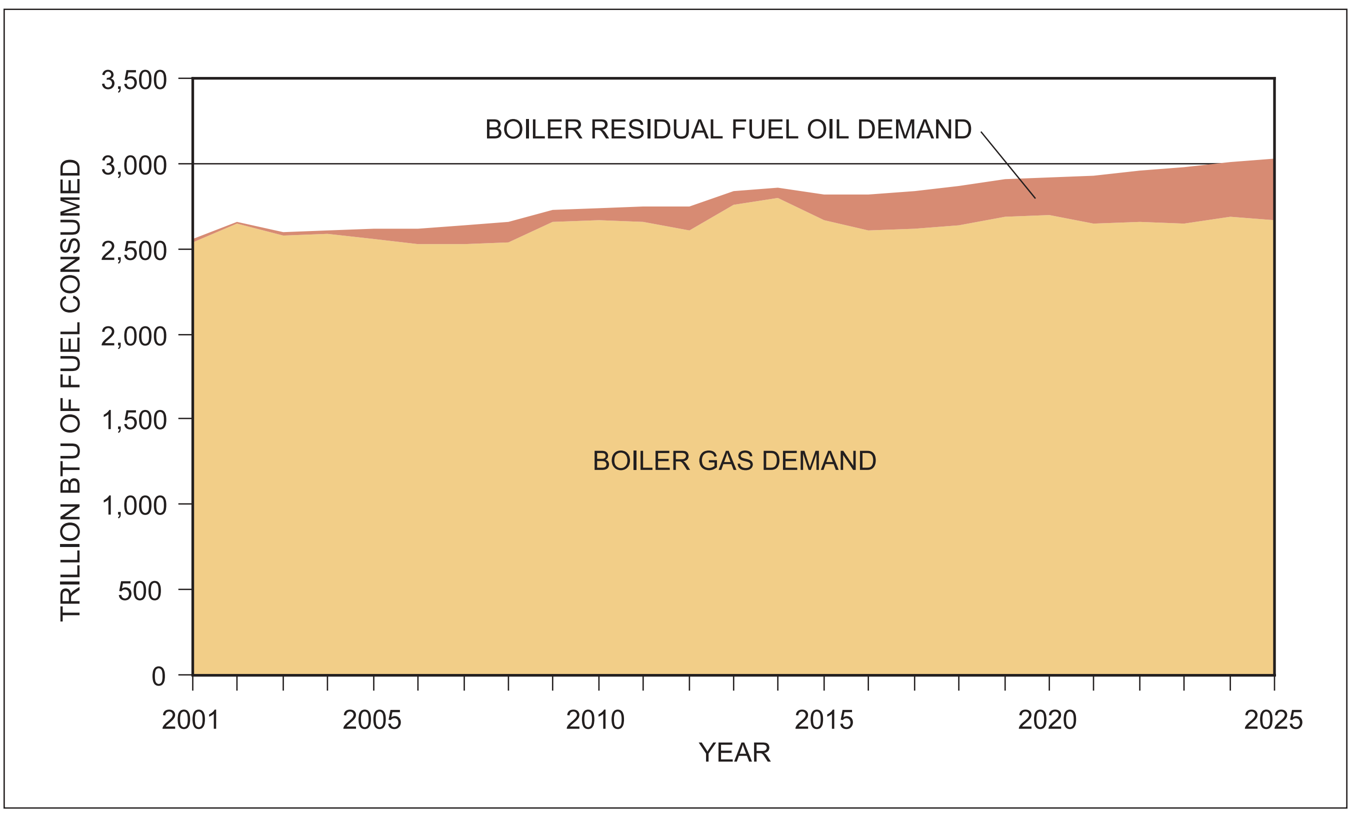


Figure 3-23. Industrial Boiler Fuel Use in Balanced Future Scenario

Year	Food & Beverage	Paper	Petroleum Refining	Chemicals	Stone, Clay, & Glass	Iron & Steel	Primary Aluminum	Other Primary Metals	Other Manufacturing	Non-Manufacturing
2001	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
2002	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
2003	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
2004	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
2005	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
2006	0.996	0.968	0.991	0.974	0.982	0.967	0.953	0.992	1.004	1.012
2007	0.993	0.936	0.983	0.949	0.963	0.933	0.906	0.983	1.009	1.023
2008	0.989	0.903	0.974	0.923	0.945	0.900	0.859	0.975	1.013	1.035
2009	0.985	0.871	0.965	0.897	0.927	0.866	0.812	0.967	1.017	1.046
2010	0.982	0.839	0.957	0.872	0.909	0.833	0.765	0.959	1.022	1.058
2011	0.979	0.816	0.951	0.867	0.900	0.819	0.734	0.954	1.023	1.065
2012	0.976	0.793	0.944	0.863	0.892	0.805	0.703	0.949	1.024	1.071
2013	0.974	0.770	0.938	0.858	0.883	0.791	0.671	0.944	1.025	1.078
2014	0.971	0.748	0.932	0.854	0.875	0.777	0.640	0.939	1.026	1.085
2015	0.968	0.725	0.926	0.850	0.866	0.763	0.609	0.934	1.027	1.091
2016	0.967	0.712	0.923	0.854	0.862	0.757	0.594	0.930	1.025	1.099
2017	0.965	0.700	0.920	0.858	0.858	0.750	0.580	0.927	1.024	1.107
2018	0.964	0.687	0.916	0.863	0.854	0.743	0.565	0.924	1.022	1.115
2019	0.962	0.675	0.913	0.867	0.849	0.737	0.551	0.920	1.020	1.123
2020	0.961	0.662	0.910	0.871	0.845	0.730	0.536	0.917	1.019	1.131
2021	0.959	0.653	0.907	0.875	0.842	0.724	0.527	0.913	1.015	1.136
2022	0.958	0.644	0.905	0.878	0.838	0.718	0.519	0.909	1.012	1.141
2023	0.956	0.635	0.903	0.882	0.834	0.712	0.510	0.905	1.008	1.146
2024	0.955	0.626	0.900	0.885	0.830	0.706	0.501	0.901	1.005	1.151
2025	0.953	0.617	0.898	0.889	0.827	0.700	0.492	0.898	1.001	1.156

Table 3-4. Base Energy Intensity Trends (Indexed, 2001 = 1.000)

Year	Food & Beverage	Paper	Petroleum Refining	Chemicals	Stone, Clay, & Glass	Iron & Steel	Primary Aluminum	Other Primary Metals	Other Manufacturing	Non-Manufacturing
2000	(0.600)	(0.050)	(1.100)	(0.130)	(0.500)	-	(0.400)	(0.500)	(0.600)	(0.350)
2001	(0.610)	(0.050)	(1.103)	(0.130)	(0.507)	(0.014)	(0.407)	(0.523)	(0.617)	(0.365)
2002	(0.620)	(0.050)	(1.107)	(0.130)	(0.513)	(0.028)	(0.413)	(0.547)	(0.633)	(0.380)
2003	(0.630)	(0.050)	(1.110)	(0.130)	(0.520)	(0.042)	(0.420)	(0.570)	(0.650)	(0.395)
2004	(0.640)	(0.050)	(1.113)	(0.130)	(0.527)	(0.056)	(0.427)	(0.593)	(0.667)	(0.410)
2005	(0.650)	(0.050)	(1.117)	(0.130)	(0.533)	(0.070)	(0.433)	(0.617)	(0.683)	(0.425)
2006	(0.660)	(0.050)	(1.120)	(0.130)	(0.540)	(0.084)	(0.440)	(0.640)	(0.700)	(0.440)
2007	(0.670)	(0.050)	(1.123)	(0.130)	(0.547)	(0.098)	(0.447)	(0.663)	(0.717)	(0.455)
2008	(0.680)	(0.050)	(1.127)	(0.130)	(0.553)	(0.112)	(0.453)	(0.687)	(0.733)	(0.470)
2009	(0.690)	(0.050)	(1.130)	(0.130)	(0.560)	(0.126)	(0.460)	(0.710)	(0.750)	(0.485)
2010	(0.700)	(0.050)	(1.133)	(0.130)	(0.567)	(0.140)	(0.467)	(0.733)	(0.767)	(0.500)
2011	(0.710)	(0.050)	(1.137)	(0.130)	(0.573)	(0.154)	(0.473)	(0.757)	(0.783)	(0.515)
2012	(0.720)	(0.050)	(1.140)	(0.130)	(0.580)	(0.168)	(0.480)	(0.780)	(0.800)	(0.530)
2013	(0.730)	(0.050)	(1.143)	(0.130)	(0.587)	(0.182)	(0.487)	(0.803)	(0.817)	(0.545)
2014	(0.740)	(0.050)	(1.147)	(0.130)	(0.593)	(0.196)	(0.493)	(0.827)	(0.833)	(0.560)
2015	(0.750)	(0.050)	(1.150)	(0.130)	(0.600)	(0.210)	(0.500)	(0.850)	(0.850)	(0.575)
2016	(0.760)	(0.050)	(1.153)	(0.130)	(0.607)	(0.224)	(0.507)	(0.873)	(0.867)	(0.590)
2017	(0.770)	(0.050)	(1.157)	(0.130)	(0.613)	(0.238)	(0.513)	(0.897)	(0.883)	(0.605)
2018	(0.780)	(0.050)	(1.160)	(0.130)	(0.620)	(0.252)	(0.520)	(0.920)	(0.900)	(0.620)
2019	(0.790)	(0.050)	(1.163)	(0.130)	(0.627)	(0.266)	(0.527)	(0.943)	(0.917)	(0.635)
2020	(0.800)	(0.050)	(1.167)	(0.130)	(0.633)	(0.280)	(0.533)	(0.967)	(0.933)	(0.650)
2021	(0.810)	(0.050)	(1.170)	(0.130)	(0.640)	(0.294)	(0.540)	(0.990)	(0.950)	(0.665)
2022	(0.820)	(0.050)	(1.173)	(0.130)	(0.647)	(0.308)	(0.547)	(1.013)	(0.967)	(0.680)
2023	(0.830)	(0.050)	(1.177)	(0.130)	(0.653)	(0.322)	(0.553)	(1.037)	(0.983)	(0.695)
2024	(0.840)	(0.050)	(1.180)	(0.130)	(0.660)	(0.336)	(0.560)	(1.060)	(1.000)	(0.710)
2025	(0.850)	(0.050)	(1.183)	(0.130)	(0.667)	(0.350)	(0.567)	(1.083)	(1.017)	(0.725)

Table 3-5. Energy Intensity Price Elasticity for Reactive Path Scenario (Change in Energy Intensity per Change in Gas Price)

Year	Food & Beverage	Paper	Petroleum Refining	Chemicals	Stone, Clay, & Glass	Iron & Steel	Primary Aluminum	Other Primary Metals	Other Manufacturing	Non-Manufacturing
2000	(0.600)	(0.050)	(1.100)	(0.130)	(0.500)	-	(0.400)	(0.500)	(0.600)	(0.350)
2001	(0.610)	(0.050)	(1.103)	(0.130)	(0.507)	(0.014)	(0.407)	(0.523)	(0.617)	(0.365)
2002	(0.620)	(0.050)	(1.107)	(0.130)	(0.513)	(0.028)	(0.413)	(0.547)	(0.633)	(0.380)
2003	(0.630)	(0.050)	(1.110)	(0.130)	(0.520)	(0.042)	(0.420)	(0.570)	(0.650)	(0.395)
2004	(0.679)	(0.052)	(1.167)	(0.136)	(0.557)	(0.072)	(0.452)	(0.643)	(0.713)	(0.443)
2005	(0.727)	(0.055)	(1.224)	(0.142)	(0.594)	(0.102)	(0.485)	(0.715)	(0.776)	(0.491)
2006	(0.776)	(0.057)	(1.281)	(0.148)	(0.631)	(0.132)	(0.517)	(0.788)	(0.839)	(0.539)
2007	(0.825)	(0.059)	(1.338)	(0.154)	(0.668)	(0.162)	(0.550)	(0.860)	(0.902)	(0.587)
2008	(0.873)	(0.061)	(1.396)	(0.160)	(0.705)	(0.192)	(0.582)	(0.933)	(0.964)	(0.635)
2009	(0.922)	(0.064)	(1.453)	(0.165)	(0.742)	(0.221)	(0.615)	(1.005)	(1.027)	(0.683)
2010	(0.970)	(0.066)	(1.510)	(0.171)	(0.779)	(0.251)	(0.647)	(1.078)	(1.090)	(0.731)
2011	(1.019)	(0.068)	(1.567)	(0.177)	(0.816)	(0.281)	(0.679)	(1.151)	(1.153)	(0.779)
2012	(1.068)	(0.070)	(1.624)	(0.183)	(0.853)	(0.311)	(0.712)	(1.223)	(1.216)	(0.827)
2013	(1.116)	(0.073)	(1.681)	(0.189)	(0.890)	(0.341)	(0.744)	(1.296)	(1.279)	(0.875)
2014	(1.165)	(0.075)	(1.738)	(0.195)	(0.927)	(0.371)	(0.777)	(1.368)	(1.342)	(0.923)
2015	(1.214)	(0.077)	(1.795)	(0.201)	(0.964)	(0.401)	(0.809)	(1.441)	(1.405)	(0.970)
2016	(1.262)	(0.080)	(1.853)	(0.207)	(1.001)	(0.431)	(0.842)	(1.513)	(1.467)	(1.018)
2017	(1.311)	(0.082)	(1.910)	(0.213)	(1.038)	(0.461)	(0.874)	(1.586)	(1.530)	(1.066)
2018	(1.360)	(0.084)	(1.967)	(0.219)	(1.075)	(0.491)	(0.906)	(1.659)	(1.593)	(1.114)
2019	(1.408)	(0.086)	(2.024)	(0.225)	(1.112)	(0.521)	(0.939)	(1.731)	(1.656)	(1.162)
2020	(1.457)	(0.089)	(2.081)	(0.230)	(1.148)	(0.550)	(0.971)	(1.804)	(1.719)	(1.210)
2021	(1.505)	(0.091)	(2.138)	(0.236)	(1.185)	(0.580)	(1.004)	(1.876)	(1.782)	(1.258)
2022	(1.554)	(0.093)	(2.195)	(0.242)	(1.222)	(0.610)	(1.036)	(1.949)	(1.845)	(1.306)
2023	(1.603)	(0.095)	(2.252)	(0.248)	(1.259)	(0.640)	(1.068)	(2.022)	(1.908)	(1.354)
2024	(1.651)	(0.098)	(2.310)	(0.254)	(1.296)	(0.670)	(1.101)	(2.094)	(1.970)	(1.402)
2025	(1.700)	(0.100)	(2.367)	(0.260)	(1.333)	(0.700)	(1.133)	(2.167)	(2.033)	(1.450)

Table 3-6. Energy Intensity Price Elasticity for Balanced Future Scenario (Change in Energy Intensity per Change in Gas Price)

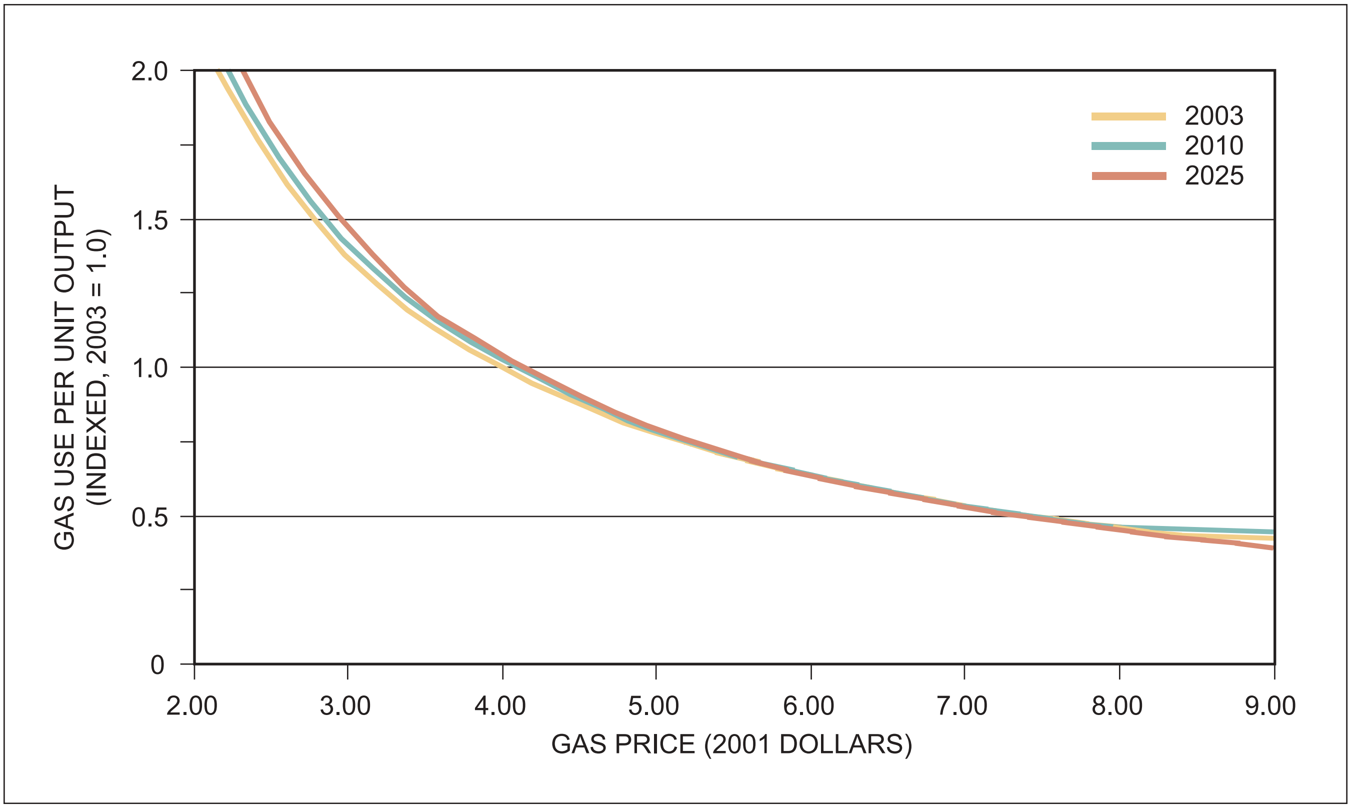


Figure 3-24. Change in Energy Intensity for Petroleum Refining Sector in Reactive Path Scenario

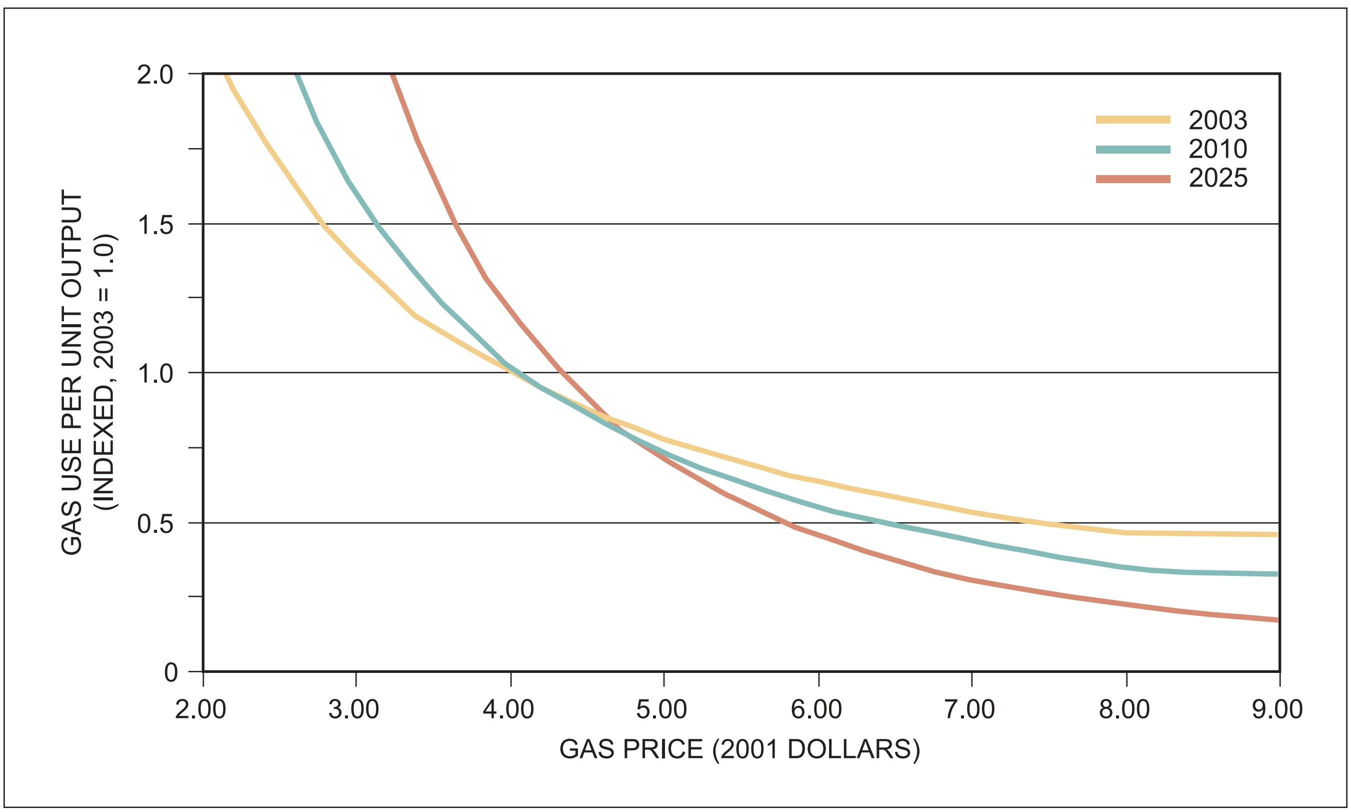


Figure 3-25. Change in Energy Intensity for Petroleum Refining Sector in Balanced Future Scenario

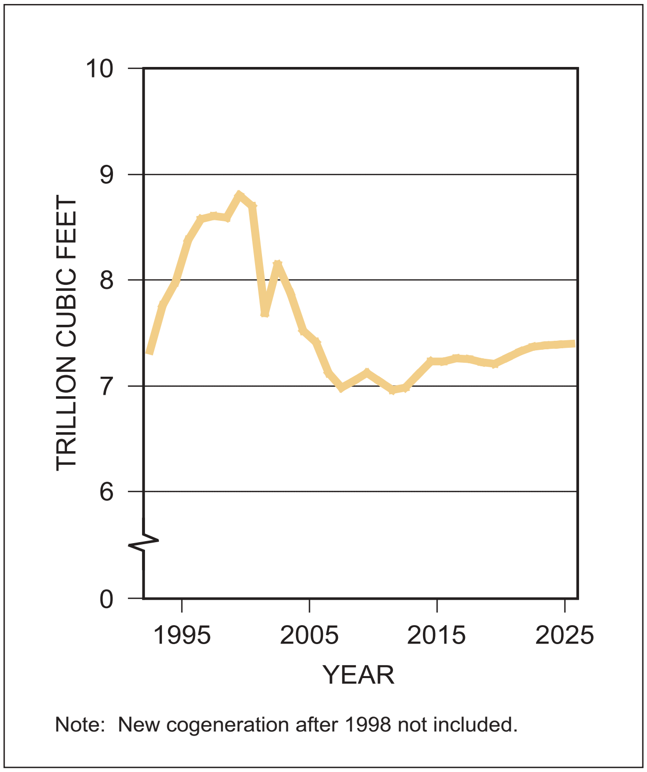


Figure 3-26. U.S. Industrial Gas Demand in Reactive Path Scenario

The petroleum refining industry is projected to remain the second largest gas consumer. Gas consumption is projected to decline at a lower rate compared to the chemicals industry. The other gas-intensive industries project fairly flat gas demand, with the exception of primary metals. The primary metals industry has the most significant and sustained decline in gas consumption of all of the industries due to continuing process change and global competition. The "other" industry group is the only segment to show an increase in gas demand in the forecast, although it does not grow above historical levels. Each industry is addressed in more detail in the Demand Task Group Report.

Figure 3-28 shows the Balanced Future forecast of overall industrial gas demand. Figure 3-29 provides this information for each industry segment modeled by the NPC. These projections show a decline from current levels, though not quite as much as in the Reactive Path scenario. The projection fluctuates around the 7 TCF per year level over most of the forecast period. Although more fuel-switching capability is in this scenario, gas consumption is actually higher. Fuel-switching

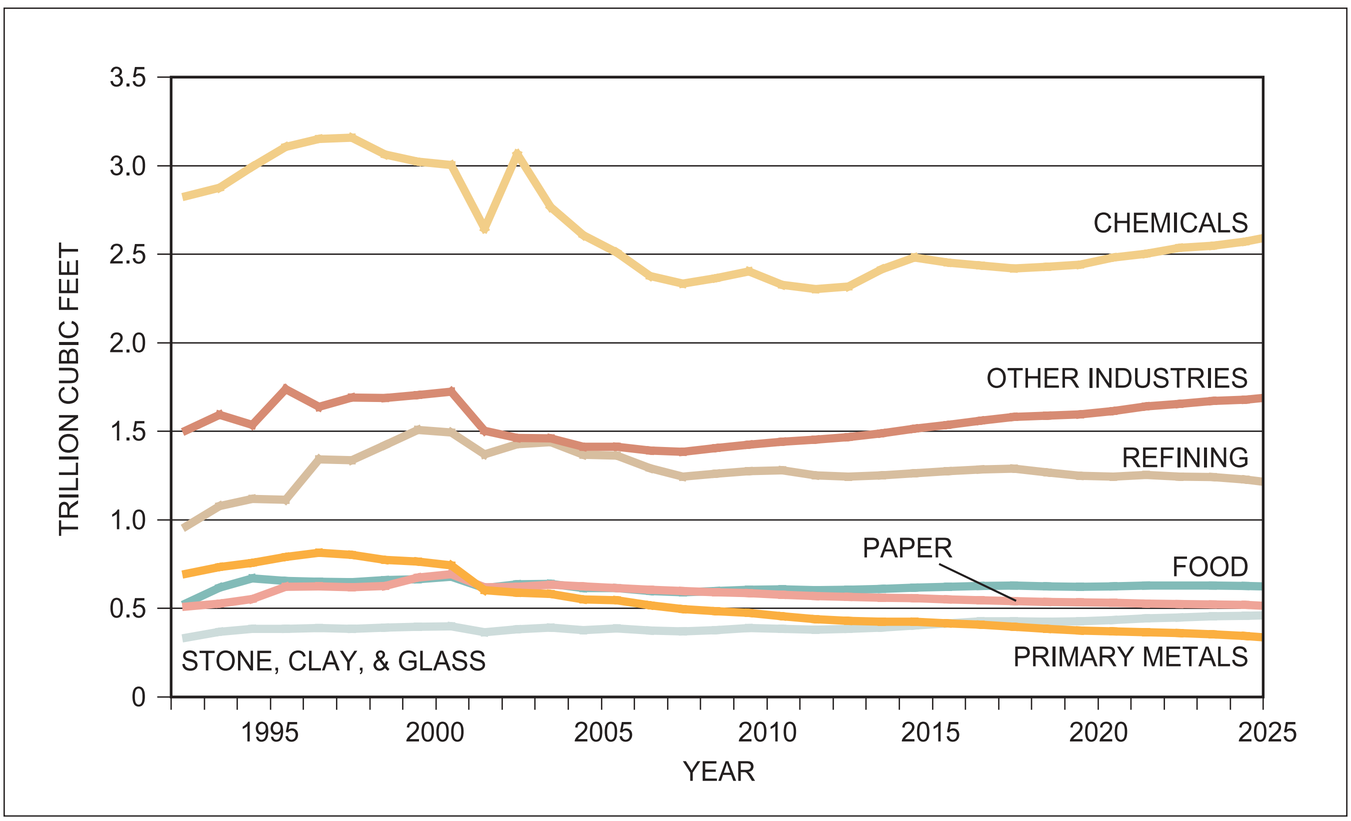


Figure 3-27. U.S. Industrial Gas Consumption by Industry in Reactive Path Scenario

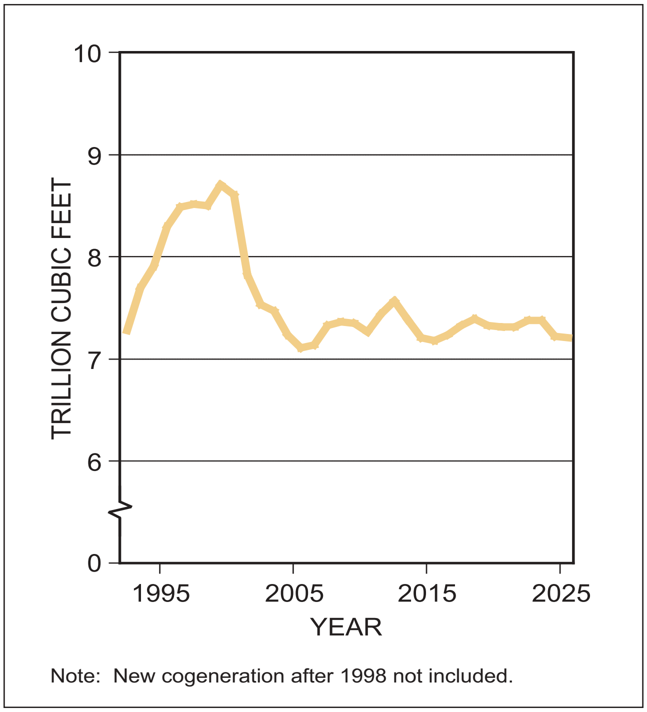


Figure 3-28. U.S. Industrial Gas Demand in Balanced Future Scenario

reduces peak demands, and thus price volatility, without large effects on annual gas load. The increased flexibility in the Balanced Future scenario lowers gas prices and allows industry to rely on gas to a greater degree.

The Balanced Future scenario shows a decline in the chemicals industry. The gas consumption in the Balanced Future for industry stays generally above 2.5 TCF per year whereas it is significantly lower in the Reactive Path. Higher gas use stems from lower prices in the Balanced Future scenario and increased competitiveness of the industry.

Major Gas-Intensive Industries

Chemicals

Natural gas is used in the chemical industry as a fuel and as a raw material. Natural gas liquids, including ethane, propane, and butane, are major petrochemical feedstocks contributing to the production of a host of other consumer goods, such as plastics, pharmaceuticals, and electronic materials.

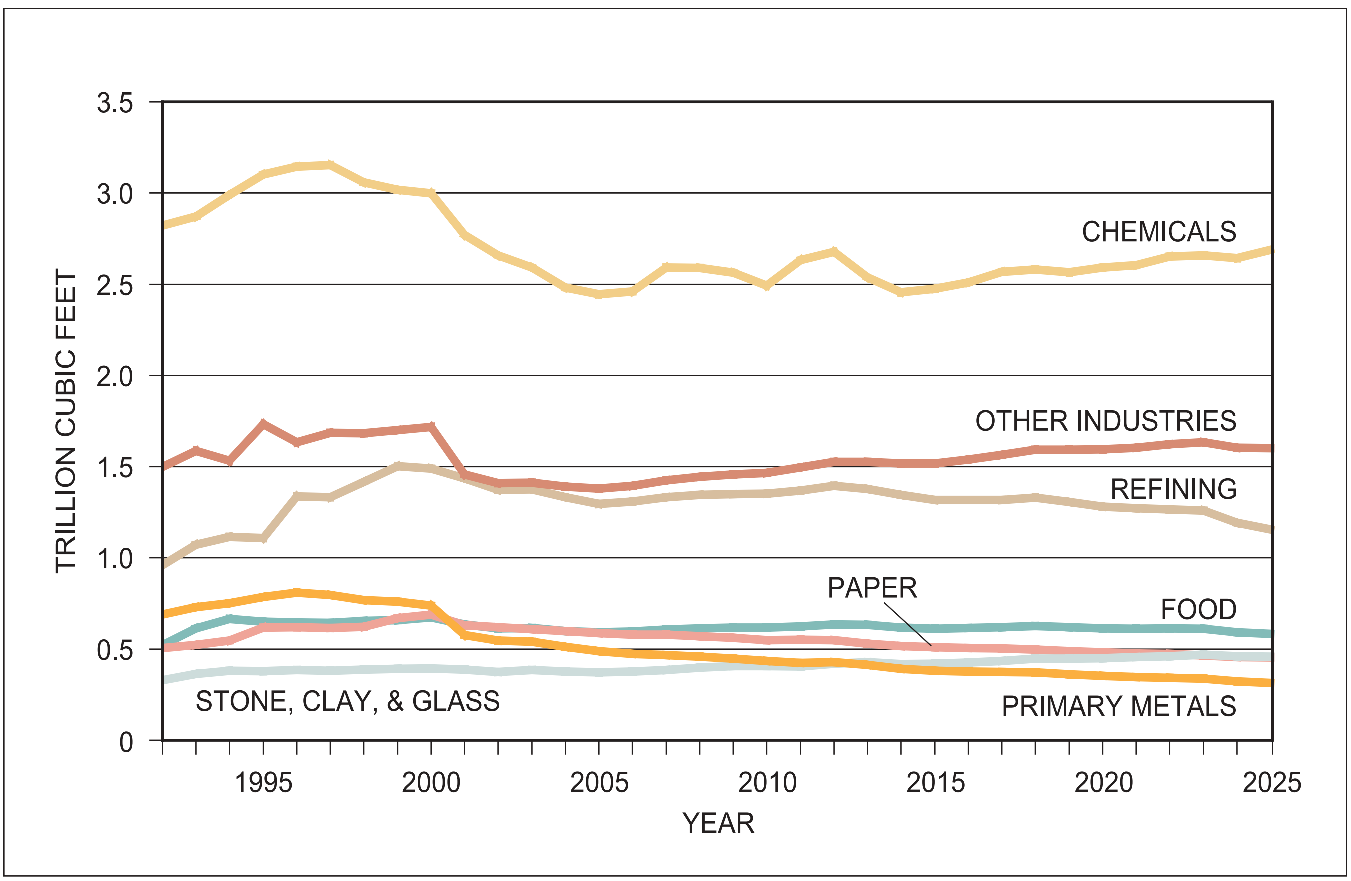


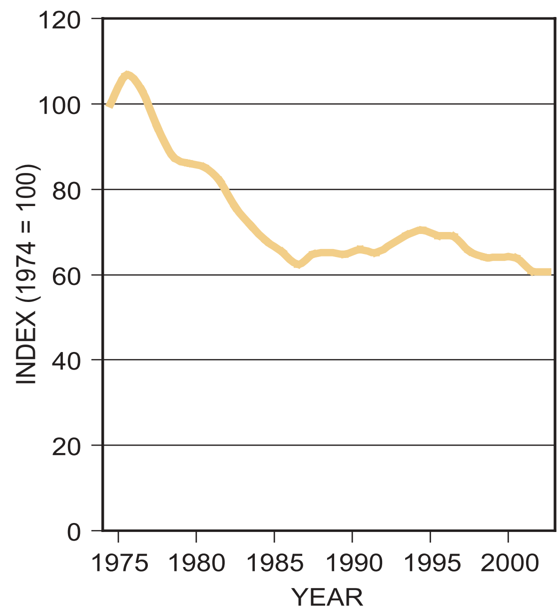
Figure 3-29. U.S. Industrial Gas Consumption by Industry in Balanced Future Scenario

Role of Chemicals in the U.S. Economy. The U.S. chemical industry (SIC 28 or NAICS 325)[1] represents 10,000 companies operating 13,500 manufacturing facilities across all 50 states. In 2001, the chemical industry contributed $163.5 billion to U.S. GDP, nearly 2% of total GDP, more than any other manufacturing industry. The industry directly employs over one million people. According to the American Chemistry Council, the industry has a 5:1 multiplier effect in the economy, such that its direct employment of one million people creates another 5 million jobs. This means that, in total, the chemical industry is responsible for about 6.1 million jobs in the United States, or about 5% of the total U.S. workforce.

The U.S. chemical industry has developed into the largest chemical segment in the world, in part from access to low-cost energy and feedstock in the form of natural gas. The U.S. chemical industry accounts for more than a quarter of total world production of chemical products. The industry is the nation's top exporter. In 2002, the industry exported $81.1 billion of goods and services, more than agriculture, aerospace, or motor vehicles. While chemicals are the largest exporting industry in the United States, imports have grown in recent years such that the balance of trade in chemicals declined from a favorable $20.5 billion surplus in 1995, to the first-ever trade deficit of $5 billion in 2002.

Intensity of Natural Gas Use in the Chemical Industry. Substantial improvements in energy efficiency have taken place in the energy-intensive chemical industry. Since 1974, the industry has reduced its energy use for fuel and power consumption per unit of output by nearly 40%, as illustrated in Figure 3-30. One of the principal sources of efficiency gains has been implementation of cogeneration technologies. These applications create two forms of energy (electric power and steam) with the same amount of fuel, and are often twice as efficient as older utility generation facilities.

Chemical Industry Demand Outlook. The chemical industry uses about 2.5 TCF of gas annually and is the largest single industrial user of natural gas (about 35%), accounting for 12% of all U.S. natural gas consumption. The industry uses 76% of its natural gas consumption for fuel and power. The majority of steam boilers and cogeneration in chemical industry facilities are fueled by natural gas. The remaining 24% of natural gas consumption is directly used as feedstock, primarily in the manufacture of hydrogen, ammonia, and methanol.



Source: American Chemistry Council.

Figure 3-30. Energy Intensity for Fuel and Power in the U.S. Chemical Industry

The average operating margin (a measure of profitability) for basic chemical companies was 6.8% in 1999, when the price of natural gas averaged $2.27 per million Btu (MMBtu). In 2001, when the price of natural gas averaged $3.97 per MMBtu, operating margin dropped to 0.6%. This decrease in operating margins led many chemical companies to evaluate whether to continue operations in the United States. During the winter 2000-2001 natural gas price spike, some chemical operations were idled: about 50% of the methanol capacity, 40% of the ammonia capacity, and 15% of the ethylene capacity simply shut down and furloughed their workforce.

In recent years, the chemical industry experienced a protracted inventory correction, impacts of the high value of the dollar, higher natural gas prices, as well as a global recession. Both the Reactive Path and Balanced Future scenarios incorporate a recovery in

[1] The North American Industry Classification System (NAICS) has replaced the U.S. Standard Industrial Classification (SIC) system.

overall industrial production, consistent with overall GDP growth of 3%.

Figure 3-31 shows the NPC Reactive Path projection with a breakdown of gas demand for boilers, process heat, other processes, and feedstocks. Production in the gas-intensive organic chemicals industry grew by only 0.6% annually from 1992 to 1998 and gas use grew by 1.3% during the same period. Gas use in boilers fell during the historical period but this was offset by increases in gas use for process heaters, feedstocks, and other processes including cogeneration. Gas use would have increased at only 0.4% per year without new cogeneration.

Gas use for feedstocks and other processes decline in the projection due to higher gas prices. The most affected industries are petrochemical and basic chemical sub-industries that use gas as a feedstock, e.g., ammonia production. The decline would be offset if there is even higher hydrogen production than currently anticipated for use in the refinery sector to manufacture low-sulfur transportation fuel. Gas use for boilers and process heat increases because of growth in other segments of the industry, including drugs, and soaps and detergent manufacture. New cogeneration is accounted for in the power sector but would contribute to increased gas consumption in the chemical industry.

Figure 3-32 shows a projection of gas use in the chemical industry for the Balanced Future scenario. All of the components are higher than in the Reactive Path scenario due to the lower gas prices.

Petroleum Refining

The U.S. refining industry (SIC 291 or NAICS 32411) transforms crude oil into transportation fuels, such as gasoline and diesel fuel; lubricants; industrial fuels; and chemical plant feedstocks. The industry is highly capital intensive with an infrastructure replacement value of about $300 billion. Each day, U.S. refineries process more than 16 million barrels of crude oil to produce 350 million gallons of gasoline, 210 million gallons of distillate products, and 125 million gallons of other finished products. The refining industry employs about 100,000 people including contract workers.

Intense competition has resulted in a low return on capital for the refining industry over the last 20 years.

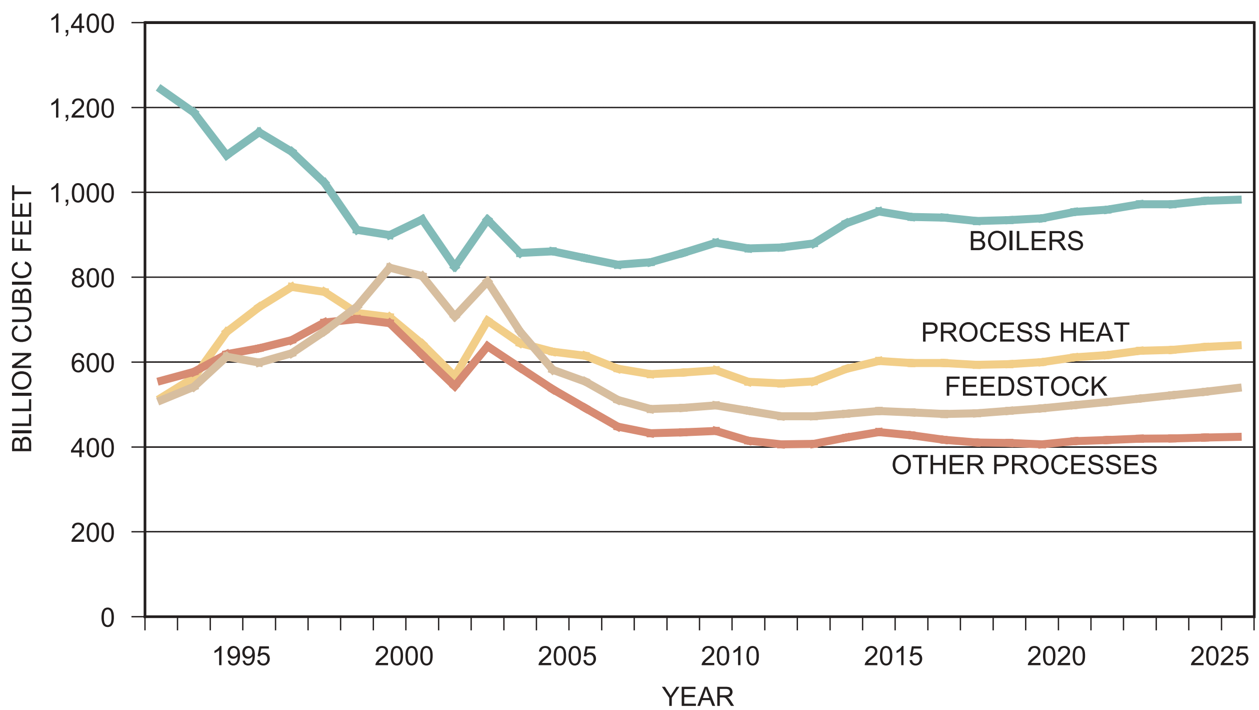


Figure 3-31. U.S. Chemical Industry Gas Demand in Reactive Path Scenario

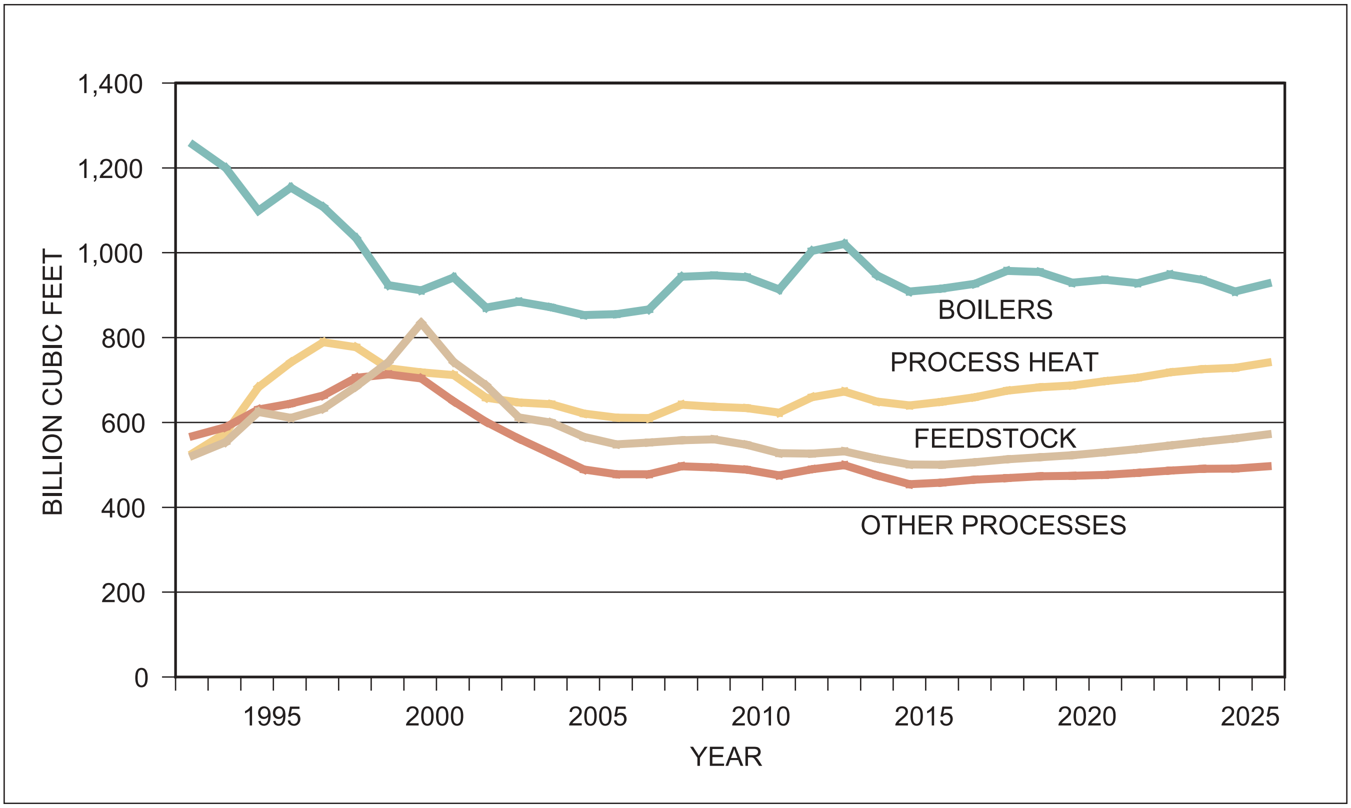


Figure 3-32. U.S. Chemical Industry Gas Demand in Balanced Future Scenario

During this period, the refining industry has invested heavily to meet environmental regulations. The pending clean fuels regulations will require an additional $17 billion in capital investment. The heavy investment burden has led to the closure of over half of U.S. refineries since the mid-1970s. The last new refinery was built in 1976. The remaining refineries have kept pace with the growing product demand through improved utilization and incremental investment. Product imports have remained essentially constant at less than 1 million barrels per day.

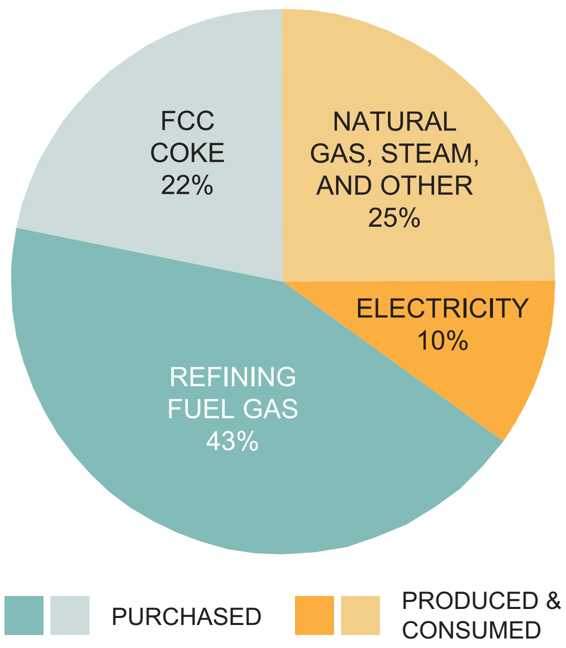
Refineries are the second largest industrial consumer of natural gas, representing 14% of total industrial consumption. Natural gas usage at U.S. refineries will be in flux from 2003 to 2025. Increasing demand for petroleum products, net efficiency gains, and clean fuels regulations are key factors impacting future natural gas demand from U.S. refineries. In general, efficiency gains in the industry will be offset by capacity expansions and increased processing complexity to produce cleaner fuels from lower quality feedstocks. The price of natural gas also affects refinery demand because fuel-switching alternatives are readily available to most refiners.

Refinery Energy Fundamentals. Petroleum refineries are energy intensive, consuming over 500 thousand Btu for every barrel of crude oil processed. Much of the energy required is derived from crude oil as it is converted into finished gasoline and diesel fuel. A breakdown of energy used in the refining process is shown in Figure 3-33.

Refineries purchase and produce energy during the refining process. Refinery fuel gas, a byproduct primarily from catalytic cracking of heavy crudes and from process heaters, augments purchased energy. Purchased energy consists primarily of natural gas, electricity, and steam. Utility companies or cogeneration facilities supply electricity to refineries. Refineries purchase steam from third parties, typically from the cogeneration units.

Natural gas is used in three principal processes:

- To supplement refinery fuel gas system
- Feed gas for hydrogen generation units
- Fuel for gas turbines used to generate power or drive large rotating equipment.



Source: ConocoPhillips.

Figure 3-33. Breakdown of Energy Used in U.S. Petroleum Refining Processes

The refinery fuel gas system is complex. Most process units produce fuel gas but it is consumed in various processes. By altering process conditions, more fuel gas can be produced but at the expense of liquid products, particularly propane, butane, and gasoline.

As natural gas prices on a Btu-basis exceed those of liquid products, overall refinery economics can favor additional fuel gas production to effectively reduce the need for natural gas. With efficiency improvements, less natural gas is required to supplement refinery fuel gas. Propane and butane typically account for about 1% of refinery energy needs. Many refineries are able to vaporize propane or butane into the fuel gas system as an alternate to natural gas. This capability is limited, however, by infrastructure and other technical factors (e.g., re-condensation of the propane and butane). Heavy fuel oil currently accounts for about 1% of refinery energy. Historically, refineries burned heavy fuel oil in some heaters and boilers thereby reducing the need for natural gas. However, environmental regulations requiring reduction of sulfur and particulate emissions have largely eliminated oil burning.

Cogeneration of electric power and steam at refineries significantly improves overall efficiency. Natural gas, as opposed to refinery fuel, is typically burned in gas turbine generators for reliability and warranty concerns. Sustained higher natural gas prices would provide an incentive for refiners to switch to distillate fuel use. Higher natural gas prices relative to purchased power prices may discourage new cogeneration projects.

Hydrogen is used in the desulfurization process of gasoline and distillate fuels. Natural gas is used typically as feed gas for hydrogen generators. The hydrogen unit converts natural gas to hydrogen and carbon dioxide (CO_2), which is most often vented to the atmosphere. Refinery fuel gas, propane, butane, and light naphtha could be substituted for natural gas feedstock to hydrogen plants with modifications to equipment. These alternate feedstocks, however, increase CO_2 venting compared to natural gas.

Projections of Future Natural Gas Needs. The refinery industry has made a projection of future gas demand, assuming demand growth and prevailing natural gas prices. Refineries expect to expand capacity by about 1.5% a year to keep pace with product demand. This growth rate is less than half the projected industrial growth rate and includes an allowance for improved fuel efficiency of motor vehicles. While somewhat higher than growth rates in the immediate past, the projected growth rate is close to actual growth over the last 25 years.

Since the late 1970s, more than half of all U.S. refineries have shut down. The remaining refineries produce more total products and have invested in improvements to increase capacity. Imports have been relatively constant over the past decade. The NPC analysis assumes refinery capacity growth of 1% a year with product imports supplying any shortfall.

The major integrated oil companies have committed to the U.S. government to improve refinery energy efficiency by 10% from 2002 to 2012. As refineries become more efficient, energy usage will increase as additional processing and new units meet more stringent clean fuels requirements. Over the past 10 years, refinery efficiency improvements have averaged about 1.5% per year, while overall energy use per barrel of crude oil has dropped by only about

0.5% per year. In addition, a point of diminishing returns on energy improvement is expected as efficiency improves.

In recent years, the most efficient refineries have reached an efficiency plateau while less efficient refineries continue to improve. For the NPC analysis, energy efficiency is expected to improve 1% per year from 2002 to 2012, 0.5% per year for 2013 to 2022, and 0.25% per year thereafter through 2030. Refinery flare losses are assumed to reduce by 50% compared to current levels, with a corresponding reduction in natural gas demand.

The clean fuels regulations will require additional desulfurization capacity at most U.S. refineries. Many desulfurizers can be revamped to achieve lower sulfur levels, but new units will be required. About 100 new units will be required to produce clean gasoline, and 90 new units to produce clean diesel.

The net energy requirements for these new desulfurizers are modest, adding about 37 billion cubic feet (BCF) per year, or 5% of current refining natural gas demand. However, the hydrogen required for the desulfurization of gasoline and diesel fuel will require a significant net increase in natural gas demand, even after efforts are made to fully utilize available hydrogen. The NPC analysis assumes that 20% of the additional hydrogen required comes from improved management of existing hydrogen systems. The additional natural gas demand is estimated to be 118 BCF per year by 2010, or about 65% more than current natural gas usage for hydrogen production.

Demand growth, net efficiency gains, and regulatory impacts were projected for the NPC study based on the assumptions described above. Assuming natural gas continues to be the most economic incremental fuel for refineries, the resulting demand projections show an increase in natural gas demand of about 0.9% per year for the period from 2003 to 2030. Overall energy use drops from 536 thousand Btu per barrel to 495 thousand Btu per barrel during the period. The higher level of efficiency assumed for the 2003-2012 period is more than offset by increased hydrogen production for clean fuels. During the 2013-2022 period, efficiency gains keep pace with capacity growth and natural gas demand is relatively flat. From 2023 to 2030, natural gas demand increases as efficiency gains fall short of capacity growth.

As natural gas prices exceed those of alternate refinery fuels (i.e., propane, butane and gasoline), refiners will adjust operating conditions to increase fuel gas production and reduce natural gas consumption. It is estimated that refiners could reduce natural gas demand in the short-term by about 45% through operational changes. Sustained higher natural gas prices would provide an incentive for refiners to invest in fuel-switching capabilities on large heaters, boilers, and gas turbines. Ultimately, natural gas for refinery fuel could be limited to the volume required to balance swings in the refinery fuel gas system. This minimum volume is estimated at 20% of the natural gas currently used for refinery fuel. However, reducing natural gas demand to these levels would require sustained capital investments.

Figure 3-34 illustrates the major elements of natural gas demand in petroleum refining. Higher natural gas prices could affect natural gas feedstock to hydrogen plants. By modifying equipment and/or the catalyst, refiners could switch hydrogen plants to fuel gas, propane, butane, or naphtha. Assuming half of refinery hydrogen plants are switched to alternate fuels, overall natural gas demand for hydrogen production would be reduced by an equivalent amount. Combined with the reduction in natural gas for refinery fuel, overall natural gas projections could be reduced by two-thirds of the levels shown in Figure 3-34 – one-third through short-term operational changes, and an additional one-third over time as fuel-switching projects are implemented.

In summary, natural gas demand at U.S. refineries is expected to increase by about 33% over current levels by 2030, assuming that natural gas remains the incremental fuel of choice. Efficiency improvements will be more than offset by the need for additional refinery fuel to meet demand growth and to produce hydrogen to make clean fuels. If higher natural gas prices fundamentally alter relative economics versus readily available alternatives, these demand projections could be reduced by up to one-third in the short term and by up to two-thirds in the long term as refiners optimize the trade-offs between natural gas costs and product value.

Petroleum refineries experienced production growth of 1.2% per year during 1992-1998 and gas use increased 6.7% per year as consumption grew from 959 BCF in 1992 to 1,416 BCF in 1998. Figure 3-35

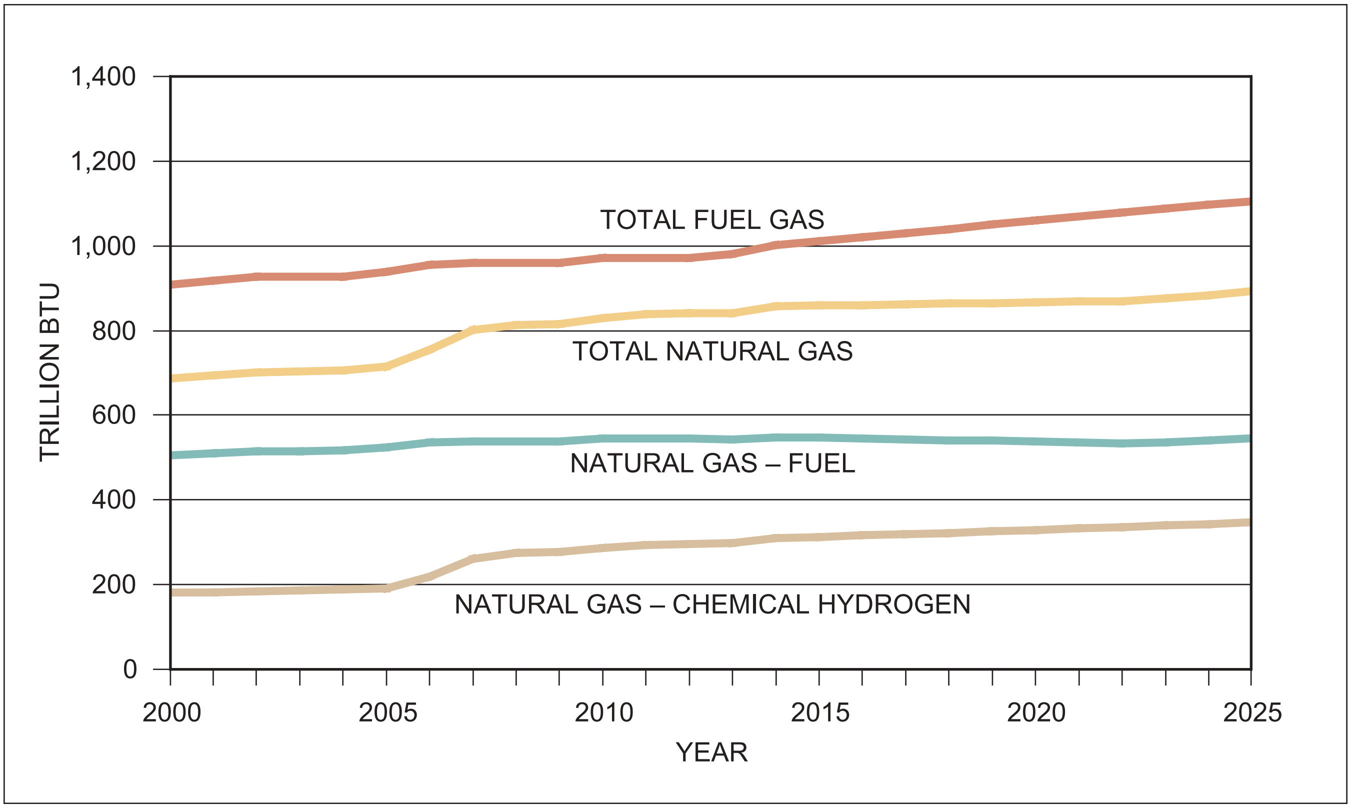


Figure 3-34. U.S. Major Elements of Natural Gas Demand in Petroleum Refining

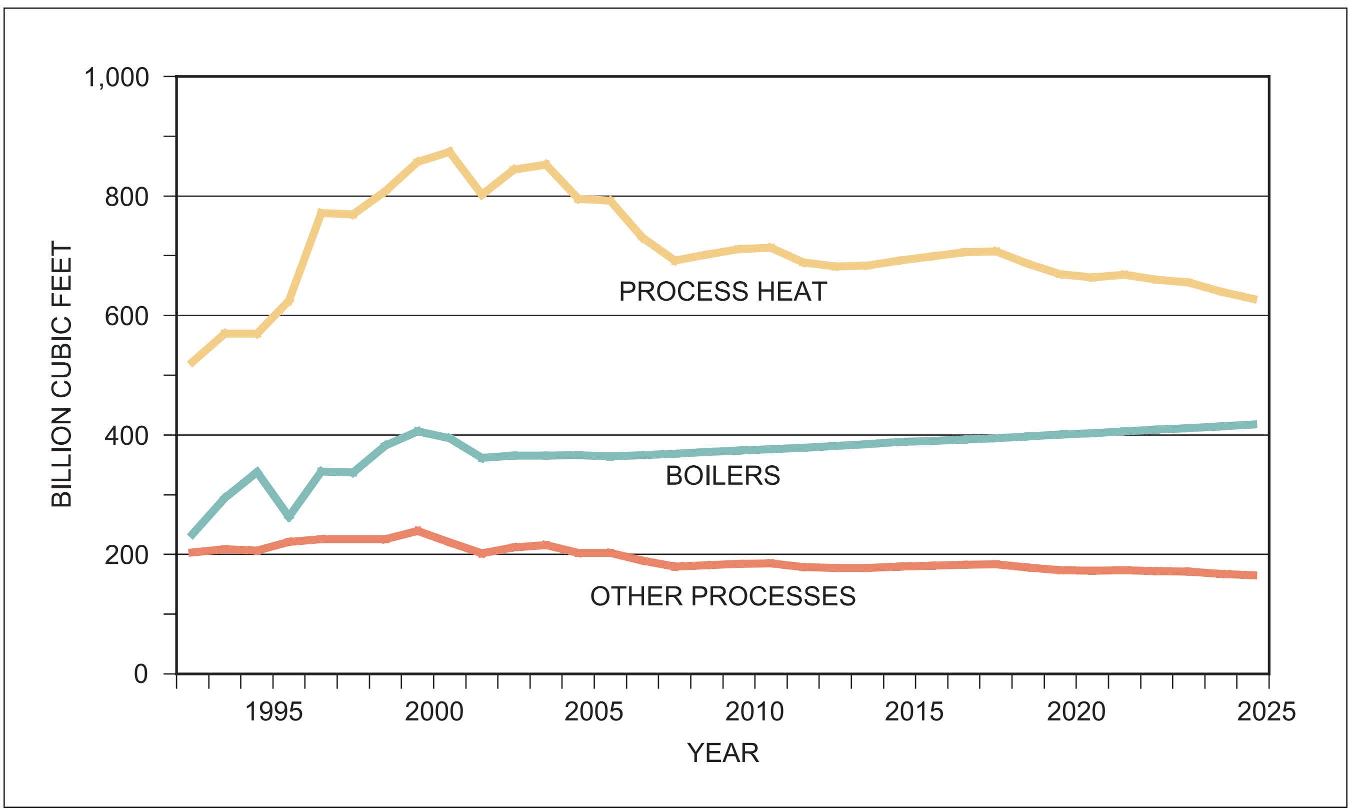


Figure 3-35. U.S. Petroleum Refining Gas Demand in Reactive Path Scenario

illustrates the refinery trends in gas use for boilers, process heat, and other processes in the Reactive Path scenario. Figure 3-36 provides this information for the Balanced Future scenario. Most of the increased gas use occurred in process heaters where low-priced natural gas displaced crude oil-derived fuels, especially fuel gas. Cogeneration with combustion turbines was another growth area because refineries preferred to use natural gas in the turbines for reliability and warranty reasons.

In the Reactive Path scenario, refinery production is expected to grow at 1% per year during the forecast period of 2001-2030 and gas use is expected to decrease by 0.7% per year. Annual gas consumption is expected to decline from 1,365 BCF in 2001 to 1,109 BCF in 2030. Gas use decreases while production increases for several reasons. Although substantial gains in energy efficiency have already been accomplished, these improvements are expected to continue. Capacity expansion at refineries is expected to focus on downstream processes where steam demand is less. Also, higher gas prices are expected to result in a shift back to fuel gas and other oil-derived fuels in some process heaters. Refiners have greater fuel-switching capabilities than other industries and are likely to react quickly when the price ratio of natural gas to crude oil price increases. Finally, new cogeneration in the forecast period is included in the power sector analysis, and such growth contributed much to the growth in gas use during the 1990s. These factors are offset to some extent by increased energy intensity required to produce lower-sulfur transportation fuels. Much of the increased hydrogen production required for these clean fuels is assumed to be produced by merchant plants in the chemical industry rather than in the refining industry itself.

The Balanced Future forecast shows slightly higher gas use due to higher consumption for process heat, indicating less fuel switching.

Primary Metals

Aluminum. The U.S. aluminum industry (SIC 333/5 or NAICS 3313) is the world's largest, producing about $39 billion in products and exports in 2000 and accounting for 17% of the world's primary aluminum production in 1997. Aluminum products are used in transportation, construction, packaging, consumer

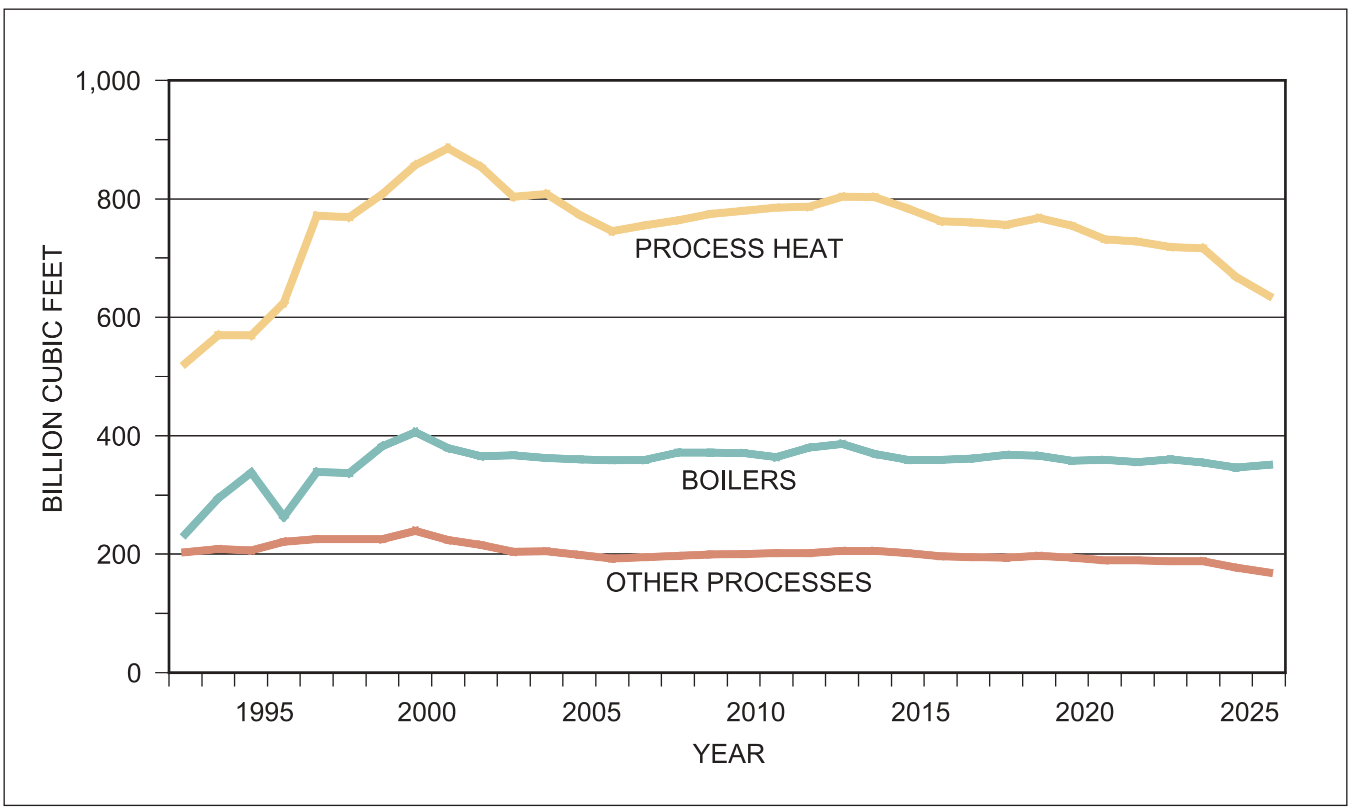


Figure 3-36. U.S. Petroleum Refining Gas Demand in Balanced Future Scenario

durables, and electrical industries. As a lightweight, high-strength, recyclable, and structural material, aluminum will continue to play an increasingly important role in the U.S. economy as applications are extended into infrastructure, aerospace, and defense industries. According to the Census Bureau, during 2000, the U.S. aluminum industry employed 141,000 people, operating over 300 plants in 35 states and impacting communities throughout the country, either through physical plants and facilities, recycling, heavy industry, or the consumption of consumer goods.

Aluminum metal is classified as primary aluminum if it is produced from ore and as secondary aluminum if it is produced predominantly from recycled scrap. In 2001, exports of aluminum products accounted for 11.3% of total shipments, while imports accounted for 38.3% of supply.

Global primary aluminum production has grown at 2.2% annually over the last ten years and demand for the product continues to rise as new applications are developed. The primary production of aluminum requires the availability of skilled labor, proximity to consumer markets, a highly developed infrastructure and, especially, low cost and reliable energy. Imported aluminum is the fastest growing source of U.S. supply and new primary aluminum facilities increasingly are being located outside of the United States, near sources of low-cost electricity.

Aluminum remains one of the most energy-intensive materials to produce. Only paper, gasoline, steel, and ethylene manufacturing consume more total energy in the United States than aluminum. Aluminum production is the largest consumer of energy on a per-weight basis and is the largest electric energy consumer of all industries. Electricity accounts for nearly 98% of the energy used in primary aluminum production, accounting for one-third of the cost.

Recycled aluminum requires only about 6% of the energy needed for primary aluminum production. In 2000, more than 48% of the aluminum produced by U.S. industry came from recycled material; 40 years ago, recycled material was used to generate less than 18% of U.S.-produced aluminum. Recycling is the largest contributor to the reduction of the energy intensity of aluminum produced in the United States.

Production variations of aluminum in the United States are more reflective of the costs to produce aluminum than of domestic demand. This factor makes energy efficiency and energy management prime industry objectives.

The large electricity demands of the aluminum industry are relevant when assessing the environmental impact of production and the sensitivity of the industry to fluctuations in the electricity market. The U.S. primary aluminum industry has more than half of its capacity sited in regions where lower cost hydroelectric power is generated.

Although the aluminum industry uses natural gas as energy input for various steps in the production process, the price fluctuations of natural gas have their largest impact in terms of the price of electricity. While the aluminum industry is a large consumer of both natural gas and electricity, its annual expenditure for electricity is over $2 billion. A key determinant of the industry's viability in the United States is access to low-cost reliable energy and the development of energy-efficient production processes.

Iron and Steel. The United States is the largest steel producer in the world, producing 107 million tons of raw steel in 1998, nearly 13% of total world production. The iron and steel industry (SIC 33 or NAICS 331) provides about 5% of the total U.S. manufacturing GDP, employing more than 150,000 production workers in jobs paying 50% above the average for all U.S. manufacturing. Steel is used in a diverse range of applications ranging from shipbuilding, national defense and construction, to food storage and transportation.

A steel import surge that began in 1998 placed significant financial pressure on the industry. Large levels of imports brought about by world steel overcapacity (from economic downturns in Asia and the Commonwealth of Independent States) drove prices down to unprecedented levels. As a result, 35 steel companies, representing 40% of total U.S. steel production, entered into bankruptcy or liquidation. American steel producers are currently engaged in a major restructuring and consolidation in response to this crisis.

Two processes are used for making steel in the United States. About 53% is made by integrated steel makers using the Basic Oxygen Furnace (BOF) process. The BOF process is used to produce steel needed for packaging, car bodies, appliances, and steel framing; it uses about 70 to 80% of molten iron and 20 to 30% recycled scrap. The Electric Arc Furnace (EAF) process accounts for about 47% of raw steel production in the United States and is used to produce steel shapes such as railroad ties and bridge spans. EAFs use electricity as the primary source of energy to melt charged materials, which typically consist of nearly 100% recycled steel or scrap.

The steel industry is highly energy-intensive. Energy costs account for 12 to 15% of the cost of manufacturing steel, on the order of $50 per ton. Steel making requires energy both to supply heat and power for plant operations and as a raw material for the production of blast furnace coke. Its aggregated average energy consumption of about 19 MMBtu per ton of steel shipped represents approximately 2 to 3% of the energy consumed in the United States and over 10% of the energy use in the industrial sector. Natural gas accounts for nearly 20% of the steel's energy consumption and electricity accounts for most of the balance.

Over the past 20 years, the iron and steel industry has invested nearly $7 billion in environmental control equipment. Through a combination of technological innovation and operating practice changes, the industry has reduced its process energy intensity by about 45% since 1975. The industry's overall recycling rate is nearly 71%; over 70 million tons of scrap were recycled in 2002. According to an Environmental Protection Agency (EPA) estimate, the energy savings associated with the use of recycled iron units, rather than iron ore, is equivalent to the annual electricity needed to power 18 million homes.

As part of the R&D effort of the U.S. steel industry, steelmakers are increasingly interested in replacing other energy sources with natural gas. The industry is stimulated by the possibility that concerns with climate change and greenhouse gas emissions, as well as other environmental considerations, might ultimately require greater fuel switching to gas.

Gas Demand Projection for Primary Metals. The primary metals industries (essentially iron and steel) have seen dramatic changes in recent decades. Large integrated steel mills have been replaced by scrap-based steelmaking in minimills and all metal producers have become subject to aggressive global competition. Surprisingly, the primary metals industry grew by 3.5% per year from 1992 to 1998. This was a fairly positive period for the sector, driven largely by a healthy demand from auto manufacturing and other metal-using sectors. Gas consumption grew at a slower rate, 1.8% per year during this period and would have grown at only 0.3% without coincident growth in cogeneration. Annual gas consumption grew from 692 BCF in 1992 to 769 BCF in 1998.

Figure 3-37 shows the trends for the Reactive Path scenario in gas use for boilers, process heat, and other processes in primary metals. New cogeneration projects, classified as other processes, contributed to increased gas use in the historical period. Gas use for process heat grew with production until 1996 when consumption began a long-term decline that continues throughout the forecast period. Gas use for boilers declines throughout the historical and forecast periods. These declines in gas use by the steel industry reflect the shift from large, integrated mills to minimills, which are less energy-intensive and use electricity as the major source of energy. Significant improvements in energy efficiency and process changes continue to reduce the amount of gas used in the metals sectors. Intense global competition also has made the primary metals industry very aggressive about reducing costs such as for natural gas in heat treatment furnaces, where oxyfuel burners and electric thermal technologies can reduce or replace gas load. Global competition has had a strong negative effect on U.S. metals production, despite these advances by U.S. manufacturers.

In the forecast period, gas consumption is expected to decline 2.7% per year while production declines 0.2% per year. The forecast assumes trends toward more efficient production technologies to continue with most of the reductions in gas consumption coming from process heat applications.

Figure 3-38 shows the Balanced Future scenario for primary metals. The results are very similar to the Reactive Path scenario because the changes are due largely to industry trends rather than gas price issues.

Paper

The U.S. forest products industry (SIC 26 or NAICS 322) employs 1.5 million people and ranks among the top ten manufacturing employers in 42 states, with an estimated payroll of $51 billion. The United States is the world's largest producer of forest products, with total annual sales that exceed $250 billion.

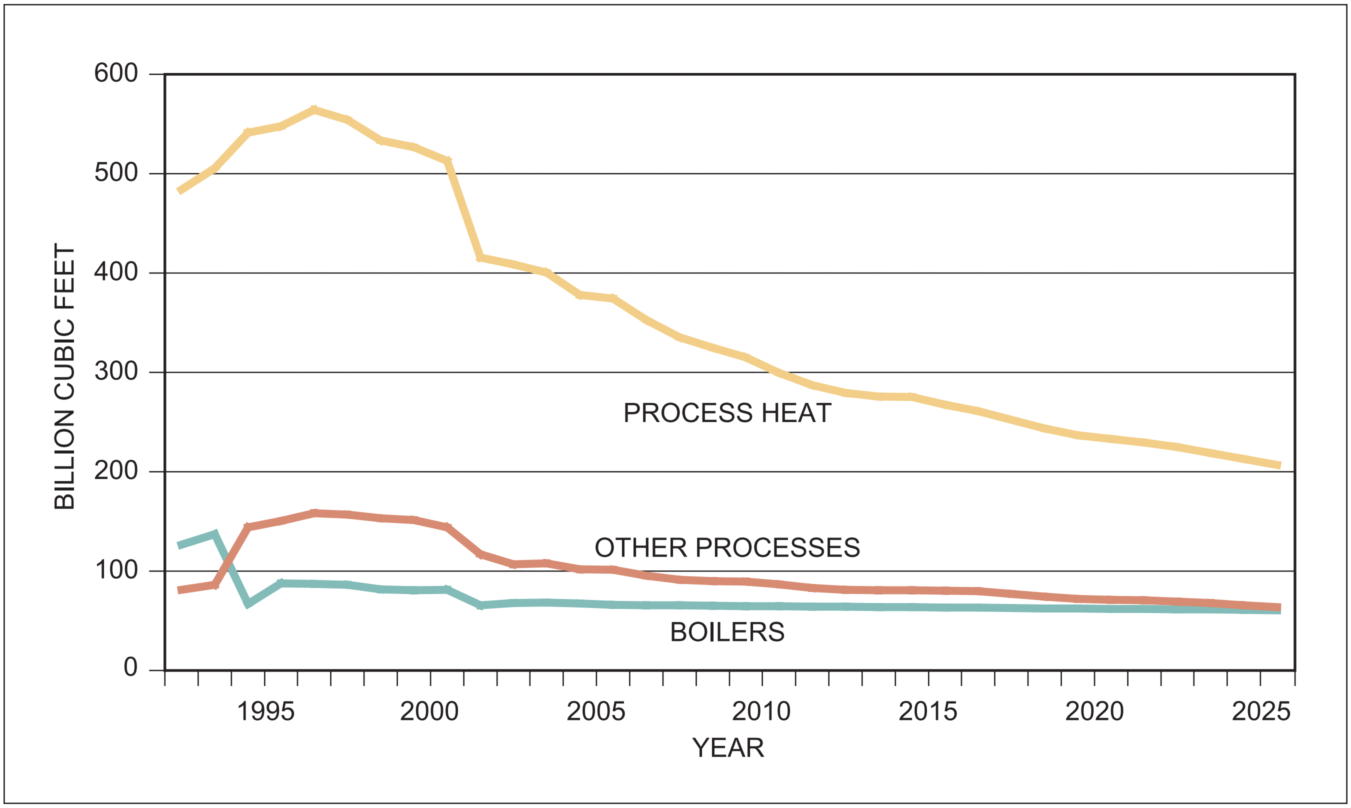


Figure 3-37. U.S. Primary Metals Gas Demand in Reactive Path Scenario

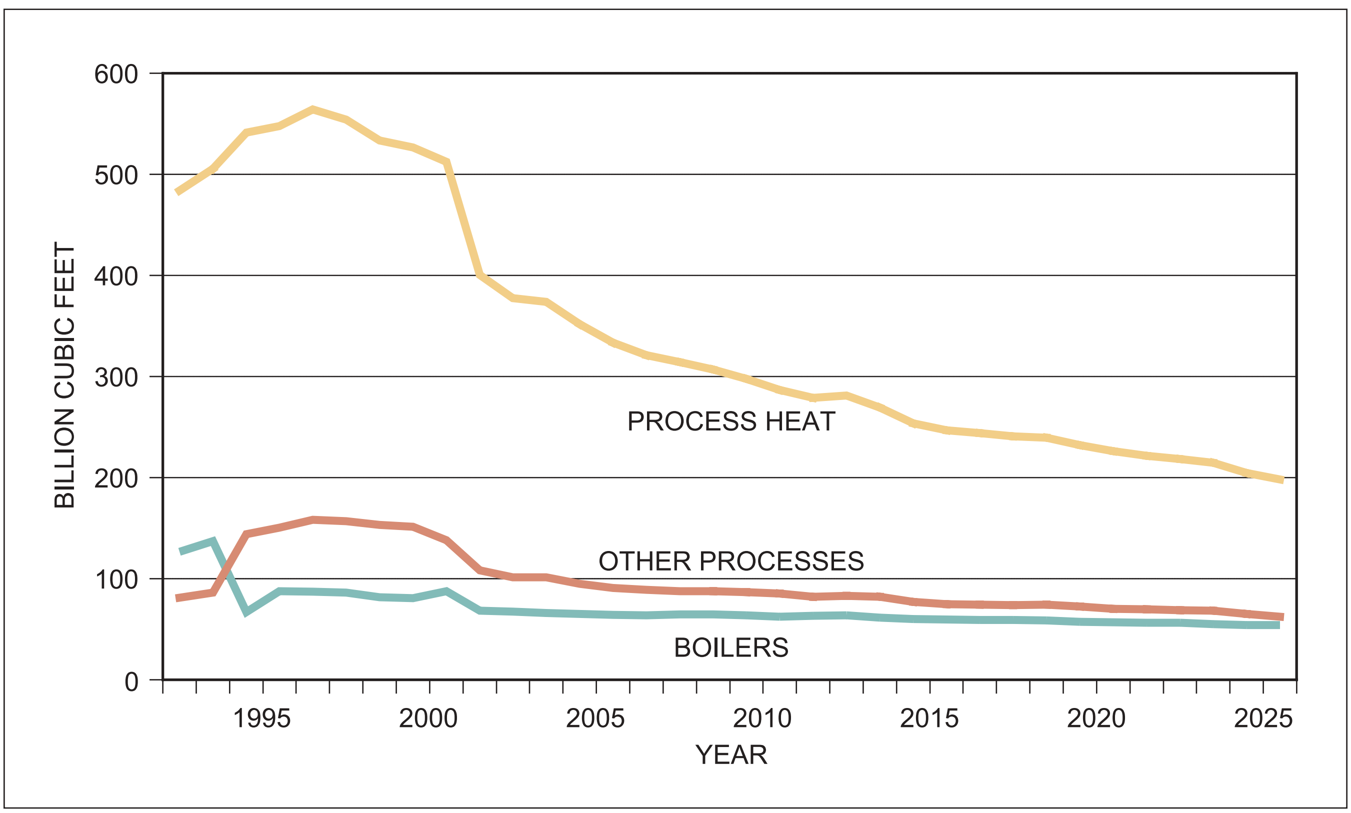


Figure 3-38. U.S. Primary Metals Gas Demand in Balanced Future Scenario

Products from America's forest and paper industry represent more than 8% of U.S. manufacturing output, making it the sixth largest domestic manufacturing sector. The annual increase in per-capita consumption averaged 1.8% from 1960 to 1980, 1.6% from 1980 to 1993, and has been projected at 0.6% from 1990 to 2040. The United States produced 88 million tons of paper and paperboard in 1999, over 700 pounds for every person.

Wood for pulping represents the largest cost among material inputs to the pulp and paper industry, accounting for an average of 21% of total material and energy costs. The industry is the third largest industrial consumer of energy. Pulp, paper, and paperboard mills account for about 12% of total manufacturing energy use in the United States. Energy intensity in the paper and allied products industry in 1991 was 20 thousand Btu per dollar value of shipments, ranking it as the second most energy-intensive industry group in the manufacturing sector. The forest products industry spent more than $7.6 billion on purchased fuels and electricity in 1998, or just less than 3% of the value of its shipments that year.

Energy costs traditionally have been in the top five cost categories for the industry; additionally energy costs as a proportion of operating costs have increased dramatically. Many paper mills that have closed recently cited rising energy costs as a main or contributing factor in the shutdown.

Since 1972, the industry has reduced its use of fossil fuels and purchased energy by about 2%, yet increased its total production by nearly 64%. Over that period, the industry also reduced average total energy use by 30% (per ton of product produced). The industry's gains in energy efficiency are in part due to the success of onsite electricity generation at mills throughout the country. The forest products industry currently meets nearly 63% of its energy needs through self-generated electricity. The industry leads all other manufacturing sectors in on-site electricity generation, producing nearly 43% of U.S. self-generated electricity. This energy is harnessed primarily through efficient cogeneration with use of woody waste products and other renewable sources for biomass fuel (bark, wood, pulping liquor).

Cogeneration processes turn waste materials into a renewable energy source that diverts waste from landfills, reduces reliance on fossil fuels and offsets greenhouse gas emissions by substituting carbon-neutral biomass for fossil fuels. The industry's use of renewable fuels represents the equivalent of about 20 million barrels of oil per year and offsets the CO_2 emissions of about 16 million automobiles annually.

Although the industry is more than 60% energy self-sufficient, it relies on natural gas, coal, fuel oil, and purchased electricity to meet the balance of its energy needs. Increases in oil and gas prices threaten the competitiveness of many mills. High energy prices have forced some companies to cease operations and sell electric capacity instead of making a product, making them vulnerable to foreign producers.

Workshops with industry representatives indicated that efforts to hold down energy costs are often countered by regulations that discourage fuel flexibility and the development of energy efficient operating processes. Implementation of New Source Review requirements was cited as a mechanism to effectively force companies to continue using fuels associated with installed equipment while discouraging new investment in energy-efficient technologies and processes. These workshops also found that in a volatile natural gas price market, forest products manufacturers would benefit from the flexibility to substitute lower-cost alternative fuels – coal, biomass, and shredded tires – to fuel boilers.

Gas Demand Projection. Gas consumption for the production of paper and allied products grew by 3.5% per year during 1992-1998 while production grew by only 0.4% per year. Annual gas use by the industry grew from 505 BCF to 622 BCF over the period. Figure 3-39 shows the gas use for boilers, process heat, and other processes in the Reactive Path scenario, and it is apparent that gas use for boilers is the major factor contributing to this increase. The major driver for the increase was strong growth in the energy-intensive components of the industry (from paper, pulp, and paperboard mills).

In both the Reactive Path and the Balanced Future outlooks, the recent rapid growth in gas consumption would not continue. Between 2001 and 2025, no net growth in production of paper products is projected and gas consumption is expected to decline by 0.7% per year. Figure 3-40 shows the Balanced Future projection for the paper industry. The scenario shows lower gas consumption in the boiler sector due to increased flexibility to switch fuels.

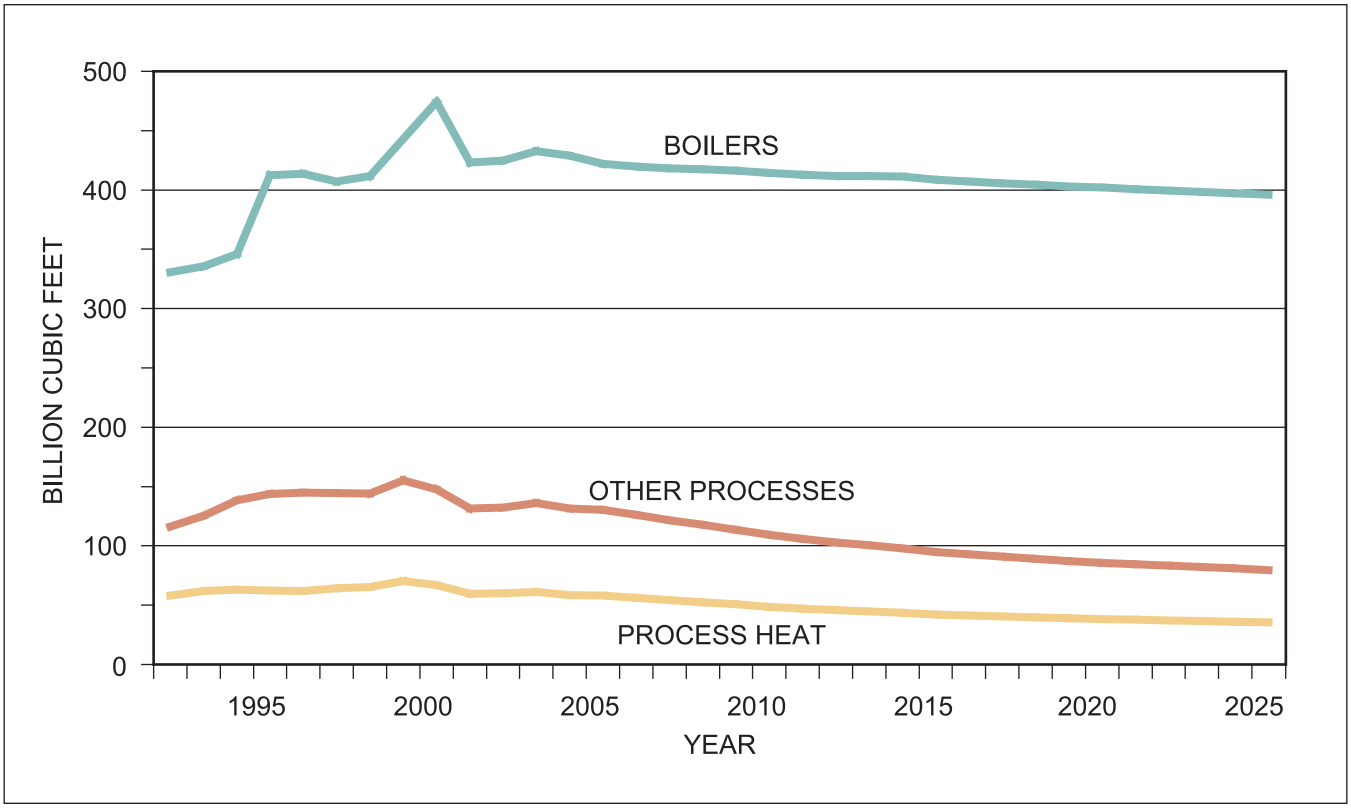


Figure 3-39. U.S. Paper Industry Gas Demand in Reactive Path Scenario

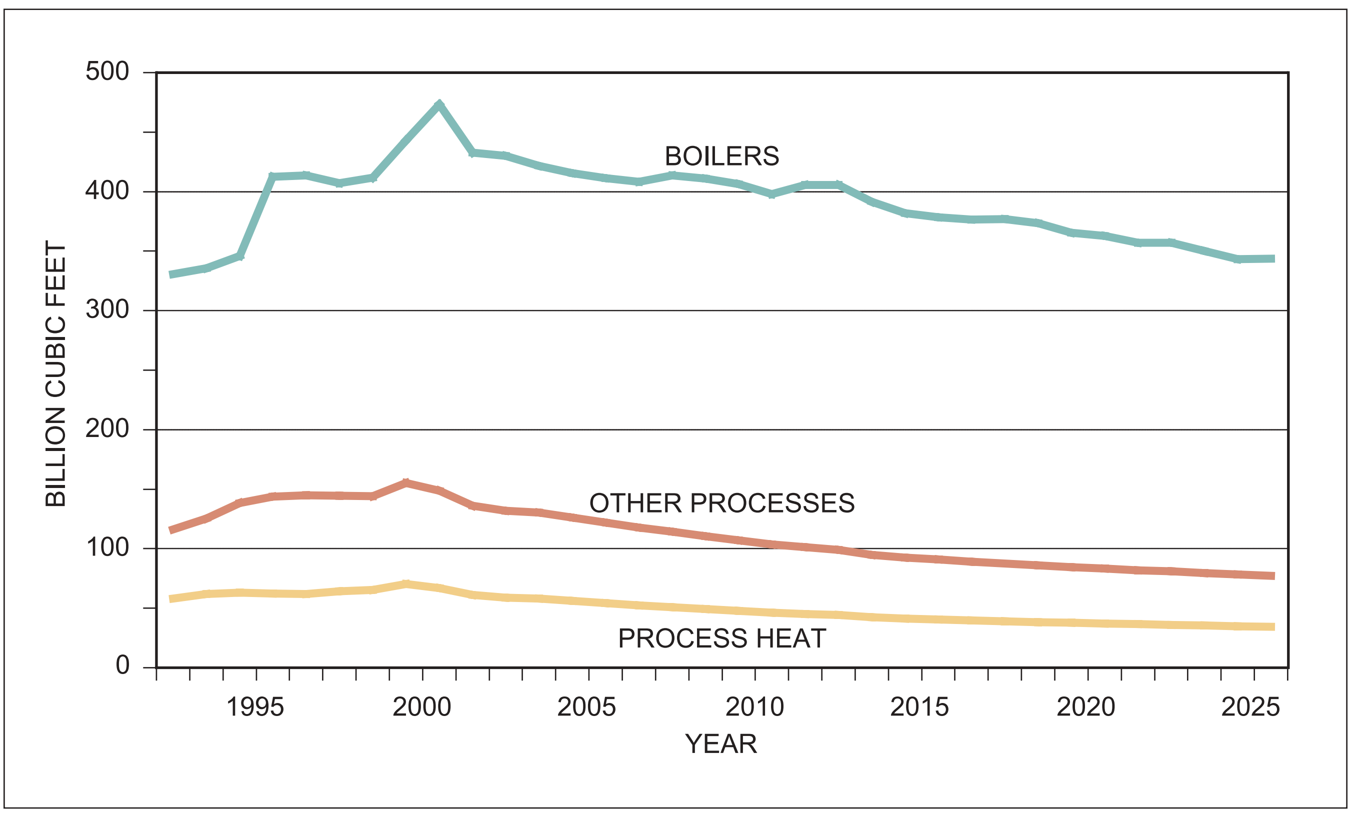


Figure 3-40. U.S. Paper Industry Gas Demand in Balanced Future Scenario

Stone, Clay, and Glass

The stone, clay, and glass industries (SIC 32 or NAICS 327) produce cut stone products and clay products, including bricks, glass, concrete, gypsum, and lime. The industry employed 508,000 people and sold $93 billion in products in 1998. The industry produces the cement, bricks, and glass products used in homes and infrastructure as well as containers for many food and consumer products. Unlike some sectors, this industry does not compete to a great extent with imports or export. Further, production is often located within the same region as the target market since its products are heavy, with a low price-to-weight ratio, thereby making transportation costs prohibitive for long-distance shipping. The highest concentration of energy use is in the East North Central and Mid-Atlantic regions where 36% of this industry's energy is consumed. After mined raw materials, energy is one of the most important inputs in production.

The major drivers for energy consumption in the stone, clay, and glass industry are demand in the construction industry and new combustion technologies. Global competition is less of a factor and fuel purchases represent less than 5% of the value of most finished products. The proliferation of oxy-fuel burners on many natural gas-fired kilns and furnaces improves energy efficiency, raises throughput capacities, and lowers emissions.

Industry natural gas use increased from 329 BCF to 388 BCF between 1992 and 1998. The annual growth in gas use was 2.8%, which is slightly less than the production growth rate of 3.8% during this period. Unlike chemicals, refining, or primary metals, boilers play a small part in this sector and cogeneration contributed little to increased gas use during the period. More than 80% of the natural gas is used for process heat, especially for the production of clay products (bricks), glass, and gypsum. The industry is using more-efficient equipment, including electric boosters and oxy-fuel furnaces, to reduce energy costs and increase production.

Gas consumption within the industry (SIC 32) are for production of glass (155 BCF), brick (47 BCF), gypsum (42 BCF), and cement (26 BCF). Natural gas provides most of the thermal energy used in the glass industry. Gypsum-producing kilns and brick-firing furnaces generally use natural gas, while cement and lime are most often produced in coal-fired kilns.

Recent increases in gas price present a challenge for manufacturers with limited options to fuel switch because the obvious alternatives (propane and distillate oil) may have little cost advantage in the longer term. Energy conservation has taken the form of incremental improvements (heat recovery and better instrumentation in kilns) and shifting from wet process kilns to dry and vertical process kilns.

Demand Outlook for Stone, Clay, and Glass. Production is expected to grow 2.8% per year during the forecast period, which is the highest rate of the six major gas-intensive industries. Gas use would grow at a modest 0.8% per year in the Reactive Path scenario with annual consumption rising from 361 BCF in 2001 to 458 BCF in 2030. The slower growth of gas use reflects a continuation of the trends seen in the 1990s, slower growth in flat glass production, and improved process efficiencies. In addition, the NPC model shows that higher natural gas prices will lead to fuel switching to oil in the glass and brick industries and to coal and waste fuels in the cement industry.

Production in the stone, clay, and glass industry is projected to grow about 1.1% per year in the long term, although incremental energy efficiency improvements will hold the growth in energy consumption to about 0.6% per year. Natural gas consumption will grow at a slower rate, about 0.5% per year, although this industry derived estimate was based on lower gas price projections than now expected.

Figure 3-41 shows the projection of major natural gas uses in the Reactive Path scenario. Figure 3-42 shows the projection in the Balanced Future scenario. In this scenario, lower gas prices increase gas use for process heat relative to the Reactive Path scenario.

Food and Beverage

The food and beverage industry (SIC 20 or NAICS 311 and 3121) is one of the most diverse and disaggregated of the six energy-intensive industries, producing numerous products from sausage to milk to frozen dinners to beer. The food industry has seen rapid consolidation in recent years but its operations remain quite varied. Food processors continually develop new and more products to meet the market demand. The industry employed 1,640,000 people and sold $491 billion of products in 1998.

The food and beverage industry spent $6.1 billion in 1998 to purchase 1,150 trillion Btu of energy. Natural

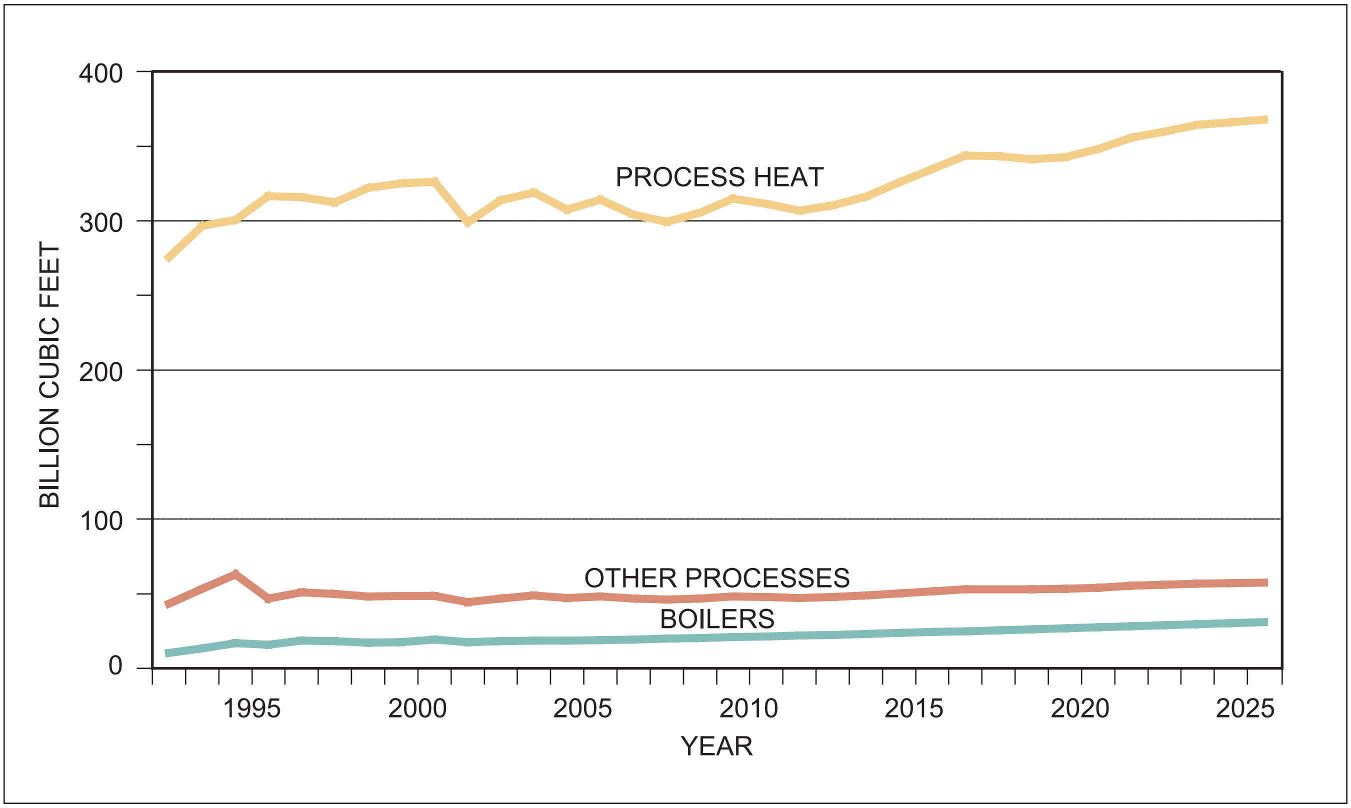


Figure 3-41. U.S. Stone, Clay, and Glass Gas Demand in Reactive Path Scenario

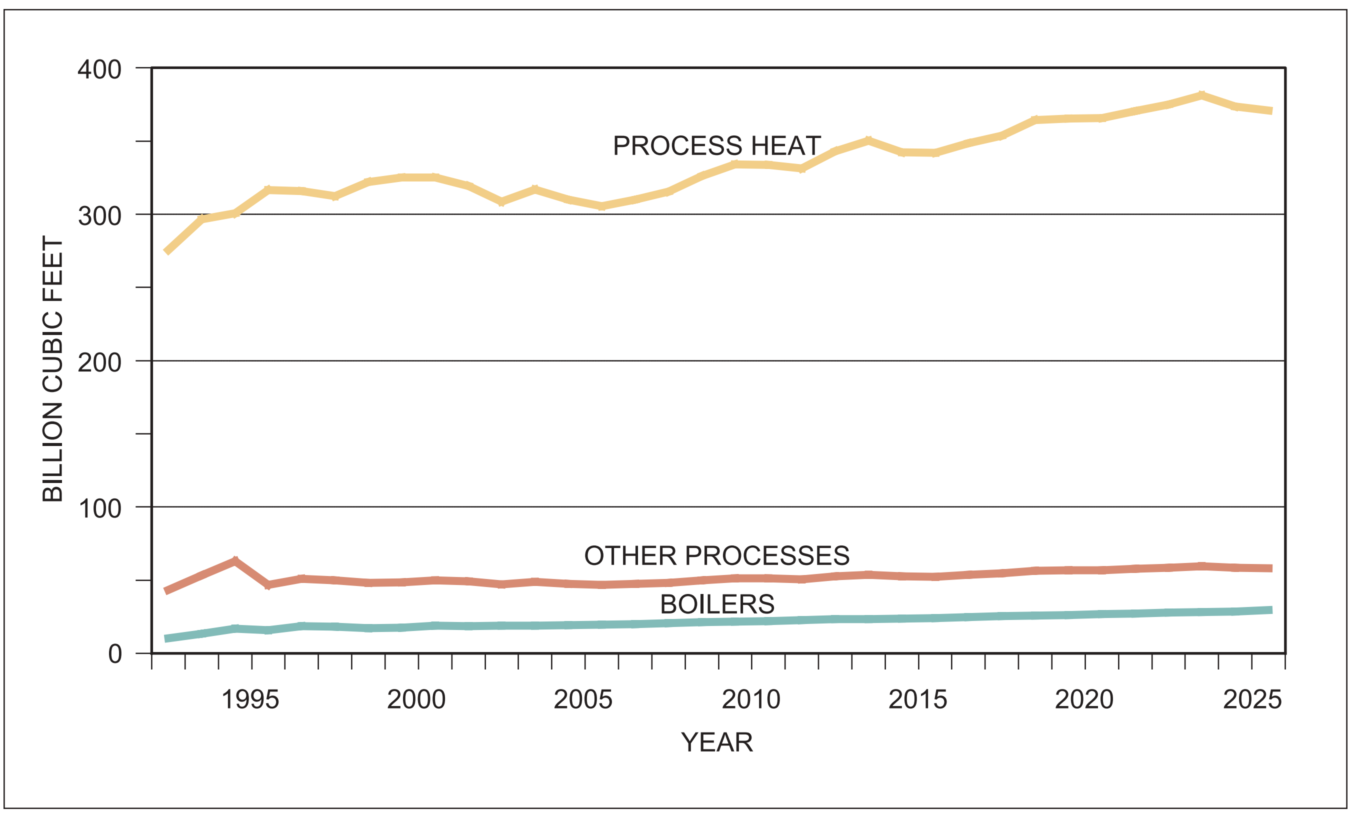


Figure 3-42. U.S. Stone, Clay, and Glass Gas Demand in Balanced Future Scenario

gas is the largest single source of purchased energy for the industry, which consumed about 655 BCF in 1998. Electricity (68 million megawatt hours) and coal (7 million tons) were the other major energy sources. The industry produces high value-added finished products; overall energy costs are just 1.4% of the value of total shipments.

Natural gas use in the food industry increased from 524 BCF to 655 BCF between 1992 and 1998, respectively. Gas use grew by 3.8% per year during this period, which is one of the highest rates in the manufacturing sector. Increase in gas use outpaced production during this period from rapid growth of the energy-intensive sub-industries (the wet corn mill, beet sugar, soybean oil mill, and malt industries), relative to the less energy-intensive sub-industries.

The food industry will likely continue improve heating and cooling technologies that achieve better product quality. In outreach sessions between the NPC and industry representatives, energy was not highlighted as a primary reason for new technology development. Energy-focused projects, however, have been successful in highly integrated operations such as wet corn milling and malt beverage production.

An important innovation in grain processing is dry corn milling. Wet corn milling is one of the most energy-intensive processes in the food industry. Dry corn milling focuses on ethanol production and simplifies the process by eliminating the initial soaking and oil separation steps. Dry milling facilities, often owned by farming cooperatives, are smaller and less expensive than wet milling plants. Generally, dry milling plants use natural gas in boilers instead of coal. Because of capital constraints, dry corn milling operations may not be optimized and may be good candidates for cogeneration projects.

The food and beverage industry relies on natural gas for a variety of process and boiler fuel uses. Boilers for steam production consume more than half of the energy used in the food and beverage industry, including about 398 BCF of natural gas. Companies prefer natural gas because gas boilers are cleaner and more flexible than the main alternative, coal boilers. Cleanliness is of primary importance at a food manufacturing facility and natural gas avoids the problems in storage, dust and air pollution control associated with coal. Also, many food plants are too small and/or do not operate on a sufficiently continuous schedule to make coal boilers practical.

Steam is used for food drying, cooking, and concentration processes. Direct process heating processes such as food drying, baking, and frying accounted for 188 BCF. Other processes, specifically space heating, used 69 BCF. Cogeneration steam boilers, turbines, and engines used 122 BCF according to the NPC estimates. The major gas consuming parts of the food industry are animal slaughtering and processing (115 BCF), wet corn milling (84 BCF), fruit and vegetable preserving (64 BCF), and dairy processing (49 BCF).

Expansion in the food companies is driven largely by population growth and is shaped by changing consumer preferences. For several decades, Americans have continued to spend about 15% of their income on food. As household wealth increases, people buy more prepared foods and dine in restaurants more frequently. The food industry has responded with products that expand and complicate the manufacturing process. For instance, supermarkets now stock hundreds of frozen food products. Product innovation, product quality, and labor costs are of greater importance to food producers than energy.

The manufacture of some product lines is concentrated in certain regions; for example, milk in the East North Central or orange juice in the South Atlantic. Other products, e.g., baked goods, generally are produced locally. Overall, about 43% of the food and beverage industry's energy consumption was in the East North Central and West North Central regions. Imports and exports are growing but remain less of a factor than in other industries.

Demand Outlook for the Food Industry. The food industry is projected grow at a moderate pace and natural gas sales will grow at a slightly slower rate, about 1% per year. Coal consumption, which is concentrated in the wet corn milling and malt beverage industries, will remain steady or slightly decline as dry corn milling gains market share and sales of malt beverages flatten.

Figure 3-43 shows the gas demand for boilers, process heat, and other processes for the Reactive Path scenario. Process heat and other processes accounted for most of the increase in gas consumption during the historical period when gas demand grew by 3.8% per

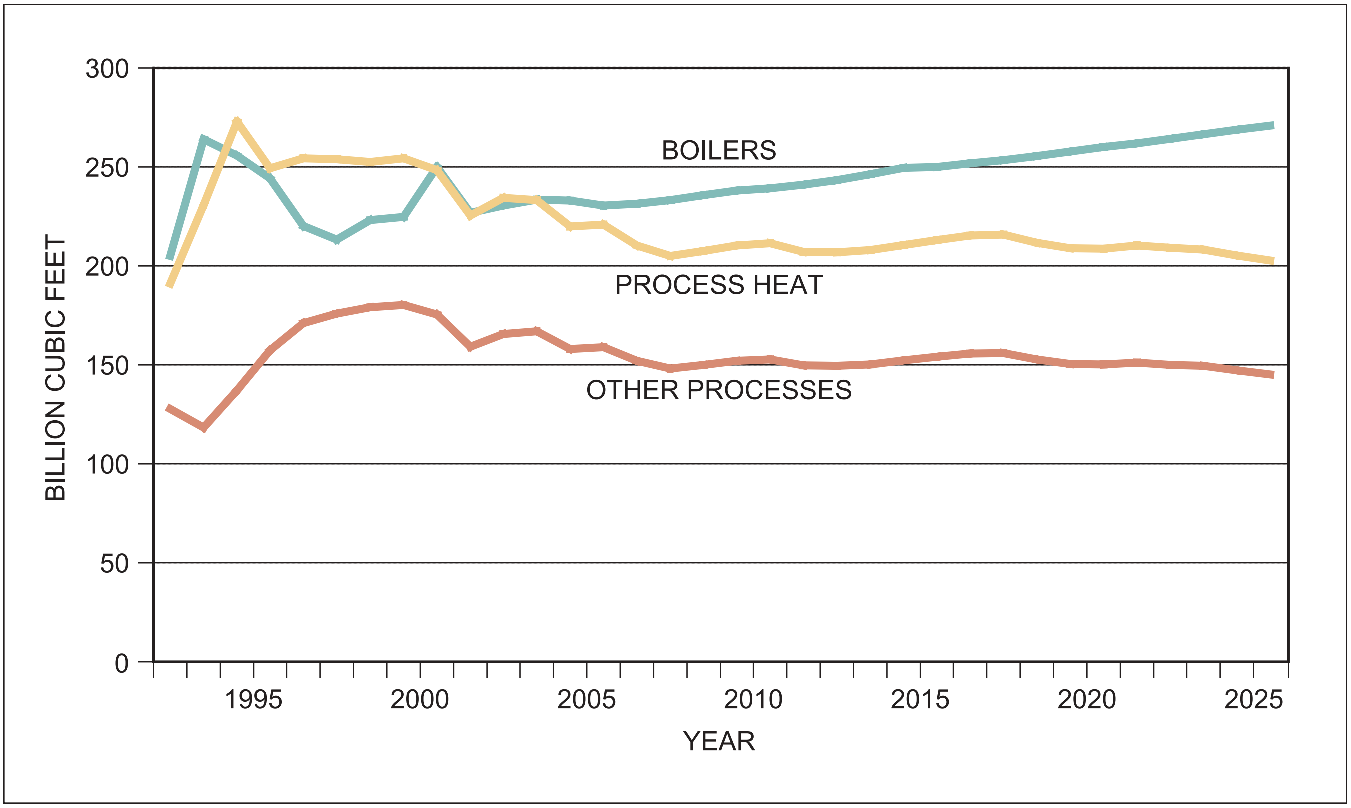


Figure 3-43. U.S. Food Industry Gas Demand in Reactive Path Scenario

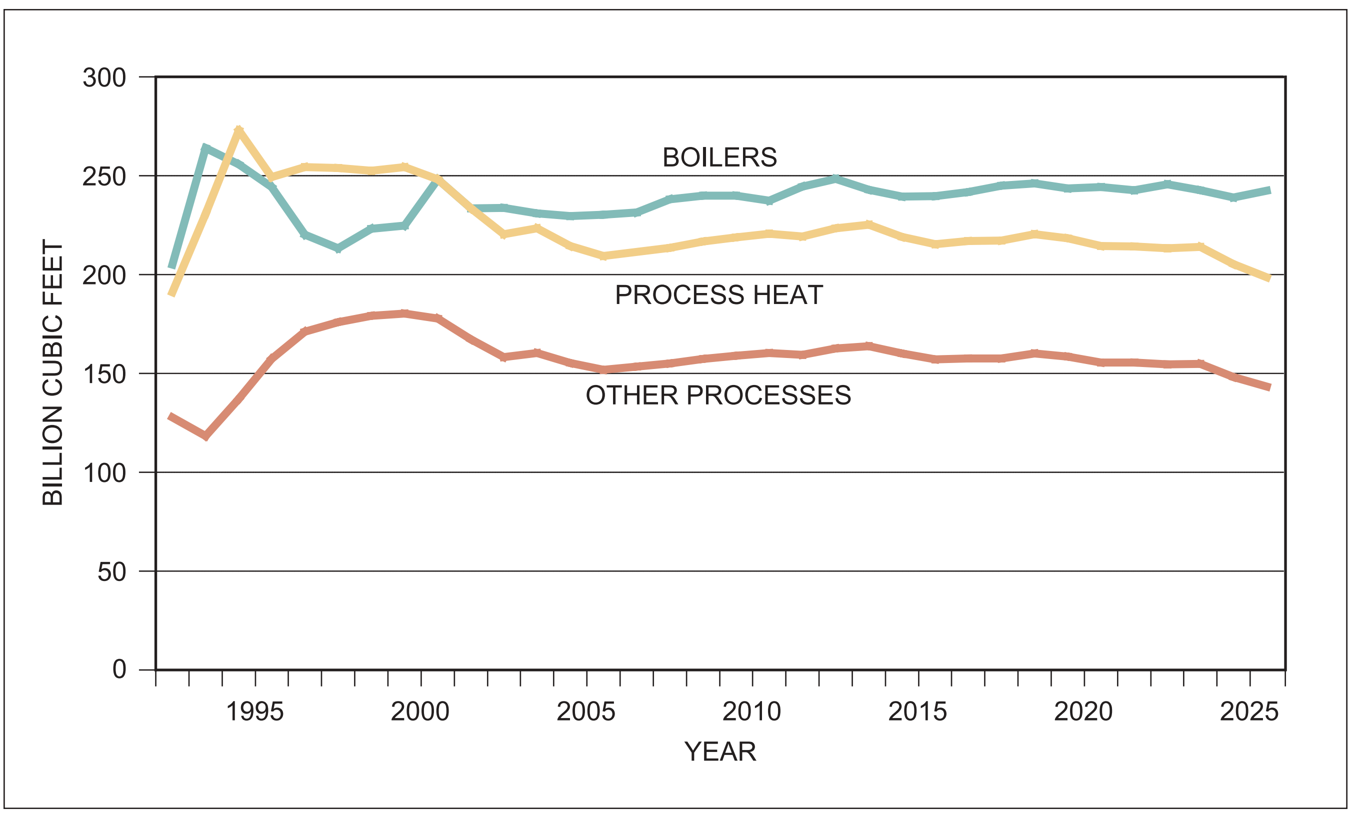


Figure 3-44. U.S. Food Industry Gas Demand in Balanced Future Scenario

year, which is greater than the growth in production (2.4%).

In the Reactive Path scenario, production increases by 1.1% annually after 2001 while gas use decreases by 0.1% per year. Gas load in 2030 is projected to be 593 BCF. Figure 3-43 reveals that gas use for boilers continues to grow but gas use for process heat and other applications is flat or declining. Two reasons for the lack of growth for these end uses are improved efficiency and slower growth in the energy-intensive sub-industries. New cogeneration is not included in the forecast. Figure 3-44 shows gas demand in the Balanced Future scenario. In this scenario, gas use for boilers is relatively flat, indicating greater potential for fuel switching in boilers.

Other Primary Metals

The major gas-consuming components of the primary metals industry are in iron and steel, and aluminum. "Other primary metals" comprises the remainder of the sector and consumes about 196 BCF per year or one-third of the gas consumed in the primary metals industries. This industry group includes metal foundries, primary and secondary smelters of non-ferrous metals (except aluminum), and establishments engaged in rolling, drawing, and extruding of metal products. In 2001, this segment accounted for almost half of the value in shipments from the primary metals industry. During the same year, the industry employed almost 330,000 workers, or over 60% of total employment in the primary metals industry. Approximately one-third of the industry's output comes from the East North Central region and another 15% comes from the Mid-Atlantic region. These regions have a heavy presence of metal fabricators (e.g., automobile manufacturers), which is the major market for the industry's products.

The major uses of natural gas in this industry are metal melting, heat-treating, and space heating. Process heat accounts for 60% of natural gas consumed in the industry, and the rest is for space heating (through direct heat or steam space heaters). The relatively high employment level and location of the plants in the Midwest and Mid-Atlantic states drive the demand for space heating.

Industrial production in this segment has grown at about 0.5% per year in recent years. This relatively high growth rate reflects a healthy period in the automobile industry and other markets for products. The NPC forecast assumes continued growth at this rate.

Other Industries

The primary focus for the industrial sector analysis is the six key industries (chemicals; petroleum refining; primary metals; paper; stone, clay, and glass; and food and beverage), which accounted for 80% of the industrial natural gas consumption. However, 19 other industries comprise the industrial sector (SIC categories 1-39), including (by SIC):

- 1 Crops
- 2 Livestock
- 10,14 Non-Energy Mining
- 11,12,13 Energy Mining
- 15 Construction
- 21 Tobacco Products
- 22 Textile Mill Products
- 23 Apparel & Textiles
- 24 Lumber & Wood
- 25 Furniture & Fixtures
- 27 Printing & Publishing
- 30 Rubber & Misc. Plastics
- 31 Leather & Products
- 34 Fabricated Metals
- 35 Non-Electric Machinery
- 36 Electric Equipment
- 37 Transportation Equipment
- 38 Instruments
- 39 Miscellaneous

Gas consumption for these 19 industries in 2001 was a little less than 1,500 BCF, about 20% of total industrial gas consumption and 7% of total U.S. consumption. The gas consumption in many of the individual industries was quite small. Energy consumption in general and gas consumption specifically is a much smaller percentage of the value added for these industries than for the energy-intensive industries. Although all costs are important to the profitability of any enterprise, the gas component of cost for these industries is typically less than 1%. For this reason, less effort was spent on detailed modeling of the individual industries and they were treated as a group.

Some distinctions among these industries are warranted. Tobacco and leather products are declining in the United States and are not large energy or gas consumers. The electronics industry is growing quickly but is not gas intensive. A few of these industries do have some significant gas consumption.

The SIC industries 1 through 15 are non-manufacturing and include agricultural, construction, and mining. The total gas consumption of these sectors in 2001 was about 600 BCF. Of this, about 480 BCF was in the mining industry and much of this was for gas-fired cogeneration related to enhanced oil recovery in central California. The remainder of the gas was used for other on-site generation, space heating and process heating.

SIC industries 20 through 39 are manufacturing. The manufacturing SICs other than the six major gas-consuming sectors consumed about 900 BCF. This consumption can be divided into three primary groupings:

- Rubber and Miscellaneous Plastics (SIC 30) – 79 BCF.
- Metal Durables (SICs 34-38) – 492 BCF.
- All Remaining SICs – 329 BCF.

The rubber and miscellaneous plastics category has been a fast-growing sector, pushed by increased demand for plastic in consumer goods and electronic items. Gas is used for steam generation and process heat. However, it is not a gas-intensive sector and gas use has lagged the production growth.

The metal durables category includes appliances, automobiles, and electronic equipment. As such, it was by far the fastest growing sector of the economy during the 1990s, growing by 15% per year. This sector is not a gas-intensive sector and it saw major decreases in energy intensity during the 1990s. The metal durables sector consumed only 1.8 thousand Btu of energy per dollar of output in 2000 compared to 40 thousand to over 100 thousand Btu per dollar of output in the energy intensive industries. In recent years, the growth in this sector has dropped substantially due to the technology downturn. The uses of gas in this segment include space heating, process heating, and some cogeneration.

Industrial production in the Other Industries grew by 5.2% per year during the 1990s. The NPC projection assumes a lower rate of 2.6% per year based on more recent industry performance. Natural gas consumption grows by only 0.1% per year in this sector due to the low and decreasing gas intensity.

Additional Policy Issues of Industrial Consumers

The NPC found that industrial consumers broadly support energy and environmental policies that lead to lower prices and improve the competitiveness of energy-intensive industrial operations. In particular, industrial consumers support policies designed to foster the development of adequate and reliable supplies of natural gas and other energy sources. Furthermore, industrial consumers also support policies to remove current impediments to fuel switching and to encourage increased fuel flexibility by allowing industrial consumers to make economically rational fuel choices.

The NPC found that industrial consumers broadly support policy initiatives that allow robust competition among energy alternatives and the lowest cost for consumers to be achieved. The industrial consumers indicated broad support for national energy policies that simultaneously pursue multiple policies related to supply, infrastructure, and demand, including:

- Continued efficiency improvements and increased conservation measures
- Rational environmental policies
- Increased access to public lands for exploration and production
- Streamlined permitting for LNG facilities
- Streamlined permitting for natural gas pipeline projects
- Enabling legislation for the Alaska pipeline project.

Some gas-intensive industrial consumers have been adversely impacted by relatively higher natural gas prices as well as price volatility. For some industrial consumers, higher energy costs have led to plant shutdowns and decisions by some to move operations overseas. This obviously impacts employment and the communities in which these industries are located. Despite industrial consumers' strong desires for lower natural gas prices, the NPC found that industrial consumers consistently reject wellhead price controls as a policy option to address higher natural gas prices as price controls would only aggravate the current tight supply/demand balance.

In addition to supporting the broad energy policies discussed above, the following issues (not ranked in order of importance) are of particular importance to industrial consumers:

- Fuel switching
- Technological innovations to increase conservation and efficiency
- Combined heat and power
- Biomass and renewables
- FERC policies governing pipeline tariffs and service offerings.

Fuel Switching. Industrial end-users of natural gas cannot respond to changes in natural gas prices as readily as they were able to in the past by switching to alternative fuels. Increasingly stringent environmental standards and compliance actions have created the incentive for many industrial consumers to rely more heavily on natural gas as their sole energy source. Due to environmental restrictions on burning other fuels such as coal and fuel oil, some industrial consumers have eliminated the capability to switch fuels in order to receive necessary approvals for plant expansions. Industrial consumers believe they should better communicate with local, state/provincial, and federal officials regarding the effects of mandating single-fuel capability in power generation and industrial facilities, and work to allow dual-fuel switching criteria in relevant codes and standards.

Energy Efficiency and Conservation. The NPC found that industrial consumers have made significant strides in recent years to control energy costs, both through the use of more efficient technology, as well as through conservation measures. However, many industrial consumers remain heavily dependent on natural gas both as a fuel and as a raw material. Given recent experience with higher energy costs, industrial consumers reported that they are motivated to continue to pursue research and development efforts to further improve efficiency and increase conservation, including collaborative research with the Department of Energy (DOE) where such programs exist.

Combined Heat and Power. Combined Heat and Power (CHP, i.e., cogeneration) plants are as much as twice as efficient as traditional utility power plants and are generally located at or near the demand site, which further improves efficiency by reducing energy lost through transmission line losses. Many industrial consumers believe that federal statutes, such as the Public Utility Regulatory Policies Act (PURPA) that enables the use of CHP systems in monopoly utility regions, should not be repealed or should not be repealed until competitive electricity markets are available to the CHP facility or until other mechanisms are in place to protect investments in CHP systems as the electricity markets evolve. The NPC takes no position on maintaining, eliminating, or modifying PURPA.

Biomass and Renewables. Renewable "biomass" fuels such as bark and pulping byproducts are used in the forest products industry as an integral part of many operations. In some operations, these fuels have a significant impact on overall fuel use, particularly that of natural gas. The forests products industry, in conjunction with DOE, has been developing gasification technologies to turn black liquor (a byproduct of a chemical process that turns wood into paper) and other biomass into fuels. If fully developed, the U.S. forest products industry believes these technologies could allow the industry to be energy self-sufficient, as well as provide surplus power to the grid. In addition, the paper industry indicates that carbon reductions from black liquor gasification could transform the industry facilities from an emitter of 24 million tons of carbon each year to a carbon sink capable of absorbing 18 million tons or more of greenhouse gases. Given the potential to reduce natural gas demand through increased reliance on black liquor gasification, the pulp and paper industry supports further collaborative research efforts to develop these technologies.

FERC Policies. As end-users of natural gas, industrial consumers depend on pipeline and distribution systems to deliver natural gas supplies to their plants and facilities. Thus, industrial consumers are affected by the rates charged and the regulatory policies governing the transportation and delivery of natural gas. In particular, industrial consumers participate in a variety of FERC proceedings and policy matters. These generally involve FERC's efforts to open up the interstate transportation grid to provide industrials and other shippers increased service options, pipeline tariffed services and associated rates, and pipeline creditworthiness standards.

Residential and Commercial Demand

Natural gas is used by over 60 million U.S. households and supplies over 40% of commercial energy requirements. The residential and commercial sectors accounted for over one-third of U.S. natural gas consumption in 2002. Since 1997, residential and commercial natural gas use has remained relatively constant. Figures 3-45 and 3-46 illustrate the growth in number of residential and commercial customers, respectively; Figures 3-45 and 3-46 also show natural gas demand in these sectors since 1990.

Natural gas demand growth in the residential and commercial sectors is related primarily to population growth, economic growth, and the costs of using gas versus other fuels for space heating and similar applications. Residential and commercial demand also reflects demographic shifts, penetration of gas-based technologies, growth in floor space, and levels of efficiency of gas burning appliances. Weather, measured in terms of heating degree-days, has an important short-term impact on both residential and commercial gas consumption.

To analyze future trends for residential and commercial gas consumption, the NPC used econometric models and capital stock models. These models incorporated weather, demographic trends, population growth, residential housing stock, capital stock efficiency, commercial floor space, penetration of gas-based technology, and gas prices as determinants of gas consumption.

The primary residential sector uses of natural gas are space heating, water heating, cooking, and clothes drying (see Table 3-7). Other uses include natural gas fireplaces, barbeques, swimming pool heaters, and outdoor lighting. The primary commercial sector natural gas uses are space heating, space cooling, and water heating.

Residential Consumers

In 1997, the average household consumed 91.2 MMBtu and spent $603 on natural gas. In 2001, average household consumption fell to 79.3 MMBtu but annual expenditures for natural gas rose to $750. This reflects a 13% decrease in consumption and a 24% increase in expenditures. During this period the average price increased 43% from $6.62 in 1997 to $9.45 per MMBtu in 2001.[1]

In 2002 there were approximately 119 million housing units in the United States. Total natural gas consumption by households equaled almost 5 TCF or 22% of total U.S. gas consumption. Slightly more than 62% of U.S. housing units used natural gas in 2002 (see Figure 3-47). Although newer houses are larger, average gas use per household is declining because of better insulation and more energy efficient equipment.

As a space heating fuel, natural gas competes with electricity, fuel oil, and propane. Over the decades, natural gas has become the dominant space heating fuel in the United States (see Figure 3-48).

The use of fuels for space heating differs regionally, as shown in Table 3-8. Electricity is the major competing heating source in all regions except the Mid-Atlantic and New England. Electricity is a strong competitor in the South Atlantic and East South Central regions where electric heat pumps provide space heating for 28% and 22% of households, respectively. The major alternative to natural gas space heating in the Mid-Atlantic and New England is fuel oil. In 2001, fuel oil was the main heating fuel in 25% of households in the Mid-Atlantic and 50% in New England.

New residential construction is heavily weighted toward natural gas heating. In recent years, approximately 70% of newly completed single-family homes installed gas heat.[2] In addition, the percentage of natural gas heating in new multi-family construction increased slightly. By comparison, 27% of new housing units installed electric heat, predominantly in the Southern states. Fuel oil is losing its market share as a heating fuel nationwide. Table 3-9 provides summary information on the application of natural gas and competing fuels in new housing in 2001.

Water heating is the second most important residential use of natural gas. Unlike space heating, water heating is not weather sensitive. The market penetration of natural gas water heating is similar to that of space heating. Regionally, the greatest penetration is in the Midwest followed closely by the West. Penetration was lowest in the South, where electric heating is the greatest. The Northeast region experienced significant

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1 American Gas Association, *2002 Gas Facts: A Statistical Record of the Gas Industry, 2001 Data,* 2003, pg. 59.

2 Ibid, pg. 72.

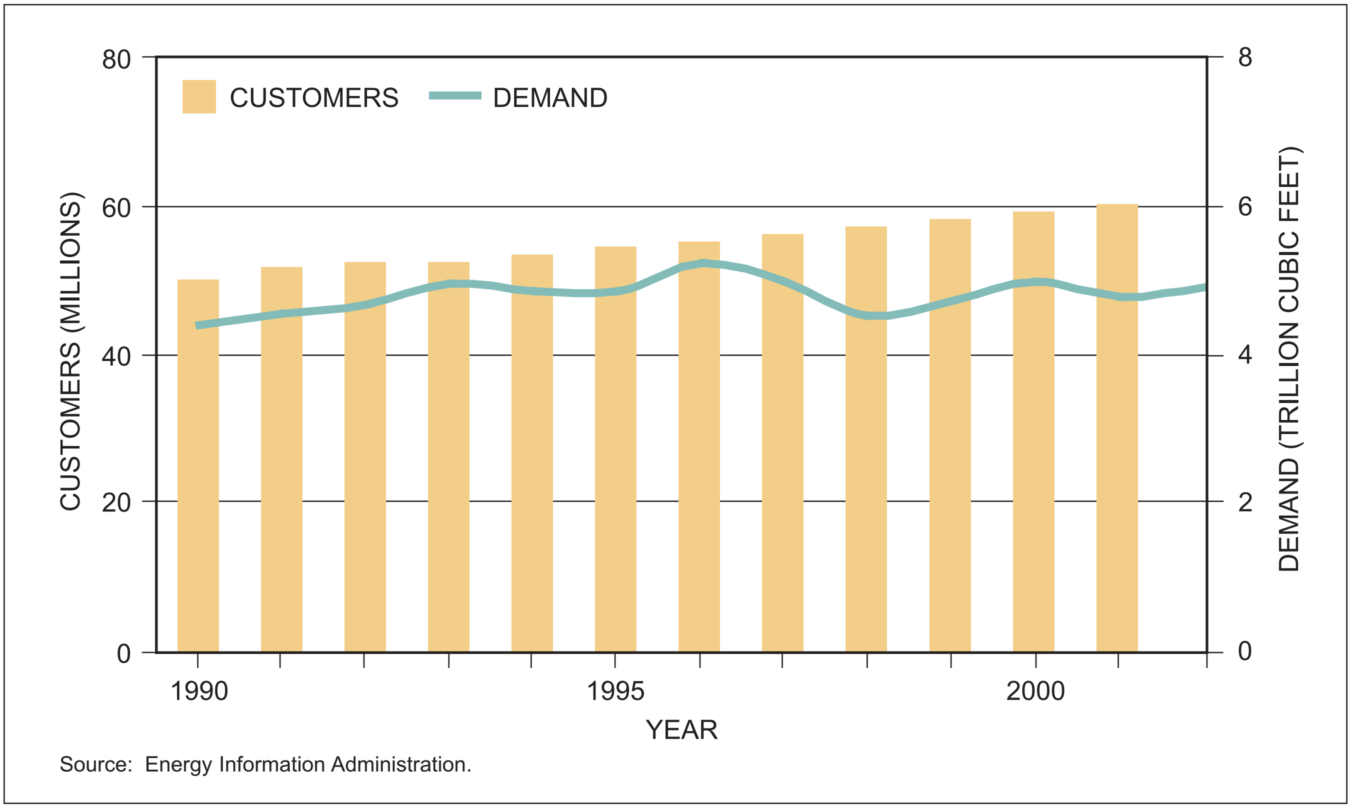


Figure 3-45. U.S. Residential Customers and U.S. Residential Demand

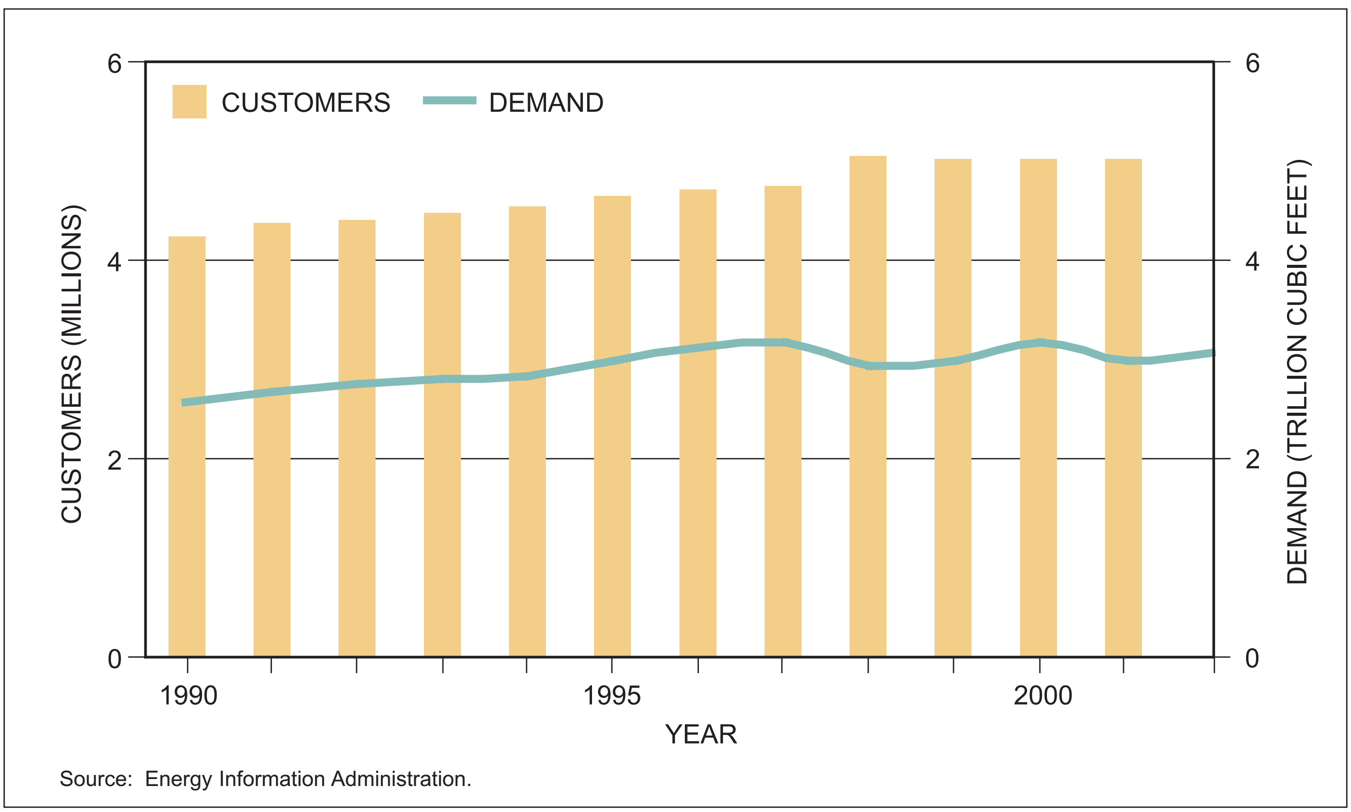


Figure 3-46. U.S. Commercial Customers and U.S. Commercial Demand

	Consump-tion (MCF)	Appliance Market Share (Percent)
Space heating	69.7	52
Water heating	34.1	51
Cooking	11.7	35
Clothes drying	3.7	22
Gas Fireplaces	9.7	NA

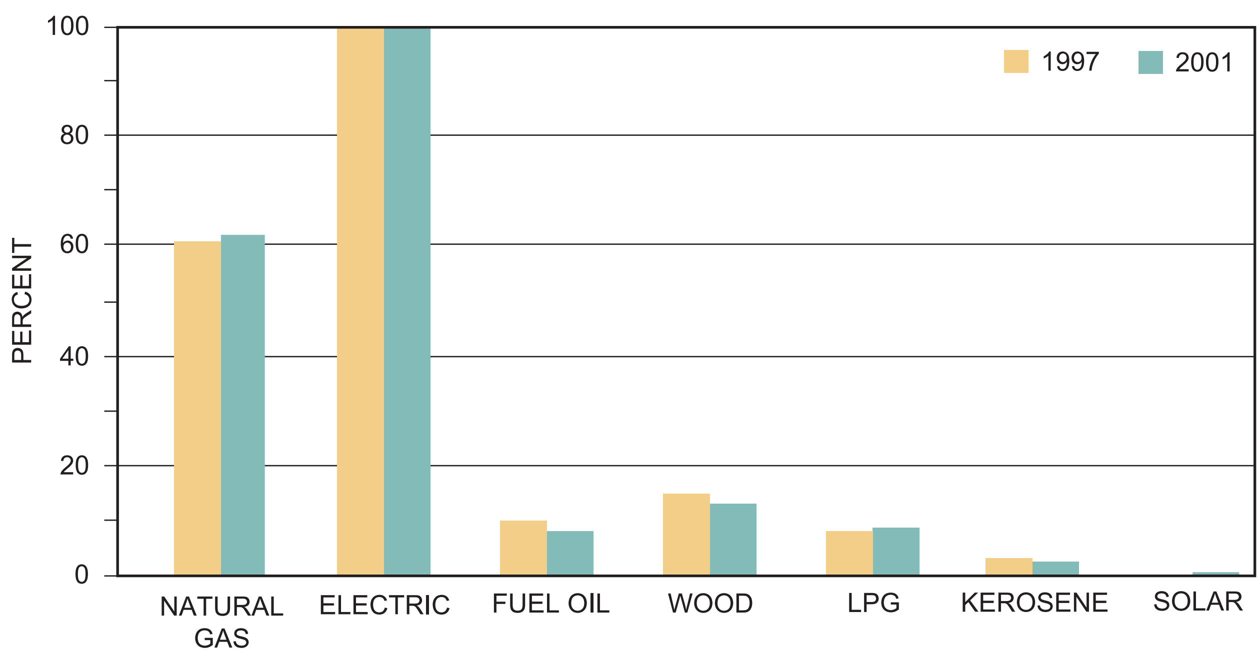
Source: American Gas Association, *2002 Gas Facts: A Statistical Record of the Gas Industry, 2001 Data*.

Table 3-7. U.S. Residential Market 2001 Annual Natural Gas Consumption per Appliance

growth in gas water heating while growth in the other regions was marginal.

Gas cooking is the third most important residential use of natural gas. Nevertheless, both oven and range sectors are dominated by electric appliances. All regions showed a slight decline in natural gas appliance penetration with the exception of the South, which exhibited a modest increase in natural gas ranges. Most of the decline in the percentage of natural gas appliances is attributed to growing penetration of electric appliances in new houses. In addition, the widespread use of microwave ovens appears to have decreased gas use in cooking.

Natural gas consumption and expenditures are positively correlated with household income: the higher the household income, the more a household consumes and spends on energy. This higher use and related expenditures reflects in the typically larger homes owned by higher-income families, requiring more heating. However, the cost of fuel is, on average, a higher proportion of household income for low-income families. The average residential energy costs in 2001 (including heating, cooling and all other energy uses in the home) for U.S. households in 2001 was $1,537 per household, or 7.0% of income. Low-income households spent an average of $1,311 on energy, representing 14.0% of household income; for households qualifying for Low Income Home Energy Assistance Program (LIHEAP) funding – two-thirds of which have incomes less than $8,000 per year – the



Note: Households may use more than one fuel.
Source: Energy Information Administration, Residential Energy Consumption Surveys, 1997 and 2001.

Figure 3-47. Fuel Used in U.S. Housing Units

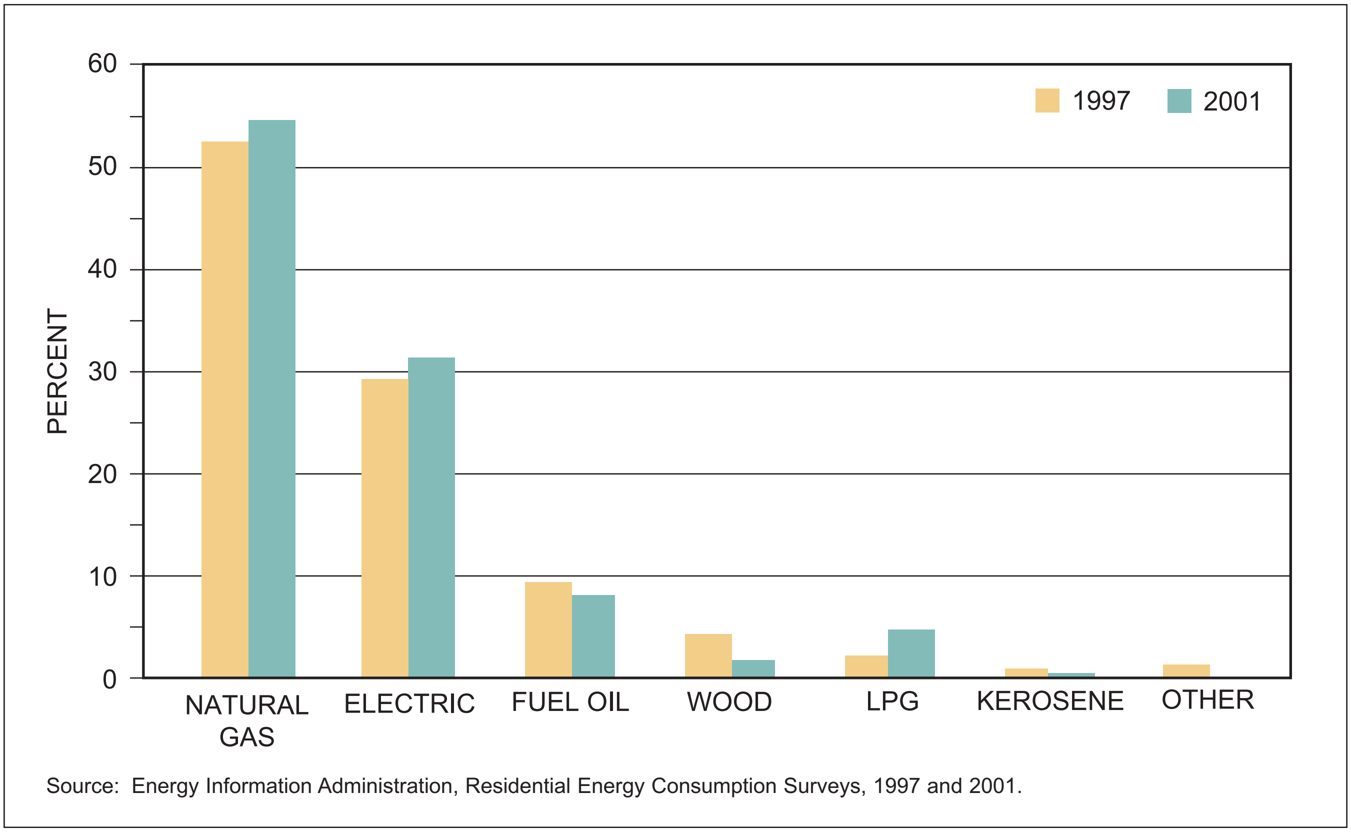


Figure 3-48. U.S. Primary Household Heating Fuel

Region	2001	1997
Total U.S.	**54.8%**	**52.7%**
Northeast	52.4%	46.0%
Midwest	76.8%	75.0%
South	39.5%	38.0%
West	59.5%	58.0%

Source: American Gas Association, *2002 Gas Facts: A Statistical Record of the Gas Industry, 2001 Data*.

Table 3-8. Percentage of U.S. Households with Natural Gas as the Main Heating Fuel

percentage of income represented by energy expenditures was 17.2%.[3]

The LIHEAP program commenced in 1982 with the objective of assisting low- and fixed-income households in paying their fuel and utility bills, including winter heating bills and summer cooling bills. The program was designed to be a targeted assistance program with government funding, rather than a utility program where low-income assistance was built into rates and spread among a larger number of consumers. Between 1981 and 2000, LIHEAP funding increased 22%. The funding stands at $1.7 billion for FY 2003. However, for the same period the number of federally eligible households rose over 49%.

Commercial Consumers

The commercial sector accounts for about 14% of total U.S. gas consumption. This sector is more diverse than the residential market, consisting of business establishments and service organizations such as retail and wholesale facilities, hotels and motels, restaurants, and hospitals. The commercial sector also includes public and private schools, correctional institutions, and religious and fraternal organizations. The end-use markets in the commercial sector are less seasonal than residential customers. Commercial customers consume about 7.5 times more gas, on a per customer basis, than customers in the residential sector.

[3] The LIHEAP Home Energy Notebook for FY 2001.

	Single-Family	Multi-Family	Combined
Natural Gas	70%	47%	65%
Electric	27%	53%	32%
Fuel Oil	3%	Less than 500 units	2%
Other	1%	–	1%
Total	100%	100%	100%

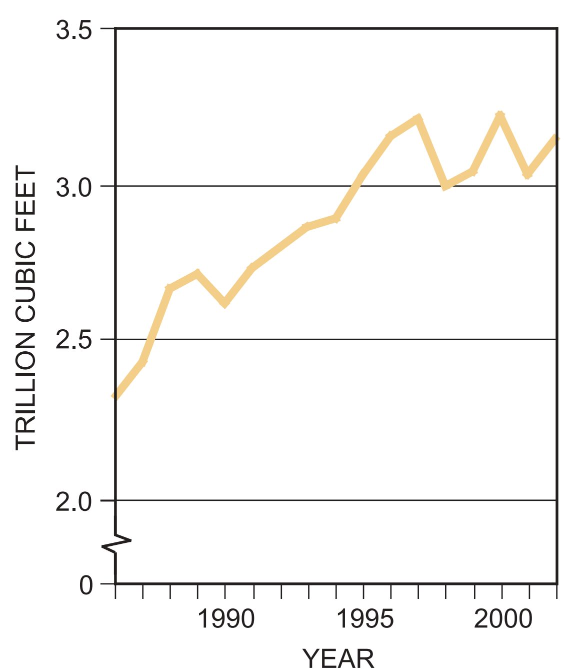
Source: American Gas Association, *Residential Natural Gas Market Survey, 2001 Data*.

Table 3-9. U.S. Private Housing Completions in 2001 by Heating Fuel

Commercial natural gas consumption grew at an average annual rate of approximately 2.6% between 1990 and 1997, compared to 1.6% for residential consumption. Although total consumption was rising, use per customer was reduced. Between 1990 and 1997, the average annual consumption per commercial customer declined by 0.7%.

The average growth rate for commercial gas consumption was -0.5% between 1997 and 2002. As shown in Figure 3-49, some of this variation was due to weather – a cold year (1997) followed by a warm year (1998). The number of commercial natural gas customers increased approximately 6% between 1997 and 2001, from 4.6 million to 4.9 million.

Figure 3-50 illustrates the growth in the number of commercial natural gas customers. The commercial market fluctuates, and the upward trend in the number of customers does not necessarily reflect the amount of floor space served by natural gas. New commercial buildings are constructed and older buildings are



Source: Energy Information Administration.

Figure 3-49. Natural Gas Delivered to U.S. Commercial Consumers

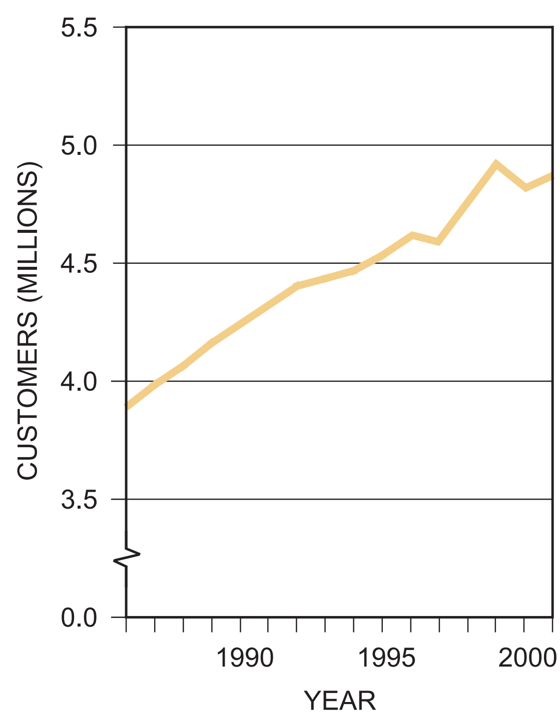


Figure 3-50. Number of U.S. Commercial Natural Gas Customers

converted to commercial uses. At the same time, older commercial buildings may be razed or converted to noncommercial uses. Commercial floor space may also fluctuate concurrently. Commercial floor space may be converted to non-commercial uses, which will impact commercial demand. Minimal growth in commercial demand is due in part to efficiency in building design and natural gas appliances and equipment.

Most of the natural gas consumed by the commercial sector is used for space heating and water heating, and there has been a strong trend for customers to choose gas for these applications where gas is available. Other uses such as cooling, cooking, drying, desiccant dehumidification, and cogeneration applications comprise a smaller share of natural gas applications. While space and water heating usage have become increasingly efficient, alternate uses of natural gas have continued to make up a larger share of total commercial gas use.

Natural gas has been losing market share among commercial customers to electricity in most end-uses except cooking. The loss has been the greatest in cooling and space heating.

Commercial customers normally operate under a firm utility rate, paying a premium compared to an interruptible rate. Many commercial consumers are capable to installing dual-fuel applications. These applications are designed to use either natural gas or oil as a fuel. To take advantage of dual-fuel capabilities, some commercial consumers typically elect interruptible utility service at a lower rate. Consequently, unlike the residential sector, energy prices and weather may encourage fuel switching for some end-uses in commercial markets.

One of the newest and most promising growth driver in commercial gas use is on-site power generation. In order to provide backup capability and to limit power use during peak periods, many commercial customers have installed on-site generators to support their buildings' electrical needs. In certain capacity-constrained regions customers with on-site generation receive capacity payments where this product is part of the region's electricity market design. Natural gas powered reciprocating engines, turbines, and fuel cells are used in many commercial settings to generate electricity. This type of on-site generation is also referred to as distributed generation and allows commercial buildings to be more independent from the utility grid and the possibility of power disruption and inconsistent high-quality electricity. It also provides commercial building managers with more control over their power supply.

Cogeneration has slowly penetrated certain commercial markets in recent years. Like distributed generation, cogeneration can be an alternative source of electric power during peak periods for power demand. Electricity is generated with a natural gas generator and is the co-production of electrical and thermal energy, also called combined heat and power (CHP). Because the thermal energy that is produced during electric production is used to provide heating, the energy conversion efficiency of cogeneration facilities can be as high as 70%, allowing for substantial savings in fuel commodity costs for the building owner. Hospitals, airports, and other establishments that cannot afford to be subject to brownouts or blackouts use cogeneration.

Natural Gas Vehicles

For purposes of this study, natural gas vehicle (NGV) usage was assessed within the commercial sector. In recent years NGVs have penetrated fleet vehicle and urban transit bus markets. There are almost 60,000 natural gas vehicles in the U.S., according to the Natural Gas Vehicle Coalition. The U.S. Postal Service currently operates the nation's largest fleet of natural gas vehicles and United Parcel Service (UPS) operates the largest private fleet. Furthermore, utilities, airport shuttle services, taxi companies, police departments, school districts, police departments, and ice rinks (Zambonis) also operate large fleets of natural gas vehicles. A prominent off-road application of NGVs is forklifts in warehouse operations.

There were approximately 6,200 natural gas transit buses operating in the United States at the end of 2001. Natural gas buses represented approximately 11% of all transit buses and 97% of all alternatively fueled transit buses. At the beginning of 2002, an additional 1,313 natural gas transit buses were on order. Almost 21% of all transit buses on order are natural gas powered. Nearly 28% of 2002-2005 "potential bus orders" of 11,195 are powered all or in part by natural gas.

The main attraction for most NGV purchasers is the favorable environmental characteristics. Many of the companies and governmental agencies that are converting their fleets to natural gas are doing so to comply with air quality regulations.

Regional Considerations in Residential and Commercial Demand

Current natural gas consumption is affected by historical accessibility to natural gas. The Northeast, which includes New England and the Mid-Atlantic states, has been more gas-limited than other areas of the country. New England, in particular, has the lowest rates of natural gas penetration due to limited access to natural gas for most of the 20th Century. Consequently, households in the Northeast have historically tended to use oil for heating because of its wider availability.

The Northeast markets are relatively distant from traditional major natural gas supply areas in the Southwest and in western Canada, and the region receives the vast majority of its natural gas supplies through pipelines from these regions. A recently completed pipeline from Canada's Sable Island gas fields to New England and expansions and/or other projects are expected to help meet the growing demand for natural gas in the Mid-Atlantic and New England regions. The Maritimes and Northeast Pipeline and Portland Gas Transmission System projects, which will transport Canadian gas to the New England area, provided more than half of new capacity in 1999. Those two projects increased overall pipeline capacity into the Northeast region by 5%.

Over the past 20 years, residential natural gas use has increased in the Northeast as new natural gas pipelines have been built. Newly constructed and existing homes were able to choose natural gas instead of heating oil. As new infrastructure is integrated into the current system allowing new supplies to reach the New England and Mid-Atlantic areas, and regional utilities to expand their distribution system accordingly, total demand for this region should show growth. For those areas in New England where natural gas is available, LNG supplements supply but is used only for short durations.

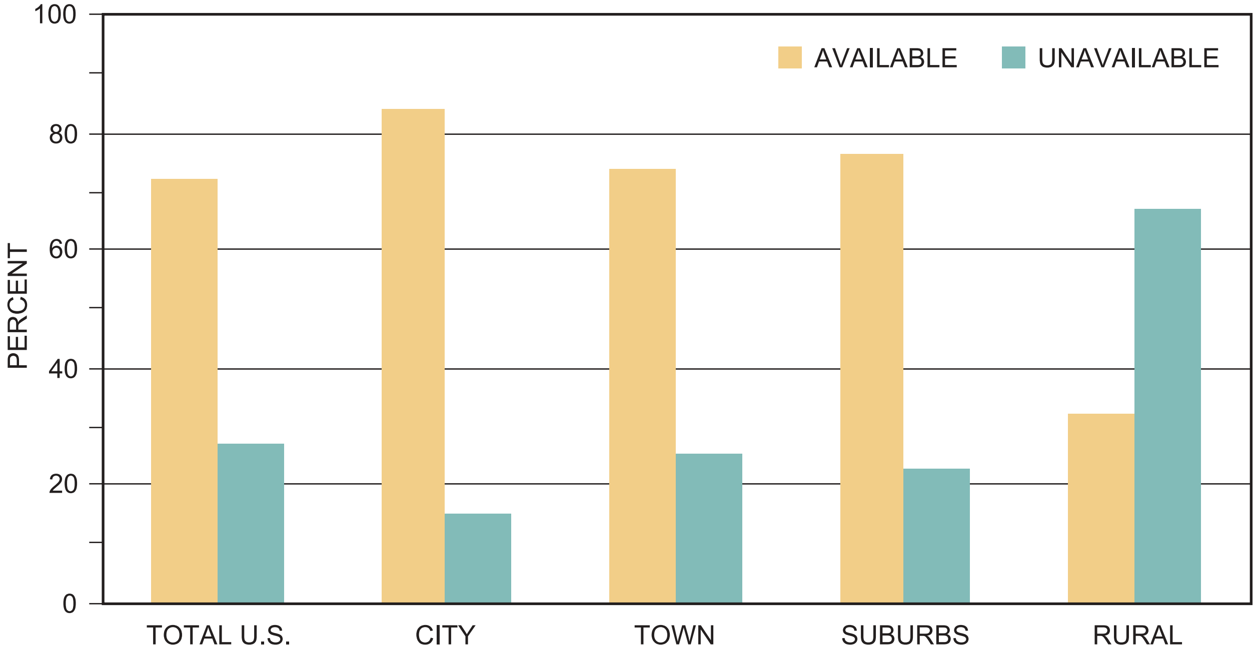
The South Atlantic and East South Central regions are other areas with unique space heating profiles. There has been a significant decline in the percentage of consumers that use natural gas as the main heating fuel. In these regions, the dominant residential space heating fuel has become electricity. Space heating is predominantly from built-in electric units, electric central warm-air furnaces, or heat pumps. The heat pump has become increasing popular in these regions. The evolution of the heat pump is a reflection of changes in the construction of residential structures, particularly multi-family housing units, where duct work and vents are replacing pipes and radiators as well as new heating equipment and technology. The American Gas Association reported that electric utilities in these areas encouraged consumer to add heat pumps and maintain gas furnaces as backup systems. Consequently, the percentage of household demand for natural gas for heating is low in these two regions.

Current natural gas consumption is also an outcome of historical accessibility to natural gas in urban and rural locations. Sub-regional profiles of households with natural gas service may differ from the regional profile. Households with gas service are predominantly in the more urban areas, while the percentage of households with gas service in rural areas is much lower. Figures 3-51 and 3-52 illustrate this trend.

Efficiency in Residential and Commercial Consumption

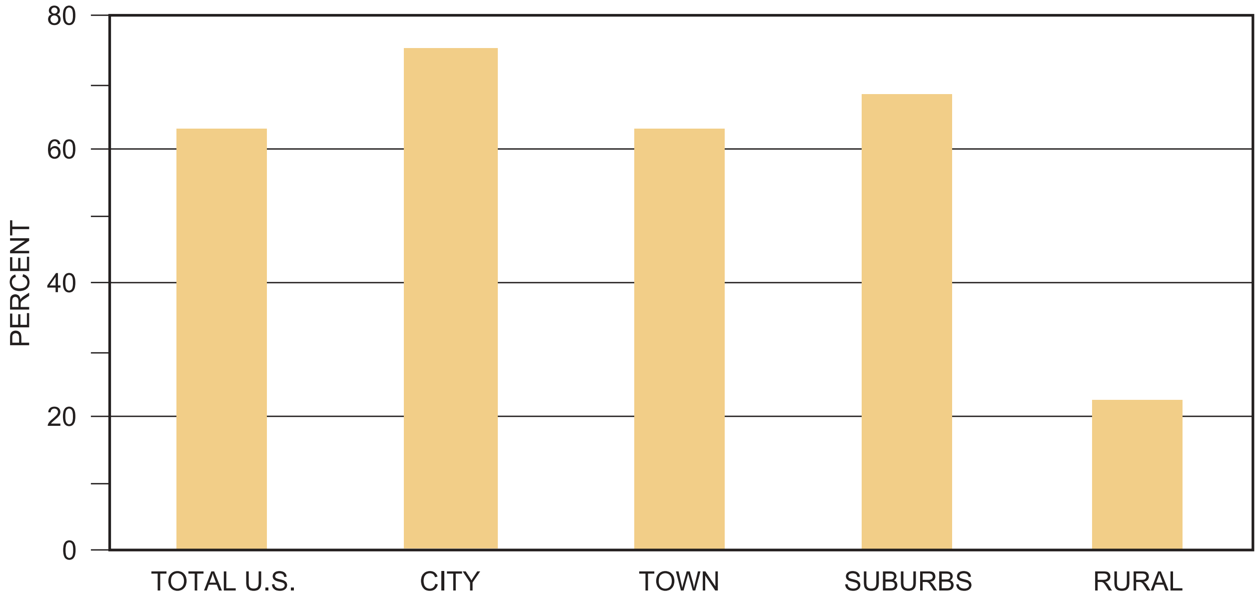
One of the most significant energy efficiency and conservation measures for the natural gas industry was the adoption of efficiency standards for commercial appliances in the Energy Policy and Conservation Acts of 1975 and 1978. The 1975 legislation established an energy conservation program for major household appliances, many of which used natural gas. The 1978 legislation broadened the mandate of the 1975 act to include commercial building heating and air conditioning equipment as well as water heaters. In 1987, additional measures were put into place with the National Appliance Energy Conservation Act, which set energy efficiency standards for appliances according to a statutory time schedule stretching into 21st Century.

The U.S. Environmental Protection Agency introduced ENERGY STAR in 1992 as a voluntary labeling program designed to identify and promote energy-efficient products. The ENERGY STAR label is now on major appliances, office equipment, lighting, home electronics, and more. The EPA has also extended the label to cover new homes, and commercial and industrial buildings. The ENERGY STAR program delivers technical information and tools that consumers need in order to choose energy-efficient solutions and best management practices. Energy efficiency can result in the delivery of the same (or more) services for less energy. Energy efficiency helps the economy by saving



Source: Energy Information Administration, *2001 Residential Energy Consumption Survey*.

Figure 3-51. Percentage of U.S. Housing Units with Natural Gas Available in Neighborhood in 2001



Note: More than one use may apply.
Source: Energy Information Administration, *2001 Residential Energy Consumption Survey.*

Figure 3-52. Natural Gas Used in U.S. by Type of Location in 2001 consumers and businesses millions of dollars in energy costs. Energy-efficient solutions can reduce the energy bill for many homeowners and businesses by 20% to 30%.

In the residential sector, newer housing stock is, on average, 18% larger than the existing housing. However, energy use per square foot is lower for new construction.[4] This trend will likely continue, with newer houses being tighter as a result of more stringent building codes, better insulation, tighter window treatment, and tighter building design. Ongoing structural efficiencies will continue to reduce the demand for natural gas per customer.

Newer housing units are equipped with more efficient natural gas heating equipment. In the 1970s, natural gas furnaces averaged annual fuel utilization efficiency (AFUE) of about 65%. New furnace shipments in 2001 averaged an AFUE of 86%. Currently, all installed natural gas furnaces in 2001 averaged an AFUE of 77%. According to the American Gas Association, technological enhancements in furnace efficiency resulted in an average 4% fall in gas space heating use per customer nationwide between 1997 and 2001.

In the commercial sector, use per customer declined by 18% from 1979 to 1999. The decline in consumption can be attributed to the gained efficiencies brought about by legislation and building codes. Another measure of customer conservation is consumption intensity (use per square foot of space). An examination of natural gas use per square foot confirms that the average commercial building uses less gas compared to 1979 levels. This measure fell roughly 40% over the past two decades.

Summary of Residential and Commercial Demand

Demand in the residential and commercial sectors was analyzed for both the Reactive Path and Balanced Future scenarios. Residential and commercial natural gas demand is expected to increase in both scenarios due to the combined effects of penetration of gas-based technology, population growth, and growth in floor space, offset by energy efficiency gains. The 2000 to 2025 annual growth rate in the Reactive Path scenario is slightly less than 1.0% in both the residential and commercial markets. In the Balanced Future scenario, residential demand increases by approximately 0.5% annually, while the annual average growth rate of commercial demand is higher at 1.0%.

The Balanced Future scenario assumes significantly greater efficiency gains in residential appliances, commercial equipment, and building standards. The Balanced Future scenario demonstrates that policy changes such as expanding and diversifying natural gas supplies, increasing energy efficiency and fuel flexibility, improving energy market efficiency and sustaining and expanding natural gas infrastructure can lower prices and dampen the demand for natural gas in the residential sector.

Residential demand in the Balanced Future scenario is lower than in the Reactive Path scenario primarily due to increased efficiency in space and water heating per household. Figure 3-53 depicts projections for total U.S. residential natural gas demand in the two scenarios. Table 3-10 compares the difference in

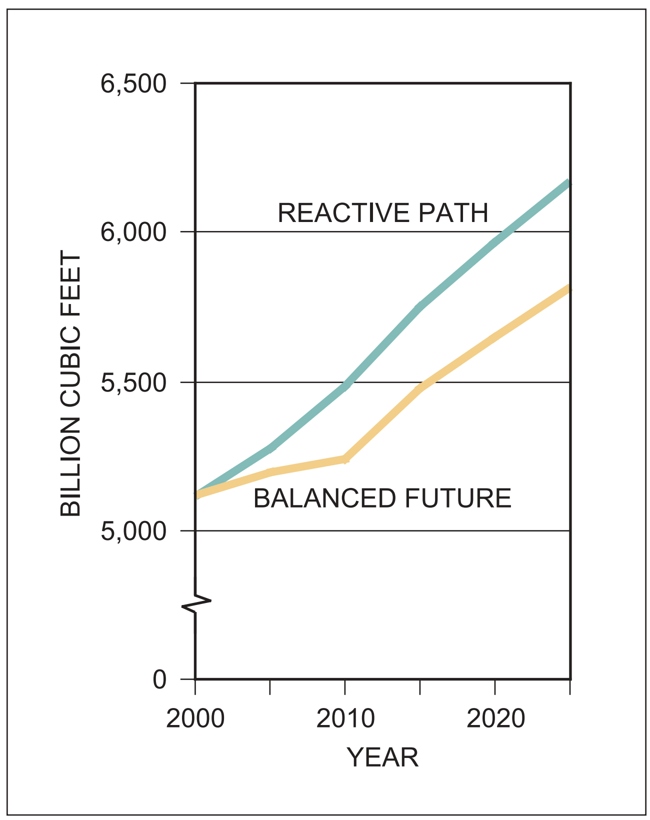


Figure 3-53. Total U.S. Residential Natural Gas Demand

[4] Energy Information Administration, *Annual Energy Outlook 2003*, pg. 57.

	Consumption: 2000 (BCF)	Consumption: 2025 (BCF)	Annual Percent Change: 2000-2025
Reactive Path	5,116	6,167	0.75
Balanced Future	5,116	5,817	0.51
High Economic Growth	5,116	6,252	0.81
Low Economic Growth	5,116	6,091	0.70

Table 3-10. U.S. Residential Natural Gas Consumption

demand and the average annual growth rate of the scenarios. Additionally, this table shows the effects of different economic growth rates modeled in sensitivity analyses, comparing higher and lower GDP growth to the Reactive Path scenario. Figure 3-54 illustrates the effects of energy efficiency modeled in the Reactive Path and Balanced Future scenarios.

Unlike the residential sector, the commercial sector experiences higher demand growth in the Balanced Future scenario than in the Reactive Path scenario. The conservation assumptions reflected fewer opportunities for additional conservation than in the residential sector, and the lower prices in the Balanced Future scenario were modeled as stimulating additional commercial gas consumption. Figure 3-55 depicts projections for total U.S. commercial natural gas demand in the two scenarios. The figure indicates that gas consumption in the Balanced Future scenario rises above that of the Reactive Path

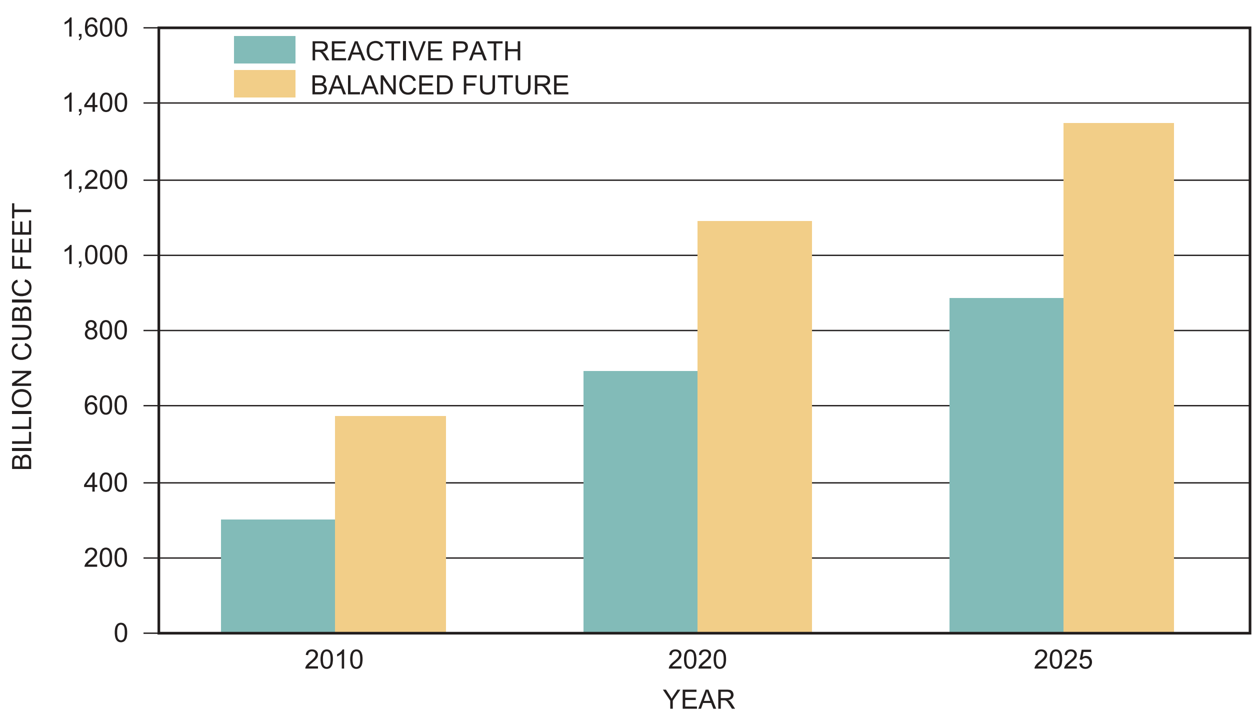


Figure 3-54. Cumulative Energy Efficiency Effects in U.S. Residential and Commercial Sectors

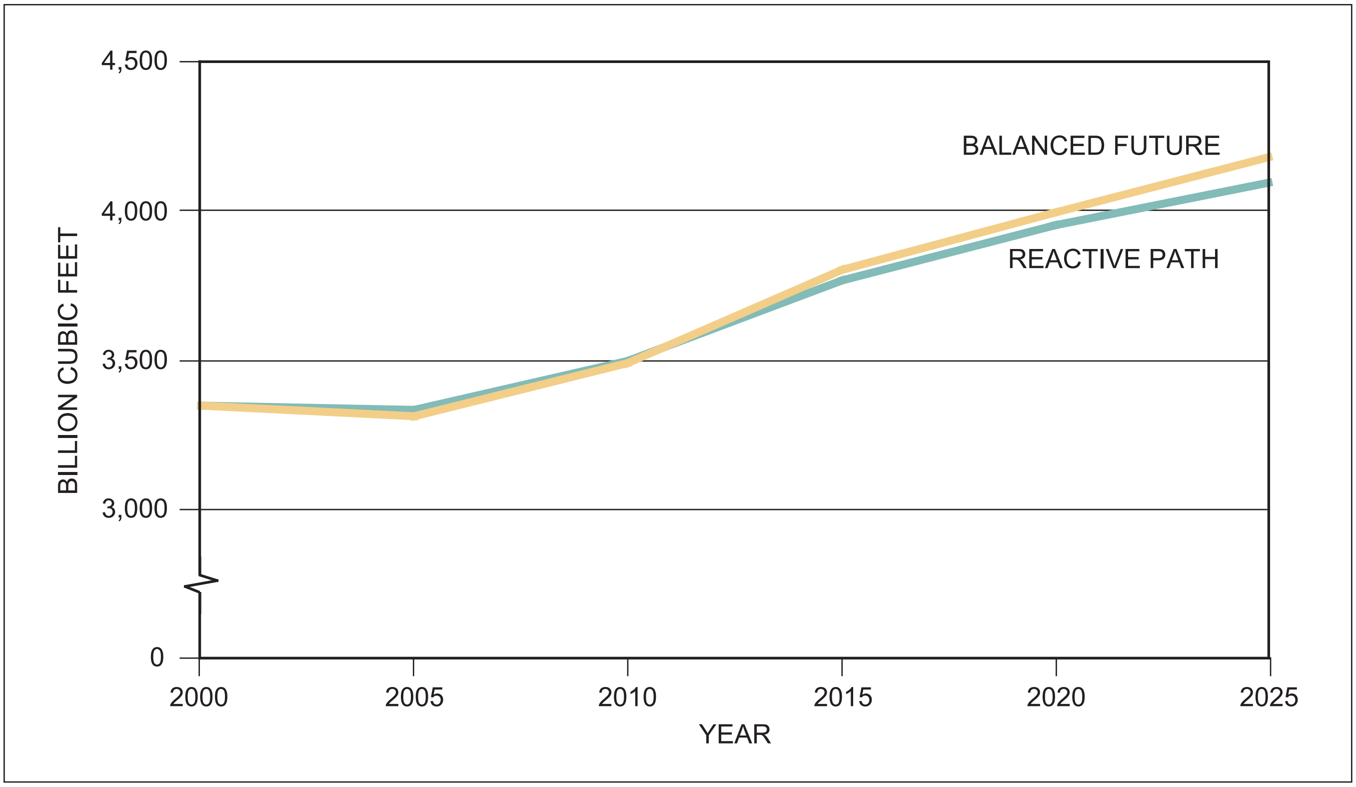


Figure 3-55. Total U.S. Commercial Natural Gas Demand

scenario, especially after 2020. Table 3-11 compares the difference in commercial demand and the average annual growth rate of the Reactive Path and Balanced Future scenarios, as well as sensitivity analyses assessing higher and lower economic growth.

Although increased efficiency for space heating, water heating, and space cooling per square foot was built into the Balanced Future scenario, the impact of lower gas prices was greater, resulting in an overall increase in gas consumption.

As noted earlier, consumption is also a function of the growth rate of the economy. This study analyzed residential and commercial consumption under low and high GDP growth assumptions. Demand growth will be mitigated by efficiency gains as old, inefficient equipment is replaced and houses are renovated and become more energy efficient. In addition, high

	Consumption: 2000 (BCF)	Consumption: 2025 (BCF)	Annual Percent Change: 2000-2025
Reactive Path	3,346	4,093	0.81
Balanced Future	3,346	4,180	0.89
High Economic Growth	3,346	4,153	0.87
Low Economic Growth	3,346	4,043	0.76

Table 3-11. U.S. Commercial Natural Gas Consumption

natural gas prices will likely provide a catalyst for residential and commercial consumers to consume less natural gas by reducing the amount of energy services they consume. The most immediate means to reduce energy consumption is to adjust thermostat settings and use more energy-efficient natural gas equipment. Table 3-12 illustrates demand reduction results from an aggressive response scenario that includes improved efficiency, lower gas market shares, and permanent thermostat turn-back of 2°F – down in winter, up in summer.

Figure 3-56 illustrates the projections for regional growth in residential and commercial natural gas demand for the Reactive Path scenario. The largest impact projected was in the South Atlantic, East South Central, and West South Central regions. The Mid-Atlantic, New England, and the East North Central regions exhibited the smallest percentage change in consumption.

Regions	Decrease
New England	9.2%
Mid-Atlantic	9.7%
East North Central	9.3%
West North Central	9.1%
South Atlantic	31.9%
East South Central	27.6%
West South Central	27.0%
Mountain	10.4%
Pacific	19.9%
United States	**15.1%**

Table 3-12. U.S. Residential and Commercial Sensitivity – Decrease in Gas Consumption in 2025

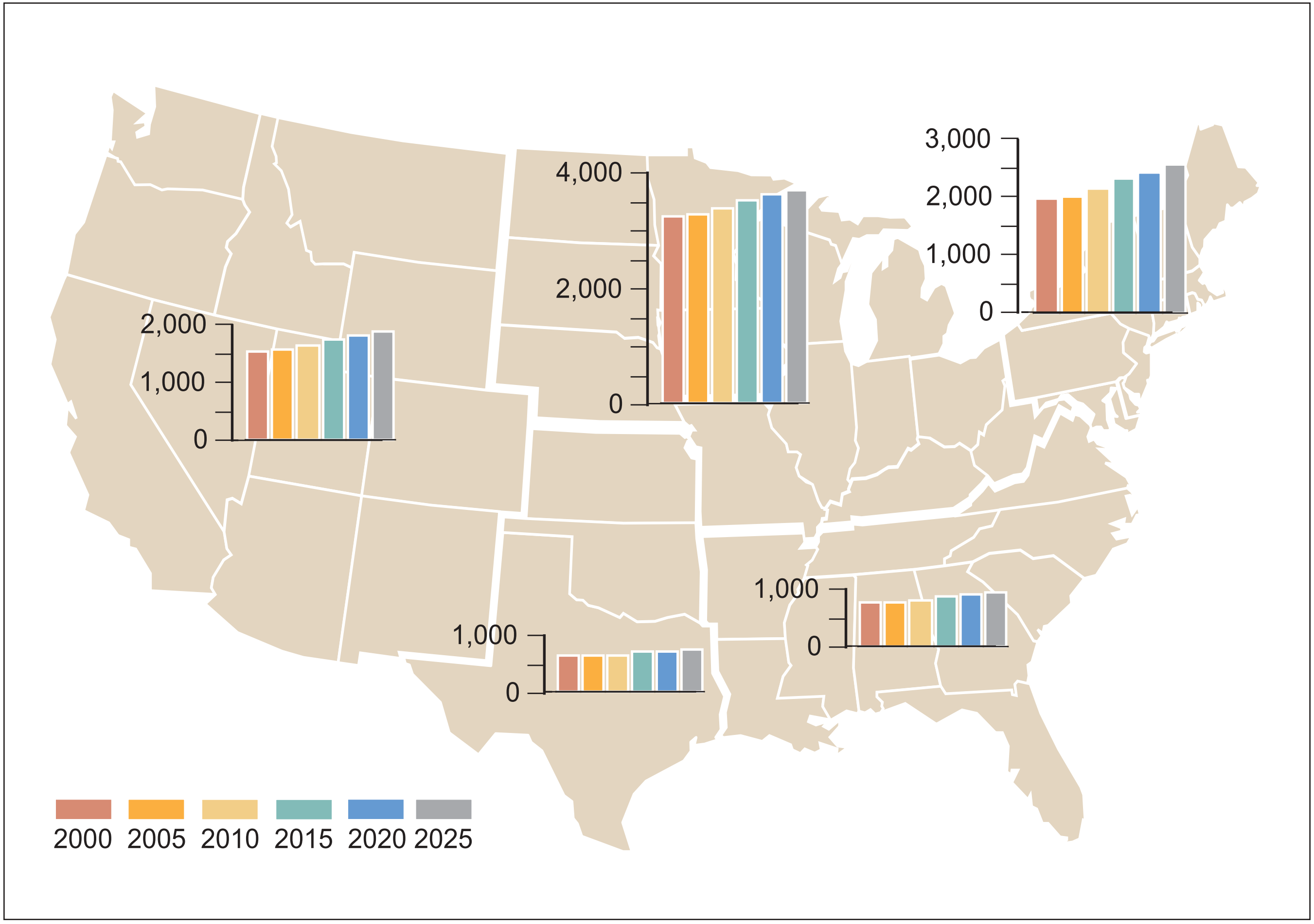


Figure 3-56. U.S. Residential and Commercial Natural Gas Demand in Reactive Path Scenario (Billion Cubic Feet per Year)

Electric Power Sector

The electric power industry is the largest consumer of primary energy in the United States, as shown in Figure 3-57. It converts fossil fuels like coal, natural gas, and oil plus nuclear, hydropower, and renewable energy into electricity, which is then transmitted and distributed to end-use customers.

The electric power industry is comprised of many stakeholders including vertically integrated utilities, municipalities, rural cooperatives, governmental authorities, independent power producers, fuel suppliers, federal and state regulators, and the all-important consumer. Each stakeholder has a compelling interest in the efficiency, environmental impact, cost, and reliability of the power industry.

The United States and Canada have organized their transmission grids into three frequency synchronous regions. These regions operate at the same alternating current frequency and are only interconnected with direct current transmission ties. These regions have been organized in this manner to strive for highest degree of reliability. The overall organization responsible for the guidelines and operating procedures is the North American Electric Reliability Council (NERC), which is comprised of the regional councils as shown on Figure 3-58. The three synchronous regions are: ERCOT, WECC, and the Eastern Interconnect (comprised of all remaining regional councils – MAPP, MAIN, ECAR, NPCC, MAAC, SPP, SERC, and FRCC).[1]

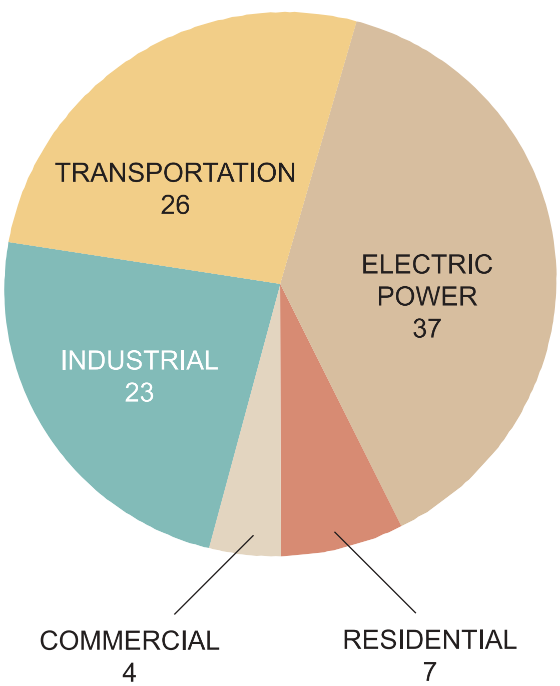


Figure 3-57. Annual Average Primary Energy Demand by Sector, 1997-2001 (Quadrillion Btu)

The power industry has been in significant transition, which is expected to continue for several more years. Wholesale power markets have been opened to more competitors and prices are market based. Some states have initiated retail competition with mixed degrees of success. Merchant generators have built or acquired significant quantities of generation capacity and constitute a large percentage of the ownership of total capacity. Industry restructuring has impacted the financial strength and credit quality of numerous market participants. Independent system operators of transmission have grown in importance. Environmental regulations continue to be promulgated piecemeal with uncertainty over timing, flexibility, and stringency. Partially as a result of these factors, natural gas is becoming a more important fuel source for the industry.

In the time period of this study, the electric power generation segment is anticipated to be the primary driver of increases in overall natural gas demand. Power generation becomes the primary driver of natural gas demand growth due to the increased percentage of gas-fired generation capacity in the United States' generation fleet coupled to the close correlation between electric power demand growth and the United States economic growth. A correlation between growth of electric power and the U.S. economy is expected to continue into the future.

Approximately 200,000 megawatts of gas-fired generation will have been added to the generation fleet by the end of 2005, representing a 31% increase of total generation capacity and a 290% increase in the gas-fired only generating capacity, measured from the end of 1998. This new fleet is a combination of combustion turbines, used mainly for peaking power, and

[1] See North American Electric Reliability Council website (www.nerc.com) for full names and details of the regional councils.

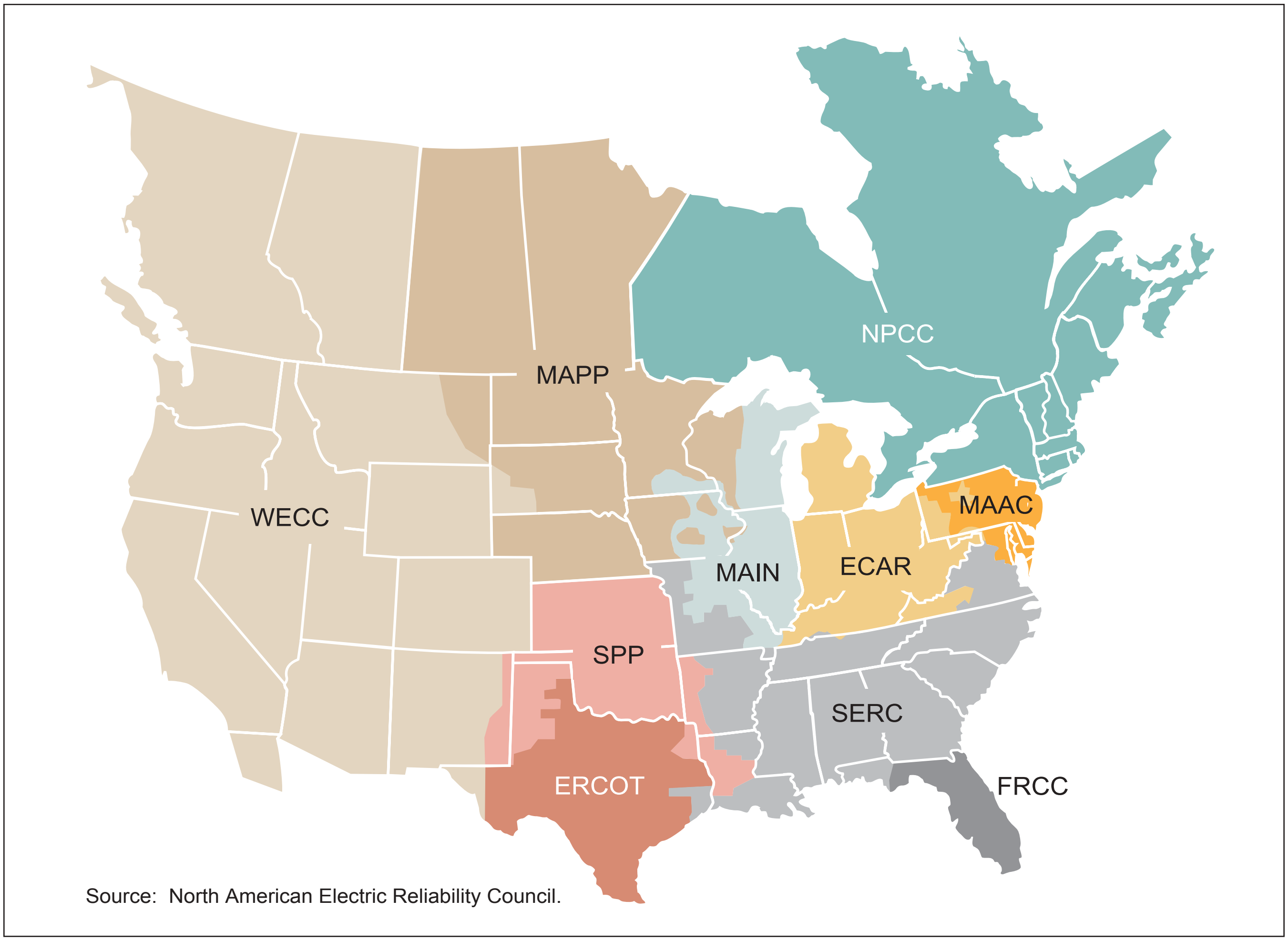


Figure 3-58. NERC Regions

combustion turbines combined with a steam generator, commonly referred to as a combined cycle plant. The generation fleet includes the portion of industrial sector's CHP facilities that provide power, and excludes the portion that produces steam for process use. The combined gas fleet can consume large quantities of gas at any given time depending upon weather-driven demand and the relative competitiveness of other fuels, normally either residual fuel oil or distillate oil, available to meet peak loads.

A comprehensive understanding of power generation's role in natural gas demand requires insight into the demand for electricity, the economics and mechanics in power generation dispatch, regional differences in generation fleet composition, transmission grid capabilities, power pool dispatch operations, and key drivers to investment decisions and fuel choices for new generation construction.

Study Approach

The NPC evaluated electric power supply (capacity) and demand regionally using a model that solves for monthly electricity demand, power generation by type of fuel, generating capacity additions, and fuel use. New capacity builds were determined in a separate model using logic parameters provided by study participants. Wide ranges of potential generation technologies were considered whenever the model logic called for new capacity to be built. The study participants imposed some constraints on new builds fueled by coal and residual fuel oil, but the general approach was to allow economically rational choices to be made in both the Reactive Path and Balanced Future scenarios. Canada was modeled and analyzed, but with much less detail and rigor than the U.S. lower-48. The portions of Mexico that are interconnected at border regions were treated as interconnected net power transfers.

Nuclear and hydroelectric based generation quantities were input into the dispatch models as discrete exogenous values implying the models did not "dispatch" these units. Additionally, wind power was used as a proxy for all renewable technologies, but this decision was a simplifying assumption, not an endorsement of wind generation technologies over other renewable technologies.

The study approach was to model current laws and regulations in environmental emissions, siting, and ongoing operations. The power model used for the study does not allow discrete generation unit evaluation of environmental emissions, but each case, sensitivity and scenario output was evaluated to ascertain whether total calculated emissions met projected allowance budgets for sulfur dioxide (SO_2) and NOx.

Electric Power Demand

Demand for electricity in the United States is coupled to the economy. Growth in GDP has consistently been accompanied by growth in electric demand. The rate of electric demand growth as a function of GDP (known as "electric intensity") has decreased over the past 50 years, and is likely to continue decreasing over the period of this study. Through the 1960s, annual electric energy demand grew at a rate faster than GDP. Coincident with the energy price shocks to the U.S. economy in the 1970s, electric energy demand began growing slower than the GDP. The reasons for this change have been attributed to increased efficiency, energy conservation, the completion of the overall electrification and air conditioning of U.S. society, and a fundamental shift in the levels of energy-intensive industry in the United States. As shown in Figure 3-59, the relationship between GDP growth and power demand growth has been fairly constant. No empirical data suggest this trend will substantially change during the study period. However, higher energy costs and the resultant consumer response, industrial capacity losses, and governmental policies are likely to further accelerate the rate of decline in the electric intensity.

The rate of growth in electric energy demand has been modeled in the Reactive Path scenario to vary from a starting factor of 0.72 times the forecasted growth in GDP in 2003 and decreasing linearly to a level of 0.62 times the forecasted growth in GDP by 2025. Assumptions used for GDP are described in Chapter Two of this report. Forecasted GDP growth is one of the most critical variables in assessing potential growth in electric power demands and the resulting

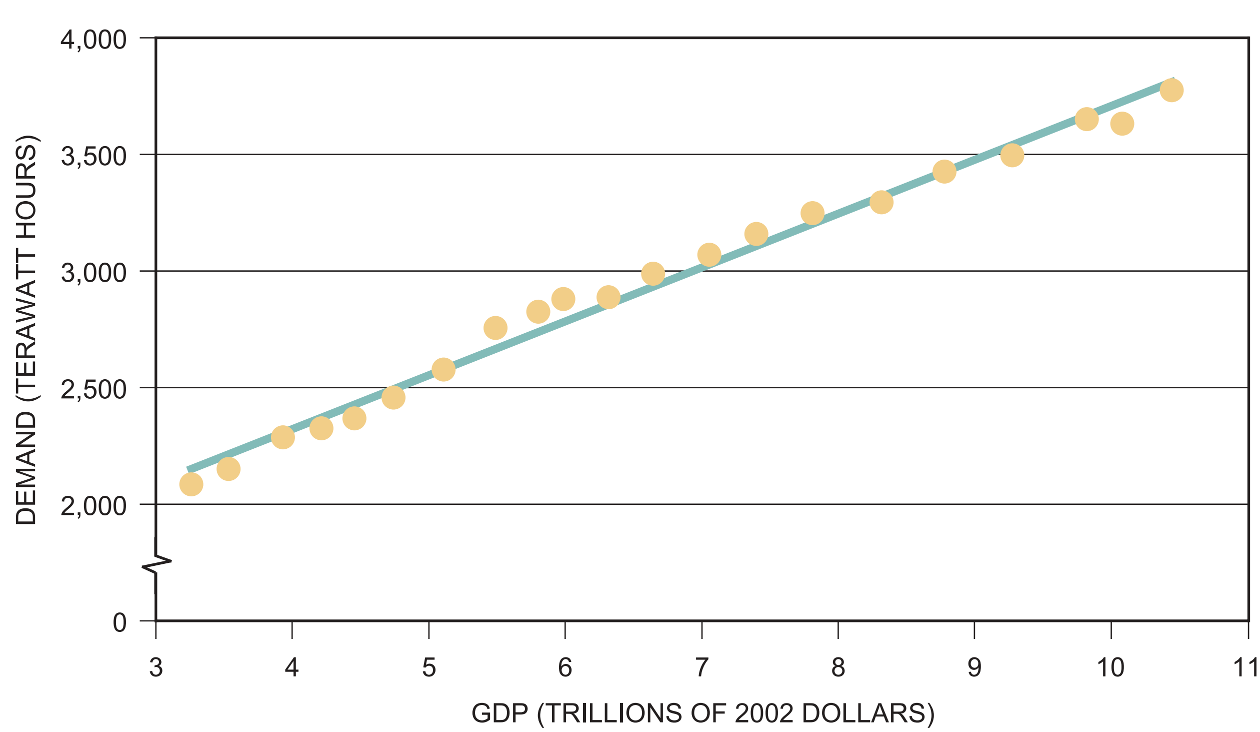


Figure 3-59. Electric Power Demand vs. GDP, 1982-2002

impact upon natural gas. However, the study participants felt the future relationship between GDP growth and electric power demand growth had a fairly wide band of potential outcomes, particularly in a higher energy price environment.

Weather conditions are the other major driver of electric demand. Hot weather routinely causes demand to fluctuate by more than 10% within any region. Cold weather has slightly lesser impact upon power demand due to the lower saturation level of electric-based residential and commercial heating equipment compared to air conditioning equipment particularly in northern climates. Both modeled scenarios used normal weather assumptions so there is no inherent weather-driven difference between them. Weather impacts were evaluated using sensitivities.

In the Reactive Path scenario, electric energy demand is estimated to grow from 3,470 terawatt hours in 2003 to 5,420 terawatt hours in 2025. Figure 3-60 shows historical growth plus the modeling results from the study efforts. The overall level of electric energy demand is a primary driver to fuel consumption and consequently to demand for natural gas. Relatively small changes in the rate of growth in electric energy demand can significantly impact the amount of natural gas consumed within the power segment. Each annual terawatt hour of retail sales differential can be equivalent to 5 BCF per year of gas consumed or conserved. In 2025, the difference in retail power demand between the Reactive Path and Balanced Future scenarios is estimated to avoid consuming 265 BCF of natural gas for that one year.

The amount of natural gas required by the power sector is a direct function of the overall level of power demand at any moment, and natural gas' competitive position within the regional generation capacity supply stack available to meet the power demand. Natural gas is used more heavily during peak electric demand periods. This is due to the fact that while gas-fired generation has one of the lowest capital costs to install, even the most efficient of gas generators are more expensive to operate on a variable cost basis than most nuclear and coal capacity based upon historical fuel prices. Therefore, gas is not dispatched during periods of lower demand when baseload nuclear and coal capacity is available to run. In seasons of higher demand, more gas-fired combined cycle generation is dispatched, followed by less efficient gas steam units, and finally during peak hour periods of certain days, gas

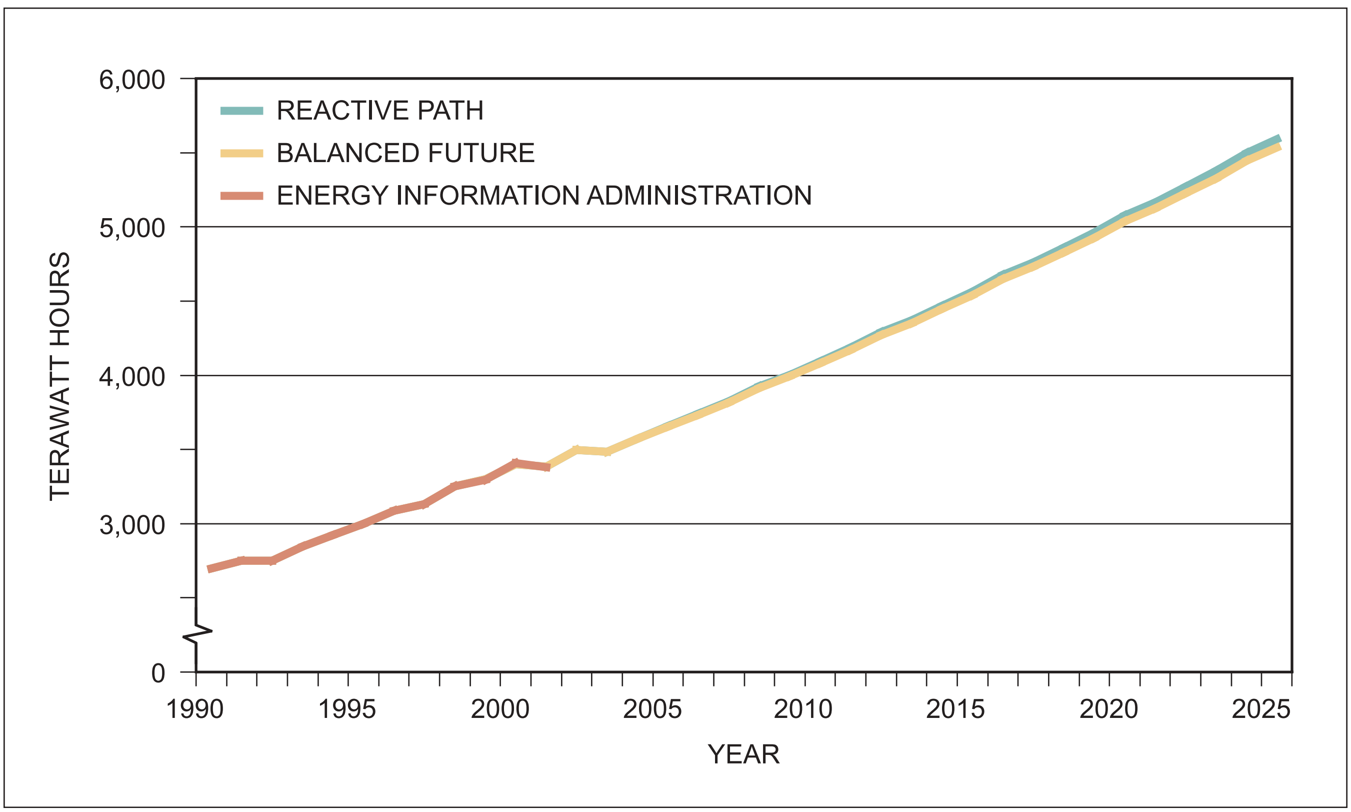


Figure 3-60. Lower-48 Electric Power Retail Sales

combustion turbines are used to meet the highest peak loads. As overall electric energy and peak demand grows, more of the baseload fleet's limited remaining availability is committed, thus requiring other units that have higher variable costs to be more heavily utilized. In most regions these units are predominately the newer gas-fired combined cycle units. This inexorably increases the demand for natural gas and represents a significant increase compared to past years.

Generation Capacity

In 2002, lower-48 installed generation capacity totaled 860 gigawatts, consisting of the fuel types shown in Figure 3-61. Gas, oil, and dual-fuel units combined to be the second largest block of capacity. These units have historically been used to meet intermediate and peak demand requirements in most areas of the country. Baseload nuclear, hydro, and coal contribute electric energy to the supply demand balance in higher proportions to installed capacity than gas, oil, and dual-fuel generation units. The relative contributions of generation by fuel type are also shown in Figure 3-61. Canada's capacities and fuel usage are described in the electric power segment of the Demand Task Group Report.

The United States has experienced periods of both rapid generation capacity expansions and limited expansions. The 1990s was a period of limited capacity expansion that coincided with strong economic growth and related robust power demand growth. This culminated in a period where installed capacity could not reliably meet peak load in different regions, which resulted in higher power prices and extreme volatility in different regions during the latter years of the 1990s. During this time, regulatory driven structural changes were occurring in the wholesale power markets. These changes encouraged the introduction of merchant powerplants into the wholesale markets.

The net result of these circumstances is a power plant construction boom that will add approximately

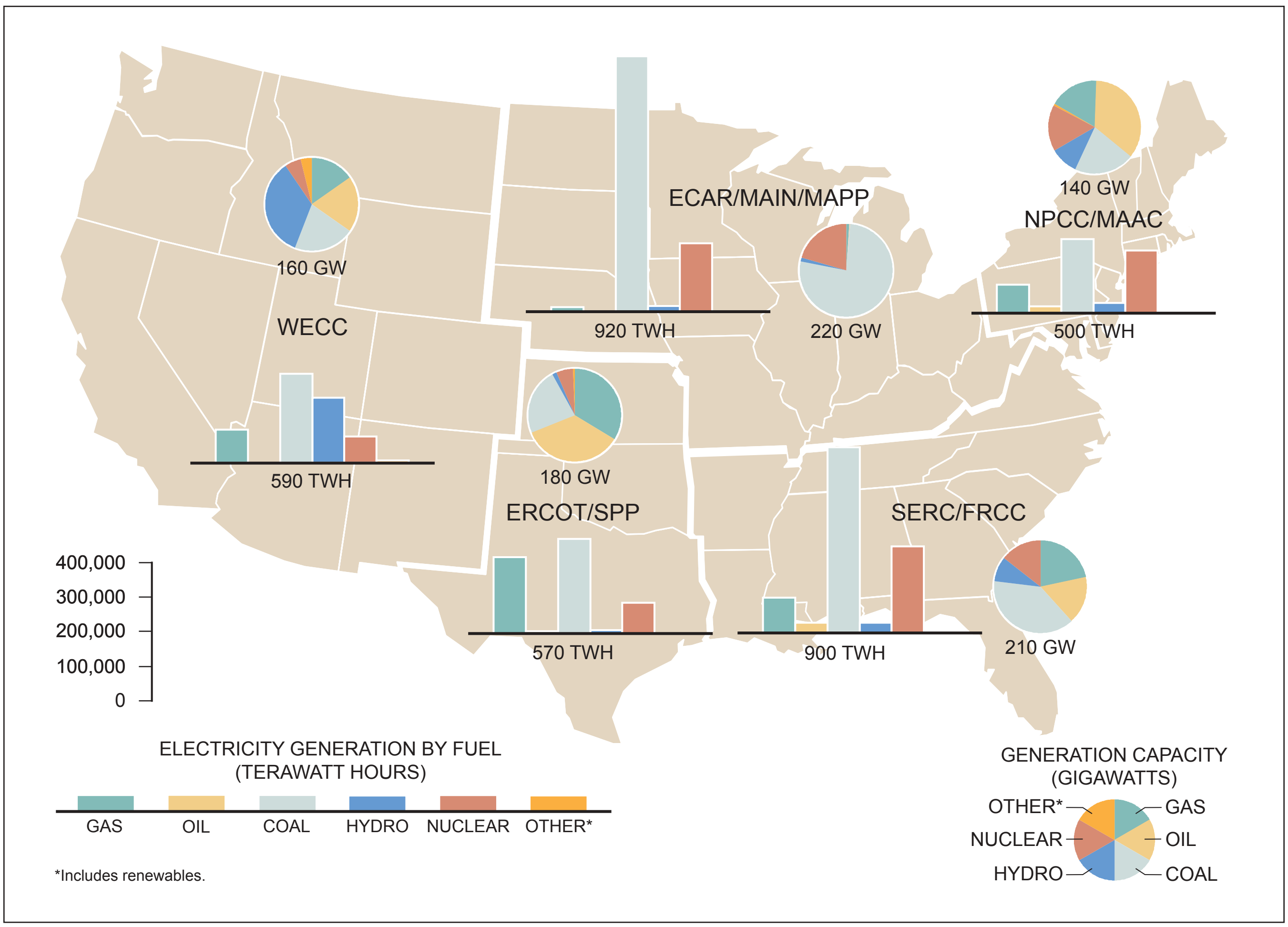


Figure 3-61. U.S. Electricity Generation and Generation Capacity in 2002, by NERC Region

220 gigawatts of generation capacity between the year 1998 and the end of 2005. Almost all of this new capacity is gas-fired and less than 20% of the units have alternate fuel capability. In this study, capacity additions for 2004 and 2005 were limited to projects under construction that did not have any publicly announced delays.

New generation capacity added during the five-year period from 2000 through 2004 rivals the largest amount of new construction experienced by the electric power industry. Furthermore, the reliance on a single source of fuel is unprecedented. As shown in Figure 3-62, the prior construction boom in the 1970s resulted in coal, nuclear, gas, and oil generation capacity being built. This new reliance on a single fuel is the result of a confluence of factors: lower emission rates, ease in siting, relative capital costs, short lead time for installation, modular size, and ease in specific site expansion.

Alternate Fuel Capability and Fuel Substitution

Many older steam units were built to be dual fueled with natural gas and one of the fuel oil products. Energy Information Administration data and other official reports suggest approximately 150,000 megawatts of capacity is oil and gas switchable. However, observed market behavior suggests this capacity is becoming more limited in switching capability or can no longer switch to non-gas fuels. Historically, most oil switching occurred in Florida, New England, New York, and the Mid-Atlantic region because they have the most residual fuel oil capacity. Residual fuel oil has historically competed with natural gas on the margin for generation by steam (boiler) units. These regions also have oil-only units that substitute for natural gas whenever oil is more economic. Additionally, Florida has historically been pipeline capacity constrained, which leads to oil consumption to meet demand since gas is not available.

The ease, operational risk, and economics of fuel switching vary depending upon the technology. Steam units, combined cycles, and combustion turbines have very different considerations for the decision to switch. Older steam units can switch "on the fly" through a simple communication with the plant operators for changes to the fuel burn mix. The process requires somewhat imprecise adjustments to the oil-gas intake flows and replacements of various boiler fuel guns. Also, typical fuel-switching requests can be accomplished under a wide range of plant megawatt outputs and have very limited risk of unit output runback or tripping when being executed. Conversely, combined

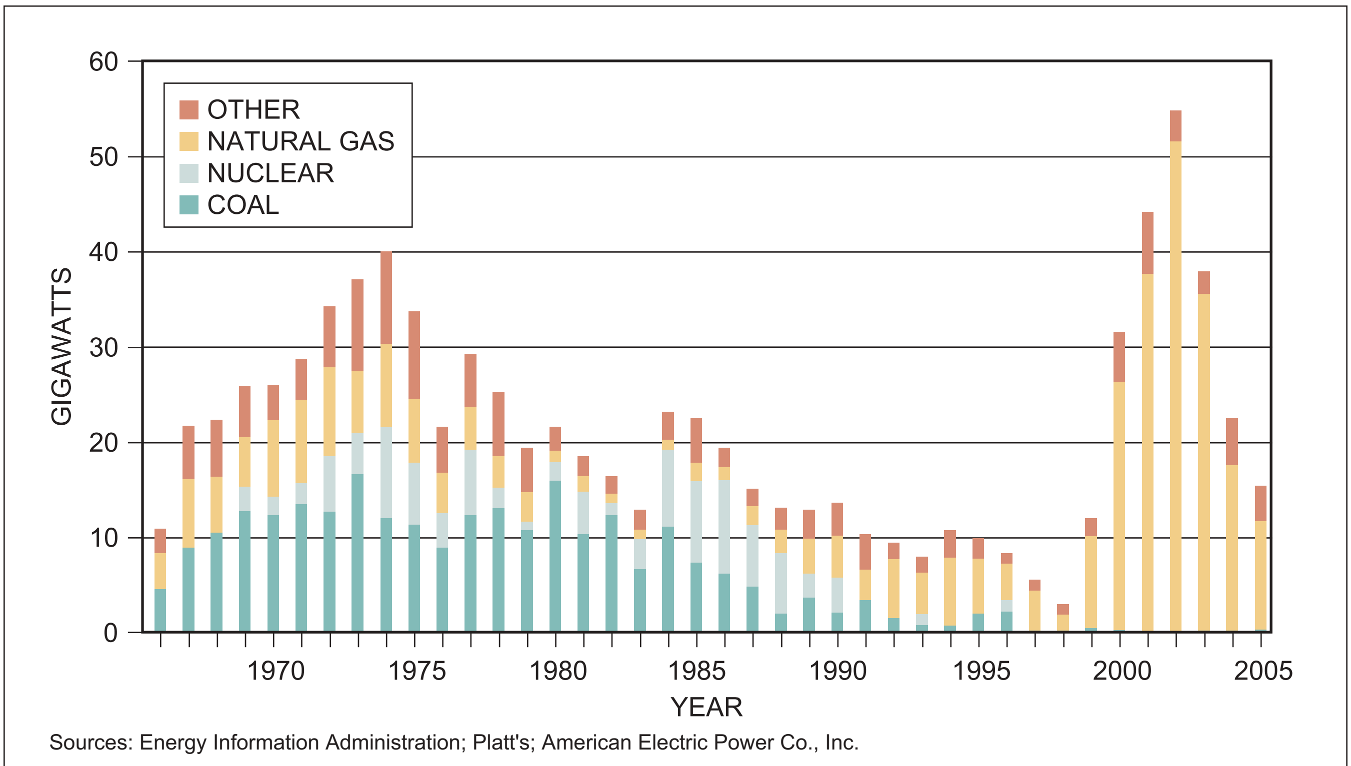


Figure 3-62. Comparison of U.S. Annual Installed New Generation Capacity

cycles and combustion turbines have far greater sensitivity to the procedures for switching fuels. They must be at specific megawatt outputs or in some cases must be shut down completely to avoid unit runback or tripping off-line from the transmission grid.

Switching economics do not depend solely on the competing delivered cost of fuels. Consideration for differences in fixed and variable maintenance costs, increased emission costs, unit megawatt derates, and fuel infrastructure capability/costs are distinct parts of the calculation. Regulated utilities also consider the fuel recovery and operational and maintenance cost recovery risks as part of the decision to switch. The net effect of these costs, operational constraints and environmental issues has led to a significant decline in oil usage for power generation and an increase in the price differential needed to encourage fuel switching. Figure 3-63 illustrates this trend.

The modeled population of oil- and gas-fired generation capacity consists of three distinct types of units: those that run exclusively on gas (gas-only), those that run exclusively on oil (oil-only), and those that can switch between gas and oil (dual-fuel). The oil used in these units ranges from residual oil (Nos. 4, 5, and 6) and distillate oil (No. 2 oil/kerosene). The relative economics of dispatching these units depends upon the delivered fuel price, emissions, and variable operating and maintenance expenses. Therefore, the term "fuel switching" applies to two conditions: (1) the shift between the use of gas or oil at dual-fuel units; and (2) when both gas-only and oil-only units are available within a dispatch region, the shift of dispatch between these units by substituting the dispatch of one unit for another. This results in modeling of both switching and substitution behavior in determining the capacity and generation output of the regional powerplants.

The Reactive Path scenario assumed a number of limits on the addition of either oil-only or dual-fuel units. The NPC assumed that no new oil-capable capacity would be allowed in the northeastern or west coast states, and that the amount of switching capability for the United States as a whole would be limited to 25% of the gas and oil capacity total. Additionally, the construction of residual oil-only units was limited to regions where it was felt that there would be sufficient existing infrastructure to accommodate the additional oil consumption. Due to a number of constraints, such as permit conditions and the availability of oil, there are also limitations to the amount of switching possible at dual-fuel units. Therefore, the total capability to switch from gas to oil is the sum of all the oil-only

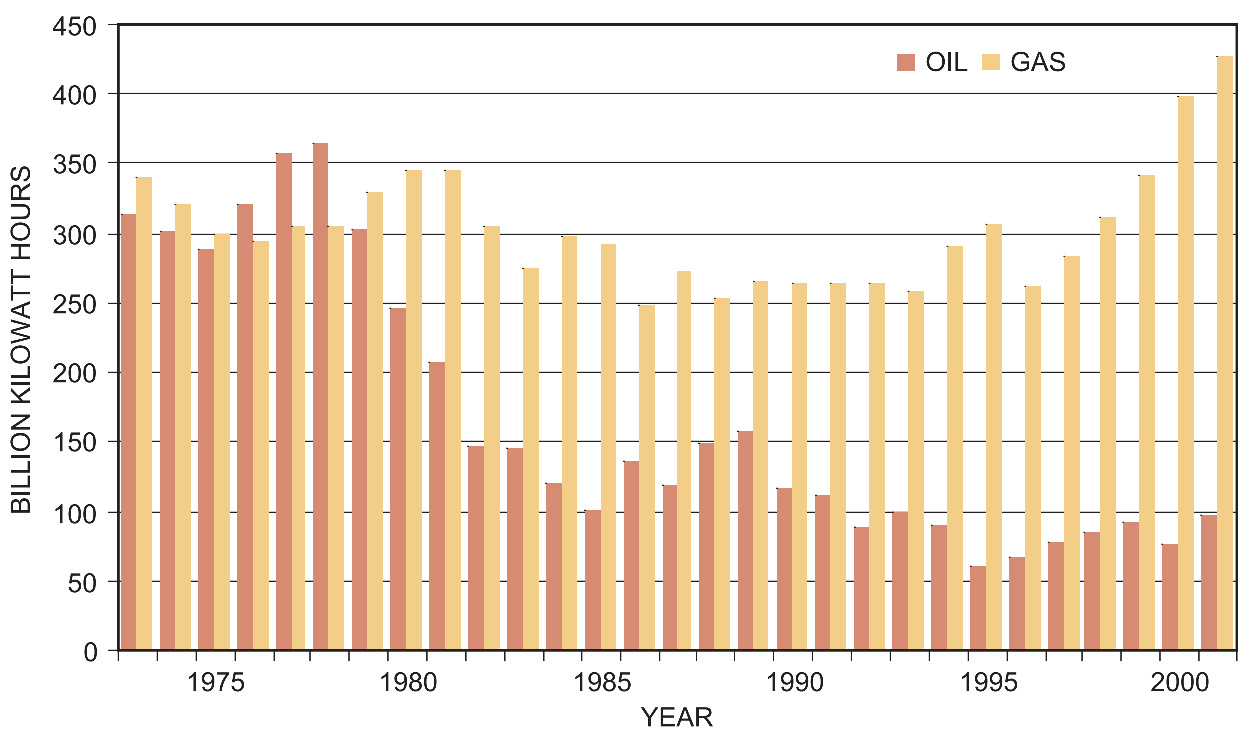


Figure 3-63. U.S. Electricity Generated, by Oil and Gas

capacity plus a fraction of the dual-fuel capacity, based on the maximum number of hours per year the dual-fuel units can operate on oil.

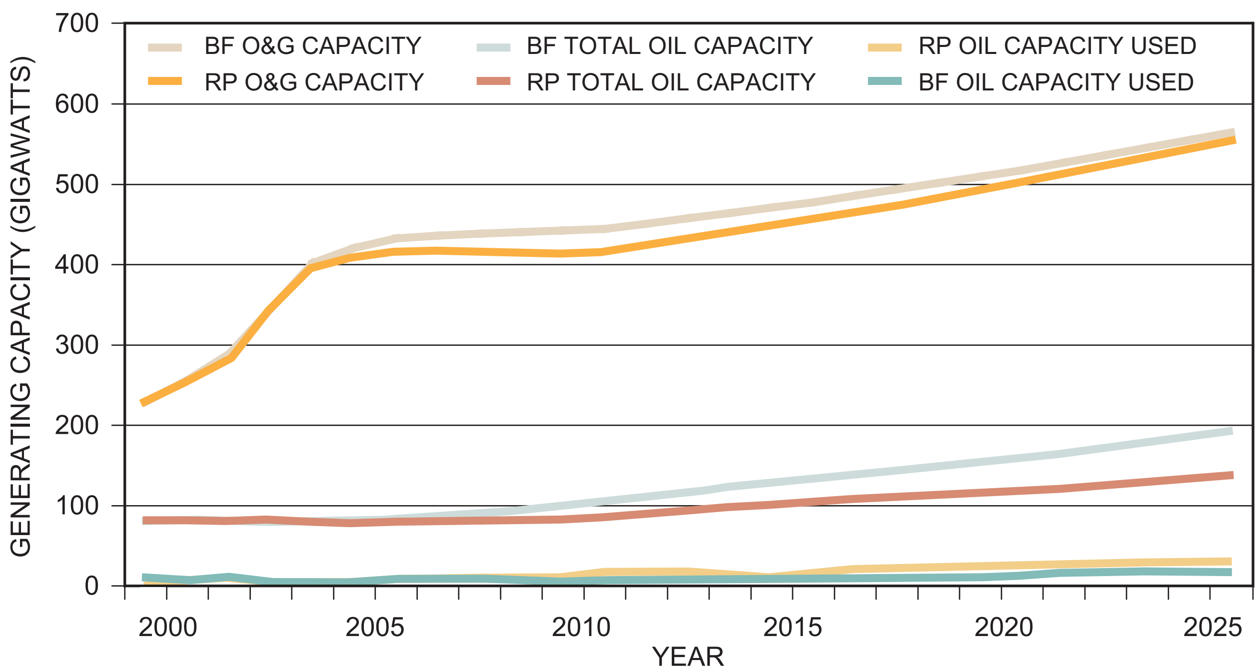
Since gas and oil capacity primarily serves peak and intermediate load, the overall capacity utilization of all gas- and oil-fired units was found to be relatively low in the Reactive Path scenario, ranging from 20% in the near term to nearly 30% by 2025. In the Reactive Path scenario, the total amount of oil-capable capacity increased from 81 gigawatts in 2003 to 137 gigawatts by 2025. Additionally, the utilization of fuel-switching capability during this period was found to increase in the Reactive Path scenario from a near-term average of about 10% to 22% by 2025. These values represent the annual average utilization and are depicted in Figure 3-64 and compared to the Balanced Future scenario. On a seasonal basis, the utilization of the fuel-switching capability were found in the Reactive Path scenario to be greatest in the winter months when gas prices were modeled to be at their peaks.

Figure 3-64 shows the amount of fuel switching in electric power generation for the Balanced Future scenario. This scenario assumes actions are taken by power generators to increase the amount of fuel switching beyond that contemplated by the Reactive Path scenario by retrofitting 25% of existing combined-cycle and combustion turbine facilities for backup fuel. The overall lower price environment of the Balanced Future scenario leads to less overall fuel switching, and lower annual average usage is forecasted. However, the actions assumed in the Balanced Future scenario allow greater level of fuel switching at times of peak demand, such as during periods of cold weather. This was demonstrated by sensitivity analyses that considered extreme weather cycles, showing the greater fuel switching capability contributed to lower overall prices. The net effect of these changes between the scenarios is Balanced Future has more oil capability that allows it to reduce peak requirements on natural gas, leading to lower annual gas prices and higher annual oil switching and substitution in power generation fuel choices.

Assumptions and Case Results

Reactive Path

The Reactive Path scenario incorporates assumptions that range from aggressive to moderately conservative on the issues of new build economics, new build fuel selection, technology advances, re-licensing of nuclear and hydroelectric units, environmental regulation impact, and fuel usage. It is important to note that



Note: RP = Reactive Path; BF = Balanced Future; O&G = oil and gas.

Figure 3-64. U.S. Gas-to-Oil Switching and Substitution in Reactive Path and Balanced Future Scenarios many study participants felt the totality of the collected assumptions represented a "success" scenario wherein market-based decisions triumph, regulatory impediments are not notably increasing, and environmental policies limiting non-gas fuels are not substantially expanded. One large driver of natural gas demand from electric power in the Reactive Path scenario is the assumption that approximately 20 gigawatts of coal-fired capacity is retired prior to 2010 as a result of mercury emission regulations that are scheduled to be proposed in December 2003 by the U.S. Environmental Protection Agency.

Balanced Future

The Balanced Future scenario represents additional enhancements to electric power assumptions that reduce gas demand and contribute to a more relaxed balance between supply and demand.

The complete list of common and differential assumptions are shown below, but some worth highlighting are: (1) the assumption on greater efficiency in the United States' consumption of electricity as measured by income elasticity in the GDP scalar; (2) a resolution of upcoming mercury emission regulations that avoids substantial coal capacity retirement; and (3) substantial increase in renewable generation capacity.

The two scenarios result in significant differences in gas demand by power generation, as shown in Figure 3-65. The Reactive Path scenario consistently has higher demand starting concurrently with retirement of old, small coal units due to mercury air quality regulations, and continuing with less flexibility to use alternate fuels over the study period.

Table 3-13 shows a side-by-side comparison of key model outputs including those driven by input assumptions affecting generating capacity. Table 3-14 shows the major power assumptions common to each scenario or differential to each scenario. A brief description of each assumption is bulleted below.

Detailed Assumptions

- Both scenarios assumed an electric demand growth factor starting at 0.72 times the change in GDP; the Reactive Path scenario declined this factor to 0.62 while the Balanced Future scenario declined to 0.55 over the study period. This reflected greater energy efficiency driven by market forces and enabled by government policies.

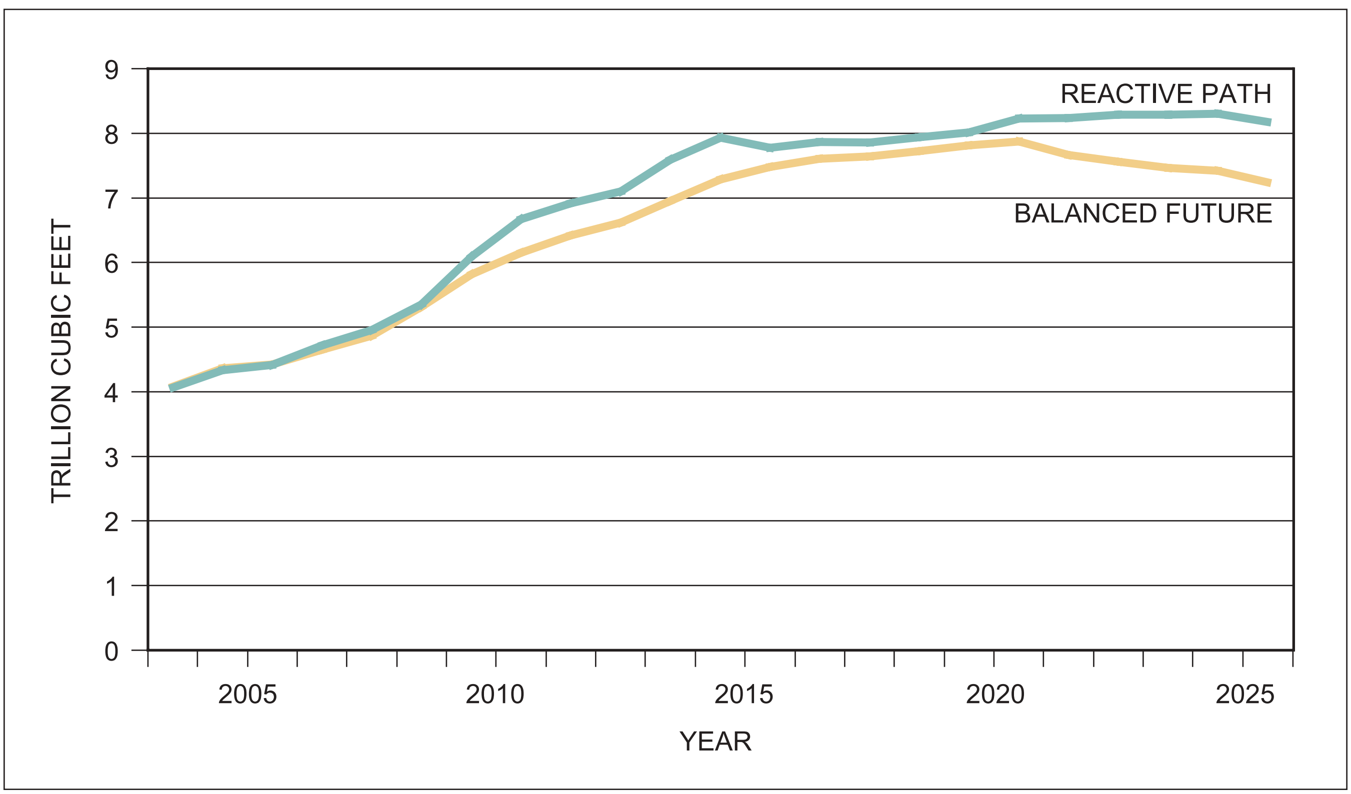


Figure 3-65. Natural Gas Consumption in the U.S. Power Sector

	Reactive Path	Balanced Future
Natural Gas (Trillion Btu per Year Average)	7.13	6.71
Coal (Trillion Btu per Year Average)	23.3	23.5
Oil (Trillion Btu per Year Average)	1.4	0.9
Generation (Terawatt Hours per Year Average)	4,497	4,472
Post-2005 New Gas-Fired Capacity (Gigawatts)	148	128
Post-2005 New Coal-Fired Capacity (Gigawatts)	132	133
Post-2003 Nuclear Capacity Improvement (Gigawatts)	1.9	9.7
Post-2003 New Renewable Capacity (Gigawatts)	73	155
Cumulative Oil/Gas Retirements (Gigawatts)	9	0
Cumulative Coal Retirements (Gigawatts)	20	0

Table 3-13. Scenario Results and Associated Assumptions

Assumption	Status	Assumption	Status
Energy Intensity-GDP based	Changed	SO_2 Emissions	Same
Coal Prices	Same	NO_x Emissions	Same
Oil Prices	Same	Mercury Emissions	Changed
Nuclear Licenses	Same	Carbon Emissions	Same
Nuclear Capacity Enhancement	Changed	Coal Plant Siting	Same
Hydro Licenses	Same	Oil Plant Siting	Same
Hydro Enhancement	Same	Renewable Plant Siting	Changed
New Build Economics	Same	Alternate Fuel Capability*	Changed
Renewable Capacity	Changed	Alternate Fuel Capability†	Changed
Weather	Same	Transmission Capability	Same

*Retirement quantities of oil/gas steam units.
†Percentage of operating hours oil can be used.

Table 3-14. Common and Differing Assumptions Between Scenarios

- National average coal prices are assumed to be $1.28 per MMBtu on a volume-weighted basis, declining by 1% real dollars annually.

- The forecast price of West Texas Intermediate crude oil (WTI) was assumed to be constant in real terms at $20.00 per barrel (2002 dollars). The refiner acquisition cost of crude oil (RACC) was assumed to be 90% of WTI. Residual fuel oil and distillate prices are based on a percentage relationship to RACC on a dollars-per-Btu basis. The resulting ratios are residual fuel oil at 80% of RACC and distillate at 140% of RACC. The resulting prices are: high-sulfur fuel oil No. 6 – $2.48 per MMBtu; No. 2 oil – $4.34 per MMBtu (2002 dollars).

- Each scenario assumes that all nuclear plants have one successful license extension.
- The Reactive Path scenario assumes nuclear capacity is enhanced by approximately 6%, but that some capacity is lost due to regulatory actions for a net increase of 2%.
- The Balanced Future scenario assumes nuclear capacity is enhanced by a net amount equal to 10%.
- Each scenario showed hydropower as an exogenous input of megawatt hours that was derived from historical averages for each month by geographic region. No capacity enhancements or degradations are included in the input amount.
- New build economics were the same in both scenarios. They varied in sensitivity cases.
- Renewable generation in the Reactive Path scenario increased by 73 gigawatts between 2003 and 2025, while it increased by 155 gigawatts in the Balanced Future scenario. The amounts and geographic distribution of renewable capacity in the Reactive Path scenario were based on meeting state-level renewable portfolio standards; these amounts were significantly increased in the Balanced Future scenario based on analyses by the NPC. In both cases, these amounts and geographic distributions were exogenous inputs to the models. (Wind turbines were modeled as a proxy for all renewables in both scenarios, which is not an endorsement of it over other technologies. These other technologies are discussed in more detail within the electric section of the Demand Task Group Report.)
- Weather was same in both scenarios.
- SO_2 emissions were calculated post model runs in both scenarios.
- NOx emissions were calculated post model runs and powerplant dispatch was altered if the levels of emissions exceeded the allowable amount.
- Mercury emissions per se were not modeled, but the potential impact of the impending mercury regulations were modeled by retiring approximately 20 gigawatts of coal capacity in the Reactive Path. These generating units were older than 40 years, smaller than 200 megawatts, and not co-located with a larger unit or plant site.
- Carbon emissions were considered in a sensitivity.
- One main assumption on coal was a modeling restriction that did not allow any coal-fired plants to be built in EPA-designated non-attainment areas for ozone or other major pollutants. Additionally, no coal-fired units were added in California, Washington, and Oregon and total additions were limited in Florida to 4 gigawatts.
  - Overall coal-fired generation construction was limited to 14 gigawatts per year.
  - New coal generation capacity was added, beyond the amount needed to meet the model's 15% reserve margin requirement, whenever the fuel and power price relationships provided financial incentives.
  - Maximum annual availability of coal-fired generation was assumed to be 80%.
- Residual fuel oil-fired combined cycles were limited to the south Atlantic, Gulf Coast, and Gulf Coast waterways to reflect the fuel logistics. Geographic restrictions similar to those of coal were used for the east and west coasts.
- Renewable generation was largely placed in California and Nevada in the Reactive Path scenario; it was more geographically distributed in the Balanced Future scenario to reflect both successful market penetration of technologies and industry response to government policies addressing Renewable Portfolio Standards requirements.
- Gas-fired generation added after 2005 was able to dispatch on distillate oil up to 10% of the time in the Reactive Path scenario, while the Balanced Future scenario allowed it to dispatch up to 15% of the hours if fuel economics justify switching.
- In the Reactive Path scenario, approximately 20 gigawatts of existing oil/gas steam units retired post-2001, while in the Balanced Future scenario they did not retire.
- The power transmission grid was assumed to be the same in both scenarios. The underlying assumptions increased interregional capacity by 50% over the study period.

New Build Economics

A model outside the electric dispatch model determines new generation capacity. When electric power demand grows to a level where the system reserve margin in any region is less than 15%, the model compares the generation capacity options and selects the most economic technology and fuel. The expansion planning process in the EEA models is a heuristic approach relying on busbar curves to determine the appropriate capacity factor operating ranges and production simulation to determine if the newly added units are operating in those ranges.

"Busbar" refers to the transmission equipment just at the edge of the powerplant's site. The costs "behind the busbar" include all fuel costs, construction costs, financing costs, taxes, operations and maintenance expenses, and all the other costs of owning and operating a powerplant. These cost inputs were developed in "real" or "constant dollar" terms and converted to "nominal" dollars using escalation rates for the various costs.

In the production simulation, the newly added units were integrated with the existing fleet and all units were dispatched to meet load. The capacity factor tests only give proper answers if the analysis is approached from one perspective: units operating above their capacity factor range should be replaced with the next type of unit but units operating below their capacity factor range may still be the economic choice. This is due to the fact that the new units may be operating at lower capacity factors because there are existing units in a similar dispatch price range. For example, a new efficient coal unit may operate at a high capacity factor, but it may not be economic in some regions because it is simply decreasing the operation of slightly less efficient coal units.

Table 3-15 shows the technologies considered and a selection of the input criteria. A more detailed list is

Technology Description	Lead Time (Years)	Capital Cost (2002 Dollars per Kilowatt)	2010 Heat Rate (Btu per Kilowatt Hour)	Maximum Capacity Utilization (Percent)
Conventional Pulverized Coal w/ Scrubber	7	1,200	9,300	85
Integrated Coal Gasification Combined Cycle Greenfield	6	1,400	9,000	90
Integrated Coal Gasification Combined Cycle Brownfield	5	1,400	9,000	90
Super Critical Pulverized Coal w/ All Environmental	7	1,250	8,600	85
Gas Combined Cycle	3	600	7,000	92
Low-Sulfur Diesel Combined Cycle	3.5	600	7,200	90
Distillate Combined Cycle	4	670	7,400	88
E-Class Residual Oil Combined Cycle w/ Environmental	4	800	8,100	70
Gas Combustion Turbine	1.5	350	10,000	15*
Low-Sulfur Diesel Combustion Turbine	2.5	400	10,600	15*
Advanced Nuclear	10	1,500	10,500	92
Renewable – Wind	3	1,100	N/A	30

* 30% maximum capacity factor in West for low hydro years and backup for renewables.

Table 3-15. Generation Technologies Model Input Parameters

Regulation	Issuance Date	Implementation Date
NSR Enforcement	Ongoing	
NSR Rule – Routine Maintenance		2004
NOx (Section 126) State Petitions		2004
NOx SIP Call		2004
Clean Water Act 316(b)		2004
Mercury controls (MACT)	2003	2008
Ozone (8 hour)		2010
Fine particulate standards		2010
Regional Haze (BART)		2012

NSR = New Source Review
SIP = State Implementation Plan
MACT = Maximum Achievable Control Technology
BART = Best Available Retrofit Technology

Table 3-16. Major Federal Environmental Regulations Affecting Power Industry

included in the Appendices to the Demand Task Group Report.

Environmental Issues

Uncertainty over the extent and timing of environmental rules, particularly air quality regulations, are a significant factor in electric industry decision-making for investments in new generation. The Reactive Path scenario attempted to predict industry actions in response to existing laws and regulations, including those scheduled to be implemented under current laws and rulemakings. Our Balanced Future scenario did not attempt to model any specific legislative initiative, such as "Clear Skies," but it did envision action that reduces uncertainty over emissions standards, provides clear and extended timelines for compliance, and promotes cap and trade emission systems that are market driven and useful.

One example is the mercury emission control rule, which is scheduled to be released in December 2003 in draft form, and in final form by December 2004. Actual implementation is forecasted to be 2008. However, almost certain litigation by all sides in the debate may either postpone implementation, or create greater uncertainty over final implementation. The net consequence of these types of uncertainty is to stifle some of the needed investments in control technology for economically marginal plants, until clarity is achieved. This can result in short or intermediate-term dislocations in non-gas-fired generation capacity, which directly impacts the amount of gas built, and dispatched during the period that non-gas-fired capacity is unavailable. Table 3-16 lists some of the known upcoming environmental issues facing the electric power industry.

Siting and New Source Standards

The U.S. Environmental Protection Agency describes the new source standards as follows:

> Section 111 of the Clean Air Act, "Standards of Performance of New Stationary Sources," requires EPA to establish federal emission standards for source categories which cause or contribute significantly to air pollution. These standards are intended to promote use of the best air pollution control technologies, taking into account the cost of such technology and any other non-air quality, health, and environmental impact and energy requirements. These standards apply to sources that have been constructed or modified since the proposal of the standard. Since December 23, 1971, the Administrator has promulgated nearly 75 standards. These standards can be found in the

Code of Federal Regulations at Title 40 (Protection of Environment), Part 60 (Standards of Performance for New Stationary Sources).

Generally, state and local air pollution control agencies are responsible for implementation, compliance assistance, and enforcement of the new source performance standards (NSPS). EPA retains concurrent enforcement authority and is also available to provide technical assistance when a state or local agency seeks help. EPA also retains a few of the NSPS responsibilities – such as the ability to approve alternative test methods – to maintain a minimum level of national consistency.

In areas with acknowledged air quality issues, these standards are typically used to drive decisions towards natural gas generation technology without the ability to switch to alternate fuels, normally No. 2 oil. This observed behavior was a primary reason for modeling assumptions that limited new coal and oil fired generation capacity in general, and that did not allow construction of any new capacity in the northeast United States or the west coast.

A subset of these rules known as New Source Review applies to modifications within existing units. These rules are in the process of being reviewed and reissued to clarify the issues. Litigation resulting from the proposed clarifications and modifications to the existing interpretation of the rules is certain. The uncertainty of the outcome continues to inhibit the electric power industry from modifying and upgrading existing coal generation that could quickly provide substantial capacity. Industrial energy users face the exact same issues within their plants and processes as discussed in their section of the report.

Sensitivities and Scenarios Summary

The sensitivities that impact power generation the most are:

1. Fuel Flexibility
2. High Electricity Sales to GDP Elasticity
3. Low Electricity Sales to GDP Elasticity
4. High GDP Growth
5. Low GDP Growth
6. Weather Cases
7. Carbon Reduction

The first 5 sensitivities are graphed in Figure 3-66 with Reactive Path and Balanced Future scenarios to compare natural gas demand. There is a wide variance in overall demand. The results suggest that continued improvements in efficiency for power consumers and flexible fuel arrangements are critical keys to minimizing the amount of natural gas consumed within the power sector.

A continuation of current improvements in efficiency coupled with a more flexible fuel regulatory outlook would save over 3 TCF per year by 2025 when compared to a future that has no additional electric power efficiency. Additional fuel flexibility could result in saving 1.7 TCF per year in 2025 when compared to the Reactive Path scenario. The weather sensitivities and carbon reduction scenario are described in the Demand Task Group Report.

Other Considerations

Power Markets and Transmission

The electric power wholesale market is regional in nature due to the operation of the transmission grid and the ability to flow power between different areas of the grid. Control of the power transmission grid is very different than the control capability of the gas transmission system. Interconnect capacity between the regions is expected to improve due to technology improvements in the limiting equipment. However, siting power transmission lines remains very difficult. Consequently, little improvement is expected in the ability to move large blocks of power, from regions with lower cost generation (usually coal, hydroelectric, and nuclear) to higher cost areas. Approximately 1,000 circuit miles of new transmission of 230 kilovolts or higher, which represents approximately a one-half percent increase in circuit miles, are added each year to the North American regions in participation with NERC. This, however, does not translate into the same amount of increase in capacity to transfer load within or between regions.

Renewable Power Generation Technologies

The two scenarios assumed significant quantities of renewable generation technology is installed during the period of this study. Reactive Path assumes 73 gigawatts and Balanced Future assumes 155 gigawatts of capacity. In both scenarios, wind was the modeled technology, but this is not an implied endorsement of wind versus other technologies. These quantities are within the wide range of many projections by governmental agencies and non-governmental organizations. The drivers to renewable generation in the near future will be the

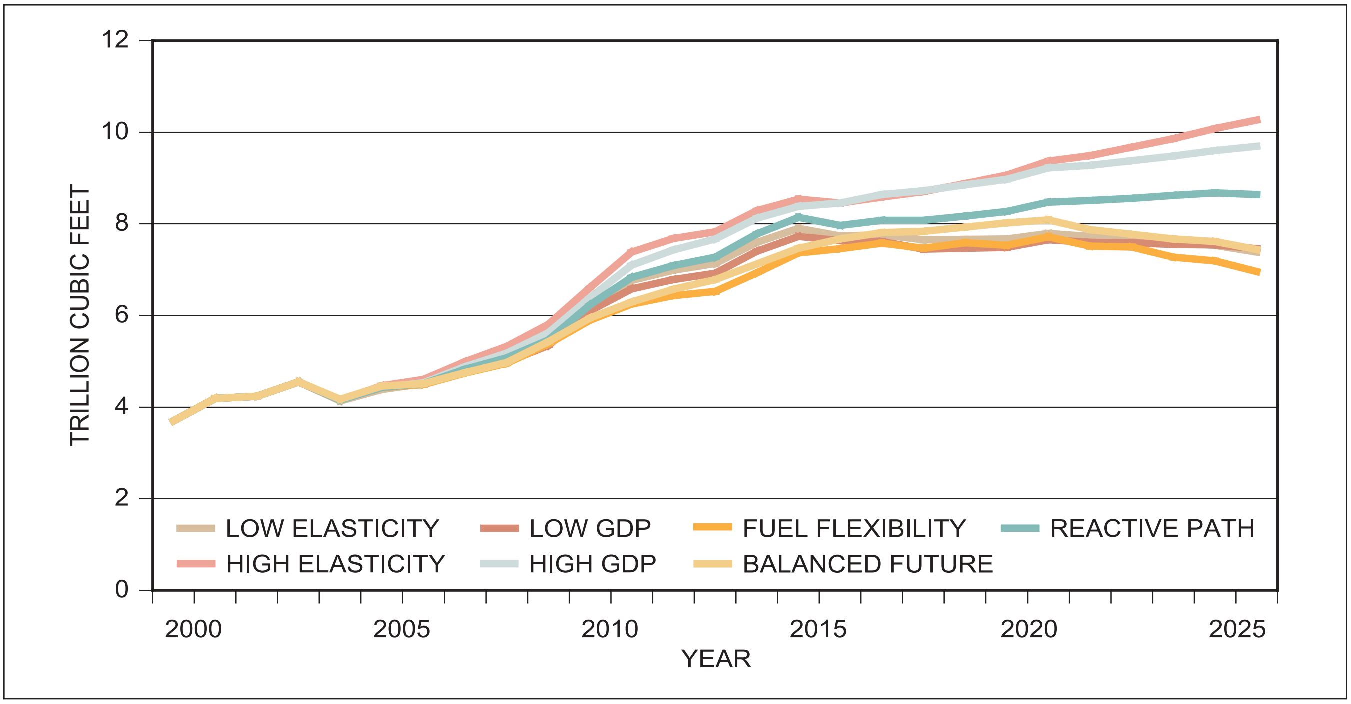


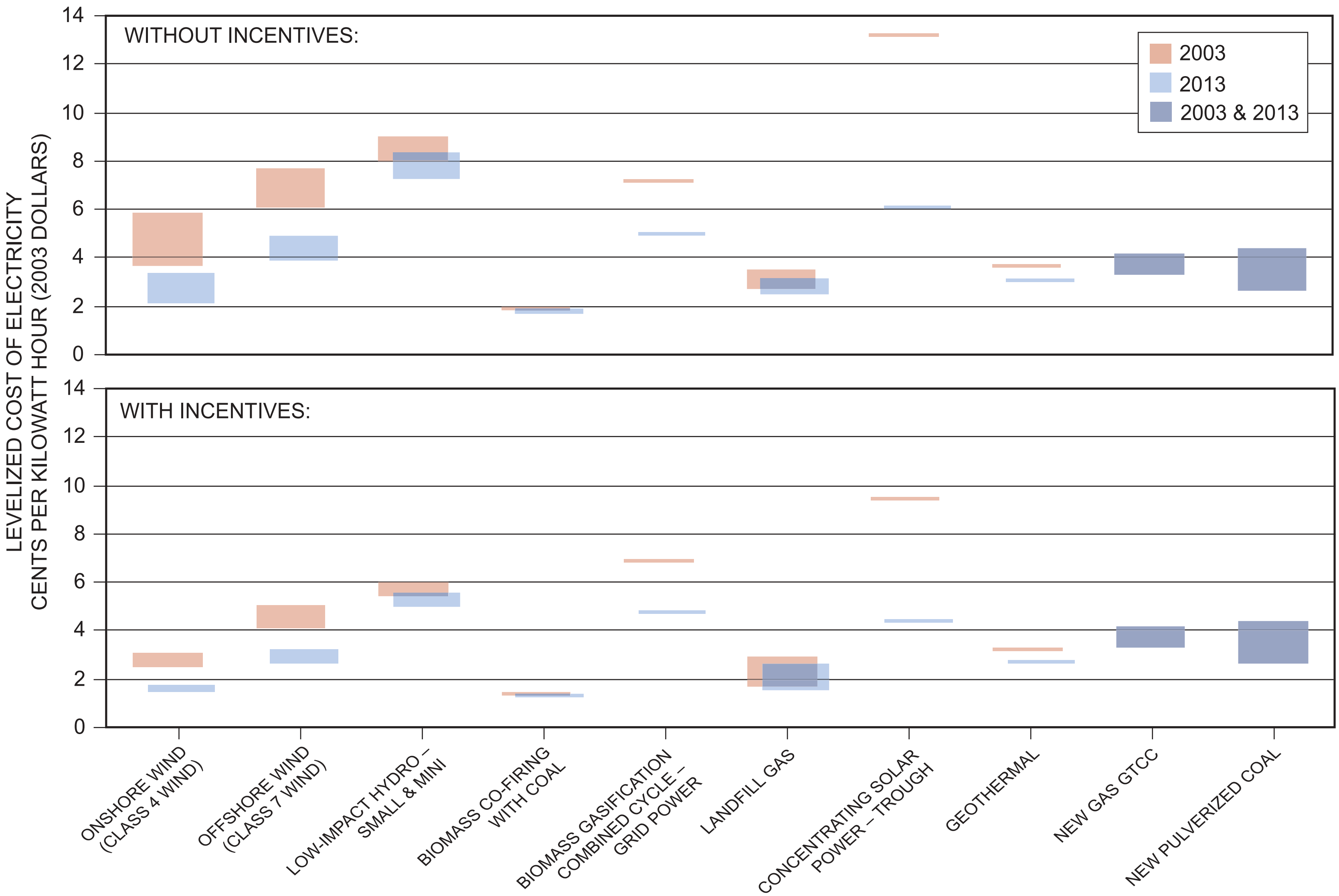
Figure 3-66. Comparison of Natural Gas Consumption in the Power Sector

continuation of Renewable Portfolio Standards (RPS) and potentially an extension of tax credits that have spurred development over the past few years. Currently 12 states have RPS in place, 3 states have "best efforts" goals, and 7+ states are actively considering some level of RPS. Canada is also actively promoting some level of RPS. Over the long term, economic competitiveness will be the primary driver to the market penetration of these technologies. Figure 3-67 shows the relative competitiveness of various technologies with and without incentives in 2003 and projected for 2013.

Conclusions, Recommendations, and Uncertainty Discussion

Study participants in the Power Generation Subgroup concluded the following:

- The magnitude of new gas-fired capacity added to the generation fleet creates the potential for large surges of demand for natural gas under a variety of circumstances:
  - Sudden reductions in baseload capacity like nuclear, coal, or hydro, whether by regulatory action, poor rainfall, environmental rulings, security issues, or other reasons.
  - Hot weather events in the summer driving short-term gas peak dispatch will reduce gas available for storage injections.
- Energy efficiency reflected by lower electric intensity reduces the need for capacity investments and reduces the forecasted demand for natural gas.
- Lack of alternate fuel capability in the recent natural gas new builds, retirement of existing oil/gas steam, and local sentiment in opposition to oil infrastructure at plants is leading to less flexibility in fuel choices and less price elasticity in gas purchases. This creates a higher probability of electric power gas purchases contributing to gas price volatility.
- Economically rational market solutions should be the primary driver in fuel choices while recognizing environmental standards as a relevant factor.
- Environmental regulation uncertainty and long-term concerns on potential carbon legislation create reluctance to invest in coal-based technology. Coal builds included in cases reflect a bias towards making the investment, rather than waiting for increased certainty.
  - Construction activity for coal has been at a low point for five years and is expected to continue for several more years.
- The structure of power markets have limited impact on gas demand, although in some regions less-efficient steam units dispatch at levels higher than expected even though new combined-cycle efficient units are available.



Source: Navigant Consulting, Inc., *The Changing Face of Renewable Energy,* June 19, 2003 (Public Release, October 2003).

Figure 3-67. Life Cycle Cost of Electricity – Renewable Energy Options, With and Without Incentives

Comparison with 1999 Study Results

Figure 3-68 illustrates the demand projections for the Reactive Path and Balanced Future scenarios together with the NPC 1999 Reference Case projection. The 2003 demand forecast of the Energy Information Administration's Annual Energy Outlook (AEO) is also depicted for reference.

The most visible difference between 1999's study and this study is the approach to evaluating the supply/demand balance. The primary focus of the 1999 study was to test supply and delivery systems against significantly increased demand. The current study built up demand as part of the two scenarios and sensitivities. Like this study, the 1999 NPC study assessed demand on a regionally disaggregated basis in the following sectors: residential, commercial, industrial, electric power generation, and lease/plant/pipeline fuel. Major differences in approach and assumptions between these studies are as follows:

- This study developed and employed a descriptive model for industrial demand that estimated demand for boiler fuel, feedstock, process heat, and cogeneration/other demand in ten industry groups. The 1999 study did not perform a detailed assessment of industrial demand.
- This study was based on in-depth analyses of alternative power generation technologies and the heat rates and expected efficiency improvements of these technologies, and it gave consideration to potential future transmission enhancements in North America. The 1999 study took a more limited approach to generation capacity, made global assumptions for expected generation efficiency improvements, and did not consider transmission enhancements.
- The 1999 study assumed that new gas-fired generation additions would grow by 88 gigawatts from 1998 to 2010. The 2003 study reflected the actual new generation buildup of over 200 gigawatts from 1998 through 2005.
- The 1999 study assumed that 15 gigawatts of nuclear generation capacity would retire by 2015. The 2003 study assumes all nuclear generation facilities will be relicensed once, such that overall nuclear capacity will remain essentially constant through 2025. The 1999 study assumed nuclear capacity factors would increase from 75% to 80% annually. The 2003 study

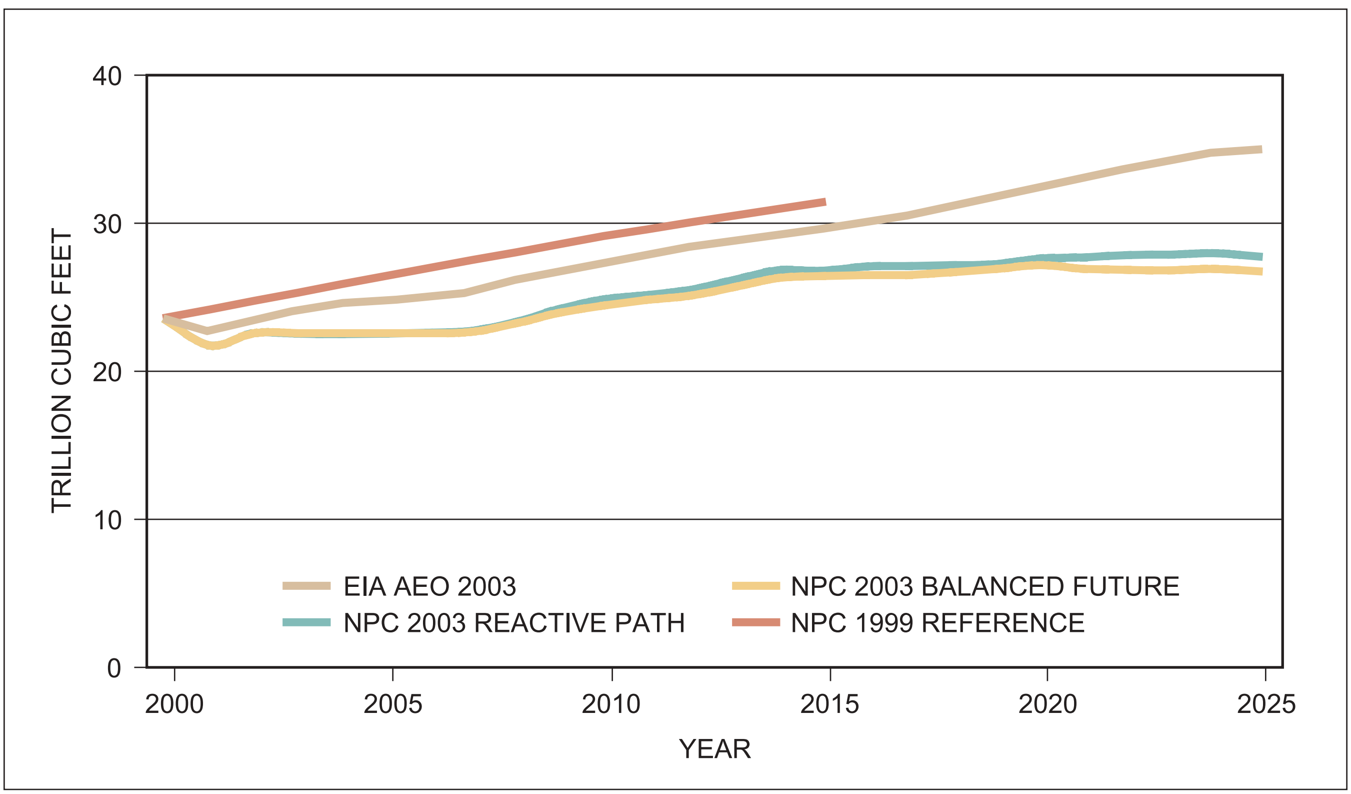


Figure 3-68. Comparison of U.S. Demand Projections

assumes more recent performance that approaches 90% capacity factors will persist.

- Coal capacity factors were assumed to increase from 64% to 75% in 2015 as part of the 1999 study. The 2003 study sets the maximum coal availability at 80% annually, which coal generation achieves by 2015.
- The 2003 study assumes much larger capacity installations of renewable generation than the 1999 study.

Recommendations Related to Natural Gas Demand

To achieve our nation's economic goals and meet our aspirations for the environment, natural gas will play a vital role in a balanced energy future. Stable and secure long-term supply, a balanced fuel portfolio, and reasonable costs will be enabled by a comprehensive solution composed of key actions facilitated by public policy at all levels of government. The foundation of demand-related recommendations is to improve demand flexibility and efficiency. Natural gas is a critical source of energy and raw material, permeating all sectors of the economy. Each sector of the economy can make contributions to using natural gas resources more efficiently.

The changes in demand require involvement of each consumer segment and can be broadly characterized as:

- Energy efficiency and conservation
- Fuel switching and fuel diversity.

In the very near term, reducing demand is the primary means to keep the market in balance because of the lead times required to bring new supply to market. While current market forces encourage conservation among all consumers and fuel switching for large customers who have that capability, proactive government policy can augment market forces by educating the public and assisting low-income households. Key elements of this recommendation are summarized below.

Encourage Increased Efficiency and Conservation through Market-Oriented Initiatives and Consumer Education

Energy efficiency is most effectively achieved in the marketplace, and can be accelerated by effective utilization of power generation capacity, deployment of high-efficiency distributed energy (including cogeneration which captures waste heat for energy), updating building codes and equipment standards reflecting current technology and relevant life-cycle cost analyses, promoting high-efficiency consumer products including building materials and Energy Star appliances, encouraging energy control technology including "smart" controls, and facilitating consumer responsiveness through efficient price signals.

- **Educate consumers.** All levels of government should collaborate with non-governmental organizations to enhance and expand public education programs for energy conservation, efficiency, and weatherization.
- **Improve conservation programs.** DOE should identify best practices utilized by states for the low-income weatherization programs and encourage adoption of such practices nationwide.
- **Review and upgrade efficiency standards.** DOE, state energy offices, and other responsible state and local officials should review the various building and appliance standards that were previously adopted to ensure that decisions reached under cost/benefit relationships are valid under potentially higher energy prices.
- **Provide market price signals to consumers to facilitate efficient gas use.** FERC, Regional Transmission Organizations (RTOs), and state utility commissions should facilitate adoption of market-based mechanisms and/or rate regimes, coupled with metering and information technology to provide consumers with gas and power market price signals to allow them to make efficient decisions for their energy consumption.
- **Improve efficiency of gas consumption by resolving the North American wholesale power market structure.** FERC and the states/provinces, and if necessary congressional legislation, should improve wholesale electricity competition in the United States, Canada, and interconnected areas of Northern Mexico. FERC should mitigate rate and capacity issues at the seams between adjoining RTOs to maximize efficient energy flows between market areas.
- **Remove regulatory and rate-structure incentives to inefficient fuel use.** FERC, RTOs, and state regulators should ensure central dispatch authority rules, procedures and, where applicable, cost recovery mechanisms, require dispatch of the most efficient generating units while meeting system reliability requirements and minimizing cost.
- **Provide industrial cogeneration facilities with access to markets.** Congress, FERC, RTOs, and,

where applicable, state regulators should ensure that laws, regulations, and market designs provide industrial applications of cogeneration with either access to competitive markets or market-based pricing consistent with the regulatory structure where the cogeneration facility is located.

- **Remove barriers to energy efficiency from New Source Review.** Remove barriers to investment in energy efficiency improvements, and investments in new technologies and modernization of powerplants and manufacturing facilities by implementing reforms to New Source Review such as those proposed by the U.S. Environmental Protection Agency in June 2002.

Increase Industrial and Power Generation Capability to Use Alternate Fuels

Natural gas has become an integral fuel for industrial consumers and power generators due to a range of factors, including its environmental benefits, and these consumers should continue to be allowed to choose natural gas to derive these benefits. However, the greatest consumer benefit will be derived from market-based competition among alternatives, while achieving acceptable environmental performance. The ability of a customer to switch fuels serves to buffer short-term pressures on the supply/demand balance and is an effective gas demand peak shaving strategy that should reduce upward price volatility. Increasing fuel diversity, the installation of new industrial or generation capacity using a fuel other than natural gas, serves to reduce gas consumption over the life of the new capacity. Most facilities that would consider installing non-gas fueled capacity tend to be large and energy intensive. Therefore, increasing fuel diversity will have a large cumulative effect on natural gas consumption over the period of this study.

- **Provide certainty of air regulations to create a clear investment setting for industrial consumers and power generators, while maintaining the nation's commitment to improvements in air quality.**
  - **Provide certainty of Clean Air Act provisions.** Congress should pass legislation providing certainty around Clean Air Act provisions for SOx, NOx, mercury, and other criteria pollutants. These provisions should recognize the overlapping benefits of multiple control technologies. The current uncertainty in air quality rules and regulations is the key impediment to investment in, and continued operation of, industrial applications and power generation facilities using fuels other than natural gas. Congress should ensure that such legislation encourages emission-trading programs as a key compliance strategy for any emissions that are limited by regulation.
  - **Propose reasonable, flexible mercury regulations.** The Environmental Protection Agency's December 2003 proposed mercury regulations should provide adequate flexibility to meet proposed standards. These regulations should acknowledge the reductions that will be achieved by way of other future compliance actions for SOx and NOx emissions, and provide phase-in time frames that consider demand pressure on natural gas.
  - **Reduce barriers to alternate fuels by New Source Review processes.** Performance-based regulations should meet the emission limits required without limitations on equipment used or fuel choices. State and federal regulators should ensure that New Source Review processes, and New Source Performance Standards in general, do not preclude technologies and fuels other than natural gas when the desired environmental efficiency can be achieved.
- **Expedite hydroelectric and nuclear powerplant relicensing processes.** FERC, the Nuclear Regulatory Commission, and other relevant federal, state, regional, and local authorities should expedite relicensing processes for hydroelectric and nuclear power generation facilities. These authorities should fully consider the increased future requirements for natural gas-based generation in the affected regions that could arise from "conditions of approval" or denial of relicensing. In the case of denial, adequate phase-in time specific to the fuel type of replacement resources should be provided to bring alternative generation resources onto the grid to replace non-renewed facilities.
- **Take action at the state level to allow fuel flexibility.**
  - **Ensure alternate fuel considerations in Integrated Resource Planning.** Where Integrated Resource Planning is conducted at the state regulatory agency level, state commissions should require adequate cost/benefit analysis of adding alternate fuel capability to gas-only-fired capacity.
  - **Allow regulatory rate recovery of switching costs.** State public utility commissions should provide rate treatment to recover fuel costs and increased non-fuel operating and maintenance costs when

units switch to less expensive alternate fuels as matter of practice and policy, since the fuel switching either directly or indirectly benefits ratepayers by reducing gas price and/or volatility through fuel switching.

– **Support fuel backup.** State executive agencies should ensure that policies of state permitting agencies encourage liquid fuel backup for gas-fired power generation, and encourage a balanced portfolio of fuel choices in power generation and industrial applications.

- **Incorporate fuel-switching considerations in power market structures.** RTOs, Independent System Operators, and tight Power Pools should ensure bidding processes and cost caps provide appropriate price signals to generation units capable of fuel switching. FERC should ensure that wholesale power markets, containing any capacity components, should have market rules facilitating pricing of alternate fuel capability.

Additional Demand Considerations

There are additional actions and policy initiatives that could be undertaken to create a more flexible and efficient consumer environment for natural gas, while assuring environmental goals are achieved.

- **Permit Reviews.** State environmental agencies, in consultation with the U.S. Environmental Protection Agency, should review existing alternate fuel permits, and opportunities for peak-load reduction during non-ozone season. All new permits should have maximum flexibility to use alternate fuels during all seasons, recognizing the ozone season may require some additional limitations. During ozone season, cap and trade systems should govern the economic choices regarding fuel choice to the maximum extent possible.

- **Forums to Address Siting Obstacles.** With respect to coordination among multiple levels of government, federal agencies should consider facilitating forums to address obstacles to constructing new power generation and industrial capacity. Participants would include the relevant federal, state, and local siting authorities, as well as plant developers and operators, industrial consumers, environmental non-governmental organizations, fuel suppliers, and the public. The objective of these forums would be to address with stakeholders the impact of siting decisions on natural gas markets.

- **Potential Limits on Carbon Dioxide Emissions.** Ongoing policy debates include discussion of carbon reduction, including potential curbs on CO_2 emissions. Many actions would constitute the market's response to such limitations, including shutdown and/or re-configuration of industrial processes, additional emissions controls including carbon sequestration, or the shifting of manufacturing to other countries.

  Natural gas has lower CO_2 emissions than other carbon-based fuels. Therefore, natural gas combustion technologies are likely to be a substantial aspect of the market's response to limitations on CO_2 emissions in industrial processes and power generation. The most significant impact of CO_2 emission curbs would likely be restrictions in operation of much of the coal-fired power generation, since coal-combustion processes tend to emit the highest levels of CO_2. Depending on the level of emission restrictions, the requirements for natural gas in power generation alone could increase substantially. Alternatives to natural gas would be additional nuclear power and/or coal-fired generation employing carbon sequestration technologies that are unproven on a large scale. Renewable electric generation capacity is likely to play a growing role in the future, but has not demonstrated the ability to have a large impact.

  This study tested the impacts on natural gas demand and the resulting market prices, by performing sensitivity analyses; the impact on gas demand could be significant, as discussed elsewhere in this study, depending on the degree to which carbon intensity might be reduced. Natural gas consumption for power generation would clearly increase under any CO_2 reduction scheme during the time frame of this study, placing enormous demand pressure on natural gas. This would likely lead to much higher natural gas prices and industrial demand destruction.

- **DOE Research.** With respect to government research, the NPC is supportive of DOE research where it complements privately funded research efforts. DOE and state energy offices should continue to support research and commercialization of wind, solar, biomass, and other renewable generation technologies. DOE should continue to support government and industry partnership in funding improvements such as advanced turbines, clean coal, carbon sequestration, distributed generation, and renewable technologies. DOE should also continue to support the efficient use of natural gas.

CHAPTER 4

NATURAL GAS SUPPLY

This chapter of the Integrated Report describes the methods used by the Supply Task Group to develop an outlook for natural gas supplies and discusses the results of the study effort. These results provide the basis for the supply elements of the Summary of Findings and Recommendations. What follows is a summary of the supply outlook, along with additional details from each of the functional subgroups. Full documentation is found in the Supply Task Group Report and its appendices.

Study Approach

In undertaking its analysis of natural gas supply, the Supply Task Group considered the most important factors affecting the current supply situation and the long-range outlook. This analysis included the following:

- A comprehensive review of the North American gas resource base using the best publicly available data. This assessment included a thorough review of both conventional and nonconventional resources (including tight gas, coal bed methane, and shale gas). In order to gain a solid understanding of potentially commercial recoverable resources, the review also included a detailed assessment of drilling and development costs, and the likely number and size of future discoveries.

- A comprehensive review of the production performance history for the mature basins of North America. This was needed in order to gain an understanding of the future production decline rates of existing reserves, the likely response to future drilling, and the potential for growth in proved reserves from revisions and extensions to existing fields.

- An evaluation of the effect of the permitting process and access restrictions on development of indigenous resources.

- An assessment of the effect that technology advances might have on the cost and availability of gas resources.

- An assessment of the potential contribution from major new supply sources, such as imported liquefied natural gas (LNG) and Arctic gas.

The Supply Task Group had five subgroups. The Resource Subgroup was led by ExxonMobil, Technology by ChevronTexaco, Environmental/Regulatory/Access by Burlington Resources, LNG by Shell, and the Arctic Subgroup was led jointly by ExxonMobil, ConocoPhillips, and BP. Given the breadth of the resource work, the Resource Subgroup was further subdivided into conventional and nonconventional resource groups; the latter was led by Anadarko. The members of the Supply Task Group, whose names are listed in Appendix B, oversaw all of the subgroups.

Based on advice of participants from prior NPC studies, high priority was given to timely completion of the resource and cost estimating work. The Resource Subgroup set out to complete the resource review before the end of 2002. They also concluded that the most efficient way to access industry experts in key North American geologic plays was to hold a series of workshops across the country, inviting the contribution of as broad a group as possible. Industry workshops were held in New Orleans, Denver, Menlo Park, Houston, Calgary, and Reston. In some cases, follow-up workshops were held to reconfirm or modify assessments in light of subsequent model projections of resource development.

The Resource Subgroup further decided that publicly available data from the U.S. Geological Survey, the Minerals Management Service, and the Canadian Gas Potential Committee were the best starting points for an industry review of the resource base. Cooperation by each of these organizations was outstanding. In these workshops, each agency was asked to describe for the group their detailed, play-by-play, resource assessment. This discussion then generated debate and comment from industry experts. In the course of this discussion, consensus emerged regarding any significant modifications that the group felt appropriate for the NPC study. The intent of this work was not to judge an assessment as "right" or "wrong," but rather to develop a "best estimate" that industry could support for modeling purposes. At the same time, key cost drivers, access issues, and technology factors were discussed. All of this information was carefully documented for future use by the appropriate subgroups.

This process facilitated an excellent exchange between industry and government on natural gas resource assessment. Some important lessons were also learned that will lead to better industry and government assessments in the future. The process was essentially complete by year-end 2002. This process is described further in this chapter, with additional details contained in the Resource section of the Supply Task Group Report.

The assessment of technically recoverable resource and cost was an important part of the study, but just as important was the assessment of future production performance based upon an analysis of production history. For each significant producing basin in the United States and Canada, this analysis included the initial production rates, decline rates, and expected reserve recoveries from all gas wells drilled in the past ten years. This information was essential for assessing the production trends of proved reserves and the likely effect of future drilling on the production outlook.

One reason for this interest in production performance was the much-questioned supply response to significantly increased drilling for gas in 2000-2001. These data were used to reconcile the supply response to the drilling activity undertaken. Results of this work are described later in this chapter.

The ability to access resources and obtain timely permits is also a critical factor in determining the future contribution of indigenous resources. The Environmental/Regulatory/Access Subgroup determined early on that their evaluation of this issue needed to go beyond "stipulations" contained in oil and gas leases, to the "conditions of approval" that accompany the development of those leases. A team of experts developed a model of how those conditions impact gas drilling and development. Those results are also described later in this chapter.

Similarly, the effects of technology on future supply development can be significant. The Technology Subgroup chose a workshop process similar to the Resource Subgroup to assess how new technology might help reduce costs and increase recoveries. Many areas of technology were evaluated, including subsurface imaging, drilling and development costs, completions, coal bed methane, deepwater developments, and natural gas hydrates. The projected effects of technology on future gas recovery are significant and described later in this report.

Finally, it was clear that a good assessment of the potential contributions to supply of new, large, long lead-time resources was needed. The LNG and Arctic Subgroups undertook this task. Their work included a comprehensive review of worldwide gas resource availability, an examination of resource development and liquefaction capability together with an assessment of shipping requirements, and regasification needs. Similarly, the potential for major new pipelines to bring Arctic gas to North American markets was reviewed and assessed. These analyses represent the first comprehensive work by the NPC on these new sources. A summary of the results is presented in this report.

This chapter will present the supply outlook developed by the NPC and a summary of the results from each of the subgroups. In addition, the NPC supply outlook will be compared to other public forecasts and the outlook from the NPC 1999 study.

Summary of Supply Outlook

The primary charge of the Supply Task Group was to develop an outlook for natural gas supplies that could meet U.S. demand through the year 2025. To assist in the quantification of this outlook, Energy and Environmental Analysis, Inc. (EEA) was contracted and their Hydrocarbon Supply Model (HSM) employed for the study. The HSM is a computer model that provides a rigorous and consistent framework for analyzing and forecasting natural gas, crude oil, and natural gas liquids supply and cost trends in North America. EEA and the HSM were used in the 1992 and 1999 NPC studies, although the model was enhanced for this study as described in the Supply Task Group Report.

The HSM used input from each of the supply subgroups to calculate the costs of developing new supplies for each of the resource regions. The model then determined which new supply sources to develop, in order of lowest delivered cost, until demand was met through 2025. The cost of the last increment of supply, together with the respective transportation cost, established the end-use price for the gas. The supply outlook that follows is the result of this process.

In addition to the EEA modeling, an NPC group began work on a model based on a license from Altos Management Partners. This effort was designed to supplement the efforts of EEA and to provide a contrasting modeling approach. Additional details on the modeling process are provided later in this report.

Overall Supply Outlook

The total supply outlook for the Reactive Path scenario is illustrated in Figure 4-1. Overall, total supplies grow at an annual rate of 1% through 2025 to keep pace with North American demand for natural gas. During this period, production from the U.S. lower-48 and Canada is projected to remain relatively constant, with the overall growth being met from new Arctic and LNG gas supplies.

This outlook formed the basis for the first supply-related finding:

Finding: Traditional North American producing areas will provide 75% of long-term U.S. gas needs, but will be unable to meet projected demand.

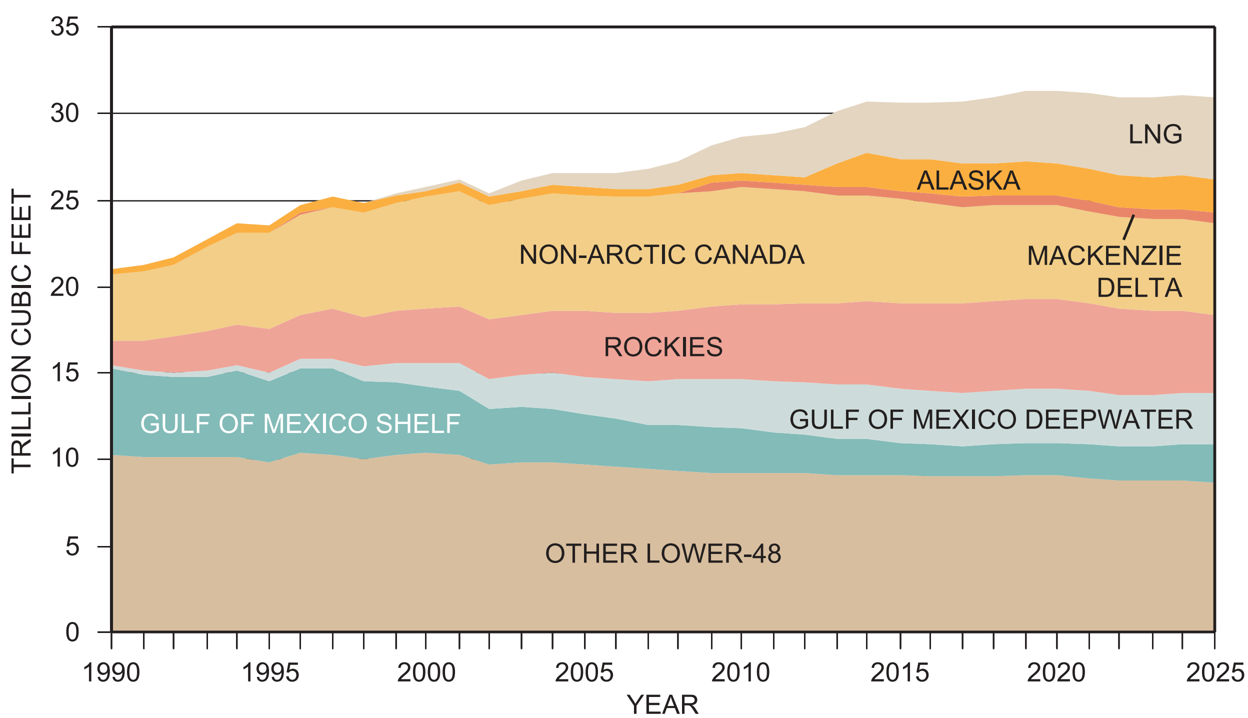


Figure 4-1. Components of North American Supply

The material to follow will provide details on the analysis that supports this finding.

The largest component of North American supply remains traditional supply sources in the United States and Canada. These sources supply almost 100% of U.S. and Canadian demand today, and are expected to still represent over 75% of demand in 2025, as production levels are maintained in the robust price environment contemplated by the Reactive Path scenario. In the U.S. lower-48, growth in the Rockies and deepwater Gulf of Mexico is offsetting declines in virtually all other U.S. mature basins. In Canada, production from the Western Canada Sedimentary Basin is also expected to decline throughout the study period, with some increase from offshore Eastern Canada.

The Arctic supply results from new pipelines from Mackenzie Delta and Alaska. Mackenzie Delta is assumed to come on stream at 1 billion cubic feet per day (BCF/D) in 2009 and expanded to 1.5 BCF/D in 2015. The outlook for Alaska is for production to start in 2013, reaching 4 BCF/D capacity in 2014. In total, the new Arctic supplies will contribute about 8% of North American supply by 2025.

Small volumes of LNG are currently imported into the United States, providing 1% of North American supply. The outlook in the Reactive Path scenario is for LNG imports to grow to 12.5 BCF/D by 2025, providing 12% of North American supply. This assumes that the 4 existing U.S. regasification terminals are fully utilized by 2007, and that 7 new terminals will be built. In addition, 7 of these 11 terminals will be expanded.

Although it is based upon the best available data and expertise, the overall supply outlook has inherent uncertainty. A number of factors can significantly affect production forecasts from North American indigenous sources. For example, there is uncertainty in the estimated size of the undiscovered resource base. In addition, the predicted rate at which technology will grow and contribute to production is uncertain. And finally, the commercial factors that will influence future drilling activity and subsequent production are highly variable.

In order to quantify uncertainty in the factors influencing future production, model sensitivities were run to bracket the range of possible outcomes. These are described later in this chapter.

A key issue in this projection of future production is that North America has never experienced a sustained price environment like the one anticipated by the Reactive Path scenario. In this new environment, the use of past experiences to project the future will be less reliable. Econometric models can help to describe plausible, internally consistent futures; but of themselves, they do not create more reliable predictions than the experts who provide data for the models.

In the Reactive Path supply outlook, the volumes of Arctic gas and LNG were fixed based on capacity and start-up timing described above. The lower-48 and Canadian production outlook was the result of modeling supply/demand balance. The overall size of the resource base plays a central role in determining the model's output, but there are several other key considerations. These include the costs to develop the resource, the production characteristics of the resource, technology improvements that lower costs and improve recovery, assumptions regarding access to the resource base, drilling activity levels, and reserve development pace. A discussion of these items follows.

Resource Base

The technical resource base identifies that volume of natural gas that is technically recoverable without regard for costs or price. The technical resource base was determined through an extensive workshop process involving a wide cross-section of industry experts. These workshops covered 72 regions of the United States, Canada, and Mexico, which were consolidated into 17 "super-regions" as shown in Figure 4-2.

The NPC's assessment of the most likely technically recoverable resource volume for North America that resulted from that process are annotated on the map, with additional details shown in Table 4-1.

The resource base is described for proved reserves that can be produced from existing wells, growth to proved reserves in existing fields, and undiscovered conventional and nonconventional (tight gas, coal bed methane, and shale gas) potential.

The assumptions of technology advancements play a key role in this assessment. Improvements in recovery, exploration tools, and other areas will increase the resource base as shown in the Table 4-2. The technical resource is shown for technology advances through 2015 for comparison to the 1999 NPC study, as well as technology advances through to 2030. Details of the

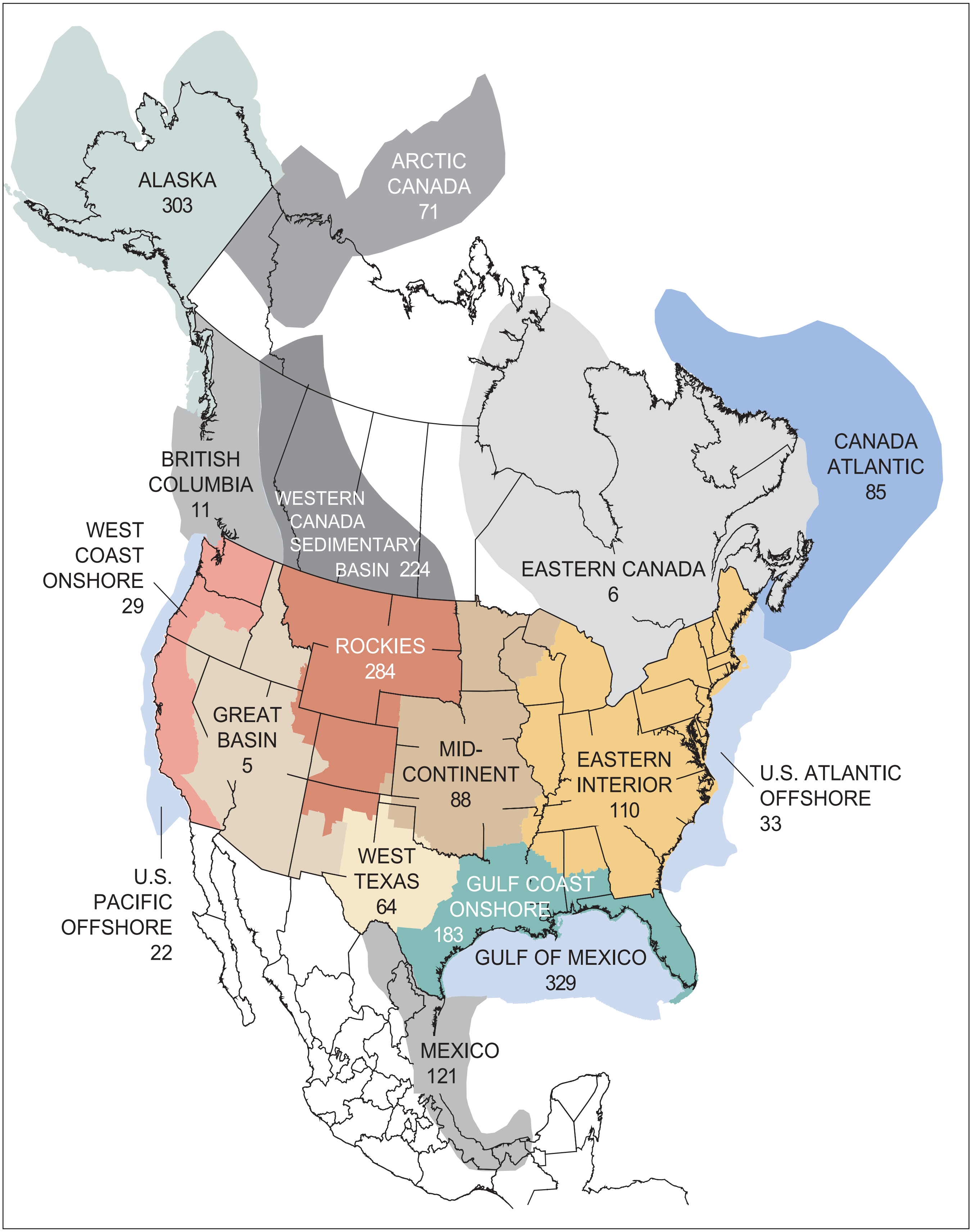


Figure 4-2. Super-Region Technical Resources (Trillion Cubic Feet)

	Proved Reserves (as of Dec. 2001)	Growth* to Proved Reserves	Undiscovered Conventional Potential	Undiscovered Non-conventional Potential	Total Technical Resource
Lower-48 Onshore	145	148	189	282	764
Lower-48 Offshore	30	57	298	0	384
Alaska	9	36	201	57	303
United States	**184**	**241**	**687**	**339**	**1,451**
Canada	**60**	**69**	**219**	**50**	**397**
Mexico	**28**	**22**	**70**	**0**	**121**
North America	**272**	**332**	**976**	**389**	**1,969**

*Includes 55 TCF of discovered non-proved.

Table 4-1. North American Technical Resource Base – Current Technology (Trillion Cubic Feet)

	Current Technology	2015 Technology	2030 Technology
Lower-48 Onshore	764	839	1006
Lower-48 Offshore	384	415	486
Alaska	303	331	395
United States	**1,451**	**1,585**	**1,887**
Canada	**397**	**420**	**475**
Mexico	**121**	**130**	**147**
North America	**1,969**	**2,135**	**2,508**

Table 4-2. Impact of Technology Improvement on the Resource Base (Trillion Cubic Feet)

basis for the technology improvement factors are provided in the Technology Improvements section of this chapter.

The technical resource base is compared to previous NPC studies and the USGS/MMS assessments in Figure 4-3. This comparison is based on advanced technology through 2015. For the U.S. lower-48, the technical resource of 1,250 trillion cubic feet (TCF) is 14% (210 TCF) lower than the 1999 study. Half of this reduction is in the growth to proved reserves category. Similar methodologies were employed to estimate the volume of growth resource, but lower expected recoveries were used in this study in line with recent experience. The reduction from the USGS/MMS reference assessment is primarily from lower nonconventional potential.

The overall North American assessment is also lower than the 1999 and 1992 NPC studies (see Figure 4-4). The Canadian assessment is lower than the 1999 study based on lower potential assessed for the Arctic region

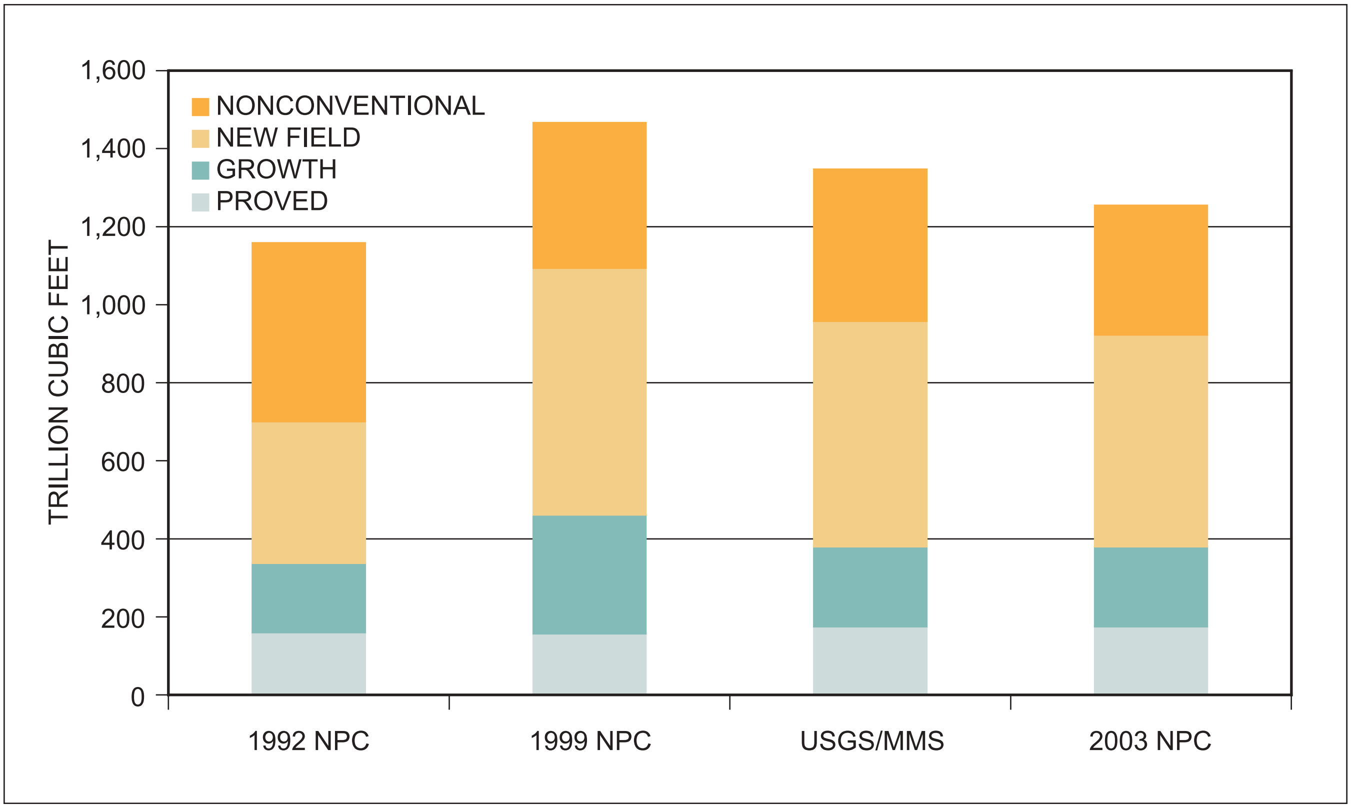


Figure 4-3. Lower-48 Mean Assessment – 1999 Base, Advanced Technology

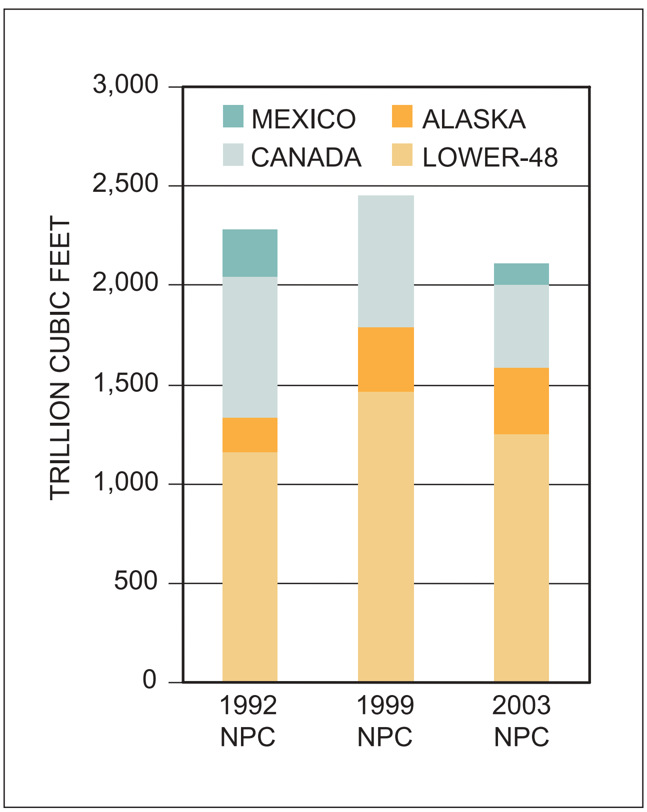


Figure 4-4. North American Mean Assessment 1999 Base, Advanced Technology

and a lower nonconventional assessment for the Western Canada Sedimentary Basin. There was no Mexican assessment made in the 1999 study, but the current assessment is about half of the 1992 study as a result of lower assessed undiscovered potential and a lower current level of proved reserves.

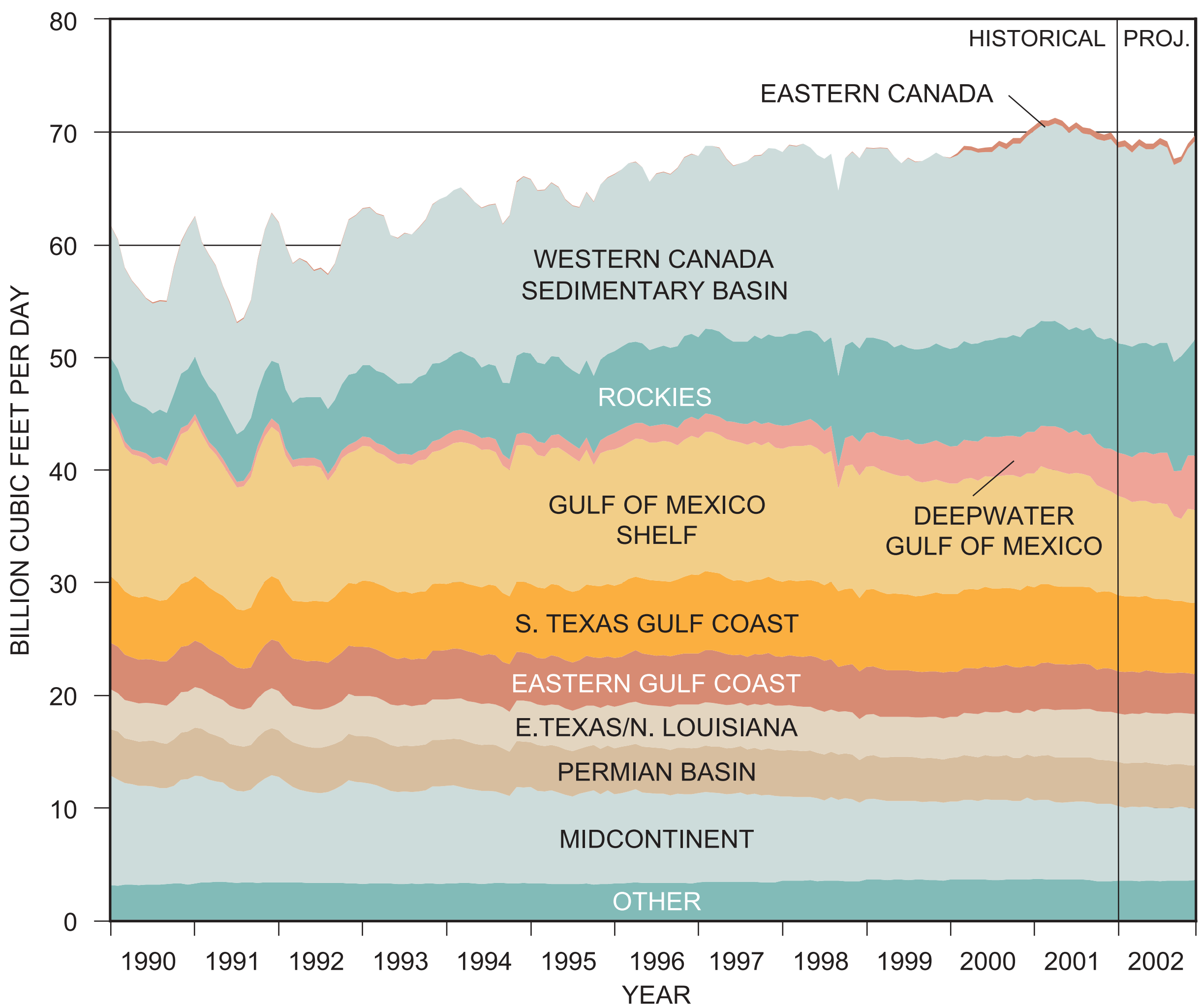
Given the uncertainty associated with estimating the technical resource base, low and high cases were developed to define the range. The low end of the resource range is defined as P90, which means there is a 90% probability of that volume actually being found. The high end is defined as P10, which means there is only a 10% chance of that volume being found. The P10 and P90 values bracket the mean, which represents the best estimate of resource volume. The NPC defined the P10 as 135% of the mean and the P90 as 70% of the mean. This resource range was used to evaluate the impact on the production outlook and will be discussed further in the sensitivity section.

Production Performance

A key aspect of the NPC resource study was an evaluation of the production performance of existing U.S. and Canadian basins from 1990 to the present. This analysis looked at the performance of individual gas wells drilled over the period, determining initial production rates, initial decline rates, and expected recoveries per well. Also evaluated were base production decline trends and the production response to increased drilling activity. The results of this analysis were used to estimate future well performance parameters and calibrate the HSM model results.

Some of the key observations from the analysis are as follows:

- While North American production grew 11 BCF/D (1.8% per year) between 1990 and 2002, growth slowed dramatically after 1996, as shown in Figure 4-5. Growth in the lower-48 Rocky Mountains, deepwater Gulf of Mexico, and more recently, East Texas/North Louisiana has been offset by production losses in the other regions, particularly the Gulf of Mexico shelf and Midcontinent. Canadian production growth, which comprised 65% of the total growth since 1990, slowed dramatically and began to decline, even as the number of Canadian gas well completions more than tripled.
- Conventional gas production in the U.S. lower-48 has been declining since 1990 and nonconventional production (tight gas, coal bed methane, and shale gas) has doubled from 12% to 25% of production, as shown in Figure 4-6. Aside from the deepwater Gulf of Mexico, the only U.S. basins maintaining sustain-



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure 4-5. U.S. Lower-48 and Canadian Production by Region

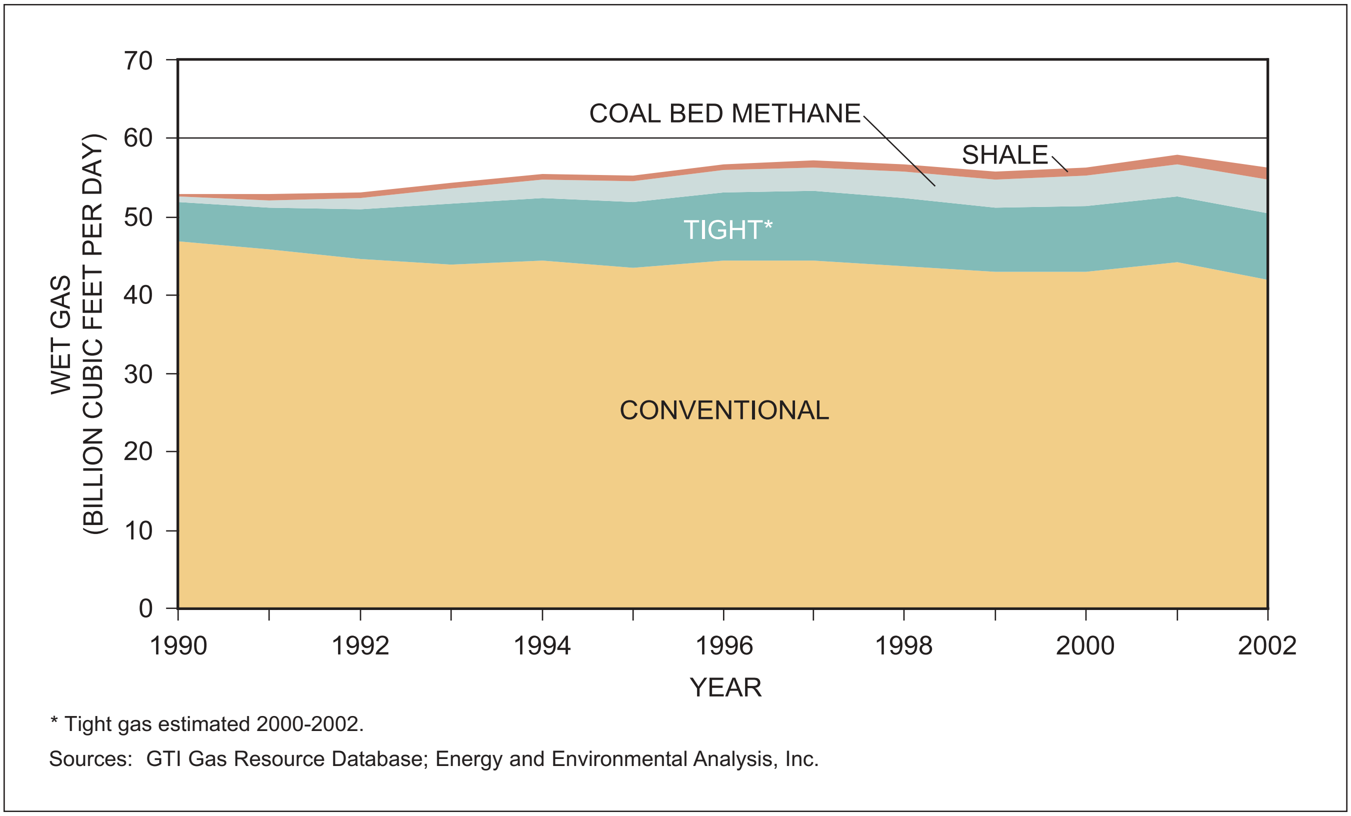


Figure 4-6. Lower-48 Wet Gas Production by Resource Type

able production increases (Rockies, East Texas/North Louisiana) have being driven by increased nonconventional production.

- Average estimated ultimate recovery (EUR) per gas connection in the U.S. lower-48, excluding nonconventional and the deepwater Gulf of Mexico, fell 15% between 1990 and 1999 as the resource base matured and technology gains and higher prices made smaller prospects economic. As drilling ramped up in response to the 2000-2001 price spike, average EUR fell a further 18%, as more marginal wells were drilled. Western Canadian average EUR has fallen dramatically as the basin has matured and the industry concentrated on lower-risk, shallow-depth drilling (see Figure 4-7).

- Initial Production Rates (IPs) increased markedly through the early to mid-1990s, helping the industry to maintain production rates, as the industry employed technology to accelerate production and improve drilling economics. Increases in IPs flattened in the latter part of the 1990s as per-well reserves fell and fracture technology implementation neared saturation level in most basins. Declining EURs and increasing IPs have resulted in steepening initial well decline rates.

- As more and more high decline wells have been added to base production, base decline rates have steadily risen. Figure 4-8 shows that the decline rate of lower-48 base production has increased to over 25%, from just over 15% in the early 1990s. Just to maintain production levels requires first year production from new wells of 12-13 BCF/D, up from 8 BCF/D in 1992. Western Canada has shown a similar increase in base decline.

- Industry responded aggressively to the 2000-2001 price spike, with the gas rig count climbing to an all-time high over 1,050 as shown in Figure 4-9. The incremental activity yielded a limited production response as: (1) the resource base continued to mature, (2) additional drilling yielded very low marginal results, (3) much of the incremental activity occurred in low rate regions, (4) gains from completion/stimulation technology slowed, (5) base decline rates continued to increase, (6) higher gas prices made it possible to drill lower quality prospects, and (7) rig efficiency declined.

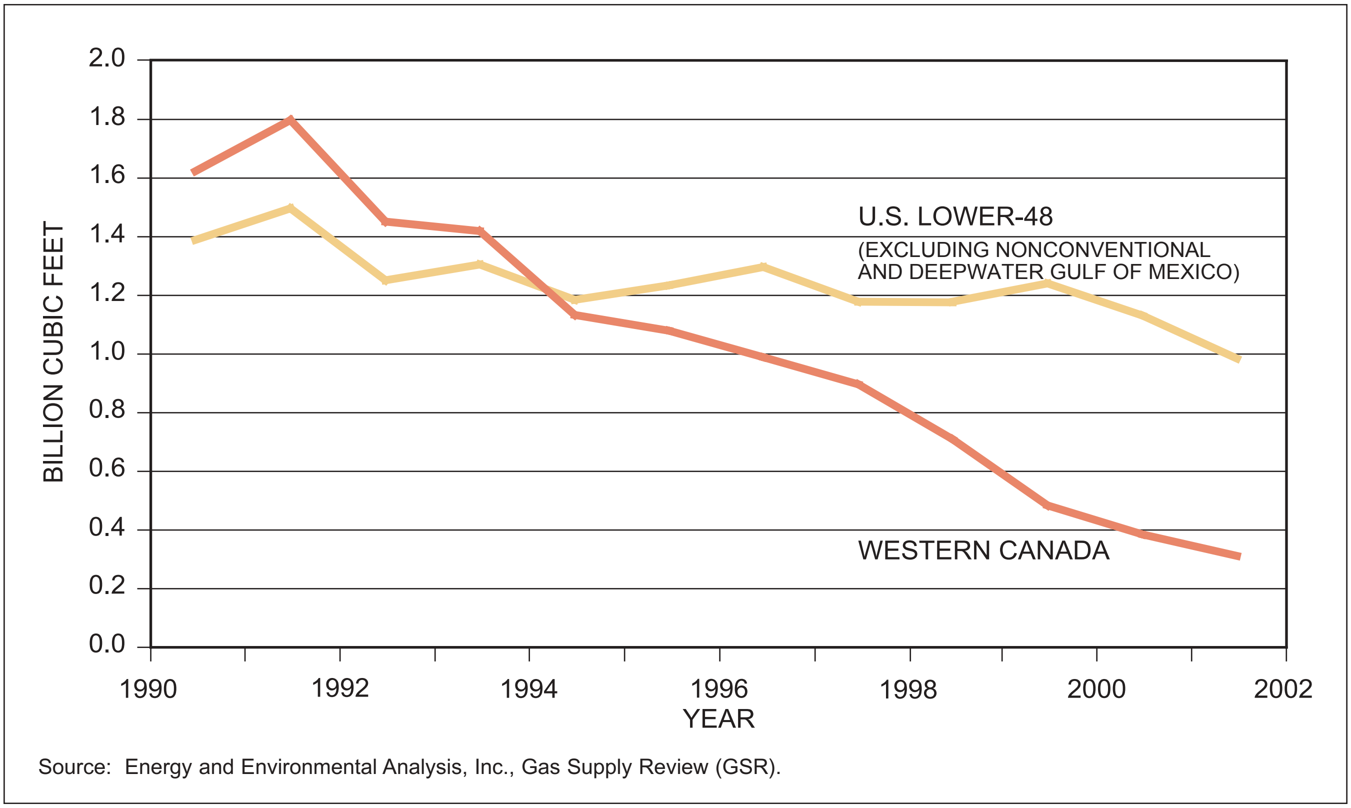


Figure 4-7. Recovery per Gas Connection

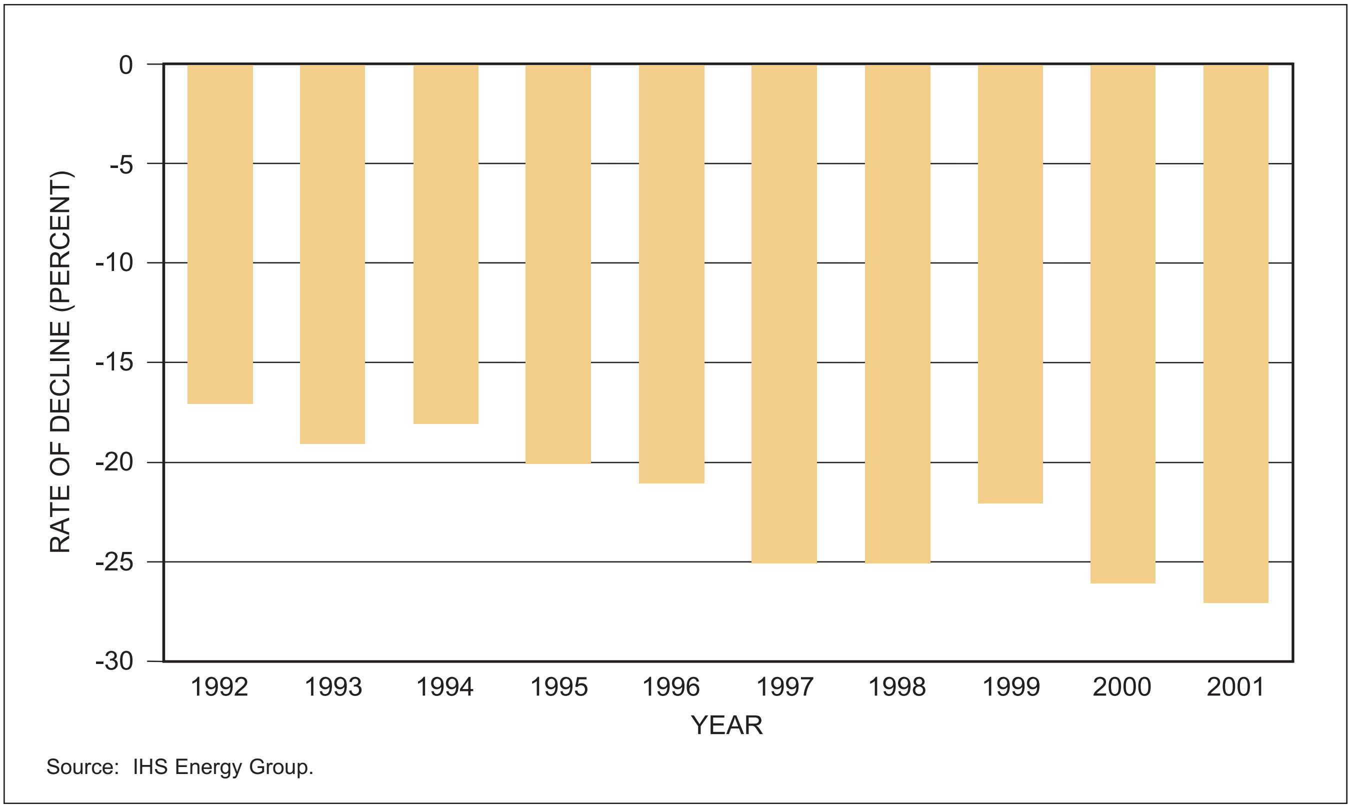


Figure 4-8. Lower-48 Base Production Decline Rates

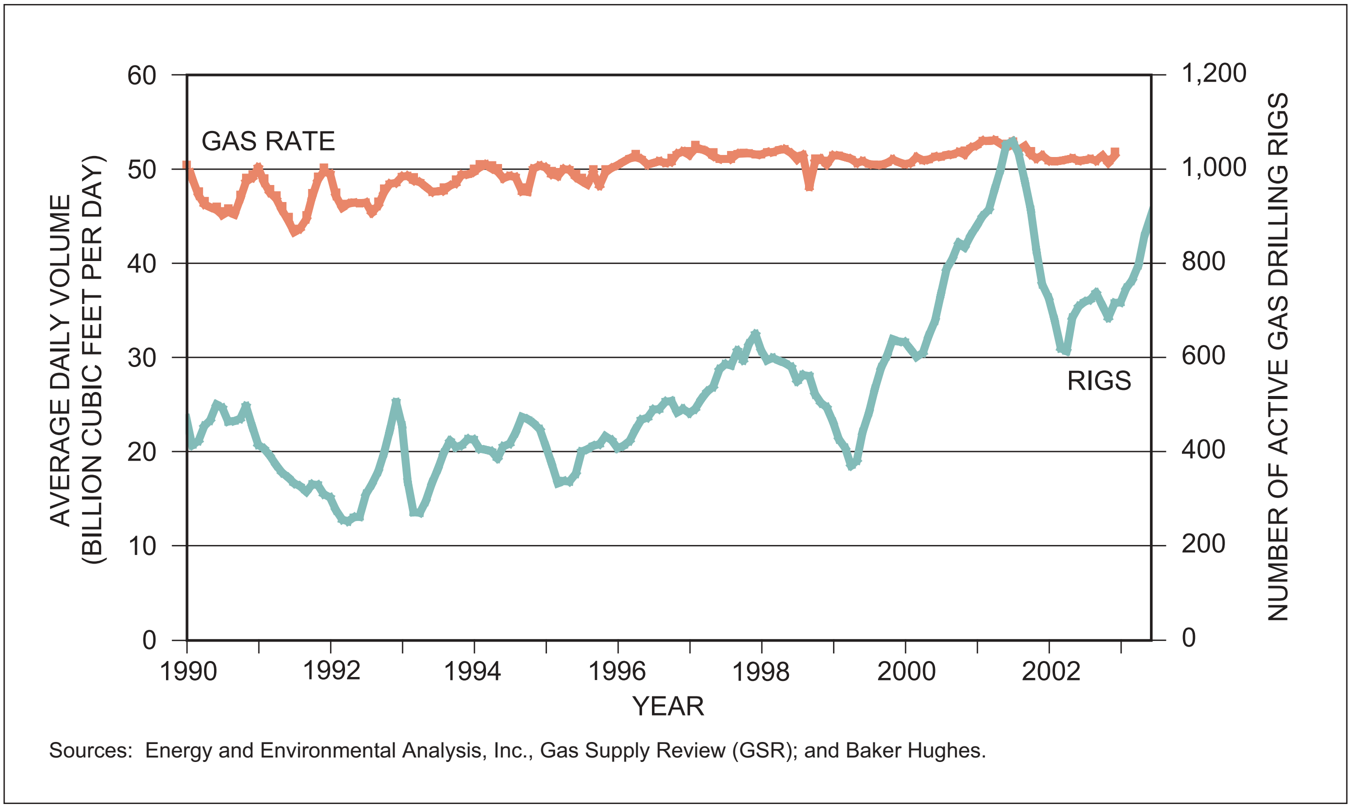


Figure 4-9. Monthly Lower-48 Gas Production

Development Costs and Technology Improvements

The costs to develop the technical resource, including exploration and development drilling, production facilities, and operating and maintenance, were developed and provided as input to the econometric modeling effort. Public and commercial databases, from sources such as American Petroleum Institute and Energy Information Administration, were used as the reference for estimating the costs. The costs were discussed at the regional resource workshops and benchmarked against the experiences of various industry representatives. Costs were developed for each of the main resource regions and for different depth intervals to match the granularity of the resource description. Overall, the estimated costs were similar to the 1999 study, with the primary difference being higher drilling costs for deeper reservoirs.

In addition to developing detailed costs, the rate of drilling rig attrition was evaluated and an estimate made of future rig availability. Industry input on this evaluation led to a significantly lower rate of attrition than assumed in the 1999 study. The view was that in a robust price environment significant efforts would be expected to keep rigs working. Ultimately, the rig attrition is used to determine the number of new rigs, and the corresponding costs, required to support the projected drilling activity levels.

As was discussed earlier, assumptions of improving technology increase the technical resource base assessment by 8 to 27%. In addition, the technology improvement factors developed by the Technology Subgroup also enhance the ability to commercialize the technical resource. Factors such as drilling and completion costs and recovery per well are estimated to improve with time, thus increasing the volume of commercial resource. As a result of the technology improvements assumed in the Reactive Path scenario, the overall level of gas production in 2025 is 14% higher than if no improvements were included.

Additional details on cost development and technology improvement can be found later in this chapter, with detailed study results contained in the Supply Task Group Report.

Commercial Resource

While the technical resource base represents the potential available natural gas resource, calculating how much of that resource can be commercial and at what price will ultimately determine the volume of natural gas that can be developed. Utilizing the drilling, development, and operating costs estimates, the technology improvement factors, and the production performance parameters, the model calculates the volume of natural gas that can be commercially developed at any given price. Figure 4-10 shows the volume of lower-48 resource that is commercial at three different price thresholds. This shows that 760 TCF, or 60% of the total technical resource (advanced technology), can be commercial at a $4.00 per million Btu (MMBtu) price (wellhead price, 2002 dollars).

This relationship of commercial to technical resource can also be illustrated with a cost-of-supply curve as shown in Figure 4-11. This plot shows the volume of lower-48 natural gas that is commercial to develop as a function of price and for the range of assessed technical resource. Proved reserves are excluded from these curves since they are the same for each of the resource curves.

The curve for the mean assessment shows that at a price of $4/MMBtu, 585 TCF, or 55% of the unproven technical resource base, can ultimately be commercially produced. This compares to the 760 TCF shown in Figure 4-10 that includes proved reserves. The curves for the P10 and P90 resource base represent the probabilistic range of the lower-48 resource assessed by the NPC. It should be noted that while these commercial volumes may appear large in relation to current U.S. annual production (18 TCF), it will take many decades for these resources to ultimately be produced. The vast majority of this resource base will be produced from fields that have yet to be found and from wells that have yet to be drilled.

Similar curves were developed for each of the producing regions. The commercial potential varies significantly by region, as illustrated in Figure 4-12. Factors such as resource quality, undiscovered field size distributions, and development costs determine the shape of the supply curve. For example, the Midcontinent and Gulf Coast regions tend to have higher quality reservoirs that allow for a relatively high percentage of technical resource to be commercial. On the other hand, the Rocky Mountain and Eastern Interior areas, are dominated by nonconventional resources, which are poorer quality and thus higher cost supplies.

The volumes of technical resource that can be commercial will also vary significantly by resource type as

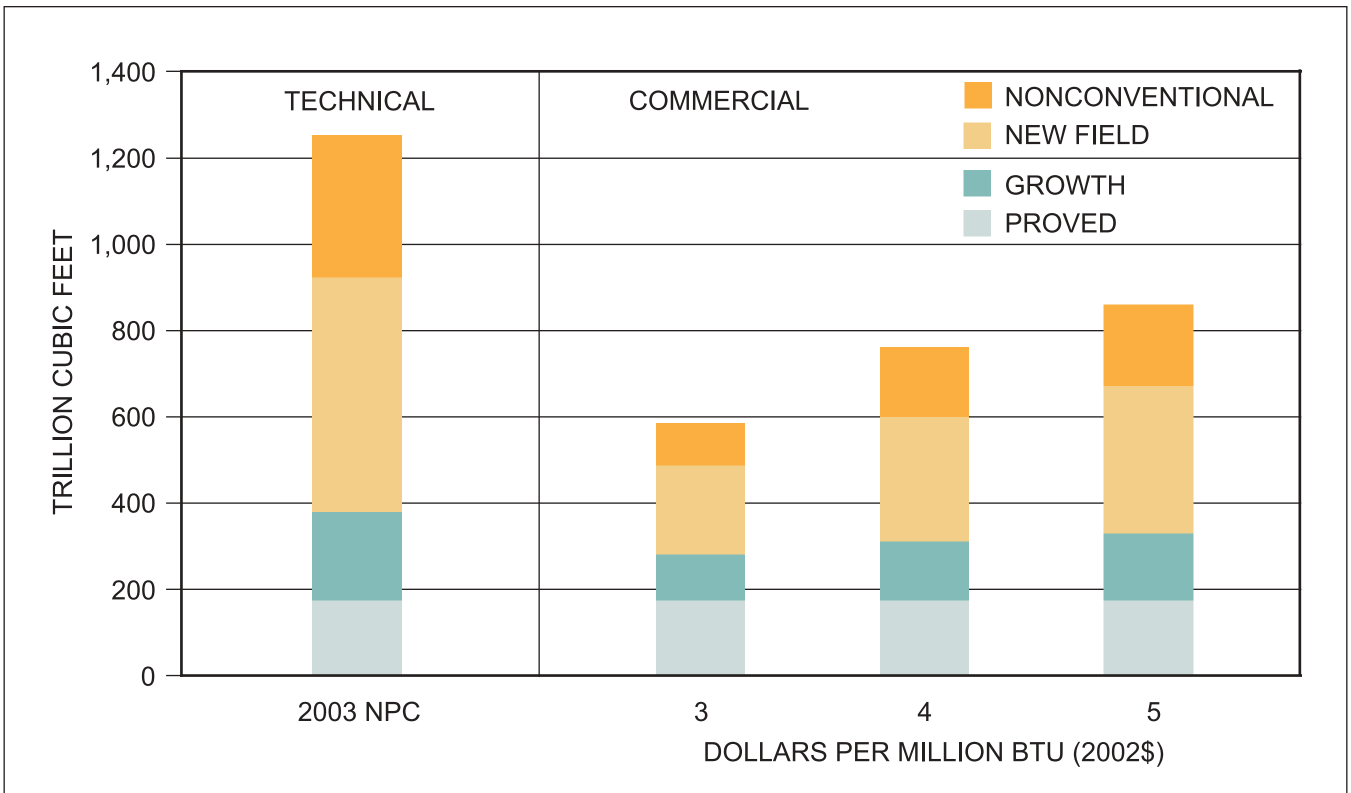


Figure 4-10. Lower-48 Technical Resource vs. Commercial Resource

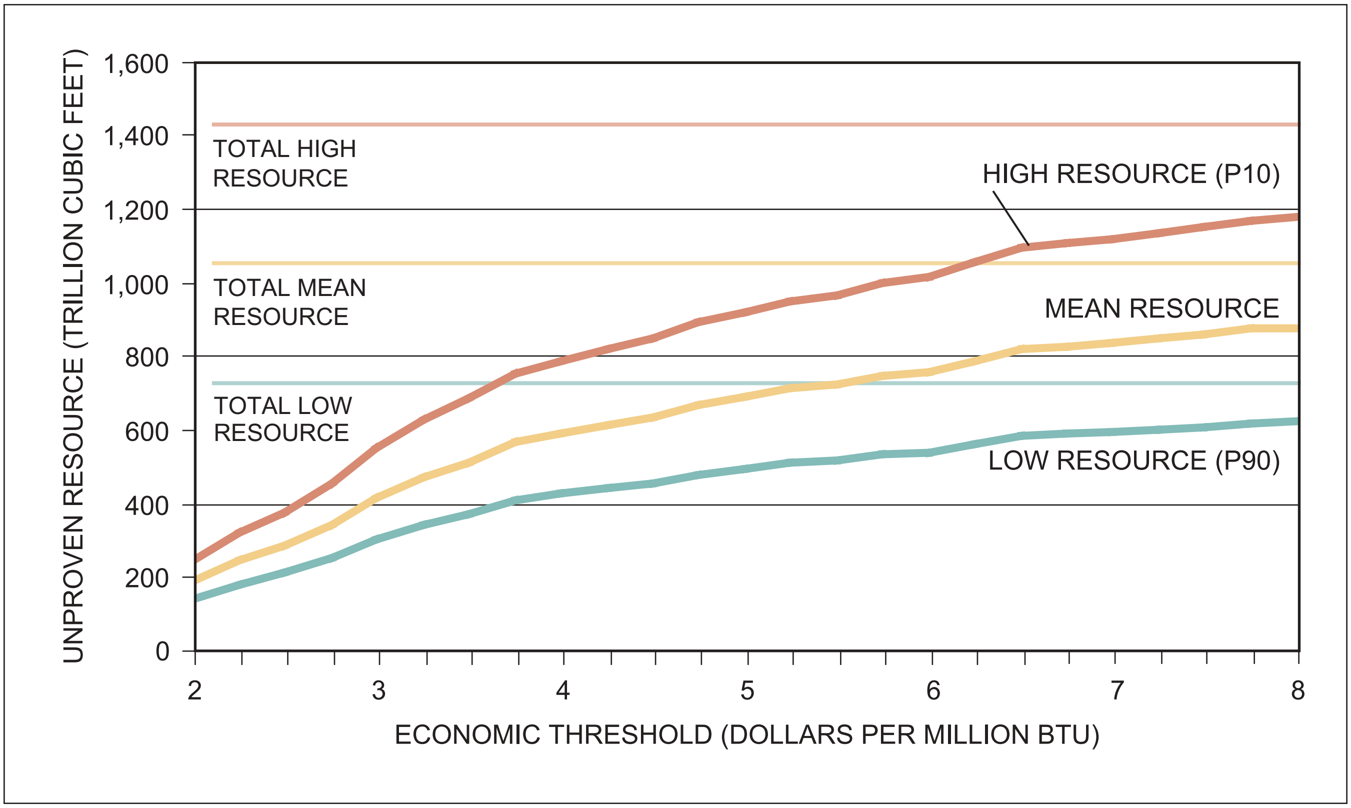


Figure 4-11. Cost-of-Supply Curves for Lower-48 Resource Range

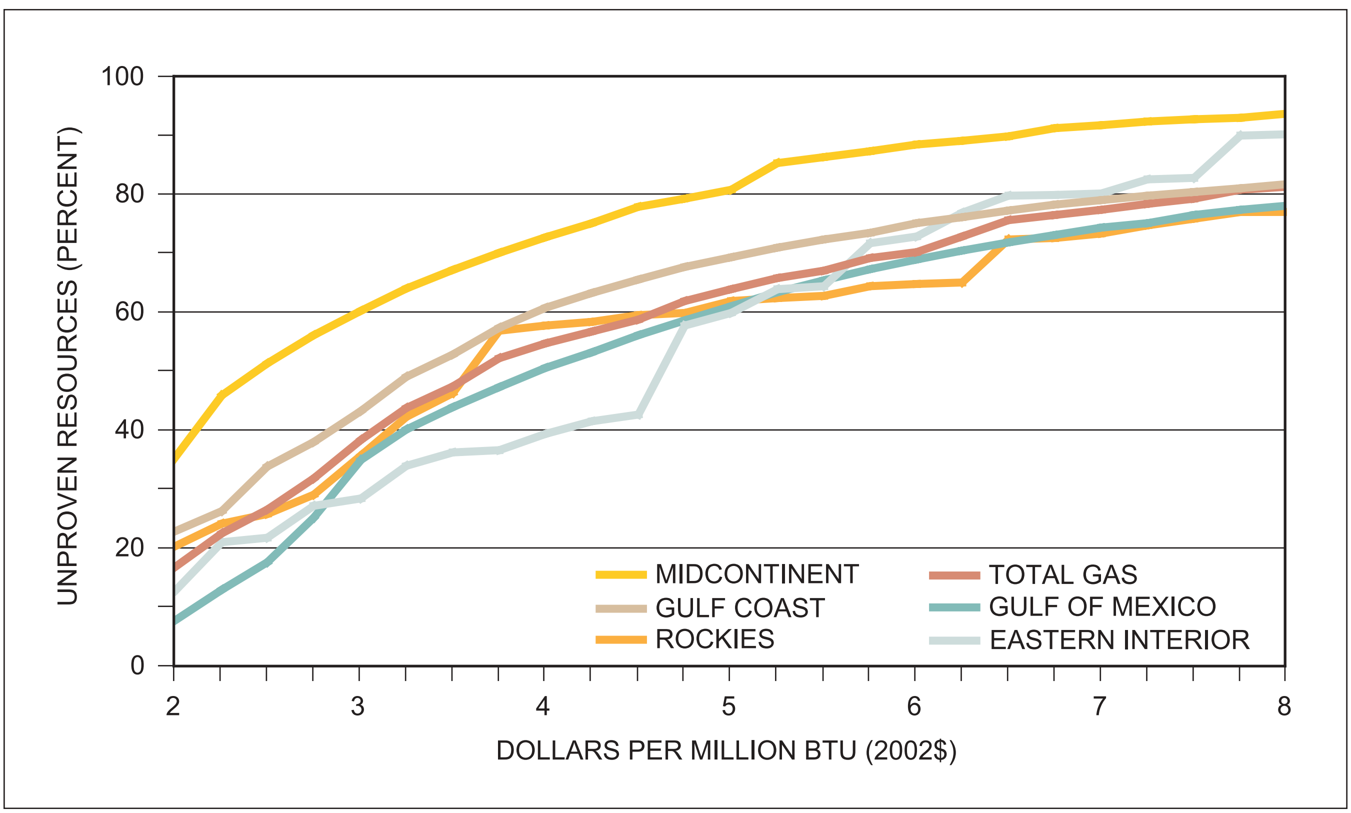


Figure 4-12. Cost-of-Supply Curves by Lower-48 Region

shown in Figure 4-13. A larger percentage of growth technical resource can be commercial than new fields or nonconventional technical resources. This is a result of the growth resource requiring primarily lower risk drilling in producing fields to develop and thus having a lower cost.

Following supply cost development, the econometric model was used to project future U.S. and Canadian production required to meet expected demand. That production outlook will be discussed next.

North American Production Outlook

Future North American natural gas supply can be characterized by three components. The first is production from traditional areas in the U.S. lower-48, Canada, and Mexico. The second comprises the Arctic areas of Alaska and Canada. And the third source of supply is imported LNG. Arctic and LNG supplies are discussed in a subsequent section of this chapter.

Mexico's current production is less than 2 TCF/year, but is expected to grow significantly. However, demand is projected to outpace supply, so that Mexico will remain a net natural gas importer through 2025. Future supply and demand were not modeled in detail for Mexico, although the net supply/demand balance was incorporated into the econometric model and is discussed in more detail in Chapter Six.

This section reviews the production outlook for the U.S. lower-48 and non-Arctic Canada in the context of the Reactive Path scenario. For supply, this includes the Mean resource assessment and incorporates the expected technology improvement factors. Access to indigenous resources is assumed to be unchanged, with the existing Outer Continental Shelf (OCS) moratoria not lifted and leasing and permitting restrictions in the Rocky Mountain region continued, although the permitting process is assumed to improve to allow a continued high level of drilling activity. The resulting production outlook for the United States and Canada (excluding new Arctic developments) is shown in Figure 4-14.

North American gas production grew rapidly in the early-1990s, as the industry was deregulated. Growth rates slowed considerably in the mid-1990s through the early-2000s, as excess productive capacity was gradually eroded. Production peaked in 2001 following major drilling ramp-ups in the United States and Canada, and have since declined.

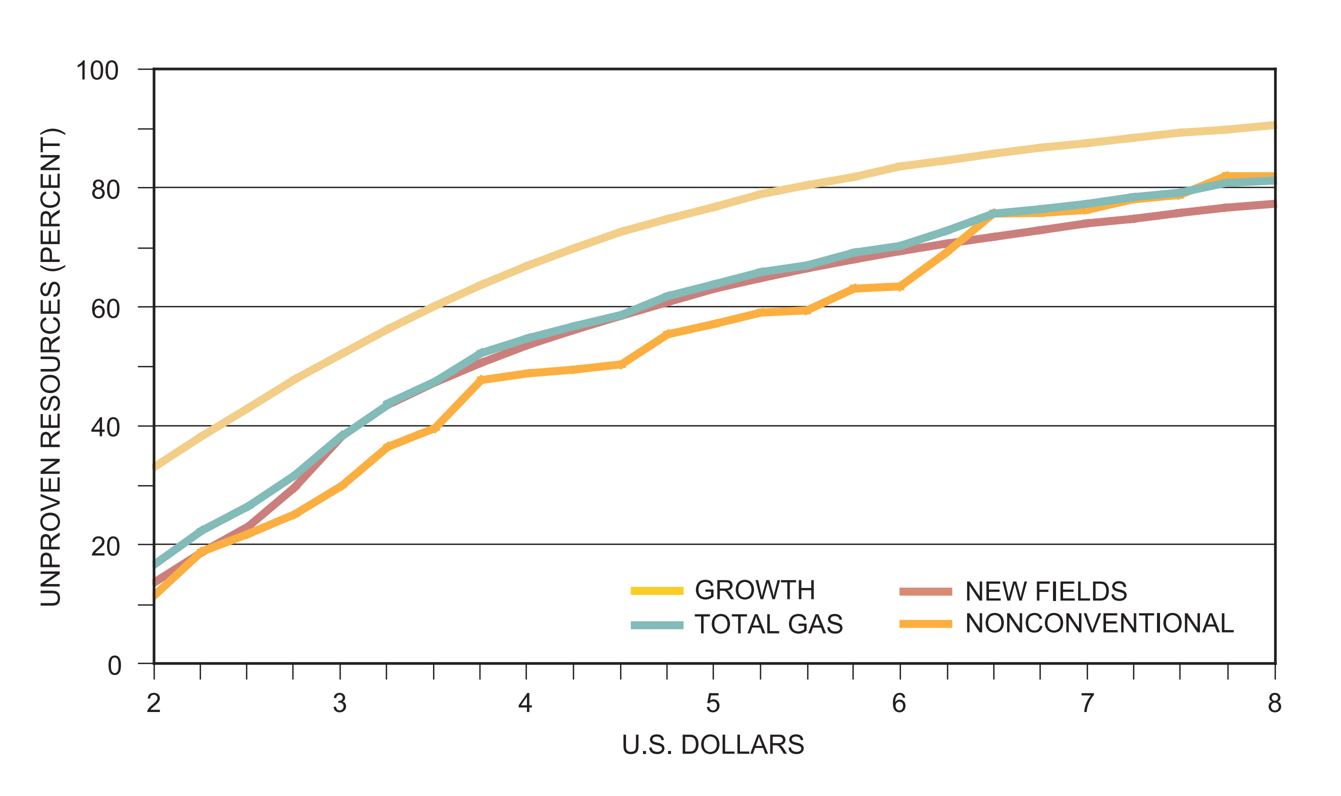


Figure 4-13. Cost-of-Supply Curves by Resource Type

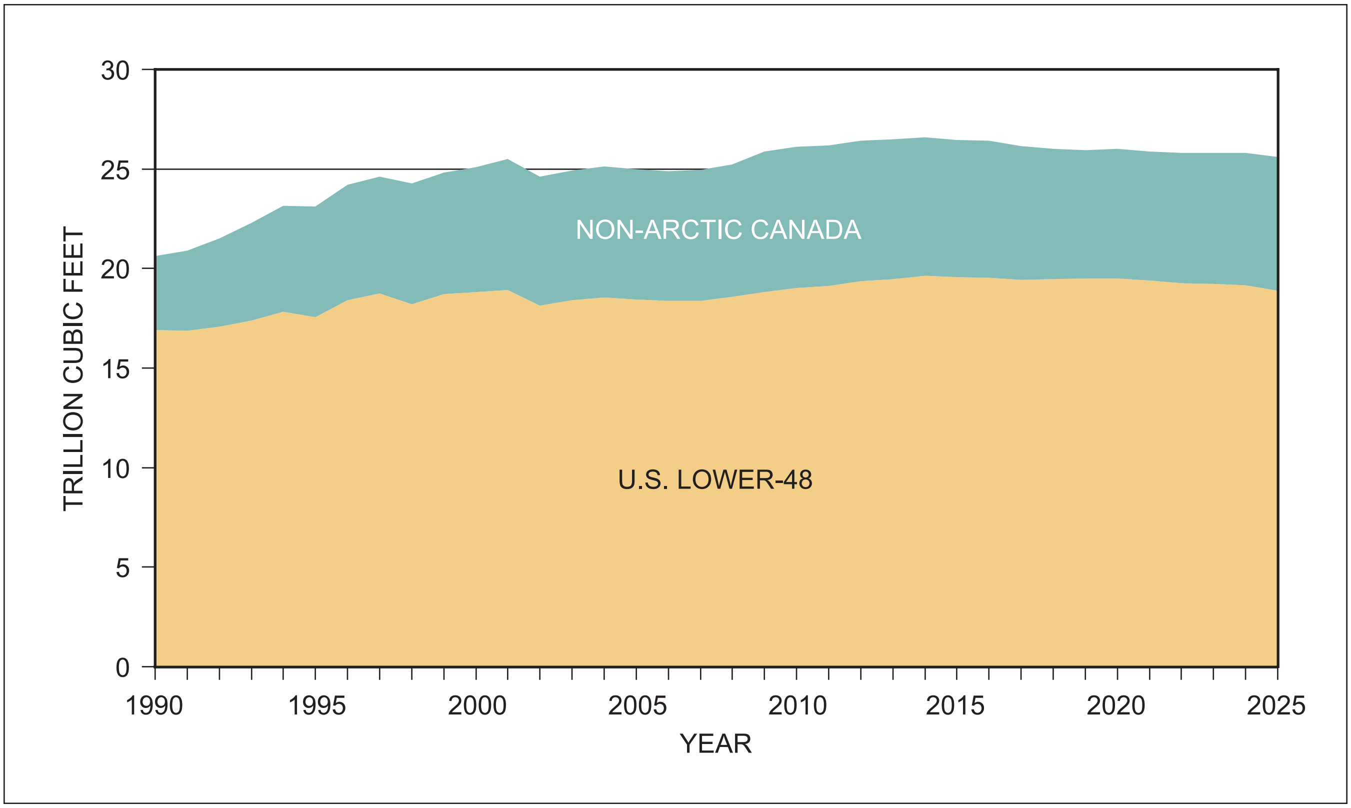


Figure 4-14. U.S. Lower-48 and Non-Arctic Canada Production Outlook

Looking ahead, in the absence of new Arctic sources, the outlook is for generally flat production through 2025 assuming a robust price environment. Individually, both the U.S. lower-48 and non-Arctic Canada are expected to have flat production levels, as the traditional producing areas in the U.S. lower-48 and Canada continue to mature.

Production is continuing to shift from declining conventional gas production to nonconventional sources (tight gas, coal bed methane, and shale gas) as shown in Figure 4-15. The ability to continue growing nonconventional production will be critical to sustaining production levels.

The next two sections contain more details of the U.S. lower-48 and non-Arctic Canada production outlooks.

U.S. Lower-48 Production Outlook

Looking forward, the ability to maintain the pace of new drilling and development activity will play a critical role in sustaining gas supplies. Declines from existing reserves have gradually become steeper, with current base decline rates of over 25% in the first year. Production from existing wells will drop by over 50% from 2000 to 2005. In order to offset these declines, new wells will be required to develop additional resources in the growth, undiscovered conventional, and undiscovered nonconventional categories, as shown in Figure 4-16.

Historically, through improvements in technology and effective development programs, industry has successfully increased recovery from producing fields and "grown" the reserves that are ultimately produced. As Figure 4-16 illustrates, these expected resources represent more reserves than are currently categorized as proved by the industry. Growth remains a large and important low-cost wedge of future reserves and production.

Production from undiscovered conventional fields represents the single largest source of new supply in the NPC outlook. In a tight market environment, significant exploration will occur for resources undiscovered today. Although these future resources will be increasingly small, deep, and of poorer quality, many will be commercially viable in a higher price environment.

The growing contribution to supply from nonconventional resources is projected to offset the production

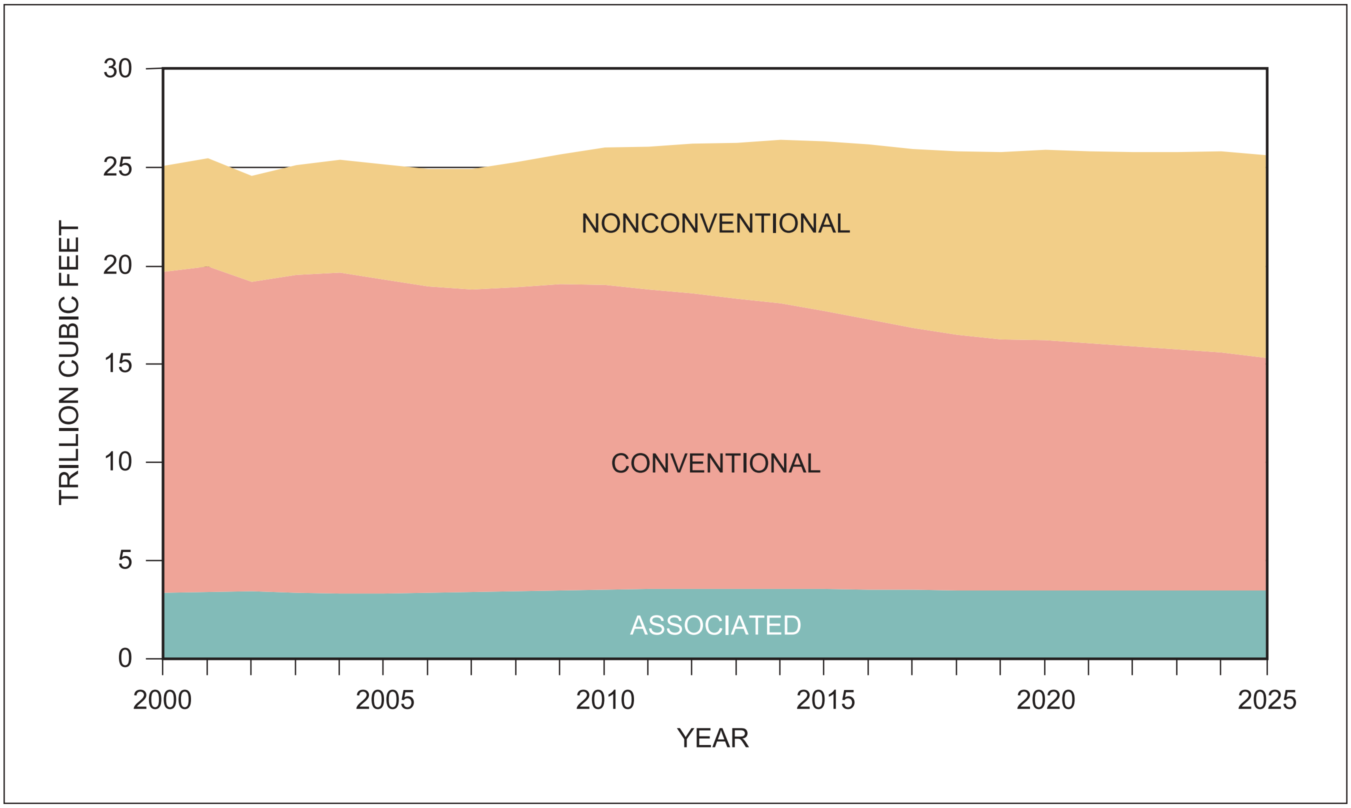


Figure 4-15. U.S. Lower-48 and Non-Arctic Canada Gas Production by Type

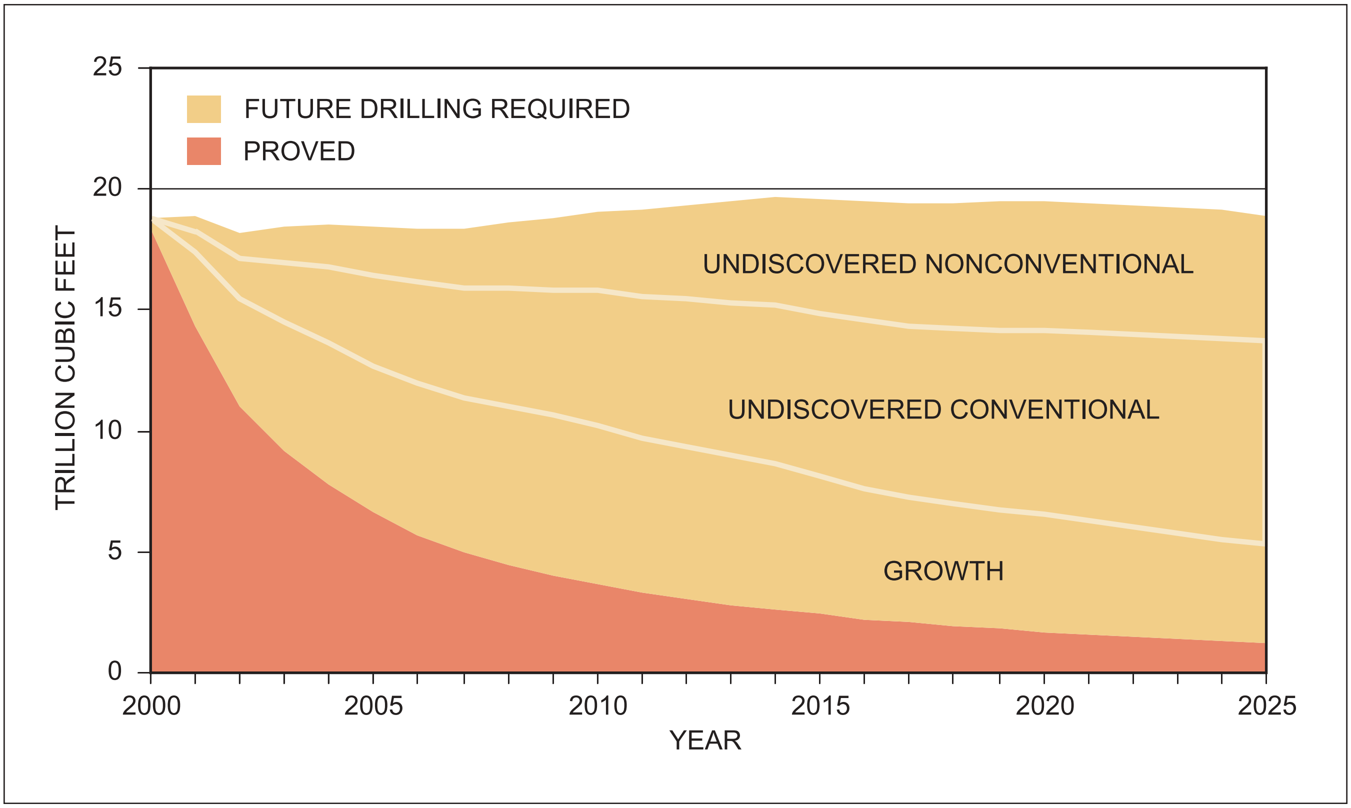


Figure 4-16. Lower-48 Production by Resource Category

decline from conventional sources (proved, growth, and undiscovered conventional in Figure 4-16) in a robust price environment. The increase in production from this segment reflects access to and development of large nonconventional resources, particularly in the Rocky Mountain region.

Lower-48 production was also evaluated by major supply regions. Figure 4-17 shows historical production from 1990 and the projections for the Reactive Path scenario though 2025. The large producing regions, Gulf of Mexico shelf, Midcontinent, Permian Basin, South Texas, and East Texas are all projected to experience production declines. These regions are becoming increasingly mature. Future drilling, while expected to continue at high levels, will be targeting smaller reservoirs, with lower initial production rates and lower reserves per well.

Offsetting this decline will be increasing production from nonconventional resources and deepwater Gulf of Mexico. Nonconventional resources represent over 35% of the undiscovered potential and technology advances and the robust price outlook in the Reactive Path scenario make more of this resource commercial to develop. The Rocky Mountain region contains the majority of the nonconventional resource and production is projected to grow by 50% by 2020. Increasing nonconventional production is also projected for the Eastern Interior.

Production from the deepwater Gulf of Mexico made this area the fastest growing region during the 1990s. This increase is expected to continue, although at an overall slower pace. It should be noted that the areas of projected production growth are less mature than the declining regions and therefore have a greater uncertainty in resource base size.

The supply outlook developed is an aggregate of individual supply regions and individual wells within those regions, all of which are required to meet expected demand for natural gas. The Reactive Path scenario establishes a supply/demand balance and a price for natural gas required to achieve that balance. While this price level ultimately determines the volume of gas that can be commercially developed, an assessment was also made of the supply volumes that would be developed at varying prices. Figure 4-18 depicts the volume of lower-48 supply that would be developed at three different price levels. For example, if the price outlook for natural gas was a constant $3/MMBtu, lower-48 production is projected to continually decline through 2025. This is a result of insufficient supply being available at that

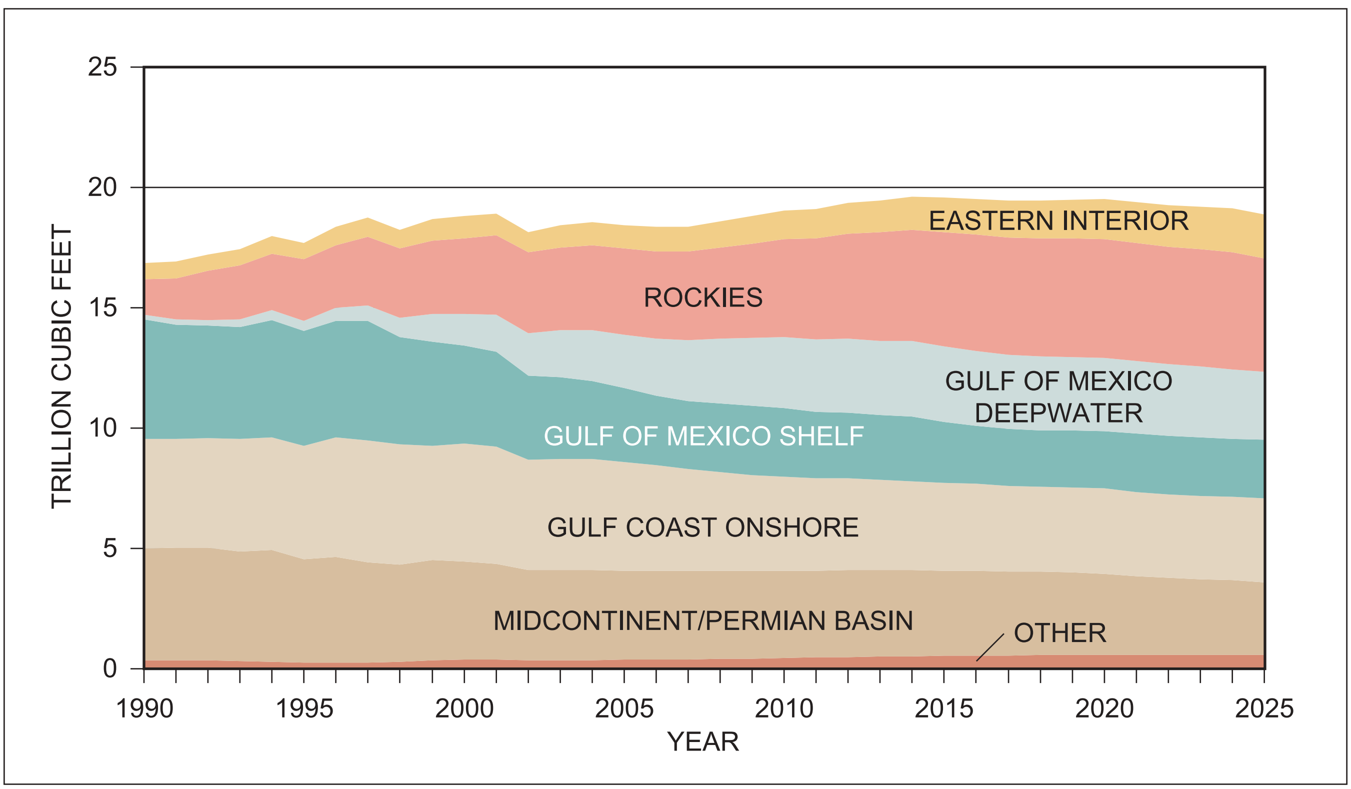


Figure 4-17. Lower-48 Production by Region

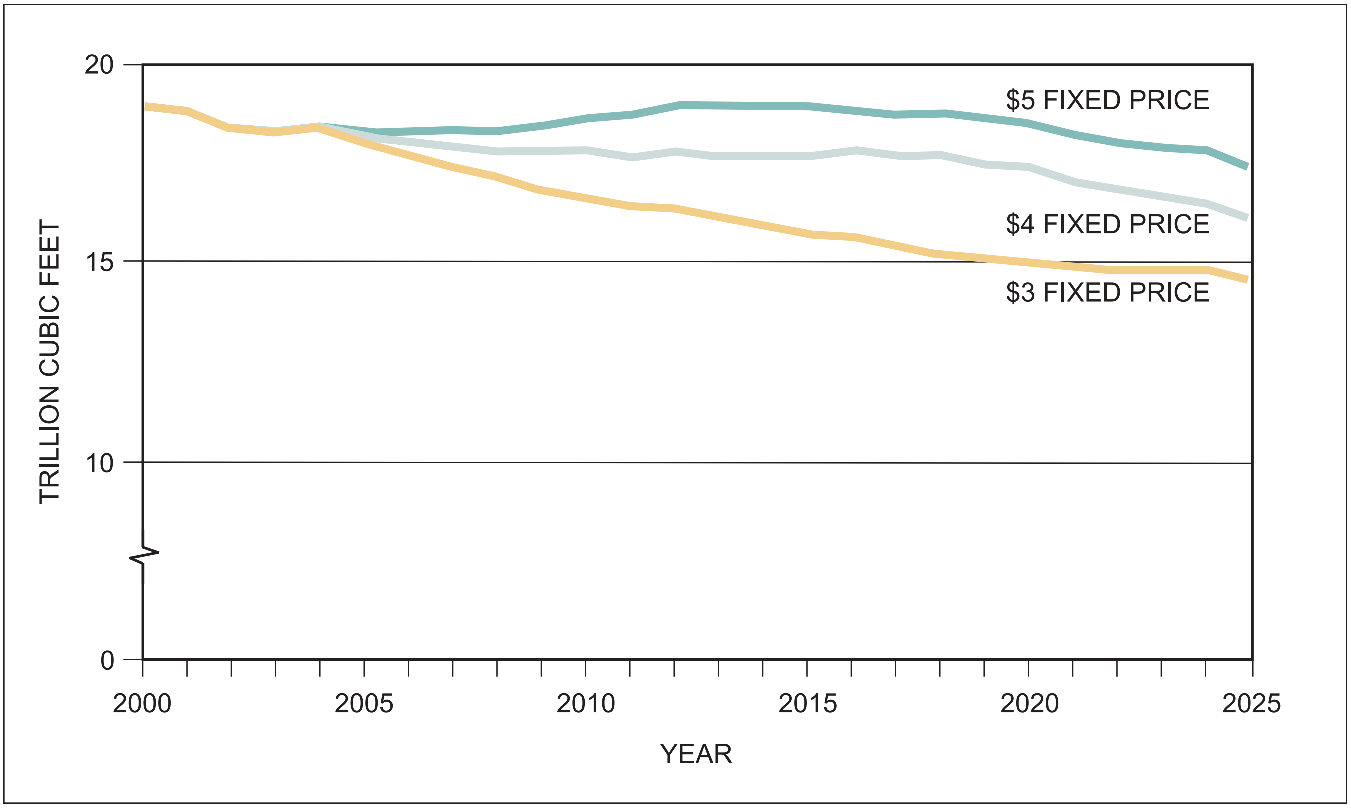


Figure 4-18. Lower-48 Production at Different Prices

price level to sustain production. At a price level around $5/MMBtu, the model projects additional supplies to be commercially viable and overall production levels would remain relatively flat.

The lower-48 production outlook in the Reactive Path scenario is lower than projections from the 1999 NPC study and the government's preliminary EIA 2004 Annual Energy Outlook. Figure 4-19 compares the three production outlooks. It should be noted that this lower production outlook is with a higher price environment than either of the other projections. A more detailed reconciliation of the differences in these outlooks is included at the end of this chapter.

Canadian Production Outlook

Production from the Western Canada Sedimentary Basin was one of the key contributors to the growth of North American production in the 1990s, providing over 50% of total North American growth. Like much of the U.S. lower-48, however, growth rates in Western Canada have been rapidly flattening as the basin has matured, even as activity rates have been increasing. Production from Western Canada is no longer projected to continue to rise.

Production from offshore Eastern Canada began in 2000, and the outlook is for moderate growth from anticipated future discoveries. Figure 4-20 shows the outlook for Canadian regional production, excluding the Mackenzie Delta, which is included in the Arctic supply region.

While the production outlook for Western Canada overall is declining, production from coal bed methane and shale gas is expected to rise and partially offset the fall in conventional output. Figure 4-21 breaks out the nonconventional components of the Western Canadian outlook. The potential opening of offshore British Columbia has not been incorporated into the Canadian projection.

In summary, the production outlook for the United States and Canada is characterized by declining production from maturing supply regions that is offset by growing nonconventional production and new offshore developments. This flat outlook is fully dependent on the ability of future drilling programs to find and develop new reserves to offset rapidly declining base production, and a robust price environment to support the high drilling activity level.

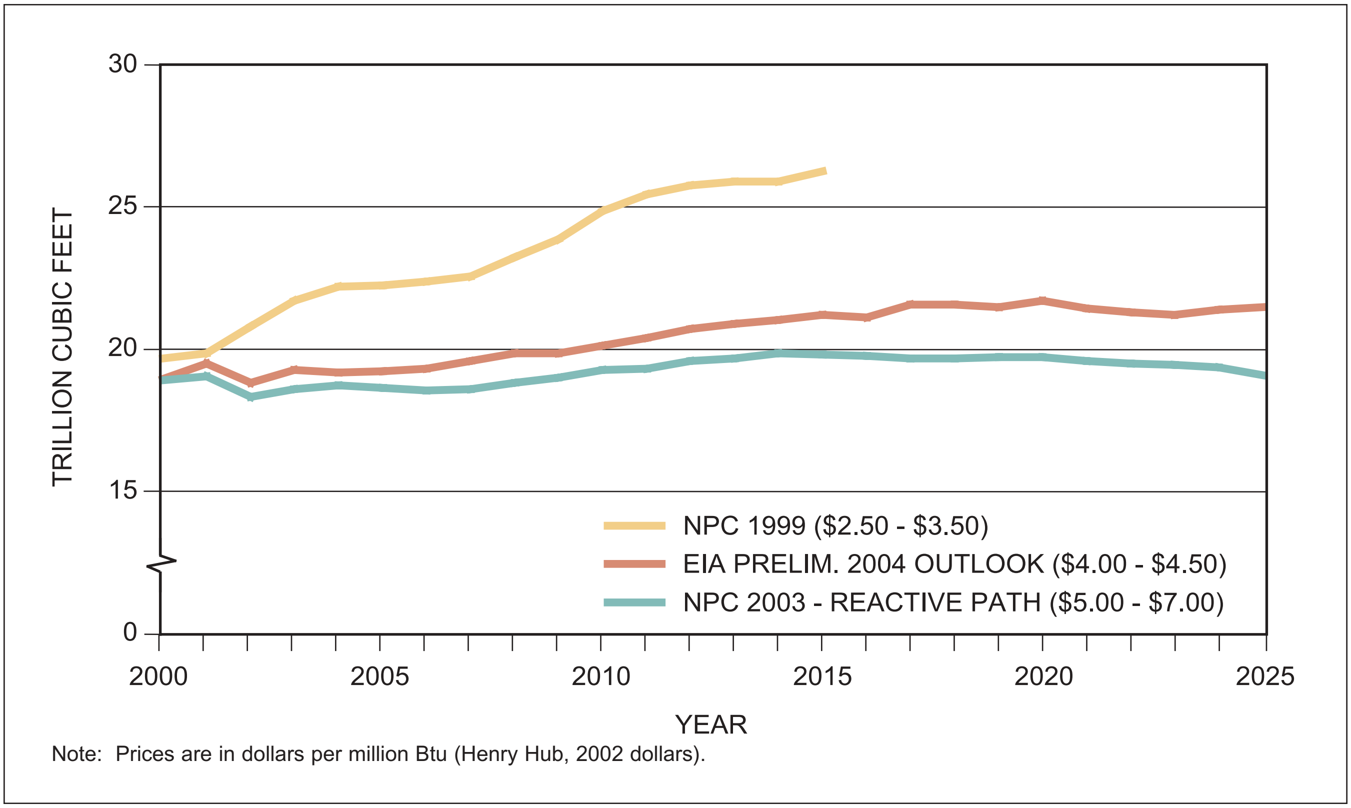


Figure 4-19. Lower-48 Production Outlooks

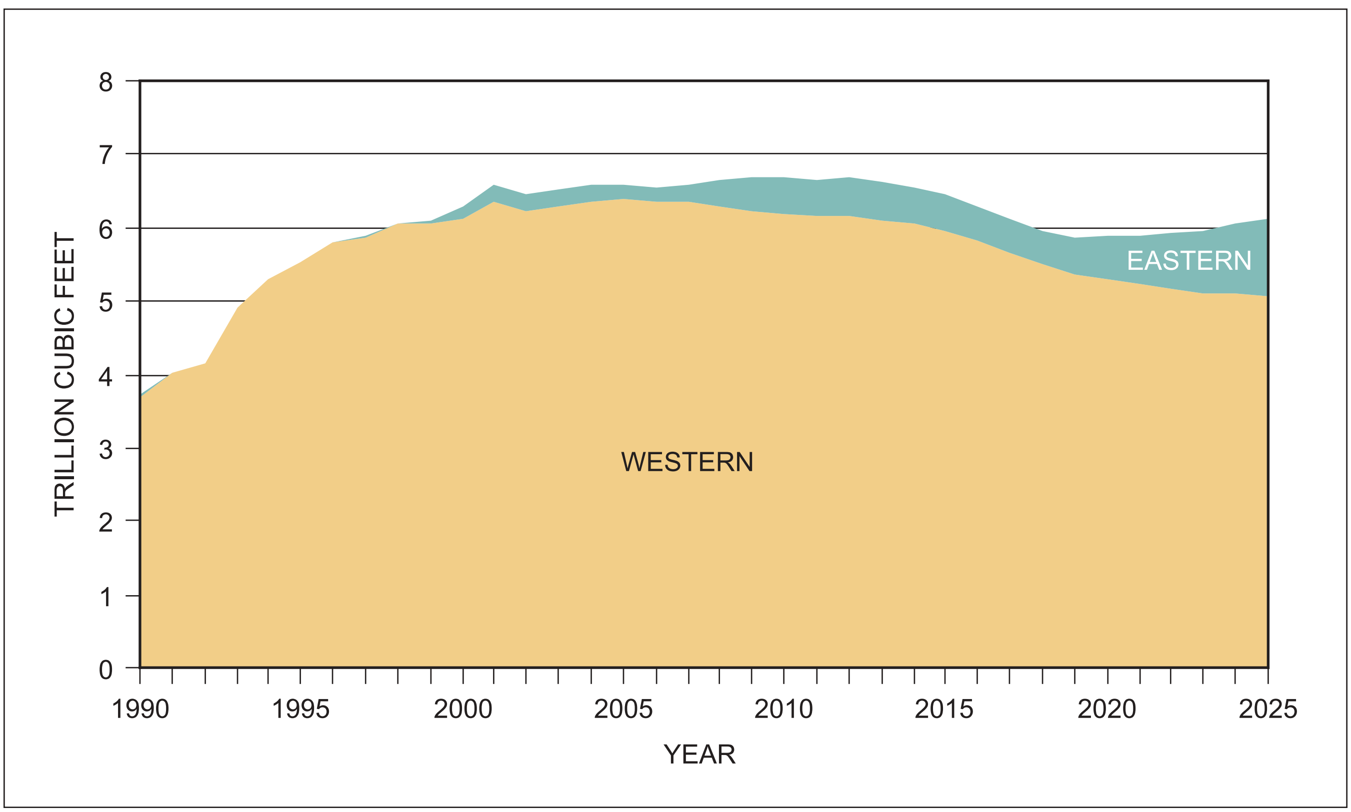


Figure 4-20. Canadian Regional Production (Excluding Mackenzie Delta)

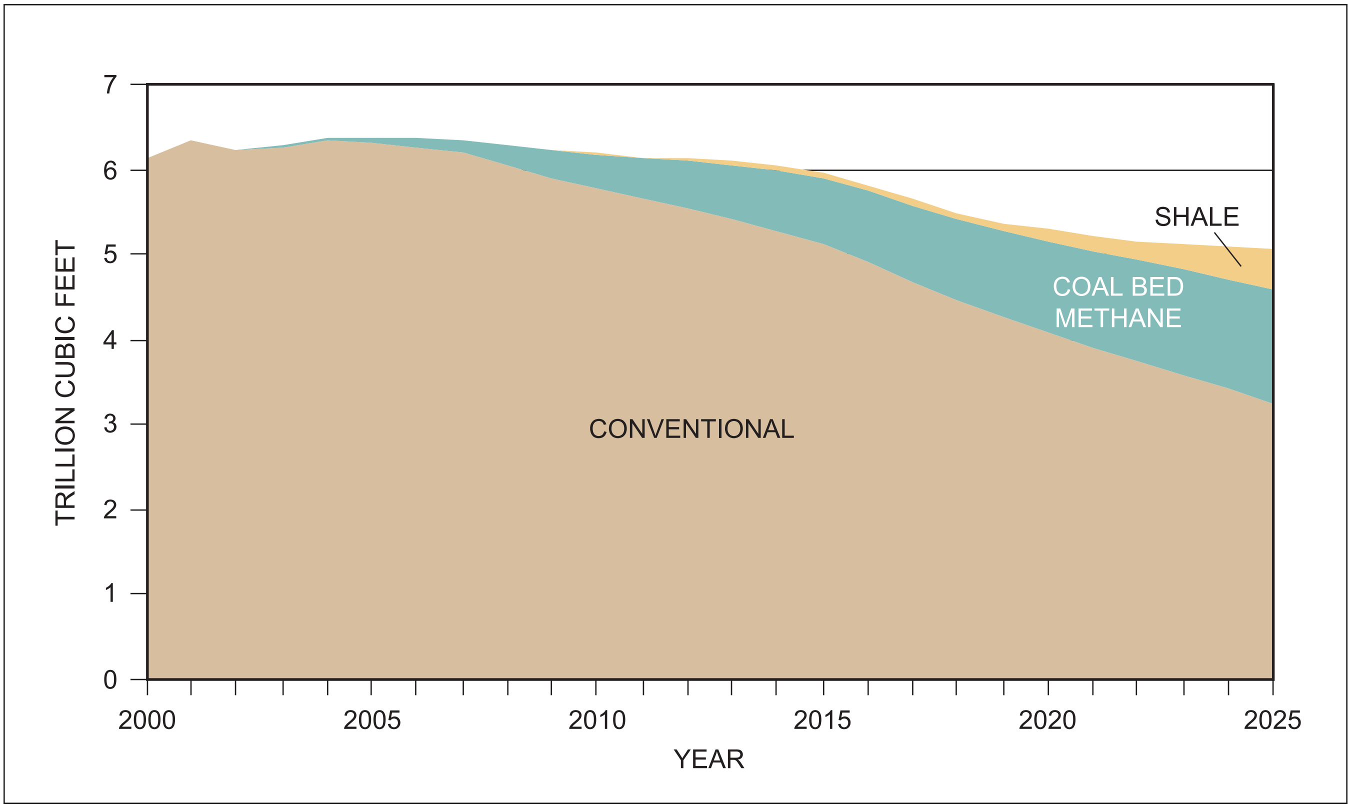


Figure 4-21. Canadian Production by Category

Drilling Activity

The future outlook for production in the United States and Canada is critically dependent on the maintenance of a very active drilling program. Historically, even as production growth has flattened in the United States and Canada, the number of gas wells annually required to maintain this production has increased dramatically (Figure 4-22). In the United States, the number of gas wells has increased from less than 10,000 per year in the early 1990s to nearly 17,000 in 2001. In Canada, the increase has been even more dramatic, increasing from less than 2,000 in the early 1990s to over 10,000 in 2001.

This outlook projects that drilling activity levels will remain at near record highs throughout the study period. Industry "reality-check" workshops were held to confirm that higher activity levels were plausible in the basins where the model predicted an increase.

Figures 4-23 and 4-24 show a breakdown of new gas completions by resource category. Nonconventional completions comprise over 50% of the activity. Coal bed methane wells, after declining recently, return to historical levels. The number of shale and tight gas wells increase significantly over the period.

The conventional resource to be developed will be more challenging than in the past, with reservoirs tending to be deeper, hotter, tighter, less productive, and more costly to develop. Technology improvements have played a critical role in allowing the commercial development of these resources. The outlook assumes that advancements will continue. Not only do technical advances provide the means to access increasingly challenging reservoirs, they also drive down overall costs, allowing additional commercial development from less traditional areas.

Reserves Development and Resource Replacement

The high drilling activity levels in the outlook are necessary for new production to meet demand and also discover new resources for future development. Figure 4-25 shows that with this high drilling level, lower-48 gas production remains relatively stable in 2010-2025. However, the figure also shows that the annual reserve additions and the reserves-to-production (R/P) ratio are expected to go on a gradual but sustained decline.

The R/P ratio (the number of years that a given resource would last if produced at the current rate) is a

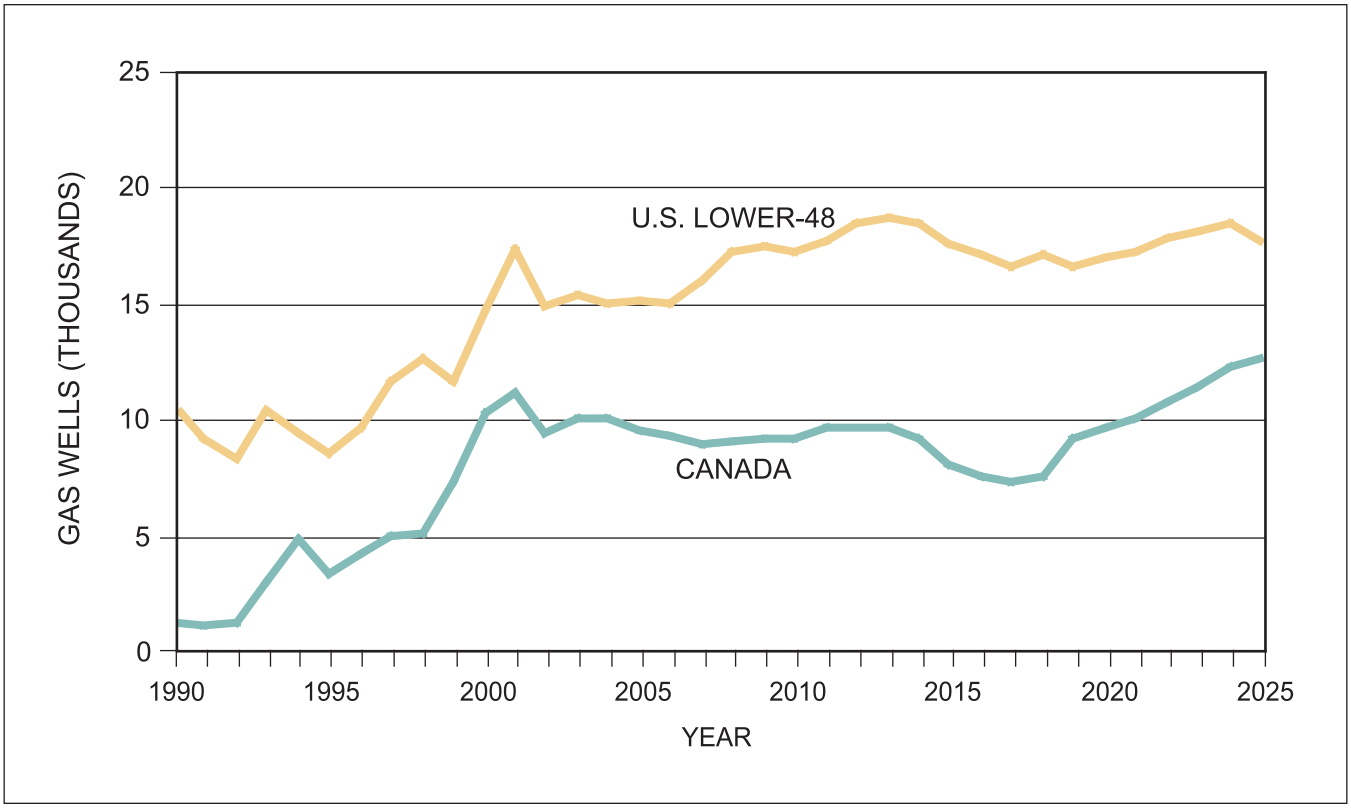


Figure 4-22. Gas Well Activity in the U.S. Lower-48 and Canada

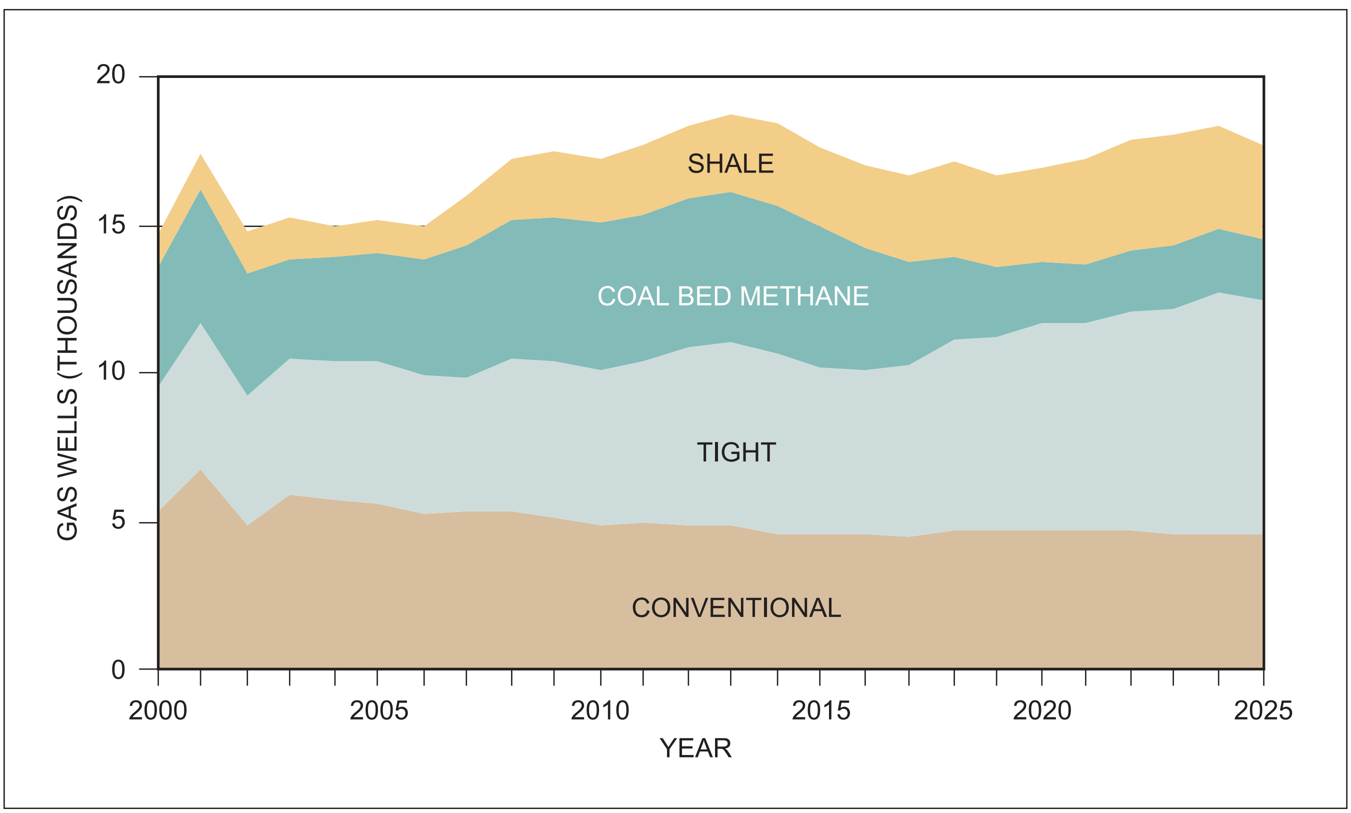


Figure 4-23. U.S. Lower-48 Gas Wells by Type

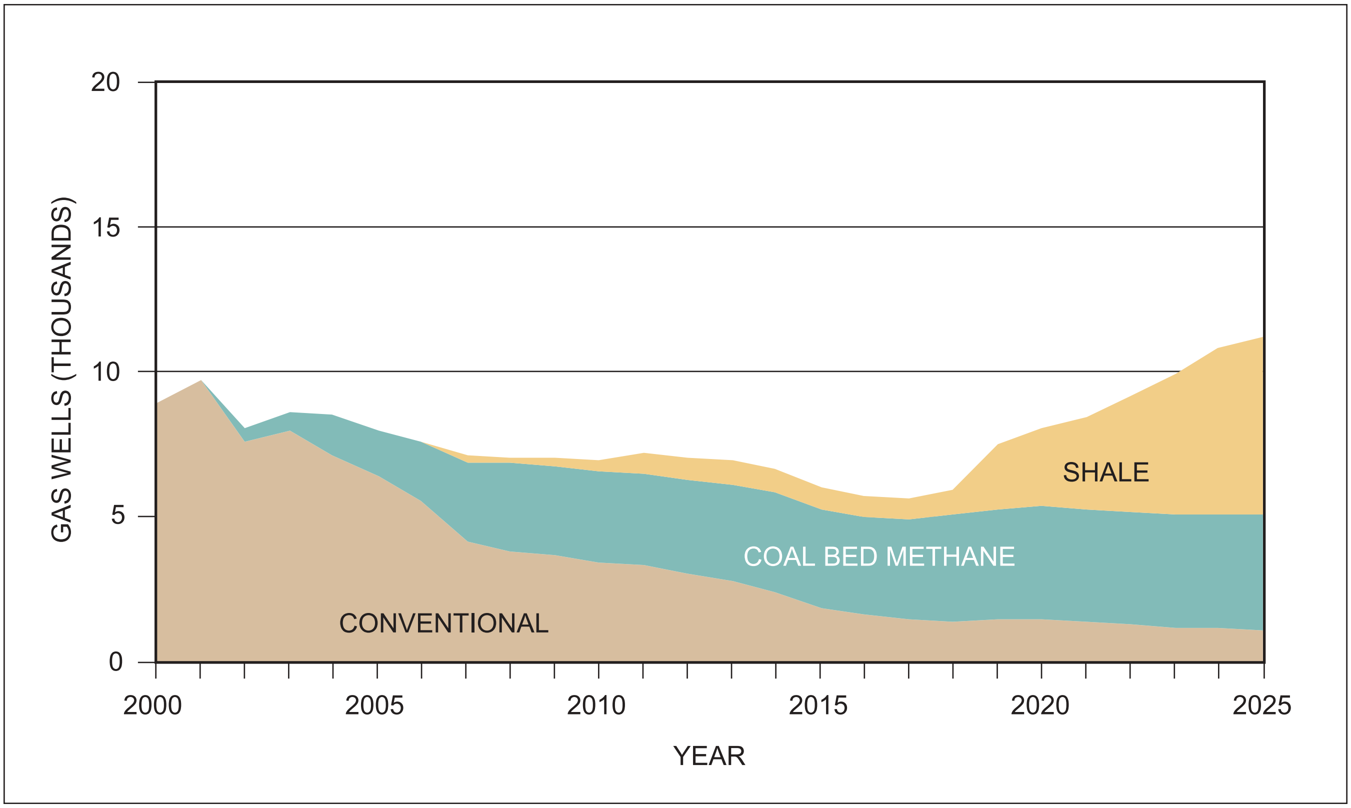


Figure 4-24. Canadian Gas Wells by Type

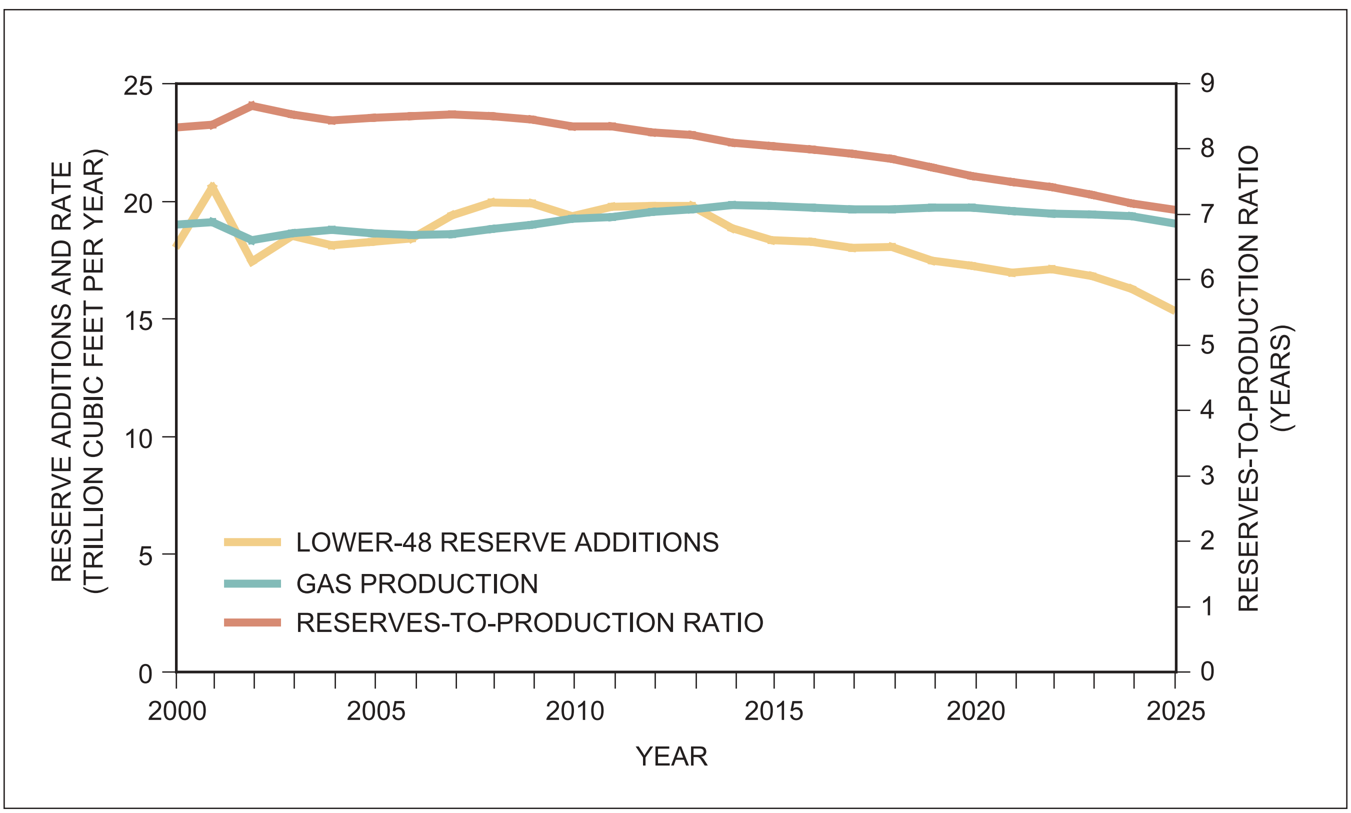


Figure 4-25. Lower-48 Reserve Additions, Production, and Reserves-to-Production Ratio

useful index to measure how fast a resource is being depleted. This figure is significant because it shows that in the Reactive Path scenario, insufficient reserves are being discovered and developed in the U.S. lower-48 to fully replace production.

Access

The Environmental/Regulatory/Access Subgroup undertook a major evaluation of the complex regulatory/environmental issues faced by the industry and the impact they have on access to potential natural gas resources. A significant part of this evaluation was focused on the Rocky Mountain region and assessed the impact that permitting "conditions of approval" have on resource access. This work quantified areas where timing restrictions made them "effectively" off-limits to development, as well as other areas that had added costs or time delays associated with drilling. The corresponding technical resource for these areas was then determined, with the overall results shown on Figure 4-26. The technical resource associated with the offshore moratoria areas is also shown on this map.

The Reactive Path scenario assumes that these access restrictions (the offshore moratoria and the current Rockies conditions of approval process) remain in place. In the Balanced Future scenario, the offshore moratoria are lifted in a phased manner starting in 2005 and the permitting process in the Rockies is improved, resulting in a 50% reduction over five years in the resource volume effectively off-limits and in cost impacts and timing delays. This results in an additional 114 TCF of technical resource (9% of the lower-48 total) that would be available for potential commercial development. By region, the volumes are 34 TCF from the Rockies, 25 TCF from the eastern Gulf of Mexico, 33 TCF from the offshore Atlantic, and 21 TCF from the offshore Pacific. Overall, in this sensitivity lower-48 production increased by 3 BCF/D, or 4% of U.S. supply, in 2020. This resulted in a reduction in average Henry Hub price (nominal) of $0.60/MMBtu, which corresponds to a potential savings in natural gas costs to consumers of $300 billion for the 2005-2025 period.

The results of the access evaluation led to the second supply-related finding:

Finding: Increased access to U.S. resources (excluding designated wilderness areas and national parks) could save consumers $300 billion in natural gas costs over the next 20 years.

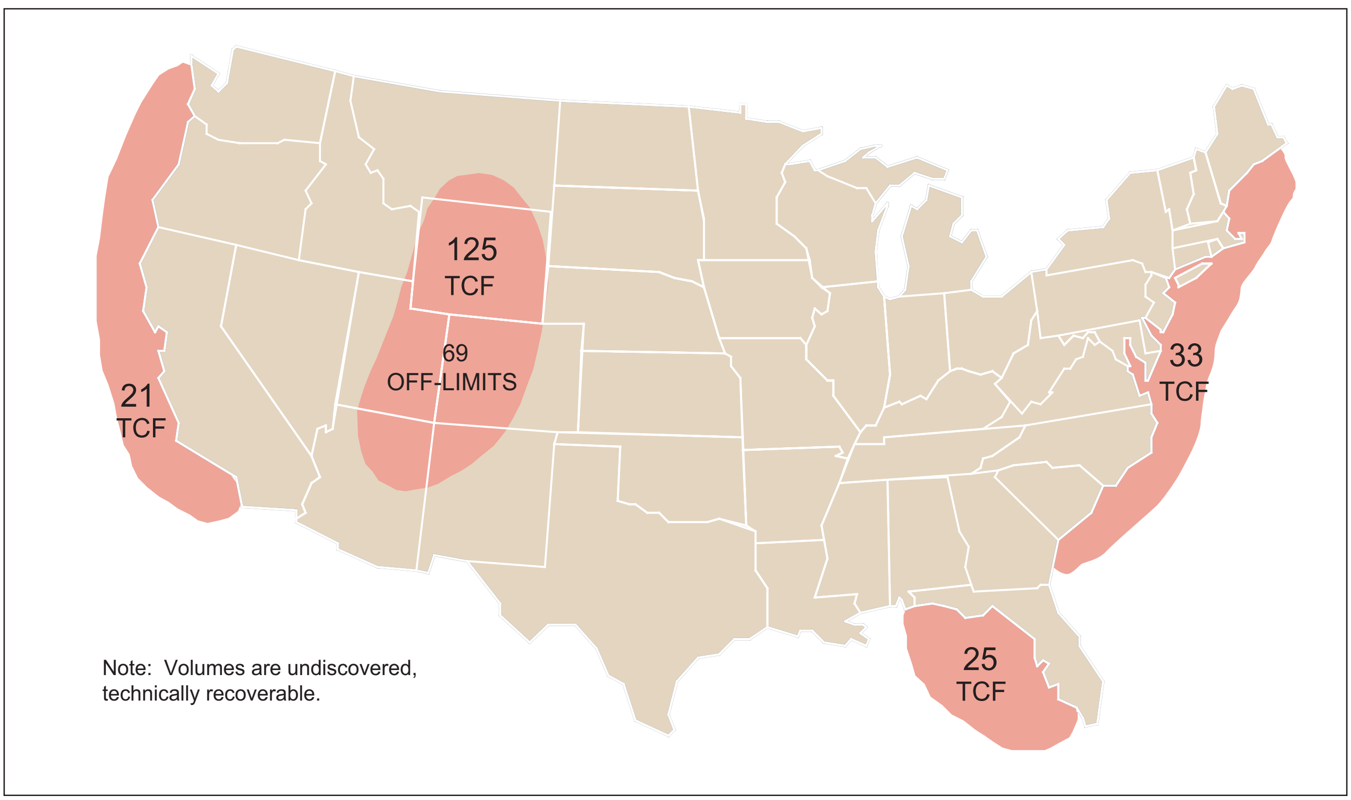


Figure 4-26. Lower-48 Technical Resource Impacted by Access Restrictions

Arctic Gas and LNG Outlook

The final supply finding is related to new supply sources:

Finding: New, large-scale resources such as LNG and Arctic gas are available and could meet 20-25% of demand, but are higher-cost, have longer lead times, and face major barriers to development.

As noted earlier, the supply contributions from new Arctic developments and LNG imports were based on assumptions for timing and the capacity of each new development. These assumptions were then input to the model as a fixed annual volume. Those annual profiles for the Reactive Path scenario are shown in Figures 4-27 and 4-28.

Gas resources in the Arctic are remote from any existing pipeline infrastructure and are located in a harsh environment, so significant investment will be required to bring these resources to market. The key hurdles associated with commercializing these resources are costs, permitting, Alaska state fiscal issues, and market risks. There are some favorable developments regarding these resources. Industry is maturing technology advancements to reduce capital costs and the supply/demand picture supports the need for additional supplies. Also, the governments of the United States, Alaska, and Canada recognize the significant risks with such large-scale projects and are working to put frameworks in place to address some of the hurdles.

The Mackenzie Gas Project is assumed to start delivering 1 BCF/D of natural gas in 2009 with a 50% capacity expansion in 2015. Most of the necessary resource has already been discovered in three major fields and the project is being actively progressed.

An Alaskan gas pipeline project is assumed to start delivering 4 BCF/D of natural gas in 2013. Approximately 35 TCF of discovered resource in north Alaska will anchor the project, although additional undiscovered resource will be needed to maintain deliveries at full capacity for a 30-year project life.

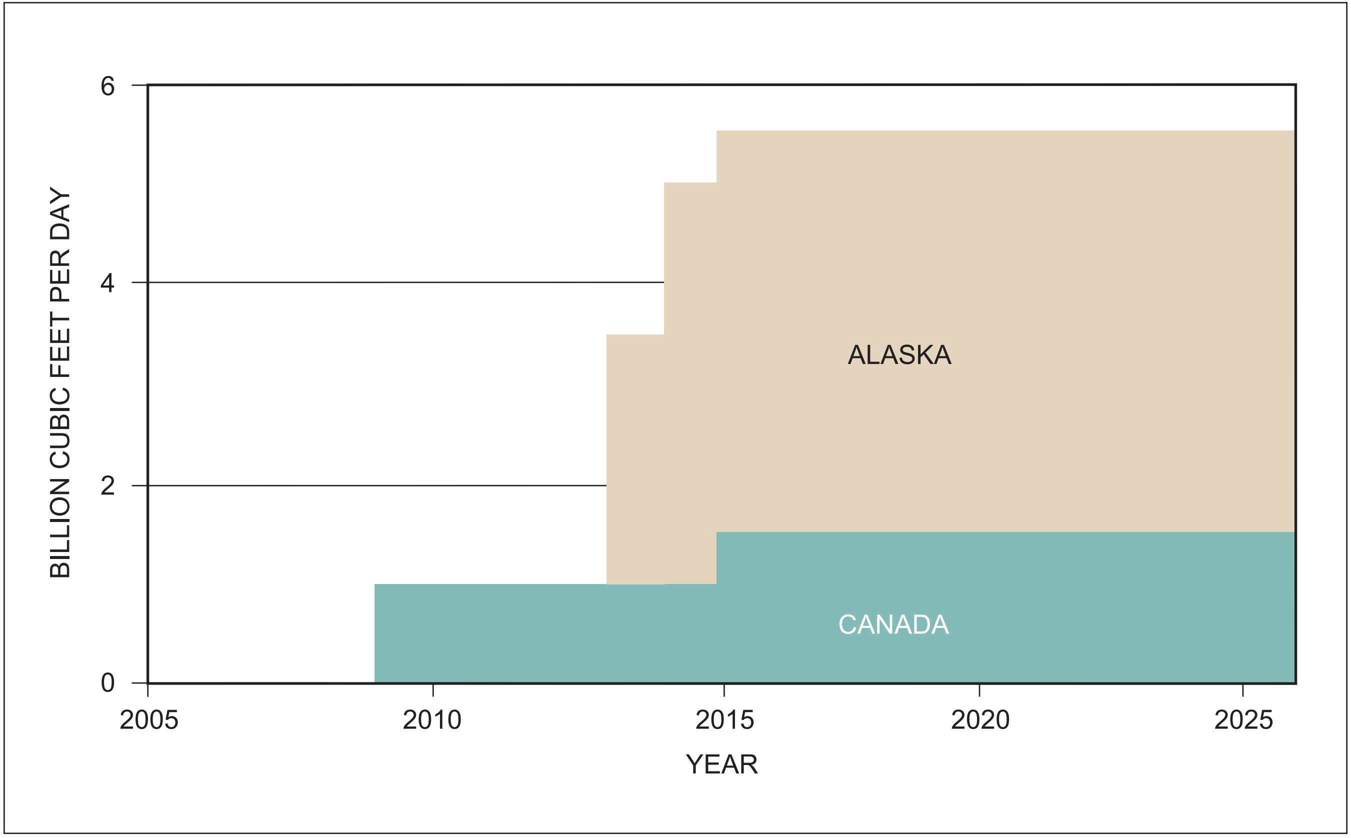


Figure 4-27. Arctic Production Profile

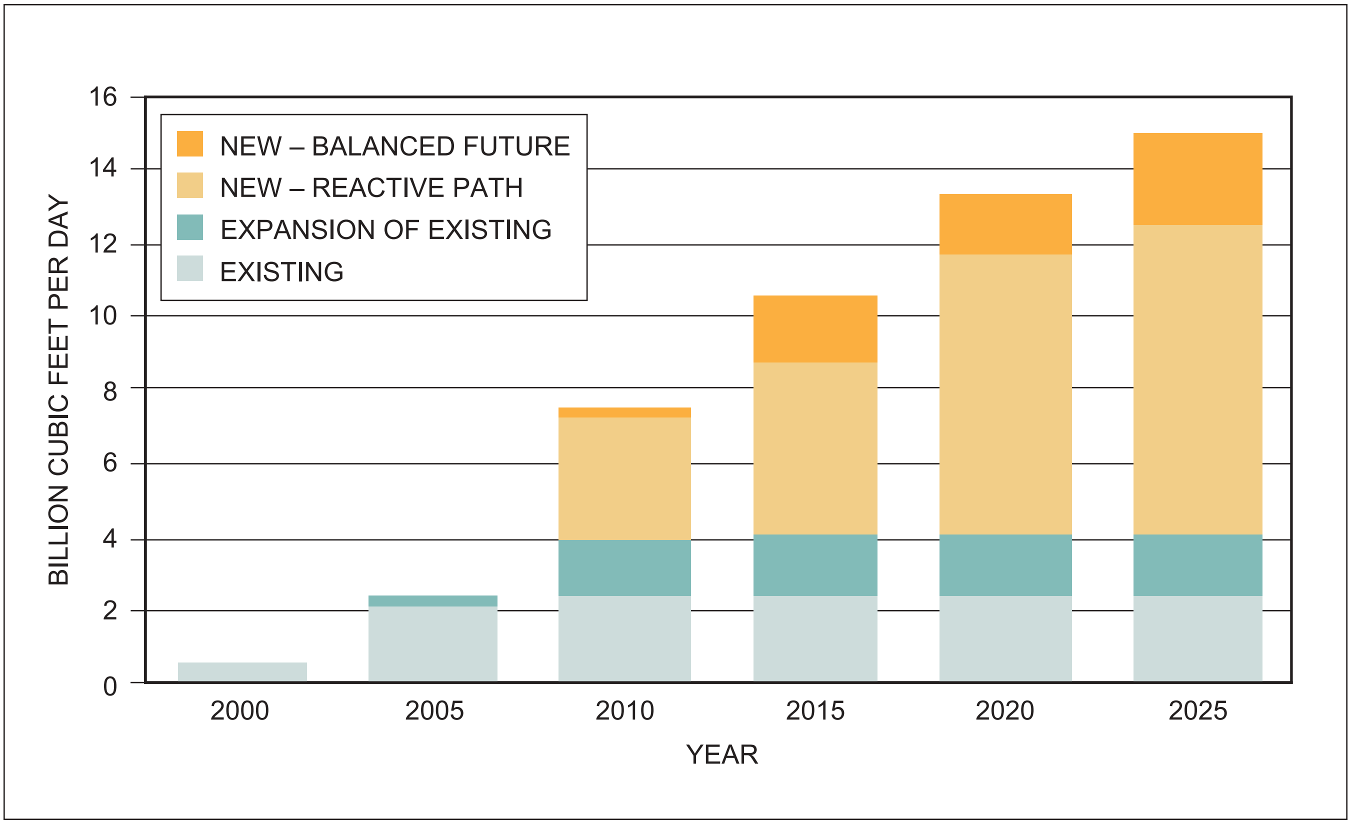


Figure 4-28. North American LNG Imports

The assumptions over the timing and volumes of Arctic gas are consistent for the Reactive Path and the Balanced Future scenarios, reflecting earliest feasible start-up dates. A sensitivity case was developed where the Alaska pipeline project is not developed during the study period. In this case, the average gas price is projected to increase by 7% through 2025 as a result of the 4 BCF/D Alaska production not being available.

From its current 1% share of North American supply, LNG is projected to grow to a 12% share by 2025 in the Reactive Path scenario. This will require large capital investment in the field development of foreign sources, and its subsequent liquefaction, ship-borne transportation, and eventual regasification in North America. Although the needed volumes of natural gas resource are potentially available globally, the pace of LNG infrastructure development in both producing countries and in North America will provide the upper limit for import volumes. In addition, concurrently growing markets in the Far East and Europe will provide strong competition for sales into North America.

Figure 4-28 shows the build-up of LNG supply from the four current U.S. regasification terminals that have been operating at less than capacity since their construction. Starting in 2007, seven new terminals and seven expansions are projected in the Reactive Path scenario.

In the Balanced Future scenario, permitting time is reduced from two years to one year, and two additional terminals and two additional expansions are assumed as a result of improved permitting processes. The incremental LNG imports for this scenario are shown in Figure 4-28.

To evaluate the impact of a lower rate of imported LNG growth, a sensitivity case was developed in which only two new LNG terminals were constructed due to permitting difficulties. In this case, LNG import capacity was reduced to 6 BCF/D and the average gas price increased by 10% from 2005 to 2025.

Resource Base Sensitivity

The range around the resource base volume was the largest uncertainty tested in the supply outlook. The range of technical resource was probabilistically assessed at 35% above the mean estimate to 30% below

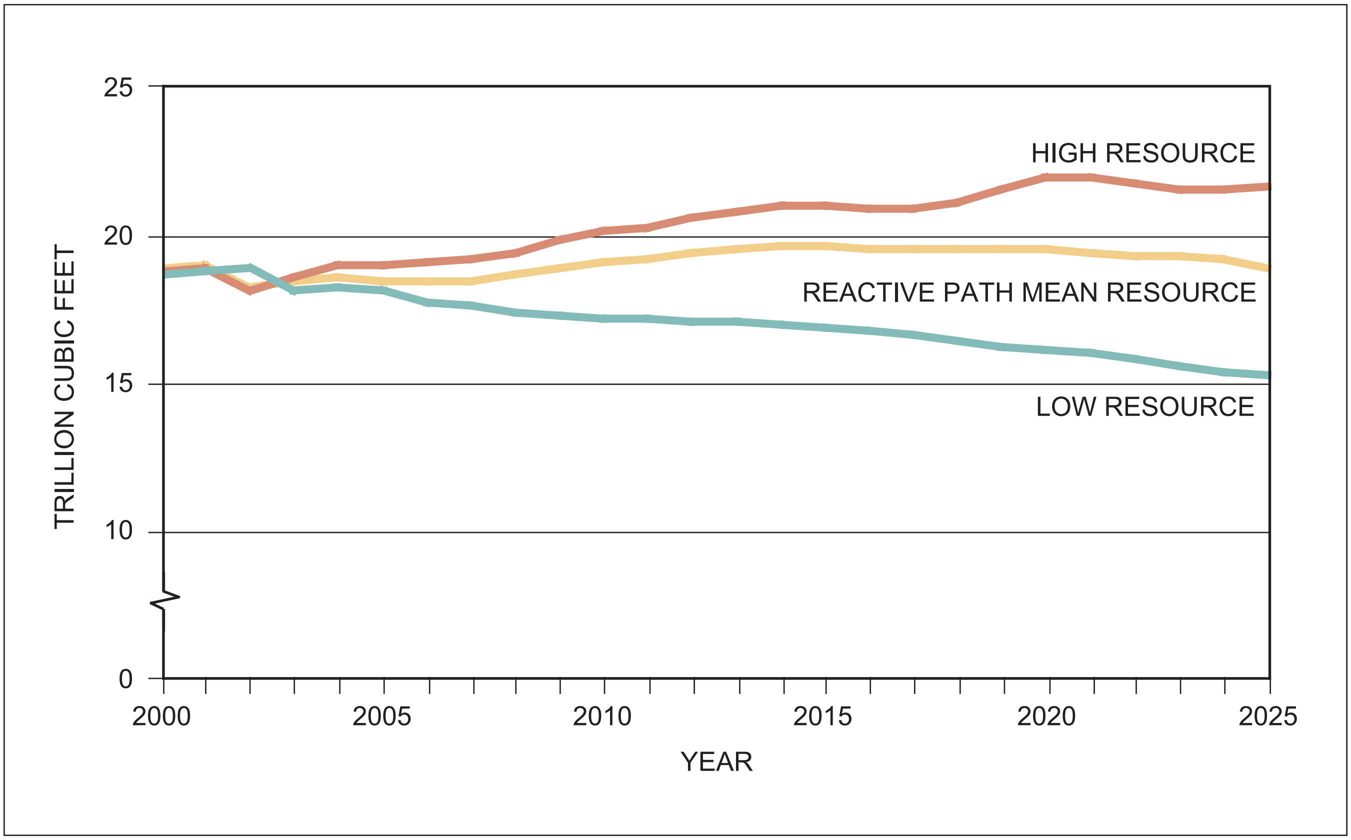


Figure 4-29. Lower-48 Production Outlook and Resource Base Sensitivities

the mean estimate, each with a 10% probability of occurrence. Figure 4-29 shows the lower-48 production projections for this resource range in the Reactive Path scenario. In these sensitivity runs, the LNG and Arctic import assumptions were not changed. The low resource base sensitivity shows production declining 17% in 2020 from the Reactive Path scenario, while the high resource base run shows an 11% increase. Clearly, maintaining production levels in the U.S. lower-48 would not be possible if a lower resource base were in place.

In addition to the volumes impact, the average gas price increased 38% in the low resource base sensitivity and was 25% lower in the high resource base sensitivity. This further demonstrates the effect that the resource base uncertainty has on the future outlook for natural gas supplies and prices.

Conclusions

From an overall perspective, supply in a robust future price environment will grow to meet rising demand. Growth from the Rocky Mountain and deepwater Gulf of Mexico areas will offset declines in other traditional basins in the United States and Canada. Additional growth will come from new sources of supply such as LNG imports and Arctic gas.

Resource Assessment

This section describes the assessment of natural gas resources in North America. This assessment, together with cost and production performance data were used as inputs by an econometric model to determine the size of the of commercial resource base and to derive an outlook for natural gas production through 2025.

Assessment Process

The resource assessment was based on best practices learned from prior NPC studies and from other similar studies. It was designed to use publicly available data, to be play-based, and to provide a thorough review by geoscientists and engineers. The resulting assessment represents an industry consensus.

Many sources of public and commercial data were used. For the United States, data from the Minerals Management Service (MMS) and United States Geological Survey (USGS) comprised the baseline. For Canada, the Canadian Gas Potential Committee (CGPC) assessment was primarily used. For Mexico, a combination of IHS Energy Group (IHS) and USGS data were used. Production-performance and field-size data were derived from the Energy Information Administration (EIA), IHS, and NRG Associates (Nehring). Cost data were derived from the American Petroleum Institute (API) in the United States and the Petroleum Services Association of Canada (PSAC) in Canada.

Early on, best practice teams were organized to formulate methodologies for reserve growth, new field (undiscovered) assessment, cost, etc. Following that, major workshops were held for the purpose of reaching industry consensus on the various assessment parameters for significant plays and basins. Subsequently, a further series of workshops was held to re-validate, or change, assessment parameters in response to information learned from the models used to develop long-term forecasts. The work process is shown diagrammatically in Figure 4-30.

The smallest unit used for assessment is the “play” (or “Assessment Unit” as it is called in updated USGS terminology). A play has a coherent set of petroleum geology characteristics. North America contains approximately 700 plays. For the purposes of the current NPC study and for use in supply modeling, these plays have been aggregated into 72 regions. In their turn, the regions have been aggregated into 17 super-regions as shown in Figure 4-31.

Although comprised of many different plays, each super-region displays its own distinguishing features. For instance, the Rockies super-region contains predominantly nonconventional gas resource and has far more access restrictions than any other lower-48 onshore area. The super-regions are discussed in a later section of this chapter.

Definitions

In most cases, natural gas is a mixture of hydrocarbons (primarily methane) plus small amounts of non-combustible gases. Natural gas may be produced in association with oil, or it may come from non-associated gas fields. Approximately 87% of North American gas is non-associated.

All volumes of natural gas referenced in this study are dry gas remaining after liquefiable portions and non-hydrocarbon gases have been removed as required by marketing considerations.

Technical resource is defined as that quantity of gas recoverable with current technology without regard to the economics of doing so. Commercial resource estimates are derived from econometric models.

In this study, remaining technical resources include proved reserves, proved growth, and undiscovered, or yet-to-be-found, resources.

Proved reserves are defined as those reserves that have a high confidence of being produced, and by implication, they are already economic.

The estimated volume of gas that a field will ultimately produce is known as the estimated ultimate recovery (EUR). At any time during the life of a field, the EUR is equal to the sum of those volumes that have been produced (cumulative production) plus the remaining proved reserves. Statistically, it can be shown that with the passage of time successive field EUR estimates tend to grow due to improved knowledge gained through operational experience during the life of the field. Growth is the estimated technical resource remaining in a field above the current estimate of proved reserves.

Undiscovered resource is the total volume of natural gas expected to be found in the future that is not due to growth of existing fields. It assumes current

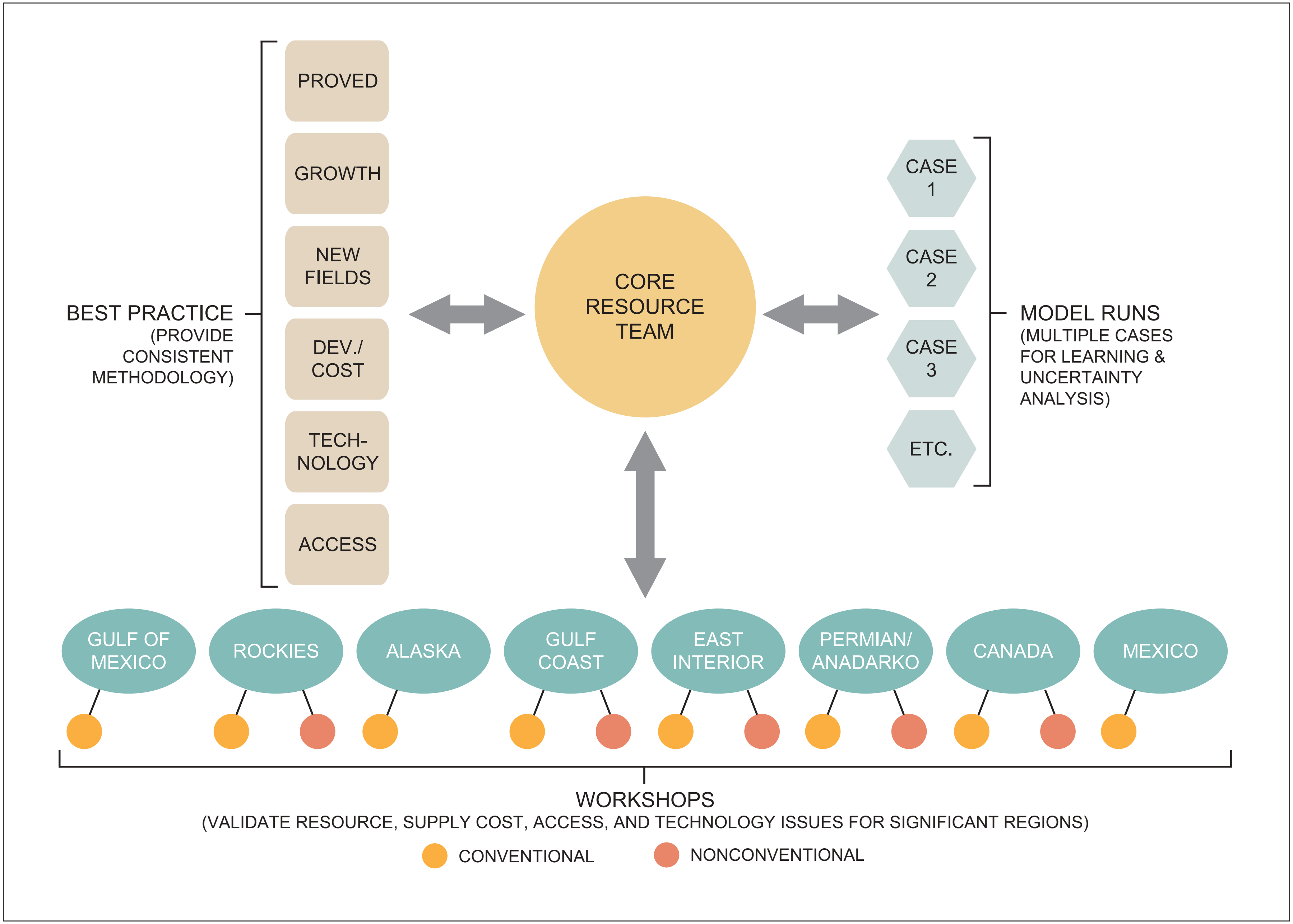


Figure 4-30. Resource Assessment Process

Figure 4-31. The 17 Super-Regions

technology and is not necessarily economic. Undiscovered resource is sometimes termed new field or yet-to-find.

Technology advancement (described later in this chapter) will tend to increase the size of the undiscovered resource depending upon the model-based timing of exploration and development. The assessments reported in this section are based upon current technology and are independent of modeling assumptions.

Technical Resource Base

Figure 4-32 shows the relative contributions of technical resource in North America. Of the 1,969 TCF North American technical resource, 69% is undiscovered. The remaining 31% is associated with known fields in the proved and growth categories. In general, the uncertainty in the undiscovered category is larger than in the growth category, and the uncertainty in "growth" is larger than in the proved category.

The undiscovered resource is split into two categories: conventional and nonconventional. Although the distinction is not absolute, conventional resources are located in discrete accumulations. They tend to have better production performance characteristics and they are amenable to traditional exploratory techniques. Nonconventional resources, including coal bed methane, shale gas, and basin-centered gas, are typically continuous accumulations that are much larger in area than conventional discrete accumulations. They also tend to have poorer production performance. Prior to drilling, traditional exploratory techniques are relatively inaccurate at predicting productivity in a nonconventional accumulation.

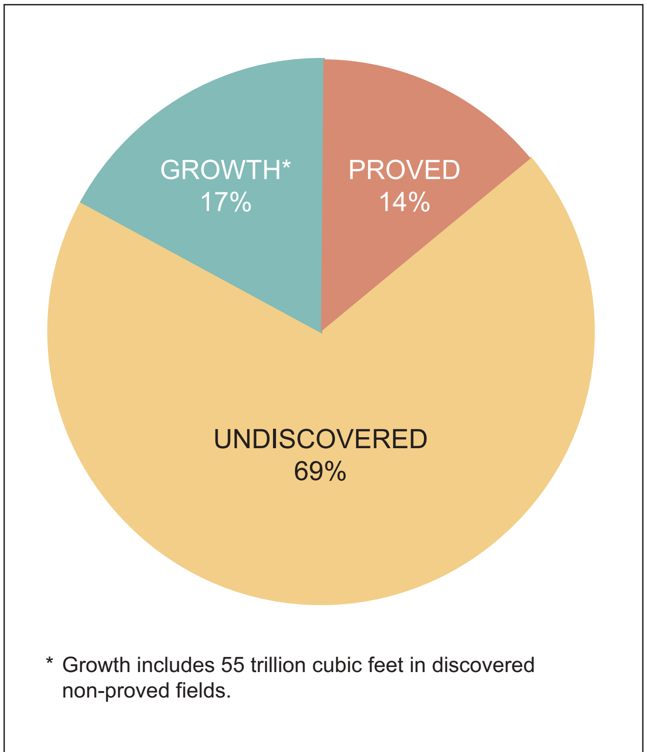


Figure 4-32. North American Technical Resource

Figure 4-33 shows the relative contribution of conventional and nonconventional undiscovered resource in North America.

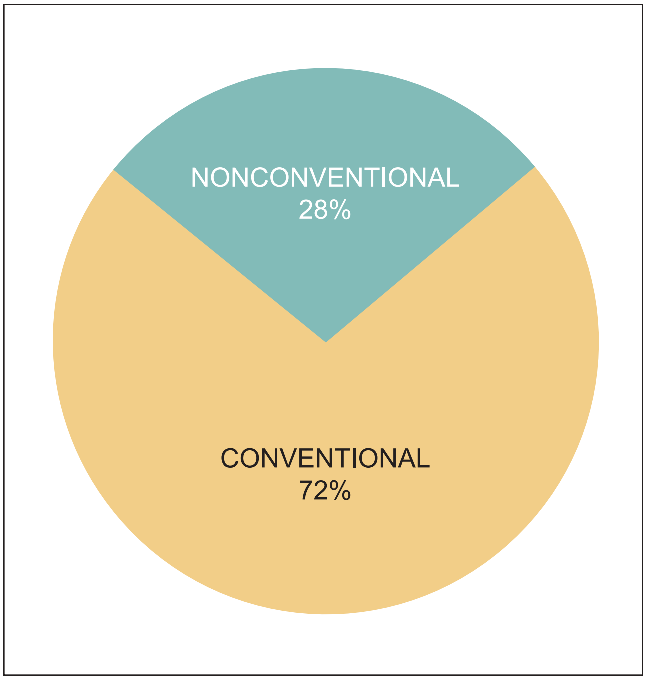


Figure 4-33. North American Undiscovered Resource

Methodology

For the purposes of this report, it is more manageable to contrast the 17 super-regions (Figure 4-31) than to work with the 72 individual regions, which are the basic supply unit used in the supply/demand modeling. For example, the Rockies super-region is comprised of 11 regions, each with its own supply characteristics. Figure 4-34 illustrates the 72 regions.

In their turn, each region contains many plays, which are the basic units of technical resource assessment. The three major sources of baseline assessment data use variations of the same methodology to estimate the volume and distribution of undiscovered field sizes in each play.

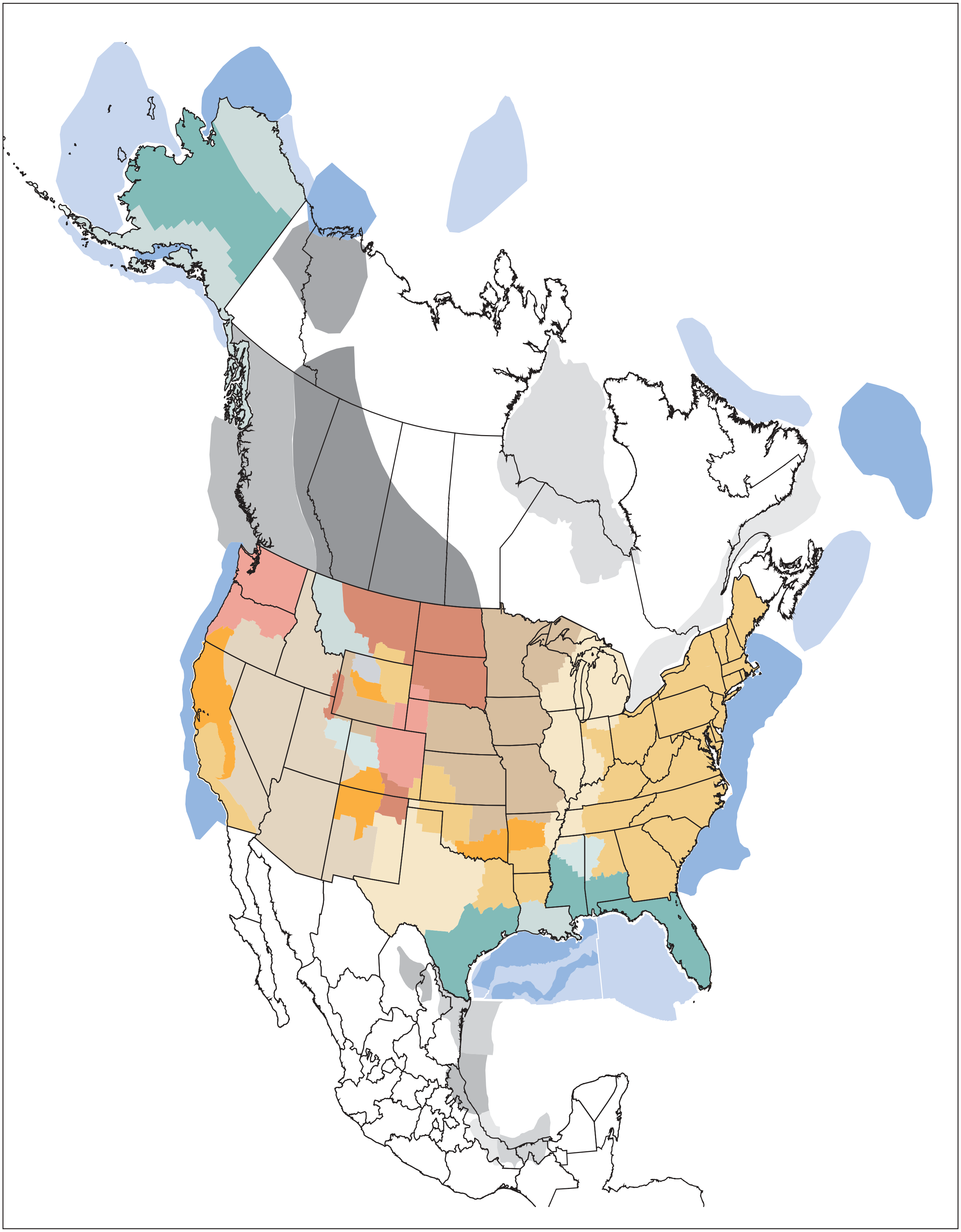


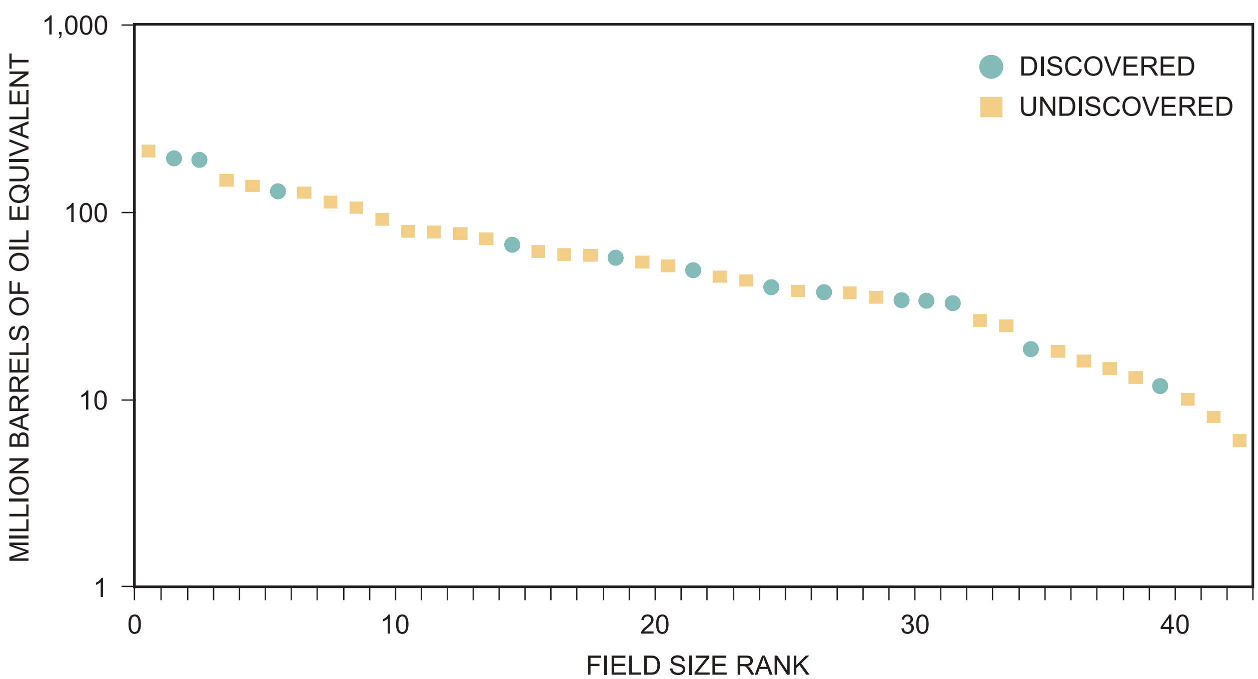
Figure 4-34. The 72 Supply Regions

For conventional resources, the assessment process defines a distribution of all discovered and undiscovered fields within a play. This distribution is a relationship between the sizes and numbers of fields. Geoscience experts provide estimates such as the volume of undiscovered resource as well as the maximum and mean size of undiscovered fields, which, when combined with the data from discovered fields, fully defines the total distribution of resources within a play. The distribution of undiscovered fields is then easily derived. An example field size distribution is shown in Figure 4-35.

This process works reasonably well for the distribution of field sizes greater than economic threshold because the anchor points from discovered fields are well quantified. Generally, sub-commercial discoveries are either underreported or poorly quantified, because there is no economic incentive to be precise. Therefore an adjustment has to be made to the assessment of undiscovered small fields below 6 BCF. This is done using a theoretical distribution and can add approximately 20% to the technical resource volume. It is important to estimate the distribution of currently uneconomic fields, because the threshold size for economic fields will decline with advances in technology.

Nonconventional technical resource assessment is based on an entirely different methodology. Discrete gas fields do not exist in the conventional sense. Resources are generally distributed over large areas where nearly every well may find natural gas, although production rates may be highly variable and sometimes non-commercial. In this case, the assessment is based upon the total areal extent of the nonconventional reservoir unit, the area that one well can drain, and the EUR that can be recovered by a well.

The assessment of growth was done at the region level and was based on an analysis of the historical development of fields. The method makes the assumption that a field is developed rationally by drilling the best opportunity at any given time. It further makes the assumption that, on average, "best" equates to highest available EUR per well. For all fields discovered in any particular year within a region, the rate at which the EUR per well decreases is analyzed. The sequence of completions is divided into cohorts, which are more



Source: OCS Report MMS 2001-087.

Figure 4-35. Example of a Field Size Distribution

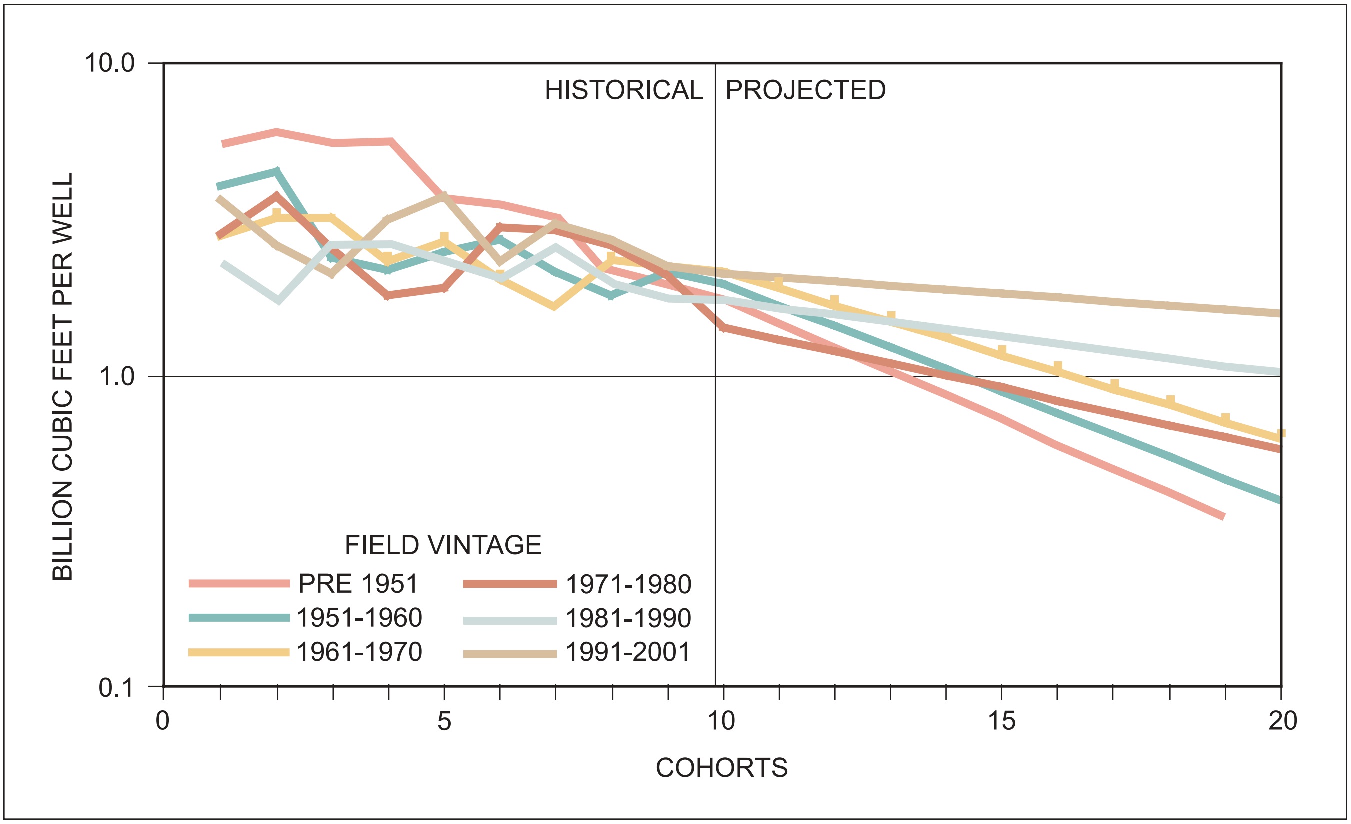


Figure 4-36. Growth-to-Known Methodology

fully described in the Supply Task Group Report. Growth is then calculated by extrapolating this EUR per well analysis to an economic limit in the future. Figure 4-36 is an example of growth analysis showing how EUR per well trends are projected.

Assessment estimates are often cited as precise values, but in practice all values are subject to a range of uncertainty. Generally a play resource assessment is the statistical mean of its field size distribution (or pool size distribution in much of Western Canada). In order to define a range of uncertainty around the mean, this study has chosen to use a P10 value as the high side and a P90 value as the low side. P10 means there is a 10% chance that the high-side value will actually occur. P90 means there is a 90% chance that the low-side value will occur.

To arrive at the correct resource distribution for an aggregation of plays, the Monte Carlo method was used. After several statistical tests, it was decided to use a high side of 135% of the mean and a low side of 70% of the mean for the complete North American aggregation. Although some simplifying assumptions were made in defining this uncertainty range, the industry consensus was that it was reasonable.

Technical Resources of the United States, Canada, and Mexico

The proportion of North America's proved, growth (including discovered non-proved), and undiscovered technical resources in each country is shown in Figure 4-37. The United States has 1,451 TCF of technical gas resource, Canada has 397 TCF, and Mexico has 121 TCF. In each country, undiscovered is the largest category of technical resource, ranging from 58% in Mexico to 78% in the United States. The remaining resource is split approximately equally between proved and growth in all three countries.

The top three super-regions in terms of volume are the Gulf of Mexico with 329 TCF, followed by Alaska with 303 TCF, and the Rockies with 284 TCF (shown in Figure 4-2). Although these three super-regions each contain a large technical resource base, they are quite distinct in character. In the Gulf of Mexico, a growing proportion of new production will come

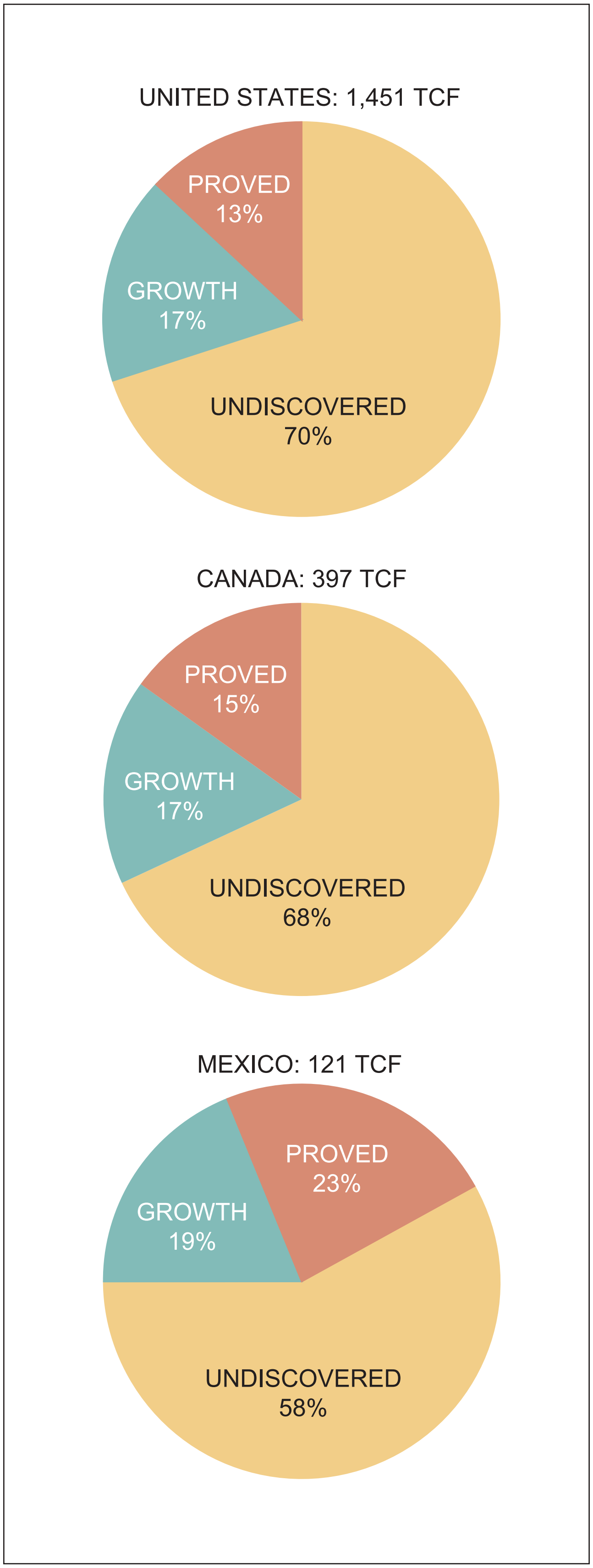


Figure 4-37. Technical Resources of United States, Canada, and Mexico

from costlier, deeper water developments. In the Rockies, a growing proportion of new production will come from costlier nonconventional resources. On the other hand, in Alaska most of the resource is stranded due to the hostile Arctic environment and lack of a commercially viable export pipeline. Table 4-3 contains details of North America's technical resource base.

A short description of the characteristics of each of the significant super-regions in the United States, Canada, and Mexico follows.

United States

The United States contains 11 super-regions, described below. Current annual lower-48 production of around 19 TCF satisfies 85% of demand. In 2025, lower-48 production will satisfy about 70% of demand.

Three of the super-regions provide just over 70% of current U.S. gas production: the Gulf of Mexico, 27%; the Gulf Coast Onshore, 25%; and the Rockies, 18%. In terms of technical resource, the same three super-regions contain 63% of the remaining 1,451 TCF. Thus the relative production contribution from the U.S. super-regions will change through the study period.

Alaska. Alaska contains a very large undiscovered resource (258 TCF), located both onshore and offshore. North Alaska has a large discovered gas resource (40 TCF), which is currently stranded due to lack of pipeline infrastructure. Development depends on the commercial viability of constructing a pipeline to markets in Canada and the U.S. lower-48. The remoteness and harsh environment add significantly to exploration and development cost. In addition, access to resource in the Arctic National Wildlife Refuge (ANWR) and the National Petroleum Reserve, Alaska (NPRA) is still a contentious issue. The potentially large nonconventional undiscovered resource has a large assessment uncertainty mainly because there is a lack of data.

U.S. Pacific Offshore. This area has moderate undiscovered resource potential (21 TCF), but it is under a moratorium for new leases. Some wells were drilled offshore in northern California and Oregon in the 1960s with minor gas shows but without commercial success. Southern California has minor gas production associated with oil.

	Discovered Remaining			Undiscovered			
Super-Region	**Proved Reserves**	**Growth to Proved Reserves***	**Total Discovered Remaining**	**Undiscovered Conventional Potential**	**Undiscovered Nonconventional Potential**	**Total Undiscovered Potential**	**Total Technical Resource**
Alaska	9	36	45	201	57	258	303
West Coast Onshore	3	3	6	10	13	23	29
Great Basin	1	1	2	3	0	3	5
Rockies	50	26	75	36	173	209	284
West Texas	16	21	38	20	7	27	64
Gulf Coast Onshore	38	60	98	77	8	86	183
Midcontinent	24	32	56	27	5	32	88
Eastern Interior	14	5	18	15	76	92	110
Gulf of Mexico	29	55	84	244	0	244	329
U.S. Atlantic Offshore	0	0	0	33	0	33	33
U.S. Pacific Offshore	1	1	2	21	0	21	22
Western Canada Sedimentary Basin	57	28	86	93	46	138	224
Arctic Canada	0	25	25	46	0	46	71
Eastern Canada Onshore	0	0	1	2	4	6	6
Canada Atlantic Offshore	2	15	18	68	0	68	85
British Columbia	0	0	0	11	0	11	11
Mexico	28	22	51	70	0	70	121
North American Total	**272**	**332**	**604**	**977**	**389**	**1,366**	**1,969**
United States	183	241	425	687	339	1,027	1,451
Canada	60	68	128	219	50	269	397
Mexico	28	22	51	70	0	70	121

* Growth includes 55 TCF of discovered non-proved in Alaska (14 TCF), Arctic Canada (25 TCF), Canada Atlantic (15 TCF), and Gulf of Mexico (1 TCF).

Table 4-3. North American Technical Resource Base – Current Technology (Trillion Cubic Feet)

West Coast Onshore. Approximately half the total undiscovered resource of 23 TCF is nonconventional. This occurs in the north and is unlikely to be commercial during the study period because of poor reservoir quality and a thick volcanic overburden.

Great Basin. This large area has an extremely small potential (3 TCF) owing to a combination of geological factors. Most of this is concentrated in a small area in the east (Paradox Basin). Recent exploration results in other areas of the Great Basin have been disappointing.

Rockies. The total undiscovered potential here is very large (209 TCF) and is 80% nonconventional. There are significant access issues and, until 2002, there was a shortage of pipeline export capacity. Nevertheless, production has grown and the Rockies super-region is one of the few areas where indigenous production is likely to continue growing. Discovery of the world class San Juan coal bed methane play in the 1980s led to significant, although less prolific, coal bed methane plays in other parts of the Rockies. Water discharge and operational footprint issues are likely to be future concerns. Advances in well completion technology have improved the viability of nonconventional tight gas and shale gas plays. Access and technology will determine how much of the technical resource base becomes commercial.

West Texas/New Mexico. Total undiscovered potential is moderate (27 TCF), because the main producing areas, such as the Permian Basin, are mature. However, downspacing and infill drilling provide some opportunities for field growth. The super-region also contains the large nonconventional Barnett Shale play in the Fort Worth basin, where the recent production ramp-up has been driven by improvements in completion and stimulation technology.

Midcontinent. Although it is an important area of current production, this super-region contains only moderate undiscovered resource (32 TCF), mostly (85%) conventional. The Anadarko Basin has potential for further deep conventional discoveries, and other basins have small nonconventional potential.

Gulf Coast. The Gulf Coast is an important area of current production with a large undiscovered potential (86 TCF), over 90% conventional. Although reasonably well explored, the complex geology allows for the possibility of new trends, particularly deeper. Using improved completion and "sweet spot" detection technology, there is also the possibility of finding additional moderately large nonconventional tight and coal bed methane resources.

Gulf of Mexico. This is the most prolific producing super-region, even though the mature shelf plays in shallower water are in rapid decline. Total undiscovered resource (244 TCF) is mainly in the deeper water plays where the complex geology due to salt causes higher exploration risk. Risk and deep drilling make this the highest cost area for exploration and development in the U.S. lower-48. The eastern Gulf of Mexico contains moderate undiscovered potential, but access to that region is restricted.

U.S. Atlantic Offshore. Although this area has moderate undiscovered resource (33 TCF), it is under a leasing moratorium. It was fairly well explored in the 1970s with no commercial discoveries, but the deeper water has not been tested. There was a gas discovery offshore New Jersey, but at the time it was not economic to develop. Recent adjacent Canadian discoveries are reason for moderate optimism for potential in the north of this super-region.

Eastern Interior. This area contains a very large, mainly nonconventional, undiscovered resource (92 TCF). Almost three-quarters of this potential is located in the Appalachian Region. However, production has barely grown over several decades. The main issues are low recoveries per well and the disparate mineral ownership. Technology improvement and a sustained higher price environment will cause moderate production growth in the Eastern Interior.

Canada

Canada contains five super-regions. The current annual production of 6 TCF more than satisfies internal demand. The surplus of about 3 TCF is exported to the United States. The Western Canada Sedimentary Basin contributes 97% of current production, but only 56% of Canada's 397 TCF of technical resource. As in the United States, the relative production contribution of Canada's five super-regions will change through time.

Western Canada Sedimentary Basin. The Western Canada Sedimentary Basin is mature and its production has plateaued. The remaining undiscovered conventional resource (93 TCF out of a total undiscovered resource of 138 TCF) is located in increasingly smaller average pool sizes. Nonconventional resources are not as well assessed as in the United States and have a large uncertainty range. Coal bed methane development is immature compared with the Rockies. Unlike the Rockies, access is a relatively minor issue.

Arctic Canada. A fairly large volume of stranded resources (25 TCF) has been discovered onshore and offshore, although much is remote. Approximately 30% of the stranded gas will be developed as part of the Mackenzie Gas Project. Undiscovered resource is 46 TCF. However, much of this will not be developed through 2025 because of remoteness and Arctic conditions.

Canada Atlantic (offshore). Like the Canadian Arctic, stranded resources (15 TCF) have been discovered, particularly off Labrador. The undiscovered resource is also large (68 TCF). High cost and lack of pipelines will limit development of much of this resource through 2025.

British Columbia (onshore and offshore). Excluding that part of British Columbia assessed in the Western Canada Sedimentary Basin, there is moderate undiscovered potential (11 TCF) in the inter-montane and the offshore/coastal basins. Offshore access is restricted, although there is potential that restrictions will be lifted.

Eastern Canada (onshore). This very large area has only small undiscovered conventional and nonconventional resource (6 TCF). There is some coal bed methane activity in Nova Scotia.

Mexico

For the purposes of this study, Mexico has been defined as a single super-region. Current annual gas production is 1.8 TCF. The annual shortfall of 8% of demand is provided by exports from the United States. Mexico has started an ambitious program to increase its exploration and development of gas resources.

Mexico has a moderate technical resource (121 TCF), which is mainly non-associated in the north and associated with the prolific oil production in the south. Compared to adjacent U.S. areas, Mexico has been more lightly explored, particularly offshore.

Resource Comparisons

As described earlier, the technical resource available for potential future production is composed of three categories: proved, growth, and undiscovered. The relative distribution of these three components of the resource base in the North American super-regions is described below.

Proved

Figure 4-38 ranks the super-regions by their proved gas reserves. The Western Canada Sedimentary Basin

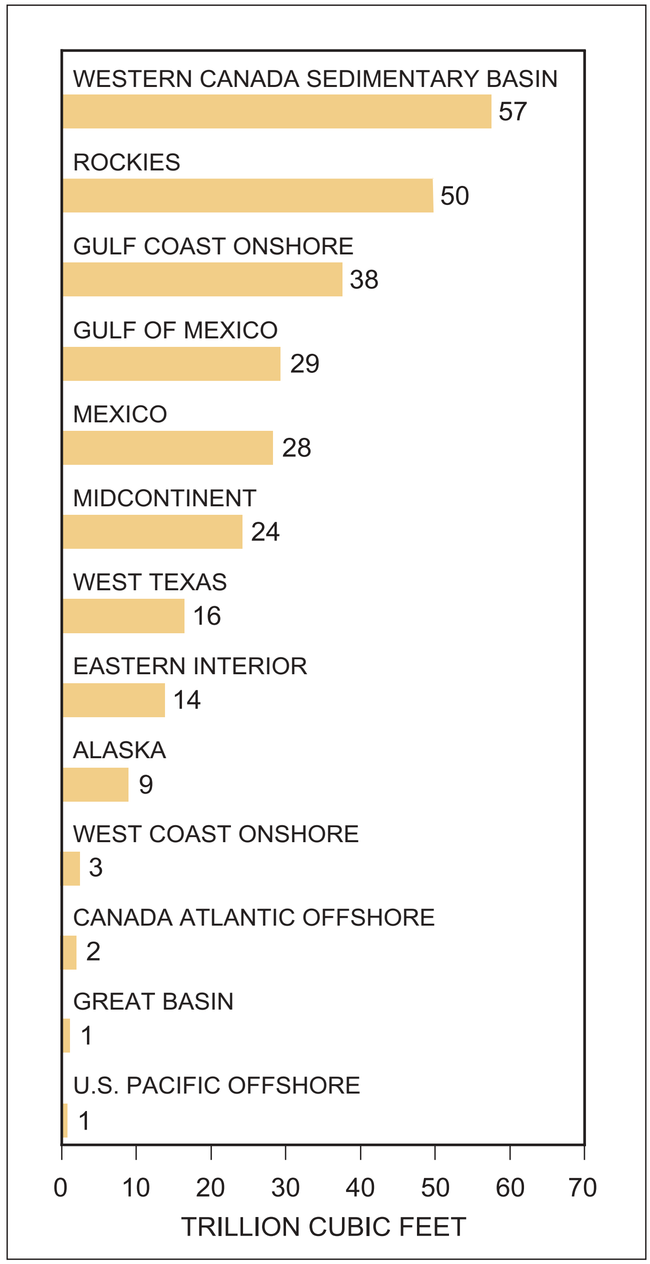


Figure 4-38. Super-Regions Ranked by Proved Reserves

contains the most proved reserves (57 TCF), followed by the Rockies (50 TCF), the Gulf Coast Onshore (38 TCF), and the Gulf of Mexico (29 TCF). Proved reserves in Alaska consist of 2 TCF from south Alaska and 7 TCF of fuel gas for ongoing Prudhoe Bay oil development. Northern Alaska has an additional 33 TCF of discovered gas resource, which is not booked as proved because of the current lack of a pipeline to market.

Of the three technical resource components, proved reserves is the least uncertain. In a given area, industry will generally develop proved reserves more economically than growth or undiscovered resources.

Growth

As described earlier, estimates of EUR generally increase over time. The difference between the current estimate of proved reserves and what is ultimately produced is known as growth. Figure 4-39 shows that 53% of the 277 TCF of reserve growth will be come from three super-regions. The largest is the Gulf Coast Onshore with 60 TCF, followed by the Gulf of Mexico with 55 TCF, and the Midcontinent with 32 TCF.

Growth estimates have intermediate uncertainty between proved and undiscovered. In a given area, industry will generally develop growth more economically than undiscovered resources.

Undiscovered

Figure 4-40 shows the super-regions ranked by volume of undiscovered technical resource. This technical resource is further split into conventional and nonconventional. Alaska ranks highest with 258 TCF, with 57 TCF of this nonconventional. The Gulf of Mexico ranks second in terms of undiscovered resource (244 TCF), although it has the largest conventional resource of all super-regions. The Rockies ranks third with 209 TCF of undiscovered resource, 173 TCF of which is nonconventional. The Mexico super-region ranks 7th with 70 TCF.

Of the three categories of technical resource, undiscovered estimates are the most uncertain. Since most of the North American super-regions are relatively mature, the average remaining undiscovered field size is small. Combining this with the higher risk of exploration failure causes a smaller proportion of undiscovered to be economic compared to proved or growth.

Figure 4-41 shows each super-region's relative contribution of conventional undiscovered resource. The distribution is skewed, with only a few major contributors.

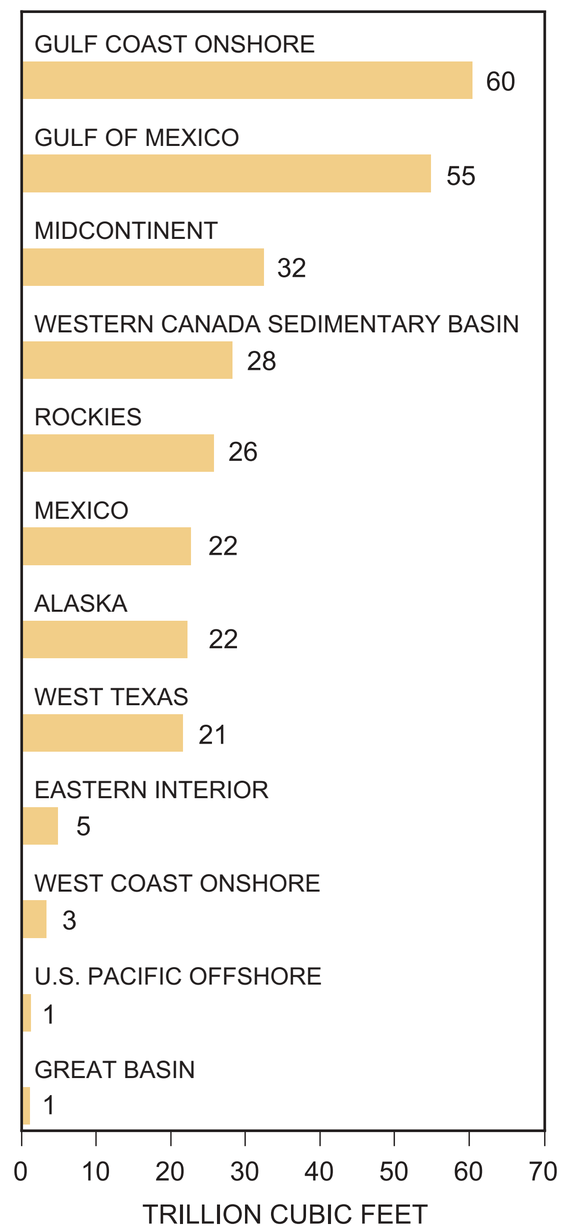


Figure 4-39. Super-Regions Ranked by Reserve Growth

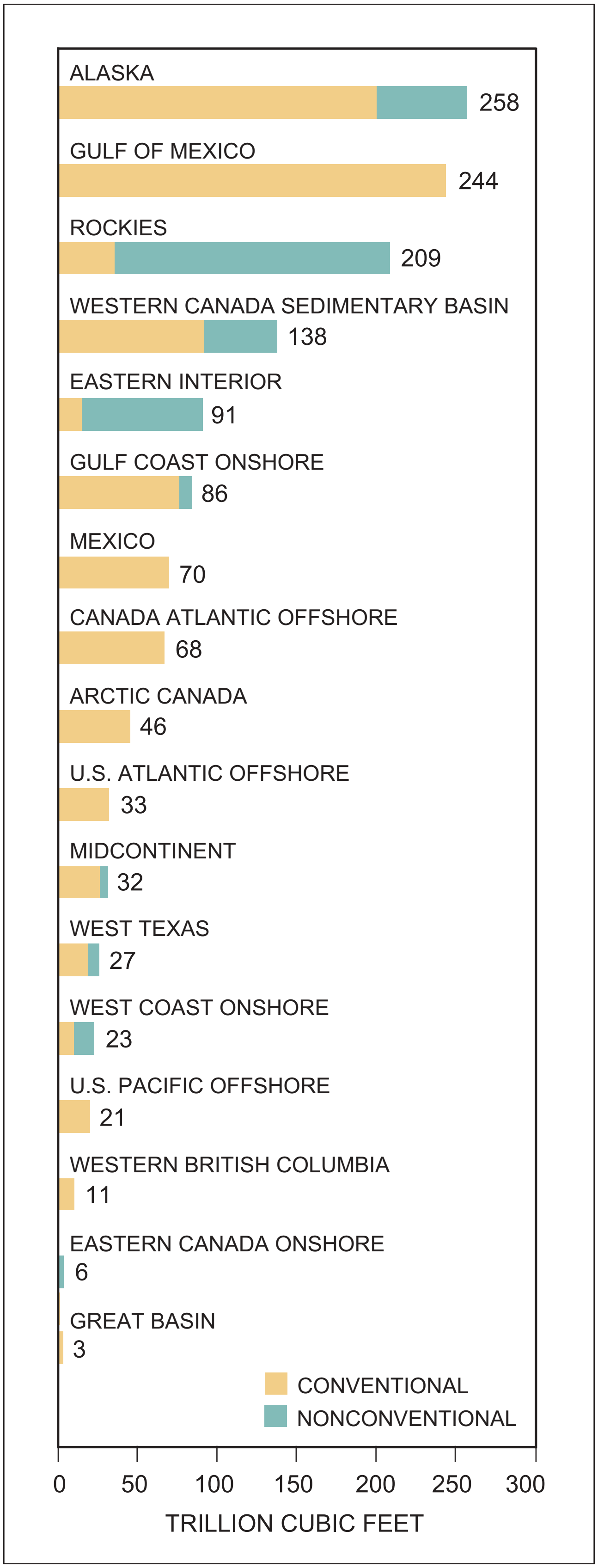


Figure 4-40. Super-Regions Ranked by Undiscovered Technical Resource

The Gulf of Mexico ranks first with 25%, followed by Alaska with 21%, and the Western Canada Sedimentary Basin with 9%.

In contrast, Figure 4-42 shows the relative contribution of nonconventional undiscovered resource. This distribution is even more skewed than for conventional undiscovered. Only 9 of the 17 super-regions contain nonconventional resource of any significance. In this case, the Rockies ranks first with 44%, followed by the Eastern Interior with 20%, Alaska with 15%, and the Western Canada Sedimentary Basin with 12%.

Main Conclusions from Super-Region Comparison

- Of the total 1,969 TCF of North American technical resource, 69% is undiscovered, 17% is growth, and 14% is proved. In any one area, proved will generally be developed first, followed by growth and then undiscovered.

- Four super-regions (Gulf of Mexico, Rockies, Western Canada Sedimentary Basin, and Alaska) contribute a large proportion (62%) of North America's undiscovered resource.

- In terms of nonconventional resource, just four super-regions (Rockies, Eastern Interior, Alaska, and Western Canada Sedimentary Basin) contribute 90% of the undiscovered potential.

- The current North American proved reserve base, which now totals 272 TCF, is expected to grow by 277 TCF, or by 102%. The Gulf Coast Onshore, the Western Canada Sedimentary Basin, the Gulf of Mexico, and the Rockies will contribute over 63% of the proved reserves plus growth total, providing a large proportion of near-term production volume.

- Although North American production will increase slightly by 2025, the relative contributions of the super-regions will change significantly. Decline will be most severe in the Gulf Coast Onshore, West Texas, and the Western Canada Sedimentary Basin. On the other hand, these declines will be offset by production increases in the Rockies, Eastern Interior, Alaska, and Mexico.

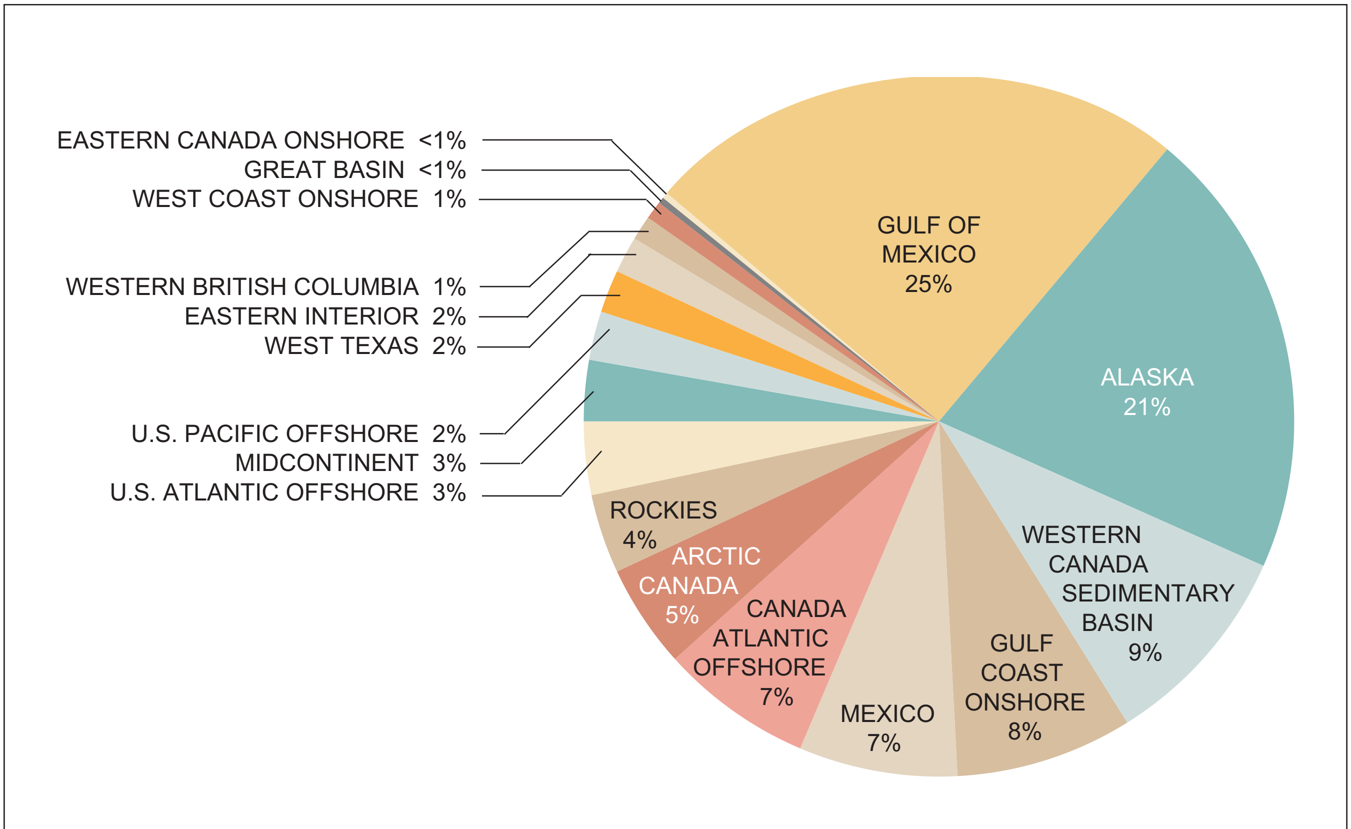


Figure 4-41. Distribution of Conventional Undiscovered Resource

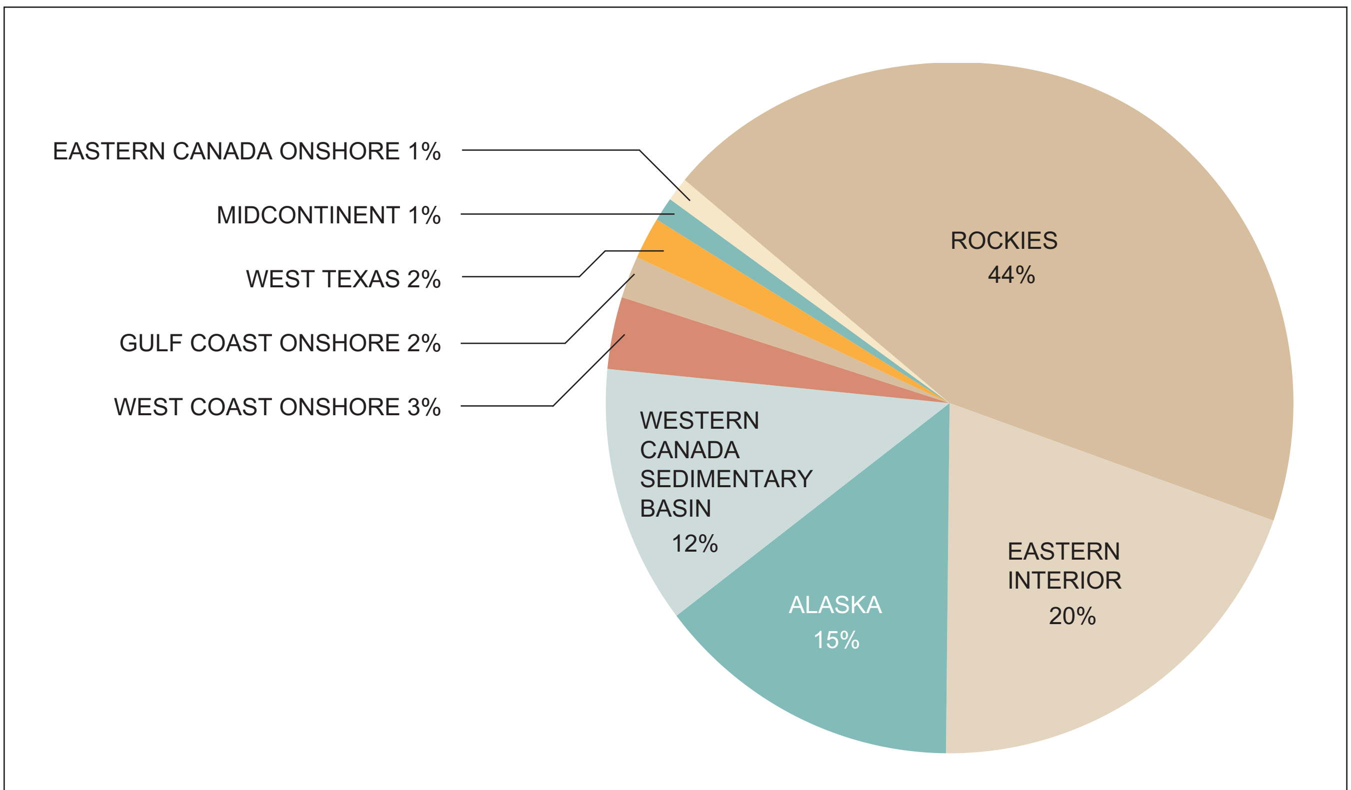


Figure 4-42. Distribution of Nonconventional Undiscovered Resource

Cost Methodology

A critical part of the NPC study was estimating reasonable costs for use in the model to determine commercial resources. Costs were needed for all aspects of onshore and offshore gas development – exploration and development drilling, production and lease facilities, and operations and maintenance. Where possible, public and commercial databases were used to estimate costs. Sources included, among others, the API Joint Association Survey on Drilling Costs, the PSAC Well Cost Studies, and the EIA Oil & Gas Lease Equipment and Operating Costs report. In areas where adequate public and commercial data were not available, costs were based on available information and circulated for review and comment to industry experts familiar with costs in that area. Costs were then revised based on the input received. At each of the regional workshops, which were held primarily to review the resources, costs were also discussed in order to determine the key factors that might affect costs in that region (i.e., infrastructure, weather, drilling depths, etc.).

The costs used in the model are average costs for generic operations. For example, the well costs are for generic wells at an average drill depth. Actual costs will vary with regards to water depth, drill depth, pore pressure, rig type, etc., depending on specific locations. The same is true for development costs. Actual costs will depend on location, infrastructure, metocean conditions, well productivity, etc. All costs used in the modeling exercise were expressed in year 2000 dollars.

Gulf of Mexico

The Gulf of Mexico was divided into eight super-play regions and subdivided by six water-depth intervals. Well depths were based on the resource weighted average reservoir depth, referenced to sea level, for a given super-play and water depth. Costs were developed for both shallow-water and deepwater scenarios. For the shallow-water scenarios, two water depths were assumed (100’ and 400’), and costs were developed for both exploration wells and platform development wells. For the deepwater scenarios, four water depths were assumed (1000’, 2000’, 4000’, and 6000’), and costs were developed for exploration wells and both subsea-completed and platform-completed development wells.

The Minerals Management Service provided the initial drilling and completion (D&C) costs. These costs were sent to industry experts for review and were adjusted based on their comments.

Non-drilling costs make up a substantial part of offshore development costs. These non-drilling development costs include production platforms, production equipment, subsea equipment, abandonment costs, and the costs of gathering pipelines. These costs are dependent on the development concept selected for a field. Field size, water depth, location, and well productivity determine this concept. For this study, the following development concepts were used for costing purposes in the Gulf of Mexico: a steel pile jacket (SPJ), which is a bottom-founded fabricated steel structure; a tension leg platform (TLP), which is a seabed anchored buoyant/compliant substructure constructed in steel or concrete; a spar, a buoyant concrete caisson that is anchored to the seabed; and subsea production systems/tiebacks.

The initial non-drilling development costs were based on spreadsheets from EEA and were benchmarked and adjusted based on the Wood Mackenzie database. Development costs were calculated for 20 different field sizes for all of the water depths and drill depths associated with each super-play. These costs were plotted and sent to industry experts for review and were adjusted based on their comments.

Operating costs for the Gulf of Mexico were based on the Wood Mackenzie U.S. Gulf of Mexico Deepwater Study (November 2001). Summaries of these costs were sent to industry experts for review and were adjusted based on their comments.

Lower-48 Onshore

Drilling and completion costs for the lower-48 onshore wells were based on the API Joint Association Survey on Drilling Costs. This survey has been conducted annually since 1959 and is sent to operators who have conducted drilling operations during the year. The survey provides total D&C costs for oil, gas, and dry wells on a state and regional basis by depth intervals. All cost components such as permitting, location construction, mobilization, rentals and services, tangible items, and stimulations are assumed to be included. The API Joint Association

Survey on Drilling Costs also contains a breakdown of D&C costs for coal bed methane, horizontal, and sidetrack wells.

For this NPC study, the 1999 and 2000 surveys were used to determine an average base case cost for oil, gas, and dry wells in 26 regions. The regions were divided into four depth intervals at 5,000-foot increments.

Onshore development costs, also known as lease equipment costs, consist of everything needed to produce a well downstream of the wellhead tree (i.e., flowline and connections, separators, dehydrators, pumps, and storage tanks). Onshore development costs were derived from EIA's Report "Oil and Gas Lease Equipment and Operating Costs 1986 Through 2000." This report, which has accompanying Excel spreadsheets, presents estimated costs of all equipment and services that are in effect during June of each year. The aggregate costs for typical leases by region, depth, and production rate are averaged, and these averages provide a general measure of the changed costs from year to year for lease equipment and operations. The report is in the public domain and can be viewed on EIA's website.

Alaska – Onshore and Offshore

Cost parameters (water depth and reservoir depth) were provided for fourteen regions. D&C costs for six onshore regions were initially based on limited data contained in the API Joint Association Survey. These costs were sent to industry experts and adjusted based on additional industry experience. D&C costs for eight offshore regions were initially based on previous EEA-generated costs. These costs were also sent to industry experts and adjusted based on additional industry input.

Onshore development costs consist of the same components as onshore U.S. lower-48 estimates, with additional costs added for access road and utility construction due to the remote locations of the new fields. Onshore development and operating costs, expressed on a per-well basis, are based on EEA-generated costs that were reviewed and adjusted by industry experts.

Offshore development costs consist of the same components as U.S. Gulf of Mexico estimates. The development concepts considered in this study for offshore Alaska were: an offshore platform, usually a steel pile jacket; a gravel island; a gravity based structure (GBS), a platform constructed in concrete which sits on the seabed; and subsea production systems/tiebacks.

Initial development costs were based on EEA-generated costs benchmarked and adjusted using the Wood Mackenzie database. These costs were sent to industry experts for review and were adjusted based on their comments.

Offshore operating costs, expressed as costs per well, are based on EEA-generated costs that were reviewed and adjusted by industry experts.

Atlantic Offshore

Cost parameters (water depth and reservoir depth) were provided for six regions. Due to lack of recent drilling and development activity in the Atlantic Offshore region, D&C, development, and operating costs were based on Gulf of Mexico costs for similar water depths and reservoir depths. Adjustment factors based on industry experience were used to account for the differences in infrastructure, logistics, weather, drilling conditions, etc. D&C cost adjustment factors ranged from 1.4 to 1.75, while development cost adjustment factors ranged from 1.4 to 1.6.

Pacific Offshore

Cost parameters (water depth and reservoir depth) were provided for six regions. Due to minimal drilling and development activity in the Pacific Offshore region, D&C, development, and operating costs were based on Gulf of Mexico well costs for similar water depths and reservoir depths. Adjustment factors based on industry experience were used to account for the differences in infrastructure, logistics, weather, drilling conditions, etc. D&C cost adjustment factors ranged from 1.1 to 2.0 while development cost adjustment factors ranged from 1.2 to 1.5.

Western Canada Onshore

D&C costs were based on the Petroleum Services Association of Canada's well-cost studies. The PSAC is the national association of Canadian oilfield service, supply, and manufacturing companies; it develops two well-cost studies per year, one for the summer drilling season and one for the winter drilling season. These studies contain D&C costs in a detailed Authority for Expenditure (AFE) format for the "typical" or "most popular" wells being drilled. The studies generally include 30 to 35 wells.

Western Canada was divided into five geographical regions and then subdivided by depth intervals. The summer 2002 and winter 2003 cost studies were used to determine average D&C costs, which were then de-escalated to 2000 dollars for model input.

Onshore development costs consist of the same components as the U.S. lower-48 onshore estimates with additional costs added for access road and utility construction due to the remote locations of the new fields. Onshore development and operating costs per well were based on EEA-generated costs that were reviewed and adjusted by industry experts.

Canada Offshore and Onshore Other

Cost parameters (water depth and reservoir depth) were provided for three onshore regions and eleven offshore regions. D&C costs were initially based on preliminary work (December 2002) by the Canadian Energy Research Institute (CERI) and previous EEA-generated costs. These costs were sent to industry experts for review and were adjusted based on their comments. Offshore wells were assumed to be drilled with a jack-up or semi-submersible drilling rig.

Onshore development costs consist of the same components as the U.S. lower-48 onshore estimates with additional costs added as required for access road and utility construction due to remote locations of the new fields. Onshore development and operating costs per well, are based on EEA generated costs that were reviewed and adjusted by industry experts.

Offshore development costs consist of the same components as U.S. Gulf of Mexico estimates. Development concepts considered in this study for offshore Canada were: an offshore platform, usually a steel pile jacket; a gravel island; a gravity based structure (GBS), a platform constructed in concrete which sits on the seabed; and subsea production systems/tiebacks. Initial development costs were based on EEA-generated costs, preliminary work by the Canadian Energy Research Institute, and the Wood Mackenzie database. These costs were sent to industry experts for review and were adjusted based on the comments received.

Mexico

Cost parameters (water depth and reservoir depth) were provided for seven onshore and three offshore regions. D&C costs for onshore areas were based on data from the Pemex website for multiple services contract for the Burgos Basin. The costs for the Burgos Basin were extrapolated to other areas based on average depth. Offshore D&C costs were based on Gulf of Mexico well costs for similar water depths and reservoir depths. An adjustment factor of 1.5 was used to account for the differences in infrastructure, logistics, drilling conditions, etc.

Development costs for Mexico came from the IHS Mexico study. For onshore developments, the development plan included wellsites tied back to a dedicated production facility incorporating separation, condensate stabilization, gas dew-pointing, gas export, compression and condensate export. Gas and condensate are exported to main gas and oil export pipelines that send oil and gas to a processing plant.

Two development concepts were used in the IHS study for offshore developments. For small fields and shallow water, a lightweight steel jacket supporting wellheads was used. For larger fields and in deepwater, the development plan consists of steel jackets supporting wellheads, production, quarters, and compression.

Nonconventional Gas

Costs for nonconventional gas development (coal bed methane and tight gas) were handled in each geographical area using essentially the same cost methodology used for conventional developments. For coal bed methane developments, adjustments required for the unique production style (i.e., dewatering of the coal prior to onset of gas production) were made. Dehydration and storage tank costs were removed from the lease equipment cost component, and costs for water handling equipment and compression were added. In addition, capital and operating and maintenance costs for water disposal, dependent on the type of disposal (i.e., surface discharge or re-injection), were included. Costs for stimulation of tight gas zones were accounted for in the D&C costs.

Rig Fleet Availability

An important consideration in the development of future resources is the future availability of equipment, particularly drilling rigs. Most of the rigs currently available for use today were built in the late 1970s and early 1980s. Since this time period, which also had the peak number of active rigs, both the onshore and offshore rig fleets have declined. One annual survey that tracks the number of available U.S. rigs is the Reed-Hycalog Rig Census. Conducted since the 1950s, this survey tracks the number of rigs available by surveying drilling contractors. Rigs are considered available if they have worked during a 45-day qualification period. Rigs not considered available include those requiring a capital expenditure (excluding drillpipe) of $100,000 for a land rig and $1,000,000 for an offshore rig and those rigs stacked for more than three years. Also not considered are rigs that cannot drill below 3,000 feet.

Figure 4-43 shows the Reed-Hycalog Census data for the past 15 years. In 1987, the total number of rigs available, both land and offshore, was 3,331 (peak was in 1982 with 5,644 available rigs). In 2001, the total available was 1,722.

For this study, major drilling contractors were consulted in order to estimate future attrition rates for rigs. Different rig fleet attrition scenarios were discussed and a consensus was reached on a scenario for both the onshore and offshore rig fleets. Figures 4-44 and 4-45 show the estimated rig fleet availability out to 2025.

For the onshore fleet, a period of slight growth and stabilization was assumed out to 2005. For the next 20 years, the following attrition rates to the existing rig fleet were assumed: 2006-2010, 1%; 2011-2015, 1.5%; 2016-2020, 2%; 2021-2025, 3%.

For the offshore fleet, a period of slight growth and stabilization was also assumed out to 2005. For the next 20 years, the following attrition rates to the existing rig fleet were assumed: 2006-2010, 2%; 2011-2015, 2.5%; 2016-2020, 3%; 2021-2025, 3.5%.

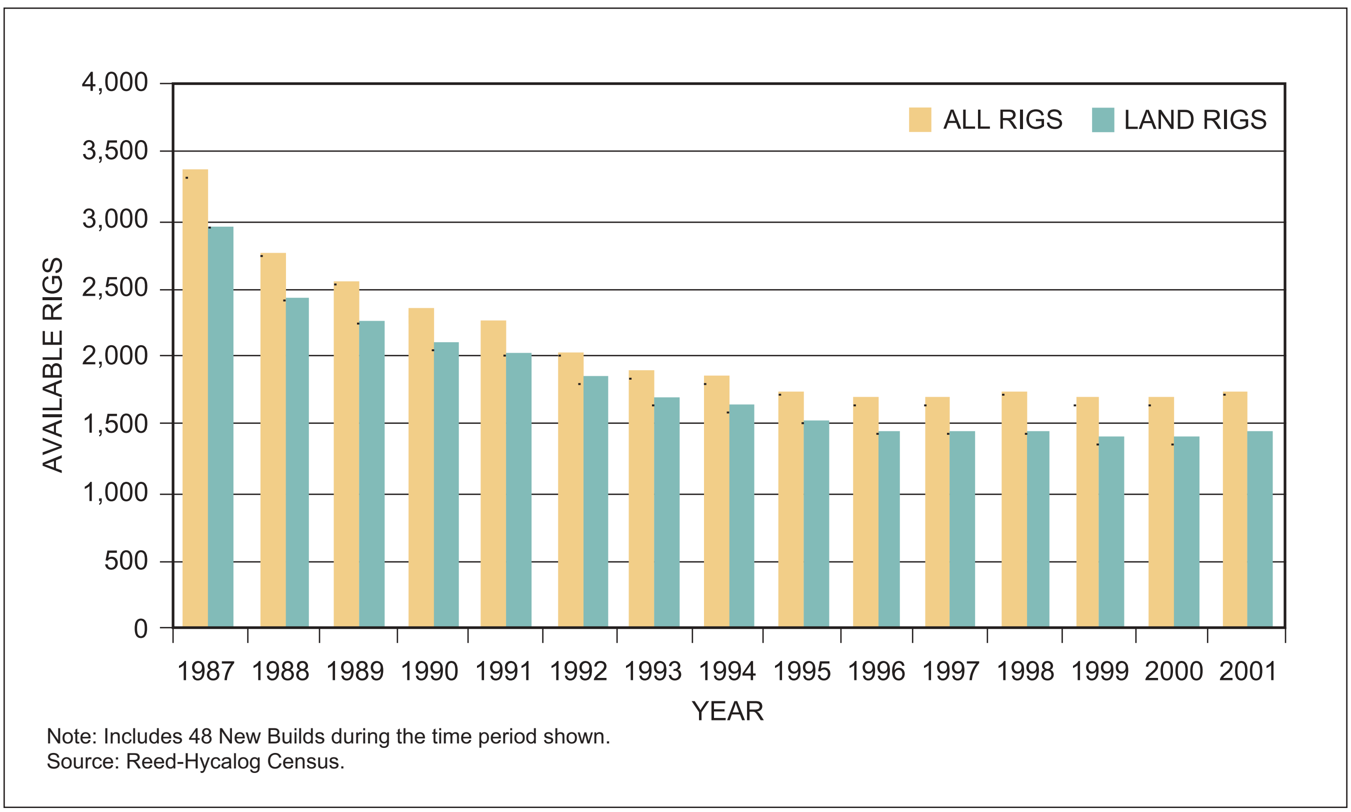


Figure 4-43. Rig Fleet Availability

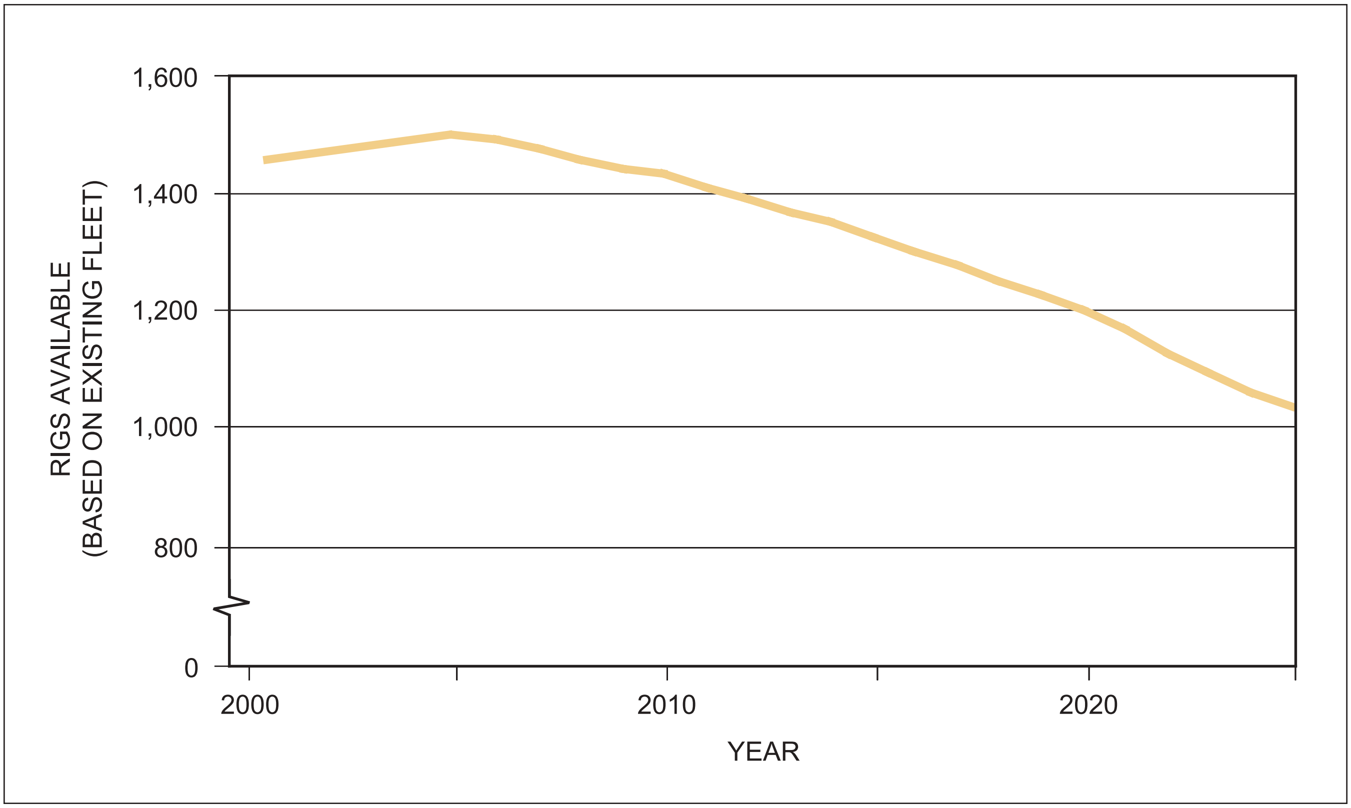


Figure 4-44. Projected Onshore Rig Fleet Attrition

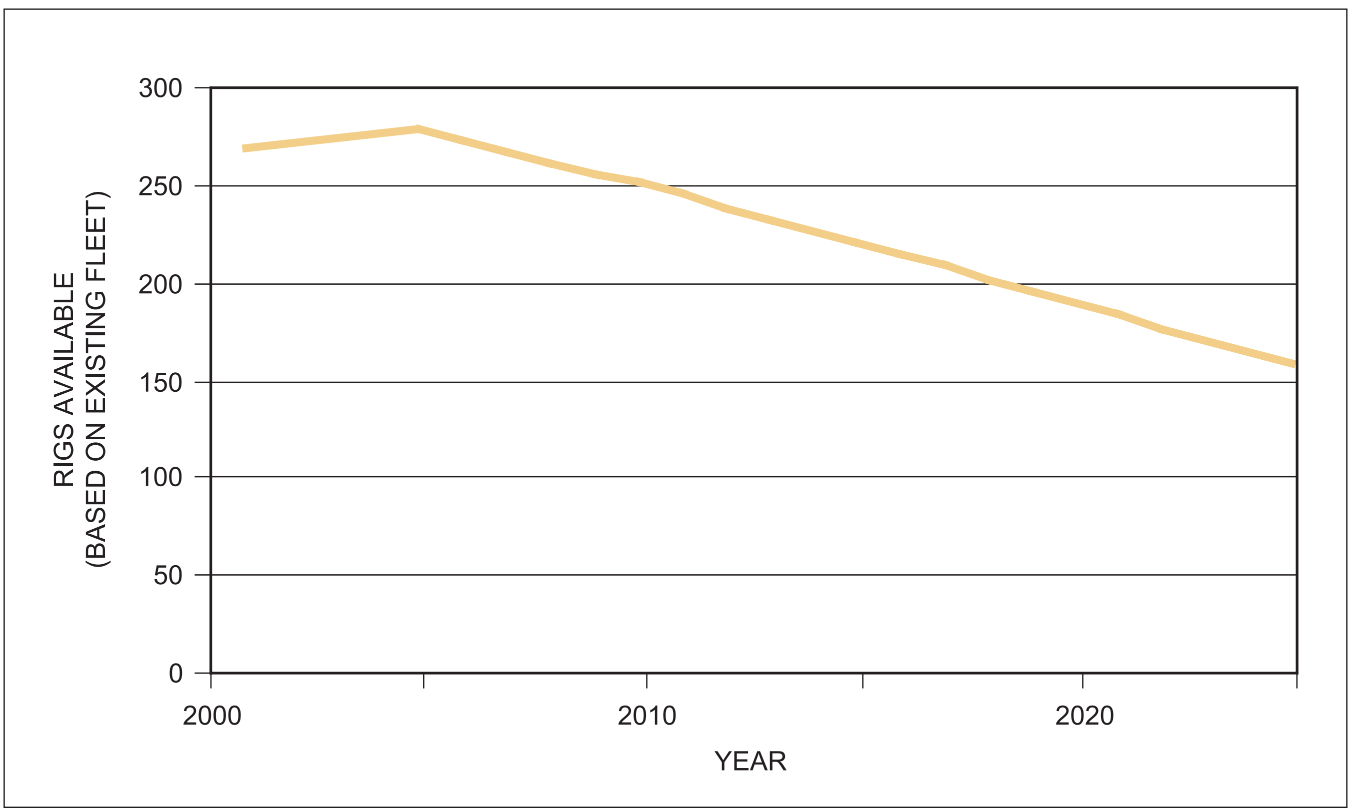


Figure 4-45. Projected Offshore Rig Fleet Attrition

Production Performance Analysis

In order to help estimate future well performance parameters and to calibrate HSM model results, an analysis of historical production performance was undertaken for the U.S. lower-48 and Western Canada. Analyses were conducted for the period from 1990 to 2002, in order to put current trends into a long-term context. The analysis then focused on the last four years of production performance with the aim of understanding the reasons behind the lack of significant, sustained production response following the large ramp-up of industry activity in 2000 and 2001.

Production performance was analyzed using four parameters to describe key trends and to understand the causes of those trends. The four parameters were:

- Gas Well Drilling Activity vs. Production
- Individual Gas Well Performance
  - Estimated Ultimate Recovery
  - Initial Production Rate
  - Initial Decline Rate
- Base Decline of Existing Reserves
- Reserves and R/P Ratios.

Production performance parameters were summarized on a regional basis, although most areas were analyzed on a much more granular basis looking at individual formation response, response by depth tranche, and response by resource type (i.e. coal bed methane vs. conventional performance).

The NPC utilized EEA's Gas Supply Review (GSR) as its primary data source to analyze production performance. The majority of the data for the analysis emanated originally from the IHS Production Database under license to EEA. Thus, source references in this chapter to EEA's Gas Supply Review include data supplied by Petroleum Information/ Dwights LLC; Copyright (2003) Petroleum Information/Dwights LLC.

To standardize the vast amount of data and perform standard analyses, the IHS production data were conditioned by EEA to ensure completeness and standardization. The production performance parameters generated in the analysis were used either as direct inputs to the HSM, or to check HSM outputs.

U.S. and Canadian Production Overview

Annual average production of dry gas in the U.S. lower-48 and Canada has increased 11 BCF/D (0.9 BCF/D per year) from 57.8 BCF/D in 1990 to 68.9 BCF/D in 2002, an increase of 19% (1.8% per year). As illustrated in Figure 4-46, peak production rates have increased substantially less, as the excess gas deliverability present in the early 1990s has been progressively used to satisfy increasing summer power demand and to fill incremental gas storage.

As the North American gas basins have matured, total supply growth has slowed considerably, from 2.3% per year in the early 1990s, to 0.6% per year over the 1996-2002 period. U.S. lower-48 production has remained essentially flat since 1996. Gas production declined in 2002 from the United States and Canada as a whole and from the Western Canada Sedimentary Basin, North America's largest producing region.

Production gains were largely concentrated in three regions, Western Canada, the Rocky Mountains, and the Deepwater Gulf of Mexico, as technology and advancing infrastructure allowed the industry to exploit these less mature, highly prospective areas. These three areas now account for approximately 45% of total gas production, up from 27% in 1990. In the more mature Gulf of Mexico shelf and onshore lower-48 basins, while the industry was able to maintain stable production levels through the mid-1990s, as these basins continued to mature their production began falling, offsetting increases in other basins.

In the U.S. lower-48, the character of the production has also been changing. Conventional gas production actually fell throughout the 1990s, as shown in Figure 4-47. Nonconventional production – namely coal bed methane, shale gas, and tight gas – grew from 12% of production in 1990 to over 25% in 2002.

U.S. Lower-48: Activity vs. Production

Industry activity levels for natural gas exploration, development, and production, as measured by rig count and gas well connections, have historically exhibited a strong correlation to the price of natural gas, as shown in Figure 4-48. The early 1990s were characterized by low gas prices ($1.75 average Gulf Coast Spot Price) and a gas rig count of approximately 400 rigs. Gas prices rose in the 1997-1999 period, averaging $0.45/MMBtu higher, or $2.20/MMBtu. As prices rose, the gas rig count rose to an average of 540

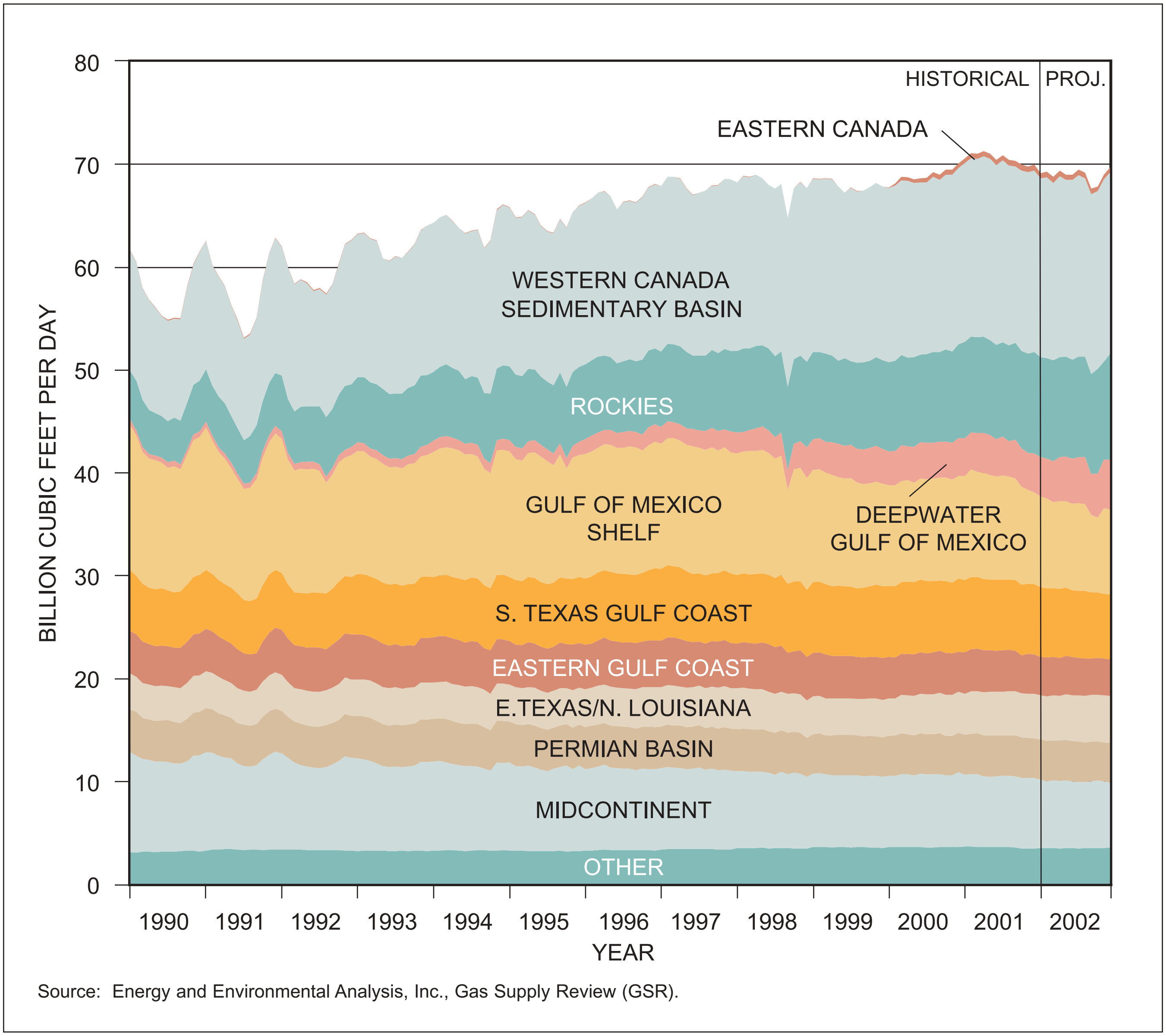


Figure 4-46. U.S. Lower-48 and Canadian Production by Region

rigs. Gas prices continued to climb and Gulf Coast Spot Prices averaged $3.65/MMBtu from 2000 through 2002. As prices increased, rig activity also rose, with an average gas rig count of 780 rigs over the period. In June 2003, the rig count stood at approximately 900 gas rigs and a Gulf Coast Spot Price at $5.80.

As measured by gas well completions, a similar pattern of increasing activity emerges and is shown in Figure 4-49. In the early part of the decade, the industry averaged 400 gas rigs and 9,700 gas completions per year. As the rig count increased by 35% to 540 gas rigs during the 1997-1999 period, average gas completions rose by 25% to 12,100 gas completions per year. Over the 2000-2002 period, gas completions increased to 19,300 gas completions per year, almost double what they were averaging a decade before.

While yearly annual production rates grew in the early 1990s, this growth was primarily due to a change in production patterns, rather than a true increase in wellhead deliverability. Peak production rates remained flat at 50 BCF/D year on year. Increasing production during summer months for storage and to meet growing summer power demands allowed annual average production to increase.

Since the early 1990s, the rig activity level needed to sustain production has increased substantially as shown in Figure 4-50. While an average gas rig count

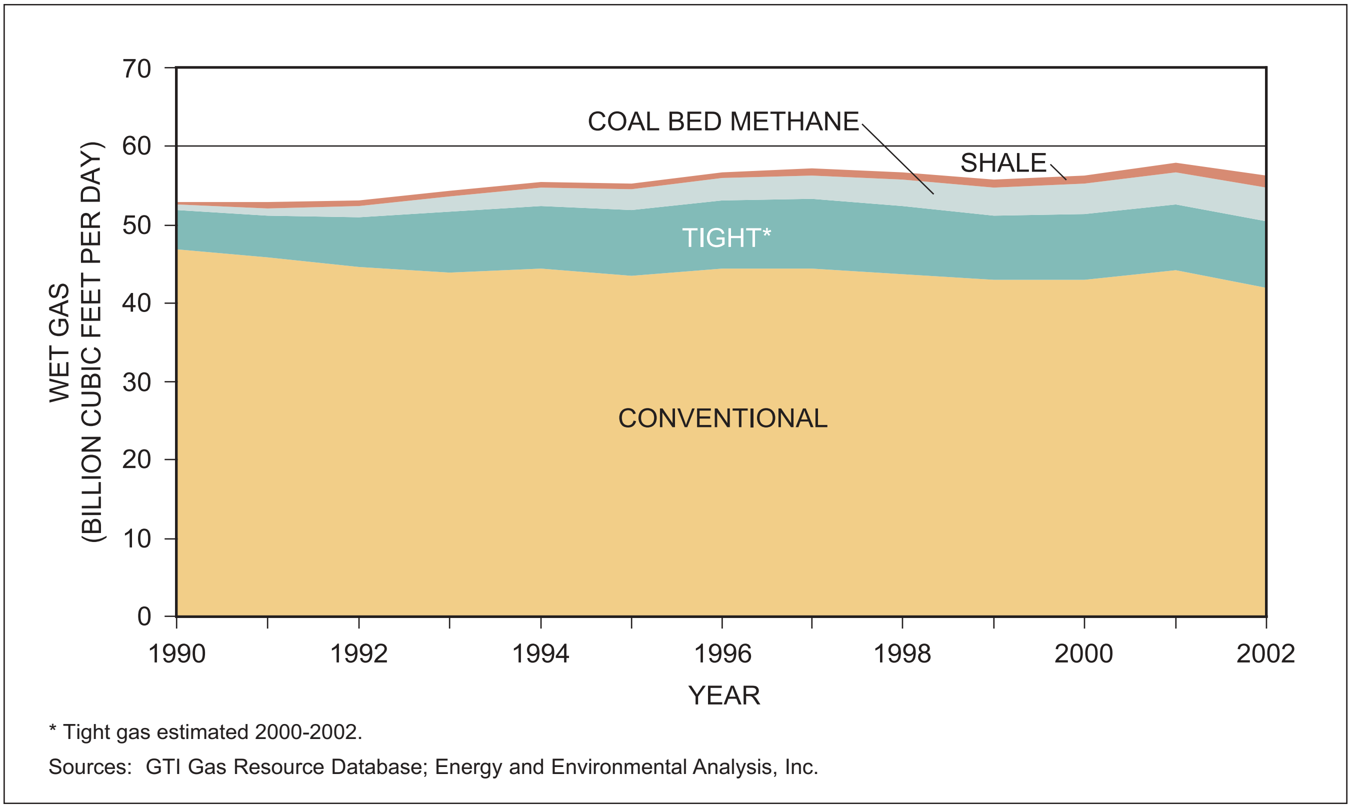


Figure 4-47. Lower-48 Wet Gas Production by Resource Type

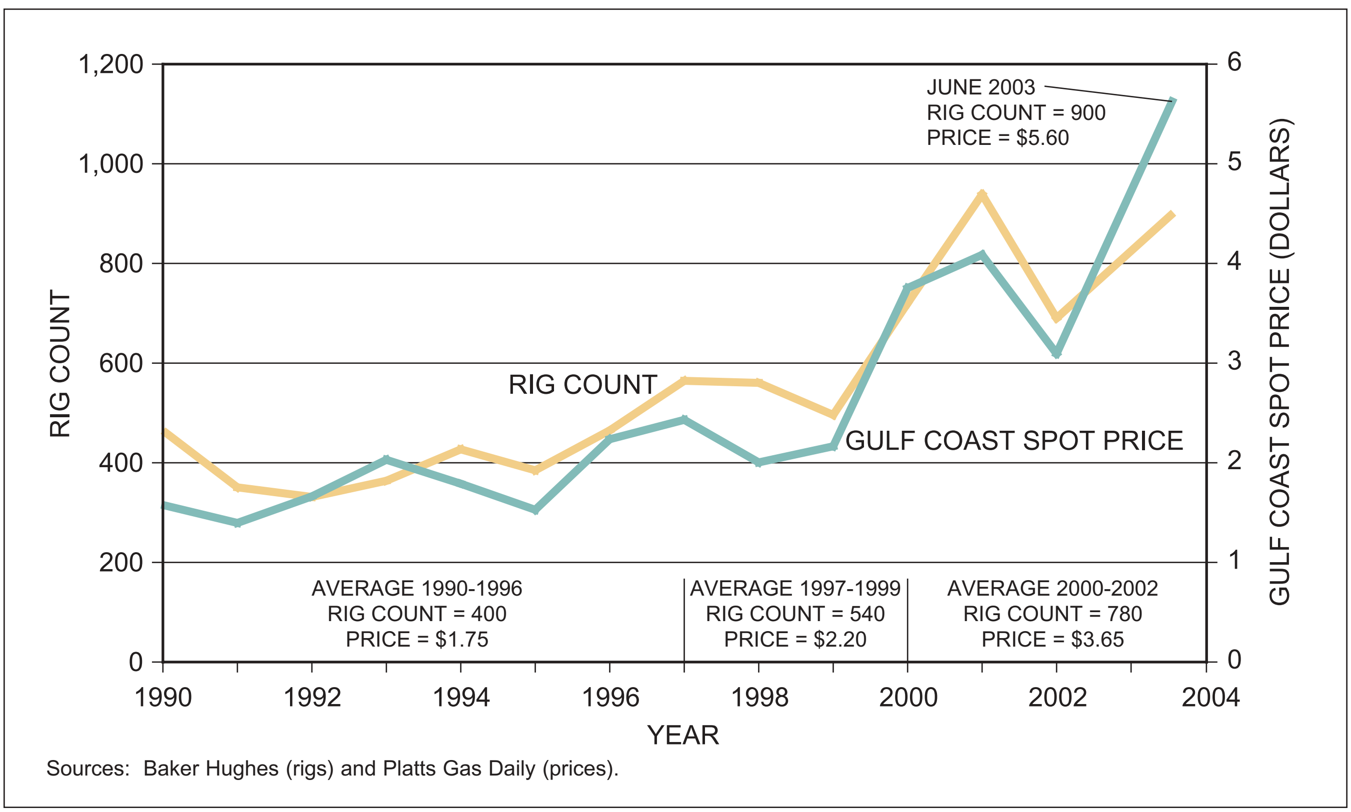


Figure 4-48. Lower-48 Gas Rig Count and Gulf Coast Spot Price

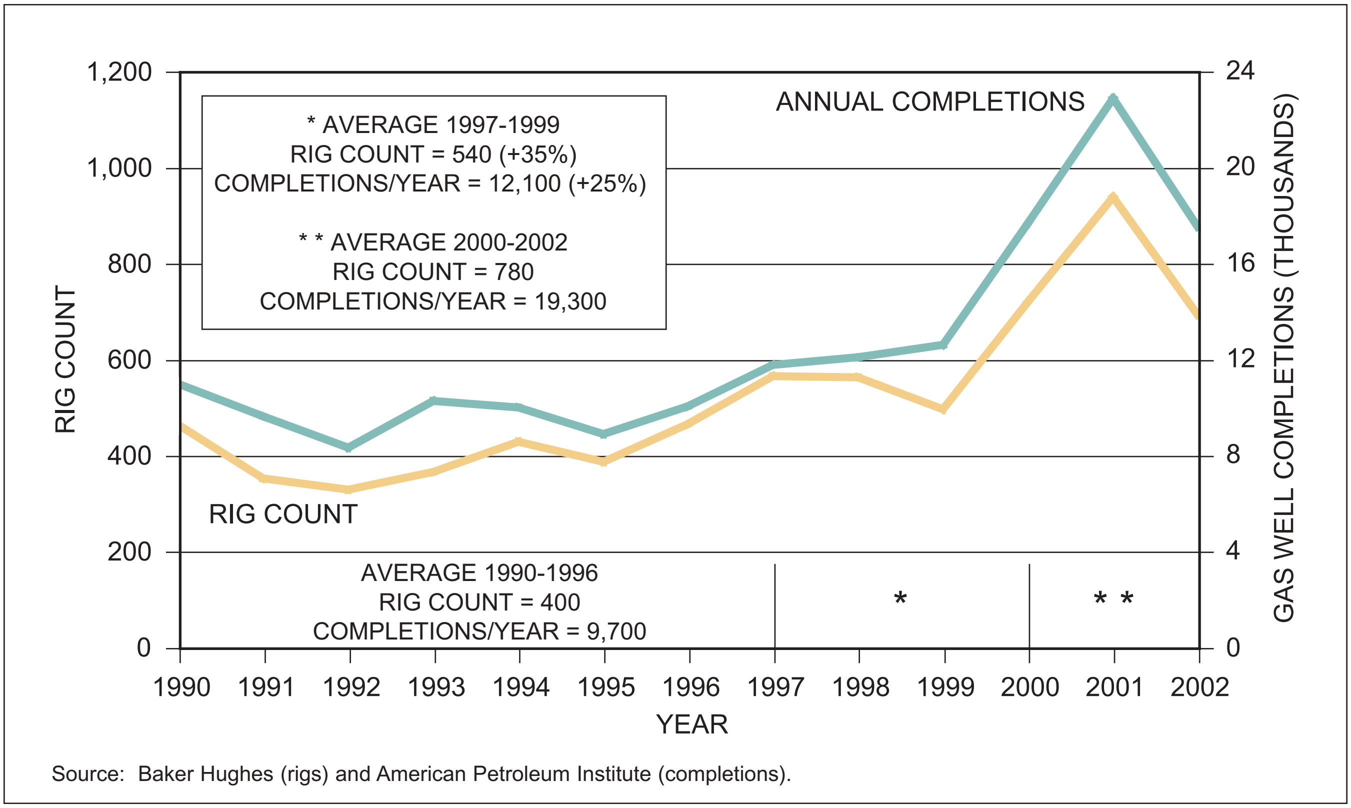


Figure 4-49. Lower-48 Gas Rig Count and Gas Completions

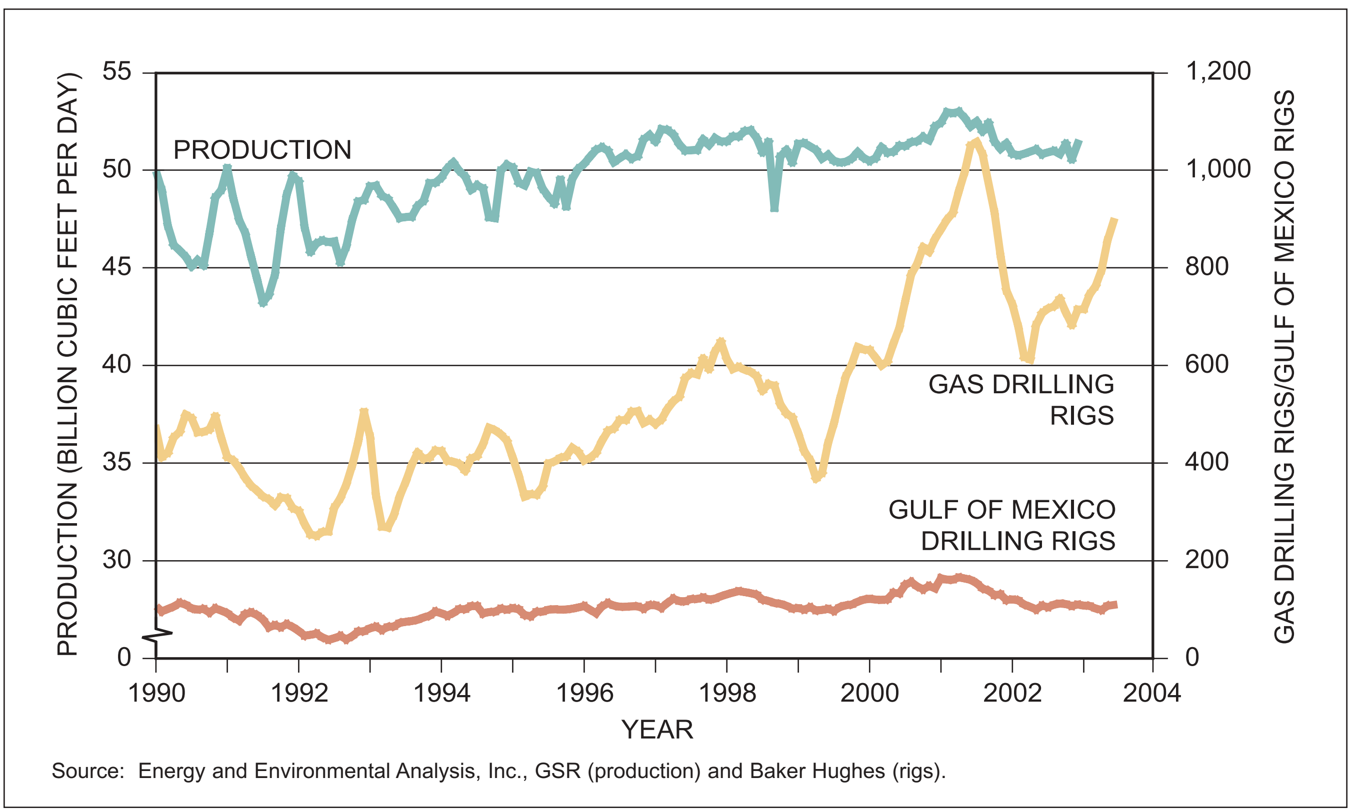


Figure 4-50. Lower-48 Total Dry Gas Production and Rig Count

of 400 was sufficient to sustain production peak rates in the early 1990s, the industry has averaged much higher rig counts recently. The latter half of the 1990s has seen two complete industry drilling cycles (1997-1999 and 2000-2002). In the 1997-1999 ramp-up, production increased by 2 BCF/D as the gas rig count rose from 400 to 650. Following this peak, production gradually fell off as activity levels declined. In the 2000-2002 cycle, the rig count increased from 400 to over 1,050 rigs, nearly double the peak rates in 1997 to achieve an increase in production of a roughly similar amount. As prices fell and drilling slowed, production fell dramatically, even with rig activity levels above the peak rig count in 1996-1998.

Western Canada: Activity vs. Production

Since 1990, 65% of the incremental supply of North American gas has come from increasing Canadian production, primarily from the Western Canada Sedimentary Basin. However, production growth in Western Canada has slowed dramatically, so much so that 2002 was the first year that the Western Canada Sedimentary Basin experienced declining production (Figure 4-51). In the early 1990s, as gas export infrastructure grew, Western Canadian production grew by 4.5 BCF/D from 1990-1995 from an average of 3,000 gas well completions per year (Figure 4-52). Growth rates slowed through the rest of the 1990s, even as gas well completions peaked at over 10,500 completions in 2001, or over three times the completions in the beginning part of the decade. The 2001 and 2002 production rates were boosted by significant production from the Ladyfern Field in British Columbia, a field that is beginning to decline.

Individual Gas Well Performance

Individual gas well performance was analyzed using three basic parameters: (1) Estimated Ultimate Recovery, (2) Initial Production Rate, and (3) Initial Decline Rate.

Estimated Ultimate Recovery

Estimated Ultimate Recovery is an estimate of how much gas an individual gas connection will produce over its economic life. EURs generally decline as basins mature, as the industry targets the larger, more economic prospects first. However, the EUR profile can be very complicated, with natural EUR decline being mitigated by a number of factors:

- Technology (e.g., 3D seismic opening deeper, underexplored parts of the basin)

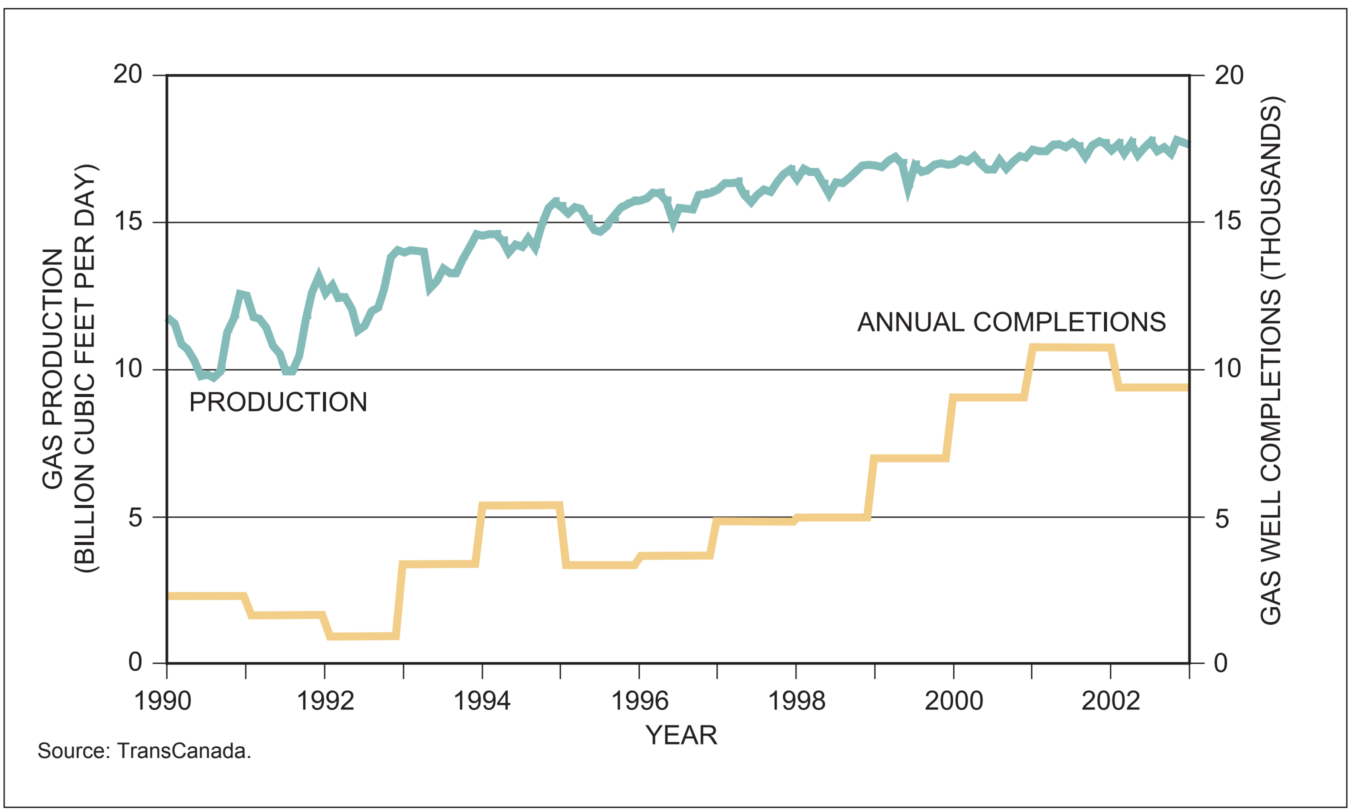


Figure 4-51. Western Canada Sedimentary Basin Production and Gas Well Completions

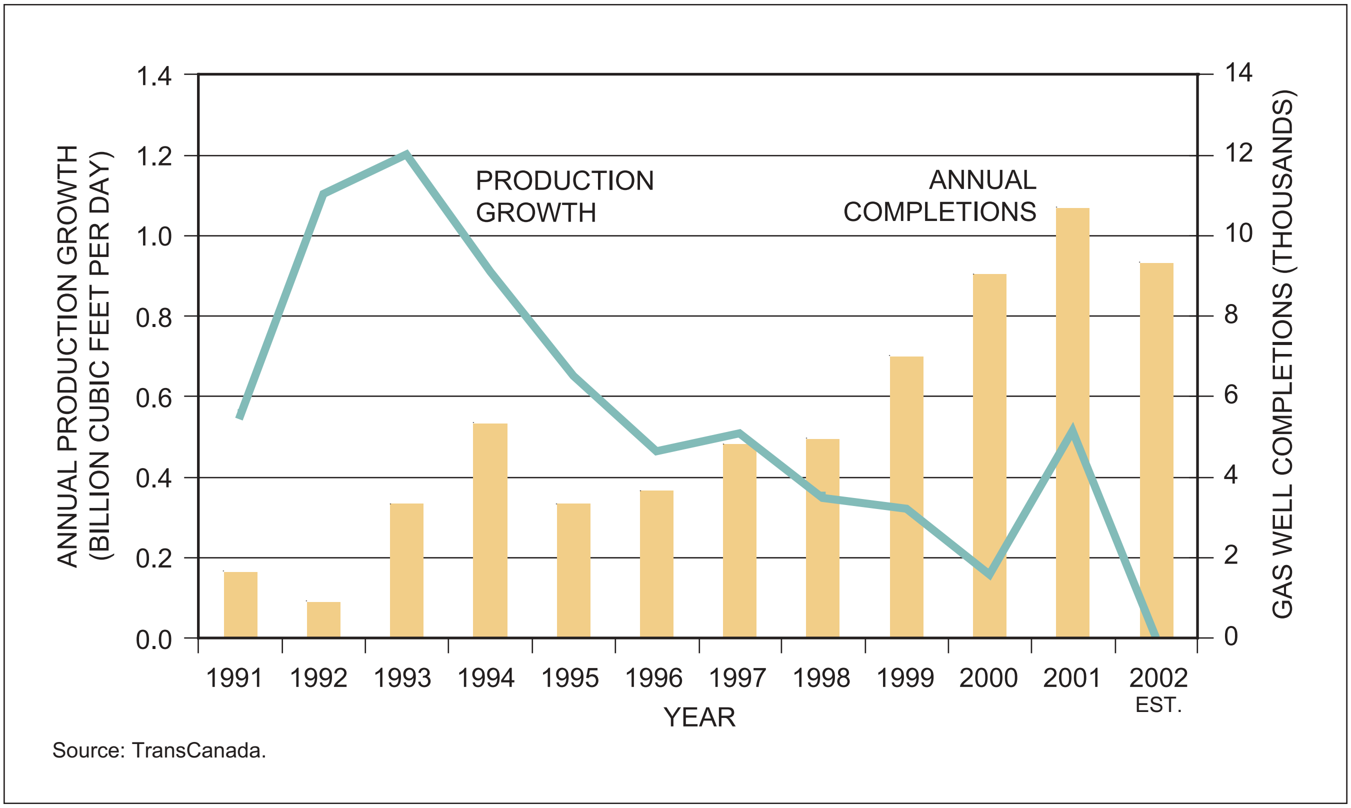


Figure 4-52. Western Canada Sedimentary Basin Production Growth and Gas Well Completions

- Well mix (e.g., targeting shallow, low-risk exploitation wells vs. higher risk exploration wildcats)
- Economics (e.g., increase in gas prices spurring rapid development of in-fill locations)
- Basin character, reserve type, and other items.

Figure 4-53 shows that during the 1990s the EUR per average gas connection in the U.S. lower-48 fell from 1.4 BCF in 1990 to 1.2 BCF in 1999, a decline of 15%. As drilling and completion activity increased significantly in 2000 and 2001, average EURs fell a further 17% to just under 1 BCF.

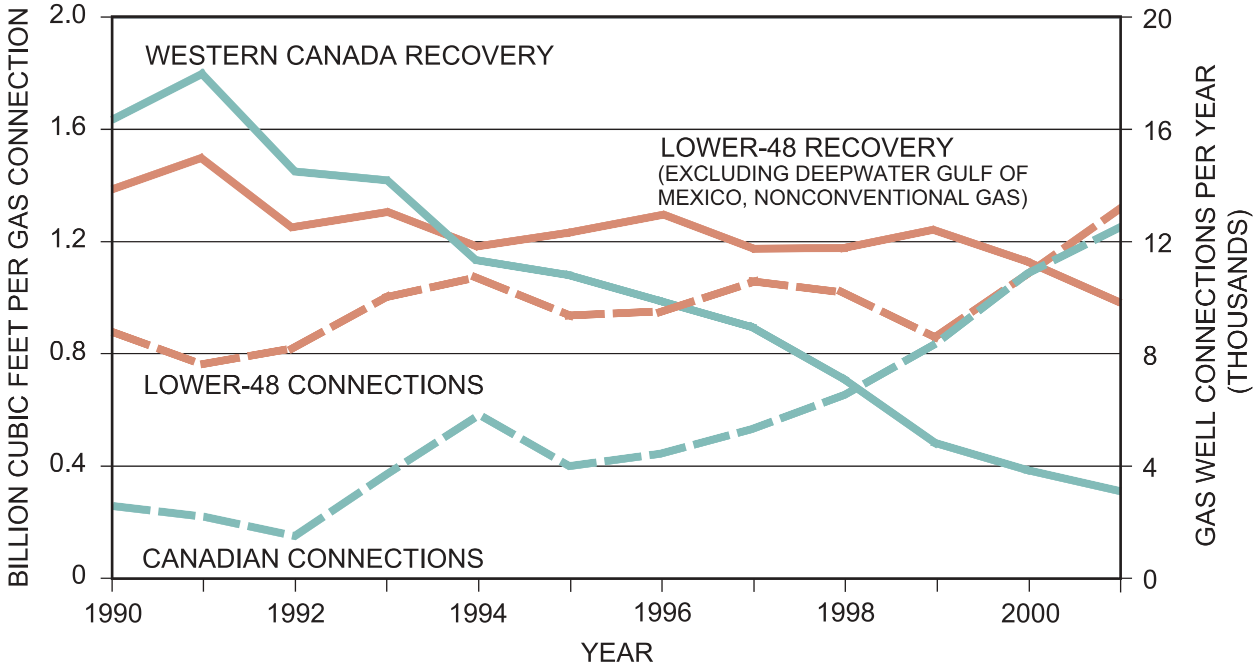
In Western Canada, EURs have shown even a more marked decline, falling from about 1.7 BCF in the early 1990s, to 0.3 BCF in 2001, as annual completions increased from approximately 3,000 per year to over 10,000 gas completions in 2001.

The Gulf of Mexico shelf showed a more rapid reduction in EURs than onshore. On the shelf, EURs fell 34% between 1990 and 1999 from 5.1 BCF to 3.3 BCF (Figures 4-54 and 4-55). Judging from the lack of recent rig response on the shelf, EURs from similar plays likely did not improve after 1999.

Initial Production Rates

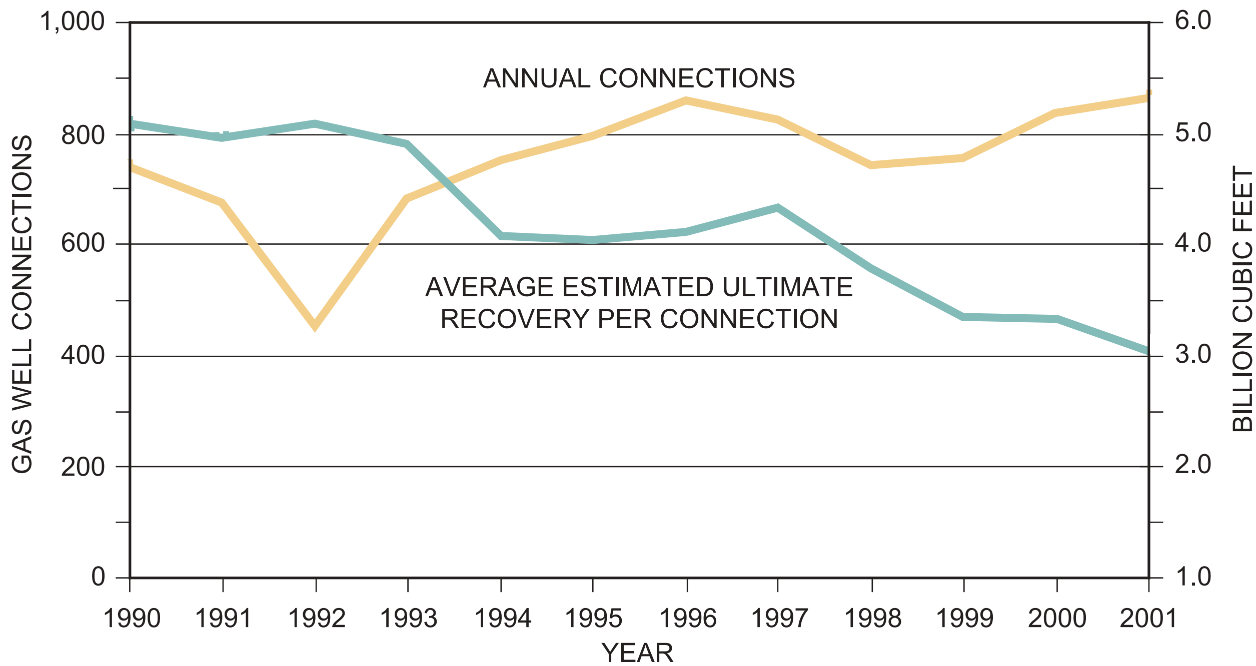
In a period of falling EURs, the industry has been able to partially compensate by accelerating individual well production. As regulatory constraints on gas well production were eased in the early part of the 1990s, the rapid application of completion and stimulation technology, combined with producer's economic drive to lower R/P ratios, caused IPs to increase rapidly. Average gas well IPs increased from 1.1 million cubic feet per day (MMCF/D) in 1990 to just under 1.6 MMCF/D by 1996, as shown in Figure 4-56. Average IPs remained near that level in the late 1990s and increased to a peak in 1999 of 1.6 MMCF/D before falling in 2000.

On the Gulf of Mexico shelf, peak rates and plateau times reached their maximum in the 1996-1997 time frame (Figure 4-57). Since then, peak rates have fallen marginally and plateaus have shortened noticeably. Onshore, IPs rose rapidly to 1996, but rose only marginally through the latter half of the



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure 4-53. Estimated Ultimate Recovery per Gas Well Connection



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure 4-54. Gulf of Mexico Shelf Recovery per Gas Well Connection (Excludes Norphlet)

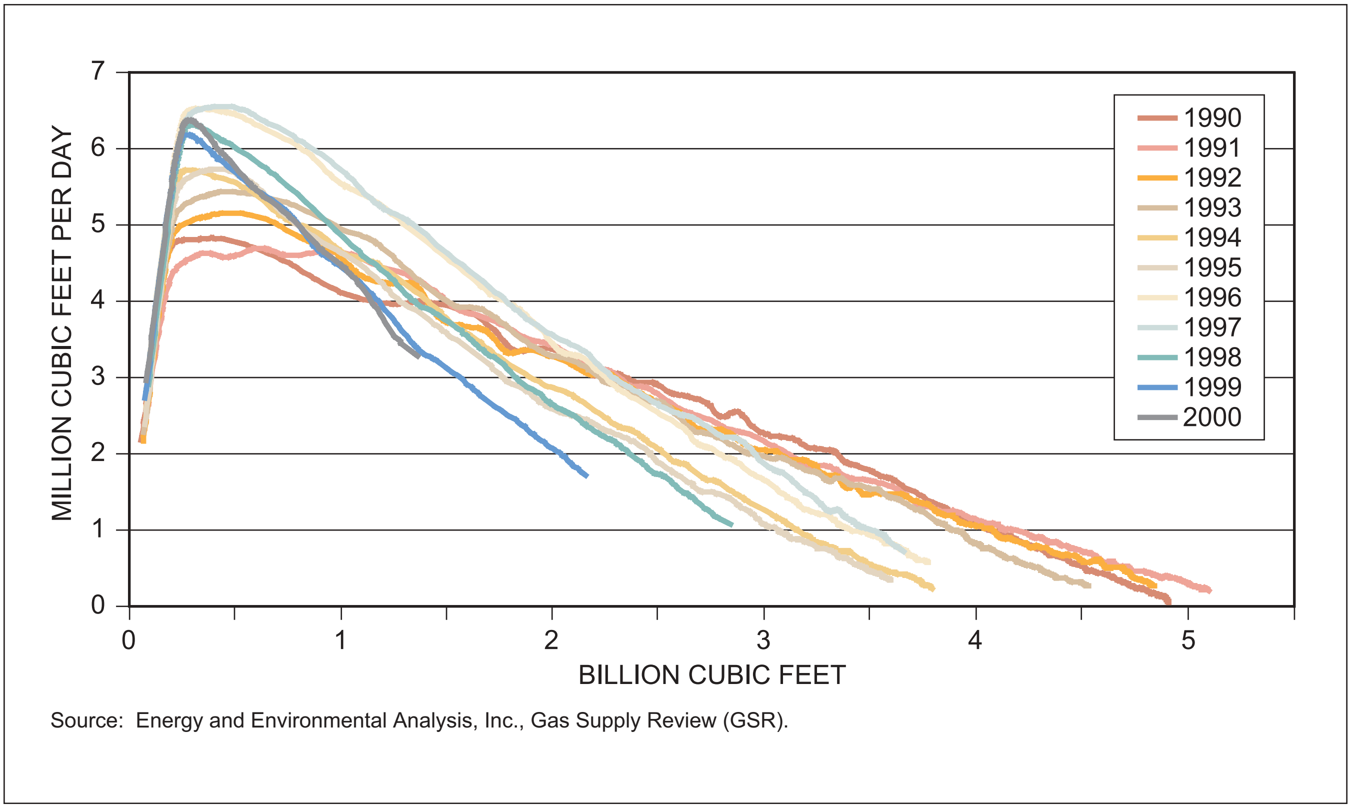


Figure 4-55. Gulf of Mexico Shelf Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production

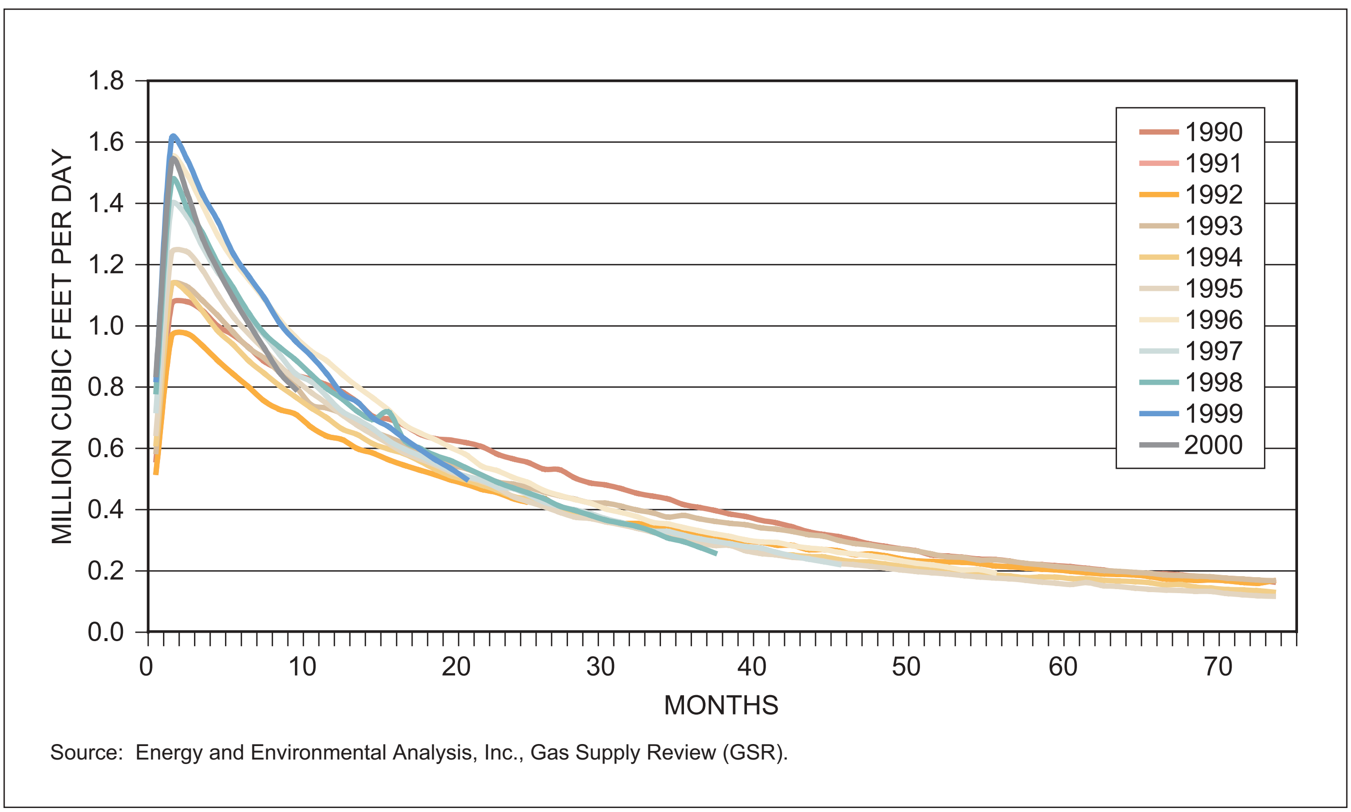
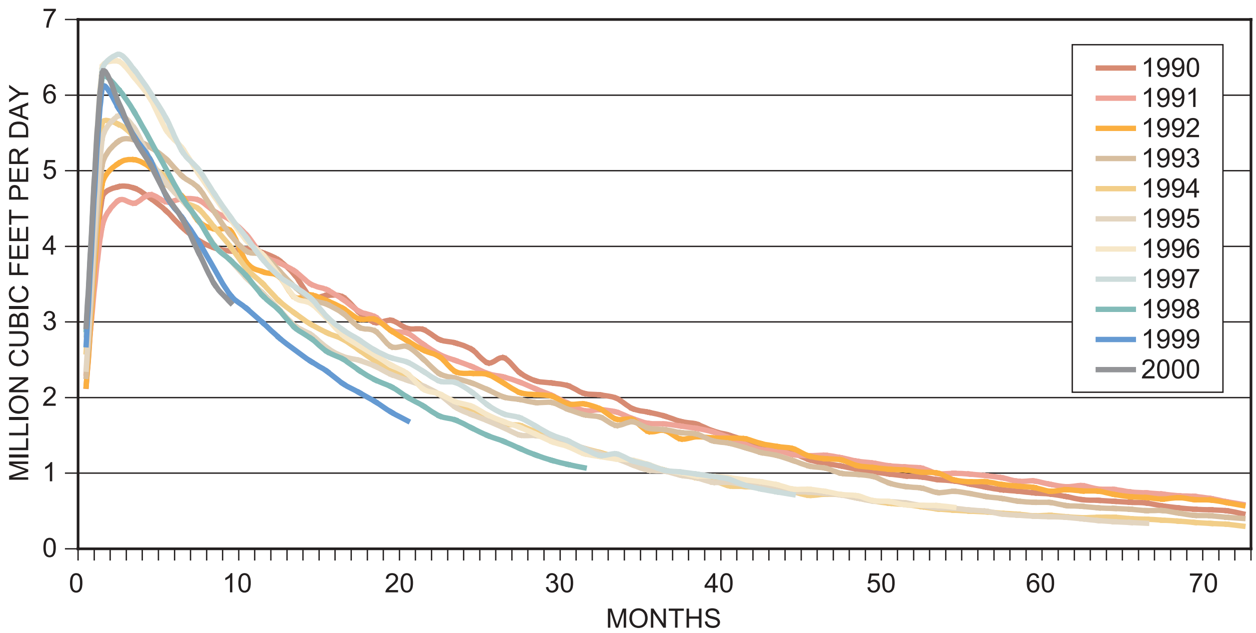
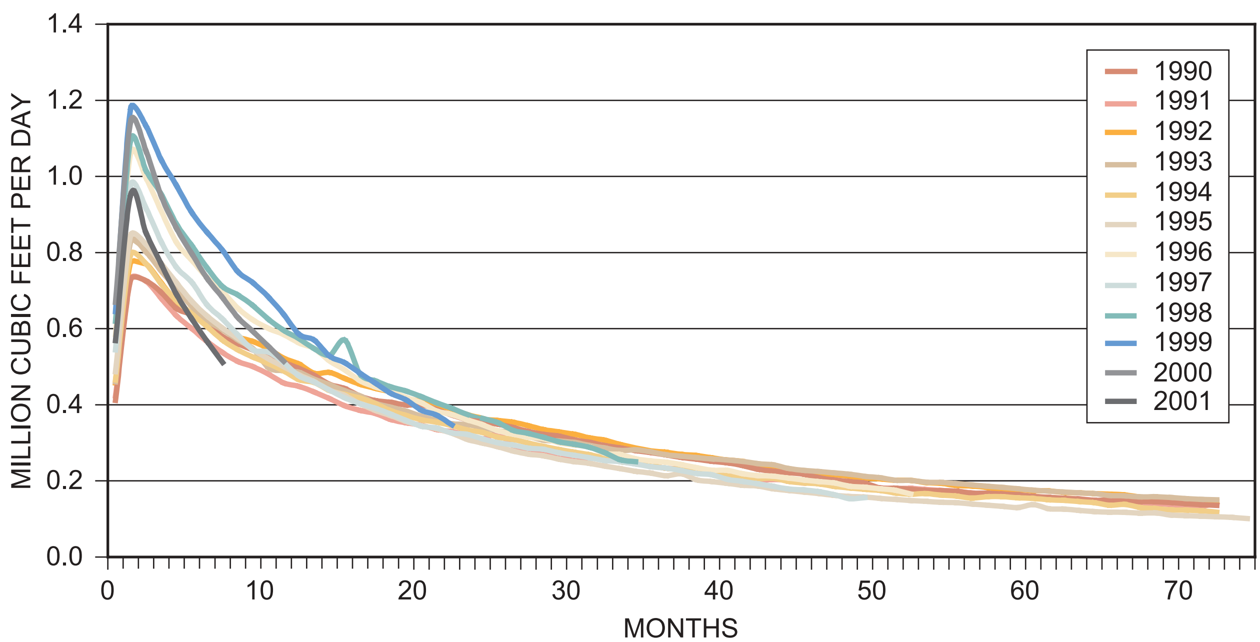


Figure 4-56. Lower-48 Conventional Average Daily Gas Well Production vs. Time, by Year of First Production



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure 4-57. Gulf of Mexico Shelf Average Daily Gas Well Production vs. Time, by Year of First Production



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure 4-58. Lower-48 Onshore Conventional Average Daily Gas Well Production vs. Time, by Year of First Production decade (Figure 4-58). IPs fell marginally in 2000, and then more substantially during the 2001 drilling ramp-up.

One of the drivers of the increase in IPs has been the increasing application of fracture stimulation technology. More wells are being fracture stimulated and often with larger stimulations. Stimulation technology has also advanced, allowing longer fracture lengths to rapidly drain larger areas of a tight reservoir. In East Texas, for example, while a significant percentage of wells were fracture stimulated in the early part of the decade, that percentage increased until almost 100% of completions are now fracture stimulated as shown in Figure 4-59. East Texas is characterized by tight reservoirs, but many other basins are also reaching a high level of utilization. The trend of increasing IPs from fracture technology that was enjoyed through the middle of the 1990s will likely not be continued.

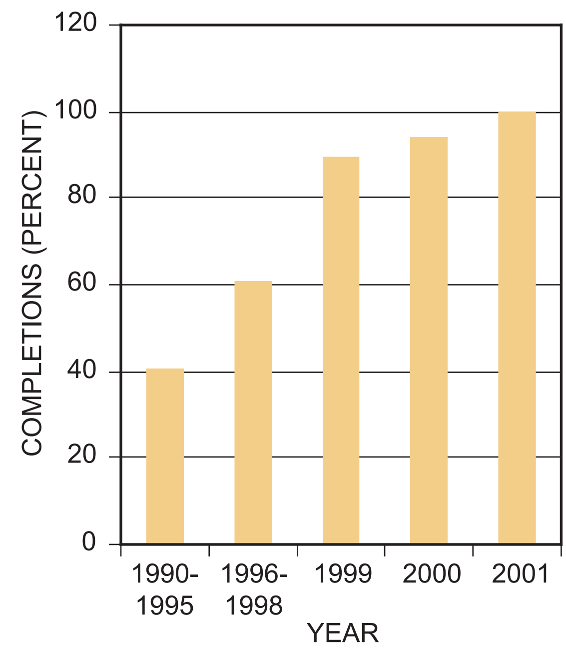


Figure 4-59. Percentage of Completions in East Texas that were Fracture Stimulated

Initial Decline Rates

As higher IPs have increasingly been bringing production forward, and EURs have been falling, decline rates have been progressively steepening, as shown in Table 4-4. While both the onshore and Gulf of Mexico shelf have witnessed increasing decline rates, the effect has been more pronounced on the Gulf of Mexico shelf, with its rapidly falling EURs.

Base Decline Rates

As the industry has continued to add more and more high decline wells to base production, overall

	1990		1998		2000	
	1st Year Decline (%)	% of EUR Produced	1st Year Decline (%)	% of EUR Produced	1st Year Decline (%)	% of EUR Produced
E. Texas/ N. Louisiana	40	22	61	25	64	N.A.
South Texas Gulf Coast	41	27	62	34	67	N.A.
Anadarko Basin	28	12	52	21	58	N.A.
Permian Basin	40	16	37	17	53	N.A.
Gulf of Mexico Shelf (w/ Norphlet)	30	28	53	48	74	N.A.
Rockies (non-Coal Bed Methane)	38	12	44	16	64	N.A.

Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Table 4-4. Gas Well Decline Rates

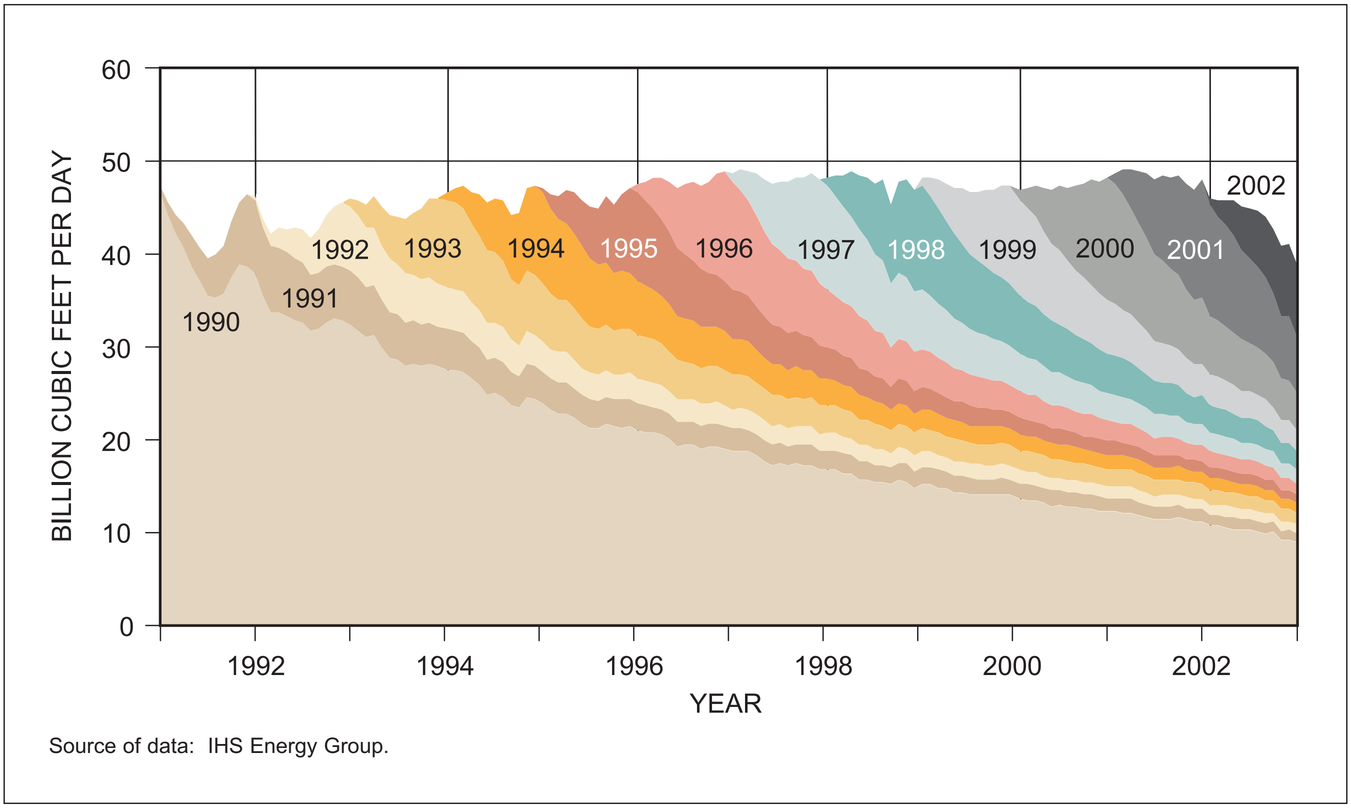


Figure 4-60. Lower-48 Daily Wet Gas Production from Gas Wells, by Year of Production Start

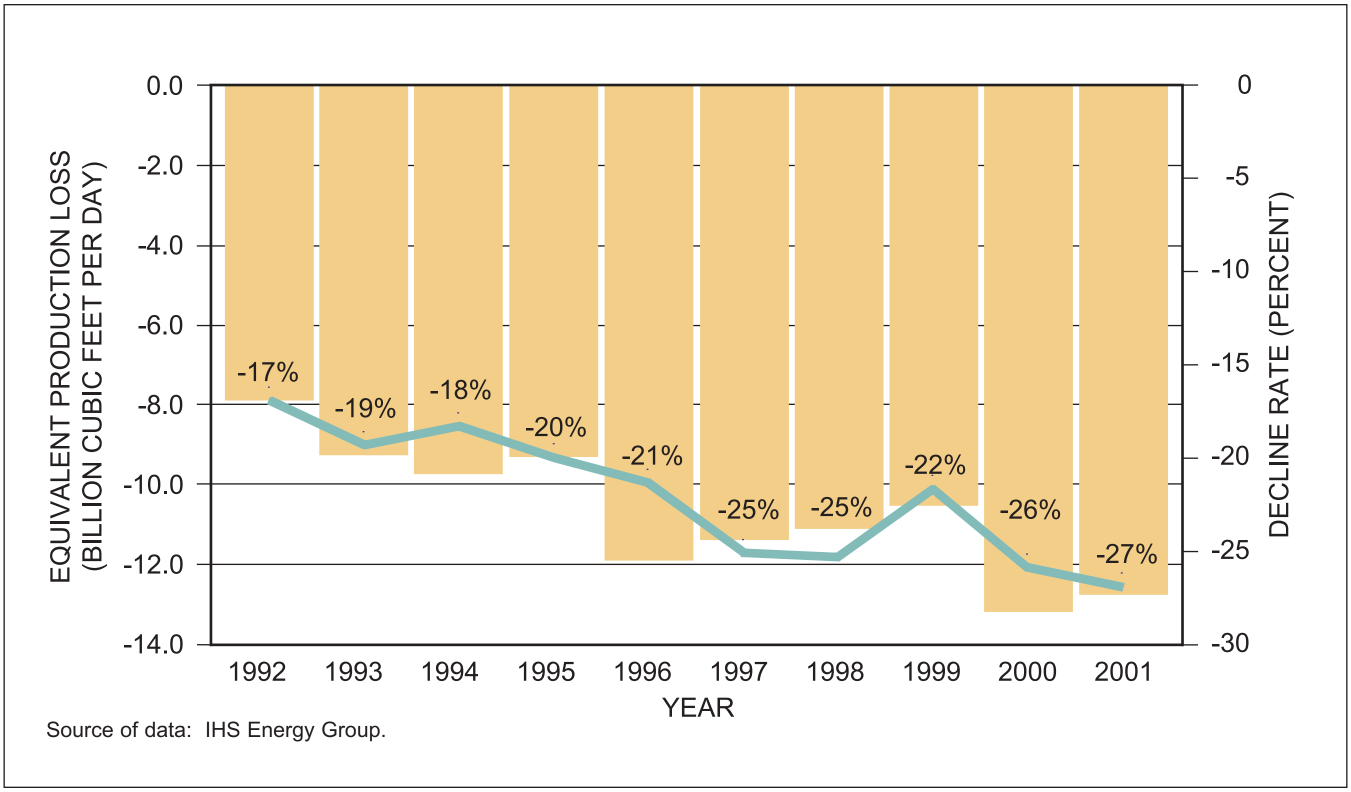


Figure 4-61. Lower-48 Base Gas Production Decline Rate if No New Wells had been Drilled, and Equivalent Production Loss

decline rate has increased. In 1992, the base decline rate was 17%. To simply hold production flat, the 1992 gas drilling program needed to replace deliverability of 8 BCF/D.

Over the period, the base decline rate has increased as shown in Figures 4-60 and 4-61, and perhaps more importantly, the amount of production from new gas wells required to maintain production levels has dramatically increased. To keep production flat in 2000 and 2001, the gas-drilling program had to replace over a quarter of production, or almost 13 BCF/D. Compared to just 10 years ago, the recent yearly drilling programs have had to replace an additional 4-5 BCF/D just to maintain production levels more than 50% higher than earlier levels.

Proved Reserves

During the 1990s, the overall lower-48 proved reserve base has remained remarkably consistent, beginning the decade at 158 TCF of dry gas and finishing the decade at 158 TCF of gas. Over that period lower-48 gas production totaled 177 TCF. Accordingly, the industry proved 177 TCF, or about 18 TCF/year.

Reserve additions in 2000 and 2001 were larger than the historical average. In a period in which 39 TCF of gas were produced, gas reserve additions totaled 57 TCF of gas in 2000-2001, an average of 28 TCF/year, or about 10 TCF/year higher than the industry averaged in the 1990s. While the industry was able to increase total proved reserves, proved producing reserves actually fell, as shown in Figure 4-62. At year-end 2001, non-producing reserves totaled just under 53 TCF of gas, up 24% from just a year earlier. Total R/P increased from 8.50 in 2000 to an estimated 9.35 in 2002, but producing R/P has remained steady.

The two regions that have exhibited the strongest reserve growth, the Rocky Mountains and East Texas/North Louisiana have a significant percentage of nonconventional reserves. Basins with only conventional reserves either showed declines or only modest increases.

In Western Canada, the industry has not been able to replace production. In the 1991-2002 period, proved reserves and R/P have steadily fallen from 70 TCF of reserves with an 18 R/P in 1991 to an estimated 57 TCF

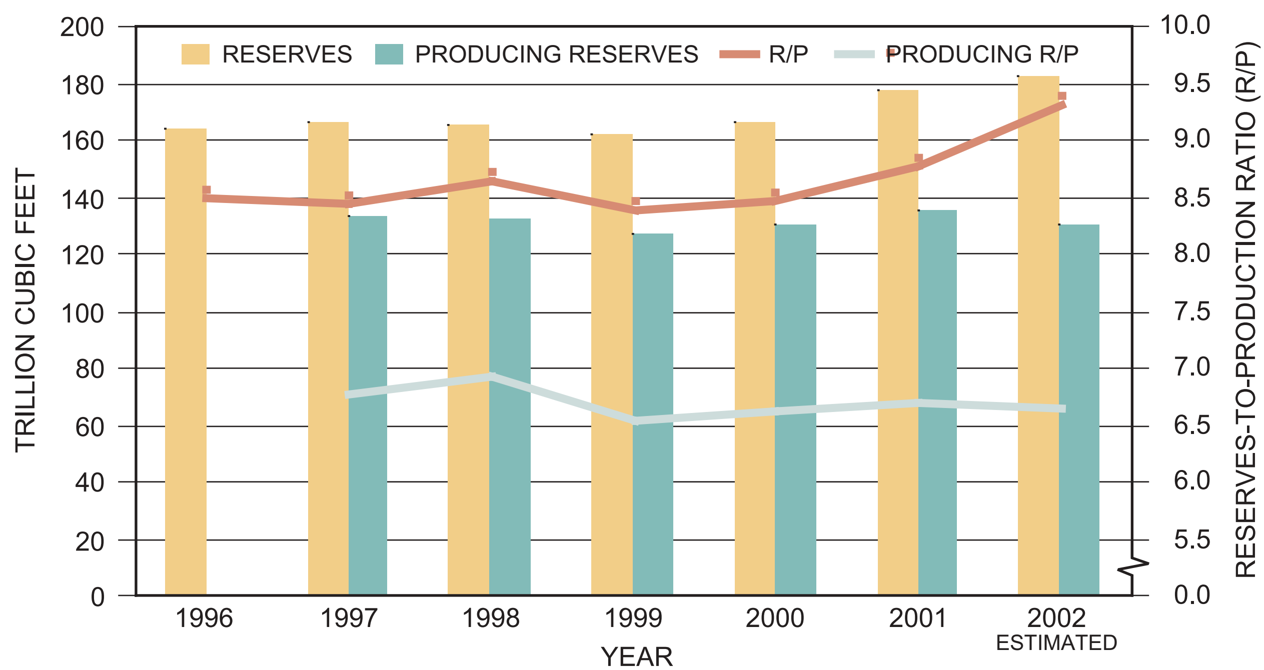


Figure 4-62. Lower-48 Wet Gas Proved Reserves

of reserves with an R/P of approximately 9 in 2002. This is illustrated in Figure 4-63.

Regional Production Summaries

In an overall environment of slowing production growth, individual producing regions have followed their own unique production profiles, as basins have been explored and developed, matured, and new technologies have been applied to the resource.

As Figure 4-64 demonstrates, in the more mature regions of the Gulf of Mexico shelf and the mature onshore areas of the U.S. lower-48, overall flat production levels were maintained in the early part of the decade. After 1996, as these areas continued to mature, they began a sustained decline in production, which was slowed by the big drilling ramp-up in the 2000-2001 time frame.

In the frontier areas of the U.S. lower-48 and Canada, technological advances and infrastructure connections have opened up less mature opportunities. Production from the Rockies and deepwater Gulf of Mexico has grown from 5.0 BCF/D in 1990 to 14.2 BCF/D in 2002. While increases in these regions contributed to an overall increase in production in the early part of the 1990s, declining production in the mature regions has more recently more than offset these increases.

Declining Regions

Gulf of Mexico Shelf. The Gulf of Mexico shelf began the 1990s as the largest producing region in North America, with peak production rates of 14 BCF/D. While shelf production held fairly steady in the mid-1990s, after 1996 the shelf began declining at a rate of 0.8-1 BCF/D per year as shown in Figure 4-65. The reason was that new drilling could not keep up with the rapidly declining EURs and steep decline rates as the shallow, 3D seismic-driven "bright spot" play rapidly matured. While the drilling ramp-up of 2000-2001 flattened the decline on the shelf, the shelf appears to have resumed its rapid decline as drilling rates have once again begun to fall. By the end of 2002, the shelf had become the third largest producing region in North America, behind the Western Canada Sedimentary Basin and the Rocky Mountains. However, industry has recently begun to explore and develop deeper prospects on

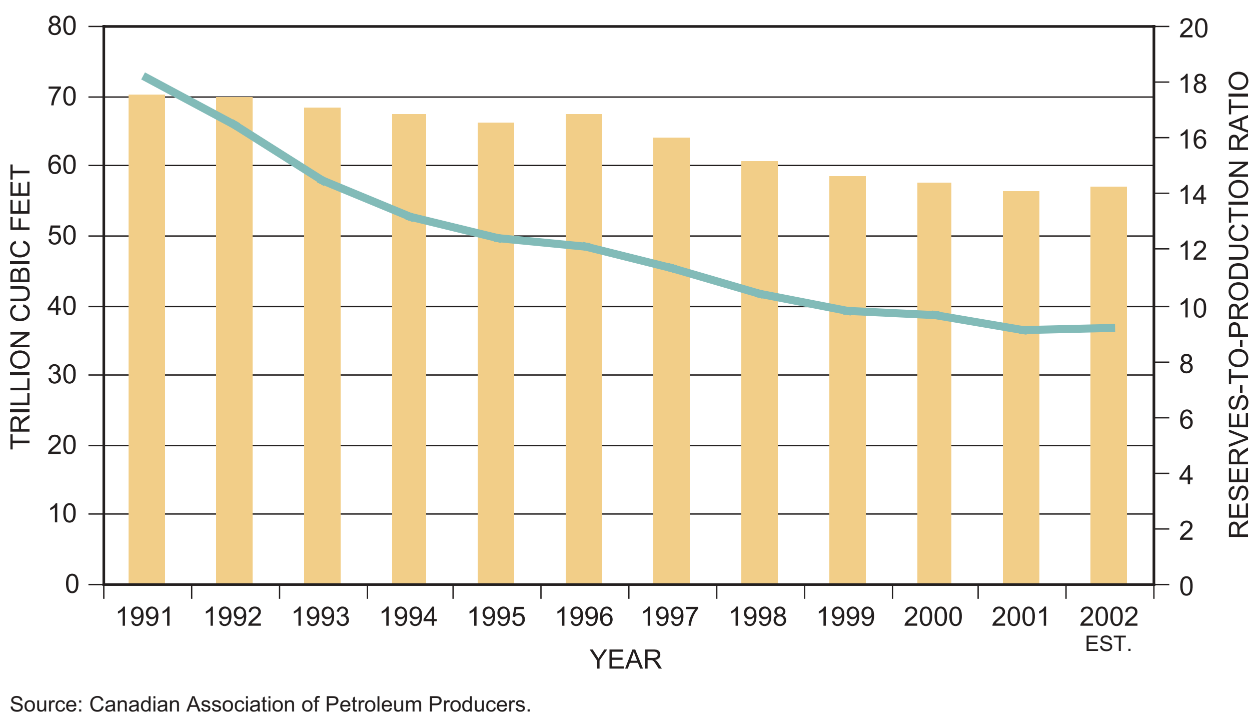


Figure 4-63. Western Canada Sedimentary Basin Proved Reserves

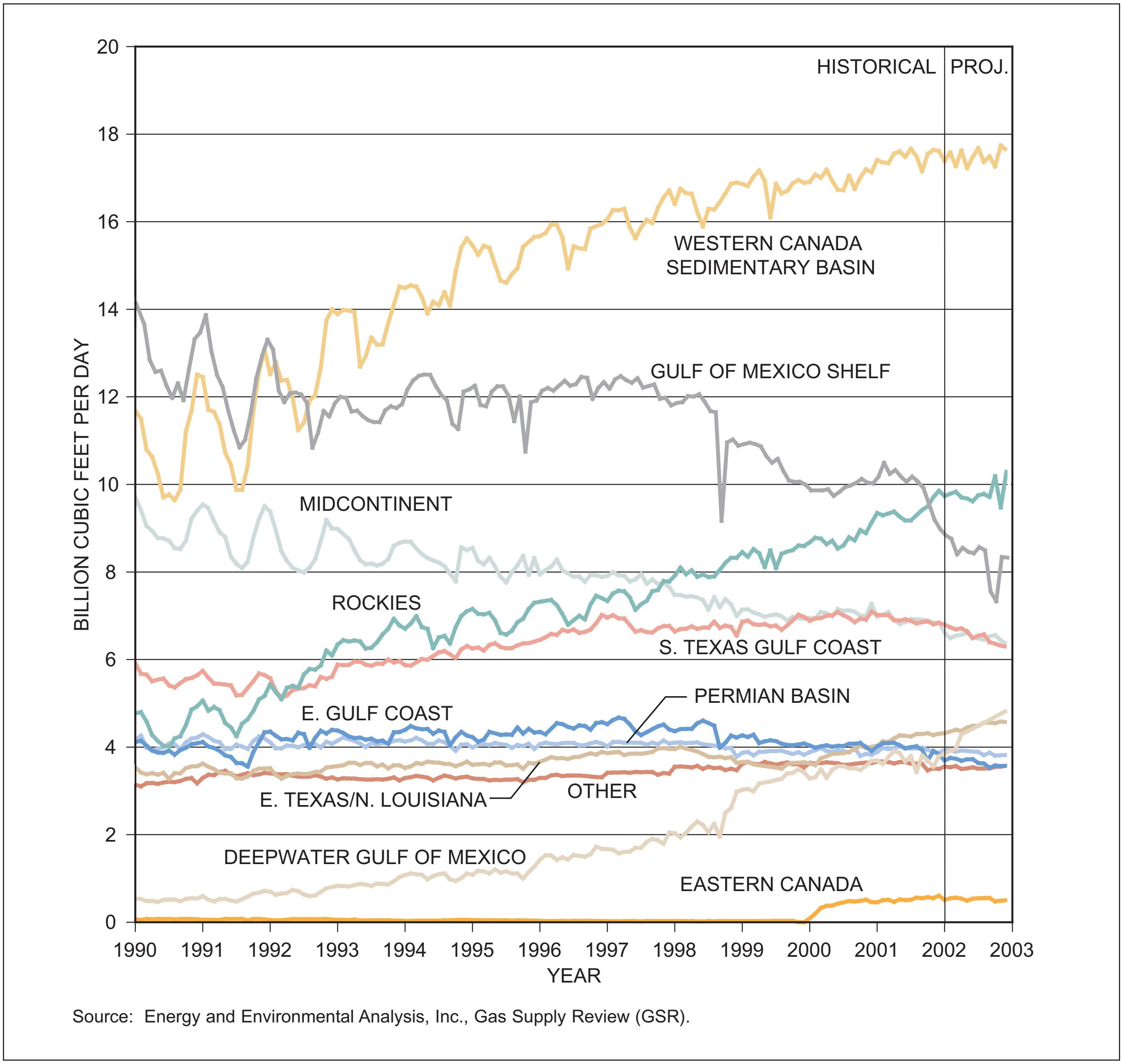


Figure 4-64. North American Gas Production by Region

the shelf, which if successful could help reduce future production decline.

Eastern Gulf Coast. After rising marginally in the early 1990s, the Eastern Gulf Coast has been declining since about 1996, with peak production falling over 1 BCF/D from a peak of 4.7 BCF/D in 1996 to 3.5 BCF/D at the end of 2002.

Midcontinent. The Midcontinent region started the decade as the third largest producing region in North America (second in U.S. lower-48) at peak rates of 10 BCF/D. Production has gradually fallen to less than 6.5 BCF/D currently as EURs have steadily declined throughout the period.

Permian Basin. Peak gas production in the Permian Basin has slowly dropped from 4.3 BCF/D in 1990 to the current production rate of approximately 3.8 BCF/D.

Holding Steady/Slightly Increasing Regions

South Texas Gulf Coast. In the early-mid part of the 1990s, production increased from a peak rate of

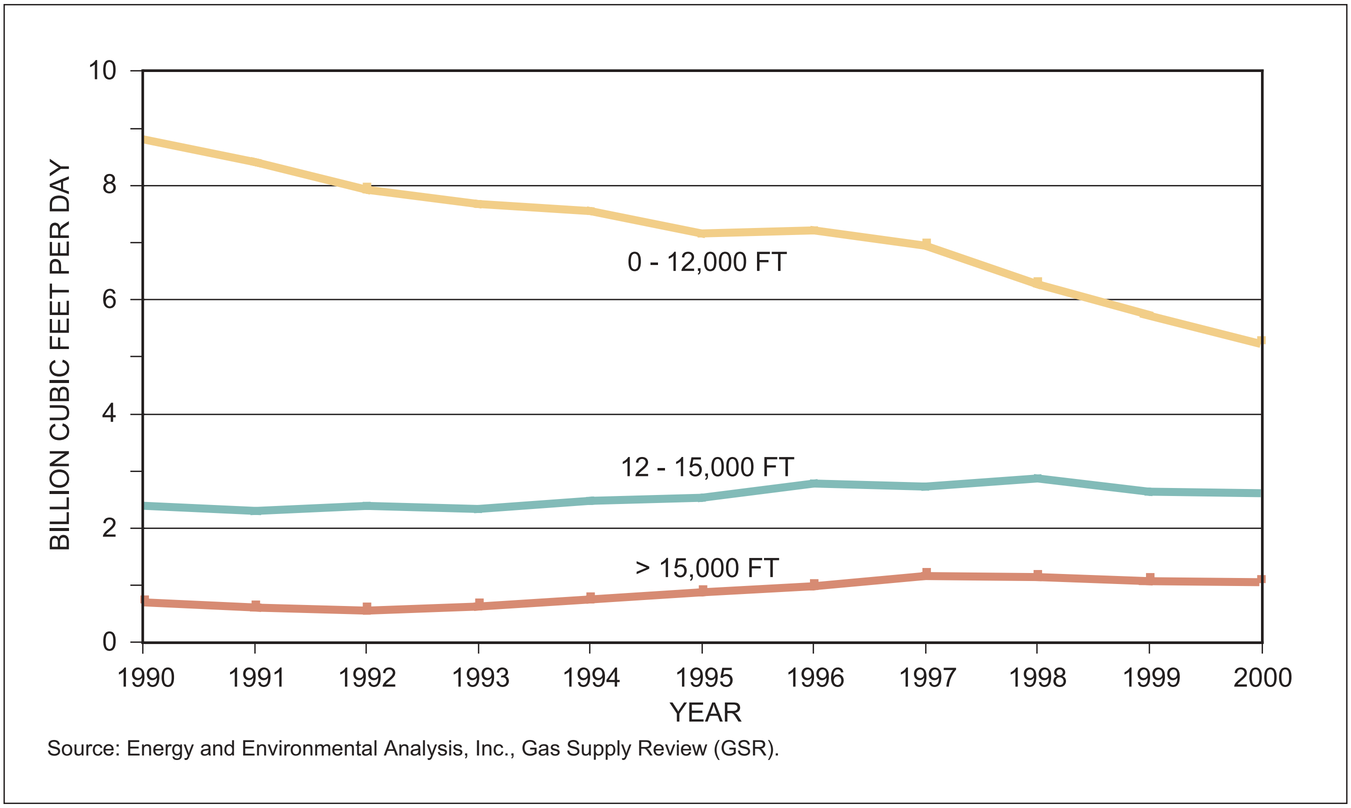


Figure 4-65. Gulf of Mexico Shelf Production by Depth

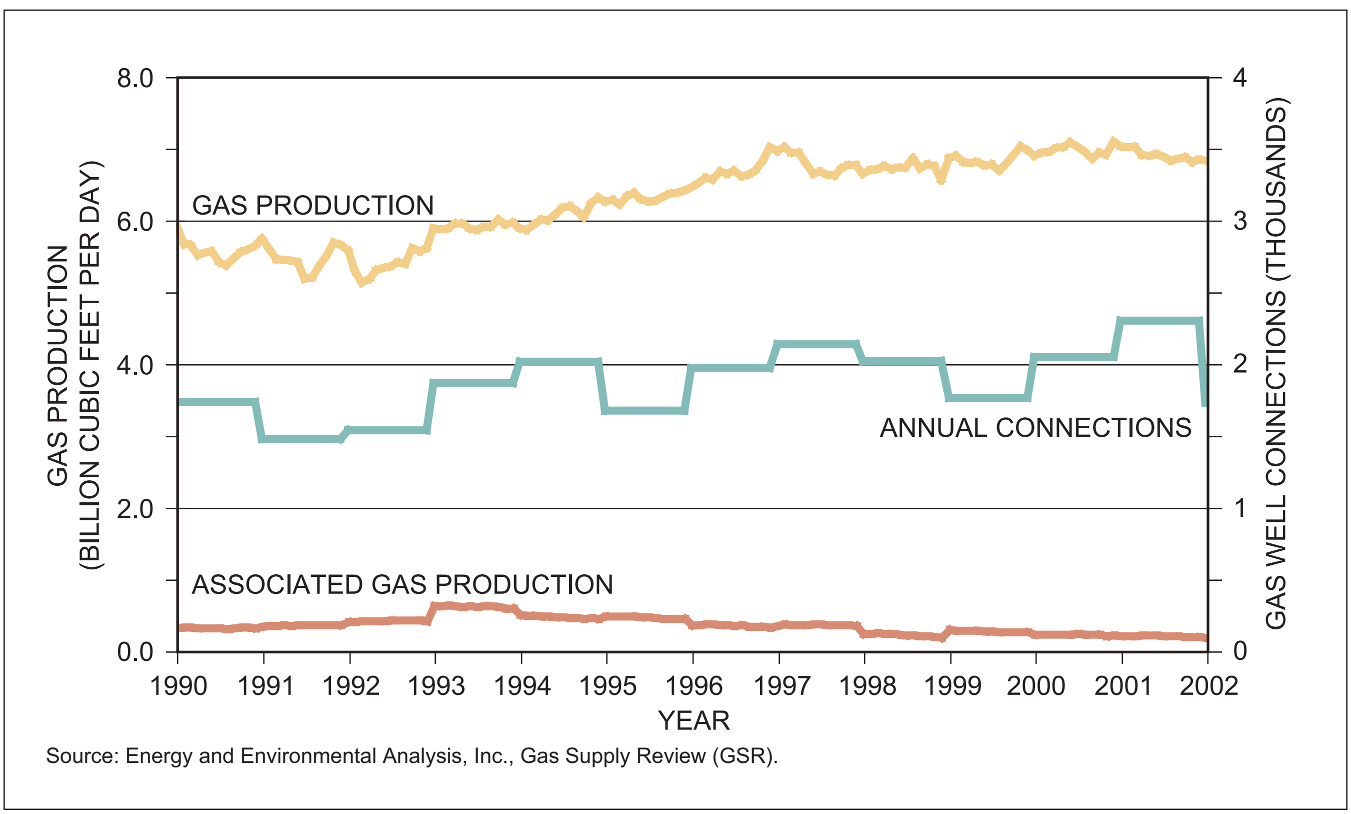


Figure 4-66. South Texas Gulf Coast Production and Gas Well Connections

5.8 BCF/D in 1990 to 7.1 BCF/D in 2001 (Figure 4-66), an increase of 1.3 BCF/D as regional 3D seismic coverage allowed deeper prospects and smaller, shallow prospects to be more accurately imaged and exploited. As the basin matured, growth slowed in the later part of the 1990s. Production declined to 6.3 BCF/D by the end of 2002, down almost 1 BCF/D from its maximum.

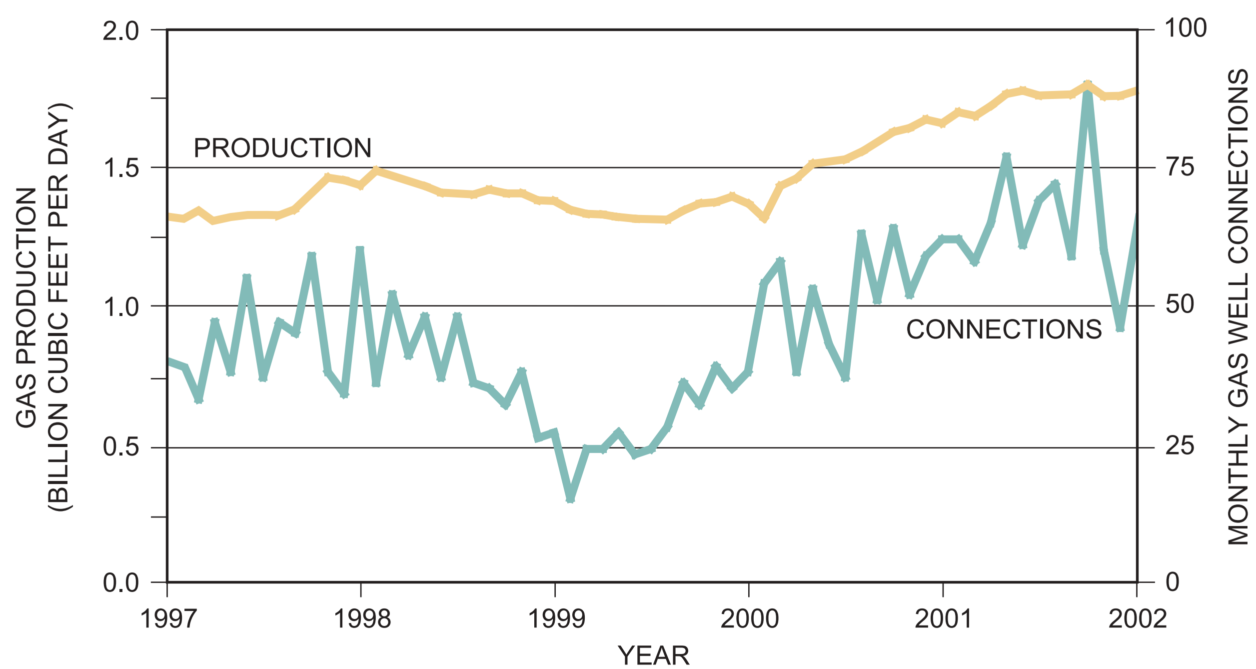
East Texas/North Louisiana. After holding steady throughout much of the 1990s, production has grown from 3.5 BCF/D in 1999 to 4.6 BCF/D by the end of 2002 as nonconventional tight sands of the Cotton Valley Formation (Figure 4-67) and shales of the Barnett Shale (Figure 4-68) were exploited using applied fracture stimulation technology. While drilling has ramped up substantially, average well productivity has also held generally flat so that recently producers have been able to generate sustained increases in production.

Increasing Production Regions

Western Canada Sedimentary Basin. As gas export infrastructure was expanded in the early 1990s, exploration and development interest picked up rapidly in this region. The Western Canada Sedimentary Basin has grown to be the largest producing region in North America. While the basin grew strongly in the early 1990s, growth has slowed considerably as the basin rapidly matured. Average well productivity has fallen dramatically (Figure 4-69) and basin decline rates have steepened (Figure 4-70). In recent history, 2002 was the first year of flat to declining production in Western Canada.

Rocky Mountains (including the San Juan Basin). Production from the Rocky Mountains has grown steadily throughout the decade (Figure 4-71), even with periods of low regional prices, and the Rockies are currently the second largest producing region in North America (first in U.S. lower-48). While much of the Rockies growth has come from nonconventional resources (Figure 4-72), both conventional and nonconventional production rates have been increasing.

Deepwater Gulf of Mexico. 3D seismic technology and advancing development/production technology have opened this frontier area to drilling. While



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure 4-67. Cotton Valley Production and Gas Well Connections

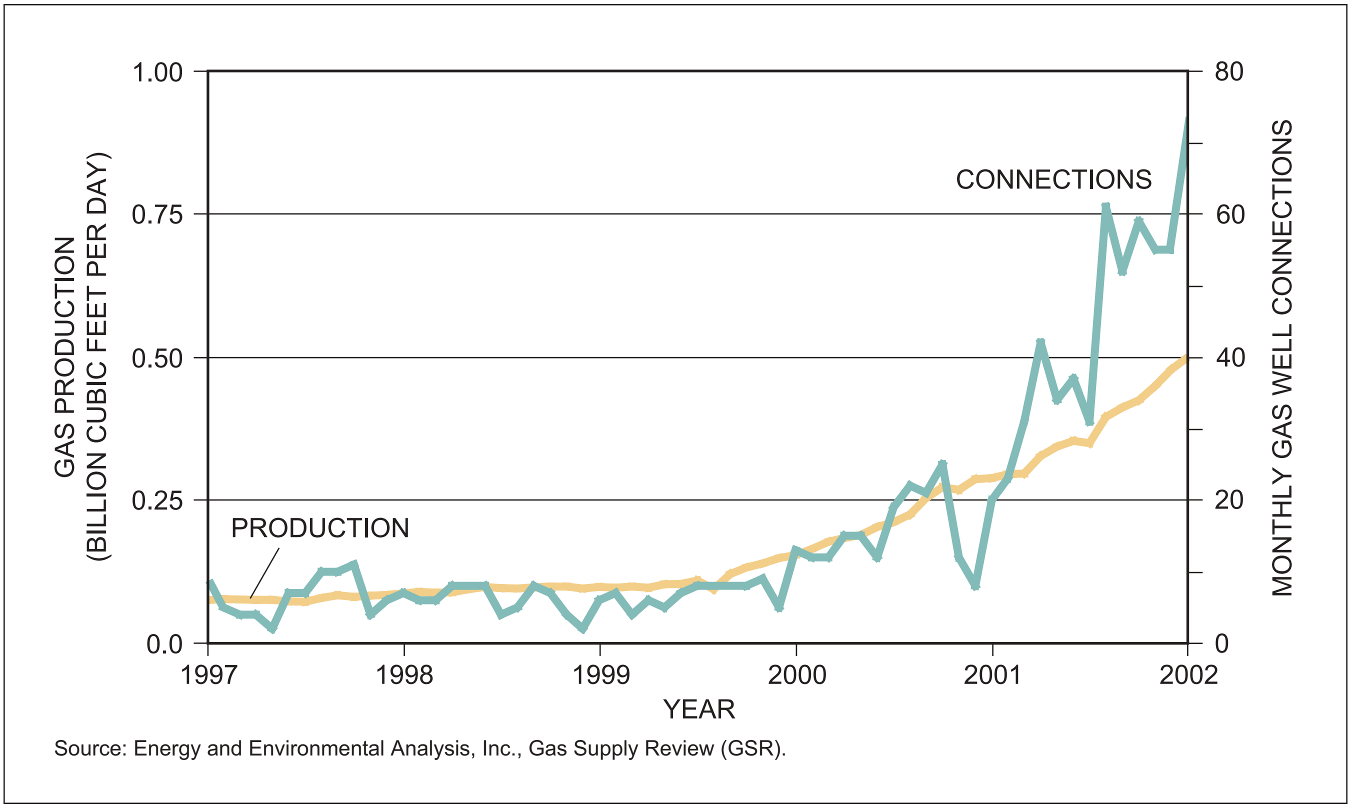


Figure 4-68. Barnett Shale Production and Gas Well Connections

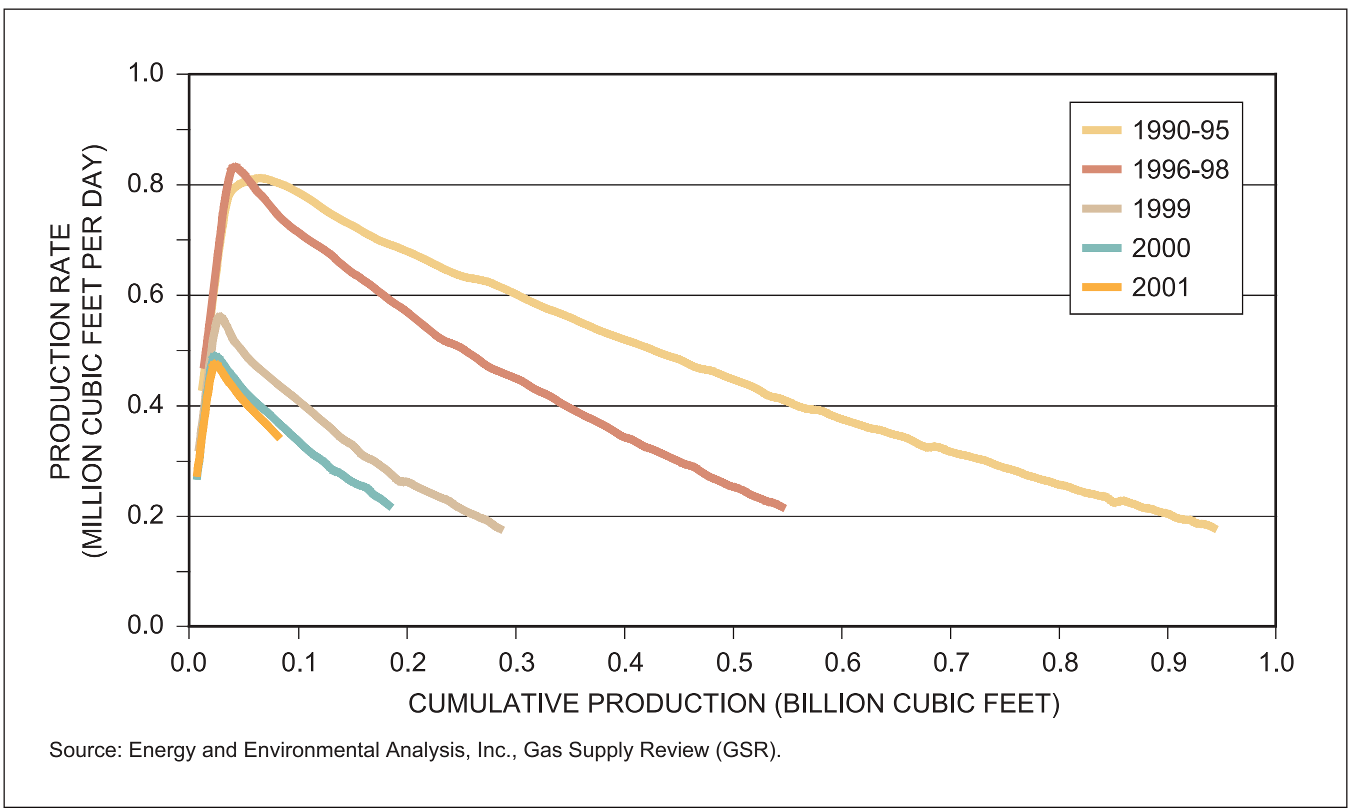


Figure 4-69. Western Canada Sedimentary Basin Production Rate vs. Cumulative Production

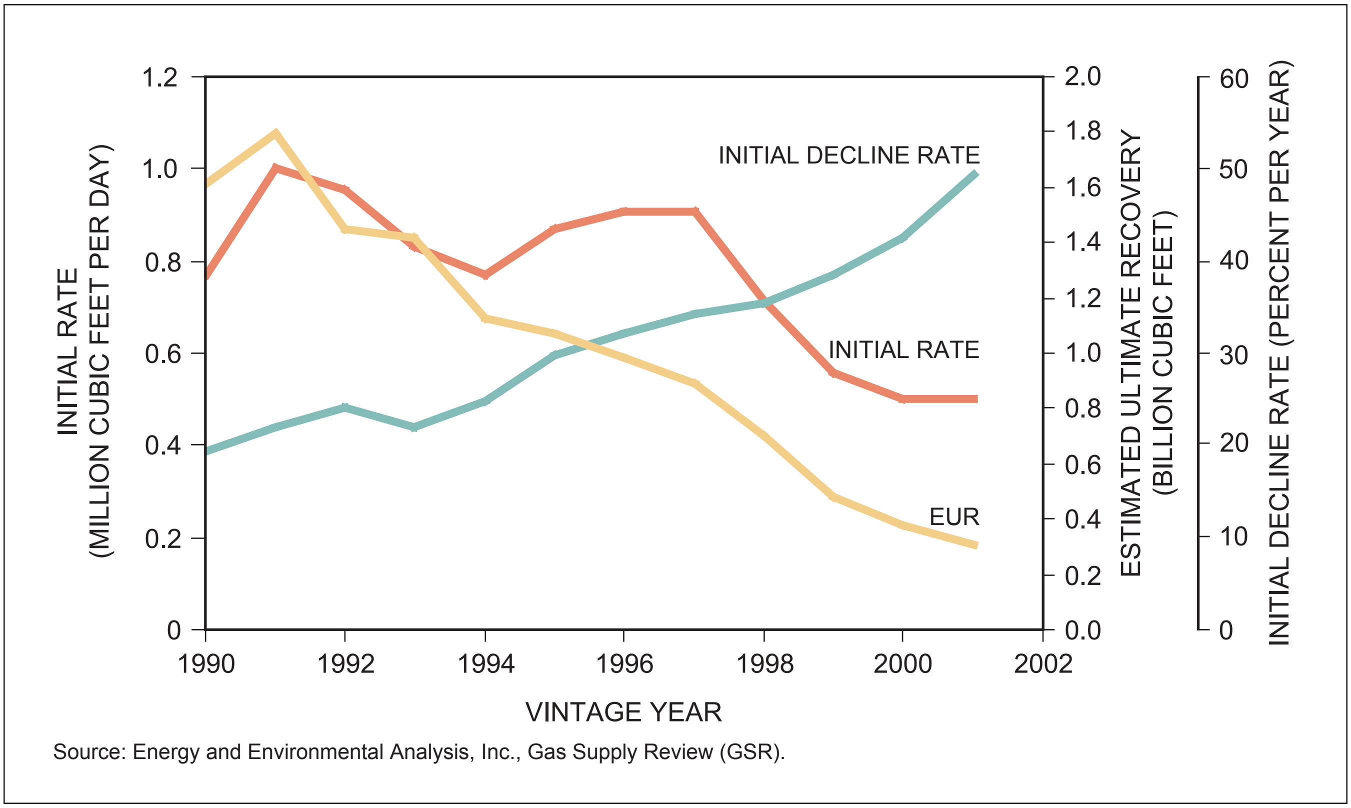


Figure 4-70. Western Canada Sedimentary Basin Production Performance Trends

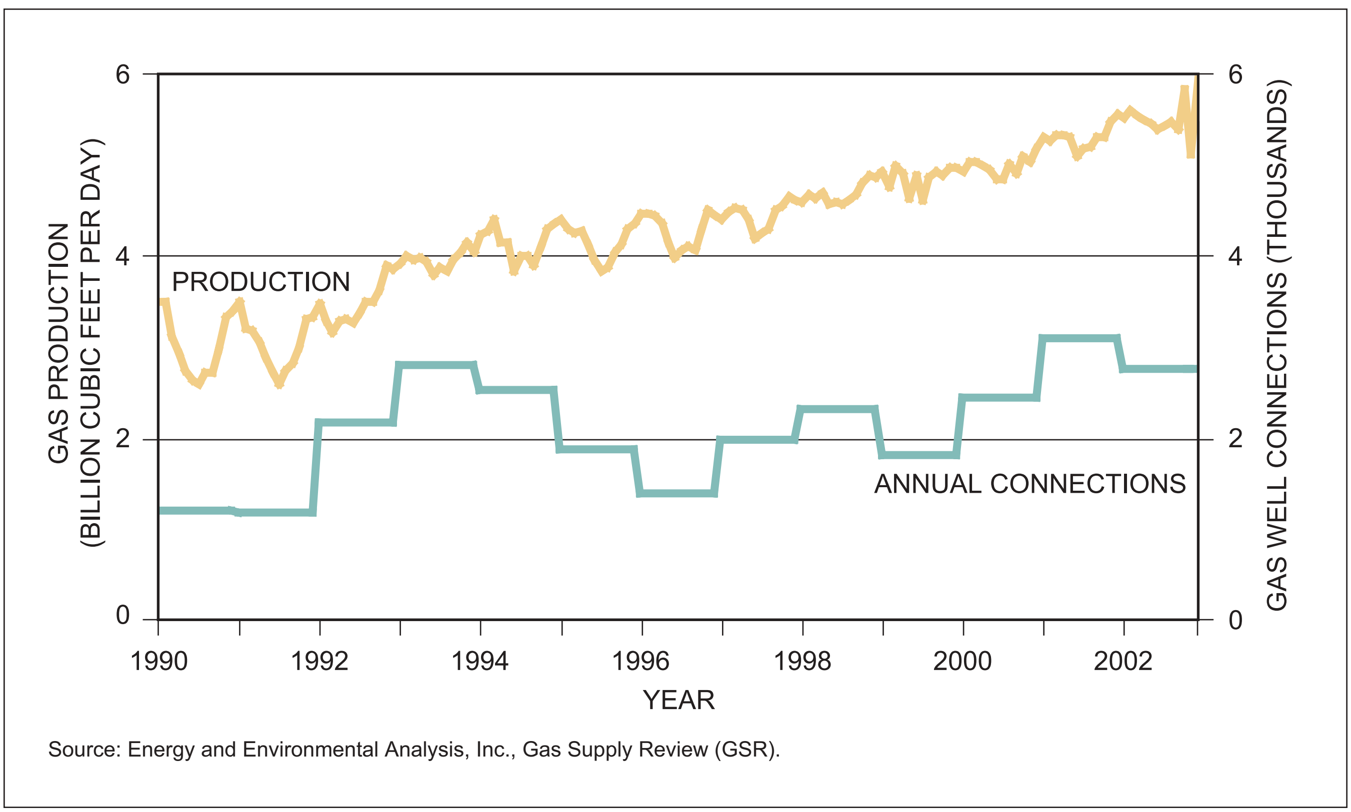


Figure 4-71. Rockies Production and Gas Well Connections, Excluding Coal Bed Methane

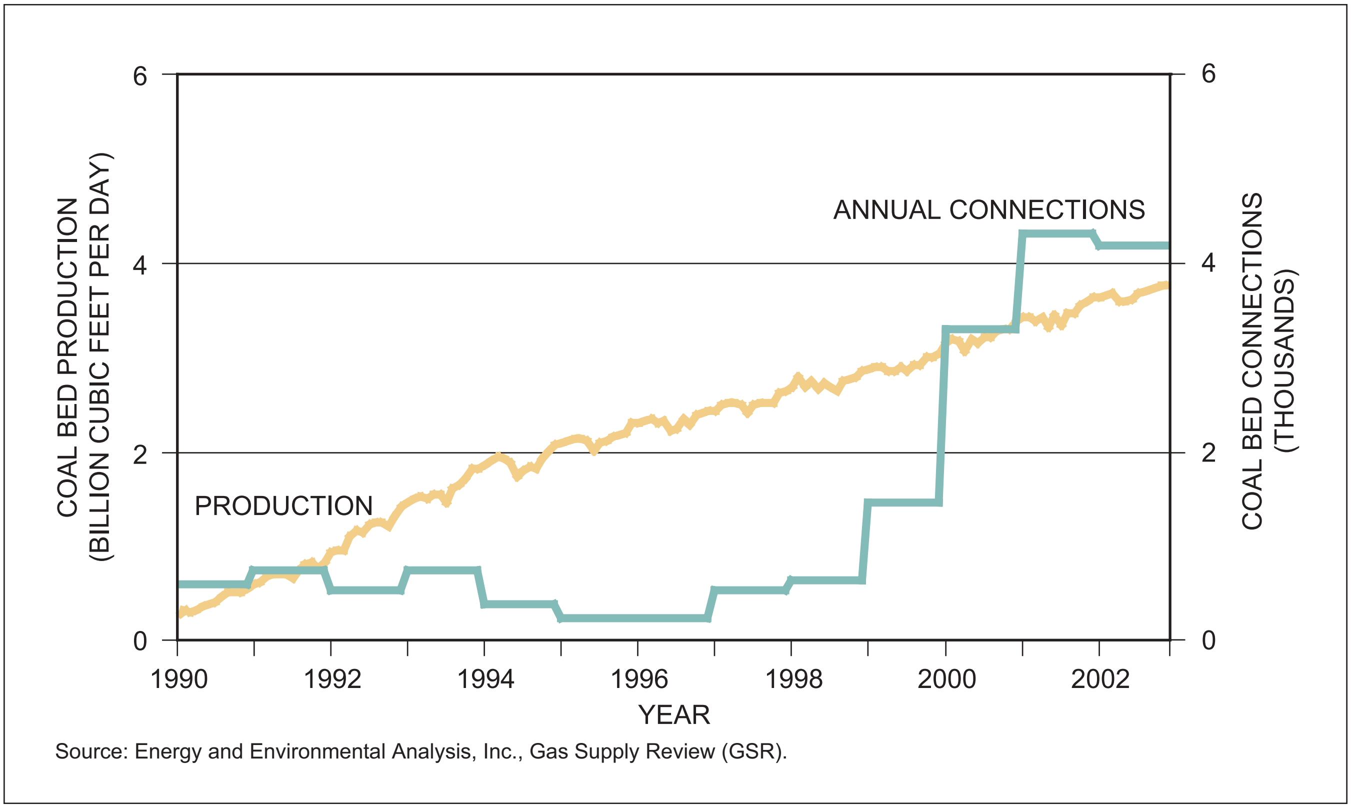


Figure 4-72. Rockies Coal Bed Methane Production and Connections

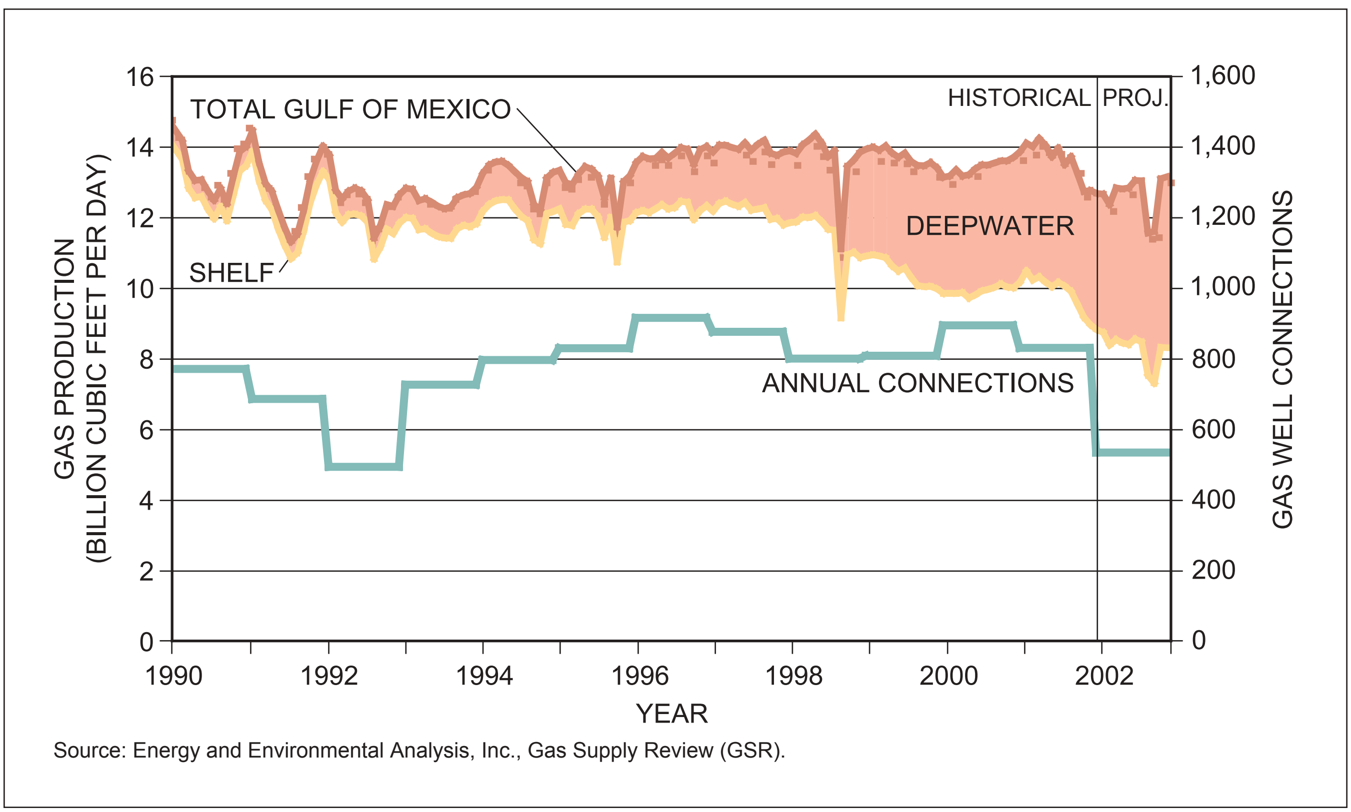


Figure 4-73. Gulf of Mexico Shelf and Deepwater Production and Connections

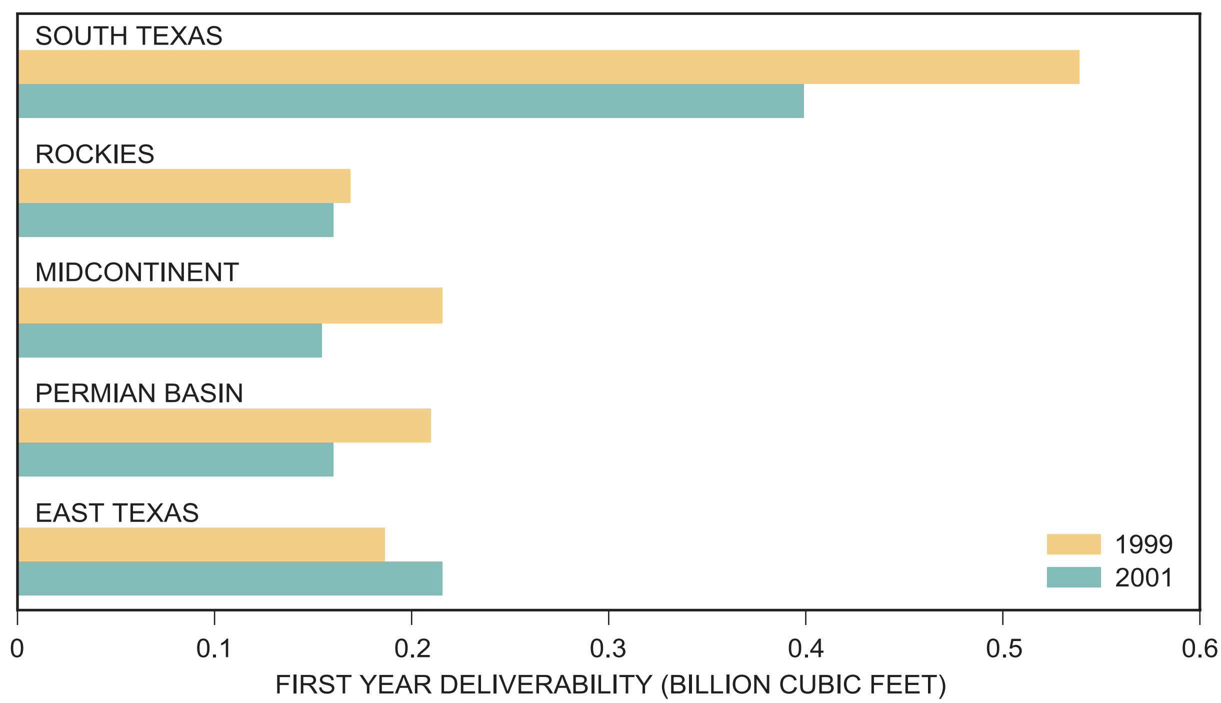
primarily an oil play, gas production has grown strongly as new developments and infrastructure are being built out (Figure 4-73). While shelf production has been falling rapidly, increased deepwater production has been able, until recently, to sustain total Gulf of Mexico production at approximately 13-14 BCF/D.

Future production growth will depend largely on whether the industry can sustain the recent pace of adding proved reserves and developing large fields, which typically require high-cost, long lead-time projects. The pace of development will also be more dependent on oil-price driven economics than natural gas economics.

2000-2001 Drilling Campaign

The 2000-2001 drilling campaign saw gas rig activity increase from a low of 400 rigs in 1999 to over 1,050 rigs in 2001, which was essentially 100% of rig capacity. This was almost double the peak rig rate in 1997-1998. However, the production response was similar, up approximately 2 BCF/D. When drilling slowed to average 700 rigs in 2002, still above the peak drilling rates in 1997-1998, production fell dramatically, rather than rising. What was the difference?

- The resource base has continued to mature. Average well EUR has been on a long-term decline, and the drilling campaign of 2000 and 2001 only accelerated this trend.
- Marginal drilling was dominated by low productivity wells. In terms of first year buildup, the onshore basins, with the exception of East Texas, showed average first year buildup falling 15% to 25% (Figure 4-74).
- The majority of gas completions occurred in low rate, high R/P areas such as the Powder River Basin coal bed methane wells (Figures 4-75, 4-76, and 4-77).
- While technology had allowed industry to sustain production at lower activity levels in the mid-1990s by accelerating well production, these technologies had largely matured and reached saturation.
- As individual well production was accelerated, base declines steepened over the period. It took 8 BCF/D



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure 4-74. First Year Production – 1999 and 2001

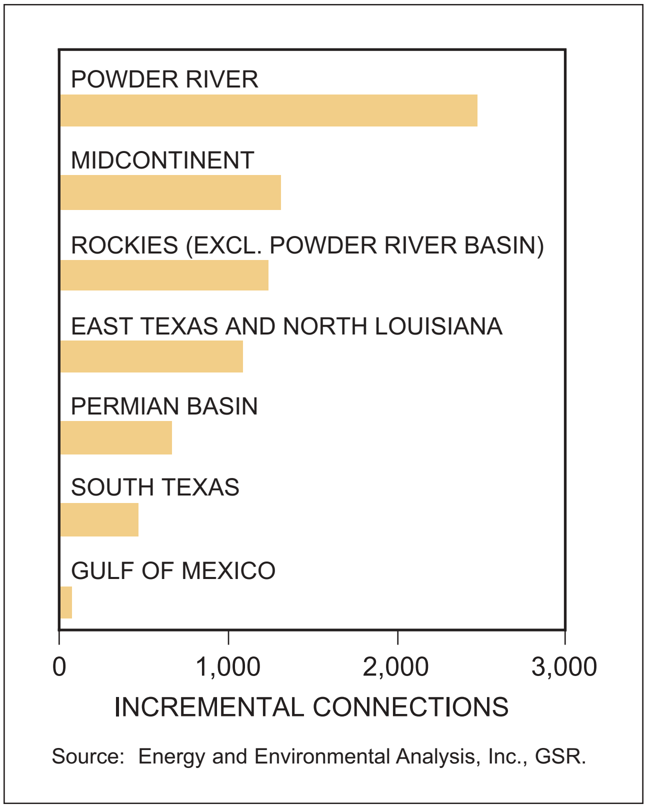


Figure 4-75. Incremental Drilling by Region – 2001 vs. 1999

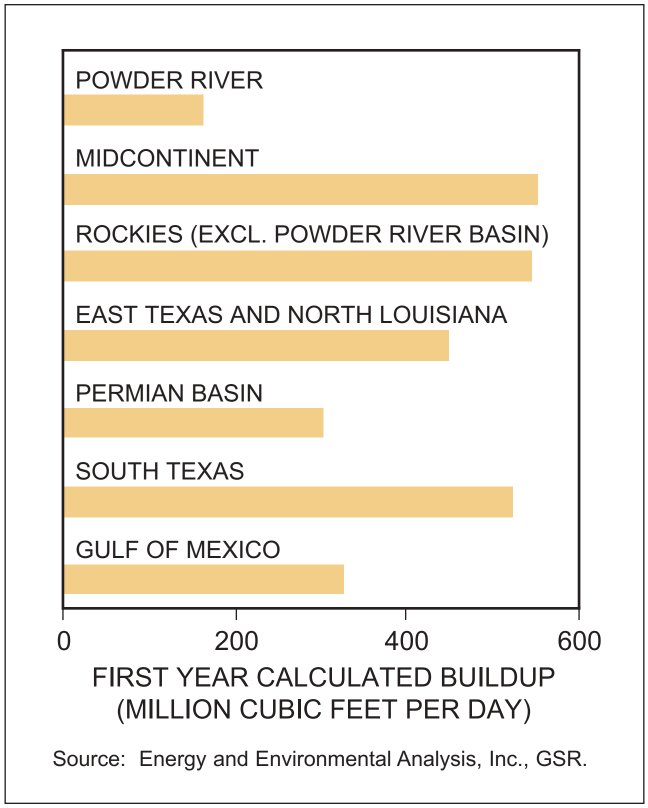


Figure 4-77. Incremental Drilling Buildup by Region – 2001 vs. 1999

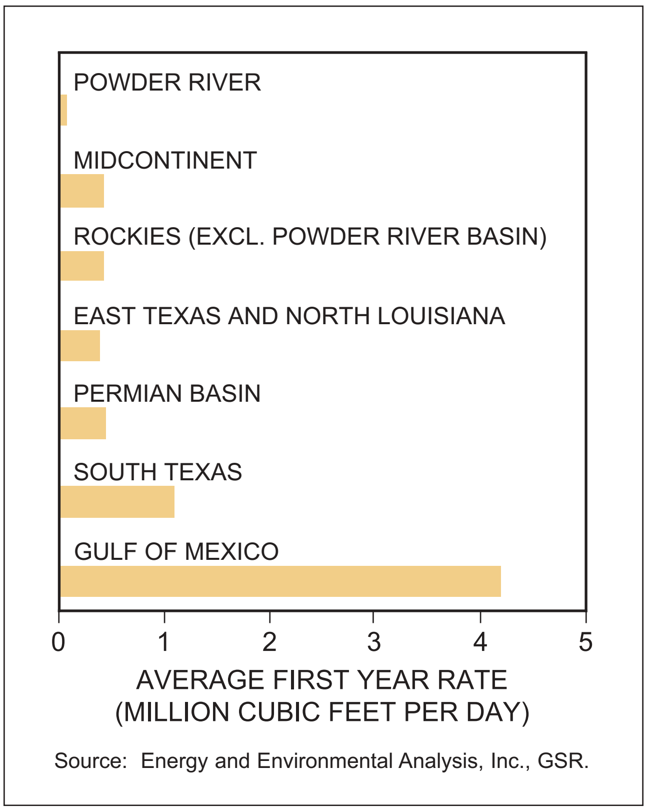


Figure 4-76. First Year Well Production by Region

of new production to replace base declines in the early part of the 1990s. That had increased by over 50% to almost 13 BCF/D.

- Higher gas prices made it possible to drill lower quality prospects.
- As rig activity increased, rig efficiency fell as measured in completions per rig-year and footage per rig-year.

Model Calibration

Production performance parameters generated in this analysis were either used as inputs (either directly or as directional trends) to the HSM model, or were used to check HSM outputs. For example, the production profile of the HSM model's Proved Reserve base was compared with the actual decline of pre-1998 completions. As historical individual gas well performance parameters were generated for each region, depth interval, and production type, they were checked against conventional decline analysis and used to provide a check of future well performance parameters.

Technology Improvements

The Technology Subgroup under the Supply Task Group was formed with representation from various segments of the oil and gas industry to assess the role and impact that technology will have on natural gas supply in North America. Several workshops and meetings were organized to provide a forum for industry experts to discuss the role that current and future technology will play in sustaining the supply of natural gas. From this process, a forecast of technology improvement parameters was developed for input into the natural gas supply model used for the study. Also, sensitivity cases were run to assess the effects of a range of high and low rate of advancement of technology development and application. For the purpose of the study, technology was defined broadly as any new or improved product, process or technique that enhances the overall result compared with the current results observed today.

Technology Subgroup Process for the Study

Scope

The Technology Subgroup was established to provide insights into the role and impact of upstream technology in delivering natural gas supply during the study period. Composed of thirteen members from a cross-section of industry organizations, the Technology Subgroup determined its scope to be:

- To design a methodology for measuring the impact of future technologies in the econometric model
- To estimate the technology improvement parameters for the scenarios developed and a range of sensitivity cases
- To compose an upstream technology commentary for the final report that provides a current-state industry view of research and development, its impact on the outlook, and the role of technology in the future deliverability of North America natural gas through the year 2025
- To recommend actions that will facilitate the use of new technologies to improve the economics and increase the future deliverability of natural gas.

Workshops and Special Technology Sessions

To achieve these goals, the Technology Subgroup scheduled a series of workshops providing a forum to understand previous studies, provide input into the supply model, and prepare the report. In addition to the workshops, six special technology sessions were held to discuss with industry experts specific issues related to core, high-impact technology areas. The selected technology areas were Coal Bed Methane, Drilling, Completions, Subsurface Imaging/Seismic, Deepwater Development, and Natural Gas Hydrates. Held in January and February 2003, these special sessions enabled the Technology Subgroup to hear the views and foresights of a large cross-industry expert community, a total of 128 in all. These sessions were helpful in assessing the effect of technology on future supplies. They also helped to improve the quality of technology input parameters for the econometric model.

Methodology for Developing Technology Improvement Parameters for the Model

The Technology Subgroup reviewed the econometric model to understand how technology improvement is factored in the supply model. Some of the members attended the various regional resource assessments workshops to gain an understanding of the technologies applied and challenges ahead. The subgroup then reached consensus on the technology improvement parameters for the Reactive Path scenario for each assessment region and in some cases, by type of reservoir. The technology improvements parameters developed for input into the supply model are as follows:

- Exploration success – annual percent improvement in the ratio of completed versus non-completed exploration wells
- Development success – annual percent improvement in the ratio of completed versus non-completed development wells
- Estimated ultimate recovery per well – annual percent improvement in the estimated ultimate recovery (EUR) of natural gas per well
- Drilling cost – annual percent improvement in drilling costs per well including site preparation, rig mobilization, drilling, and installing casing
- Completion cost – annual percent improvement in the completion cost per well, including perforating, stimulating, and installing down-hole production equipment
- Initial production rate per well – annual percent improvement in the initial production rate estimated in the model for each well completed

- Infrastructure costs – annual percent improvement in the major surface infrastructure costs associated with the development of new fields, such as offshore platforms, sub-sea production and gathering systems, field processing plants, and field gathering lines
- Fixed operating expenses – annual percent improvement in the operating expenses associated with the production of natural gas.

Three time periods were used to forecast the technology improvement parameters where technology application would likely change through the study period. They are as follows:

- First five-year period – 2003-2008
- Second seven-year period – 2009-2015
- Third ten-year period – 2016-2025.

Furthermore, two cases of improvement parameters, beyond the Reactive Path scenario, were generated to create a range of possible outcomes for technology impact in the supply model. The two cases were:

- High pace of technology advancement and application
- Low pace of technology advancement and application.

After reviewing the model runs, the input parameters were then checked for reasonableness and consistency with the expectations described during the discussions at the workshops and special sessions. Some modifications were made for the final model runs.

Historical Perspective of Technology Contributions

The Technology Subgroup reached the consensus that technology has historically contributed significantly to the ability of the petroleum industry to find, develop, and produce natural gas resources. If the industry relied on the same tools and methodologies used thirty years ago, it would only be able to produce a small fraction of what is currently being produced today. How much of an impact technology has had is difficult to precisely determine, because the industry does not measure the impact of technology directly. However, one can find indirect evidence of technology's impact by looking at cost trends or production performance trends in any given area or field. Also, there is indirect evidence that identifies improvement in the ability of the industry to explore for natural gas. Most evidence, however, is anecdotal.

Projected Technology Improvements

Even with the noted technology advancements, over the last ten years, investments in upstream research and development have declined and the industry has been cautious in using high-cost, high-risk technologies regardless of their potential. This reluctance is particularly evident if the technology is perceived to have a longer-term impact. With this observation and the maturity of the exploration and production environment, the subgroup postulated that technology will play a somewhat lesser role in gas resource enhancement in the near future. Technology will gain slight momentum beyond five years as the industry invests more in technology developments, motivated by the challenges of the resources and higher gas prices. This is not intended to imply that there will not be continued improvements. Indeed, there will be continued improvements in both tools and techniques, but there are no foreseeable major breakthroughs on the horizon.

With this back-drop, the Technology Subgroup developed a series of technology improvement parameters for the Reactive Path scenario in the supply model that reflect the anticipated rate of improvement in each major core technical area of application.

Different improvement parameters were determined for each major region and in some instances, for each type of reservoir, as for example coal bed methane or deep, high-temperature, high-pressure reservoirs. Also, to reflect the anticipated behavior of the industry, different improvement parameters were adopted for each of the different time periods, 2003-2008, 2009-2015, and 2016-2025+. The consensus of the members of the Technology Subgroup was that for most of the technical areas and geologic regions, the later time periods would probably see a faster pace of improvement than the early time period.

The actual technology improvement parameters used in the Reactive Path supply model are provided in the full report appendices. However, in order to get a sense of the magnitude of these improvement parameters, Table 4-5 summarizes the improvement parameters by averaging them for each parameter.

The values shown in Table 4-5 were not calculated from any theory or formula. Instead, the values were

Technology Area	% Annual Improvement*	% Improvement Extrapolated for 25 Years
Improvement in Exploration Well Success Rate	0.53	14
Improvement in Development Well Success Rate	0.46	11
Improvement in Estimated Ultimate Recovery per Well	0.87	24
Drilling Cost Reduction	1.81	37
Completion Cost Reduction	1.37	29
Improvement in Initial Production Rate	0.74	20
Infrastructure Cost Reduction	1.18	26
Fixed Operating Cost Reduction	1.00	22

* These numbers reflect the average of the parameters, not the actual parameters used in the supply model.

Table 4-5. Technology Improvement Parameters for the Reactive Path Scenario Supply Model

determined by the Technology Subgroup, using all available information and insights generated during the study. The parameters were based more on collective experience and intuition, than on theory. However, the Technology Subgroup agreed that the parameters seemed reasonable given all of the discussions developed at the workshops and special technology sessions.

It was appropriate to also look at a range of parameters that reflect a high and low pace of technology advancement and application. The Technology Subgroup developed parameters for these two additional cases assuming various factors that influence the pace of developing and applying new technologies. These parameters are described in the full report.

Issues and Challenges

Several issues and challenges will face the North American petroleum industry and governments as they pursue research, development, and application of new technologies to enhance the supply of natural gas.

Although many of the North American producing basins are maturing, significant technically recoverable resources still remain. Higher prices will support technology development; however, declining reserves may make it difficult to justify major investments in new technology. Majors, independent companies, and the service industry will all play a role in support of the required technology development.

Industry must also improve processes for the acceptance and utilization of new technology. The shift toward more collaborative research increases the difficulty of testing and deploying new technologies. Professional societies, trade associations, and academic and government research institutions, along with the industry will need to increase efforts to communicate and work together to effectively deploy new applications.

Another challenge will be to effectively transfer the knowledge and experience of the existing professional workforce near retirement to the new generation entering the industry and research institutions. Otherwise, the risk of "reinventing the wheel" will loom over the industry.

With the expected tight supplies of natural gas, potentially higher prices, and ever-increasing technical challenges, the petroleum industry, research institutions, and governments need to adopt innovative technology strategies to respond to these challenges.

Key Findings

The key technology findings are as follows:

- **Technology improvements play an important role in increasing natural gas supply.** During the last decade, 3D seismic, horizontal drilling, and improved fracture stimulation have had significant effects on natural gas production in many basins in North America. Also, due to advanced designs in deepwater developments, additional production from the Gulf of Mexico slope regions has been realized.

  In addition to these step-change technologies, continued improvements in core technical areas have been implemented as a result of industry's continuing efforts to search for more cost-effective ways to find, develop and operate oil and gas fields. This trend is especially evident in the production of nonconventional gas reservoirs such as coal bed methane, shale gas and tight sand formations. New designs in drilling bits, improved well planning and modern drilling rigs have also lowered drilling costs in many regions. Advances in remote sensing, information technologies and data integration tools have served to keep operating expenses in check.

  As modeled in the Reactive Path scenario and illustrated in Figure 4-78, by the year 2025, advanced technologies contribute 4.0 TCF/year of the 27.8 TCF/year produced in the United States and Canada. This amounts to 14% of the natural gas produced during that year.

- **Adding new North American natural gas supplies will require finding, developing and producing more technologically challenging resources than ever before.** Overall, when assessing the natural gas resources that will be found and developed over the next 25 years, they can be generally described as deeper, hotter, tighter, more remote, in deeper water and smaller, harder-to-find prospects. The combination of more difficult natural gas resources and higher prices of natural gas should catalyze increased efforts in research, development and application of new technologies by the industry and governments.

- **Investments in research, development, and application of new technology have declined over the last 10 years.** Although it is difficult to obtain information concerning how much the total oil and gas industry spends on technology improvements focused on North American natural gas assets, over the last decade the trend in upstream research and development spending has been downward, as reported by the U.S. major energy producers through the EIA (see Figure 4-79).

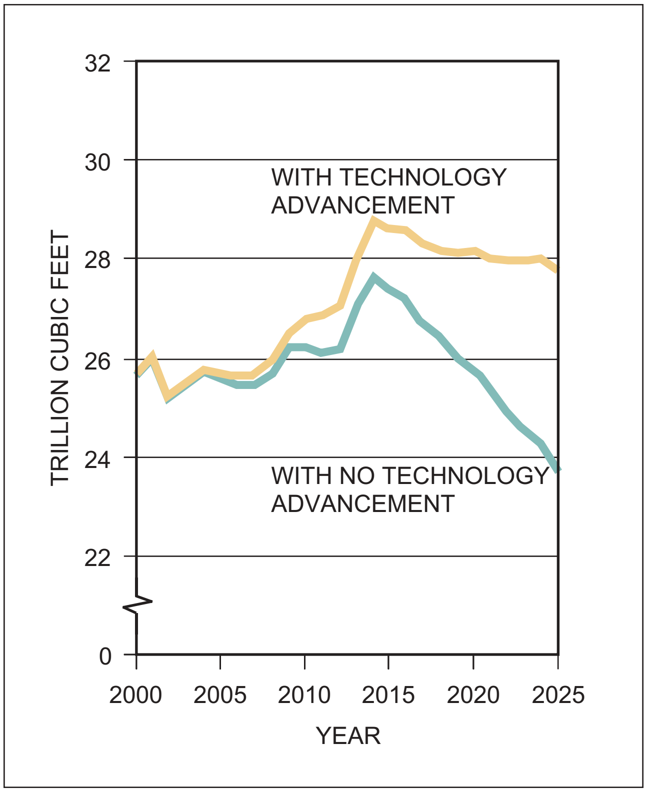


Figure 4-78. Impact of Technology on U.S. and Canadian Natural Gas Production

Forecasting future technology investment is difficult. As a result, the implication of technology improvements on production and prices are cast in terms of a range of outcomes as shown in Figures 4-80 and 4-81. The low advancement sensitivity case reflects a slower pace of technology development and application caused by reduced investment in research. The high advancement case reflects a faster pace of technology development and application. The improvement parameters developed for these sensitivity cases are described in the Technology section of the Supply Task Group Report.

Service industries and joint-sponsored research programs are playing an increasing role in research and development. This can be viewed as a cost-effective and less redundant method for research. It may also have the effect of slowing down the application of the new technologies, and diminishing focus on long-term or high-risk research. In many cases, long-term or high-risk research has been undertaken through joint industry and/or government-sponsored programs.

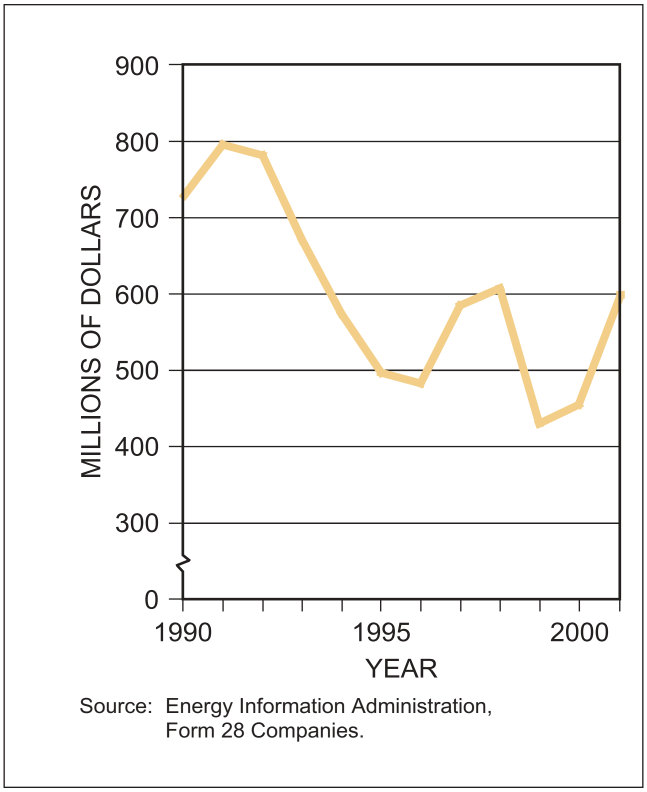


Figure 4-79. Upstream R&D Expenditure History

- **The gas exploration and production industry should collaborate more effectively with the Department of Energy on the planning and execution of complementary, not competitive, research and development programs.** The Department of Energy plays an important role in facilitating and sponsoring joint research and development programs within the gas supply industry.

  During fiscal year 2003, the Department of Energy plans to fund $47.3 million towards jointly sponsored natural gas technology research and development programs. This represents 53% of the funding allocated by DOE to sponsor oil and gas R&D programs but only 9% of the total $529.3 million funds directed at fossil energy programs. As a comparison, coal research attracts $349 million in DOE funding. With the new insights developed from this study, the Department of Energy should address the obvious question of whether the current funding level towards natural gas research is appropriate in relationship to other R&D programs and the increasing challenges facing the new natural gas resources within the United States. Figure 4-82 shows R&D program funding in 2002.

  In addition to the question concerning the level of R&D funding by the DOE, another important issue is whether the funds are focused on the right natural gas technologies. The DOE's role is to support the public interest in technology pursuits that the industry is not adequately addressing. It is therefore essential that effective communication and collaboration exist between the DOE and the industry's technology developers to accomplish this goal and prevent duplication. This is not an easy task since the developers are split among many entities, such as national labs, sponsored research organizations, gas producers, service companies, consultants, and universities. In addition, it is critical to have effective collaboration and communication by technology users to ensure mutual understanding of the problems to be solved and how effective application can be achieved.

  Service companies have been hesitant to participate in jointly funded DOE-industry projects for the development and demonstration of advanced technology, assuming incorrectly that their proprietary technologies would be made public. The Department and the service industry need to increase their discussions regarding future technology directions to ensure that the two do not duplicate efforts and to increase the opportunities for service companies to participate in government-supported technology development.

- **Environmental and safety considerations are significant drivers in the development and application of new technologies.** The oil and gas industry continues to focus a significant amount of technology development effort to address environmental concerns and reduce potential safety issues in the field. In some cases, these new technologies and approaches also contribute to improved operational performance. As an example, new smaller modular rig designs to reduce the environmental footprint also reduce downtime for rig moves improving economics. Drilling and completing multi-lateral and long-reach horizontal wells reduce the number of well locations for equivalent reservoir drainage and simultaneously increase the recovery per well. Environmentally compatible drilling and completions fluids may reduce the cost associated with zero discharge requirements in certain sensitive areas. Designing rigs and equipment to reduce safety hazards such as manual pipe handling can also improve the drilling efficiencies and shorten downtime while

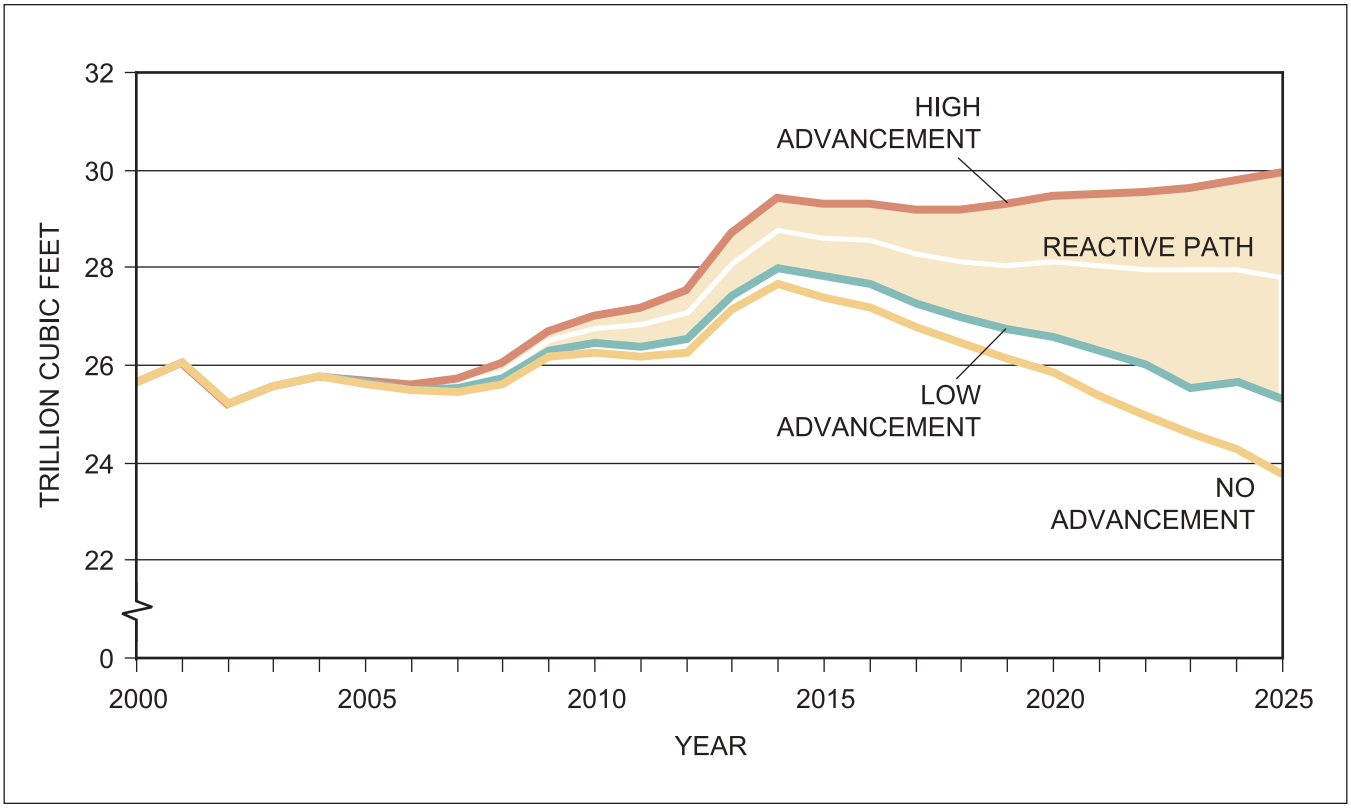


Figure 4-80. Impact of Technology Change on U.S. and Canadian Natural Gas Production

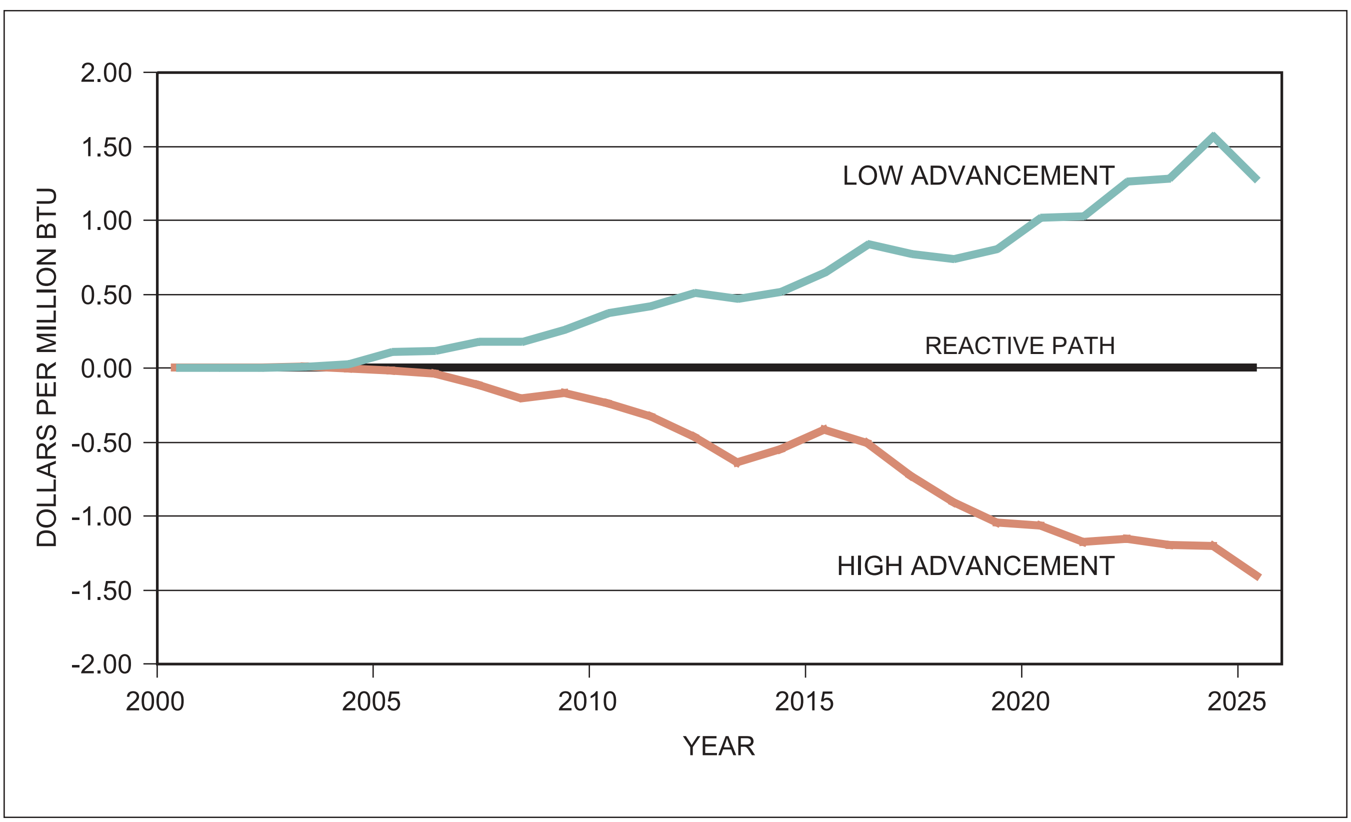


Figure 4-81. Impact of Technology Change on Gas Price at Henry Hub (2002 Dollars)

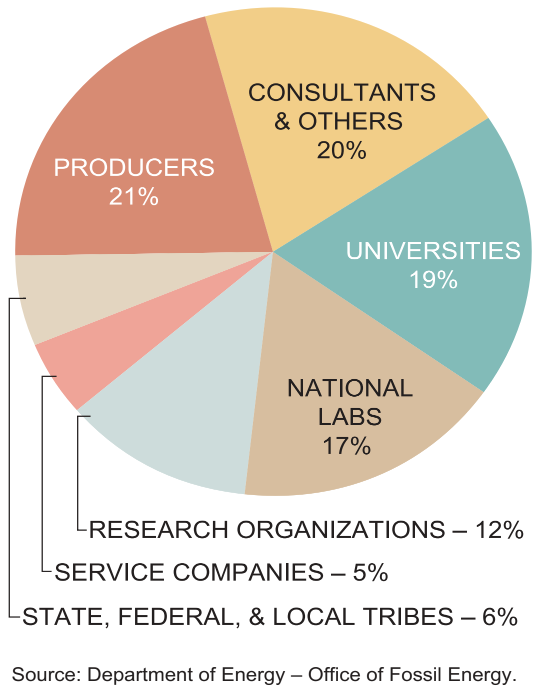


Figure 4-82. Upstream R&D Funding by Performer (FY 2002)

tripping in and out of the hole. As the industry and government regulatory agencies search for acceptable methods to access new areas and reduce costs of compliance with environmental and safety regulations, these advances in technologies may enable balanced solutions.

Natural Gas Hydrates

The Technology Subgroup had the charge to investigate the technologies associated with natural gas hydrates and determine the feasibility of their contribution in the Hydrocarbon Supply Model. To gather data on the subject of natural gas hydrates, a workshop was held on January 28, 2003, in Houston, Texas. The objectives of the workshop were to (1) determine whether the production of natural gas from natural gas hydrate deposits would be feasible between now and the year 2025, and (2) identify the technologies that would be required to produce natural gas from natural gas hydrate deposits in North America.

The following conclusions were derived from the special session.

- Natural gas production from naturally occurring gas hydrate deposits should not be included as a major source of gas production in the NPC gas supply forecast before the year 2025. Their contribution as a significant supply of natural gas is anticipated beyond 2025.
- Production from natural gas hydrate deposits in the deepwater Gulf of Mexico and other deepwater areas around North America will depend on both the development of significant technology advancements and infrastructure availability. Technology development will depend on the level of both government and private industry funding.
- Production from natural gas hydrate deposits in the Arctic areas of Alaska and Canada will depend primarily upon available pipeline capacity. If commercial production of gas hydrates is determined to be feasible, it is more likely to be a source of fuel used in the Arctic oil and gas field operations.

Synthetic Gas/Coal Gasification

Synthetic gas or syngas, a mixture of hydrogen and carbon monoxide, was previously known as "town gas" and was used in many domestic and commercial applications. It was largely displaced after the exploration and production industry developed cheap natural gas supplies last century. Current equipment, systems and infrastructure are now designed for natural gas, with which syngas cannot be blended in existing infrastructure. However, it can displace natural gas where an entire system is converted or designed to use syngas.

Historically, syngas was typically generated from coal, but current technology allows almost any hydrocarbon to be gasified. Gasification produces clean syngas and leaves contaminants concentrated in an easily handled slag. It is therefore often used to convert low-value, impure hydrocarbons such as refinery bottoms, coal, and petroleum coke into a useful product in an environmentally sound way.

The major syngas uses are as fuel, for instance in boilers or gas turbines, to generate hydrogen and as feedstock to make chemicals. As a fuel, it can normally be blended with natural gas.

At high gas prices, coal gasification begins to look economically attractive and may have some application as an alternative fuel source in future power plants built in North America. At lower gas prices, it is almost certainly uneconomic although it may suit niche applications (e.g., where environmental issues are important) and geographic areas where suitable feedstock is cheap (e.g., in coal mining areas or near refineries producing coke or bottoms) and/or natural gas is costly.

Access Issues

The natural gas study represents an opportunity to broaden understanding and to offer recommendations for easing restrictions that adversely affect access to natural gas resources. The objectives of the analysis of access issues were:

- To identify the regulatory and environmental issues affecting access to gas resources. These issues derive from varied interests (mineral extraction, wildlife resource management, environmental protection, historic preservation, local, state, and federal economies, recreation) and diverse organizations (administrative agencies, industry, special-interest groups, general public). The attempt to suit these many interests has resulted in regulations that are complex and often difficult to understand and administer.
- To quantify the volumes of natural gas affected by access restrictions and the impact on gas markets of alternative access policies.
- To recommend actions that might reasonably be taken to support environmentally sound gas resource development.

Focus

The Environmental/Regulatory/Access Subgroup studied a limited number of the lower-48 basins that were reviewed by the Resource Subgroup. The access analysis focused on those basins with large remaining potential and with significant access constraints. These basins are located in the Rocky Mountain region of the United States (Green River, Uinta/Piceance, Powder River, San Juan, Wyoming Thrust Belt) and offshore Atlantic, Pacific, and Eastern Gulf of Mexico.

The study also examined the issue of access in Canada, and, referencing the recently published study on Potential Canadian Gas Supply (conducted by the Canadian Energy Research Institute) estimated the percentages of the various producing basins that are currently off-limits to leasing. These percentages were used in the long-range modeling process. Although there are other access and environmental issues in Canada, generally speaking, access issues in Canada are less significant than in the United States. Therefore, alternative policy cases related to Canadian access restrictions were not conducted and likely would not have had a material impact on the 2003 NPC study.

Expert Teams for Analysis

Two teams of industry experts – one for the Rocky Mountains and one for the U.S. offshore – were assembled to perform the detailed data gathering, compilation, and evaluation work. These teams brought with them extensive, practical industry experience in dealing with environmental and regulatory issues that affect petroleum resource development. These teams also had access to specialized contractors to provide added assistance and expertise. Equally important, the teams sought input from associations and regulatory agencies, such as the Bureau of Land Management (BLM), Forest Service, and Minerals Management Service, in order to ensure that their work looked at these issues from the broadest possible perspective.

Rocky Mountain Area

Prior Reports – Federal Lease Stipulations

Participants in the 2003 NPC study had three previously published Rocky Mountain access-related reports to use as points of reference:

- The 1999 NPC Study
- The 2001 Greater Green River Basin Study
- The 2003 Energy Policy and Conservation Act Study – Scientific Inventory of Onshore Federal Lands' Oil and Gas Resources and Reserves.

These reports are primarily or exclusively concerned with the effects of federal lease stipulations; they generally regard lands as falling into two categories, either off-limits (areas not leased for various considerations) or available for lease. The participants in the 2003 study quickly determined that the three prior reports had done an excellent job quantifying the impacts of lease stipulations, and that the direction of the 2003 study should be to examine the impacts arising from post-leasing requirements.

Conditions of Approval – Post Leasing

The term "conditions of approval" (COA) refers to development requirements that arise during the permitting process that takes place after leases are obtained. These COAs are governed by several controlling authorities, but the most significant and wide-ranging tend to be those based on federal legislation concerning environmental policy, species protection, and historic preservation.

In many instances where leasing is permitted, these COAs are actually more of an impediment to exploration and development than the lease stipulations. This is not to say that COAs are inappropriate, but rather to provide a baseline for improvement in COA processes.

Methodology – Green River, Uinta/Piceance, Powder River, San Juan

The teams developed extensive maps showing the surface areas subject to COA issues. To perform this mapping, NPC contracted with Hayden-Wing and Associates, an environmental consulting firm located in Laramie, Wyoming. Hayden-Wing is widely recognized for its expertise in wildlife surveys, environmental impact statements, wetland evaluations, and developmental permitting.

In addition to the preparation of these maps, Hayden-Wing quantified the percentage of the land areas in these basins that are covered by each habitat and migratory range. They also estimated the frequency of occurrences requiring specific survey or mitigation actions on the part of oil and gas operators, such as active raptor nests, active Sage Grouse leks, big game birthing habitats, and other similar circumstances.

Thus, for example, a given area of a studied basin has the potential for a particular protected species habitat. Surveys within that habitat will find the species a certain percent of the time. If the species is found, COAs will be placed upon resource access

The Rocky Mountain expert team estimated the cost and time delay caused by the COAs related to the species occurrences described above, as well as for archaeological activities governed by the National Historic Preservation Act and for environmental analyses and environmental impact statements required by the National Environmental Policy Act (NEPA). These data were developed by analyzing costs and delays incurred on actual projects conducted in these basins. The team also determined whether each COA also applied to state and fee lands, in addition to federal lands. The team drew from its own extensive experience as well as that of Hayden-Wing, industry associations, and regulatory agencies for cost, time, and applicability information.

Once all of the data had been compiled, they were analyzed with the help of a probability analysis program created by EEA specifically for this project. The data consisted of:

- A list of circumstances that might potentially result in COAs
- An estimate of the percentage of each basin area where those circumstances might be found and initial surveys would have to be done
- An estimate of the conditional probability that the initial survey would find that the circumstance is, in fact, present for a given well in that area and further mitigation steps would have to be taken
- Cost, time delays, and surface occupancy bans for surveys and mitigation steps
- Activity sequencing and grouping to ensure logical scenarios and to eliminate redundancies or inconsistencies.

A simplified data input matrix is shown in Table 4-6.

The program analyzed the cumulative effect of the COAs in each basin for 1,000 hypothetical wells. Separate runs were made to determine the impacts on federal lands, state lands, and fee lands, and for exploratory versus development wells. The quantification process from map areas to cost-and-delay output information is shown schematically in Figure 4-83.

By calculating a weighted average based on the cumulative acreage of each of the three land types, the team was able to estimate the average cost and timing delay per well in each basin associated with COAs. Some well locations, although available for leasing, were rendered effectively off-limits due to the cumulative effects of COAs. For purposes of this report, any acreage that was rendered unavailable for surface occupancy for 9 months or more per year due to the cumulative effect of COAs is considered to be "effectively off-limits to development."

Efforts were next made to normalize the areas of acreage effectively off-limits due to COAs to the play areas within each basin, and to subtract the percentage of lands in each basin already determined by the 2003 EPCA study to be off-limits due to leasing restrictions. This allowed the team to determine the net basin-wide percentage of natural gas resource that is effectively off-limits due to COAs for each of the major basins.

These findings are summarized in Table 4-7.

		Surface Authority			Activity Sequence, Probability, and Grouping					Wildcat Wells		Development Wells		
Item Number	Item	Federal Action	State Lands	Private Lands	Contingent on Item X Happening First	Probability or Contingent Probability %	Correlation with Item X	Correlation Factor	Item Numbers of Common Group	Added Cost (Dollars)	Time Delay (Months)	Added Costs (Dollars)	Time Delay (Months)	No Access
1	Raptor Survey General	1	1	0		99.4				700	1			
2	Raptor Nest Survey	1	1	0		28.1			1	3,500	1	350	1	
3	Active Raptor Nests Found: No Access	1	1	1	2	5.7								X
4	Active Raptor Nests Found: Mitigation	1	1	1	2	30.0	3	-1	3	106,000	3	106,000	3	
5	Big Game Survey	1	1	0		40.0				1,200		360		
6	Big Game Found: Relocate/Directional	1	1	0	5	10.0				150,000	3	150,000	3	
7	Big Game Found: Mitigation	1	1	0	5	90.0	6	-1	6	5,280	3	5,280	3	
8	Blackfooted Ferret Survey	1	1	0		54.5				7,500	6	7,500	6	
9	Blackfooted Ferret Found: No Access	1	1	0	8	1.0								X
10	Blackfooted Ferret Found: Mitigation, etc.	1	1	0	8	10.0	9	-1	9	106,000	3	106,000	3	

Note: Approximately 50 key items per basin.

Table 4-6. Rockies Access Analysis Matrix

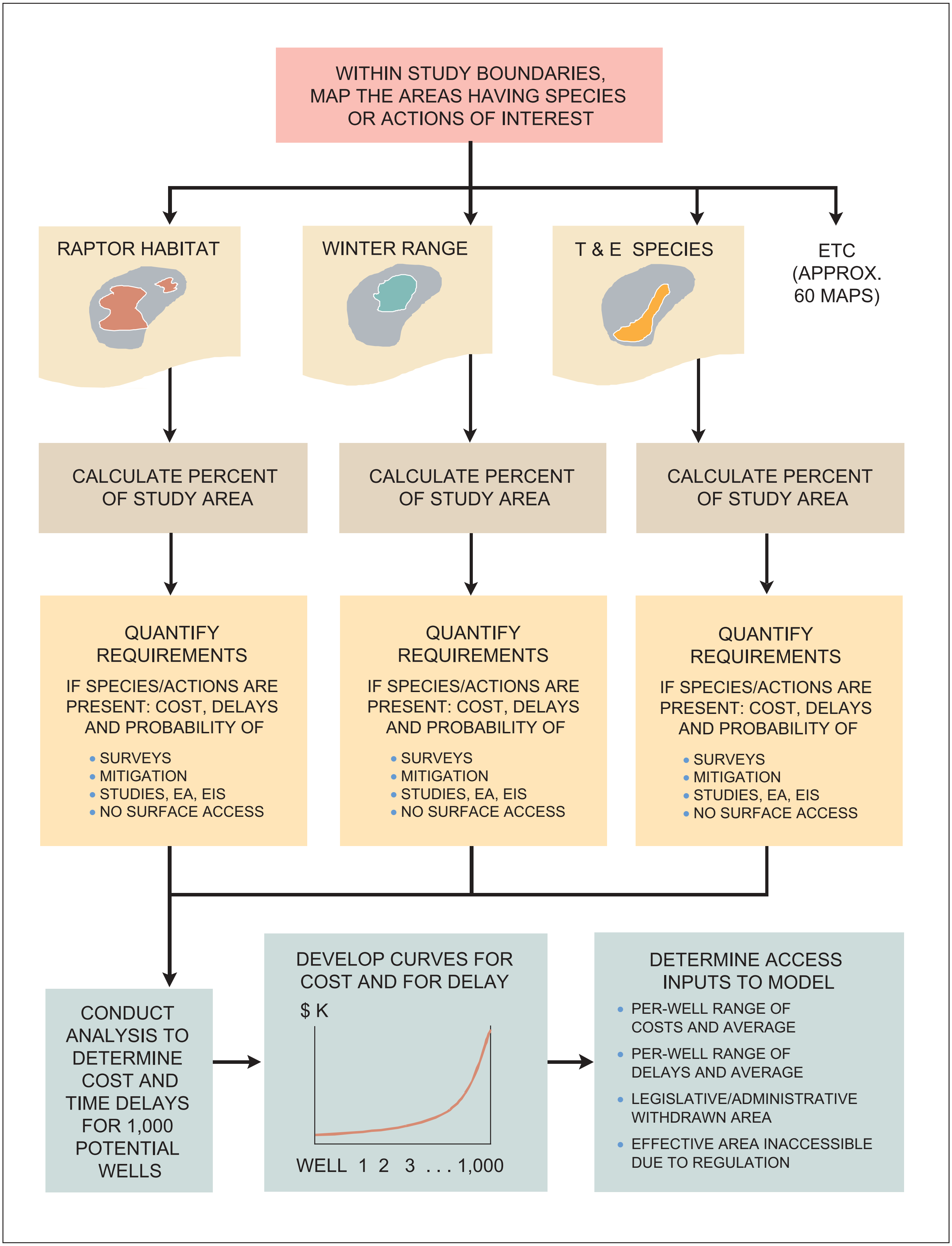


Figure 4-83. Access Quantification Process

Category	Green River	Uinta/ Piceance	Powder River	San Juan
Resources Off-Limits				
Federal Statutory/ Administrative No Leasing	8.7%	4.1%	4.6%	2.3%
Prohibitive Conditions of Approval				
12 Months Off-Limits	24.5%	15.2%	5.7%	6.2%
9-11 Months Off-Limits	6.9%	1.8%	20.3%	0.1%
Total Restricted Percentage	**40.1%**	**21.1%**	**30.6%**	**8.6%**
Average Added Costs per Well Due to Conditions of Approval (Thousands of Dollars)				
Federal/State Exploratory	240-250	146-152	103-108	63-68
Federal/State Development	90-95	104-108	57-61	53-57
Weighted Average	103	107	62	55
Fee Exploratory	48-52	54-56	15-20	30-34
Fee Development	54-58	68-70	17-21	30-35
Weighted Average	56	69	19	33
Average Time Delay (Months)				
Federal/State Exploratory	12-14	9-11	2-4	5-7
Federal/State Development	20-22	7-9	13-15	6-8
Fee Exploratory	2	2	6	1
Fee Development	2	2	2	1

Note: Percentages refer to new field and nonconventional resources only. Proved reserves and growth of old fields are not included.

Table 4-7. Rockies Access Restrictions

Analysis Extension – Wyoming Thrust Belt

In addition to the four major producing basins discussed above, the Rocky Mountain area expert team examined access restrictions in the area defined by this study as the Wyoming Thrust Belt. This examination was conducted by comparing land use planning maps of this region to the play areas developed by the NPC Resource Subgroup. The expert team also applied its knowledge of administrative leasing policies currently being employed in the area by the governing agencies. Using this information, the expert team determined that roughly 80% of the resource underlying the Wyoming Thrust Belt area is currently withdrawn from leasing due to administrative decisions.

Permitting Pace

The process of issuing permits requires resources that are not always immediately available. This is particularly true whenever a new play develops in a given area and there is a sudden increase in demand for permits. Therefore, a limitation on the yearly increase in the number of permits issued by the governing agencies was developed and included in the modeling process. For periods of very heavy permit loads (over 300 wells drilled per year), the increase is limited to 15% of the prior year's level.

Offshore United States

The single largest access restriction to natural gas resources in the offshore United States is the Presidential Order issued by former President Bush. President Clinton extended the reach of that restriction by withdrawing additional acreage in the Eastern Gulf of Mexico, thus creating a moratorium on exploration and development activities that covered not only the entire Atlantic seaboard, but also extended to most of the Pacific Coast and most of the Eastern Gulf of Mexico as well. This moratorium is to last through June 30, 2012. In addition, the remainder of the Eastern Gulf of Mexico remains off-limits due to opposition from the state of Florida and the subsequent decision by the Department of the Interior to greatly reduce the Lease Sale 181 area.

The OCS expert team analyzed the effects of existing environmental and access-related restrictions in the offshore U.S. in terms of time delays and increased costs per well, and ensured these data items were accurately reflected in the EEA model. The team also identified the key issues affecting access to development in the OCS and compiled detailed analyses of them, including the public policy recommendations contained elsewhere in this report, and developed the modeling assumptions for the modeling cases conducted throughout the course of this study.

For the Reactive Path scenario, the following modeling assumptions were made:

- All Presidential Order moratoria remain in place through 2025.
- All waters placed off-limits due to administrative decisions of the Department of the Interior remain off-limits during the time period covered by this study.
- No additional acreage beyond that covered in the Minerals Management Service's 2002-2007 Five-Year Leasing Program will be offered during the time period covered by this study.

Access Analysis

Sensitivity Case Summaries

To estimate the potential effects on price and recoverable natural gas resource of future implementation of the Onshore and Offshore recommendations contained in this report, the NPC specified several modeling sensitivities to be run by EEA. Since the Reactive Path scenario described elsewhere in this report assumes that current restrictions to access will remain constant throughout the scope of this study, the NPC also specified decreased supply access cases designed to estimate the effects that might result from a continuation of the steady increase in restrictions that have occurred in the United States over the past 30 years.

The Balanced Future scenario included increased access assumptions that are the combination of two sensitivities discussed below – the Gradual Increase Rockies Access case and the Increased Offshore Access case.

Increased Rockies Supply Access Cases. The NPC determined it would be useful to perform two enhanced access cases as a part of its modeling work: (1) an analysis designed to estimate the impact of the current regulatory regime (the "Full Effect Case") on natural gas prices and available resource; and (2) an analysis designed to estimate the potential positive impacts from the implementation of the public policy recommendations contained in this report (referred to herein as the "Gradual Increase Case") on prices and available resources.

In running these two cases, the following assumptions were made:

- Full Effect Case – The cost and timing restrictions arising from the cumulative effects of post-leasing COA are immediately lifted. The percentage of the resource that is off-limits to leasing by statute remains unchanged. It is important to note that this case is not intended to advocate the repeal of these COAs. Rather, it is simply intended as a means of estimating the impacts in terms of higher prices and foregone resource of the current regulatory regime. As noted elsewhere in this report, the NPC fully recognizes and supports efforts by the various governing agencies to protect endangered species, wilderness areas, and archaeological artifacts.

- Gradual Increase Case – The cost and timing restrictions arising from the cumulative effects of post-leasing COA are decreased by 50% over a five-year period beginning in 2004. As in the other cases, the percentage of resource off-limits to leasing by statute remains unchanged.

Increased Offshore Supply Access Case. In the OCS, the NPC wanted to test the potential effects on the price and available resource from a lifting of the presidential moratoria that are currently in place on the Atlantic and Pacific Coasts of the U.S. lower-48, as well as the Eastern Gulf of Mexico. In this case, the following are assumed:

- The moratorium ends in July 2005.
- Leasing of offshore tracts does not commence until July 2007. This two-year period is to allow time for federal, state, and local jurisdictions to develop the administrative infrastructure needed to manage this activity, and for appropriate areas for leasing to be selected.
- Full-scale production does not commence until 2012 to allow time for seismic analysis, exploratory, and development programs.

Decreased Supply Access Cases. For the decreased access cases, the NPC made the following assumptions:

- The costs and timing delays arising from post-leasing COAs in the Rocky Mountain area double over a period of 10 years beginning in 2004. This includes the average added cost per well, the average initial time delay, and the percentage of resource that becomes effectively off-limits to development. In the judgment of the Rocky Mountain expert team, this gradual increase approximates the trend that has taken place during the prior decade.
- The percentage of resource statutorily off-limits to leasing as quantified in the 2003 EPCA Report remains unchanged.
- The total "No Access" percentage of resource (statutory + COA) in each basin was capped at no more than 50%.
- In the OCS, the model assumed a one-year halt in drilling takes place in 2005, and the environmental cost of compliance doubles over a ten-year period.

Sensitivity Modeling Results

Onshore. The Southern California market obtains most of its natural gas supply from the Rockies/San Juan Basin areas that were the subject of the NPC's work related to post-leasing COAs. Figure 4-84 shows the impact on Southern California natural gas prices that result from different levels of access to resources in the Rockies.

As expected, the Gradual Increased Rockies Access case begins to show an easing of prices as the impacts of the COAs are reduced beginning in 2004. The result shows a consistent price differential of 30-50 cents per MMBtu in the later years of this study when compared to the Reactive Path scenario. However, as mentioned earlier, the Reactive Path scenario assumes that the current level of COA-related effects will remain static throughout the duration of this study, which represents an improvement over the steady increase in such restrictions that has been observed in recent years. Thus, the NPC believes it would be useful to compare the Gradual Increased Rockies Access case to the Decreased Rockies Access case, which assumes that this trend towards more COA-related restrictions will continue if there are no significant changes in public policy.

In terms of the available natural gas resource, the Gradual Increased Rockies Access case shows an immediate ramp-up in available volumes from the Onshore lower-48 compared to the Reactive Path scenario in 2004, which continues throughout the duration of the study. This differential peaks in the out years at more than 1 TCF per year. When one compares the Gradual Increased Rockies Access case to the Decreased Rockies Access case, the differential in volumes reaches 1 TCF as early as 2010, and increases steadily, reaching 2 TCF per year during the latter part of the study.

Offshore. The Increased Offshore Access case shows a consistent lowering of prices for the South Florida market compared to the Reactive Path scenario begin-

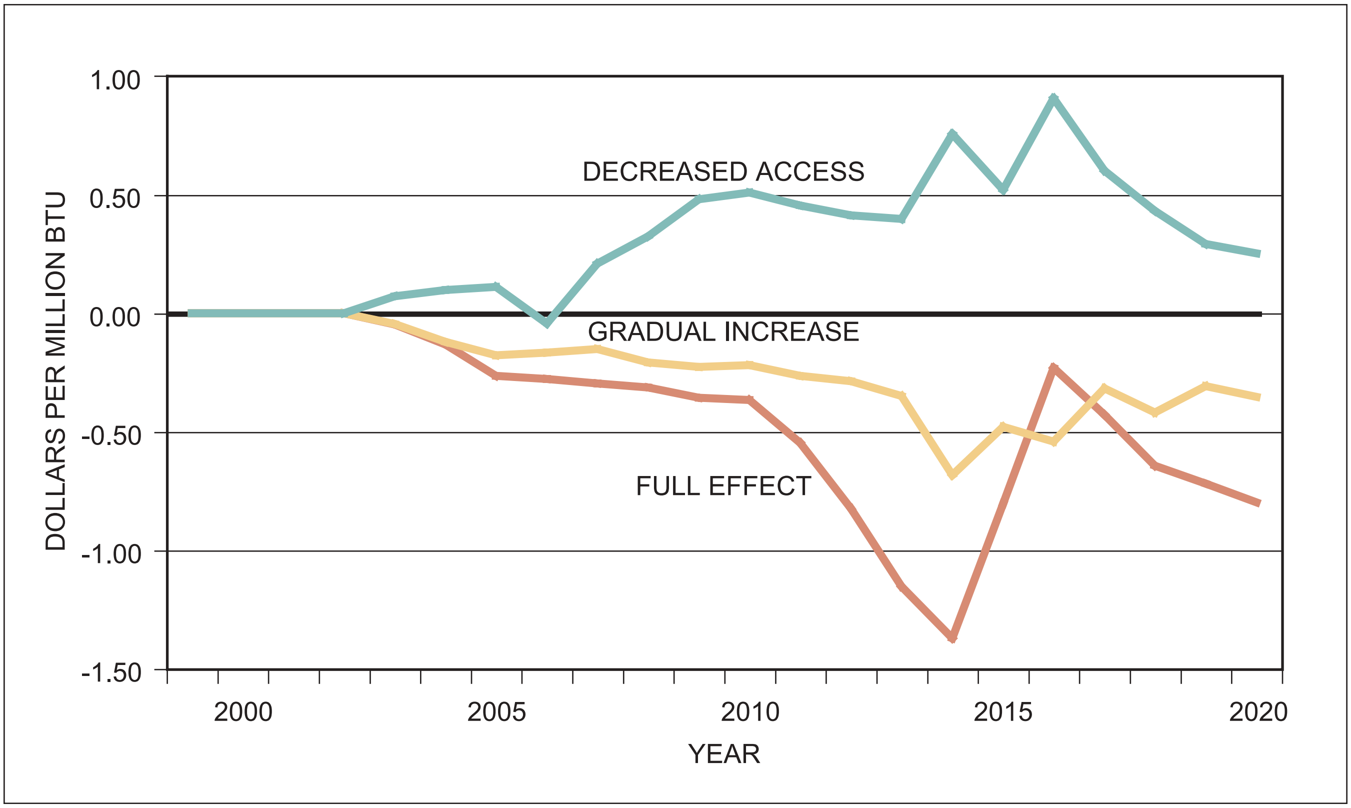


Figure 4-84. Rockies Access Impact on Southern California Prices (2002 Dollars)

ning in 2011, as new volumes from the Atlantic OCS and the Eastern Gulf begin to come on stream. This case showed a similar price impact for the New York City market as well. In addition, the Increased Offshore Access case shows a steady ramp-up of new volumes from the Offshore Atlantic beginning in 2011, growing to almost 700 BCF per year by 2025, as well as similar production volumes from the Eastern Gulf of Mexico.

In the Decreased Offshore Access case, there is a near-term price increase for the South Florida market resulting from the one-year drilling moratorium assumed in 2005.

Sensitivity Conclusion

Figure 4-85 shows the change in Henry Hub price from the Reactive Path scenario for the Increased Access (Combined) case (used in Balanced Future scenario) and the Decreased Access (Combined) case, which assumes a continuation of growing access restrictions.

Overall, the sensitivity cases related to the issue of access support the policy recommendations that follow below. None of the recommendations are by themselves a panacea for alleviating the tight supply and demand outlook that is forecast by the Reactive Path scenario in this study. However, when taken as a whole, the NPC believes that the prompt implementation of these recommendations would effectively increase available natural gas in the lower-48 areas of the United States, which in turn would have a significant effect on prices paid by consumers.

Recommendations

The following recommendations will reduce permitting response time by streamlining processes, instituting performance metrics, clarifying statutory authority, and ensuring adequate agency resourcing.

Onshore – Increase access (excluding designated wilderness areas and national parks) and reduce permitting costs/delays 50% over five years.

Onshore Advisory Task Force. The Secretary of the Interior, in consultation with the Secretaries of Energy and Commerce, should charter an advisory

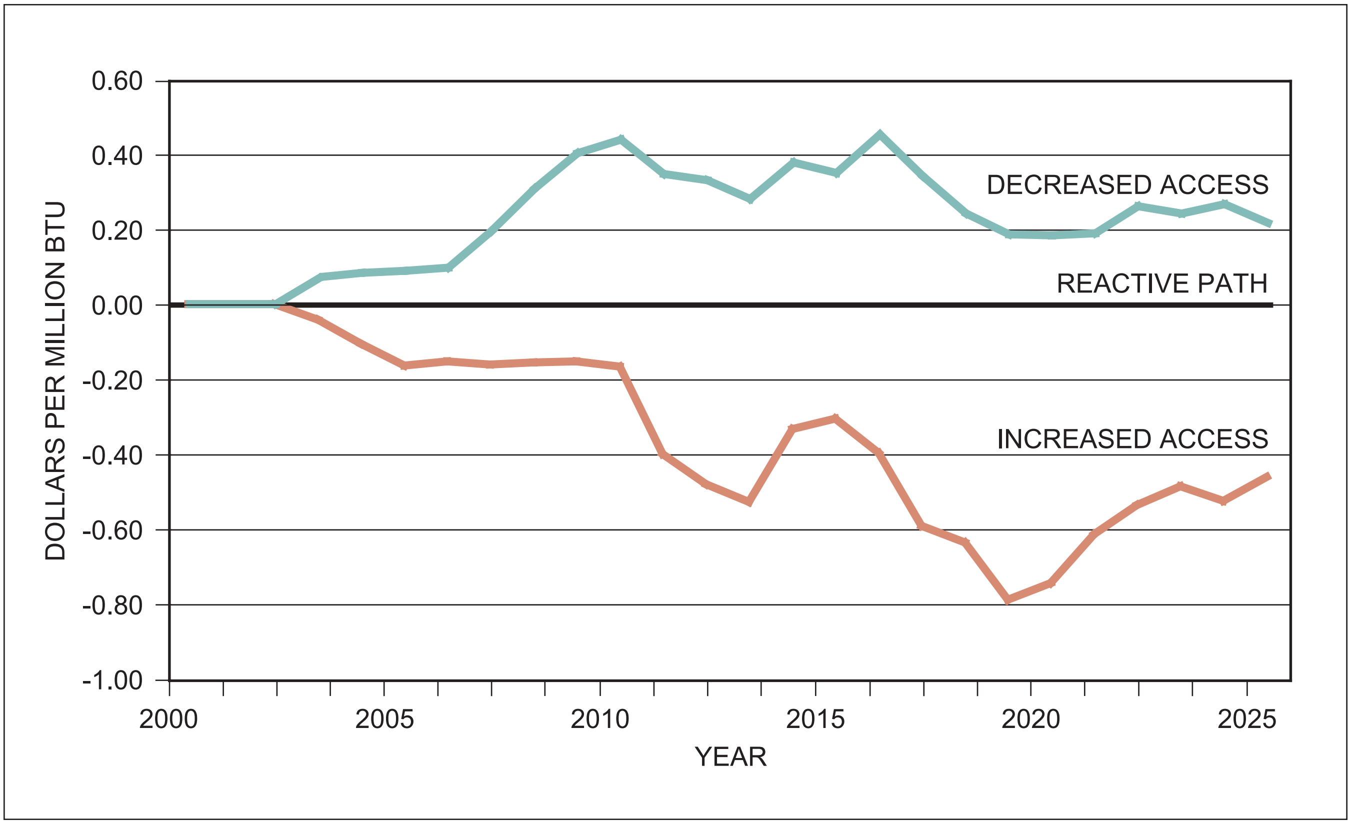


Figure 4-85. Impact of Access Restrictions on Henry Hub Price (2002 Dollars)

committee under the Federal Advisory Committee Act. The Committee's charge would be to review the various statutory and regulatory regimes that govern use of public lands in Western states, and make recommendations designed to reduce redundancy, streamline processes, and reconcile conflicting policies.

Endangered Species Act. Because there are no qualification requirements to nominate a species for listing, species are frequently proposed by groups and individuals to hinder land management planning and project permitting. This has created such a backlog that nominated species are given the same level of protection as listed threatened and endangered species without supporting scientific data. Qualification requirements and technical review procedures should be established to prevent unwarranted delays.

Land Use Planning. Provision of reasonable access to energy resources while protecting environmental values is a key challenge for land managers and producers. Federal land management agencies are required to prepare land-use plans that allocate public land uses, protect economic and environmental resources and values, and establish future management direction. These plans should use Reasonably Foreseeable Development scenarios and maximize land-use planning and cost efficiencies. Land-use planning and project monitoring need to be established as high priorities and agencies need to ensure adequate personnel to meet land use-plan, leasing, and project permitting expectations.

Roadless Areas. Modify the Forest Service's roadless rule to exempt oil and gas exploration and development activities because such activities are temporary in nature, subject to extensive environmental regulation, and are fully reclaimed after production ceases.

BLM Wilderness Study Areas. Identify areas of high natural gas potential within the BLM wilderness study areas and open them for multiple use.

Staffing. Congress should ensure that staffing for land management agencies is fully funded to enable timely and adequate planning, leasing, permitting, and project monitoring.

Permitting. Streamline the permitting process by such steps as use of categorical exclusions for wells and right-of-ways, encouragement of joint drilling and right-of-way applications, and use of sundry notices instead of full permit applications for successive wells on multi-well drill pads. Set performance goals; such as 90% of all drilling applications must be completed within 35 days. Consider use of a permitting focus team to provide assistance to field offices with high peak workloads.

Cultural Resources. Due to liberal interpretation of current regulations, operators are frequently required to perform exhaustive cultural resource studies far beyond the scope of their projects. Improved methods for determining site significance are critically needed. In-depth consultation and review should not be mandated if a site is not unique or lacks significance. BLM should ensure that its national historic trail and visual resource management guidelines are used objectively and consistently to avoid unintended effects to private landowners, lessees, and state and federal revenues.

NEPA Process. Considerable frustration exists around the inability of agencies to meet NEPA requirements in a timely and efficient manner. It is imperative that agency-specific accountability and performance metrics be developed and implemented to measure and report results to the public and Congress. The Council on Environmental Quality's (CEQ) 1997 report "The National Environmental Policy Act, A Study of Its Effectiveness After 25 Years" offers many positive and effective recommendations that should be implemented by agencies. Further recommendations include the following:

- Directing federal agency compliance with CEQ regulations at 40 CFR 1500 to 1508 (e.g., scope of environmental analysis, public participation and documentation) and relevant executive orders (e.g., requiring permit streamlining and energy impact assessments)
- Setting performance goals and targets, along with performance enhancement measure, for action on leasing and permitting for each BLM office, and reporting results to the public
- Developing internal programs aimed at improving information exchange and technology transfer with other agencies, and the manner by which relevant or new information from inventory, monitoring, research, and planning activities is incorporated in land-use plans.

Offshore – Lift moratoria on selected areas of the federal OCS starting in 2005.

Removal of OCS Moratoria. The President, Congress, and state governors should review the rationale for continued moratoria on leasing and development of prospective natural gas resources. A review process should be structured to identify current moratoria areas containing high resource potential, with a view towards the lifting of these moratoria in a phased approach beginning in 2005. The President and Congress should consider all currently existing factors when conducting this review, including but not limited to the outlook for domestic supply, the significant natural gas resources that underlie the waters currently subject to presidential order moratoria, the environmental advantages of producing and transporting OCS natural gas, and the outstanding safety and environmental record demonstrated by the oil and gas industry in other OCS areas over the last 30 years.

OCS Leasing of Available Lands. The Department of the Interior should provide continued access to those OCS areas identified in the current 2002-2007 5-Year Leasing Program.

OCS Education and Outreach. The Secretary of the Interior, in consultation with the Secretaries of Energy and Commerce, should launch a process that will lead to an energy education and outreach program encouraging a national dialogue about the existing and potential role of OCS-derived natural gas in meeting our nation's energy needs, with the goal of increasing public/stakeholder awareness of OCS natural gas activities and the key role it plays in this nation's economy.

Consideration of Existing Studies. Numerous other studies and recommendations have been developed to address energy availability. Some examples are "Energy for a New Century: Increasing Domestic Energy Supplies," 1998 OCS Policy Committee Subcommittee on Environmental Information for Select OCS Areas; "2001 Report from the Subcommittee on Natural Gas OCS Policy," OCS Policy Committee Subcommittee on Environmental Information for Select OCS Areas; "2003 Report of the

Subcommittee on Education and Outreach" of the OCS Policy Committee and the U.S. Commission on Ocean Policy principles and recommendations. Additional information on these is found in an appendix to the Supply Task Group Report. The Department of Interior in consultation with key stakeholders including states, industry, and non-governmental organizations, should review the recommendations from these various studies for action by Congress.

OCS Energy Permit Approvals. Congress should make statutorily permanent the requirement that all decisions regarding access to the OCS must (1) consider impact on the nation's energy supply, distribution, and use, and (2) decision-makers must be held accountable for the impact their decisions will have on energy supply. Congress should provide full funding to the federal agencies so they conduct all the necessarily research, analysis, and approvals of OCS-related natural gas activities in a timely fashion.

The OCS and the Role of States. Congress should support mitigation of any negative impacts OCS development may have on infrastructure and coastal communities by directing a portion of the bonus bids and royalty revenue stream from existing royalties to affected coastal states. Additionally, the OCS royalty stream should be reviewed as a possible funding source of MMS activities that support the OCS oil and gas program.

Congress and the Administration should consider legislative proposals that would definitively establish the roles and responsibilities a coastal state has with regard to reviewing and taking a role in OCS leasing and development activities based on distance from the shorelines to OCS activities, and distribute OCS revenues to the coastal states according to these leasing "zones." At some distance seaward from the shoreline, the federal government should have the sole discretion to lease OCS resources. Congress, the Administration, and coastal states should consider such leasing guidelines.

OCS Inventory. Congress should provide MMS funding and authority to obtain a more accurate assessment of the OCS resources. This would include working with affected stakeholders, including coastal states.

Coastal Zone Management (CZM). If a state alleges that a proposed activity is inconsistent with its CZM Plan, it should be required to specifically detail the expected effects, demonstrate why mitigation is not possible and identify the best available scientific information and models which show that each of the effects are "reasonably foreseeable." State CZM Plans should not be approved by the Secretary of Commerce if such implementation would effectively ban or unreasonably constrain an entire class of federally authorized and regulated activity, e.g. gas drilling, production, and transmission.

Endangered Species Act/Marine Mammals Protection Act. Regulatory changes designed to protect marine species should be based on best available scientific information and data to avoid inappropriate or unnecessary actions being taken with no benefit to the intended species. Reasonable lease stipulations and operational measures designed to protect listed species should be practical and cost effective and aimed to achieve minimal delays in ongoing operations. Congress should provide funding to NOAA and MMS to study the relationship between oil and gas activities and marine mammals in the Gulf of Mexico, with the initial focus on sperm whales.

U.S. Commission on Ocean Policy. The Commission's guiding principles and recommendations, currently being drafted, must be implemented in a manner consistent with energy-oriented principles to effectively support improved OCS resource access and development.

Summation

The NPC believes it is possible to meet the nation's environmental/endangered species goals while at the same time encouraging fuller development of critical natural gas resources. The NPC urges the government to give serious consideration to the implementation of the policy recommendations contained in this report, recommendations that would enable the industry, government, and other interested parties to work together to develop and implement innovative approaches and solutions to these difficult and complex issues.

LNG Imports

A LNG subgroup was formed as part of the NPC Supply Task Group to develop a short- and long-term (2025) outlook of potential LNG imports into North America. In addition to forming an LNG import outlook, the LNG Subgroup developed a "primer" on LNG, covering a description of the LNG value chain, LNG history, global LNG supply and demand, competitive supply cost, and U.S. terminal permitting/development. A summary of issues and recommendations facing U.S. terminal development, which may affect the level of LNG imports, was also developed.

The team made use of publicly available data to identify potential North American LNG import terminal locations and to estimate the timing of LNG imports. The approach used was to:

- Research and develop estimates of LNG supply, transportation, and regasification costs
- Utilize announcements of potential new U.S. LNG import terminals and global LNG supply
- Evaluate the competitive global LNG market
- Establish "standard" model assumptions for timing of terminal permitting and construction, terminal size, and buildup of imports
- Identify the timing of potential supply and LNG import terminal additions
- Identify "controlling" assumptions that might affect the pace of new LNG imports
- Develop three scenarios for use in modeling input
- Identify issues that might affect the pace of LNG imports
- Compile and use research in support of the LNG discussion
- Propose recommendations to address the identified issues.

LNG Overview

LNG, or liquefied natural gas, is the liquid form of natural gas that has been cooled to a temperature of –256°F or (–161°C) and maintained at atmospheric pressure. It is an odorless, colorless, non-corrosive, and non-toxic liquid. The process for liquefying natural gas reduces the volume of the gas to approximately 1/600th of its original volume. This process enables it to be transported economically in specially designed ocean vessels throughout the world.

LNG development projects are located where there is minimal local demand for natural gas or in areas remote far from traditional economic pipeline transportation systems. Once the gas is transformed into a liquid it is then transported in special LNG vessels and imported into countries where local demand exceeds the availability of supplies from domestic sources.

The LNG industry is often described by the expression the "LNG chain," as illustrated in Figure 4-86. This is a reference to the fact that LNG projects are large and required critical mass and alignment throughout the many phases of production, transportation, and distribution of the product if they are to be successful. All links of this "chain" must work together for natural gas to be produced, liquefied and exported, transported, imported and regasified, and sold as natural gas into an end-user market. LNG projects require massive reserves (7-10 TCF), produce significant volumes (0.5-1.0 BCF/D), and require investments as large as $4-$10 billion. Due to the large scale of these projects, and the considerable financial risk involved in undertaking them, a secure market for the natural gas is usually a necessary condition for their development. That is the reason why most of the world's LNG is sold under long-term contracts (20-25 years), although short-term and spot markets sales are being introduced as the market matures.

LNG Safety

The LNG industry has demonstrated an excellent safety record in its almost 40-year history. This is the result of the attention to detail in engineering, construction, and operations in all aspects of the LNG chain. The industry also has to meet stringent safety standards set by countries such as the United States, Japan, Australia, and European nations.

The LNG facilities (liquefaction and regasification and storage) are industrial sites and must meet all codes, rules, regulations, and environmental standards enforced by local jurisdictions.

LNG ships are specially designed, double-hulled ships. The LNG in these ships is stored in special containment systems at atmospheric pressure and at

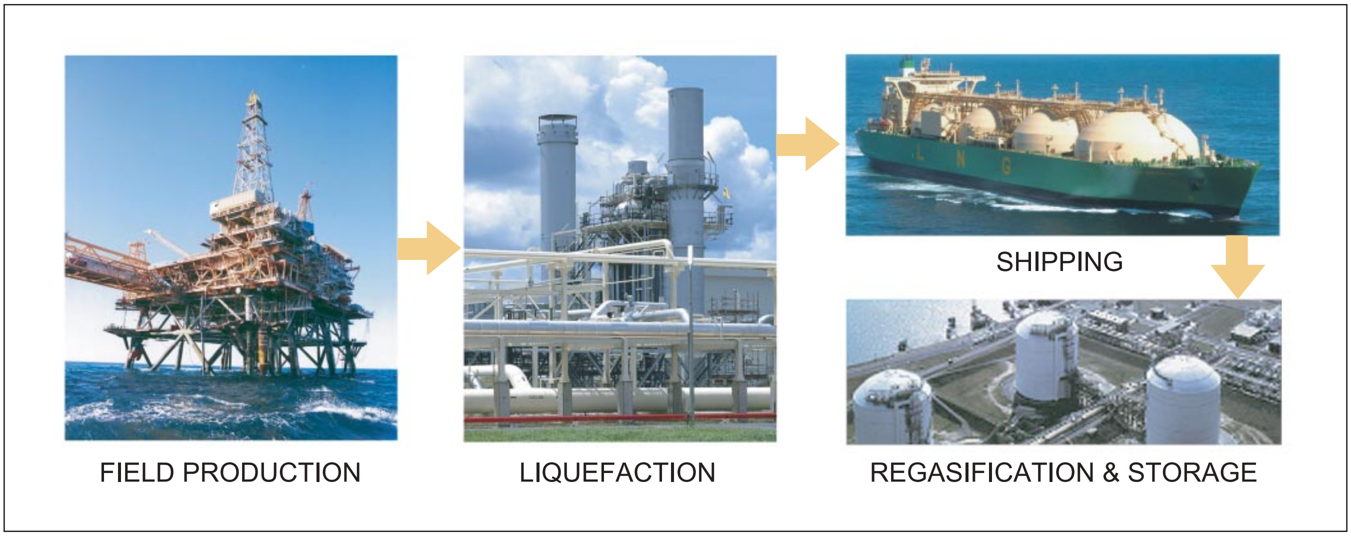


Figure 4-86. The LNG Value Chain

–256°F. These vessels are designed to protect the cargo tanks and to prevent leakage or rupture in an accident. The International Maritime Organization (IMO) has developed internationally ratified standards for the construction and operations of all ships, including LNG ships.

In 2003, there are 17 global LNG liquefaction export facilities (one in the United States), 40 regasification import facilities (four in the United States and one in Puerto Rico), and 136 LNG ships, handling about 120 million tons annually. The industry has successfully completed more than 33,000 LNG voyages, covering more than 60 million miles without major accidents or safety issues in port or on the high seas.

LNG Global Supply

LNG is currently produced in 12 countries, including the United States, from 17 operating liquefaction facilities. New supply projects are under construction and additional projects have been proposed, as shown in Figure 4-87.

The global LNG industry began in 1964 with the startup of the Algeria LNG export facilities, followed by the United States in 1969, and Libya in 1970. Significant Asian supplies were developed throughout the 1970s with new export facilities in Brunei, Indonesia, Malaysia, and Australia. Middle East supplies were first introduced in 1977 from the United Arab Emirates, with significant additions in the late 1990s and 2000 from Qatar and Oman. Additional Atlantic Basin supplies from Nigeria and Trinidad/Tobago where added in the late 1990s.

New supply projects are under construction or under evaluation. Norway is currently developing their first LNG export project and expansions are being built in Trinidad/Tobago, Nigeria, Qatar, Australia, and Oman. Proposed projects include potential production from additional expansions in Trinidad/Tobago, Nigeria, Algeria, and Qatar plus new developments in Nigeria, Australia, Indonesia, Angola, Egypt, Sakhalin, Venezuela, Bolivia, and Peru.

LNG Global Demand

LNG demand has grown continuously from the time the first deliveries of Algerian LNG entered Europe in 1964, as shown in Figure 4-88. Since the 1970s, LNG demand has grown by about 8% per year, primarily due to the fast-growing Asian markets (largest are Japan and Korea). While continued growth is forecast for Asia, developing markets in the United States and Europe are expected to support demand growth in the range of 6-10% per year. Growth at this rate will result in a doubling of the existing market by 2010.

The growing LNG demand outlook in Asia, Europe, and North America will also mean increasing competition for new supplies.

Model Assumptions

The inputs for the LNG cases were exogenous to the model, meaning the volume profile was hard coded and not determined by the model. This treatment is based

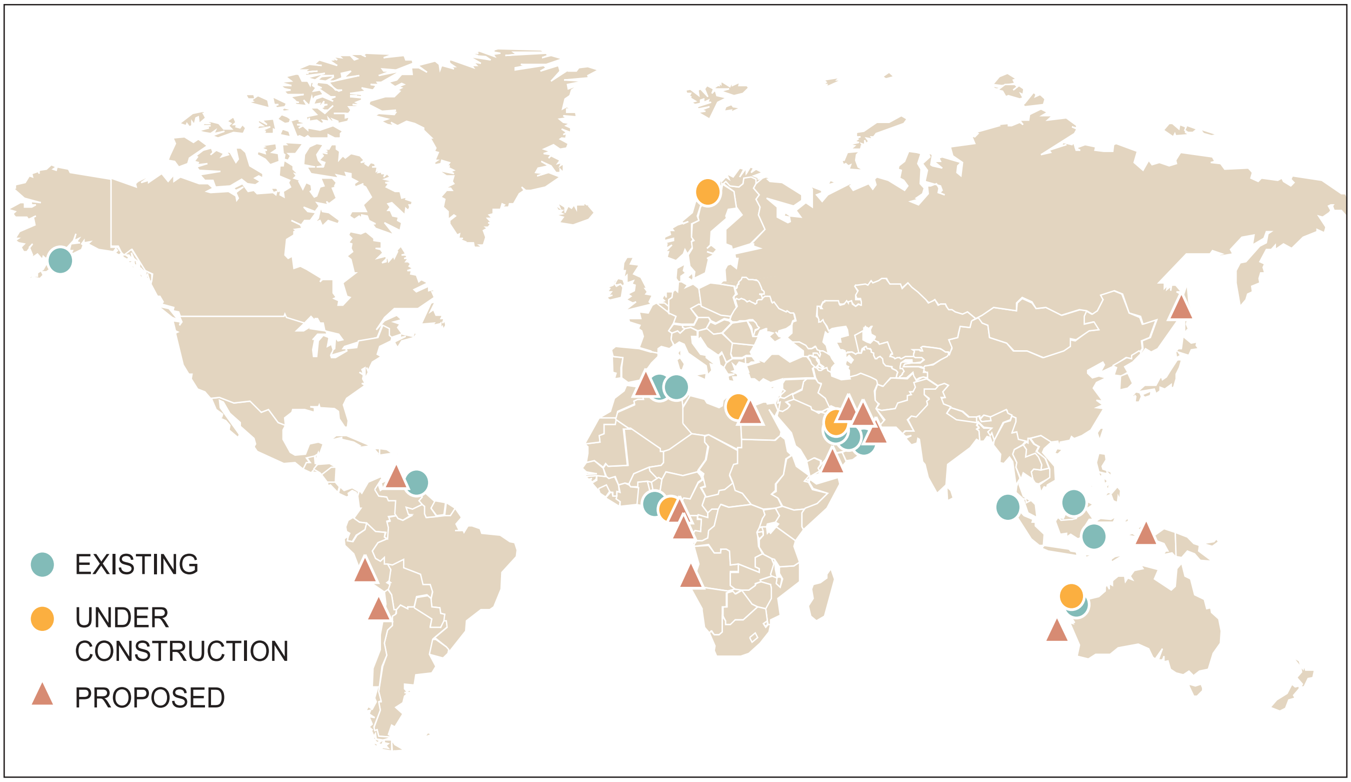


Figure 4-87. Global LNG Supply

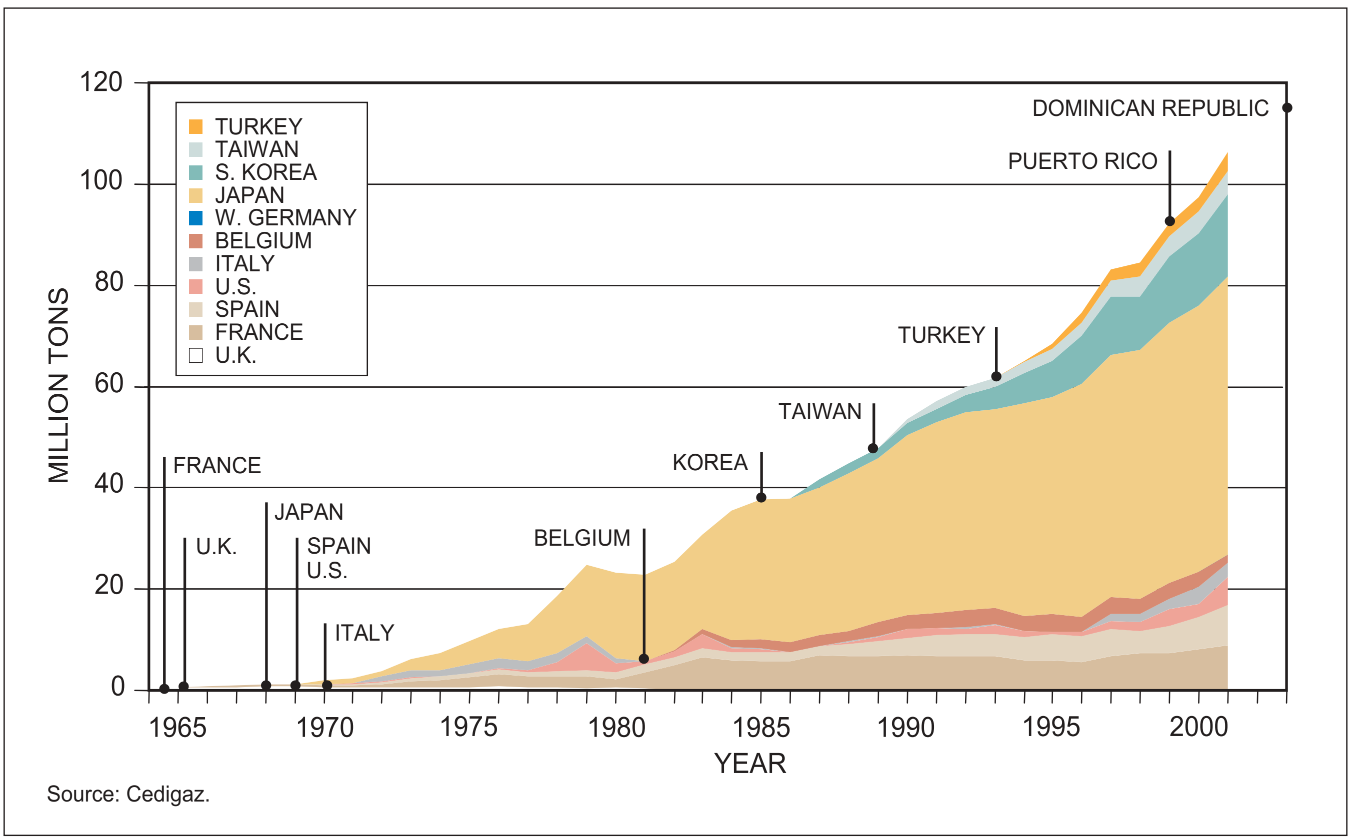


Figure 4-88. Historical LNG Demand – LNG Import Countries and their Start Dates

on the assumption that most of the projected LNG imports will be long-term base-load volumes. Once the development decision is made for these capital-intensive projects, these volumes should not be affected to any great extent by daily or monthly fluctuations in prices. The exogenous inputs include terminal locations/nodes, volumes, and timing of imports.

The following is a summary of the key model assumptions:

- Long-term prices support increased LNG imports
- New terminals sized for 750 MMCF/D base load
- New terminal expansions sized for 750 MMCF/D base load
- New terminal permitting time of 2 years
- New terminal construction time of 3 years
- Ramp-up rate of 3 years upon commencement of imports
- Existing U.S. LNG terminals supplied first, followed by their expansions, followed by new build terminals
- Location of new terminals driven by available downstream pipeline access and ease of permitting
- Timing of imports driven by supply availability, shipping, and new LNG import terminal development
- Limited shipping and LNG supplies available in the near term.

The outputs from the model runs indicate that U.S. long-term natural gas prices will support an increase in LNG imports. Dependent on supply development cost, location, and transportation cost, LNG can be imported into North America in a range of $2.00 to $4.00. Since the supply cost was determined not to be the critical assumption affecting LNG imports, the team focused on the assumptions with respect to timing and potential quantity of LNG imports.

The existing U.S. LNG import terminals have a base-load (continuous, steady) capacity of 400-750 MMCF/D. Many of the recently announced LNG terminals are in the 700 MMCF/D to 1.5 BCF/D range. Although the capacity of new terminals will very likely vary, the team elected to use a generic size of 750 MMCF/D, with expansions of 750 MMCF/D. The only exception is a terminal located in Baja California. Because the recently announced proposals for terminals there are for 1 BCF/D, the model assumed 1 BCF/D for this terminal. The model inputs assume these volumes (750 MMCF/D or 1 BCF/D) are base-load volumes, not peak-load volumes.

The rate of entry of additional LNG imports will be primarily driven by the time required to secure permits and construct new LNG import terminals. Upon application, the permitting process for an onshore U.S. LNG import terminal can take two to three years. The timing for an offshore terminal is approximately one year. Construction of an onshore terminal would take about three years; offshore terminals may take slightly longer. Combining these factors, the team assumed that each new terminal development would take five years to complete (two years for permitting and three years for construction).

A buildup of three years was assumed for each new terminal before full utilization was to be achieved. This assumption is not caused by market demand restraints but is due to the combination of supply development and new ship construction. LNG competes in a global marketplace with significant growth potential, not only in North America, but also in Asia and Europe. This competition and anticipated growth means that growth will be constrained by limitations of key resources needed by upstream supply projects and by the availability of suitable shipyards for building new LNG carriers. LNG supply liquefaction facilities are typically constructed in series of processing units referred to as trains. Depending on size, multiple trains are typically constructed one to two years following the initial train. This construction profile impacts the LNG supply availability, resulting in a buildup profile.

The model assumes the four existing U.S. terminals will first be fully utilized, then expanded (three expansions have been announced to date). Once the existing terminals and their expansions are fully utilized, additional volumes will come from new terminal development. The locations of the new terminals are driven primarily by three factors: the availability of existing or potential expansion of downstream pipelines, the perceived ease of permitting, and other physical constraints. The bulk of the new U.S.-based terminals modeled are located in the Gulf of Mexico due to declining Gulf of Mexico shelf production, spare capacity of existing infrastructure, the availability of deepwater ports (onshore) or existing offshore pipeline systems (offshore), and the perceived ease of permitting (as compared to other U.S. locations). Due to the growing gas demand in the northeast, two new LNG terminals are assumed to be built along the northeast coast. Two terminals are modeled for Mexico, one on the east coast and one on the west coast. These terminals are needed to meet the growing demand for natural gas in Mexico and California.

The timing and number of new LNG terminals was guided by many considerations. These include global LNG competition, the complexity involved with the development of the LNG Value Chain (field production, liquefaction, shipping, regasification import terminals, connection to downstream markets), and the availability of limited locations for new import terminals. Except for the Low LNG Imports case, it is assumed North America will experience robust LNG growth. North America will be competing with Asia and European markets for LNG supply. The North America market is very attractive for nearby Atlantic Basin supplies such as Trinidad, Nigeria, and potential future supplies from other countries such as Venezuela. However, because of transportation costs, Asian and European markets may remain more attractive for North African and Middle Eastern supplies. This competition, combined with political uncertainty, will have an effect on potential imports into North America.

The timing of new LNG supply will also depend on the origination of the supply source. Most of the identified LNG supply potential is located in developing countries where challenges such as government instability, boycotts, and civil unrest are found. Many of these supplies will also require project financing. While recent U.S. gas prices have shown significant increases from historically low levels, prices are nevertheless highly volatile and the long-term outlook is still uncertain. Future financing may only be available if lenders are convinced that U.S. natural gas prices have indeed achieved a "step change" compared to recent historical trends. The other constraining factor is availability of North America locations for terminal development. Onshore import terminals require access to sizeable acreage (50-100 acres); they must also be located on a deepwater port, and they must have cost-effective access to downstream natural gas markets. There are only a few onshore locations in the United States and Mexico that meet these criteria. Offshore terminals require appropriate oceanographic conditions (for unloading LNG ships), appropriate soil conditions (to support the offshore structures), and access to offshore pipelines. These criteria also limit the number of locations where offshore terminals can be built.

Potential imports of LNG are limited for the near term by a lack of available LNG supply and ships. All four U.S. LNG terminals will be fully operational by the end of 2003 (Elba Island was reactivated in December 2001; Cove Point was reactivated in August 2003). However, most of the existing LNG supply and shipping is already dedicated to other markets. While some spot cargoes will allow for increased imports, the existing terminals are not expected to be fully utilized until the recently announced LNG supply projects (Norway-Snohvit, Trinidad, Nigeria, and Egypt) are constructed. These new supplies are scheduled to commence production in the 2005-2007 time frame.

Case Descriptions

Three LNG scenarios were developed. These were Reactive Path, Balanced Future, and a Low Sensitivity case. Each of the three cases indicate significant increases in LNG imports, growing from a base of about 600 MMCF/D beginning in 2003. Table 4-8 is a summary of the three input cases.

Each of the scenarios shows a growing demand for LNG in North America in every year of the forecast. This is due to increasing U.S. natural gas prices, combined with new LNG supply and reduced LNG supply

Year	Reactive Path	Balanced Future	Low Sensitivity
2000	0.6	0.6	0.6
2005	2.3	2.3	2.3
2010	7.3	7.5	5.5
2015	8.8	10.7	5.8
2020	11.6	13.3	6.5
2025	12.5	15.0	6.5
Total # of Terminals			
Existing Terminals	4	4	4
New Terminals	7	9	2
Expansions*	7	9	4

* Includes three expansions of existing terminals.

Table 4-8. NPC LNG Scenarios North America LNG Imports (Billion Cubic Feet Per Day) cost. There are four existing LNG terminals in the United States with the last one built in 1981. Since the early 1980s, two of the terminals (Cove Point and Elba) have been mothballed. The other two terminals (Everett and Lake Charles) had minimal imports until 1999 when the first Trinidad LNG supply project was developed. The outlook for potential LNG imports has changed over the past three years with both Elba (2001) and Cove Point (2003) reactivated, Everett expanded (2003), and two of the terminals (Lake Charles and Elba) announcing expansions.

All scenarios assume the four existing terminals will be fully utilized by late 2007 (when supplies become available) and that all expansions will be constructed and fully utilized by the end of the decade. This baseline will result in an increase in LNG imports of 600 MMCF/D, up to over 3.9 BCF/D by 2010.

Reactive Path Scenario

In addition to the baseline, the Reactive Path scenario includes a total of seven new import terminals and the expansion of four of the new terminals. This scenario includes the development of five new import terminals by 2010. Two additional terminals and expansions of four new terminals are added between 2010 and 2020. Figure 4-89 shows the potential locations for these terminals. The import volumes gradually increase from 600 MMCF/D in 2003 to a peak of 12.5 BCF/D by 2025, as shown in Figure 4-90.

Reactive Path Assumptions

- Existing terminals are fully utilized by 2007
- Existing Terminal Expansions
  - + 2005 - Lake Charles and Elba
  - + 2007 - Cove Point
- New Terminals
  - + 2007-2010: 5 Total
    - – Gulf of Mexico #1 & #2 (2007, 2009)
    - – Northeast #1 (2009)
    - – East Coast (Altamira) Mexico (2007)
    - – West Coast (Baja) Mexico (2008)
  - + 2010-2020: 2 Total + 4 Expansions
    - – Gulf of Mexico #3 (2012)
    - – Northeast #2 (2020)

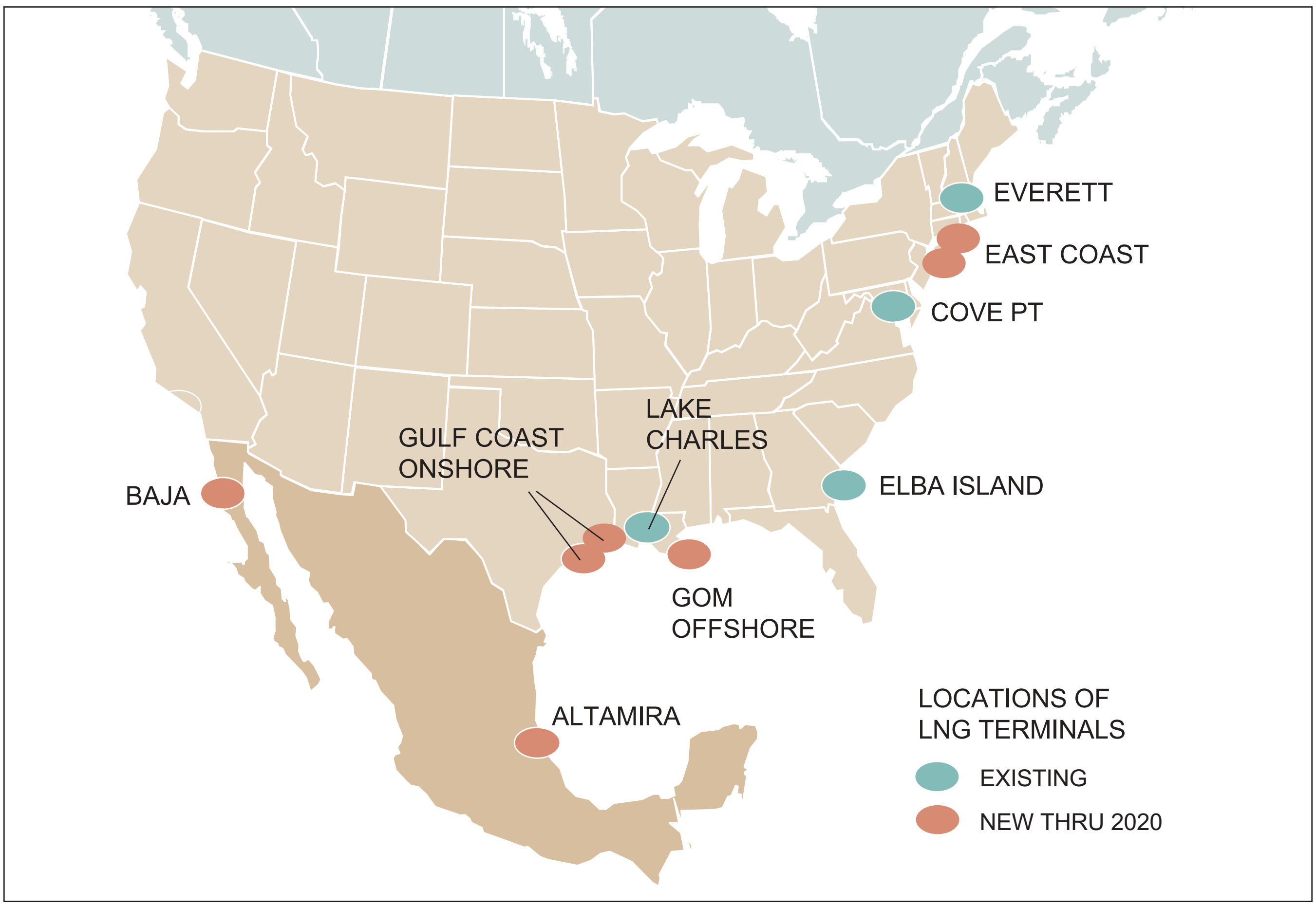


Figure 4-89. LNG Terminal Locations – Reactive Path Scenario

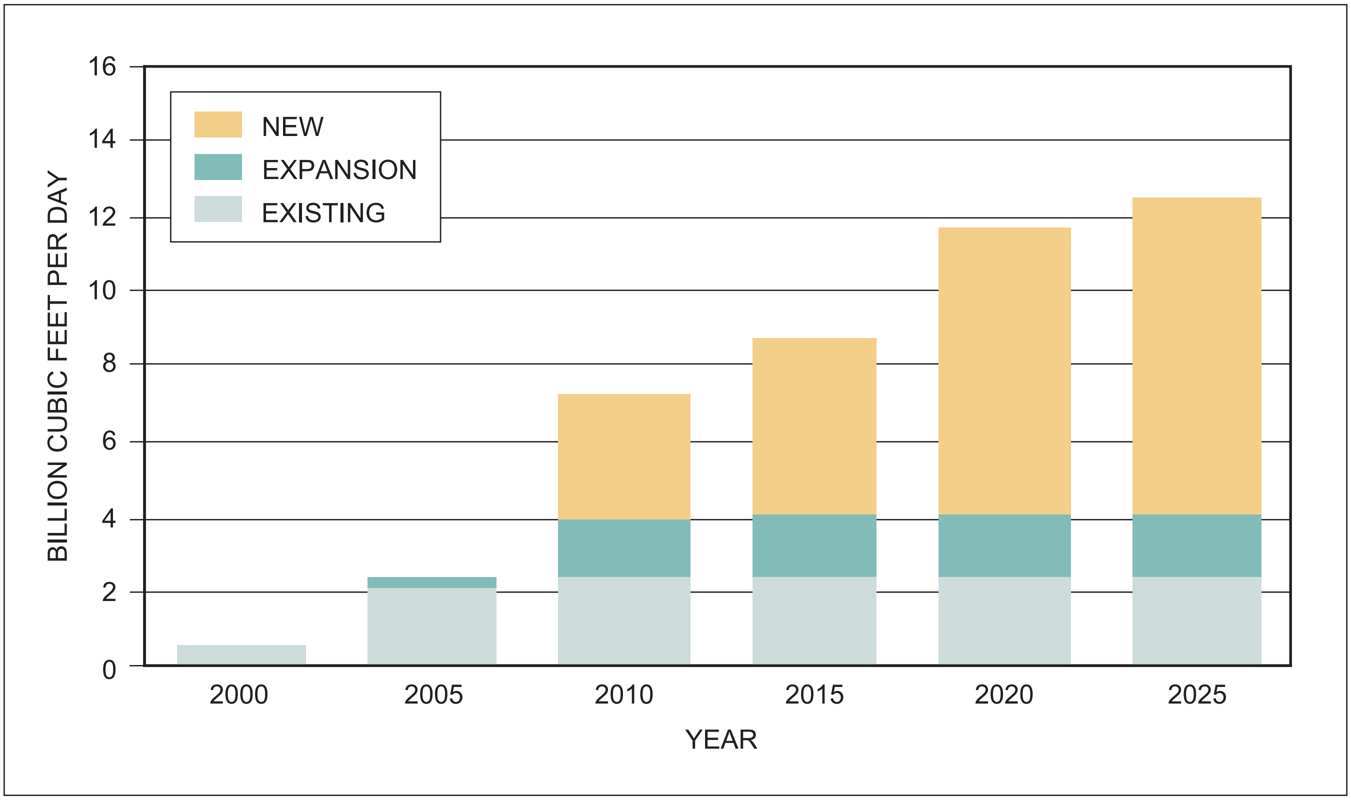


Figure 4-90. North American LNG Imports – Reactive Path Scenario

- Gulf of Mexico #1, #2, & #3 Expansions (2016, 2018, 2020)
- Northeast #1 Expansion (2016)

Balanced Future Scenario

The Balanced Future scenario builds from the Reactive Path scenario and assumes increased LNG supply and shipping availability, along with less delay in import terminal permitting. This scenario incorporates two additional terminals, one in Bahamas (serving the Florida market) and one on the U.S. West Coast. The Balanced Future scenario also includes expansions of the second Northeast terminal and an expansion of the Florida terminal, and it accelerates start-up of the new terminals by one year. Figure 4-91 shows the locations for these potential terminals.

In addition to the baseline, the Balanced Future scenario includes a total of nine new import terminals and the expansion of six of the new terminals. The Bahamas terminal is developed in 2010, with an expansion by 2012. The second Northeast terminal is accelerated to 2011, with an expansion in 2023. The West Coast terminal will be developed in 2021. The import volumes gradually increase from 600 MMCF/D in 2003 to a peak of 15.0 BCF/D by 2025, as shown in Figure 4-92.

Balanced Future Assumptions (additions to Reactive Path highlighted in **bold**)

- Existing terminals are fully utilized by 2007
- Existing Terminal Expansions
  - + 2005 - Lake Charles and Elba
  - + 2007 - Cove Point
- New Terminals
  - + 2007-2010: **6** Total
    - Gulf of Mexico #1 & #2 (2007, 2009)
    - Northeast #1 (2009)
    - East Coast (Altamira) Mexico (2007)
    - West Coast (Baja) Mexico (2008)
    - **Florida (Bahamas) (2010)**
  - + 2010-202**5**: **3** Total + **6** Expansions
    - Gulf of Mexico #3 (201**1**)
    - Northeast #2 **(2011)**
    - **Florida Expansion (Bahamas) (2012)**
    - Gulf of Mexico #1, #2, & #3 Expansions (20**15**, 20**17**, 20**19**)
    - Northeast #1 Expansion (2017)
    - **West Coast (2021)**
    - **Northeast #2 Expansion (2023)**

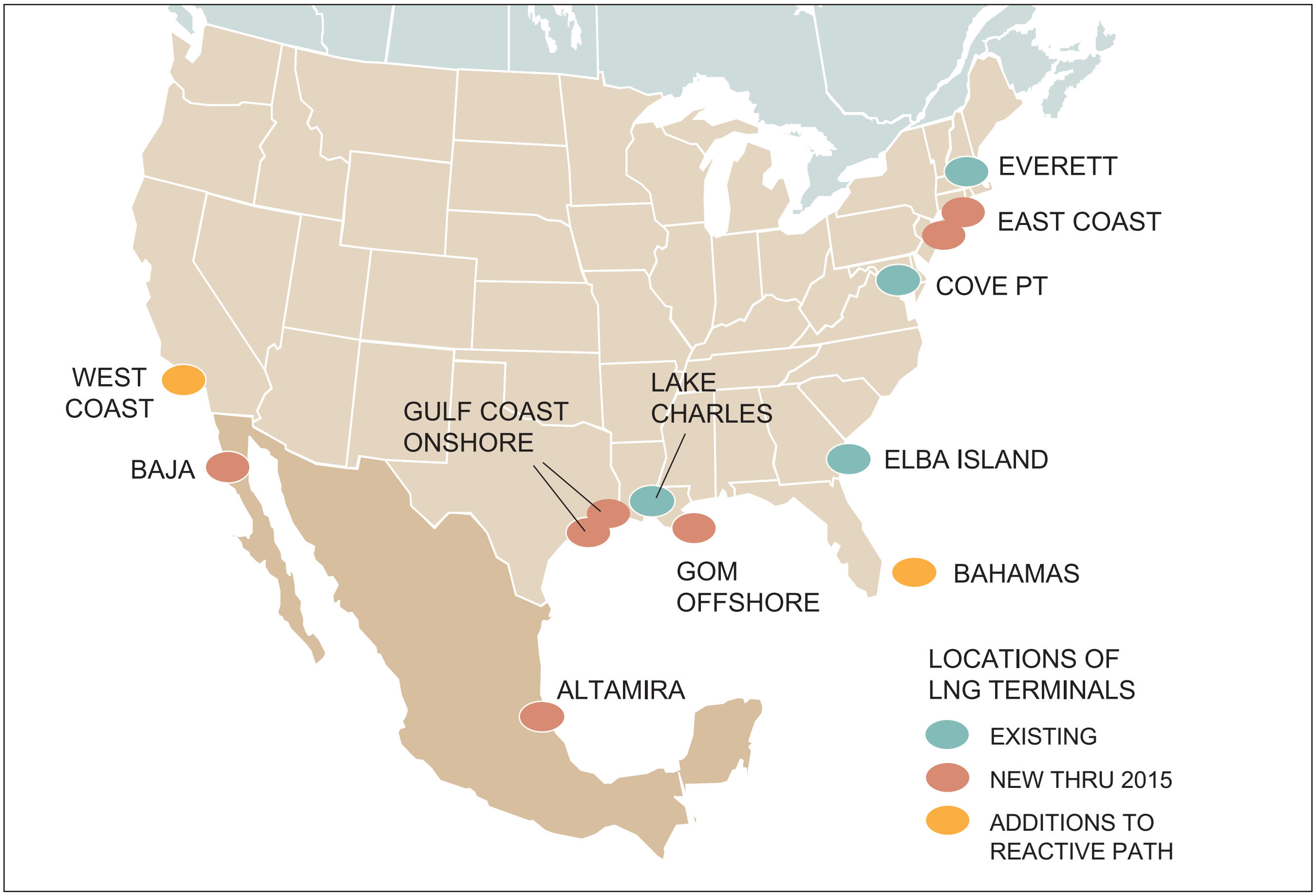


Figure 4-91. LNG Terminal Locations – Balanced Future Scenario

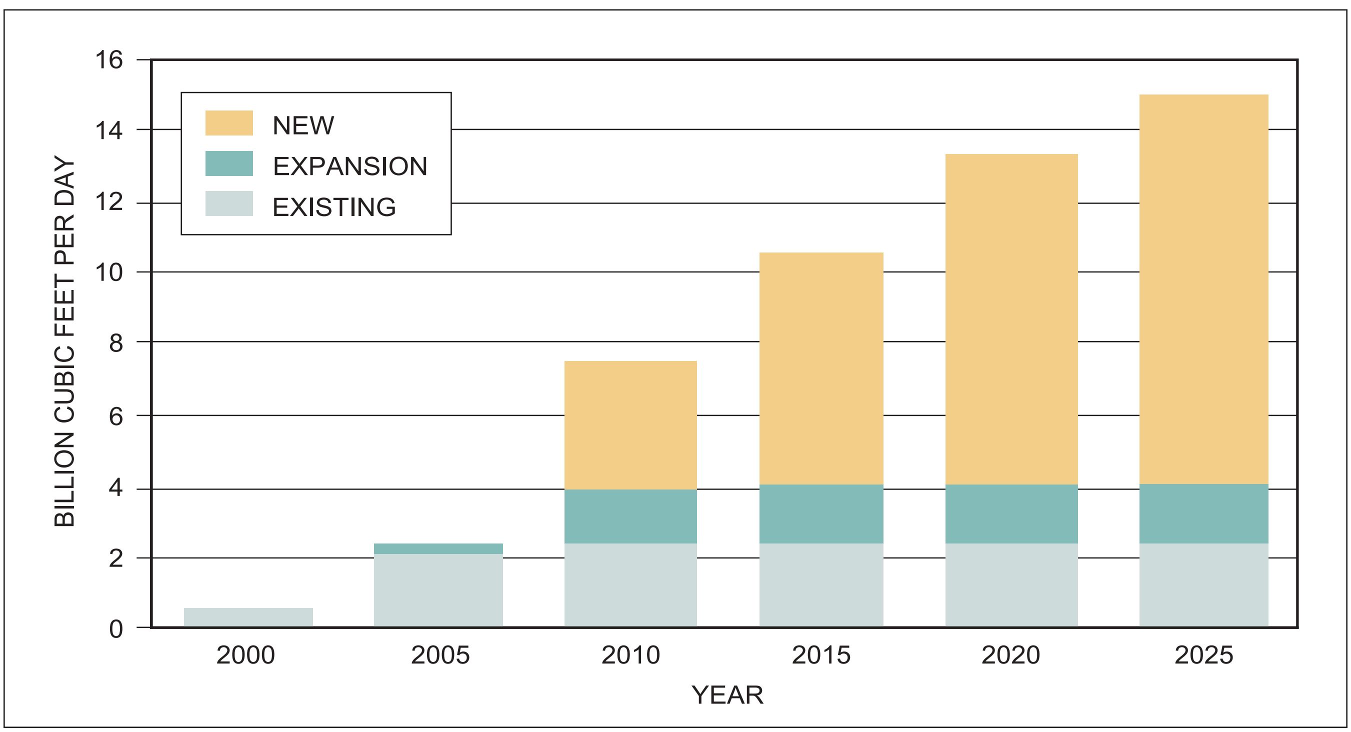


Figure 4-92. North American LNG Imports – Balanced Future Scenario

Low Sensitivity Case

The Low Sensitivity case assumes a combination of regulatory delay and successful public opposition to new terminal development. This scenario assumes that the baseline is developed with a total of only two new import terminals (Gulf of Mexico (2007), and Baja (2008)) and one Gulf of Mexico expansion (2016). The import volumes gradually increase from 600 MMCF/D in 2003 to a peak of 6.5 BCF/D by 2025 (see Figure 4-93).

Low Sensitivity Assumptions (changes from Reactive Path highlighted in **bold**)

- Existing terminals are fully utilized by 2007
- Existing Terminal Expansions
  - \+ 2005 - Lake Charles and Elba
  - \+ 2007 - Cove Point
- New Terminals
  - \+ 2007-2010: **2** Total
    - – Gulf of Mexico #1 (2007)
    - – West Coast (Baja) Mexico (2008)
  - \+ 2010-2020: **1** Expansion
    - – Gulf of Mexico #1 (2016)

Controlling Inputs

The controlling inputs concerning additional LNG imports will be the availability of new LNG supply and the ability for new LNG terminals to be permitted and constructed.

LNG is a global market and the United States will be competing for LNG supply resources. The Reactive Path scenario assumes North America LNG imports will grow to 12.5 BCF/D or about 95 MTA (million tons per annum) of LNG over a timeframe of about 20 years. To place that in perspective, the global LNG market, which began about 30 years ago and has spread to eleven countries, is some 13.5 BCF/D in 2003, or approximately 100 MTA. Each of the main market areas, Asia, Europe, and North America are forecast to grow by an average of 6.5% annually. This growth will require over 30 BCF/D of new supply. As each of the three demand areas has significant LNG demand growth potential, there will be significant competition to secure supplies.

Case Results

As stated earlier, the volume of imported LNG was hard coded in the model. Therefore, the resulting volume output of the model was equal to the input. Each

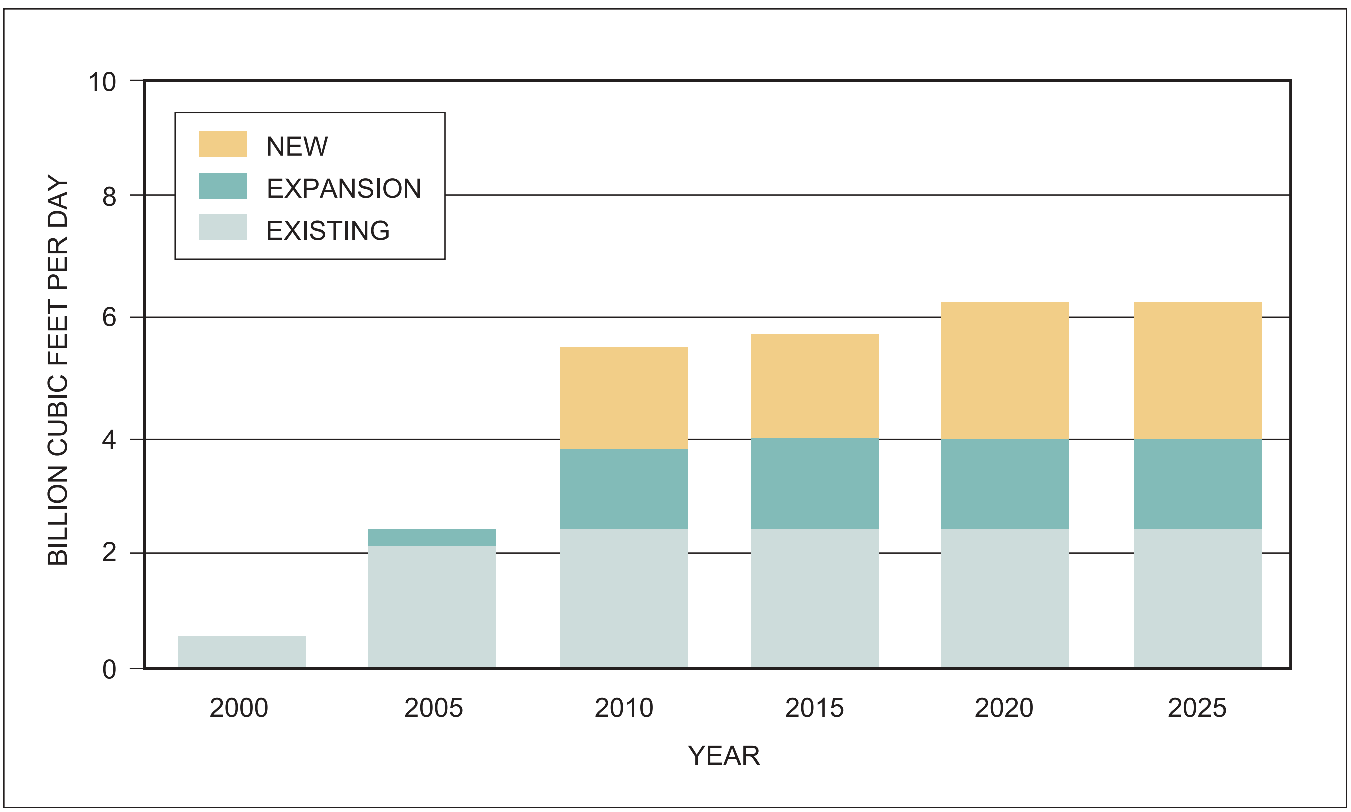


Figure 4-93. North American LNG Imports – Low Sensitivity Case

of the three cases assume that volumes of imported LNG grow, peaking by 2025 as shown in Table 4-9.

	2005	2010	2025
Reactive Path	2.3	7.3	12.5
Balanced Future	2.3	7.5	15.0
Low Sensitivity	2.3	5.5	6.5

Table 4-9. LNG Import Assumptions (Billion Cubic Feet Per Day)

Figure 4-94 illustrates the model results of the volume of LNG imports for the three cases.

The increased number of new LNG import terminals in the Reactive Path and Balanced Future scenarios has a significant impact on increased imports. In 2002, U.S. LNG imports make up less than one percent of total U.S. natural gas demand. This percentage will increase significantly with the Reactive Path and Balance Future scenarios, resulting in LNG providing 14% and 17%, respectively, of the U.S. supply of natural gas by 2025. The Low Sensitivity case, while not as robust, will still result in LNG making up about 8% of U.S. natural gas supply by 2025.

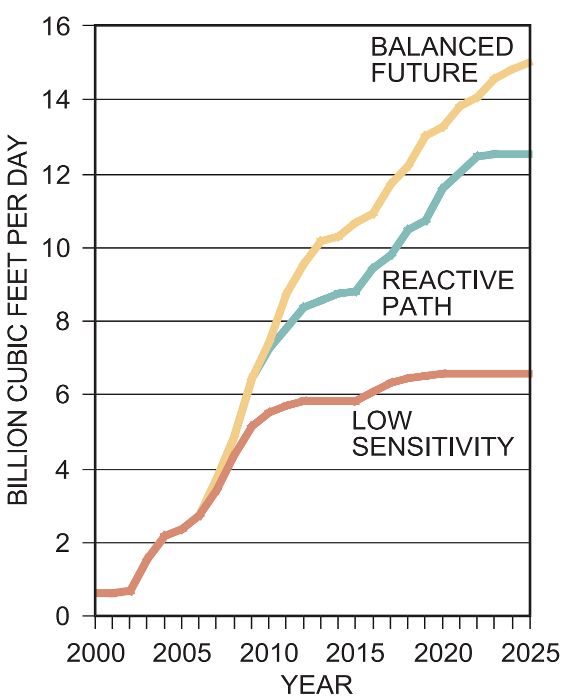


Figure 4-94. North American LNG Import Cases

As the amount of LNG imports is increased in all three scenarios, each has an effect on price. Figure 4-95 shows the price variance of the Balanced Future (higher LNG imports) and Low Sensitivity (imports reduced to half of the Reactive Path) cases in relation to the Reactive Path. The LNG imports are the same in all three cases through 2007 because the new terminals and associated new LNG supplies are not on line until after 2007. The impact of the different volume of LNG imports is illustrative through the pricing output of the model. The Balanced Future, with additional LNG imports starting in 2010, has a moderate pricing benefit of about 5% over the 2010-2025 timeframe. It is important to note that the Low Sensitivity Case (combination of regulatory delay and successful public opposition) has a much more significant impact on long-term price, with price increases of 10-12%. These cases illustrate the significance LNG imports will have in meeting the growing North America demand and the importance of getting new terminals permitted and built in a timely manner.

Recommendations

This aggressive outlook for LNG import terminal construction will require streamlined permitting and construction to achieve the projected buildup. Expediting the approval process throughout all agencies (federal, state, and local) is critical to overcome the many obstacles that may surface, including local opposition. Leveraging off the recent positive shifts by the Federal Energy Regulatory Commission (FERC) (positive changes on regulatory process, active leadership role in recent reactivation of Cove Point and Elba Island, and implementation of Memorandums of Understanding among federal agencies working together) and changes made to regulatory policies in late 2002 governing both onshore and offshore LNG import terminals, will provide a springboard for impacting positive changes down through the local level. The goal of the following recommendations is to reduce the time required for LNG facility permitting to one year.

- **Agencies must coordinate and streamline permitting activities and clarify positions on new terminal construction and operation.** Project sponsors face multiple, often-competing state and local reviews that lead to permitting delays. A coordinated effort among federal, state, and local agencies led by FERC would reduce permitting lead time. Similarly, streamlining the permitting process by sharing data and findings, holding concurrent reviews, and setting

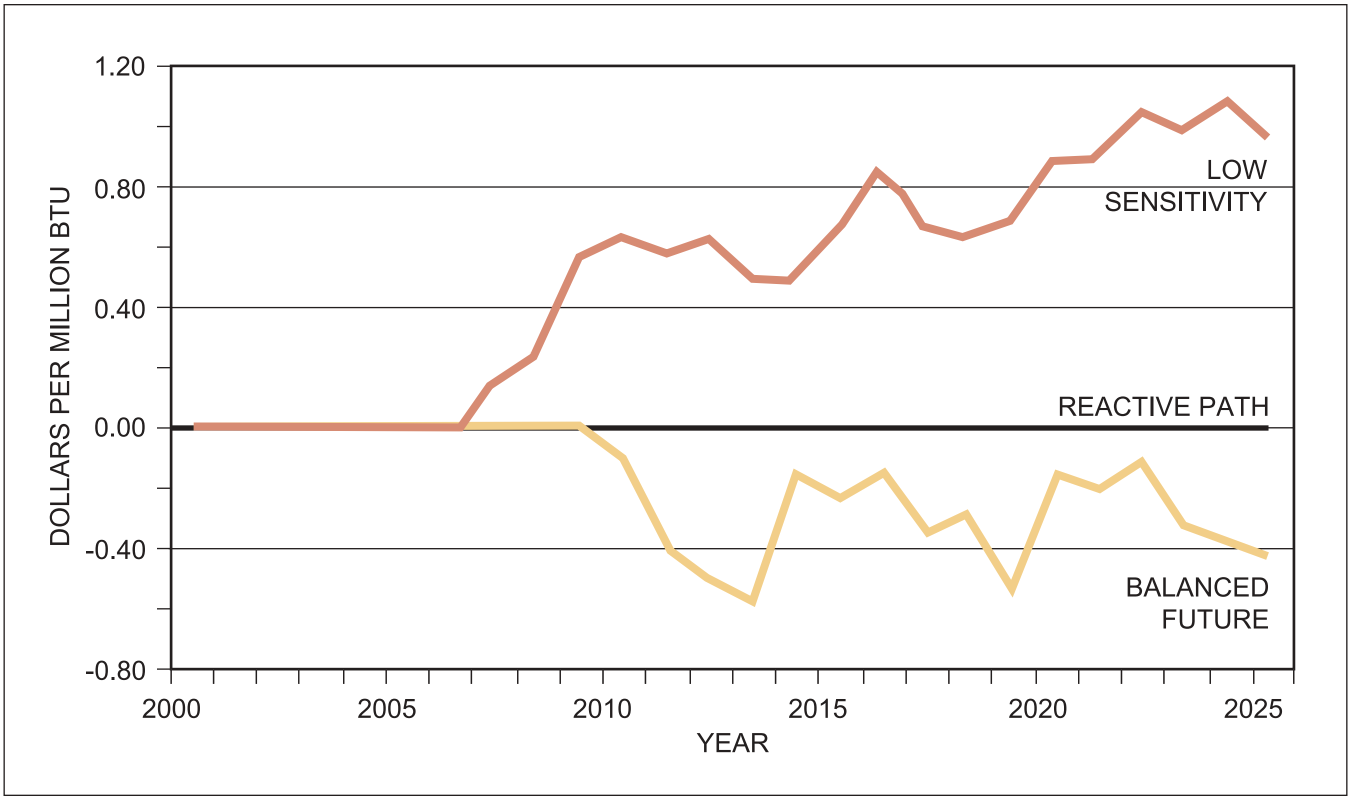


Figure 4-95. Impact of LNG Import Cases on Henry Hub Price (2002 Dollars)

review deadlines would provide greater certainty to the overall permitting process. FERC should further clarify its policy statement on new terminals so as to be consistent with corresponding regulations under the Deep Water Port Act, including timing for the NEPA review process and commercial terms and conditions related to capacity rights.

- **Fund and staff regulatory agencies at levels necessary to meet permitting and regulatory needs in a timely manner.** The expected increase in the number of terminal applications will require higher levels of government support (federal, state, and local) to process and avoid delays. Additional agency funding/staffing will also be required once these new terminals become operational, particularly to support the large increase in LNG tanker traffic.

- **Undertake public education surrounding LNG.** The public knowledge of LNG is poor, as demonstrated by perceptions of safety and security risks. These perceptions are contributing to the public opposition to new terminal construction and jeopardizing the ability to grow this required supply source. Industry advocacy has begun, but a more aggressive/coordinated effort involving the DOE and non-industry third parties is required. Emphasis should focus on understandings, safety, historical performance, and the critical role that LNG can play in the future energy supply.

- **Update natural gas interchangeability standards.** Standards for natural gas interchangeability in combustion equipment were established in the 1950s. The introduction of large volumes of regasified LNG into the U.S. supply mix requires a re-evaluation of these standards. FERC and DOE should champion the new standards effort to allow a broader range of LNG imports. This should be conducted with participation from local distribution companies, LNG purchasers, process gas users, and original equipment manufacturers. DOE should fund research with these parties in support of this initiative.

- **Review and revise LNG industry standards if necessary.** In order to promote the highest safety and security standards and maintain the LNG industry's safety record established over the past 40 years of operations, FERC, the U.S. Coast Guard, and the U.S. Department of Transportation should undertake the continuous review and adoption of industry standards for the design and construction of LNG facilities, using internationally proven technologies and best practices.

Arctic Developments

The North American Arctic regions in Northwestern Canada and Alaska contain significant gas resources that can help meet future North American gas demand. Discovered resources include about 35 TCF on the North Slope of Alaska and 9 TCF in the Mackenzie-Beaufort basin.

These gas resources are remote from any existing pipeline infrastructure and are located in an Arctic environment, so significant investment will be required to bring these resources to market. The key hurdles associated with commercializing these resources are costs, permitting, Alaska state fiscal issues, and market risks. Even though these resources were discovered over 30 years ago, these hurdles have prevented the development of commercially viable projects to date.

Industry is maturing technology advancements to reduce capital costs and the supply/demand picture supports the need for additional supplies. Also, the governments of the United States, Alaska, and Canada recognize the significant risks of such large-scale projects and are working to put frameworks in place to address some of the hurdles.

This NPC study assumes that appropriate government frameworks are achieved in a timely manner and that conditions support the commercial viability of Arctic gas projects. Consequently, it is assumed that these projects will come on line at what is considered the earliest feasible dates – 2009 for a Mackenzie Gas Project and 2013 for an Alaska gas pipeline. The volumes assumed to be transported by these projects are shown in Figure 4-96.

If these projects are delayed (due to delays in establishing government frameworks, delays in permitting, or for other reasons) there could be adverse consequences for consumers in the form of reduced gas supplies and/or higher energy prices. The NPC also recognizes that these projects may not be commercially viable due to the large investments needed, as well as the potential for additional government requirements or burdens that could increase project costs and impede the projects' ability to compete with alternatives.

Canadian Arctic Gas Background

Resource

Table 4-10 summarizes the NPC study team assumptions on the Discovered and Undiscovered Potential resource available from the Canadian Arctic and is based on information from the Canadian Gas Potential Committee.

Active drilling in the Canadian Arctic began in the late 1960s with interest being sparked by the huge oil and gas discovery made in a similar geological play at Prudhoe Bay in 1967. A number of onshore gas dis-

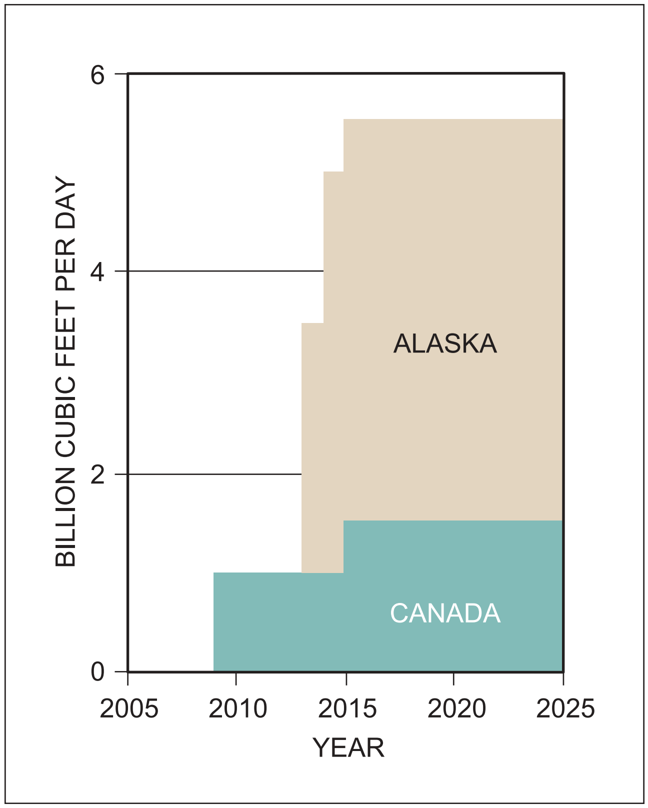


Figure 4-96. Total Arctic Gas Transported to Market

Region	Discovered	Undiscovered Potential
Mackenzie Corridor	0.7	4.6
Mackenzie/ Beaufort Sea	8.8	21.2
Arctic Islands	16.4	9.4
Total	**25.9**	**35.2**

Source: Canadian Gas Potential Committee, 2001.

Table 4-10. Canadian Arctic Gas Resource (Trillion Cubic Feet) coveries were made in the early 1970s in the Mackenzie-Beaufort region, as well as some gas discoveries in the more remote Arctic Islands region. That region is located approximately 1,000 miles northeast of the Mackenzie Delta and is in a very harsh Arctic environment.

Current Status of Project Development

The Mackenzie Delta Producers Group (Imperial Oil, ConocoPhillips Canada, Shell Canada Limited, and ExxonMobil Canada) and the Mackenzie Valley Aboriginal Pipeline Corporation are currently working to develop a Mackenzie Gas Project, including a Mackenzie Valley Pipeline. The pipeline would transport onshore natural gas resources from the Taglu, Parsons Lake, and Niglintgak gas fields, and would be accessible to other natural gas discoveries in the Mackenzie Delta and Mackenzie Valley regions. The gas would be transported through the Mackenzie Valley Pipeline to existing gas pipelines in northwestern Alberta for further transportation to market.

Figure 4-97 shows a schematic of the proposed Mackenzie Gas Project. This project is currently in the project definition phase. This phase includes technical, environmental, consultation, and commercial work required to prepare, file, and support regulatory applications for field, gas-gathering, and pipeline facilities. It is currently estimated that regulatory applications

Figure 4-97. Proposed Mackenzie Gas Project

will be filed in 2004, supporting start-up of the Mackenzie Gas Project in 2009. A study commissioned by the Government of the Northwest Territories (GNWT) and TransCanada PipeLines Limited indicates that direct investments may total $7.6 billion Canadian (2002 dollars). This estimate consists of $4.3 billion for field development costs and $3.3 billion for pipeline construction.[1]

Risks and Hurdles

There are significant risks and hurdles associated with commercializing Canadian Arctic gas as evidenced by the fact that the gas has yet to be commercialized in spite of being discovered over 30 years ago. Major risks and hurdles include permitting, costs, and market.

Alaska Arctic Gas Background

Resource

Oil and gas have been produced on the Alaska North Slope since the late 1970s. In the absence of a market, most of the gas has been reinjected to enhance the recovery of oil. The size of the discovered gas resource is well understood given the extensive development and long production history in the Prudhoe Bay Field.

Table 4-11 summarizes the discovered resource available from the Alaska North Slope. All the discovered resource data except for Point Thomson is from the January 2001 MMS report entitled *Prospects for Development of Alaska Natural Gas: A Review*. The Point Thomson data are from ExxonMobil, as reported in the June 15, 2002 issue of the Alaska Oil & Gas Reporter. The ExxonMobil data for Point Thomson (8 TCF) is higher than that reflected in the MMS report (5 TCF).

Figure 4-98 contains a map showing the major North Slope fields. Most of the discovered resource is contained in the massive Prudhoe Bay field, where the gas is being reinjected to enhance liquids recovery. The second largest resource is the Point Thomson field, which is currently undeveloped.

The undiscovered potential for the Alaska Arctic in this NPC study, based on USGS and MMS data, totals 213 TCF, including 44 TCF of nonconventional coal bed gas and 97 TCF offshore. Access to these new resources will be an important factor in the successful commercialization of Alaska gas. Some of this prospective acreage is currently available to industry, while other areas are currently not. Government policies to access gas-prone acreage in Alaska will play a key role in ensuring the necessary gas resources continue to be produced from Alaska well into the future.

Resource	**TCF**
North Slope	
Prudhoe Bay	23
Point Thomson	8
Other North Slope	4
Total	**35**

Table 4-11. Alaska North Slope Discovered Resource (Trillion Cubic Feet)

Attempts to Commercialize

Alaska gas development projects have been proposed, planned, and studied since oil and gas was first discovered on the North Slope in 1967. The options have included various pipeline, LNG, and gas-to-liquids concepts. To date, none of these options have been commercially viable.

Current Status of Project Development

The major North Slope gas producers ExxonMobil, BP, and ConocoPhillips (the Producers) completed a comprehensive study during 2001-2002 to assess the feasibility of delivering Alaskan gas to lower-48 markets. This study assessed the cost, technology, regulatory, and environmental issues associated with the project. The Producers spent $125 million on this study that involved 110 owner company representatives and over 1 million staff-hours (including contractors).

The Alaska gas pipeline system under consideration would transport approximately 4.5 BCF/D with the possibility of an expansion to increase capability to 5.6 BCF/D through intermediate compression. Approximately 0.5 BCF/D would be extracted for fuel use and for natural gas liquid (NGL) extraction, resulting in approximately 4 BCF/D being delivered to market. The major system components include a Gas

[1] *An Evaluation of the Economic Impacts Associated with the Mackenzie Valley Gas Pipeline and Mackenzie Delta Gas Development,* published May 13, 2002, by Wright Mansell Research Ltd.,and available at the GNWT website: www.gov.nt.ca.

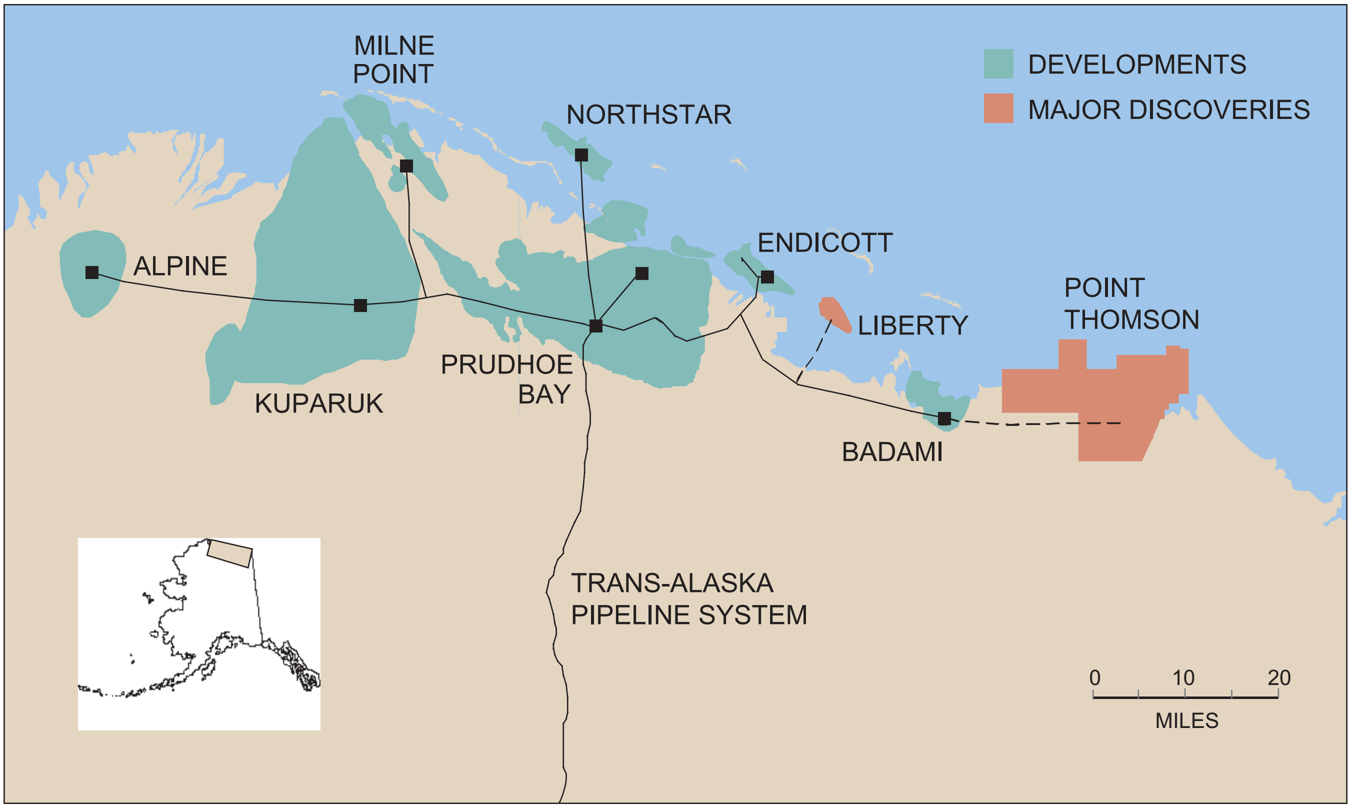


Figure 4-98. Major Alaska North Slope Fields

Treatment Plant, Alaska to Alberta pipeline system, NGL extraction plant, and an Alberta to lower-48 pipeline system. Figure 4-99 shows an overall schematic of the system studied by the Producers.

The Producers concluded that both northern and southern routes were within current technical capability. The Producers also concluded that the macroeconomic development from an Alaska gas pipeline is significant. Total government direct revenues could be over $100 billion. In addition to these direct tax and royalty revenues, there would be significant economic stimulus through creation of thousands of jobs. However, the Producers concluded that an Alaska gas pipeline project via any route was currently not commercially viable. They determined that the project risks outweighed rewards, that additional engineering work was not justified at that time, and that future activity must match progress with governments and commercial viability.

The Producers also concluded that governments will play a key role in reducing project cost and schedule risk. Mitigation of these risks could be achieved through enactment of federal regulatory enabling legislation to provide efficiency and clarify the regulatory process for the U.S. portion of the pipeline, clarity with the NEB/First Nations regulatory process, and fiscal certainty for the project with the state of Alaska.

The three major North Slope Producers continue to work on potential cost reduction concepts and with governments to establish appropriate frameworks to address these risks.

Risks and Hurdles

Four key risk areas must be addressed before an Alaska gas pipeline will attract investment capital from the private sector. The four risk areas are cost, permitting, state fiscal, and market risk. In addition, the U.S. government is debating a fiscal package related to the Alaska gas pipeline project.

- **Cost.** An Alaska gas pipeline project will be the largest-ever privately funded development project. Both the large investment required for the project and the prospect of cost overruns represent significant project risks.
- **Permitting.** Numerous permits or approvals will be required from the U.S., state, local, Canadian, territorial, and provincial governments. In addition,

Figure 4-99. Alaska Gas Pipeline System

agreements with First Nations will be required for an Alaska gas pipeline project. The permitting process and potential legal challenges could cause significant delays in an overall project schedule. In addition, permit stipulations could add significant costs to a project that could make it more difficult to become commercially viable.

- **State Fiscal.** The state of Alaska and the Producers recognize the need to establish fiscal certainty for this high-risk project. The absence of clear and predictable methods to calculate royalty and tax payments to the state of Alaska over the life of a pipeline project represents a significant uncertainty.
- **Federal Fiscal Activity.** In addition to the state of Alaska's activity to address state fiscal risk, the U.S. federal government is currently debating the need for a federal fiscal package. There are differing views within industry on the likely cost of and need for a federal fiscal package.
- **Market.** There is also significant market uncertainty in terms of the demand for gas and the price customers will be willing to pay for natural gas over a 30+ year project life. For example, in the late 1970s it was expected that there would be sufficient demand for natural gas in the U.S. lower-48 and that prices would be sufficient to warrant construction of the Alaska Natural Gas Transportation System (ANGTS). However, by the early 1980s it was clear that the high-cost ANGTS project was not economic and could not be financed. For an Alaska gas pipeline project to be commercially viable, the market outlook over a 30+ year life must be sufficiently encouraging to justify the large investment required.

Arctic Supply Assumptions for NPC Study

Canada

For purposes of this NPC study, it was assumed that the permitting, cost, and market hurdles identified earlier in this chapter are overcome and that a Mackenzie Gas Project starts up in 2009 and transports the volumes shown in Figure 4-100.

While the initial volumes that might be transported by a Mackenzie Gas Project could range from 800 MMCF/D to 1,200 MMCF/D, for the purposes of this study it was assumed that the project would initially transport 1 BCF/D. This would consist of 800 MMCF/D of gas from three anchor fields (Taglu, Parson's Lake, and Niglintgak) as well as 200 MMCF/D from other fields. It was further assumed that additional economic discoveries of gas are made to allow expansion to 1.5 BCF/D in the year 2015 and to keep the line full through the end of the study period (2025). Between 2009 and 2025, a total of 8 TCF would be transported to market.

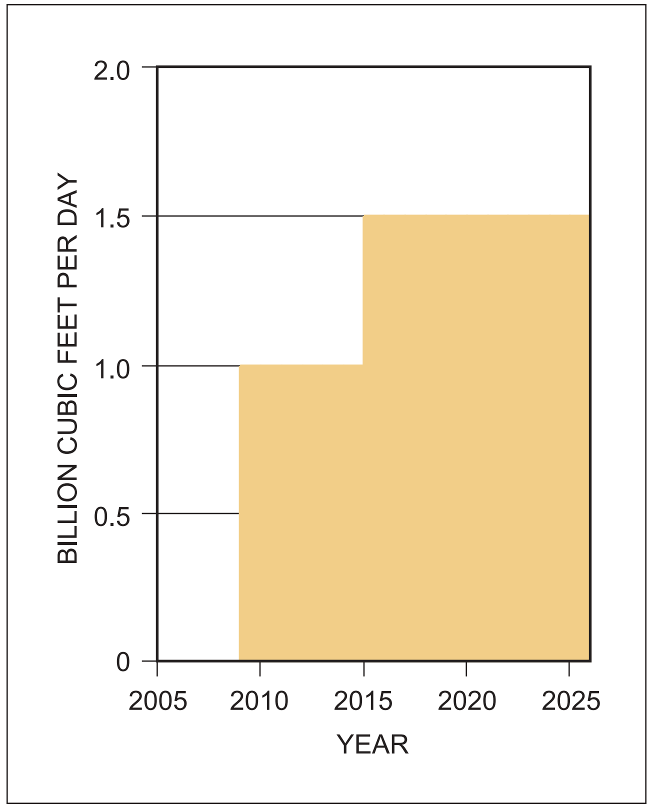


Figure 4-100. Canadian Arctic Gas Volumes

Alaska

For purposes of this NPC study, it was assumed that the permitting, state fiscal, cost, and market hurdles identified earlier are overcome and that an Alaska gas pipeline project starts up in 2013 and transports Alaska gas to Alberta. From Alberta it is assumed that the gas is transported through a combination of existing pipeline capacity or newly installed capacity to markets in the U.S. lower-48. Figure 4-101 shows the volumes transported to Alberta. During the initial year (2013), it was assumed that only 2.5 BCF/D is transported because not all the compressor stations would be commissioned that first year. During the second and subsequent years, a full 4.0 BCF/D would be transported. Between 2013 and 2025, a total of 18 TCF would be transported to market.

In addition to gas from known discoveries, an additional 16 TCF of "yet-to-find" gas would be required to

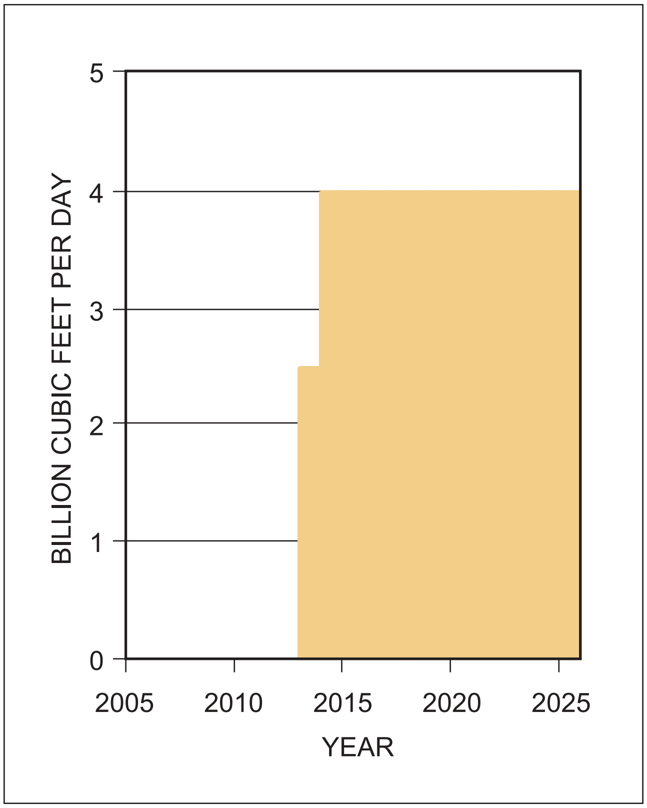


Figure 4-101. Alaskan Gas Volumes

keep the pipeline full for a 30-year project life. In addition, the pipeline could be expanded if additional economic discoveries were made.

Sensitivities

Given the commercial, regulatory, and cost-related uncertainties associated with the Alaska pipeline project, sensitivity cases were developed that looks at three alternate outcomes:

- No Alaska pipeline is built during the study period
- The pipeline is delayed 5 years and production starts in 2018
- The pipeline is expanded by 1 BCF/D to 5 BCF/D in 2020.

The results from the no Alaska pipeline and delayed pipeline cases were a projection of average natural gas prices 15% higher from 2013 through 2017. In the no pipeline case, the average natural gas price was also 7% higher from 2020 through 2025.

Recommendations

The projections in this study are generally favorable for development of Arctic resources. Based on these projections, the NPC has assumed that both the Mackenzie Delta pipeline and the Alaska pipeline are constructed in a "success case" time period, with Mackenzie gas initiating production in 2009 and Alaska in 2013. The timetable for Alaska gas is very aggressive, and can only be met with prompt government action. Currently pending enabling legislation, which at a minimum would provide regulatory certainty, creates an opportunity to take action and to ensure the legislative requirements of such a massive infrastructure project are met.

Infrastructure projects of this magnitude require the following:

- **Congress should enact enabling legislation in 2003 for an Alaska gas pipeline.** Passage of this legislation in 2003 is required to support deliveries of this gas to the market in 2013. Council members and Prudhoe Bay producers agree that Congress should immediately enact legislation that provides regulatory certainty to such a project.
- **Canadian agencies should develop and implement a timely regulatory process.** The various governments in Canada (federal, territorial, provincial) and the First Nations should continue to work cooperatively to develop and implement a timely regulatory process. An efficient process must be in place in early 2004 to support a 2009 Mackenzie Gas Project start-up and a 2013 Alaska gas pipeline project start-up.
- **Alaska needs to provide fiscal certainty for the project.** The state of Alaska should provide fiscal certainty to project sponsors in a manner that is simple, clear, not subject to change, and that can improve project competitiveness. Such action by the Alaska legislature in 2004 is required to support a 2013 project start-up.
- **Governments should refrain from potentially project-threatening actions.** Governments should avoid imposing mandates or additional restrictions that could increase costs and make it more difficult for a project to become commercially viable.
- **Infrastructure improvements incidental to Alaska gas pipeline construction must be planned in a timely and coordinated manner.** The U.S. and Canadian governments – federal, state, provincial, and territorial – should study and/or consult with one another and industry participants and affected communities to assess contemplated infrastructure improvements in support of Arctic gas development in advance of the time when these improvements are needed.

Comparison to Other Supply Outlooks

The production outlook for the NPC 2003 Reactive Path scenario is lower than the projections from the 1999 NPC study and the government's preliminary EIA 2004 Annual Energy Outlook. Figure 4-102 compares the three outlooks for production from the U.S. lower-48. While the Reactive Path outlook is for lower production, it is occurring in a more robust price environment than either of the other two outlooks. In a similar price environment, the 2003 NPC study would project even lower production.

The production outlook for the NPC 2003 Reactive Path for Canada (excluding Arctic) is for relatively flat production through 2015, as shown in Figure 4-103. The National Energy Board of Canada (NEB) and the Canadian Energy Research Institute (CERI) have similar near-term forecasts, with the NPC 2003 projecting less decline in the out years. There are some definitional differences between NPC and NEB/CERI accounting for operational fuel use, so the NPC 2003 projection has been adjusted to exclude lease and plant fuel for comparison to the marketable gas basis used by NEB/CERI.

In order to better understand the key differences in these outlooks, a detailed review evaluated the main components of each production outlook. The results of that review are summarized below.

Energy Information Administration Preliminary Annual Energy Outlook 2004

Results of the NPC 2003 Reactive Path scenario ("NPC 2003") were compared to a preliminary release of the Energy Information Administration's Annual Energy Outlook 2004 ("prelim. AEO 2004"). Detailed discussions were held between NPC study participants and DOE and EIA staff to better understand the factors influencing the differences in the outlooks. It is hoped that this type of comparative analysis will lead to better overall projections by all parties concerned. The results of that analysis are presented below.

Lower-48 Total Production

Figure 4-104 shows lower-48 total production outlooks for NPC 2003 and prelim. AEO 2004. NPC 2003 projects flat to modestly increasing total lower-48 production, rising from 50 BCF/D in 2002 to a peak of 54 BCF/D by 2015. The prelim. AEO 2004 outlook is for

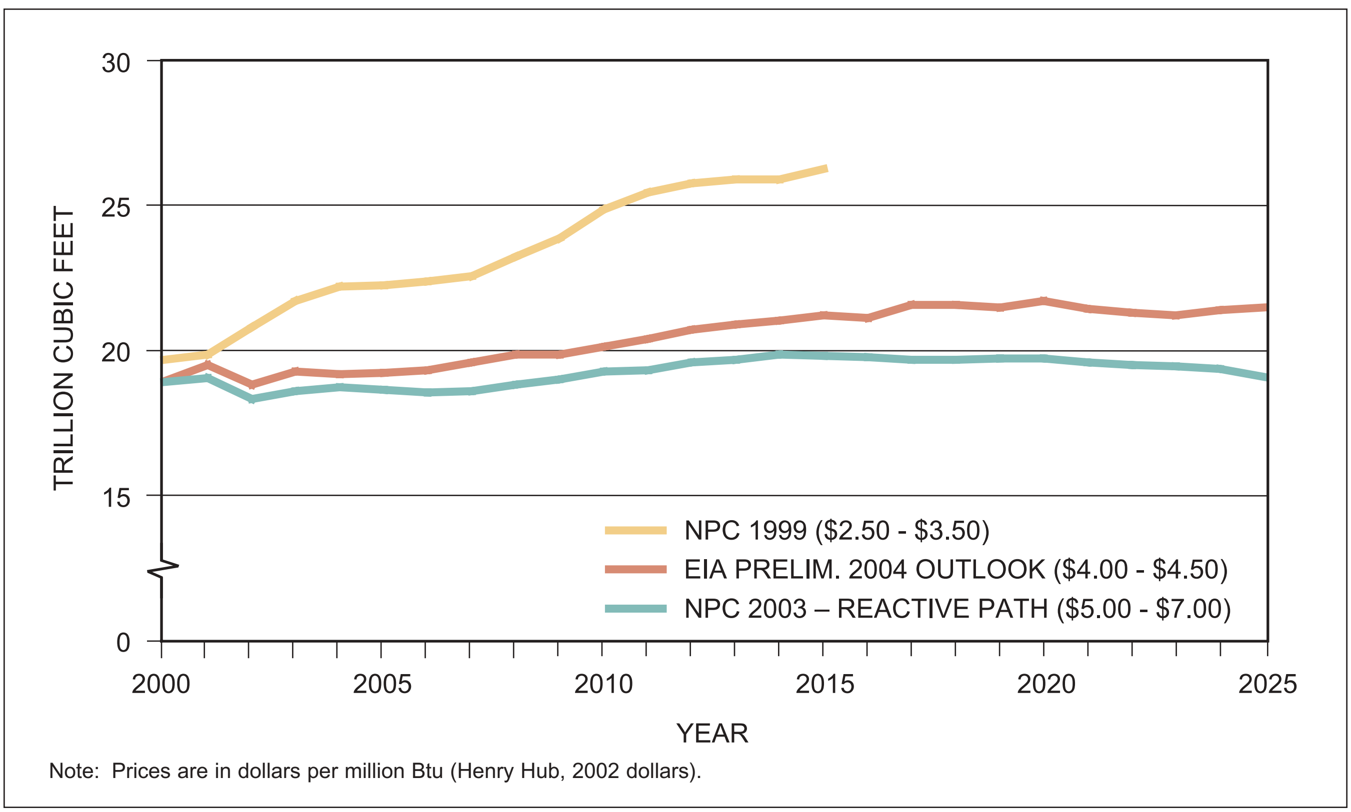


Figure 4-102. Lower-48 Production Outlooks

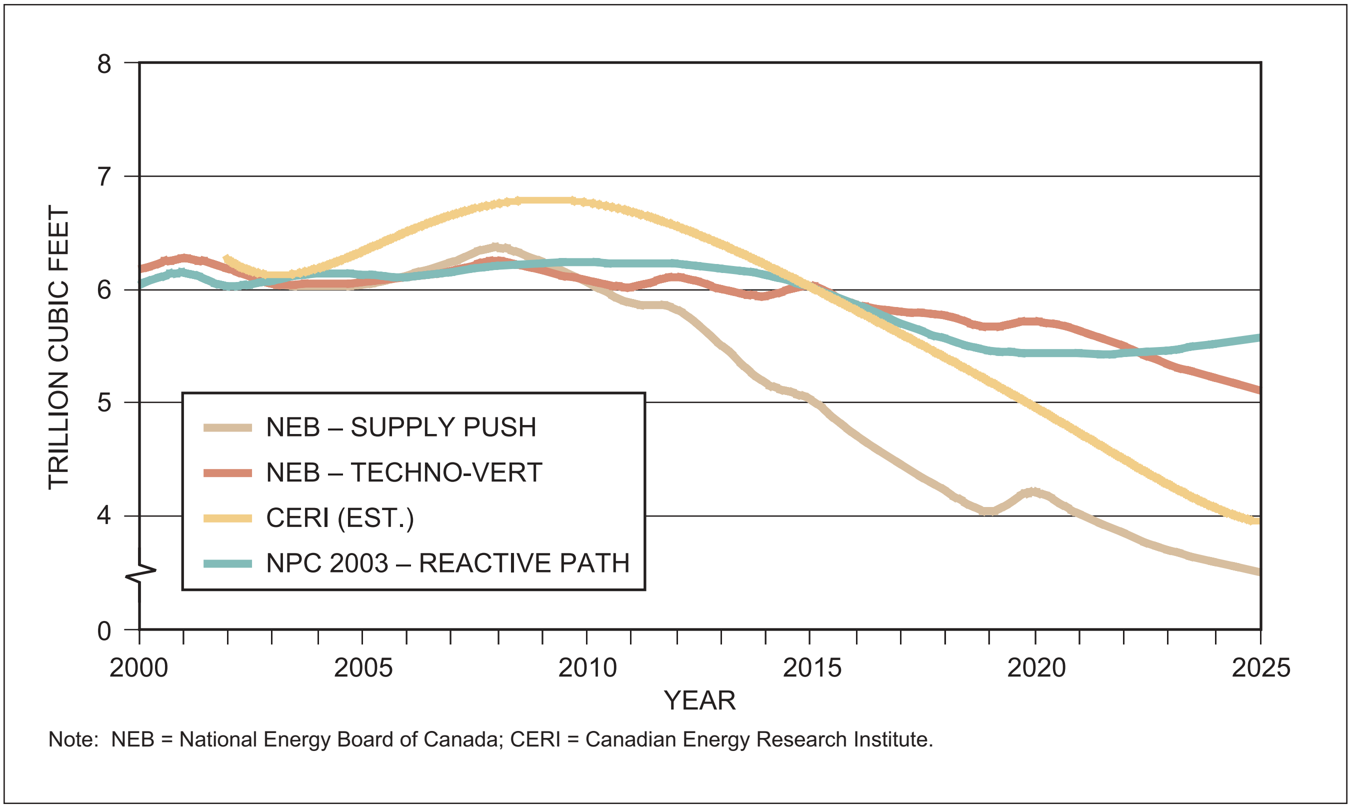


Figure 4-103. Canadian Production Outlooks for Marketable Gas (Excluding Arctic)

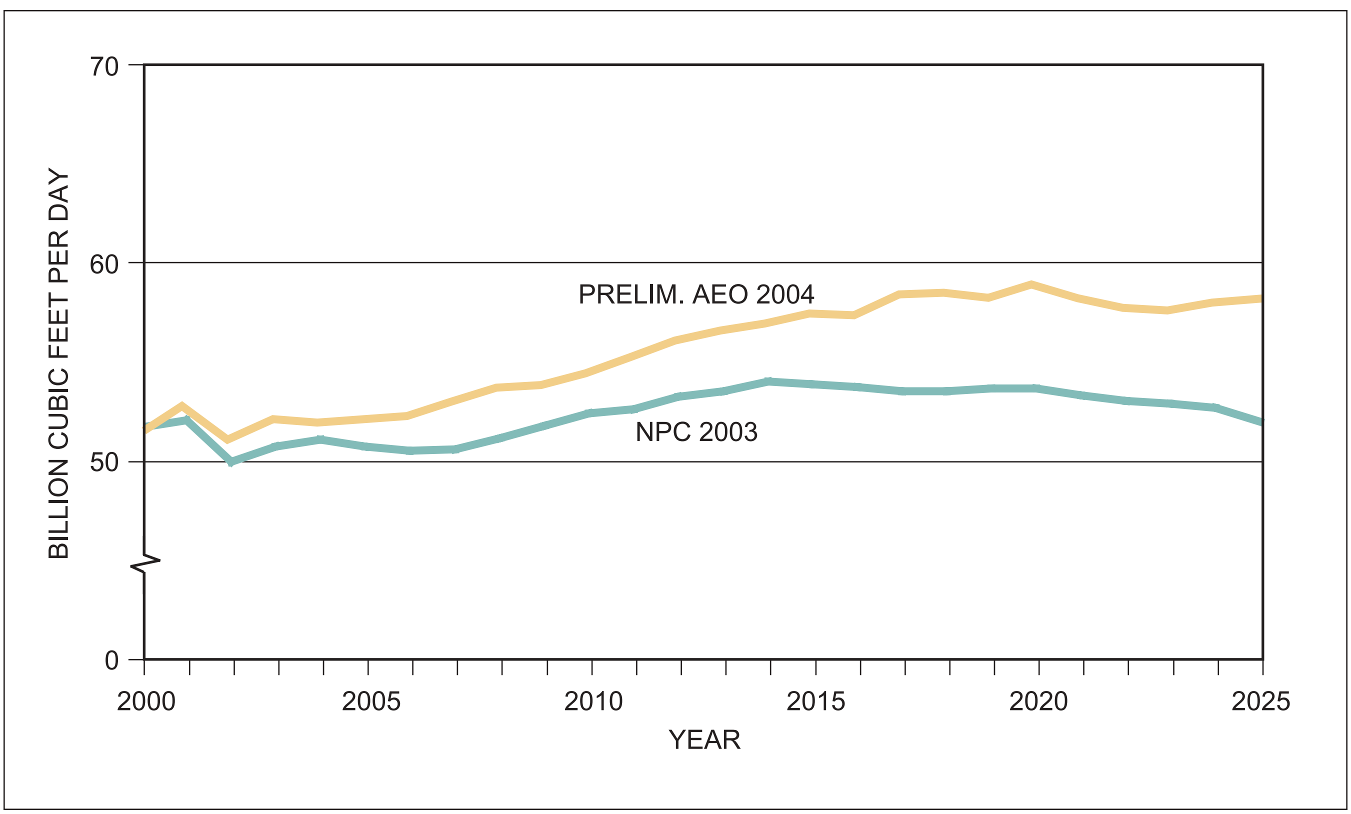


Figure 4-104. Lower-48 Production

gradually increasing production, from 51 BCF/D in 2002 to 59 BCF/D in 2020.

Technical Resource Base

The technical resource bases for both NPC 2003 and prelim. AEO 2004 start from the same general data sources, the USGS for the onshore basins and the MMS for the offshore. However, the NPC has made several adjustments to the USGS/MMS data to:

- Change the overall field size distribution for certain plays
- Add more small fields (especially offshore)
- Adjust the USGS/MMS resource quantities per expert industry opinion
- Use a different methodology to estimate Growth to Known.

In turn, the EIA adjusted the USGS nonconventional resource base.

Table 4-12 compares the prelim. AEO 2004 *accessible* technical resource base (as of 1/1/2002) with the NPC 2003 accessible technical resource base (as of 1/1/99). In order to put the studies on a similar basis, 56 TCF of gas have been subtracted from the NPC 2003 technical resource base estimate to account for three years of production. Overall, the prelim. AEO 2004 unproven technical resource base of 981 TCF of lower-48 gas is 19% (211 TCF) higher than the NPC 2003 technical resource base.

Undiscovered. Undiscovered resources are 33% (96 TCF) higher in NPC 2003 than in prelim. AEO 2004. Onshore undiscovered resources are essentially equivalent, while offshore resources are 57% higher in the NPC study. While both studies started with the MMS assessment, the NPC added more small fields to the technical resource base and included the state waters.

Growth (EIA – Inferred Resources). Growth to proved reserves are 44% (132 TCF) lower in NPC 2003 than in prelim. AEO 2004. Growth was modeled differently, with the NPC using the "cohort" methodology as described in the Supply Task Group Report, and prelim. EIA 2004 using USGS growth curves. Overall, conventional resources are 6% (36 TCF) lower in NPC 2003 than in prelim. AEO 2004.

Nonconventional. Nonconventional resources are 45% lower (175 TCF) in NPC 2003 than in prelim. AEO 2004. As detailed in Table 4-13, a significant difference is in the Rocky Mountains, where the EIA technical resource of 220 TCF (as of 1/1/2002) is over 90 TCF higher than the 124 TCF (as of 1/1/99) of gas in the NPC study. In addition, the prelim. AEO 2004 has included higher nonconventional resources in the Midcontinent, the Louisiana-Mississippi Salt Basins, the Permian Basin (including the Barnett Shale), and the Texas Gulf Coast.

It should be noted that there is possibly a definitional difference between the two studies as regards nonconventional, tight gas resources. The NPC 2003 definition of nonconventional is: "Large accumulations having regional spatial dimensions with diffuse boundaries which cannot be represented in terms of discrete, countable reservoirs delineated by down-dip hydrocarbon-water contacts. Common features include gas down-dip from water, lack of obvious traps and seals, close proximity to source rock, and abnormal pressure (high or low)."

Reserve Additions per Gas Well

NPC 2003 projects lower average reserve additions per gas well, as illustrated in Figure 4-105. The NPC 2003 projected that lower-48 onshore per well reserve additions will slowly decline from 0.8 BCF/well in 2000 to 0.65 BCF/well by 2020. The prelim. AEO 2004 projects a similar declining trend, however, it starts at over 1 BCF/well in 2002 and declines to 0.8 BCF/well by 2020.

The NPC 2003 outlook has higher conventional reserve additions per gas well (green lines) while prelim. AEO 2004 has forecast much more robust nonconventional reserve additions per well (red lines). NPC 2003 projects that nonconventional reserves per well will average approximately 0.6 BCF/well through 2020. In contrast, prelim. AEO 2004 forecasts nonconventional per well reserve additions climbing to 1.4 BCF/well through 2007 and then remaining at that level through 2020.

Drilling Activity

The number of annual gas wells projected in the NPC 2003 and prelim. AEO 2004 are depicted in Figure 4-106. The NPC is projecting annual gas wells of just under 15,000 per year in the near term, rising to 17,500 by 2013. Prelim. AEO 2004 forecasts the number of gas wells will average approximately 16,000 over

	Prelim. AEO 2004	NPC 2003			Difference	
	As of 1/1/02	As of 1/1/99	Less 3 years of production	As of 1/1/02	Change	Percent
Undiscovered	**289**	**388**	**3**	**385**	96	33%
Onshore	149	168	1	167	18	12%
Offshore	139	220	2	218	79	57%
Deep (> 200 meters)	106	129				
Shallow (< 200 meters)	33	91				
Growth to Known (Inferred Resources)	**301**	**204**	**35**	**169**	(132)	-44%
Onshore	243	148	26	122	(121)	-50%
Offshore	58	56	9	47	(11)	-19%
Deep (> 200 meters)	10	8				
Shallow (< 200 meters)	47	48				
Conventional Total	**590**	**592**	**38**	**554**	(36)	-6%
Nonconventional	**391**	**234**	**18**	**216**	(175)	-45%
Tight Gas	260	141	10	131	(129)	-50%
Shale	54	35	6	29	(25)	-46%
Coal Bed Methane	78	49	3	46	(32)	-41%
Other – Low Btu	0	10	0	10	10	
Total Lower-48 Unproved	**981**	**826**	**56**	**770**	(211)	-22%

Note: Resources do not include areas where drilling is officially prohibited.

Table 4-12. Comparison of EIA Preliminary AEO 2004 and NPC 2003 Lower-48 Gas Resources (Trillion Cubic Feet of Gas Technical Recovery; Current Technology; Accessible Resource)

	NPC (as of 1/1/99)				USGS				Prelim. AEO 2004 (as of 1/1/02)			
	Tight	**Shale**	**Coal Bed Methane**	**Total**	**Tight**	**Shale**	**Coal Bed Methane**	**Total**	**Tight**	**Shale**	**Coal Bed Methane**	**Total**
Appalachia + Warrior + Midwest	35	27	14	**76**	45	34	17	**97**	18	37	13	**67**
Midcontinent (Anadarko, Arkoma)	-	-	5	**5**	-	-	5	**5**	13		4	**17**
Louisiana – Miss Salt	6	-	-	**6**	6	-	-	**6**	34			**34**
Rocky Mountains	86	-	28	**124**	172	-	45	**216**	158	2	60	**220**
Green River	39	-	1	**40**	81	-	2	**82**	65		2	**67**
San Juan	19	-	7	**26**	26	-	24	**50**	26		17	**42**
Uinta/Piceance	18	-	5	**23**	19	-	2	**21**	22		9	**31**
Wind River	-	-	0	**0**	-	-	0	**0**	24			**24**
Northern Plains	7	-	-	**7**	43	-	-	**43**	16	2		**17**
Powder River	1	-	13	**14**	1	-	14	**15**			28	**28**
Other	2	-	2	**4**	2	-	2	**4**	6		5	**10**
Low Btu				**10**								
Permian Basin (Including Barnett Shale)		7	-	**7**	-	3	-	**3**	5	15		**21**
Texas Gulf Coast	3	-	-	**3**	-	-	-	-	24			**24**
Other	12	0	1	**13**	12	-	1	**13**	7			**7**
Total	**141**	**35**	**49**	**234**	**235**	**38**	**67**	**340**	**260**	**54**	**78**	**391**

Table 4-13. Nonconventional Technical Resource Base Comparison

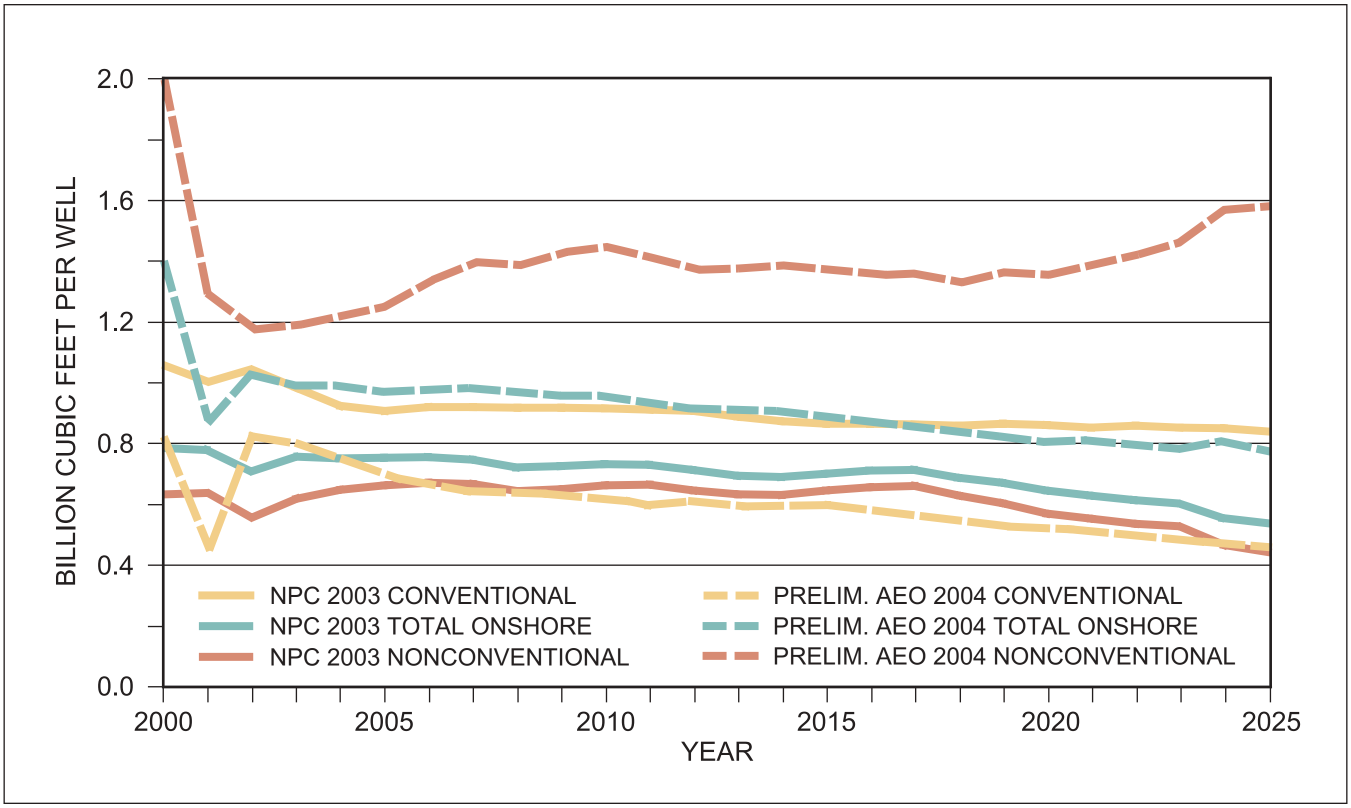


Figure 4-105. Lower-48 Onshore Reserve Additions per Gas Well

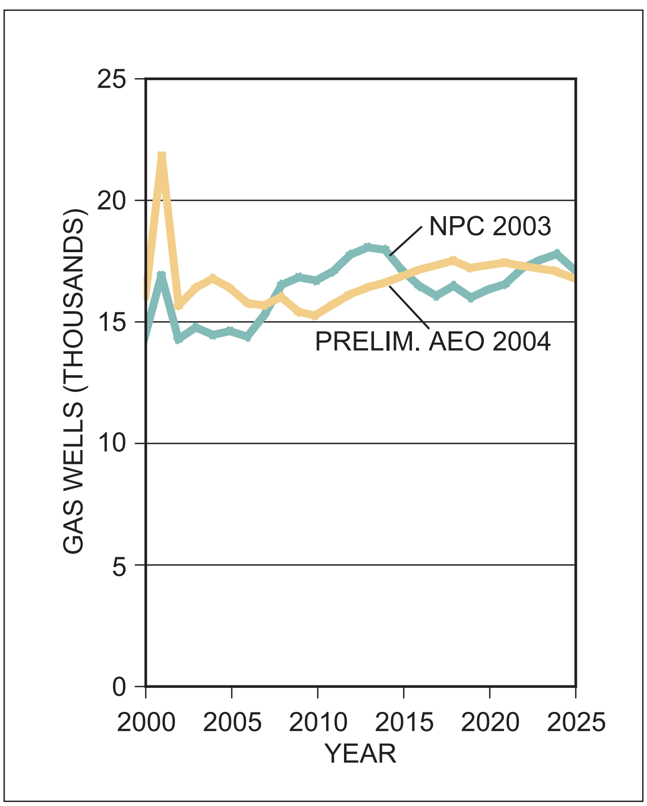


Figure 4-106. Lower-48 Onshore Gas Wells

the next ten years, before rising slowly to over 17,000 per year by 2015.

Onshore average reserve additions per well, onshore drilling activity, and production for 2015 are depicted in Figures 4-107, 4-108, and 4-109. While conventional reserve additions per well are lower, the prelim. AEO 2004 has forecast significantly higher activity levels, leading to higher onshore conventional production. While prelim. AEO 2004 is forecasting somewhat higher nonconventional production, big differences in nonconventional recoveries are somewhat offset by lower prelim. AEO 2004 activity levels.

Technology

Both the EIA and NPC outlooks incorporate technology improvement assumptions in their supply models. The model algorithms address these improvement parameters in slightly different ways, but in some cases comparisons can be made between the prelim. AEO 2004 and the NPC 2003 cases. For conventional resources, EIA and NPC use technology improvement parameters that annually improve either cost or success rates in various areas such as drilling, infrastructure, and operating

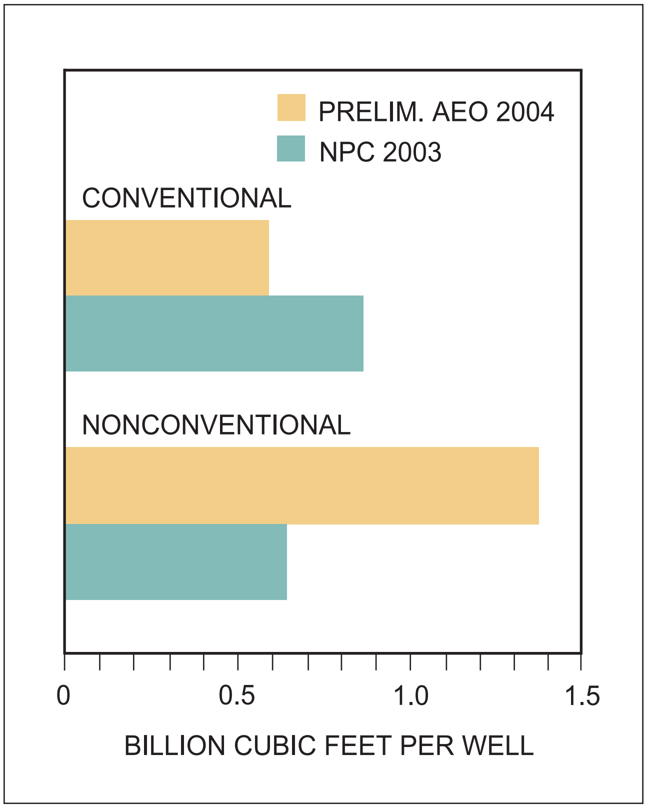


Figure 4-107. Onshore Average Reserve Additions in 2015

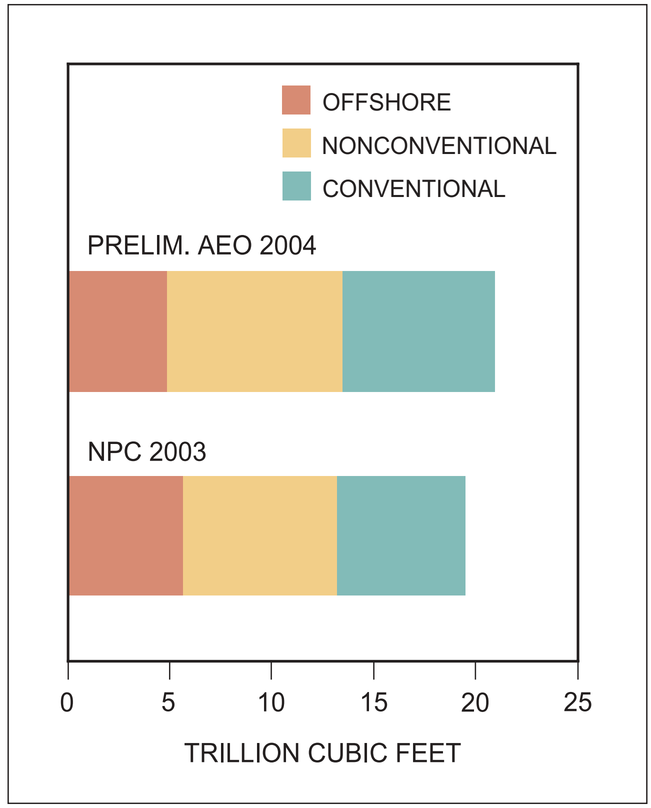


Figure 4-109. Production in 2015

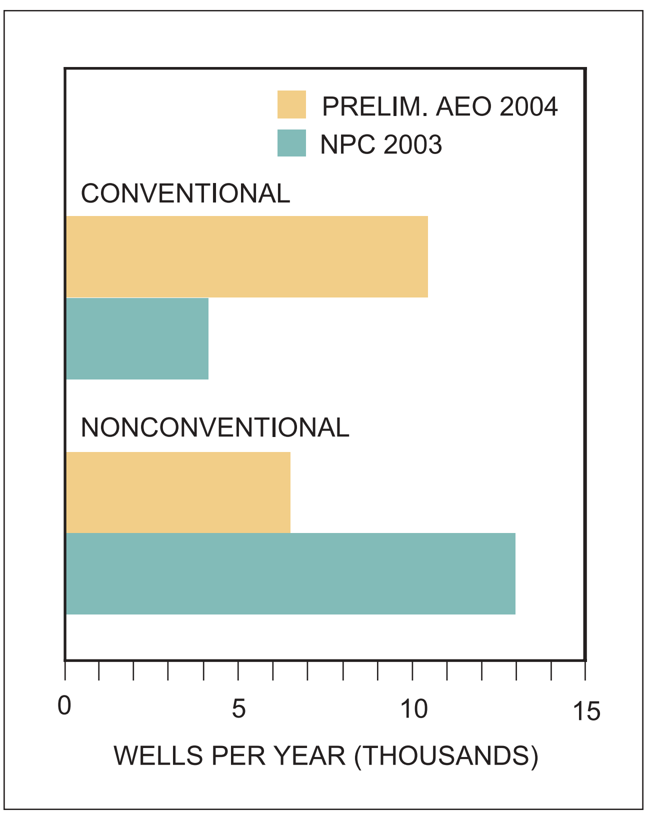


Figure 4-108. Onshore Drilling Activity in 2015

cost or exploration and development success rates. Overall these assumptions compare closely between prelim. EIA 2004 and NPC 2003 (see Figure 4-110). Also, NPC includes an EUR/well improvement parameter for conventional resources where EIA does not.

For nonconventional resources, the most critical technology parameter to compare is EUR/well improvement. Again, the algorithm between the EIA and NPC models vary in handling this parameter. However, from discussions and analysis, it appears that NPC used higher annual improvements in EUR/well than did EIA in their prelim. AEO 2004 for nonconventional resources as shown in Figure 4-111.

Lower-48 Regional Production Response

As depicted in Figure 4-112, NPC 2003 and prelim. AEO 2004 production outlooks for the offshore Gulf of Mexico are quite similar. However, onshore production in prelim. AEO 2004 is forecast to rise from 37 BCF/D in 2000 to 45 BCF/D by 2020, an increase of 8 BCF/D over the 20-year period. The NPC 2003, by contrast, projects relatively flat onshore production. Figure 4-113 shows production profiles for

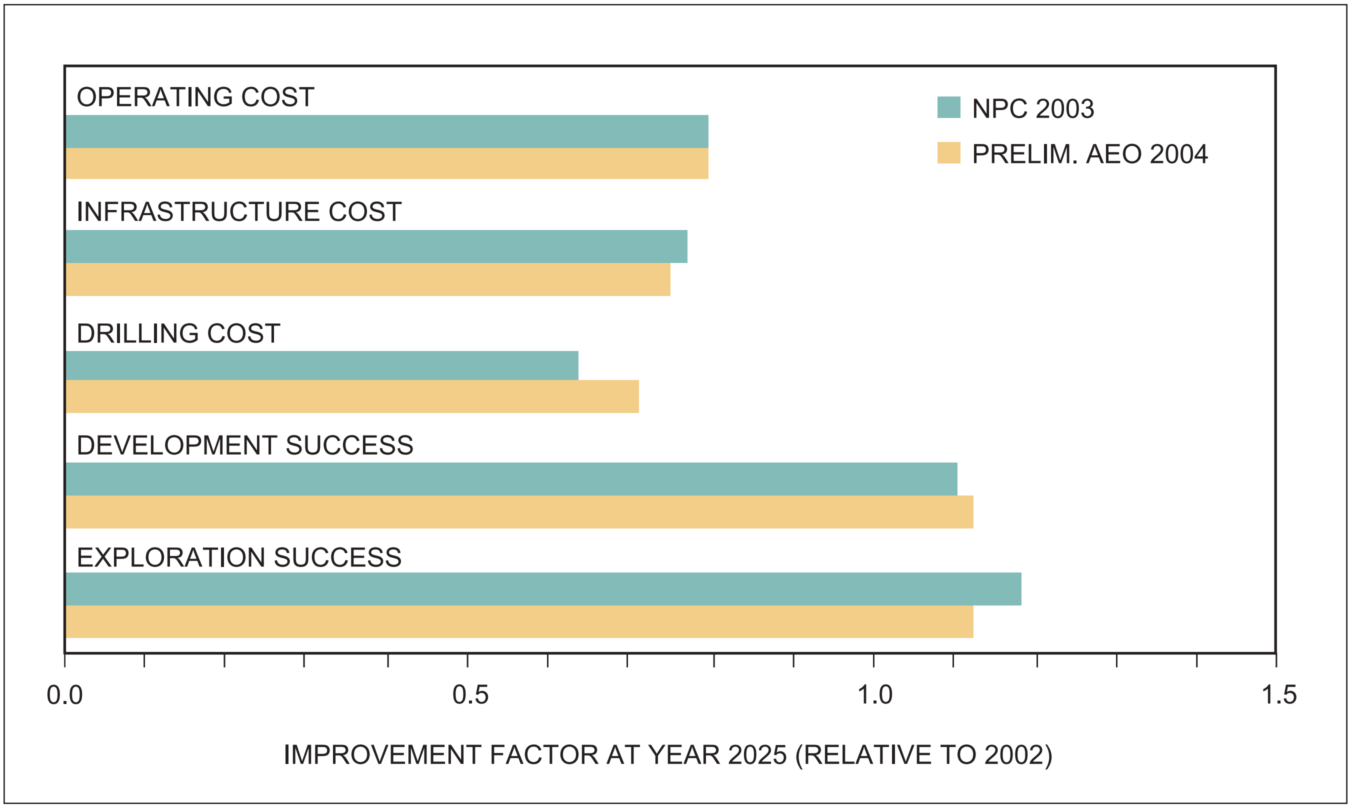


Figure 4-110. Technology Improvement for Conventional Resources

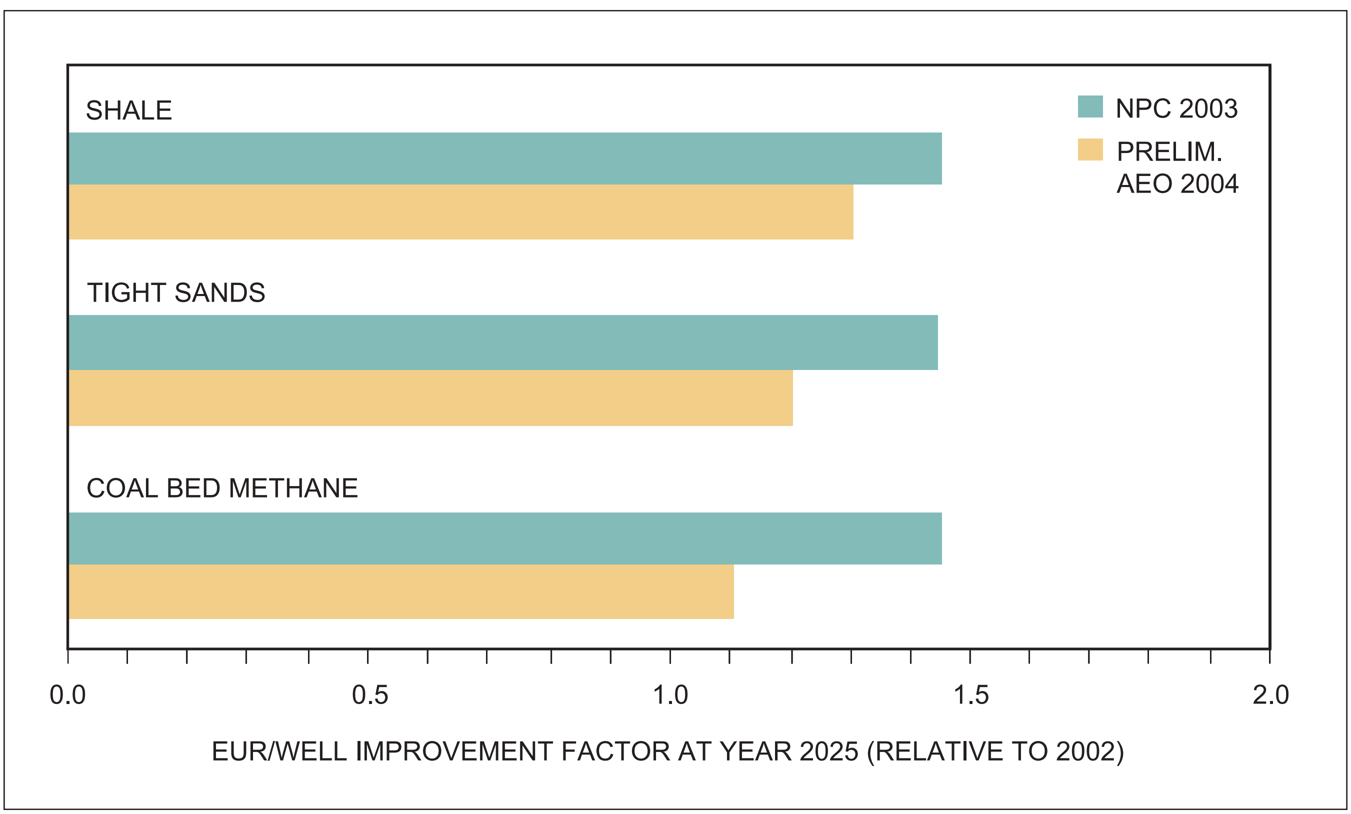


Figure 4-111. Technology Improvement for Nonconventional Resources

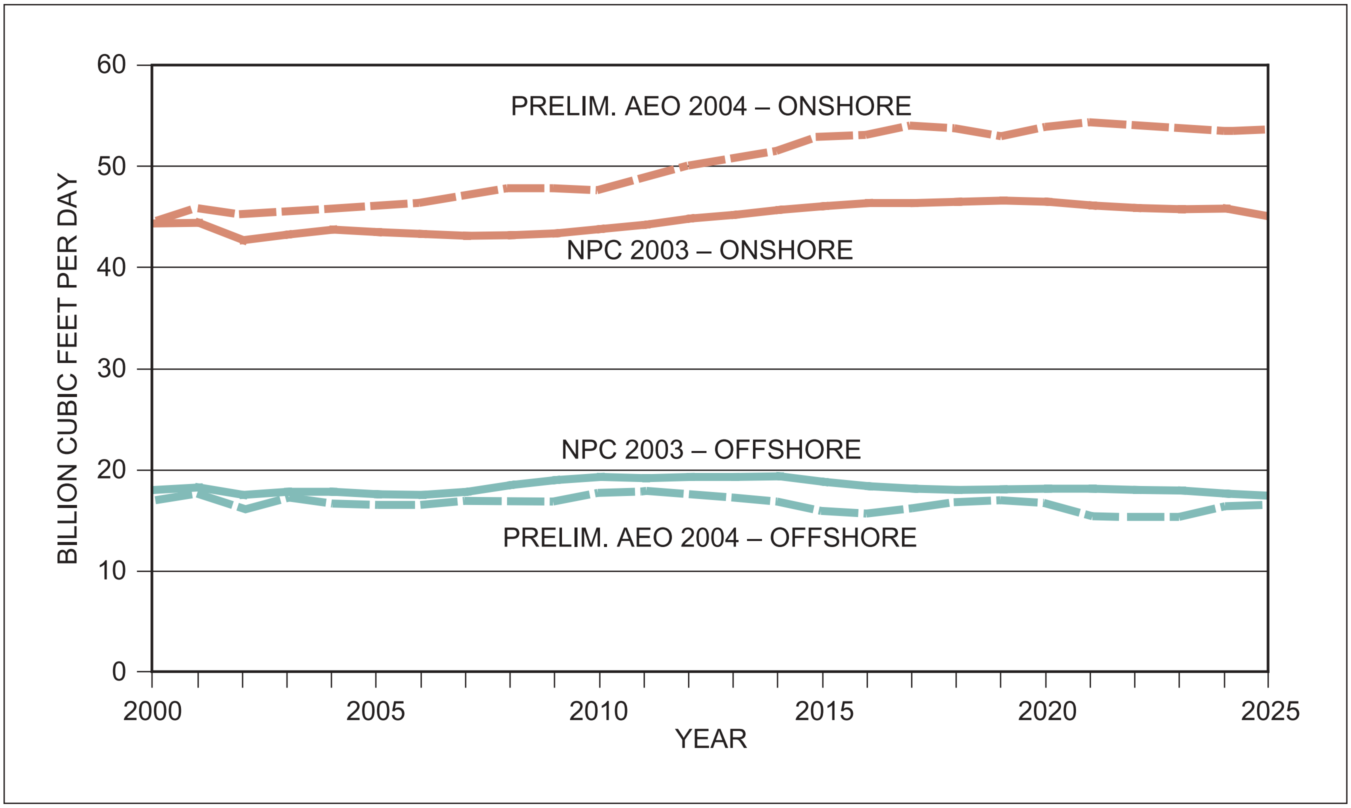


Figure 4-112. Lower-48 Gas Production – Onshore vs. Offshore

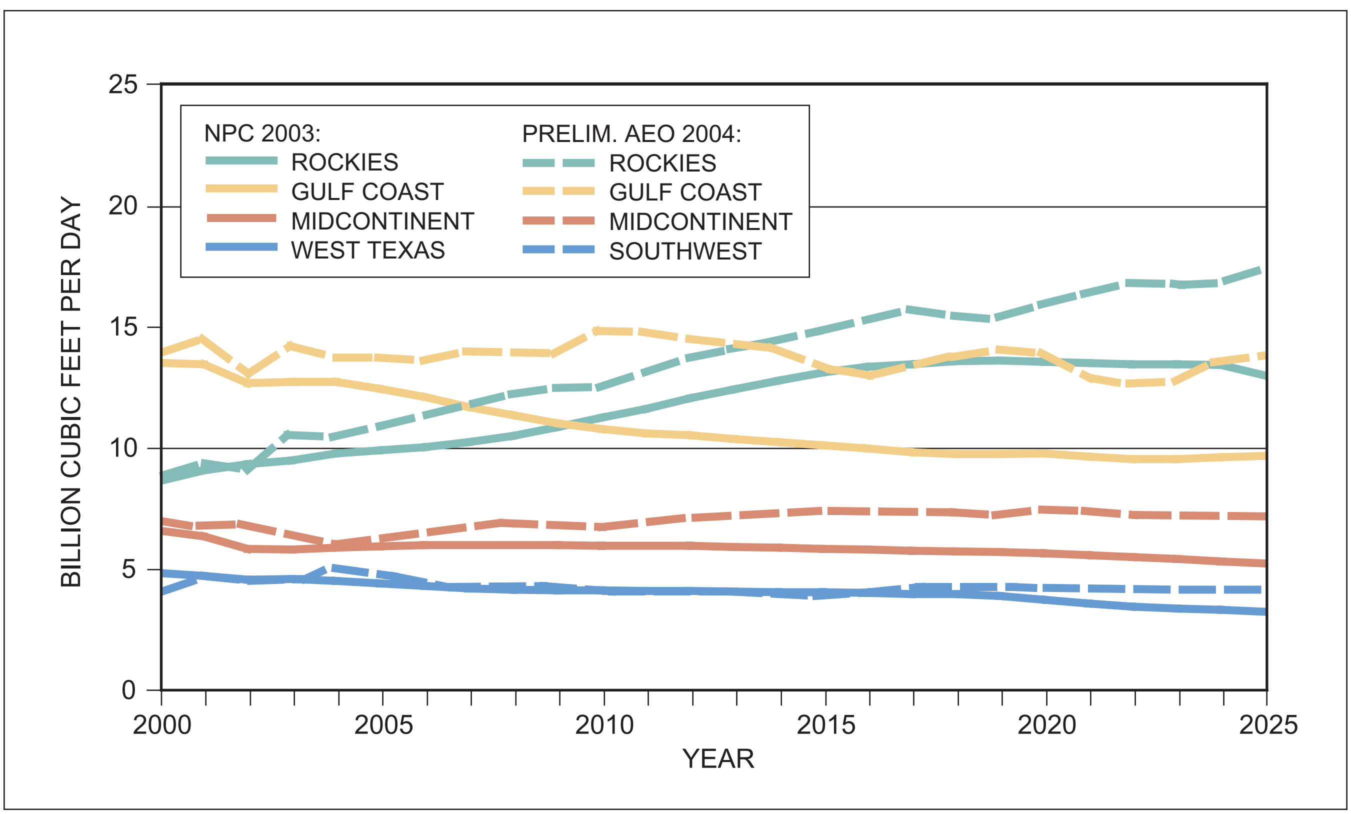


Figure 4-113. Lower-48 Onshore Production for NPC 2003 and Prelim. AEO 2004

NPC 2003 and prelim. AEO 2004 for the following regions:

- Gulf Coast Onshore
- Rocky Mountains
- Midcontinent
- West Texas (NPC 2003) and Southwest (prelim. AEO 2004).

The following observations can be made on the onshore regional comparisons:

- Rocky Mountains – The Rocky Mountains forecasts are similar, with increasing gas production. Preliminary AEO 2004 forecasts are somewhat more aggressive in the near term and then rise at similar rates to the NPC.
- Permian Basin and Midcontinent – The forecasts of the more mature basins are generally similar. The Permian Basin production plots are almost coincident. In the Midcontinent, while similar, the prelim. AEO 2004 forecasts generally flat production, while the NPC outlook is for gradually declining production
- Gulf Coast – There is a large difference between NPC 2003 and prelim. AEO 2004, as NPC 2003 outlook is for generally declining production and prelim. AEO 2004 forecast constant Gulf Coast production rates.

In terms of resource type, nonconventional production is expected to grow in both the NPC 2003 and prelim. AEO 2004 outlooks at roughly similar rates. In terms of conventional gas production, both studies project similar declines through 2010. Post 2010, the NPC projects that conventional production will continue to decline, while prelim. AEO 2004 forecasts that conventional production will flatten, as shown in Figure 4-114.

LNG, Arctic Production

The outlooks for LNG imports into the U.S. lower-48 are similar for the prelim. AEO 2004 and NPC 2003 Balanced Future cases, as shown in Figure 4-115. The NPC Balanced Future scenario assumes two additional LNG receiving terminals than the Reactive Path scenario and quicker terminal permitting.

In terms of Arctic gas, Figure 4-116 shows the outlook for Alaska production, where the prelim. AEO 2004 assumes a 2018 start-up of the Alaska pipeline while the NPC assumes 2013. For the Mackenzie

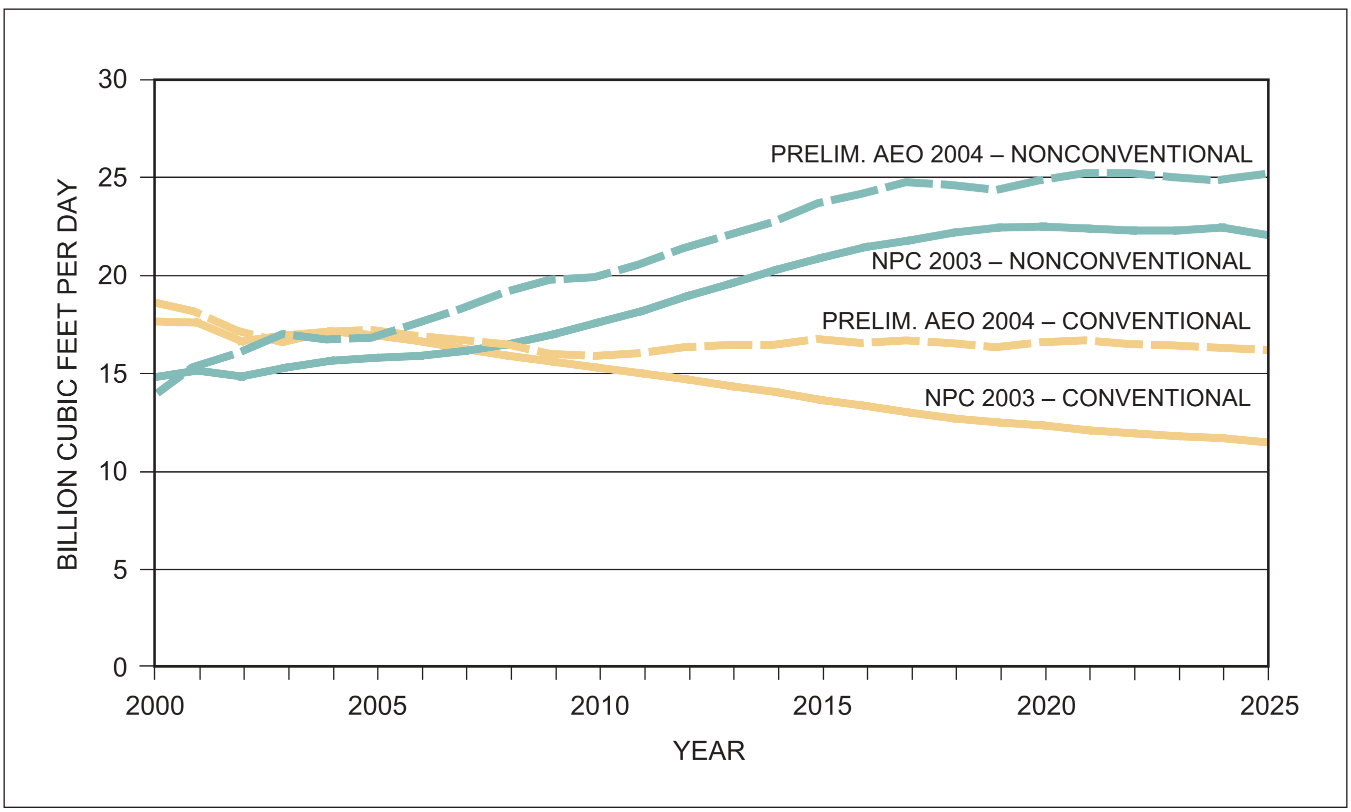


Figure 4-114. Onshore Natural Gas Production

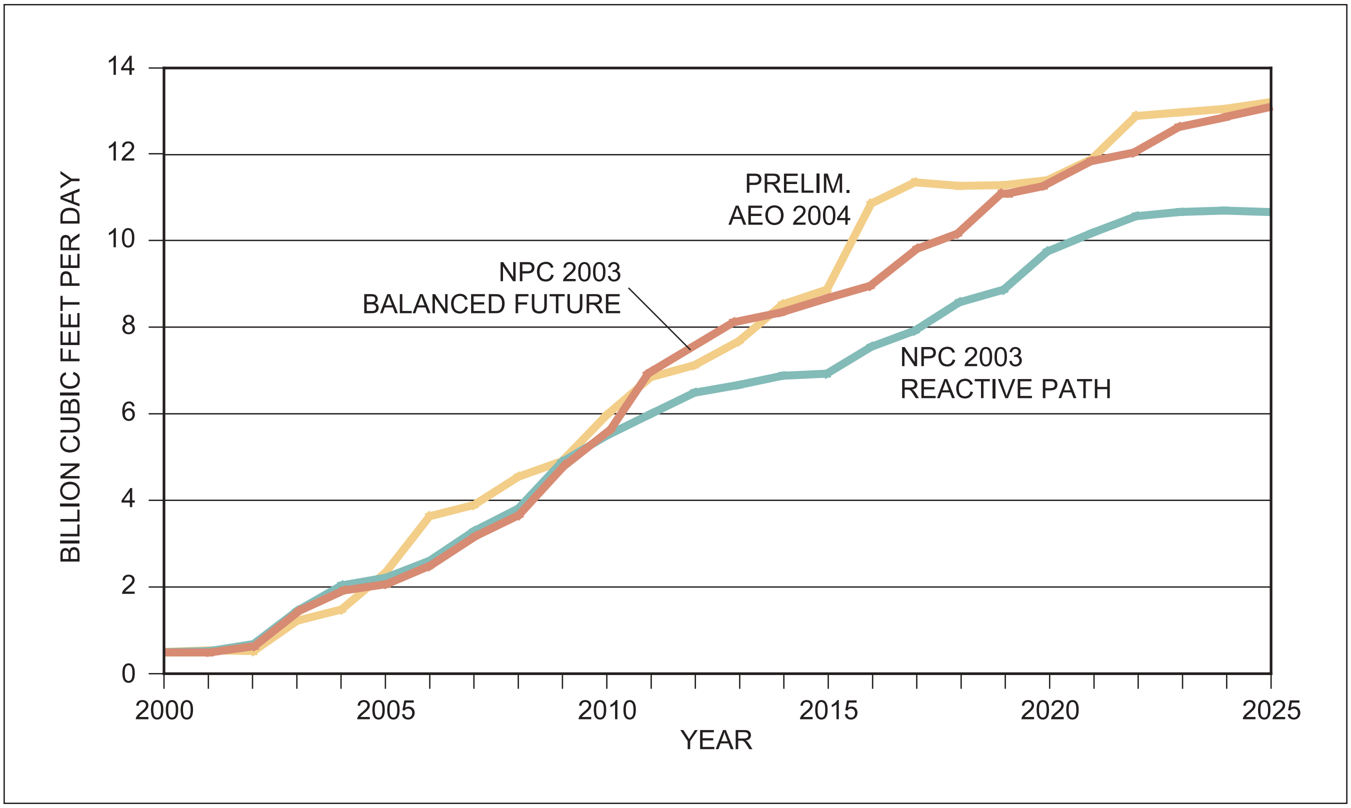


Figure 4-115. LNG Net Imports to U.S. Lower-48

Delta pipeline, both outlooks assume a 2009 start-up as shown in Figure 4-117. However, prelim. AEO 2004 has forecast initially higher volumes (1.85 BCF/D vs. 1.1 BCF/D) with the NPC 2003 projecting an expansion in 2015 to increase the production rates to 1.6 BCF/D.

Summary

The process of comparing and reconciling the EIA and NPC outlooks has been aimed at learning and improving the quality of future outlooks. Some of the key parameters that are contributing to the different outlooks are nonconventional well recovery expectations and the overall level of projected conventional and nonconventional drilling. In addition, although both outlooks use the USGS/MMS resource assessments as the reference, each apply adjustments that result in a 19% difference in assessed technical resource base. Areas of similar outlooks and assumptions were also highlighted.

The identification of the key drivers to the differing outlooks will enable both organizations to review their assumptions and methodologies, with an objective of producing improved outlooks in the future.

1999 NPC Study

The production outlooks for NPC 2003 and the NPC 1999 Reference Case (hereafter called "NPC 1999") were compared for key components, including total production, technical resource base, recovery per well, drilling activity level, technology improvements, and the resultant regional production outlooks.

Total Production

Figure 4-118 shows the production outlooks overall for the U.S. lower-48 and for Canada for NPC 2003 (solid lines) and NPC 1999 (dashed lines). In NPC 2003, total production is forecast to remain near flat at approximately 70 BCF/D through 2015. In contrast, in NPC 1999 total production is forecast to grow, reaching an annual production level of 92 BCF/D by 2015, 21 BCF/D higher than the outlook in NPC 2003.

The biggest difference in the production outlook between the two studies, in both absolute and percentage terms, is the forecast for lower-48 production. In the near term, as is evidenced by Figure 4-118, actual 2002 production levels were approximately 6 BCF/D lower than projected in the NPC 1999 outlook.

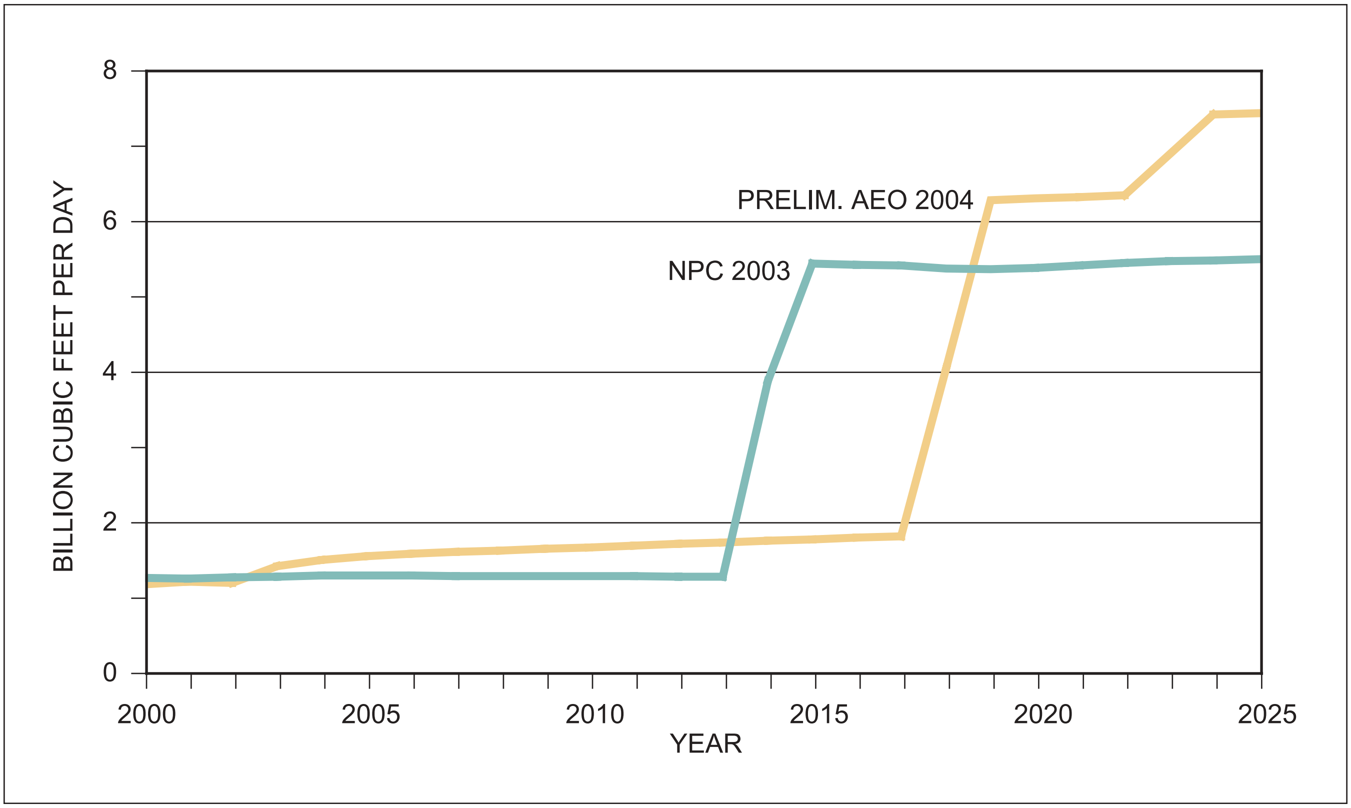


Figure 4-116. Alaskan Natural Gas Production

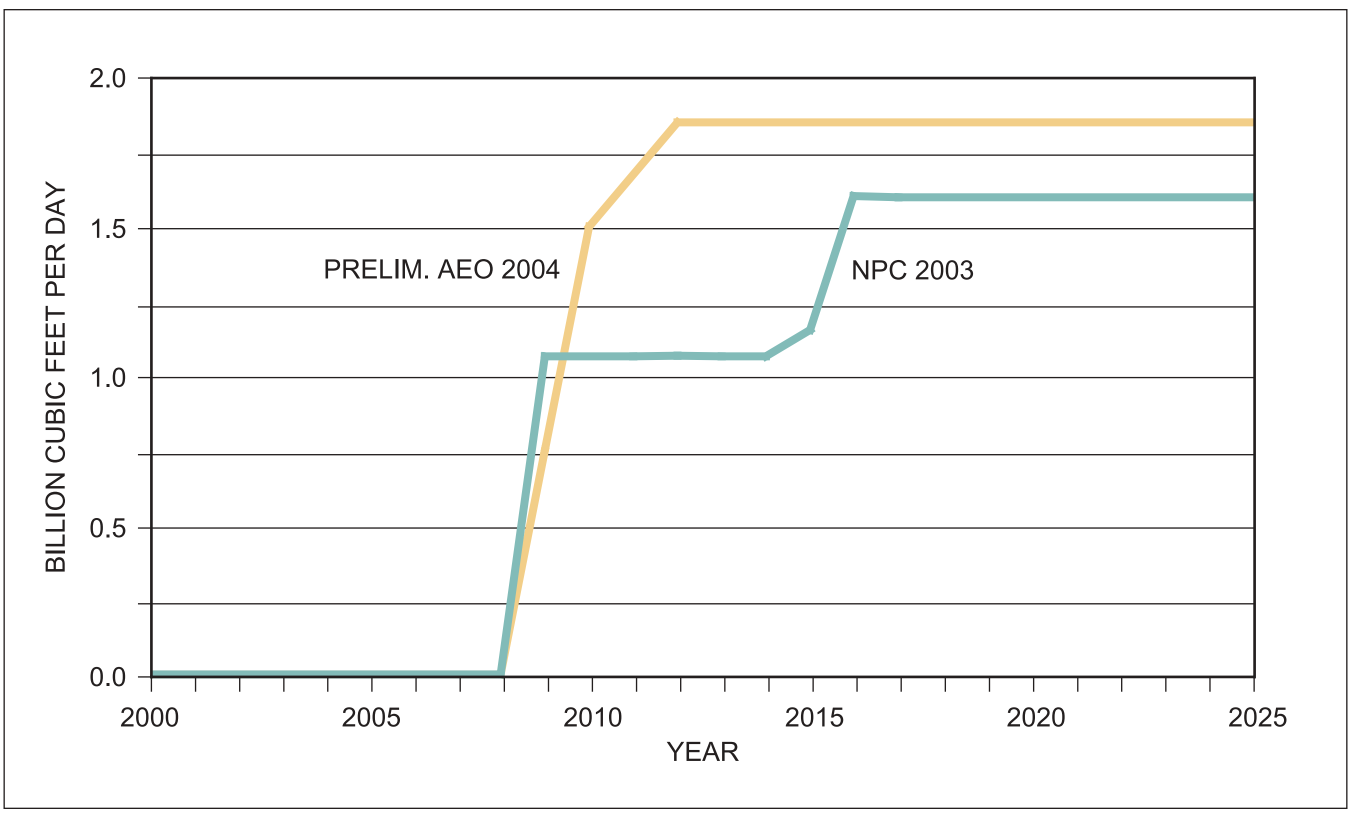


Figure 4-117. Mackenzie Natural Gas Production

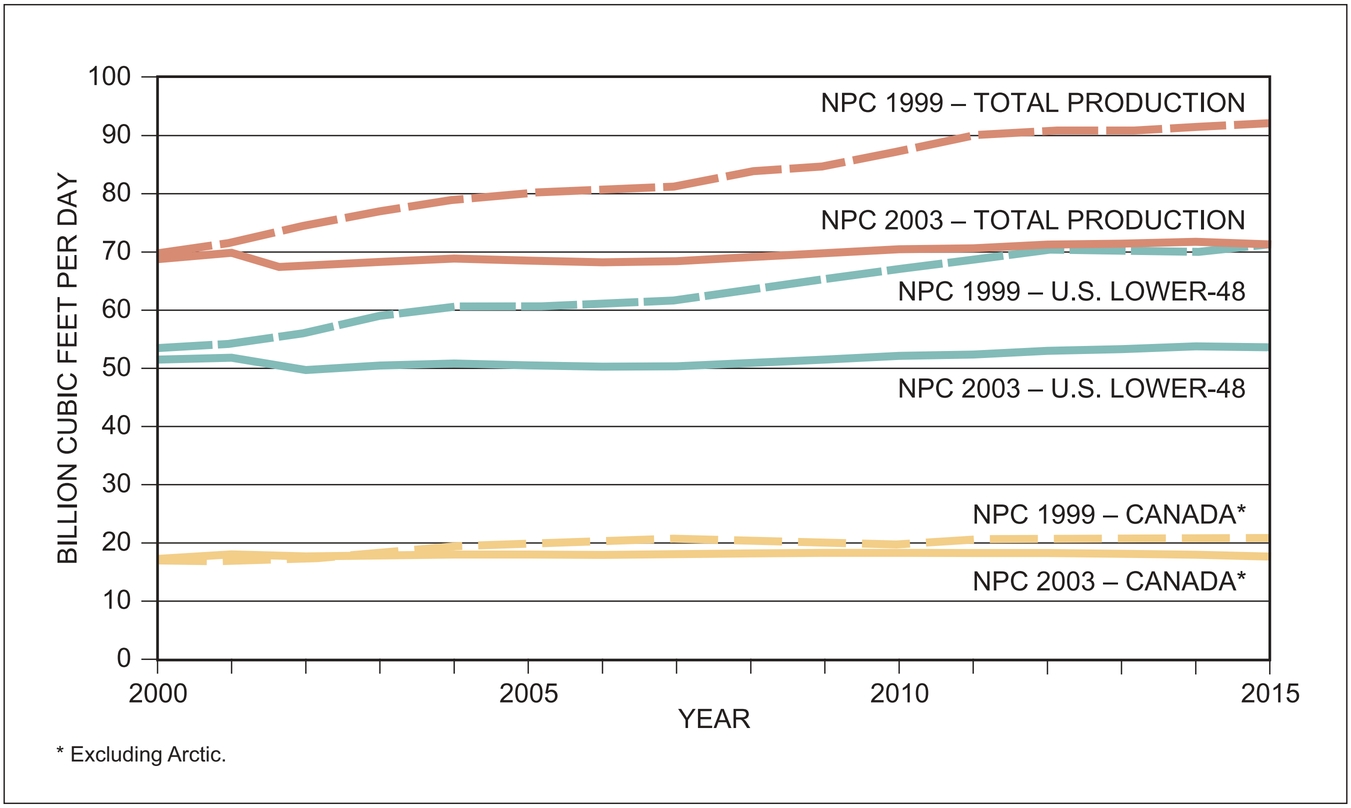


Figure 4-118. U.S. Lower-48 and Canadian Production

Looking forward from 2002, the NPC 2003 outlook was also less robust. NPC 2003 projects flat to modestly increasing lower-48 production, rising from 50 BCF/D in 2002 to a peak of 54 BCF/D by 2015. In contrast, the NPC 1999 outlook was for more strongly rising production, increasing from 56 BCF/D in 2002 to almost 72 BCF/D by 2015.

While a number of factors contributed to the different outlooks, three critical factors helped influence the more recent study:

- A lower assessment of the technical resource base
- The marginal productive response to the price/drilling run-up in 2000 and 2001
- The documentation in NPC 2003 of the rapidly maturing asset base, significant deterioration of individual gas well recoveries, and continuing increase in base decline.

Canadian production forecasts in NPC 2003 and NPC 1999 are more similar. Production levels for 2002 and 2003 are almost coincident. Post-2004, a 10-15% difference between the two outlooks gradually emerges. NPC 2003 forecasts essentially flat production levels of 18 BCF/D through 2015 as western Canadian production remains flat through 2007 and then gradually declines. Increasing eastern Canadian production offsets that decline. In contrast, in NPC 1999 Canadian production is forecast to grow from 18 BCF/D in 2003 to 20 BCF/D by 2005 driven by production increases in western Canada, and then to remain at that level through 2015.

NPC 2003 documented the maturing nature of the Western Canada Sedimentary Basin. Production increases, which were very strong in the early to mid-1990s have been slowing, and 2002 was the first year in recent history of declining production. Recoveries per well have been falling even more dramatically in Western Canada than in the U.S. lower-48.

Technical Resource Base

Figures 4-119 and 4-120 compare the technical resource base assessed in all three NPC studies. In the U.S. lower-48, the technical resource base of 1,250 TCF is a reduction of 210 TCF (14%) from the 1999 study. About half of this occurred in the growth category, where the production performance analysis performed in the 2003 study projected lower future well recoveries and hence less reserve growth in existing fields. Given

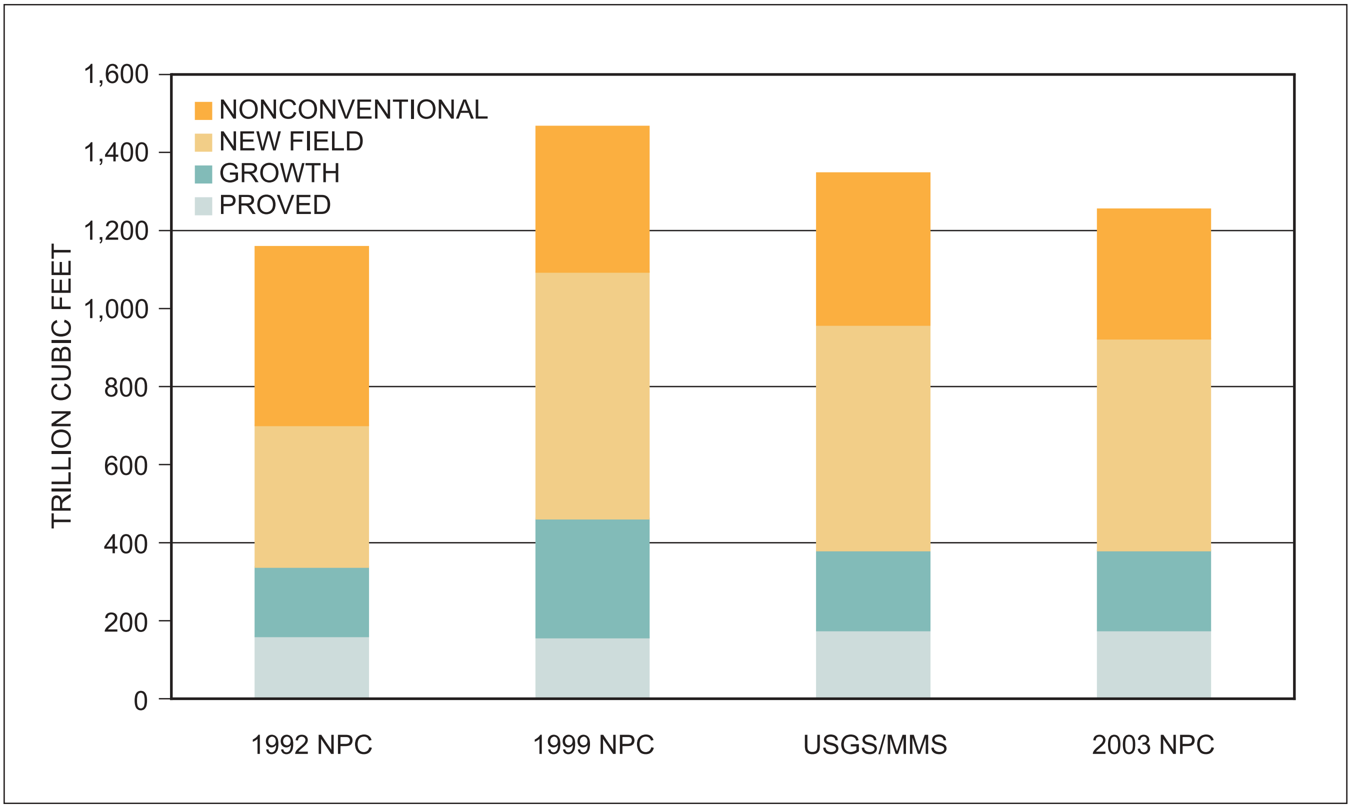


Figure 4-119. Lower-48 Mean Assessment – 1999 Base, Advanced Technology

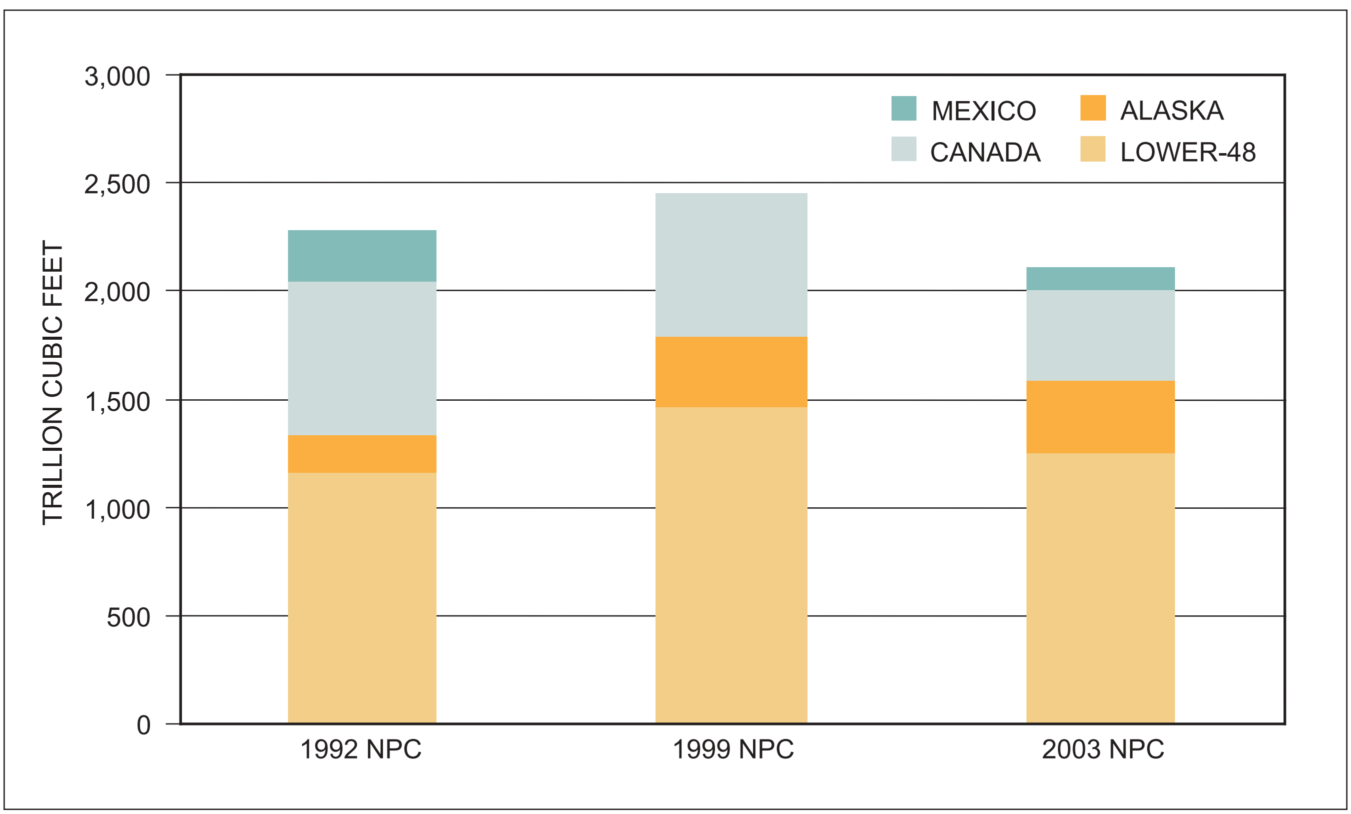


Figure 4-120. North American Mean Assessment – 1999 Base, Advanced Technology

that the growth resource has the lowest supply cost, this lower assessment in the 2003 study would result in lower near term production.

The Canadian assessment is lower in the 2003 study as well, primarily as a result of lower potential assessed in the Atlantic and Arctic frontier regions and a lower nonconventional resource assessment in the Western Canada Sedimentary Basin. Since little of the frontier resource is developed in either study, only the lower nonconventional assessment had an impact on the lower production outlook.

Recovery per Well

One of the most significant differences between NPC 2003 and NPC 1999 is in terms of forecast recoveries per gas well. In the two main producing regions, the U.S. lower-48 and Western Canada, NPC 1999 forecast significantly higher recovery per well than NPC 2003, as is depicted in Figure 4-121. In the U.S. lower-48, NPC 2003 well recoveries averaged approximately 1.2 BCF/well in 2000 and were forecast to remain essentially flat through 2007, before falling gradually to 1.0 BCF/well by 2015. In contrast, NPC 1999 projected average well recoveries to rise from 1.7 BCF/well in 2000 to 1.8 BCF/well by 2006, and then begin to decline, ending at 1.2 BCF/well in 2015. Through 2010, lower-48 well recoveries averaged approximately 30% to 40% higher in NPC 1999 than in NPC 2003.

In Western Canada, NPC 2003 forecast a gradual decline in per-well recoveries, from 0.8 BCF/well in 2000 to 0.6 BCF/well in 2010. NPC 1999, in contrast, forecast a significant increase in per-well recoveries, rising from 1.1 BCF/well in 2000 to 1.65 BCF/well by 2010. By 2010, NPC 1999 per well recovery rates In Western Canada were almost the times the average per-well recovery in NPC 2003.

The per-well performance analysis completed for NPC 2003 documented that average per-well recoveries have been falling in Western Canada, as shown in Figures 4-122 and 4-123. While well mix has exacerbated that trend, as the industry has concentrated on drilling lower risk, shallow development opportunities, declining recoveries are evident across most drilling depths and play types. Only the Devonian, favorably impacted by the rapid exploitation of the large well recoveries from the LadyFern Field, showed any deviation from this trend.

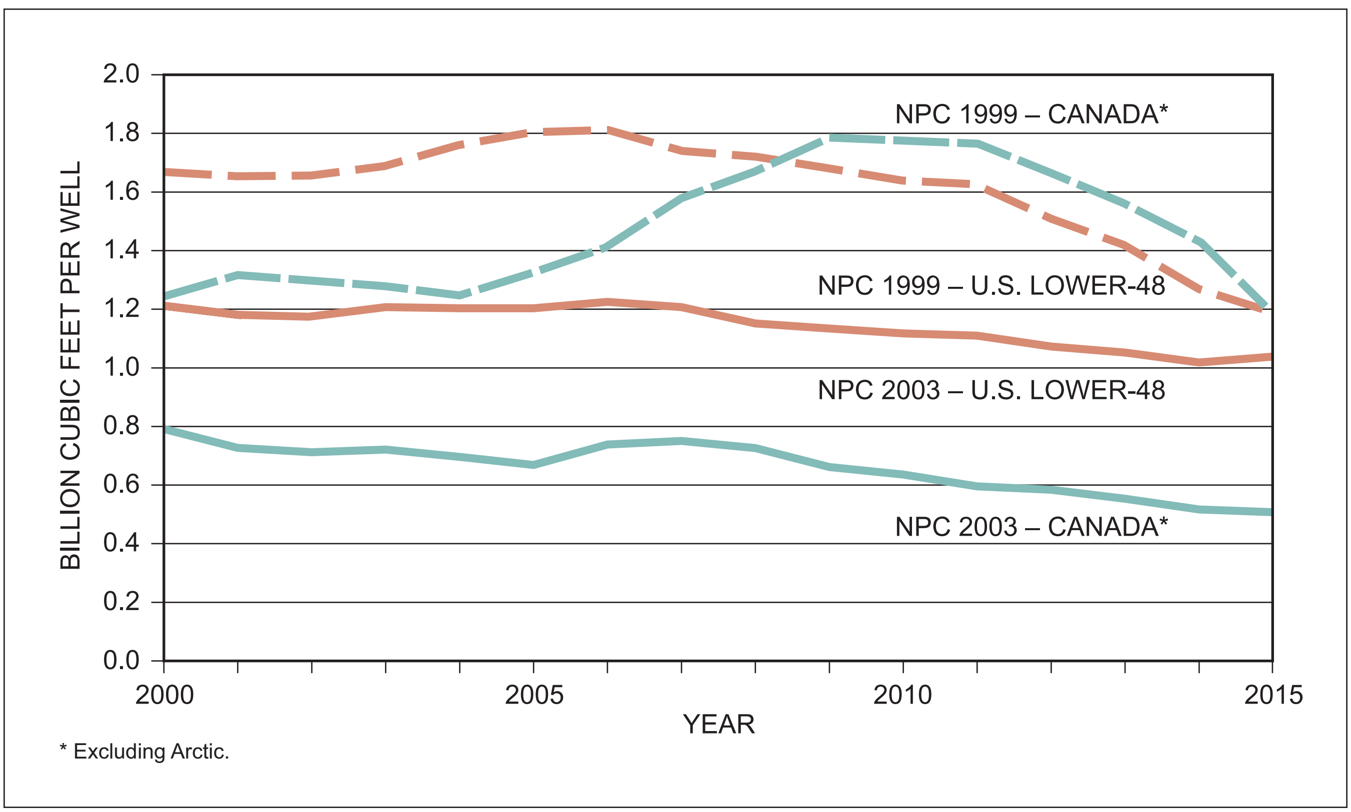
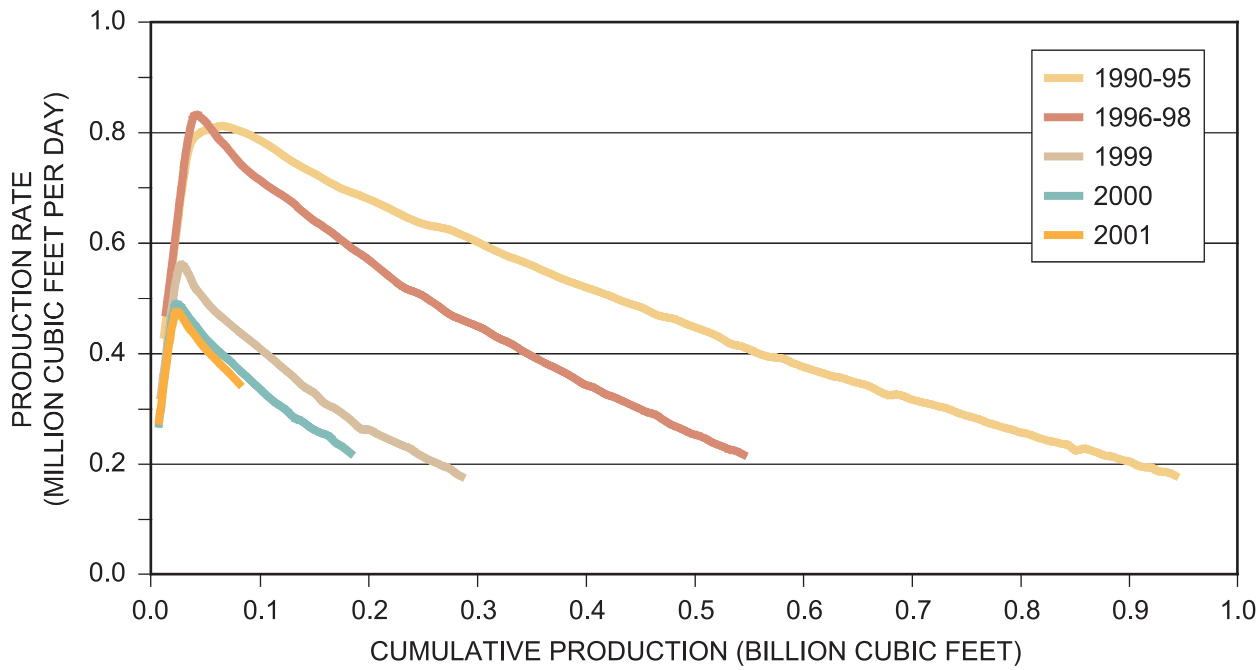
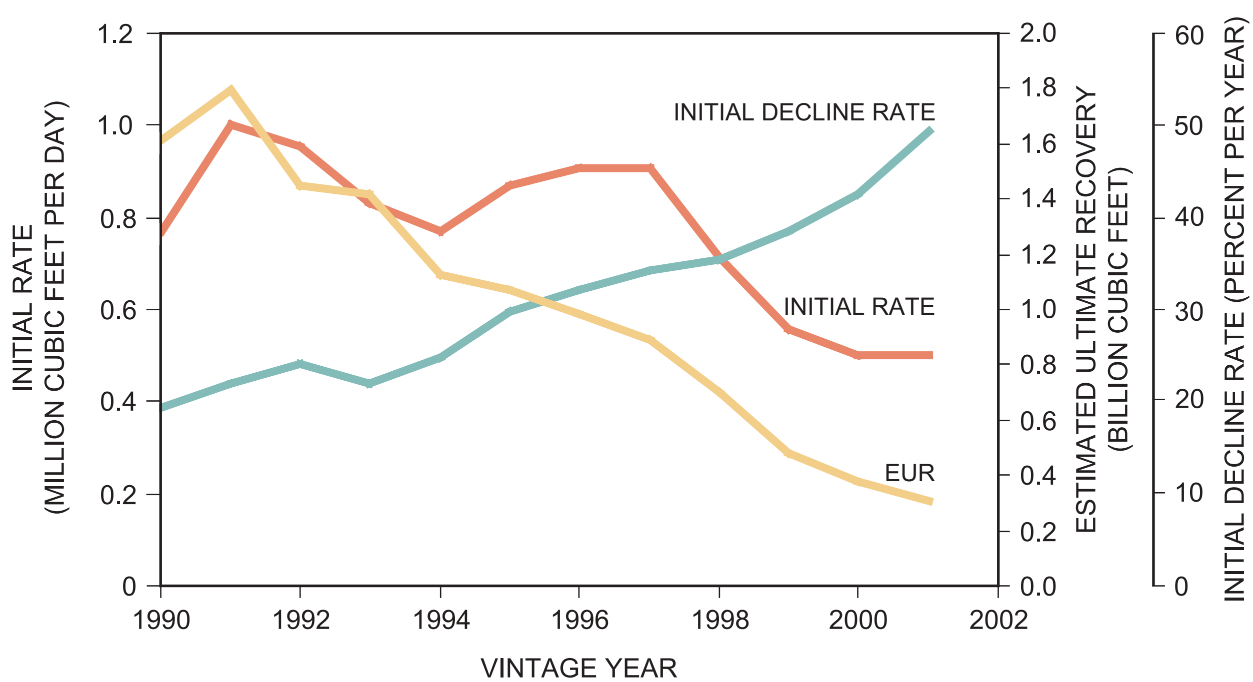


Figure 4-121. Lower-48 and Canadian Recovery per Gas Well



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure 4-122. Western Canada Sedimentary Basin Production Rate vs. Cumulative Production



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure 4-123. Western Canada Sedimentary Basin Production Performance Trends

Within the U.S. lower-48, NPC 1999 forecasts were higher both onshore and offshore. In the Gulf of Mexico, Figure 4-124 shows the NPC 2003 average well recoveries of 15 BCF/well in 2000, gradually falling to 10 BCF/well by 2013, before rising marginally through 2015. By contrast, NPC 1999 projected average Gulf of Mexico recoveries rising from 20 BCF/well in 2000 to 28 BCF/well in 2005, before declining to 18 BCF/well by 2015. NPC 2003 documented the large decrease in per well recoveries in the Gulf of Mexico shelf, from over 5 BCF/connection in 1990 to 3 BCF/connection in 2000.

As shown in Figure 4-125, onshore lower-48 well recoveries were also lower in NPC 2003. NPC 2003 projects that average well recoveries would stay near flat through 2015, at 0.8 BCF/D. This contrasts with the NPC 1999 forecast of average well recoveries increasing from 1.1 BCF/well to 1.2 BCF/well through 2011, before falling. As shown in Figure 4-126, in all critical onshore basins, NPC 1999 forecast higher average well recoveries than NPC 2003.

Drilling Activity

The outlook for drilling activity was higher in NPC 2003 for both the U.S. lower-48 and Canada (see Figure 4-127). In the U.S. lower-48, the NPC 2003 outlook is generally 5-10% higher than NPC 1999, although differences in specific years could be higher, for example, nearing 25% in 2004 and 2005, spurred by higher expected gas prices. Differences in Canada were larger, where NPC 2003 activity levels were 50% higher than those projected in NPC 1999.

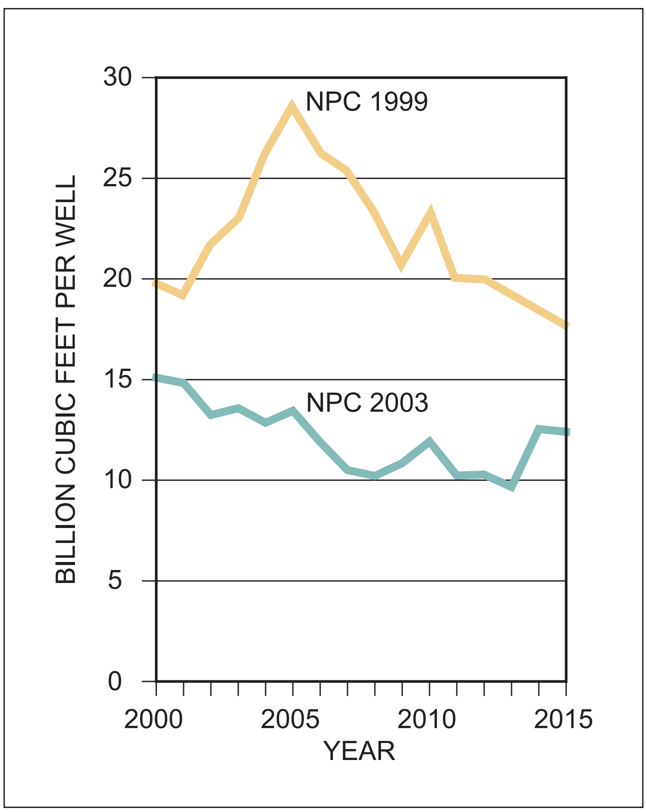


Figure 4-124. Gulf of Mexico Recovery per Well

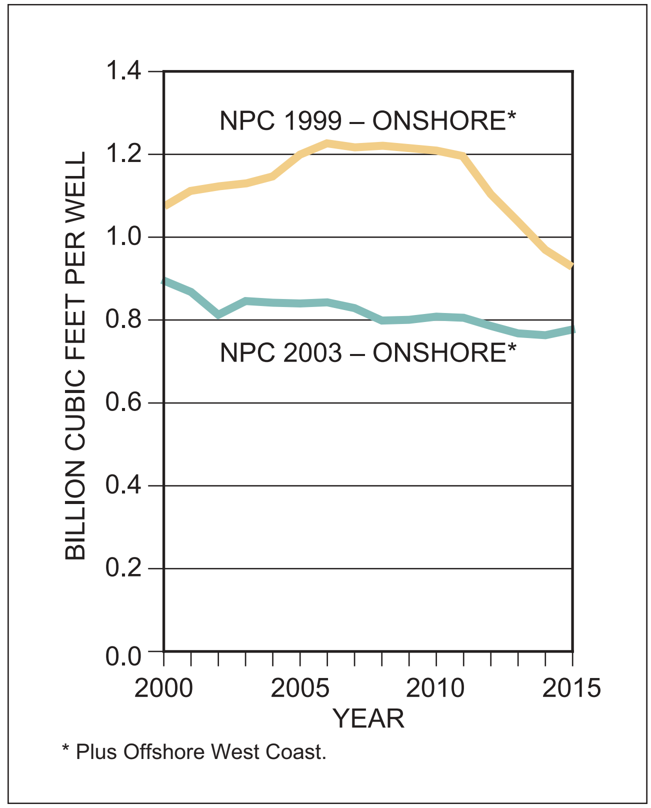


Figure 4-125. Lower-48 Onshore Recovery per Well

In Canada, these higher activity levels were able to partially mitigate the much lower per-well recoveries. In the U.S. lower-48, marginally higher activity levels were unable to offset the large differences in forecast per-well recoveries, and accordingly, the production outlook is markedly lower.

Technology

The 1999 and 2003 studies each handled technology improvement in a similar fashion. Both factored in annual improvement in costs, exploration success, and well recoveries. The 2003 study added two parameters not included in the 1999 study: operating expense improvement and development well success rate improvement. A comparison of the improvement factors between the 1999 study and the 2003 study is illustrated in the following figure. Overall, the 1999

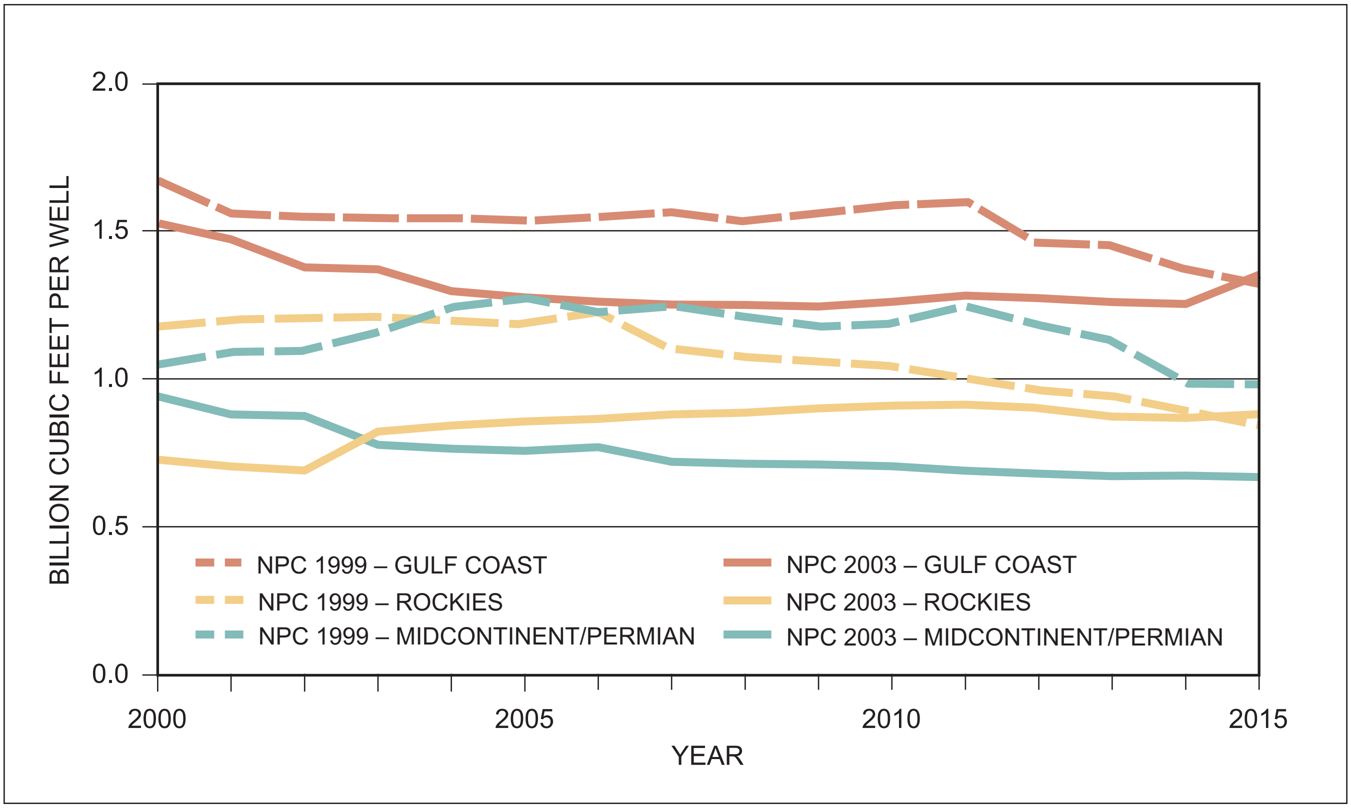


Figure 4-126. Lower-48 Onshore Recovery per Well in Critical Basins

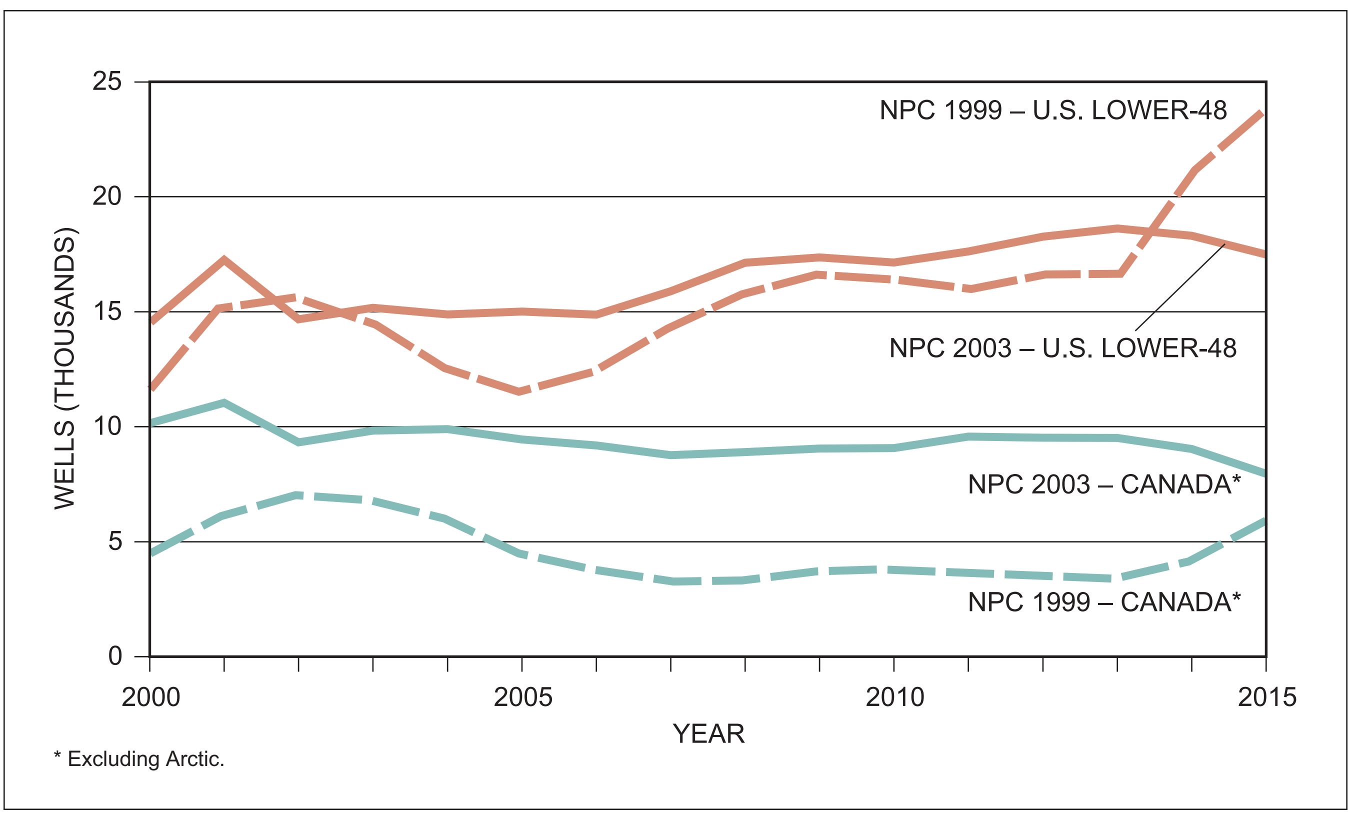


Figure 4-127. U.S. Lower-48 and Canadian Gas Wells

study assumed technology improvements to have a higher impact than the 2003 study. The largest variance is in the exploration success rate improvement. The 1999 study, following a decade of significant improvement due to 3D seismic technologies, projected exploration success rate to improve at approximately 2% per year. With the recent slowdown in 3D technology application, noted by the 2003 Technology Subgroup, the improvement in exploration success was estimated to be 0.8% per year in the 2003 study (see Figure 4-128).

Lower-48 Regional Production Response

As detailed in Figure 4-129, lower-48 forecast production differed both offshore and onshore. In the Gulf of Mexico, NPC 2003 forecast generally flat production of 14-15 BCF/D. In contrast, NPC 1999 projected near-term Gulf of Mexico production to climb strongly to 20 BCF/D by 2005, and then to continue to increase gradually to 22 BCF/D by 2010.

Onshore, NPC 2003 forecast flat to marginal production growth. In contrast, NPC 1999 forecast onshore production increasing from 38 BCF/D in 2000 to over 50 BCF/D by 2015.

Figure 4-130 shows the regional, per basin lower-48 production outlooks.

- Rocky Mountains – NPC 2003 forecast production from the Rockies is similar to NPC 1999. Both outlooks have overall gas production rising steadily from 8-9 BCF/D currently to 12-13 BCF/D by 2015.
- Permian Basin and Midcontinent – In the mature Permian/Midcontinent basins, while NPC 2003 projects production to fall to 10 BCF/D, NPC1999 forecast production growing to 12-13 BCF/D.
- Gulf Coast – The biggest difference between the two studies onshore is in the Gulf Coast forecasts, particularly in East and South Texas. NPC 2003 forecast that Gulf Coast production will fall at just under 2% per year from approximately 14 BCF/D currently to just under 11 BCF/D by 2015. In contrast, NPC 1999 projected production from the Gulf Coast to grow from 14 BCF/D to over 19 BCF/D by 2015.

Overall, most of the factors impacting production outlooks (resource base, technology, and production performance) were more favorable in the 1999 study. Production performance, and specifically recovery per well, is the biggest difference in the two outlooks and is the driver to the lower outlook in the 2003 study.

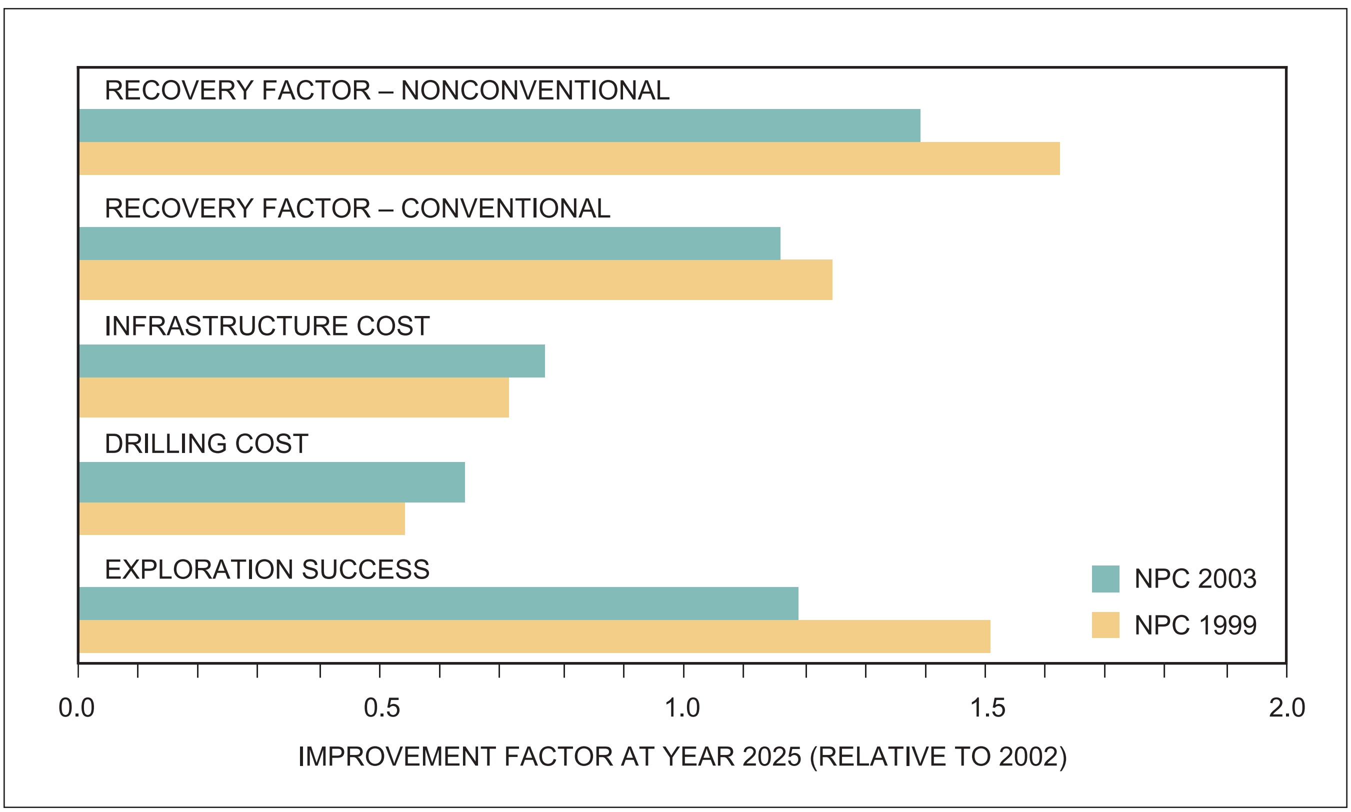


Figure 4-128. Technology Improvement Comparison – NPC 1999 vs. NPC 2003

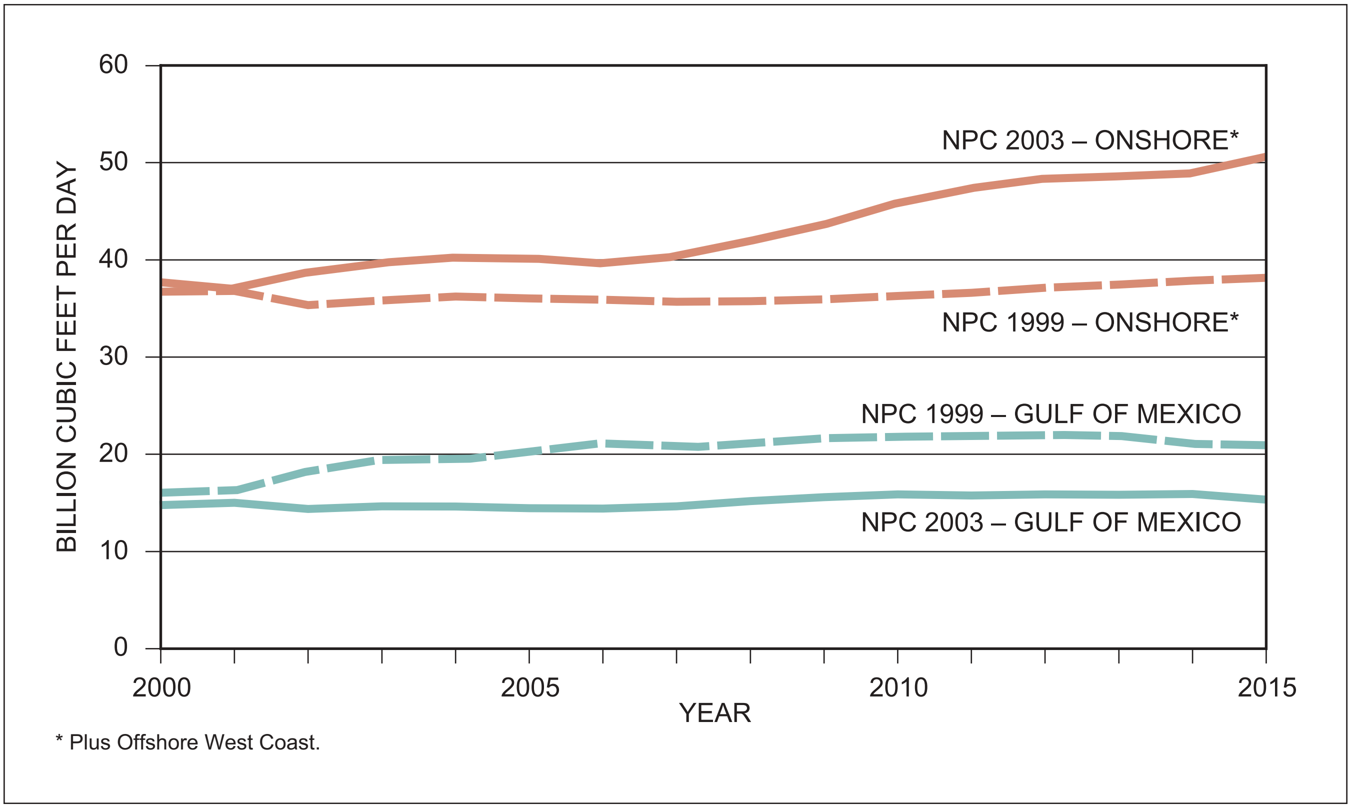


Figure 4-129. Lower-48 Gulf of Mexico and Onshore Production

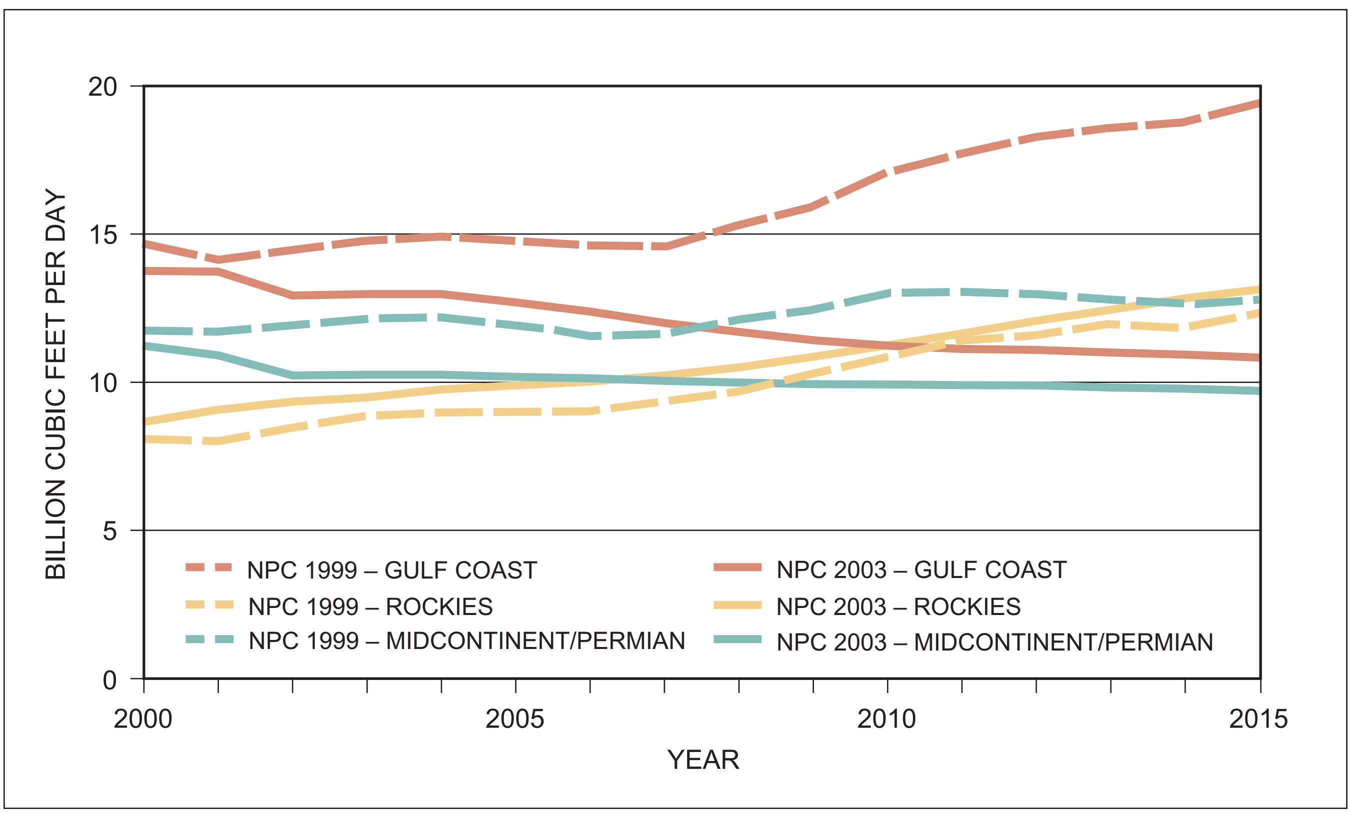


Figure 4-130. Lower-48 Production Outlooks for Onshore Basins

Supply Recommendations

The principal recommendations of the Supply Task Group are related to increasing the diversity of supply through new supplies entering the market. To facilitate this, government policies must remove impediments that inhibit delivery of the additional supplies.

The new supply sources are broadly characterized as:

- Lower-48 resources that are currently restricted or face permitting impediments
- North American Arctic gas
- Increased LNG imports.

Support for *all* new supply sources is required to meet the expected growth in natural gas demand. The recommended actions to facilitate development of these new supply sources are discussed in the Access, Arctic, and LNG sections of this chapter, and are summarized below.

Access

Onshore – Increase Access (Excluding Wilderness Areas and National Parks) and Reduce Permitting Costs/Delays 50% over Five Years

- **Improve government land-use planning.** Governing agencies should use Reasonable Foreseeable Development scenarios as planning tools rather than to establish surface disturbance limitations. Land use planning and project monitoring should be a priority in order to facilitate timely plan revisions and project permitting.
- **Expedite leasing of nominated and expired tracts.** The federal government should expedite the leasing of nominated tracts and expired leases. This can be facilitated by use of existing planning documents and reducing requirements for extraneous environmental analysis where appropriate.
- **Expand use of categorical exclusions or sundry notices as alternatives to processes imposed by the National Environmental Policy Act.** Every surface disturbance activity requires environmental analysis prior to permitting. NEPA costs and delays can be reduced through the use of categorical exclusions or sundry notices instead of environmental assessments for minimal disturbance activities and through improvement of data sharing and coordination by state and federal land management agencies.
- **Streamline and expedite permitting processes.** The permitting process should be streamlined by establishing performance goals for each office, reducing on-site inspections, increasing use of sundry notices in lieu of Application for Permit to Drill (APD), and using dedicated teams to support high workload field offices. This should be continuously monitored and refined by efficient and comprehensive reporting, benchmarking, and best practices programs within the Bureau of Land Management and Forest Service, etc.
- **Establish cultural resource report standards and eliminate duplicate survey requirements.** This is the most frequent cause of delays and expense for APD and right-of-way approvals. Significant cost reductions and time savings can be realized by eliminating duplicate surveys, developing clear standards for determining site significance, and establishing clear cultural report review requirements among governing agencies.
- **Establish qualification requirements and technical review procedures for nomination of endangered species.** There currently exists no qualification requirements to nominate a species for listing, and once nominated, these species are given the same protection as listed endangered species. This results in delays to land management planning and project permitting until a ruling on the nominated species. It is recommended that this process be changed to establish qualification requirements and technical review procedures to prevent such unwarranted delays.
- **Fund and staff federal agencies at levels, and in manners, appropriate for timely performance of responsibilities.** Federal land management agencies need to ensure adequate resources to efficiently handle responsibilities for updating land-use plans, administering the NEPA process, processing lease and permit applications, and resolving appeals and protests in a timely manner. The Bureau of Land Management should consider the formation of dedicated teams to assist field offices with high permitting workloads.

Offshore – Lift Moratoria on Selected Areas of the Federal OCS by 2005

- **Lift, in a phased manner, moratoria on selected OCS areas having high resource-bearing potential.** Federal and coastal state governments, working with industry and other stakeholders, should develop a plan to identify current moratoria areas of the Eastern Gulf of Mexico and Atlantic and Pacific Coasts containing a high resource potential, with a view toward lifting the moratoria in a phased approach beginning in 2005.

- **Update resource estimates for MMS-administered areas.** The federal government (Minerals Management Service) should coordinate the development of updated estimates of natural gas resources underlying the OCS submerged lands and identify the data gathering activities that could be undertaken to improve the technical support for this estimate.

- **Ensure continued access to those OCS areas identified in the 2002-2007 5-Year Leasing Program.**

- **Ensure that Marine Protected Areas are meeting their intended purposes.** Regulatory requirements for protection of marine species should be based on the best available scientific analysis to avoid inappropriate or unnecessary action having uncertain benefit to the intended species. Lease stipulations and operational measures should be practical, cost effective, and aimed to achieve minimal delays in ongoing operations.

- **Require federal and state joint development of Coastal Zone Management (CZM) Plans.** Ensure that federal and state authorities improve coordinated development and review of CZM Plans to understand the impact on federally authorized and regulated OCS activities. If a state alleges that a proposed activity is inconsistent with its CZM Plan, it should be required to specifically detail the expected effects, demonstrate why mitigation is not possible, and identify the best available scientific information and models which show that each of the effects are "reasonably foreseeable". The Secretary of Commerce should not approve state CZM Plans if such implementation would effectively ban or unreasonably constrain an entire class of federally authorized and regulated activities, such as gas drilling, production, and transportation.

Arctic

- **Congress should enact enabling legislation in 2003 for an Alaska gas pipeline.** Passage of this legislation in 2003 is required to support deliveries of this gas to the market in 2013. The NPC and Prudhoe Bay producers agree that Congress should immediately enact legislation that provides regulatory certainty to such a project.

- **Canadian agencies should develop and implement a timely regulatory process.** The various governments in Canada (federal, territorial, provincial) and the First Nations should continue to work cooperatively to develop and implement a timely regulatory process. An efficient process must be in place in early 2004 to support a 2009 Mackenzie gas project start-up and a 2013 Alaska gas pipeline project start-up.

- **Alaska needs to provide fiscal certainty for the project.** The state of Alaska should provide fiscal certainty to project sponsors in a manner that is simple, clear, not subject to change, and that can improve project competitiveness. Such action by the Alaska legislature in 2004 is required to support a 2013 project start-up.

- **Governments should refrain from potentially project-threatening actions.** Governments should avoid imposing mandates or additional restrictions that could increase costs and make it more difficult for a project to become commercially viable.

- **Infrastructure improvements incidental to Alaska gas pipeline construction must be planned in a timely and coordinated manner.** The U.S. and Canadian governments – federal, state, provincial, and territorial – should study and/or consult with one another and industry participants and affected communities to assess contemplated infrastructure improvements in support of Arctic gas development in advance of the time when these improvements are needed.

LNG

The goal of the following recommendations is to reduce the time required for LNG facility permitting to one year.

- **Agencies must coordinate and streamline their permitting activities and clarify positions on new terminal construction and operation.** Project sponsors currently face multiple, often-competing state and local reviews that lead to permitting delays. A coordinated effort among federal, state, and local agencies led by FERC would reduce permitting lead time. Similarly, streamlining the permitting process by sharing data and findings, holding concurrent reviews, and setting review deadlines would provide greater certainty to the overall permitting process. FERC should further clarify its policy statement on new terminals so as to be consistent with corresponding regulations under the Deep Water Port Act, including timing for the NEPA review process and commercial terms and conditions related to capacity rights.

- **Fund and staff regulatory agencies at levels necessary to meet permitting and regulatory needs in a timely manner.** The expected increase in the number of terminal applications will require higher levels of government support (federal, state, and local) to process and avoid delays. Additional agency funding/staffing will also be required once these new terminals become operational, particularly to support the large increase in LNG tanker traffic.
- **Update natural gas interchangeability standards.** Standards for natural gas interchangeability in combustion equipment were established in the 1950s. The introduction of large volumes of regasified LNG into the U.S. supply mix requires a re-evaluation of these standards. FERC and DOE should champion the new standards effort to allow a broader range of LNG imports. This should be conducted with participation from LDCs, LNG purchasers, process gas users, and original equipment manufacturers. DOE should fund research with these parties in support of this initiative.
- **Undertake public education surrounding LNG.** The public knowledge of LNG is poor, as demonstrated by perceptions of safety and security risks. These perceptions are contributing to the public opposition to new terminal construction and jeopardizing the ability to grow this required supply source. Industry advocacy has begun, but a more aggressive/coordinated effort involving the DOE and non-industry third parties is required. Emphasis should focus on understandings, safety, historical performance, and the critical role that LNG can play in the future energy supply.
- **LNG industry standards should be reviewed and revised if necessary.** In order to promote the highest safety and security standards and maintain the LNG industry's safety record established over the past 40 years of operations, FERC, the Coast Guard, and the U.S. Department of Transportation should undertake the continuous review and adoption of industry standards for the design and construction of LNG facilities, using internationally proven technologies and best practices.

Additional Supply Considerations

There are additional actions and policy initiatives that could be undertaken to potentially enhance supply sources. Among those are the role played by tax and other fiscal incentives or packages, and the desirability of additional government-sponsored research spending.

Two strongly held views of fiscal incentives emerged during the study discussions. Supporters of such incentives believe additional production would result from pursuit of marginal opportunities and/or high cost supply alternatives, helping to ease the tight supply/demand balance. Others believe market forces are and will be sufficient to stimulate additional investment without the need for tax-relates incentives or subsidies. Potential fiscal incentives such as tax credits for nonconventional resource development, low-BTU gas, stripper oil well and deep gas drilling incentives, and an Alaska pipeline fiscal package were discussed, but the NPC makes no recommendation in this regard.

With respect to government research, the NPC is supportive of a role for DOE in upstream research, particularly where it complements privately funded research efforts. DOE's natural gas research program has a significant role in technical studies and related work that support public policy decision-making regarding natural gas supply. DOE currently spends about $50 million per year on jointly sponsored natural gas technology research. This represents 53% of the funding for oil and gas research, but only 9% of the funds directed at fossil energy programs in total. The NPC believes DOE should evaluate whether this level of funding is appropriate in relation to other DOE programs in light of the increasing challenges facing natural gas. Further discussion of this issue is included in the Technology section of the Supply Task Group Report.

CHAPTER 5

TRANSMISSION, DISTRIBUTION, AND STORAGE INFRASTRUCTURE

For purposes of organization, and in acknowledgement of the differing issues of the major pipeline transmission and distribution market segments, the Transmission & Distribution Task Group (T&D Task Group) has chosen to separately report on the areas of pipeline transmission, distribution, and storage. In aggregate, the subsections form a coherent analysis, just as the separate but conjoined efforts of the study's Task Groups (Demand, Supply, and Transmission & Distribution) have been combined into an integrated document.

Study Approach

In order to incorporate a wide range of industry expertise, the T&D Task Group was comprised of 26 U.S. and Canadian representatives from the following natural gas industry sectors: pipeline transmission; distribution; storage; marketers; and producers. When issues arose outside of the specific participant knowledge areas, experts within the represented companies, as well as firms not directly represented on the panel, were contacted for their views. Care was taken to coordinate with the other Task Groups (Supply and Demand) through liaison members. This liaison approach was also followed with the important ad hoc groups, such as Arctic Gas and LNG Imports. Government representatives included participation by representatives from the U.S. Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC), and the Energy Information Administration.

This analysis relied upon supply and demand data provided by the other Task Groups as well as data from the Energy Information Administration, the American Gas Association (AGA), the Interstate Natural Gas Association of America (INGAA), and other industry associations. NPC member companies also provided data. Early in the study, the T&D Task Group determined and set the major exogenous variables required for the analysis. Examples of these determinations included: selecting pipeline capacity expansions and newbuilds within the first five years; setting the "lag" or delay between a price signal and the construction of a required pipeline developed subsequent to the first five years; determining the cost differentials for construction (pipeline, storage, and distribution) by region; and estimating the amount of storage required for human needs (residential/small commercial) services.

With regard to the issues facing the T&D Task Group, EEA's Gas Market Data and Forecasting System model makes economically justified decisions to route natural gas, expand pipeline capacities, and construct new storage facilities. The modeling software consists of a complex nodal (physical flow) structure, which is fundamentally based on unit pricing concepts. Decisions to flow gas through existing facilities and/or decisions to build pipelines between nodes, add incremental storage facilities, build additional facilities at the citygate, etc., are "calculated" in the model on a year-by-year basis. The network used in the model incorporates 115 supply/demand nodes and 317 transportation corridors (see Figure 5-1). The model will always attempt to use existing facilities to their maximum, while at the same time looking for pricing signals that would support facilities expansion either to existing facilities or with greenfield projects.

Model output was then carefully reviewed by the T&D Task Group to search for and correct any anomalies. Once the results of the major scenarios (Reactive Path and Balanced Future) were approved, sensitivities

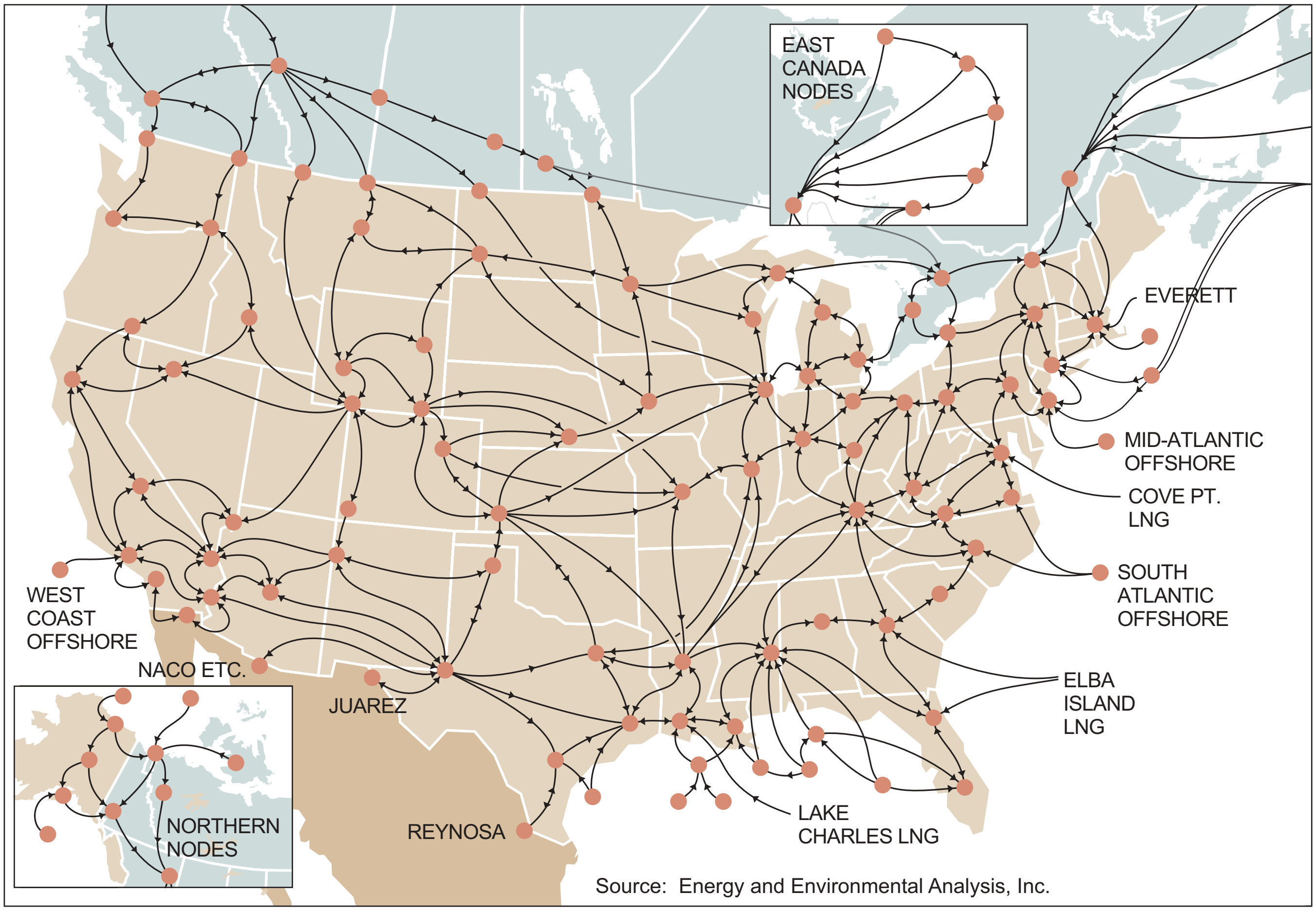


Figure 5-1. Supply/Demand Nodes and Transportation Corridors

of the Supply and Demand Task Groups (which result in differing data inputs to the T&D model) were also reviewed for their impact on T&D results. In addition, the T&D Task Group chose to evaluate its own sensitivities to validate certain stresses upon North American infrastructure.

Summary of Results

The study shows that continued expansion of gas transmission, storage, and distribution facilities will be required to meet the future needs of gas consumers and suppliers, but there remains a critical dependency on the existing natural gas infrastructure. Needed expansions or enhancements include increasing the capacity of existing infrastructure, developing pipeline laterals connecting new supply, storage, and generation facilities, expanding of distribution networks, and building multi-billion dollar pipelines that link Arctic supply regions to the North American grid.

Two scenarios and multiple sensitivities were analyzed with respect to the timing and location of new major supply sources as well as cases related to demand reduction. A status quo approach to natural gas policy yields undesirable outcomes because it discourages economic fuel choice, new supplies from traditional basins and Alaska, and new liquefied natural gas (LNG) terminal capacity. The NPC developed two scenarios of future supply and demand that move beyond the status quo. The two scenarios were the Reactive Path and the Balanced Future. The Reactive Path scenario assumes continued conflict between natural gas supply and demand policies that support natural gas use, but tend to discourage supply development. This scenario results in continued tightness in supply and demand, leading to higher natural gas prices and price volatility over the study period. The Balanced Future scenario builds in the effects of supportive policies for supply development and allows greater flexibility in fuel-switching and fuel choice. This results in a more favorable balance between supply and demand, price projections more in line with alternate fuels, and lower prices for consumers.

The major results for the Balanced Future are summarized below. These results will be compared to the Reactive Path in the Scenarios and Sensitivities section of this chapter.

Pipeline and distribution investments will average $8 billion per year, with an increasing share required to sustain the reliability of existing infrastructure.

- **Transmission.** Estimated expenditures for new North American transmission pipelines, including sustaining capital, are $2.7 billion/year (2002 dollars) over the study period, from 2004 to 2025. This compares to $3.5 billion/year expended between 1996 and 1999.

  While capital for new infrastructure declines in the projection, especially in the later years, sustaining capital increases and becomes a greater percentage of total capital requirements. This is a result of investments for continuing compliance with the Pipeline Safety Improvement Act and the fact that increasing investments are required for an aging infrastructure to assure its safe and reliable operations.

- **Distribution.** Estimated expenditures for new North American distribution pipelines, including sustaining capital, are $5.3 billion/year (2002 dollars) over the study period, from 2004 to 2025. This approximates to amounts expended between 1996 and 1999. The successful development of this distribution system infrastructure will depend on several key factors, including:
  - Obtaining inter-agency coordination and regulatory certainty in all permitting processes
  - Obtaining access to expansion capital
  - Maintaining the historical levels of reliability and flexibility of natural gas services as gas demand grows and load patterns change
  - Developing mechanisms to foster research and development.

- **Storage.** Estimated expenditures for new North American storage facilities, including sustaining capital are $0.4 billion/year (2002 dollars) over the study period, from 2004 to 2025. This is slightly higher than that expended between 1996 and 1999. It is important to note that these estimates do not include the cost of base gas, which is projected to be one of the largest components of future storage expenditures. Other observations related to storage infrastructure are:
  - Projected growth in weather-sensitive demand will require up to 700 billion cubic feet (BCF) of additional working gas capacity by 2025.
  - Given that the geologic base for potential storage capacity is highly exploited, new storage facilities may be located further from the markets they serve and may be increasingly expensive to develop.
  - A return to normal weather (30-year average) would require overall storage utilization rates above those experienced in the 4 years prior to December 2002.
  - Demand for gas storage can be as much as 25% higher than normal in a year in which winter weather is significantly colder than normal. North American storage capacity has not been tested by such a winter for many years and, as such, it is likely that current storage capacity will be severely challenged to meet such demands.

Figures 5-2 and 5-3 show capital expenditures for North America. As can be seen, there is significant volatility in the amount spent on transmission facilities, but expenditures generally decline in the outer years. In addition, as the established infrastructure ages, a significant portion of the ongoing transmission expenditures are used to sustain existing capacity. From 2000 to 2002, sustaining capital is estimated as 21% of total transmission expenditures. By 2020 to 2022, sustaining capital will increase to almost 75%. Sustaining capital for transmission, distribution, and storage is estimated as 21% of total expenditures for 2000-2002. By 2020, sustaining capital for the three segments is projected to be 45% of total expenditures.

Sustaining capital for transmission was calculated on the basis of replacing 700 miles of pipe and 77,000 horsepower of compression each year. This is viewed as a conservative estimate because it is a small fraction of the existing 290,000 miles of pipe and 16,000,000 horsepower of compression, much of which is over 40 years old. For instance, if we assumed a 50-year life for pipelines, then the appropriate replacement rate for pipe would be over 5,800 miles per year. The basis for using the lower number is that it better matches the historical level of replacement. Because of the impacts

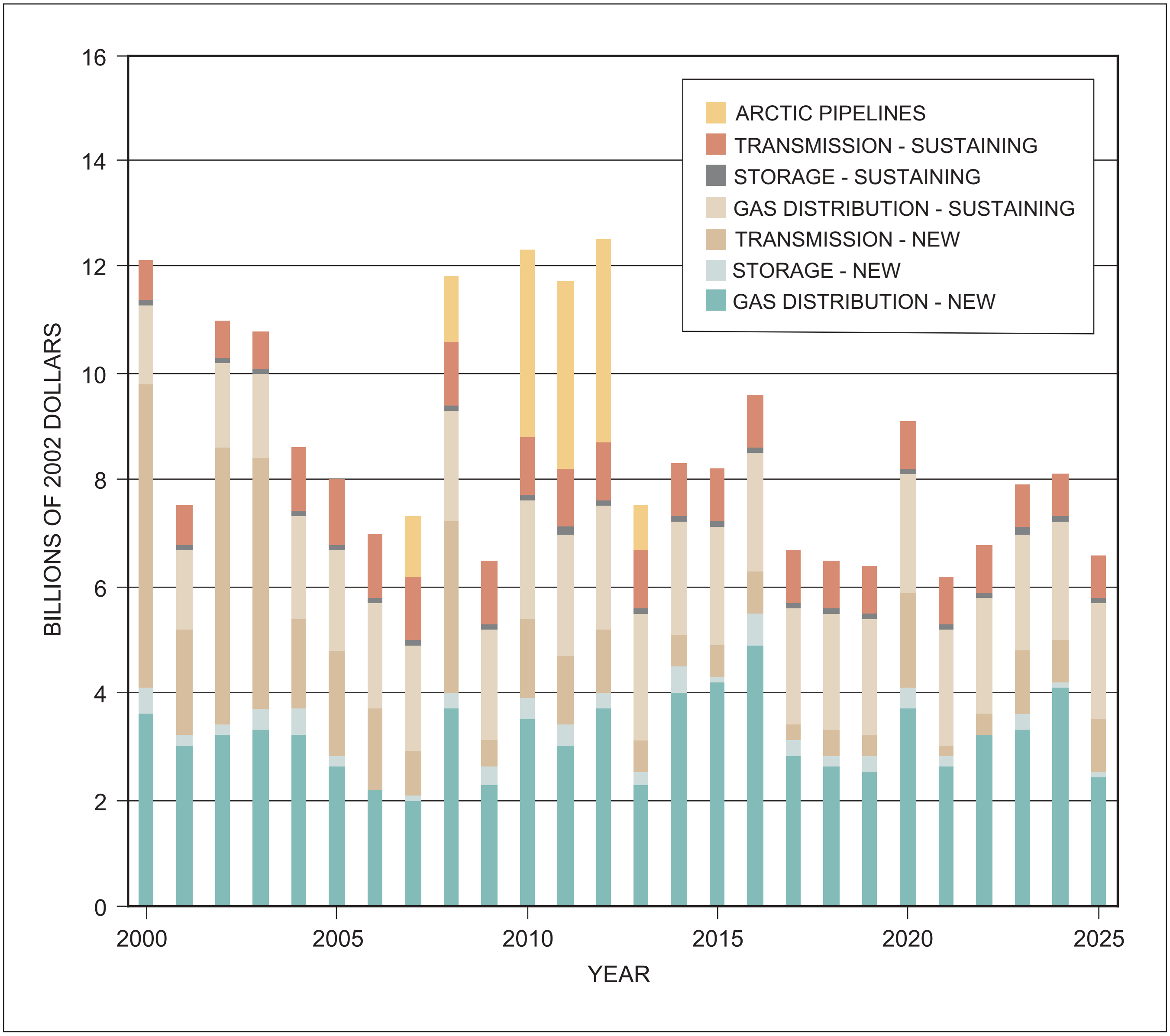


Figure 5-2. Detailed North America Capital Expenditures for Transmission, Distribution, and Storage in Balanced Future Scenario

of the Pipeline Safety Improvement Act of 2000, however, we doubled the historical levels for the purposes of the study. At some point in the future, the progressive aging of pipelines and compressors will result in a further significant increases in the miles of pipe and horsepower replaced per year.

Regulatory barriers to long-term contracts for transportation and storage impair infrastructure investment.

Pipeline and storage infrastructure developments have generally been financially supported by contracts with a term of ten to twenty years. In a free market, shippers make long-term contract commitments when they see the need for the service that will be provided. Recently, the average transportation contract term for new/proposed and existing pipeline and storage infrastructure has trended shorter. Much of the trend is the result of market choices, while some is caused by the impact of regulatory policies which may create barriers to choice. When such barriers exist to shippers making long-term commitments, investment in pipeline and storage infrastructure is impacted, as the related rev-

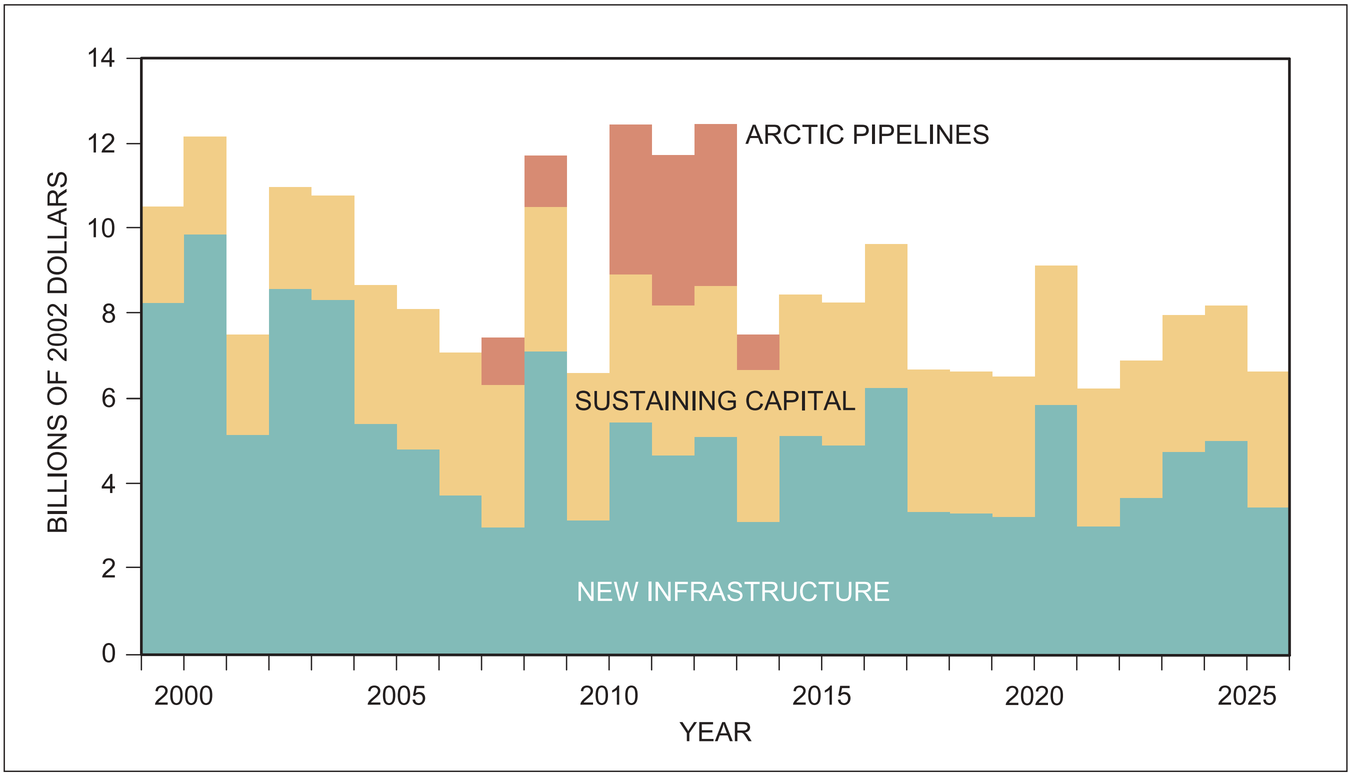


Figure 5-3. Total North American Capital Expenditures for Transmission, Distribution, and Storage in Balanced Future Scenario

enue stream is viewed as more short-term in nature and less likely to support long-term infrastructure investment.

Transmission

The United States' pipeline transmission infrastructure has been developed over a period of eight decades and has provided the nation with reliable access to North American natural gas supply. The infrastructure grew rapidly in World War II to meet the needs of the burgeoning wartime economy and continued its growth during the industrial economic expansion of the 1950s and 1960s. In the 1970s, the pipeline transmission system grew from 255,000 miles to 266,000 miles and expenditures averaged $2.7 billion per year. Despite the negative impacts of a faltering economy and price deregulation, the transmission system grew further in the early 1980s to 271,000 miles.

U.S. natural gas consumption has grown significantly from its low point in 1986, rising from 16.2 trillion cubic feet (TCF) (44.4 BCF/D) to an estimated 22.6 TCF (61.4 BCF/D) in 2001.[1] During this period, the dominant growth sector was electric generation, including industrial combined heat and power, and the gas transmission grid in the U.S. grew from 281,000 miles to 285,000 miles.[2] The U.S. grid is a significant part of the North American grid of large-diameter pipelines, which is shown in Figure 5-4.

Despite the large amount of pipeline transmission growth, there have still been periods in which the demand for capacity has exceeded its supply. These constraints have resulted in increased price differentials between upstream supply regions and downstream markets. For example, Western Canadian prices were significantly below those of the downstream markets during the 1990s, with price differentials sometimes rising above $1.25 per million Btu (MMBtu). As a result, capacity was added.

The California supply/demand imbalance during 2000 and 2001 also led to multiple pipeline construction projects including expansions on the Transwestern, El Paso, and Kern River pipelines and the conversion of Southern Trails Pipeline from oil to gas

1 Energy Information Administration, Natural Gas Annual, Table 6.5, Natural Gas Consumption by Sector, 1949-2001.

2 Department of Transportation RSPA 7100.2-1.

Figure 5-4. North American Pipeline Grid (24" Diameter and Greater)

service. In aggregate, these projects brought over 1.3 BCF/D of new capacity to California.

The one U.S. region that has experienced an ongoing capacity shortfall is the Rocky Mountain supply area. In response, a number of new export projects have recently been proposed for the region, including Advantage, Western Frontier, Front Range, Cheyenne Plains, Bison, Southern Trails, TransColorado/Silver Canyon, Powder River Basin North, Northwest Pipeline Rockies Expansion, and Ruby. Periodic constraints appear to be the result of a rapid growth in supply that surged ahead of potential shippers' commitments to the long-term pipeline contracts required to facilitate new pipeline construction. Market participants will decide which of the projects will move forward and when.

Results from the Study

In the United States, pipeline capacity utilization factors in the Reactive Path scenario are projected to undergo significant changes during the 22-year forecast period:

- The Midcontinent production region (Oklahoma/Kansas) has some of the largest changes in capacity factors, with usage factors on pipelines running from the Midcontinent to the Midwest market region dropping from 94% in 2000 to 54% in 2025.
- The Texas intrastate market sees major flow realignment, with capacity factors on pipelines running from the Permian Basin to East Texas, dropping from 81% at the start of the period to 7%. If Mexican production fails to grow at the rate forecast by SENER, then the steady growth in demand projected over the period may cause U.S. exports to Mexico to increase rather than decrease.
- Capacity factors from Northern Louisiana to the Midwest market areas drop from 75% to 57% as Arctic supply and/or Canadian supply replaces Gulf Coast gas in the Midwestern energy markets in the latter part of the study period. There is also some potential reduction in utilization factors in pipelines moving gas from the Gulf Coast to the Mid-Atlantic, assuming LNG landed in East Coast market centers helps to serve demand growth in that region as well as create additional upstream delivery capability through existing pipeline resources.
- The one supply region showing little excess capacity is the Rocky Mountains. This region shows significant production growth over the study period, growing from 4.4 BCF/D in 2000 to 9.2 BCF/D in 2018 before experiencing a slow decline to 8.7 BCF/D in 2025. As a result of the increase in transmission capacity prior to 2018 and a subsequent decline in production, capacity factors on pipelines leading east of the region have a capacity utilization rate lower in 2025 than in 2000. The capacity factors on pipelines leading to California, however, are above 93% for the entire period.
- In Canada, Western Canada Sedimentary Basin production peaks at 17.9 BCF/D in 2005. Capacity utilization to eastern Canada drops from approximately 94% in 2000 to 81% in 2025. Production in the Maritimes area of eastern Canada rises to 1.3 BCF/D in 2011, undergoes a gentle decline to approximately 1.0 BCF/D in 2019, and then rises once again to 2.2 BCF/D in 2025.
- The Balanced Future scenario also features increased supply access to the Rocky Mountain and Outer Continental Shelf regions. As a result, flow patterns change from those in the Reactive Path. For example, the Midcontinent to Midwest capacity factor is 74% in 2025 in the Balanced Future versus 54% in the Reactive Path. Other notable changes in the Balanced Future include over 1.5 BCF/D of production from the Atlantic offshore that flows into East Coast markets, a drop in capacity factors from Canada to the Pacific Northwest from 70-80% to 50-60%, and a drop in west-to-east Canadian long-haul utilization of 81% to 73%.

Pipeline capacity must also be constructed to transport gas from storage fields to high consumption centers. This is particularly true for storage developed to serve the Mid-Atlantic and New England markets. As noted in the Storage section of this chapter, these two regions will require an additional 135 BCF of working gas storage by 2025. Because the nearest suitable and undeveloped reservoirs exist in the western portions of Pennsylvania and New York, eastern Ohio, and Ontario, incremental pipeline capacity of approximately 2.0 BCF/D will have to be constructed to link new storage capacity to the coastal market centers, which include New York City, Boston, and Philadelphia. The incremental pipeline capacity required by 2025 is shown in Figure 5-5.

Future Environment

In describing throughput trends, it is illustrative to examine the balance of flows into major market regions. For this purpose, a major market region is

Figure 5-5. New Pipeline and LNG Capacity Change from 2003 to 2025 in Balanced Future Scenario (Million Cubic Feet Per Day)

defined as one in which consumption exceeds production (New England, Northeast, Mid-Atlantic, South Atlantic, Florida, East South Central, Midwest, Upper Midwest, West North Central, Pacific Northwest, and California).

Between 2000 and 2010, there is an aggregate net consumption growth (consumption minus intra-regional production) of 4.5 BCF/D in the primary market regions. Incremental LNG deliveries into these market regions are projected to account for 3.3 BCF/D of this increased demand. As such, only 1.2 BCF/D of additional long-haul deliveries are needed from net supply to net consumption regions.

Between 2010 and 2020, lower-48 consumption in the major market regions has a further increase of 3.6 BCF/D. In this period, LNG imports into net market areas is projected to increase by 1.5 BCF/D, resulting in a need to increase long-haul transport from traditional supply regions such as the Gulf of Mexico. From 2020 to 2025, net demand in major market regions is projected to remain stable. During this period, the net market area increase in consumption is exceeded by projected increases in LNG deliveries. Thus, no additional long-haul capacity development is required.

In Canada, net consumption growth in the major market regions (defined as regions where demand exceeds supply, namely Ontario, Quebec, and Manitoba) is 0.36 BCF/D from 2000 to 2010, or 1.0% per year. Between 2010 and 2020, growth is again projected to be 1.0% per year or 0.40 BCF/D. From 2020 to 2025, the net consumption is projected to decline slightly. Over the study period, there will be no growth in long-haul capacity to eastern Canada as demand growth will be met through enhancement and utilization of existing pipelines.

The projected changes in flows across the major North American pipeline corridors are displayed in Figure 5-6 (2004 to 2010) and Figure 5-7 (2010 to 2020), which are both taken from the Balanced Future scenario. As a result of the decreasing supply in the mature regions of the United States, pipelines connected to these areas will see a gradual decline in throughput. This should be particularly true for the southern sections of pipelines serving the West Texas/Permian Basin to Midwest corridor. The middle/northern sections of these systems (i.e., Kansas, Nebraska, etc.) will be re-supplied, however, by growing Rocky Mountain production fed eastward via new pipelines, such as the completed Trailblazer expansion, the Cheyenne Plains project, the Advantage proposal, and the Western Frontier proposal.

A significant source of new supply is LNG imports, which rise from less than 0.6 BCF/D in 2000 to almost 6 BCF/D in 2010 and then to 12-15 BCF/D by 2025. When located on the Gulf Coast, these supplies help to maintain throughput in pipelines originating from the Gulf Coast. When located directly in market regions, these facilities will access demand typically with only short-haul infrastructure expansion required. LNG received in the market regions also has the effect of increasing upstream pipeline delivery capability, as gas that previously used the long-haul path will be displaced to potential upstream markets by the LNG received downstream.

As mentioned above, production from the Western Canada Sedimentary Basin peaks in 2005 and then undergoes a long-term decline to 2025, when production drops to 14.3 BCF/D. Part of the production decline is replaced by Arctic gas from Mackenzie Delta and Alaska. The first flow from Mackenzie Delta into Alberta is expected in 2009 at 1.0 BCF/D, increasing to 1.5 BCF/D in 2016. The Alaska production is projected to begin in 2013 at 2.5 BCF/D and then increase in 2014 to 4.0 BCF/D for the remainder of the forecast period. The combined Arctic flow more than offsets the projected decline in western Canadian production in the early part of the study. To accommodate these changes in supply, however, major new pipeline systems will need to be constructed from the frontier regions to interface with existing pipeline infrastructure in northern Alberta.

Additional pipeline capacity will also be required to export Alaskan gas from Alberta to U.S. and Canadian markets. Options for transporting this gas include using existing capacity spared by a decline in Western Canada Sedimentary Basin production, expanding existing pipelines, and constructing new pipelines. The NPC analysis suggests that an additional 0.5 to 2.0 BCF/D of new or expansion capacity may be needed to move the gas from Alberta to downstream markets. The amount of export capacity is very sensitive to changes in the western Canadian supply/demand balances and could change significantly by the time investment decisions are made regarding Alaskan gas.

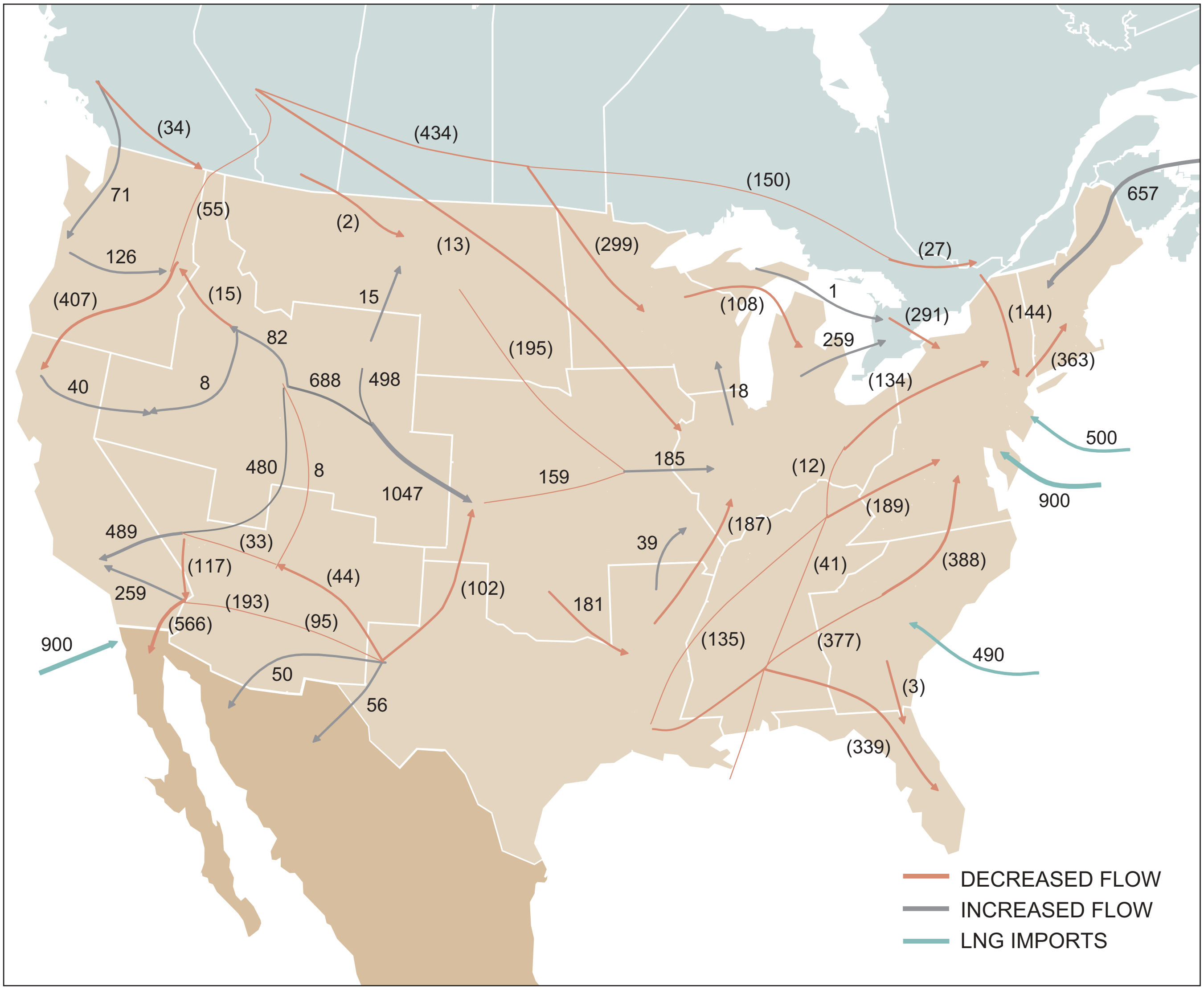


Figure 5-6. Flow Change from 2004 to 2010 in Balanced Future Scenario (Million Cubic Feet per Day)

Future development costs for long-haul pipeline infrastructure and for connection to new storage and powerplant facilities are forecast to be slightly below historical levels. The cost to construct the new North American pipeline facilities is expected to average $2.0 billion/year (2002 dollars) over the period to 2025. The projected investments are somewhat front-loaded, with the average for the years 2003 to 2010 expected to be almost $2.3 billion/year. These capital expenditure levels compare to an investment rate of $3.5 billion/year, which occurred between 1996 and 1999. The expected decline in the rate of capacity development results from several factors, including a substantial increase in LNG imports delivered to major market centers and the flow of new supplies into existing pipelines that currently have or are forecast to have spare capacity. Both of these actions promote efficiency by maximizing utilization of existing infrastructure while minimizing the need for new construction.

Scenarios and Sensitivities

The two scenarios generated results that were very close in terms of total North American transmission pipeline miles constructed and expenditures. The Reactive Path projection had 41,200 miles of interstate pipeline constructed over the 2003 to 2025 period at a cost of $1.98 billion/year. In the Balanced Future forecast, the analogous numbers were 43,500 miles and $2.02 billion/year. These cost projections in both scenarios are below actual expenditures for the last decade, which indicates interstate pipeline development should not be a limiting factor in achieving the necessary supply/ demand balance.

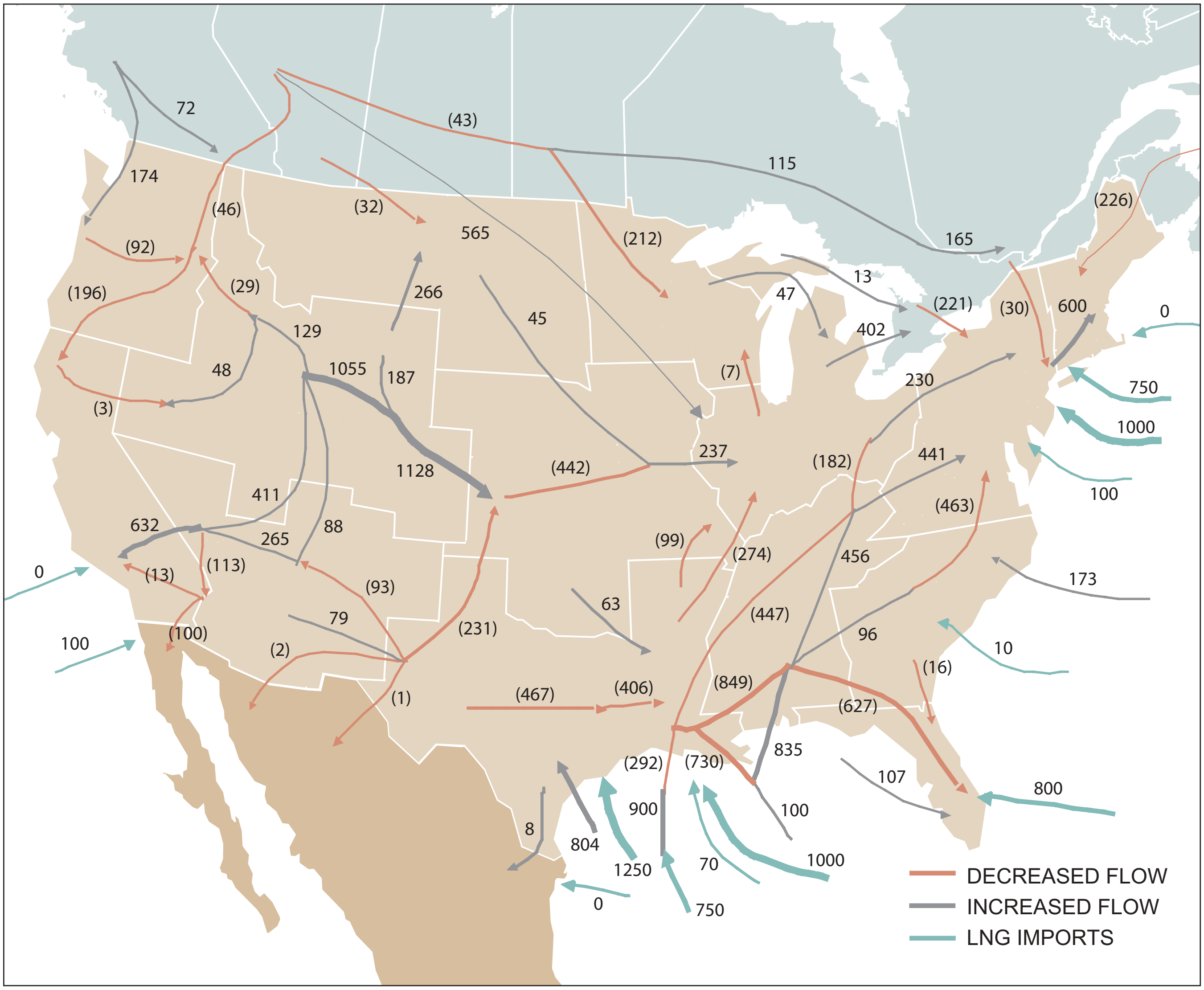


Figure 5-7. Flow Change from 2010 to 2020 in Balanced Future Scenario (Million Cubic Feet per Day)

The location of the infrastructure costs varied between the two scenarios, however, with more of the Balanced Future's expenditures occurring in the United States versus Canada. The Balanced Future shows a decline in infrastructure requirements for both eastern and western Canada due to increased production from U.S. areas currently limited by access restrictions. Since the Balanced Future postulates improved access to U.S. domestic resources, more infrastructure is required in the United States. Spending in the United States is thus \$77 million per year higher in the Balanced Future while Canadian expenditures decline by \$37 million per year.

An important sensitivity is the one in which new LNG import facilities are not approved for construction in the Mid-Atlantic and Northeast regions, causing that LNG to be landed at sites within the Gulf of Mexico. Although no new transmission capacity is required for the Reactive Path, incremental pipeline capacity of approximately 0.3 BCF/D must be built from the Gulf Coast to Florida markets in the Balanced Future to accommodate the incremental LNG proposed in that scenario. Although little incremental infrastructure is required, this sensitivity results in higher prices in the Mid-Atlantic and Northeast markets due to a tighter supply/demand balance and pipeline capacity constraints. According to the results of the sensitivity analysis, the delivered costs to New York City are about \$0.07/MMBtu higher by 2010. The variance between the two scenarios widens to \$0.30/MMBtu in 2015 and to \$0.44 in 2025. The analysis quantifies the higher gas prices associated with not allowing facilities to be built in the region that consumes approximately 8.6 BCF/D or 14% of the current U.S. total. For instance, for a consumption of 8.6 BCF/D, the difference in delivered prices of $0.30/MMBtu in 2015 results in an increased energy cost of $942 million for that year alone.

Another significant impact to gas transmission requirements occurs in the Cold Weather sensitivity. In this forecast, one of the coldest 23-year sequences of weather over the last 70 years was used to determine winter demand. The years used in the forecast were 1956 to 1978, with the temperature patterns in 1956 shifted to 2003, 1957 to 2004, etc. The average price over the full 23-year projection was little changed as the temperature average for the period was only 3% lower than the temperature pattern used in the Reactive Path and Balanced Future scenarios. The standard deviation of the price, however, was much higher, as the 23-year forecast had episodes of weather that were much colder than normal. Thus, the standard deviation of the average price for the Reactive Path was $0.69/MMBtu whereas the standard deviation for the Cold Weather sensitivity was $0.98/MMBtu. The $0.29/MMBtu variation is sufficient to support the development of additional transmission or storage infrastructure. The effect of colder than normal or warmer than normal weather on annual prices is shown in Figure 5-8.

Challenges to Building and Maintaining the Required Transmission Infrastructure

Contracting Challenges

During the first seven decades of its history, the natural gas transmission industry's development was underpinned by long-term contracts held by local distribution companies (LDCs). The LDCs ensured the financial integrity of pipeline infrastructure by signing 20-year contracts under which pipelines were responsible for the bundled purchase and delivery of the gas to the LDC citygate.

This integral relationship between the transmission and LDC industries began to change in 1983 with FERC's issuance of Order No. 380, which allowed LDCs to modify their existing gas purchase obligations with pipelines. Further changes occurred in 1986 when FERC, in Order No. 436, adopted open-access policies on interstate pipelines, which allowed "shippers" to use a pipeline's capacity to schedule the delivery and receipt of gas. In combination, these

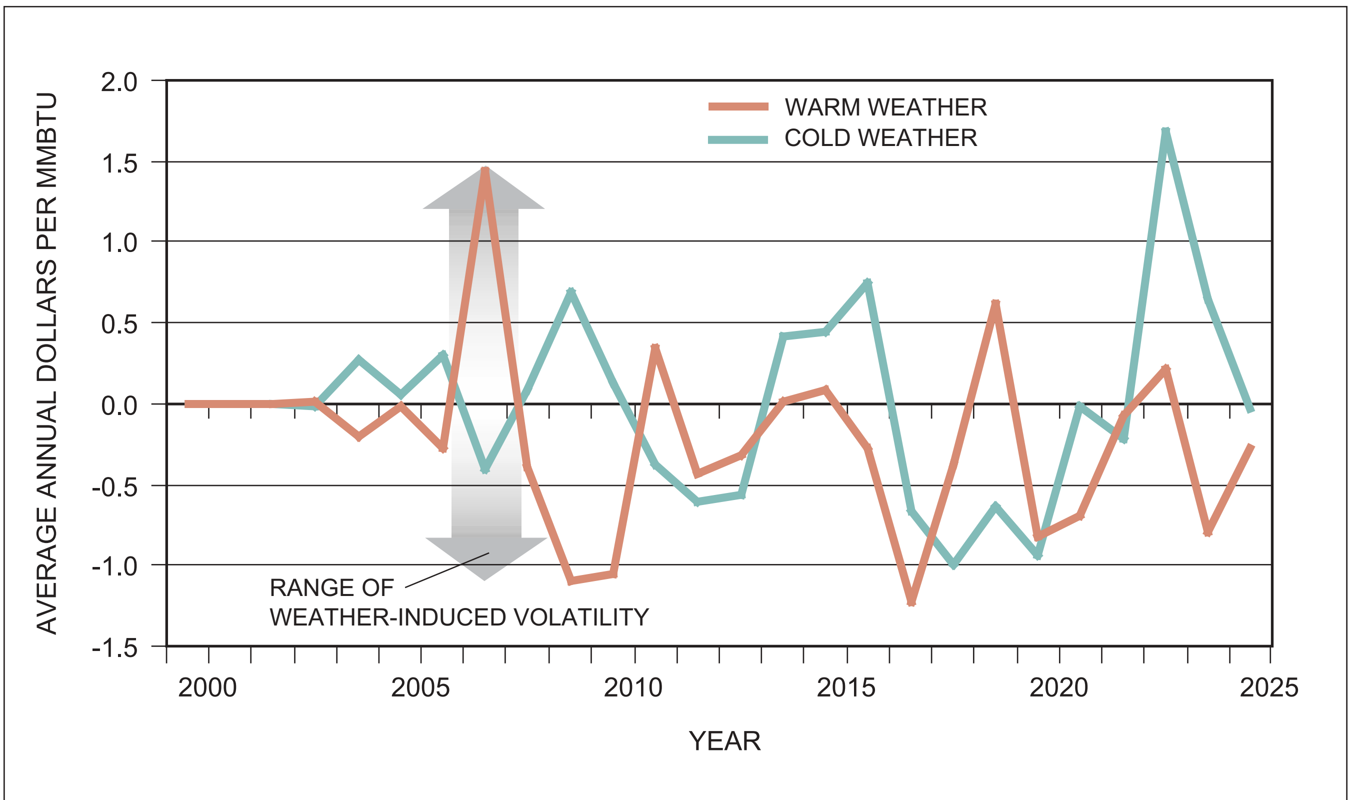


Figure 5-8. Weather Sensitivity Minus Balanced Future (at Henry Hub)

Orders gave other parties the ability to begin to compete directly with the pipelines for the gas merchant function.

FERC Order No. 636, adopted in 1992, further changed the competitive marketplace by essentially eliminating the historical pipeline gas sales function. As a result of this paradigm shift in future regulation, pipelines were limited to providing transportation and storage services only and could no longer buy or sell natural gas, except for limited operational reasons. This "unbundling" of the transportation and storage functions required each upstream supplier and downstream consumer to inherit the responsibility to arrange for the purchase or sale of gas on their own behalf. New tariffs were written and contracts were entered into for unbundled transportation and storage services. In addition, FERC required that a secondary market in transportation and storage services be allowed to develop, wherein shippers could "release" a portion of their contracted capacity to a creditworthy third party for their use, either on a short-term or long-term basis.

Soon thereafter, a new business segment of gas marketers evolved. By the end of the 1990s, marketers had significantly expanded their role to include a broad portfolio (through the capacity release process or otherwise) of pipeline transmission and storage capacity contracts as well as acting as a managing agent of such resources for others. In their role as managing agent, marketers' goals were to optimize the use of pipeline and storage assets held by their counter parties, such as LDCs and industrial users, generally reducing these parties' daily participation in the evolving market. In such business structures, LDCs and end-users "swapped" use and optimization of these assets for ongoing gas management and reduced risk. Correspondingly, marketers saw such arrangements as opportunity and potential upside, as they could use them in a variety of ways that the LDCs and end-users might not.

When LDCs and other major consumers began purchasing gas supplies from marketers, their contracts were generally chosen to be of short duration, i.e., 1-3 years. In such a scenario, marketers often mirrored their risk, becoming short-term holders of pipeline capacity as a means of matching their overall contractual exposures. Some marketers did, however, subscribe to longer-term contracts to facilitate the construction of new infrastructure.

In this unbundled interstate pipeline world, the next market evolution was the unbundling in the 1990s of the sales and transportation functions of many LDCs. This unbundling of LDC services was mandated by some state public utility commissions (PUCs) with the expectation that it would increase competition and lower prices to consumers behind the citygate. By the end of the 1990s, unbundling was complete in many states for the industrial gas and electric generation customers and was underway in some states in the residential and commercial sectors. One belief at many PUCs during this time was that unbundling LDCs, with the advent of competition, should no longer enter into long-term pipeline capacity contracts since their share of the future gas sales behind the citygate was uncertain. In fact, many LDCs were prohibited or discouraged from maintaining these contractual commitments.

During this period, producers became increasingly important as subscribers of new supply area pipeline capacity, especially capacity associated with greenfield developments (often referred to as a supply-push scenario). Where it made sense to commit to proposed infrastructure projects to assure their product was available to market, many producers have done such. The producer's goal was to ensure that they could reliably transport and sell their gas at a liquid, i.e., high volume, sales point where it could receive a market price that was not reduced by a capacity constraint.

Another subscriber to capacity during the 1990s was the marketing affiliate of interstate pipelines. Although the pipelines could no longer buy and sell gas themselves, they were allowed to have an affiliated company that did so. By the end of the 1990s, market affiliates of pipelines were subscribing to large amounts of capacity in new transmission projects, particularly where third parties weren't willing to do so. For newly constructed capacity, the FERC required such contracting with their affiliate to be under an "at-risk" condition to the pipeline when it chose to build on this somewhat speculative basis, i.e., without demonstrating long-term contracts from third parties for the proposed capacity.

Today, the recent turmoil in the gas-marketing sector has dramatically reduced the number of independent and affiliated marketers as prospective subscribers to existing and/or proposed pipeline transmission capacity. Even where such firms might want to contract for capacity, their current creditworthiness may make them too great a risk for pipelines to consider. With some LDCs still being discouraged or prohibited from entering into longer-term contracts by their PUCs, considerable uncertainty exists regarding the identity of the parties that will contract for unutilized capacity on existing pipelines or who will sign long-term capacity contracts for future pipeline projects.

Contracting New Capacity

As stated previously, a key concern for the pipeline transmission industry is the entity that will contract for new and existing pipeline capacity. To give a perspective, the Power Generation, Marketing, Production, and LDC sectors contracted for 91% of the firm transmission capacity subscribed in the United States as of December 2002. The percentage holdings of these sectors have, however, undergone a marked transformation over the last five years. The Marketing sector increased its share of total firm capacity from 13% to 24% over the period. With this business segment in turmoil over the last two years, this has exacerbated the uncertainty surrounding the identity of companies that will contract for firm transmission capacity in the future.

The Power Generation and Production sectors' pipeline capacity holdings grew at a smaller rate of 5 BCF/D and 2 BCF/D, respectively. The LDC and Industrial sectors, the most important segments of industry growth as recently as ten years ago, were essentially unchanged over the interval.

The LDC sector holds the largest amount of firm capacity of all the sectors discussed. Between 1998 and 2002, LDC firm capacity remained constant at 50 BCF/D. The key issue faced by the distribution and transmission industries is the recontracting of existing LDC contracts for firm pipeline capacity. During the next five years, 71% of all LDC firm capacity expires. As a result of the large amount of contract expirations, LDCs are viewed as unlikely to contract significant amounts of new firm transportation capacity, especially given the current reluctance of some PUCs to allow them to enter into long-term contracts.

Another marked change within the industry relates to the expiration profile of firm transportation contracts. At year-end 2002, 77 BCF/D or 64% of the total firm transportation contracts were set to expire within the following five years. In 1998, the comparable amount was 51%. The 13% increase in expirations between the two five-year periods again indicates a continuing movement to shorter-term commitments. The result is that regulatory practices (prudence reviews and ratemaking) may be inhibiting efficient markets and discouraging the financial incentives to develop and maintain pipeline infrastructure. This information is graphically displayed in Figure 5-9.

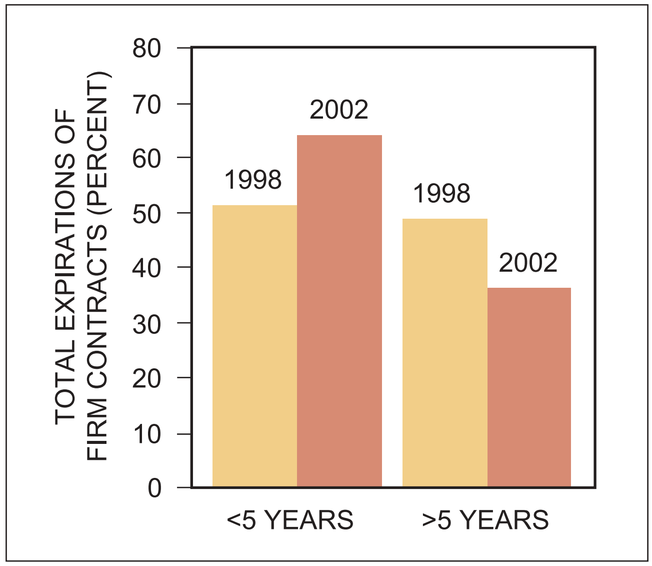


Figure 5-9. Firm Contract Expirations

Given the importance of the Power sector to the growth projections in this study, it is worthwhile to focus on that sector in more detail. The gas-fired power generation capacity increased approximately 128,000 megawatts from 1998 to 2002. This generation consisted of combined-cycle gas turbine (CCGT) installations that generally are intermediate dispatch and tend to operate more than their gas turbine counterparts, which are generally used for hourly electric peaks. If this generation capacity were to have been completely utilized, a significant amount of daily gas transmission capacity would have been required for supply to the plants. In a survey of nationwide contracts, however, firm gas transmission capacity for power generators increased by 13 BCF/D, indicating that participants in this sector chose to contract for less than 100% firm transportation capacity, determining that was within a manageable level of need and risk/exposure. From the survey, the expiration profile of the Power sector's gas transmission capacity is distributed across the next 20 years. However, the contracts are skewed in 2003 as the Marketers' tended to source numerous of these facilities, i.e., their short-term contracting orientation/strategy, as can be seen in Figure 5-10.

It is important to note that approximately 190,000 megawatts (57%) of gas power generation capacity at year-end 2002 relies on non-firm gas transmission capacity. These were market choices, as operators of these facilities have assumed the risk of service interruption by not securing firm contracts. Possible implications are as follows:

- As the utilization rate for these generation plants increases and surplus pipeline capacity declines, gas accessibility using interruptible pipeline capacity will become increasingly problematic.

- During the summer season, increasing power utilization will often conflict with traditional gas storage injections and will strain the pipeline and storage system resources. For example, gas injections may be pushed into only the evening hours and/or more injections may be required earlier or later in the summer season, i.e., in the shoulder months of April, May, and October.

- The current fleet of gas-fired generation – many of which do not have fuel flexibility to consider alternate fuels – and future power development facilities may not be able to depend on immediately available surplus pipeline capacity.

Fortunately, the natural gas industry has time to respond to any increased pipeline transmission requirements. The recent, rapid buildup of gas-fired generation has increased generation reserve margins above the required levels in most regions such that little new generation construction is likely to occur over the next few years. Under projected power demand growth in this study, the levels of throughput on long-haul pipelines should increase over time as generators are increasingly utilized, but the full potential of their demand and the need for new supporting pipeline infrastructure should not be felt until after 2008.

For a major pipeline expansion or a new project, the maximum pipeline tariff or transportation rate is normally, but not necessarily, calculated using an annualized cost component and contract volumes. Thus, the applicable tariff rate is frequently the same in a low-demand month (April) as a high-demand month (January). This non-varying cost for firm transport, when combined with large swings in seasonal market demand, can result in large variations in capacity utilization, citygate prices, and the realized market value of pipeline capacity.

This seasonal variability in the realized market values of pipeline capacity may increase its worth. The

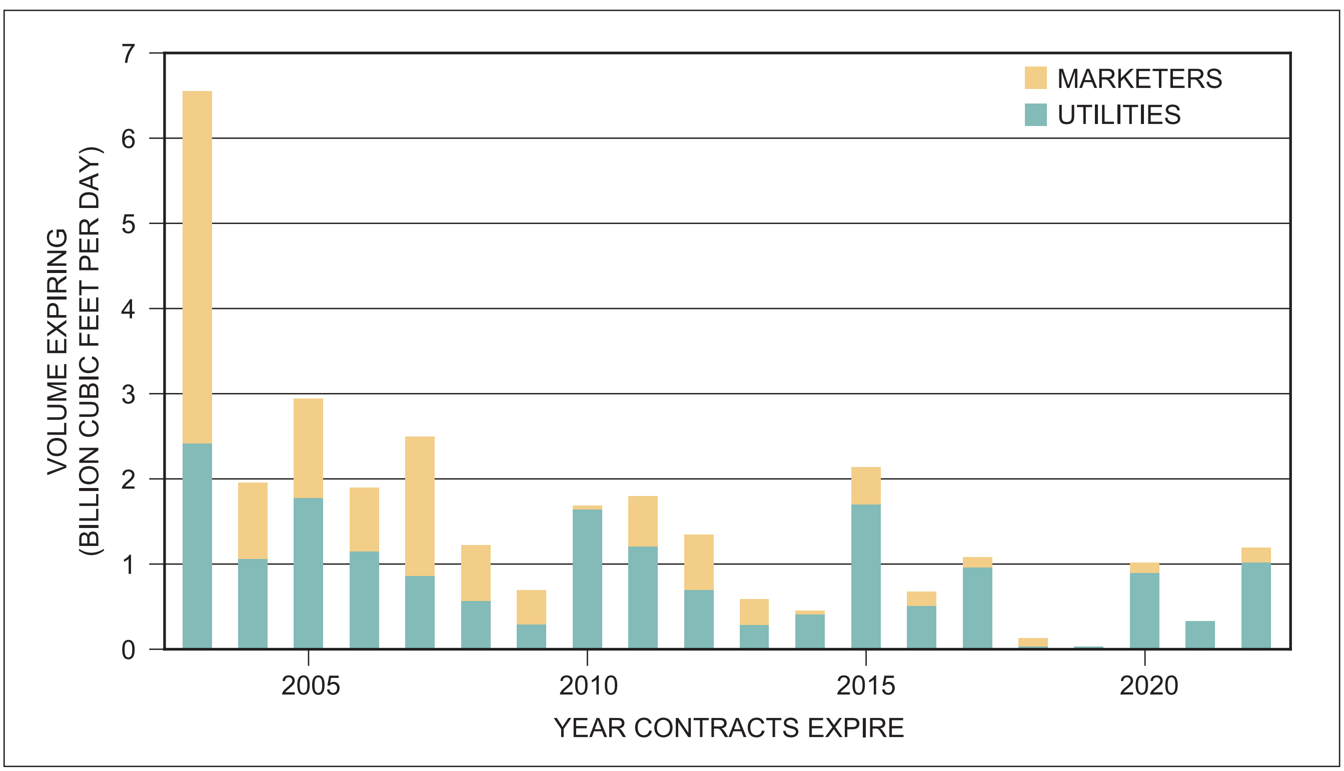


Figure 5-10. Firm Contract Expiration by Year and by Shipper Class

increased worth results from having the downside risk of holding capacity capped at the rate paid for the capacity while the upside value is not limited in today's market. Since the firm shipper has bought the right to call on the capacity at any time, the combination (capped costs, assured access, uncapped sales prices, and observed price volatility) creates a potentially valuable option. Because gas prices are volatile, the same relationship holds true for monthly and daily time intervals. In all three cases, the holder of transportation capacity has asymmetric risk with a fixed downside exposure and an uncapped but highly uncertain upside potential. Some market participants would like to "hold" this option; others would not. This option also has value in the secondary market for transportation and storage capacity that has developed. However, this opportunity is troublesome for some LDCs where regulatory barriers exist that impede them from contracting for capacity to serve their customers.

The response time or "lag" between the occurrence of a price signal, i.e., an increased price differential between two points, and the time at which a proposed project can gain sufficient commitments to go forward can vary significantly between one project and another. In cases where a number of companies are in agreement that the basis is significant and lasting, the period between a project proposal and construction can be fairly short. In the case of the most recent Kern River Expansion, the developer held an open season in August 2000, filed for a FERC certificate in November 2000, made a final investment decision in March 2001, and was in commercial operations by May 2003.

One of the challenging problems in new pipeline project development is the fact that non-contracting parties on both ends of the pipeline system may ultimately benefit from new capacity construction because of the new infrastructure's impact on price and basis value. For example, all western Canadian producers benefited from the price increase that followed the development of the Alliance Pipeline, not just the producers who actually contracted for the capacity to Chicago. As is typical in a free market, there may be considerable jockeying among potential project shippers to contract for only the minimum (or no) amount of capacity while still having a pipeline project proceed. Pipelines, of course, must seek fairly large projects so that the benefits of scale can keep proposed costs and tariffs down. Since a perceived ideal position is to allow others to commit but to still be able to reap all or a portion of the benefits from the removal of a capacity constraint, gaining a critical mass of long-term commitments can be problematic for a pipeline developer. This is why some projects have multiple open-seasons, why competitive projects surface when previously announced projects appear to falter, and why some projects just don't proceed. This is typical of a market at work, but can be very frustrating for pipeline developers and parties who desire to see such projects implemented.

Similarly in market regions, new capacity projects are also problematic when important consuming sectors are either inhibited or not motivated to sign long-term firm contracts. Merchant power generators, for example, may choose to not subscribe to firm contracts for all or a portion of their supply, as these important gas consumers may not believe a 24-hour, 365-day pipeline service is required, or the insurance value associated with such capacity certainty is not cost effective.

Another customer sector that may be disinclined to subscribe to long-term pipeline contracts is the LDC. Since LDCs have been the anchor tenants for most of the pipeline capacity constructed over the last seven decades, continuing market evolution and resultant regulatory policies may have created barriers to long-term capacity contracts that have impeded infrastructure investment. Historically, with an obligation to serve human needs customers, LDCs have maintained a level of pipeline capacity to do such. In the unbundled environment today, certain service requirements are still mandated. Where applicable, regulatory bodies must ensure that providers of last resort (POLRs) or other entities providing service to human needs customers – whether gas or electricity – are allowed to make pipeline capacity commitments necessary for long-term service reliability.

Contractual commitments by various parties are critical to the expansion of the pipeline network. However, as different approaches to pipeline contracting are evolving in a changing gas marketplace, there appears to be a new paradigm evolving in contracting practices. First of all, contracts appear to be of shorter term. Second, it is becoming increasingly difficult for some pipelines to contract the middle portion of a transportation path. A producer may elect to contract for pipeline capacity only as far downstream as the first unconstrained point, while some LDCs, on the other hand, may chose, or must chose only, to contract for capacity from the citygate to the nearest upstream liquid market point. These points are usually located within a market area, which may be located hundreds of miles from a supply region.

This trend creates a bifurcation in the pipeline capacity market. This "gap in the middle" is an anomaly of the current natural gas marketplace; this dilemma will affect the decisions of pipeline operators concerning the creation of new capacity and sustaining the existing capacity levels between the supply and market regions. Left to itself, the natural gas industry will find equilibrium. Clearly, however, governmental policies should not inhibit the ability of LDCs and POLRs to extend their contracts into the supply regions.

Construction Challenges

Regulatory approval of new pipeline proposals involves agency reviews at the federal, state and local levels. Review levels and procedures by agencies vary significantly from state-to-state with the only common review level and approach occurring at the federal agency level. Examples of project review and approval durations range from 6 months to 42 months, depending upon the number of agency approvals and complexity of the project. FERC has been making great strides in improving the time for approval, but many times, the project is held up by some other agency even after FERC has issued a certificate. These delays in project approvals can be a significant driver of project cost increases. Also, as projects are increasingly delayed, prospective customers may begin to look for alternatives and ultimately terminate their agreements, with such withdrawals sometimes causing entire projects to collapse.

Previous discussions between the industry and the federal government on the difficulties in coordinating a pipeline project among the various federal agencies led to a memorandum of understanding (MOU) in 2002. This MOU established a framework for early cooperation and participation among "Participating Agencies" to enhance the coordination of the regulatory processes through which their environmental and historic preservation activities could occur. Review responsibilities under the National Environmental Policy Act of 1969 are met in connection with the FERC authorizations that are required to construct and operate interstate natural gas pipelines. Among the participating agencies are the U.S. Army Corps of Engineers, U.S. Forest Service, National Fisheries, Land and Minerals Management, U.S. Department of the Interior, U.S. Department of Transportation, Advisory Council on Historic Preservation, FERC, Council on Environmental Quality, and U.S. Environmental Protection Agency.

The National Environmental Policy Act requires federal agencies to evaluate the environmental impact of major federal actions significantly affecting the quality of the human environment. The MOU encourages early involvement with the public and relevant government agencies in project development to foster a process to facilitate the timely development of needed natural gas pipeline projects.

The chair of the White House Council on Environmental Quality has stated that the new procedure will improve coordination and speed up natural gas pipelines that currently encounter years of environmental reviews by various federal agencies. The extension and full integration of this type of coordination to the state level will also be required, however, before genuine progress can be made.

Further progress could be made by developing a Joint Agency Review Process that would coordinate activities between federal, state, and local agencies. A lead agency (perhaps FERC) could be assigned the authority to complete the review/approval in a timely manner, while meeting the concerns of all agencies and stakeholders. In order to be effective, this process should be the "governing" process, i.e., not to be further limited or delayed when approvals have been received to proceed from other responsible agencies. The areas of greatest concern in this regard are requirements of the U.S. Army Corps of Engineers, Coastal Zone Management Act, and Section 401 of the Clean Water Act, all of which could hinder the orderly implementation of FERC certificates. One example of this concern is the escalating use of the Coastal Zone Management Act to delay pipeline progress as exemplified by the serious delays currently experienced by the Millennium and Islander East Pipelines.

The recent FERC emphasis in the United States is to identify key stakeholders early and involve them in the process at the outset of a proposed project. An effective approval process allows third parties to become involved during designated comment periods. In these designated comment periods, external stakeholders, such as landowners or other special interest groups are given the opportunity to voice any concerns with the pipeline route. FERC is required to accept and reasonably address all stakeholder comments, and thus can ask the pipeline company to research and possibly resurvey each proposed route change, involving both civil and environmental surveys, which can result in significant project delays and unanticipated cost overruns. The Joint Agency Review Process would minimize these inefficiencies, as the process should, via significant upfront participation, agree upon a route or options thereto which can uniquely be investigated.

In addition to interventions in the approval process, delays can arise from stipulations in the approval with regard to construction issues, such as short time windows for laying pipe, work space limitations in certain areas, or mandated construction methods. The limited time periods or "construction windows" are frequently required by various state and federal agencies and can add significant costs and delays during construction of a pipeline project. These restrictions require careful planning of construction timing and implementation, and even then weather conditions or other unanticipated delays (labor, materials, etc.) during the construction window can make it difficult to complete the work during the allotted time period. If a project is delayed past the end of the construction window, then the operator may have to wait until the opening of the next window (and this could be up to a year following) to complete the project, often at substantial additional cost to the project.

Environmental agencies can also require pipeline companies to limit the width of pipeline construction rights-of-way to reduce tree clearing or other earth disturbances. In some of these cases, the pipeline must then be installed by stove-piping the pipeline at the location (welding one or two pipe joints at a time and then burying them as you go – a very tedious process) or by welding a portion of the pipe at a more accessible offsite location and hauling it along the right-of-way with large equipment called "side booms." These construction requirements due to work space limits will increase project costs substantially. These are, of course, further complicated and magnified if construction windows are involved.

Mandated construction techniques often occur when pipelines have to cross water bodies, wetland areas, or major roadways. Environmental agencies, either state or federal, can order the use of special techniques, which can include horizontal directional drilling, special top-soil separation, and use of wood mats in wetland soils. Horizontal directional drilling can add in the range of $200 to $1,000 per foot in additional costs to the length of pipe. Use of mats at wetland locations can add an additional $50 to $100 per foot to the pipeline costs in areas where they are used.

Environmental agencies can also require offsite "mitigation" in wetlands construction. The purchase of property for offsite mitigation can add substantial delays and costs to the project. In many cases, the agency will not sign off on construction approvals until the corresponding property identified for mitigation has been purchased. Delays occur since the pipeline company has to search for suitable acreage for mitigation, obtain necessary clearances for the mitigation site, and then complete the purchase of the land. With the high level of mitigation ratios (two to one is common and five to one occurs), as well as having to establish the mitigation site for long-term, pristine land use quality requirements, mitigation lands can be very expensive to purchase.

For some projects, development responsibilities can extend beyond the actual construction period with increasing requirements for ongoing monitoring and repairing the pipeline corridor. Environmental agencies are now requiring pipeline companies to develop and implement a long-term monitoring program to monitor, document, and correct/repair pipeline corridor restoration. This ongoing monitoring and repair program can add significant costs to the project depending upon environmental sensitivity of the lands, streams, and rivers crossed.

The typical project timeline for a major interstate pipeline project with an Environmental Assessment that is filed under a FERC 7 (c) certificate is normally 12 to 20 months from project initiation to the reception of the FERC authorization to construct. The typical project timeline for a FERC 7 (c) filing for a major project requiring an Environmental Impact Statement from project initiation to the FERC authorization to construct is 18 to 24 months.

Once permits are obtained and land is acquired, most U.S. pipeline construction projects are typically constructed in one calendar year or construction season. Projects that transverse through areas with issues such as endangered species, high population density areas, historic artifacts, noise mitigation, and safety concerns require 6 to 18 months beyond a more typical timeline. Proposed pipelines that impact areas with these types of concerns may require numerous reroutes in the planning process to obtain final public and regulatory support for permit approvals.

One clear trend in pipeline construction in both the United States and Canada is for the continuing escalation of costs. Costs have been increasing about 3 to 4% per year, above the projected 1.5% annual rate used in the study. The rising costs associated with new construction are a barrier to infrastructure development, but the modest nature of the cost increase is not expected to necessarily make required pipeline facilities projects uneconomic.

Operations and Maintenance of Existing Infrastructure

Operational Challenges

If all the flows entering and exiting a pipeline were constant in nature, then it would be a relatively easy system to operate. Operators could set the compressors along the system to calculated levels and the pipeline would be "balanced" thereafter. This is called a "static" system in engineering and unfortunately it is not reflective of events in the natural gas industry.

Instead, natural gas transmission pipelines are dynamic systems with conditions constantly varying at large numbers of receipt and delivery points. Existing natural gas wells experience mechanical problems, freeze offs, and production declines that change deliveries into the system. At the same time, new gas wells are added and consumers vary their demand according to temperatures, industrial processes, and electric generation needs. The throughput capacity of a system thus varies with the amounts of gas entering and exiting the system, the pressures at each inlet and exit point, and the locations of these supply and demand points, particularly with regard to compressor stations.

Within the dynamic system described above, there are three major consumption cycles that affect the transmission industry. The first is a seasonal variation of demand, from winter to summer. The second cycle is a demand variation within a season or a month. The last is the change in hourly consumption during a daily cycle.

The seasonal variation exists largely due to consumption within the residential and commercial demand segments. A large component of annual natural gas demand in the United States, approximately 36%, is for residential and commercial consumers. These consumers rely on natural gas for space heating, water heating, cooking, and other purposes. The first component, space heating, comprises approximately 70% of the residential and commercial load, or 25% of total U.S. annual consumption of natural gas. Consumption for space heating, however, is closely tied to the winter heating season. Thus, approximately 50% of natural gas consumption occurs during the five winter heating months, November through March. Figure 5-11 shows the strong seasonal cycle of natural gas consumption in the United States.

Given the strong variation in seasonal demand, the industry has found it economic to use storage fields to manage the large differences between winter and summer consumption. Storage is discussed in more detail later in this chapter, but traditionally, and in large part still today, gas is injected into the storage reservoirs in summer and withdrawn in winter. This allows pipelines and wellhead production to operate at a more consistent and more efficient annual level.

As part of the industry's drive for economic efficiency, transmission lines connected to market area storage fields (in California, the Midwest, and western Mid-Atlantic) have often been constructed for different capacity levels from the supply areas to the storage fields than from the storage fields to the markets. The segment from supply to storage is typically designed based on average-day levels while that from storage to the market is based on a peak-day requirement. This design recognizes that storage withdrawals must be incremental to flowing supply and could potentially inhibit long-haul transport from the supply regions unless capacity downstream (on the market side) of storage was increased.

This dual capacity system on the upstream (production) and downstream (market) sides of storage has worked well for many decades. The growing utilization of natural gas fired turbines in the electric generation market is raising concerns about the effect on the summer pipeline and storage capacity usage, however. As summer cooling demands continue to rise over the next 25 years, the increased call on pipeline transmission capacity during the summer by electric generation will reduce the industry's ability to inject proper seasonal volumes into storage. The resulting competition for capacity on pipeline segments designed for average-day use should therefore raise overall utilization factors (actual flow/designed capacity) and associated trans-

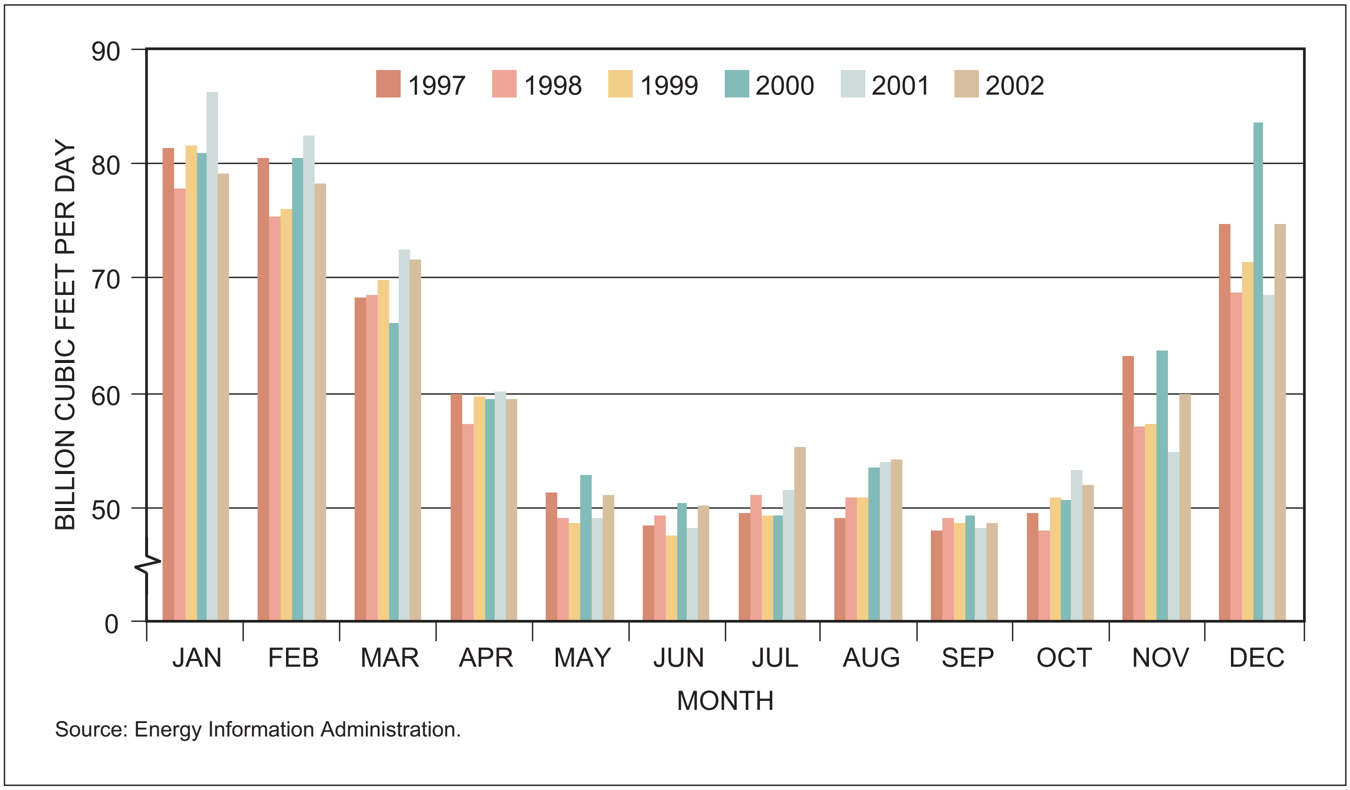


Figure 5-11. Monthly Consumption Data

mission revenues. However, there may be additional expense, e.g. compressor fuel, as the pipeline and storage infrastructure must be more dynamic and more time-of-day responsive.

One of the issues of increasing importance in the dynamics of the pipeline transmission system evolves from the intra-day market. The market demand during the course of the day can vary considerably due to residential, industrial, and electric generation consumption. Of these, the latter is of growing importance.

Demand from gas turbine electric generators is a significant and growing portion of the swing in the pipeline intra-day demand. Gas turbine and CCGT plants are significantly more efficient than the natural gas or oil fired steam generators they were designed to replace, with CCGT units having a heat rate of about 7,000 MMBtu per kilowatt hour versus 11,000 MMBtu per kilowatt hour for steam facilities. The lower heat rate therefore provides a more efficient electricity output. Based on this superior efficiency, CCGT plants will generally be chosen to produce (or dispatch) electricity before their steam-fired plant counterparts and will also stay online longer.

Though regions differ, this use of gas-fired facilities for electricity peaking can cause dramatic changes in natural gas consumption. A single 500-megawatt CCGT plant can burn 90,000 MMBtu per day or 3,800 MMBtu per hour. If a market area pipeline has a total daily delivery capacity of 1 to 2 BCF/D, then a single generation plant turned on to meet afternoon demand can raise consumption on a market area pipeline by 4-9%. The afternoon electric generation demands are thus not easily balanced due to the operating characteristics of a pipeline. The electric market has a profile driven by its electricity consumers and requires an instantaneous response while a pipeline operates best on a steady, ratable 24-hour flow. Pipeline operators, then, must deal with this growing mismatch between electric load characteristics and gas pipeline facility design using the infrastructure they have. A more flexible infrastructure would allow a more effective and more efficient response to these needs; unfortunately, capital expense would be required to accommodate such, as well as necessary filings for tariff service modifications.

It is noteworthy that the electric market and natural gas transportation markets have differing cost structures. The electric generation market is priced on baseload, intermediate, peaking, thirty-minute and five-minute intervals. Most pipeline tariffs, on the other hand, are based on an expected, even, 24-hour offtake. Thus there is a price opportunity variance between what an electric generator is earning and what a pipeline operator receives for the hourly swing service it is providing; this is often referred to as the "spark spread." Such a price opportunity difference may serve to exacerbate the swing as generators attempt to capture as much of the "opportunity" as possible. Unfortunately, these types of actions may degrade service to other customers, so pipelines may have to notify generators to reduce their offtake.

One of the services provided by interstate pipeline systems is the provision of pressure. In order to efficiently move gas, most pipelines in the interstate transmission grid were designed to operate at a maximum of 800 to 900 psi (pounds per square inch), as compared to normal atmospheric pressure of 14.7 psi. Newer pipelines have been designed to operate at pressures of 1,600 to 2,100 psi using thicker walled pipe to withstand these higher pressures. Customers frequently benefit from these high pressures. LDCs, for instance, use 100 to 400 psi for their distribution system mainlines. They can thus avoid the expense of compression for the portions of their system directly connected to interstate transmission facilities.

Electric generators also receive significant benefits from the provision of high-pressure gas. The new gas turbines, which comprise over 90% of electric generation plants constructed over the last four years, require pressure at 450 to 650 psi to operate efficiently. If these plants are not connected to high-pressure interstate, intrastate, or LDC transmission facilities, they may have to install local compression to raise the pressure of their natural gas receipts to the required level at a substantial incremental operating and capital cost.

Besides pressure, another common factor affecting pipeline transmission customers is gas quality, sometimes called gas interchangeability. Natural gas from different supply sources can be composed of different percentages of gases that are produced in conjunction with methane. Gases without heating value, such as carbon dioxide and nitrogen, are subject to strict limits in receipt areas, and gas volumes exceeding these tolerance levels can be restricted from pipeline access. The variance in gas quality, with Btu levels either higher or lower than the level for which the burner is set, can cause poor, inefficient combustion, which increases the production of pollutants such as nitrogen oxide, carbon dioxide, and carbon monoxide. There is legitimate concern, therefore, about allowing gas with improper limits to enter the pipeline system.

The main concern for pipelines is not strictly a varying level of heating content but the potential for liquid fallout within the pipeline. Some of the higher level hydrocarbon gases, pentanes and higher, will become liquids at lower pressure and temperature levels. A rapid pressure drawdown, perhaps due to a demand swing or a major pressure reduction at a valve, can cool the gas and cause this liquid fallout to occur. The presence of liquids can cause problems during compression and can also lead to corrosion if left to settle in low spots within the pipeline system. Pipeline corrosion can lead to increased maintenance costs (related to attempts to remove the liquids), removal of capacity from service, and, in severe cases, loss of system integrity. For this reason, pipelines need to specify within their tariffs the standards for monitoring the quality of gas volumes.

LNG imports will be an increasing source of supply in the study. Much of the LNG produced globally has a high ethane level. The inclusion of ethane may result in an imported gas stream with Btu content per cubic foot above 1,100, the typical market area limit.

Without treatment, such as nitrogen injection, processing, or blending with low-Btu domestic production, the ethane-rich LNG could be barred from the distribution and transmission systems in market regions. However, recent work done under the auspices of the Gas Technology Institute indicates that LNG with high ethane content does not appear to cause problems at the burner tip. This study is called "Gas Interchangeability Tests" and a draft of the first part of the study has been recently released. The initial results suggest that the Btu limits in practice throughout the industry are too narrow and that alternate indices, such as the Wobbe Index, are much more prescriptive of safe combustion. It is hoped that additional studies will help the industry determine not only what is operationally appropriate but that they will also lead to true interchangeability standards, to be incorporated in the pipeline and LDC tariffs.

Maintenance Challenges

Besides operational challenges, transmission operators will have to focus significant capital and attention to maintenance of their systems over the next 25 years. In 2002, Congress passed the Pipeline Safety Improvement Act, which has major ramifications for the transmission industry. The Act will cause enhanced maintenance programs and actual continuing inspections of all pipelines located in population centers. According to the Act's requirements, over 50% of the riskiest pipeline segments in these regions must be "physically" inspected in the next five years. The remaining facilities must be inspected during the following five years and all pipelines must be subsequently re-inspected at less than seven-year intervals. Though currently unaddressed, recovery of these costs will be of substantial concern to pipeline operators and level of costs is of concern to ratepayers.

The inspection requirements of the Act will impact the industry in several different ways. First, the Act will lead to a marked increase in expenditures for pipeline testing. There are three major methods that can be used in integrity testing: In-line inspection using "smart pigs;" hydrostatic testing; and external inspection. Each method will have its own set of cost factors and these will vary per pipeline and region.

The cost of performing these tests is still being evaluated. The industry consensus, however, is that the tests will be costly. It is assumed, but not yet certain, that FERC and other regulatory bodies will allow the cost of these tests to be included in pipeline tariffs. During periods of testing, it is clear that besides the direct cost of performing the inspection, an additional cost, or revenue loss, may occur from the reduction in throughput capacity as a result of inspections. The insertion of a smart pig or the excavations of a pipeline for external surveillance both reduce pipeline capacity due to pressure reductions during the inspection period. According to the Integrity Rule report from the Interstate Natural Gas Association of America (INGAA), a smart pig run in a pipeline designed for internal inspections will result in a 30% decline in throughput capacity for about three days. A hydrostatic test requires removal of 100% of the capacity and the process takes an average of 25 days due to the need to carefully purge the pipeline of natural gas, fill the pipeline with water, test the facility, and then properly dispose of the water.

One effect of the increased inspections, therefore, will be temporary reduction in capacity on the lines being tested. The reduced capacity will result in an increased utilization factor for unaffected capacity and could result in a short-term increase in effective transportation rates. The result may thus be an increased short-term cost to consumers, even without the inclusion of expenses to physically perform the tests.

INGAA found that integrity inspections will add an additional $6.8 billion to interstate transmission costs under the assumption of a ten-year test cycle. By far the largest of these costs will be due to short-term capacity reductions on the interstate grid, which is predicted to cost $5.7 billion. Capital expenditures on infrastructure improvements are estimated as $0.6 billion while inspection costs are forecast to be $0.4 billion.

Another result of the increased integrity activity could be a pro-active decision to change historical regulatory policy to allow operators to build capacities slightly higher than current contractual commitments. The increased capacity could then be used to maintain normal throughput during periods when supplies are diverted from an alternate system due to maintenance.

Distribution

In the natural gas industry, the distribution system is defined as that portion of the gas delivery infrastructure that delivers gas from an interconnection point with the interstate pipeline system (the "citygate") to the ultimate, end-use customer.[4] Exceptions to this general definition are common, including the increasing number of electric generation plants that receive gas directly from a pipeline. However, virtually all residential and commercial customers and most industrial customers receive their gas from a distribution system that is owned, operated and maintained by a local distribution company (LDC). LDC does not refer to the type of ownership (investor owned or municipality). Rather, LDCs in this study means the entity that distributes gas to end-use customers.

As a general rule, LDCs broadly categorize their services into firm and interruptible deliveries. Distribution systems are designed to meet all firm customer demands for gas even under design (colder than normal) weather conditions. The demands of cus-

[4] This definition roughly follows the definition used to determine those segments of pipe that are regulated by the Federal Energy Regulatory Commission, i.e., transmission, and those regulated by others, i.e., distribution. Distribution regulation is typically provided by states or municipalities. This type of regulation covers pricing (rates) and terms of service. It should be noted that the U.S. Department of Transportation, which regulates the operation and safety of pipes, uses a different definition.

tomers who are served with interruptible service may or may not be met under certain conditions as defined in the LDC's delivery tariffs, potentially during design weather conditions.

Because LDCs must design their distribution systems to deliver gas even under design weather conditions, the overall capacity utilization is much lower than that of interstate pipelines. For example, a residential customer who uses gas for heating, can have a peak wintertime monthly gas consumption that is 10 or more times what the same customer's monthly gas consumption will be in the summer. The difference in gas usage is even more pronounced if peak day to minimum use days are compared.

Thus customers with fuel oil backup, such as industrial consumers or electric generators, who can interrupt their gas usage by switching to alternate fuels, allow the LDC to use its system efficiently and reduce costs to customers. The greatest demands on a distribution system can arise when an electric generating unit uses natural gas at the same time the residential and commercial customers experience peak usage. Meeting these demands may require the LDC to expand its facilities, exacerbating its seasonal variance in capacity utilization and potentially increasing the total overall cost to serve customers.

Distribution Infrastructure Investment

Construction of new facilities to meet customer demands requires the extension of gas mains and the construction of services to bring the gas into an individual home or business. The costs of both mains and services vary depending upon many factors. The costs to install a new service average $460 in undeveloped areas, $1,400 in developed areas, and almost $5,600 in urban areas. The costs used in the NPC analysis are based on distribution system costs from a Gas Research Institute study of LDC cost trends and are refined based on the American Gas Association's "Best Practices" review. The allocation of indirect investment costs was calibrated to reflect total national LDC investment. It should be noted that these costs reflect smaller average size industrial and electric utility connections.

In addition to expansion activities, distribution systems are in a state of constant maintenance and upgrade to maintain safety, ensure system reliability and to minimize future maintenance costs. Based on AGA benchmarking information, replacement of mains ranged from 0.4 to 0.7% per year of existing installed mains among surveyed LDCs. For this study, main replacements were assumed at 0.5% per year and service replacement at 0.75% per year.

These rates imply service lives beyond 25 years. This matches the current projections for the lives of materials used to build new distribution. As a result, in this study, main and service replacements occur only for distribution facilities installed before 2002. The facilities built in this study are not replaced during the study.

Despite the use of cost-saving techniques, main and service replacements often are significantly more costly than the construction of new facilities. Frequently, replacements occur in congested public rights-of-way where numerous other underground facilities are located. Also, replacements often occur in developed urban or suburban areas where pavement restoration and landscaping or lawn restoration is required. Thus, based on AGA benchmarking studies, main replacement costs were assumed to cost 50% more than construction of new mains. Similarly, replacement of services was assumed to cost 25% more than the cost of new construction. Finally, meter replacement was assumed to cost 15% more than new construction.

The total annual facility investment requirements for distribution companies are similar in the Reactive Path and Balanced Future scenarios. To accommodate the demand projected in the Balanced Future scenario, the results from the distribution analysis show that total annual facility investment requirements for distribution companies will average $5.3 billion per year (2002 dollars), with a cumulative investment from 2004 through 2025 of $135 billion. This compares to annual expenditures during the 1990s, which averaged slightly more than $4.8 billion. However, funding for this level of expansion may be more difficult than in the 1990s because more of an LDC's cash flow will be needed in the future for other purposes, including buying higher priced gas and placing it in storage. This may result in a greater need to finance expansion of the distribution systems with external funds than was the case in the 1990s. LDC access to capital markets will, therefore, be important but, given appropriate regulatory policy, should not be a constraint.

In determining the costs to expand the distribution system, a 1% per year increase in productivity was assumed. This significantly lowers the projected costs.

Given appropriate funding for research and development (R&D), achieving increased productivity seems reasonable. Thus, it is not expected that adequacy of the distribution infrastructure will be a constraint in the future.

The improvement in overall efficiency in the residential sector in the Balanced Future reduces system throughput slightly, resulting in a modest decline in required mains reinforcement and delayed replacements. The decline in power generation demand also reduces the required investment to serve new load. This decline in investment is, however, offset by a small increase in investment to serve growth in the commercial and industrial sector load, as the lower natural gas prices in the Balanced Future scenario result in some additional growth in commercial and industrial demand.

As discussed in the Transmission section of this chapter, the United States Congress passed legislation intended to enhance the safety of "transmission" type gas pipelines[5] through stricter inspection requirements. The U.S. Department of Transportation (DOT) is currently developing the rules to implement the legislation. Companies are required to perform a baseline inspection within the first ten years of all "transmission" like pipeline located within a high consequence area. Re-inspection will be required every seven years after the initial inspection.

The AGA estimates that the LDCs operate almost 22,000 miles of pipeline that is subject to this new pipeline integrity program. While the exact requirements mandated by DOT is not known, AGA has estimated the cost of compliance for LDCs at $2.7 billion to $4.7 billion over the next 20 years. DOT has independently estimated industry (including LDC and Interstate Pipelines) costs at $4.7 billion over the next 20 years. DOT's analysis for just LDC pipelines would be somewhere between 35% and 50% of this composite figure, or $1.6 billion to $2.4 billion, somewhat less than the AGA figures. It is important to note that the cost of remediation, or addressing anomalies found, is not included in the above cost calculations for either industry or Office of Pipeline Safety estimates. Historical annual capital expenditures in 1998 dollars can be seen in Figure 5-12.

For purposes of this study, a cost of $16,000/mile or $3.5 billion for the ten-year period was assumed. Thus,

[5] The DOT definition of "transmission" differs from the definition used by the rate setting regulators like FERC. As a result, LDCs operate a significant amount of "transmission" pipelines from a DOT perspective.

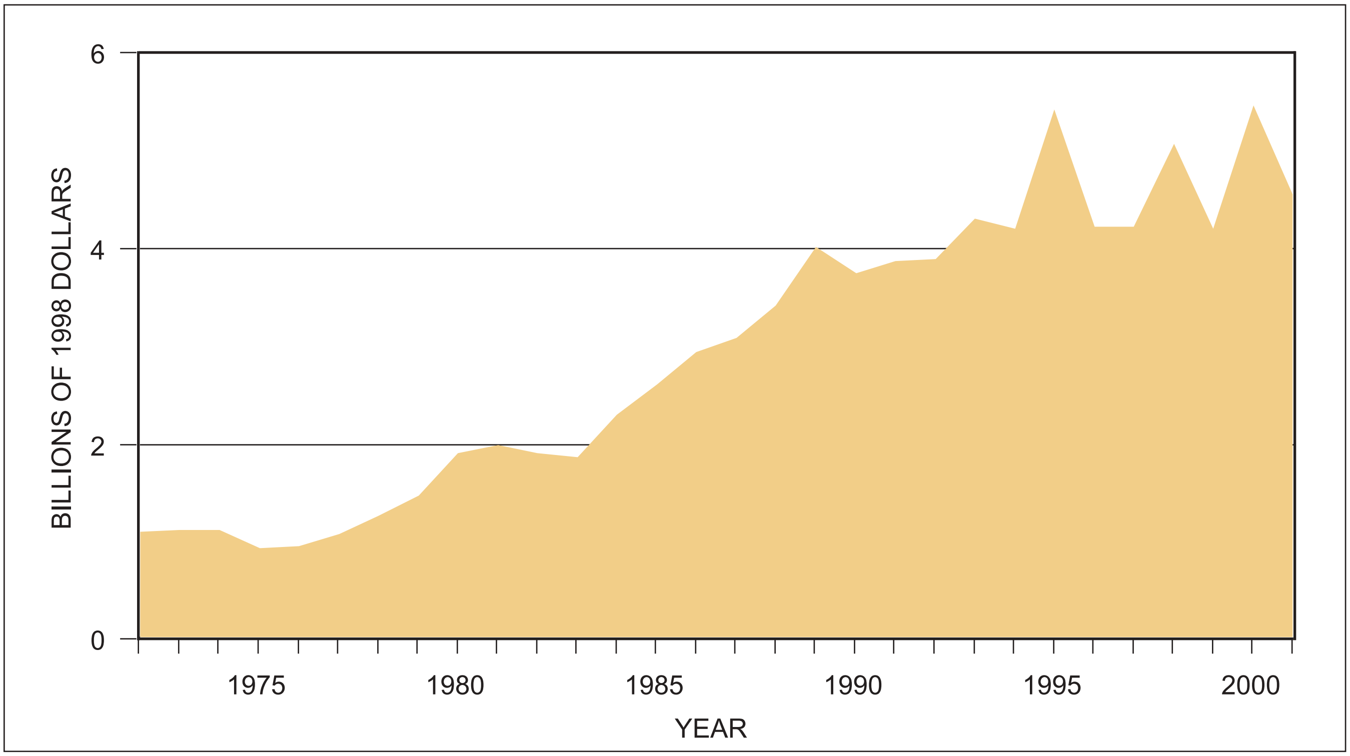


Figure 5-12. Historical Investment in Distribution Infrastructure

it was assumed that 60% of the total cost will be incurred in the initial ten-year period, when baseline inspections occur.

For the remainder of the study period, costs to comply with the pipeline integrity program will continue. However, since facilities needed to complete the inspections will have already been built, integrity management plans will have been written, and high consequence areas will have been identified and mapped, it is anticipated that costs to comply with the pipeline integrity program will decline. Offsetting this decline will be the increased amount of pipe included in the pipeline integrity program as LDCs expand their systems as well as inflationary pressures. Thus, annual costs for LDCs to comply with pipeline integrity standards in years after 2012 were assumed to be 40% of the annual costs of the initial period. In summary, from 2004 through 2013, an annual cost of $250 million was assumed to meet the pipeline integrity standards. From 2014 through 2025, an annual cost of $100 million was assumed.

In addition to pipeline integrity costs, LDCs face increased costs to protect against security threats by terrorists. These costs cannot be readily quantified. As a part of outreach, a limited number of LDCs indicated that LDCs expect some increase in costs compared to historical trends, but overall increases that are less than the costs to comply with new pipeline integrity standards. If these costs represent a 1% increase in the costs to maintain and expand the gas distribution systems, LDCs would incur new expense of $48 million per year. These costs are included here only for reference and were not included in the figures shown elsewhere in this chapter.

Challenges to Building and Maintaining the Required Distribution Infrastructure

As the LDC marketplace has evolved, the requirements for serving customers have continued but roles have changed. All states that have residential and commercial choice programs have addressed the provider of last resort (POLR) or supplier of last resort (SOLR) issue to some extent. The POLR/SOLR responsibility has been defined in varying ways, but generally is the responsibility to assure that small gas consumers will not experience an interruption in the supply of natural gas to meet their needs. Thus, POLR/SOLR can include the responsibility to provide essential needs customers with gas if the customer's supplier goes bankrupt or fails to deliver gas for other reasons. POLR/SOLR responsibility always includes small volume residential gas customers (residential or commercial) and seldom, if ever, includes very large customers like electric generators.

There is debate about what entity should be a POLR/SOLR. Some states have required that the LDC assume this role, while other states have prohibited the LDC from holding the role. While these policy debates will continue, it is important to recognize that the demand for natural gas to serve residential and commercial markets will likely continue to grow. In fact, this study projects that the number of residential customers served by the natural gas industry will grow from 61 million in 2003 to 81 million in 2025. This level of growth will necessitate that state and federal policy makers work with the various industry participants to assure that interstate pipeline and storage capacity is available to serve future customers. Clear definition of the responsibilities of the POLR/SOLR and appropriate commitments from policy makers to allow critical expansions are required to assure reliable service to customers.

The permitting and construction of new or replacement facilities is becoming more expensive as a consequence of various growth management, building code, and environmental requirements. Many of these issues have been discussed at some length in the Transmission section of this chapter. It is worth noting here, however, that access to public rights-of-way within metropolitan regions is becoming more difficult to obtain and more expensive. Increased costs from such items are not included in this study. However, governmental bodies need to consider the impacts (financial as well as safety and reliability) of added restrictions on the installation and maintenance of distribution facilities.

To address these and other concerns, states should also develop a mechanism to coordinate siting issues among affected state and local governmental entities, wherever multiple governmental entities have an impact on the siting of LDC facilities. Using the IOGCC/NARUC Pipeline Siting Work Group Report[6] as a framework, each state should consider, as needed,

[6] Philip N. Asprodites, "Roadmap to Implementation of the Final Report of the Interstate Oil and Gas Compact Commission/National Association of Regulatory Utility Commissioners Pipeline Work Group in Louisiana" (April 2003).

programs that might include the following types of initiatives:

- The governor establishing within the office of the governor a coordinating effort to organize and expedite the activities of all state and local natural gas permitting entities.

- States naming a lead agency that would have the authority to monitor processing schedules within existing regulatory requirements.

- The state economic development office (Commerce Department) being involved with the coordination effort and recommending actions to streamline the process.

Coordination and certainty in completing a permitting process are keys to meeting the growing need for natural gas while balancing many other key issues. Consistent government policy and rapid, predictable regulatory decisions are needed to enable timely and cost-effective system expansions.

The business environment in which LDCs operate has changed dramatically since the 1999 NPC study. Traditionally LDCs provided gas to all customers served by the distribution system. Based on programs that are currently operational or announced, however, 96% of all industrial customers will have customer choice. Additionally, at least 72% of all commercial customers and 57% of all residential customers will also have the option to choose their gas supplier.[7] This continuing transition has changed the decision processes related to their distribution system expansions.

Another topic of concern to LDCs arises because the reduced gas usage resulting from customer-achieved efficiency gains will lead to less gas flowing in an LDC's system and its current asset base to serve existing customers. Most LDCs have experienced this phenomenon throughout the 1990s. This normally means that expansion capital will be required to attach new customers just to maintain system throughput and the associated revenue levels. Actual growth in throughput and revenues will require additional capital investment, beyond the level described, just to keep even with customers' conservation efforts. Previous expansions have largely been financed through internal cash generated from the business; however, forecasts suggest that capital markets will need to provide more of the capital required to maintain and grow the throughput and associated revenues. Accessing capital at the lowest cost in the competitive markets requires a compelling story. To achieve favorable access to capital, traditional rate designs may need to be modified or augmented to reflect the adverse impact to the financial health of LDC's caused by customers achieving the desirable goal of greater efficiency. One such example is the state of Oregon recently implementing a "conservation" tariff that encourages greater conservation by customers while mitigating the potentially adverse impacts of reductions in LDC revenue.[8]

LDC working capital needs will expand significantly at the gas prices suggested by the NPC analysis. Currently, the United States is considered to have adequate gas in storage if more than 2.5 TCF has been stored by the beginning of the heating season. The carrying cost to store this gas for several months at \$6.00/MMBtu is significantly more than the comparable costs in the \$2 to \$3 gas price environment often seen in the 1990s.

These types of changes, as well as changes in the broader energy market, are impacting the business risks faced by LDCs. Constant attention to the financial health of the distribution industry will allow adequate access to capital markets for all future expansions needed to serve customers.

Reliable Gas Service in a Changing Market

As the natural gas marketplace changes, new demands are placed on the interstate pipeline, storage, and distribution system infrastructure. In particular, electric generating customers can dramatically change the demands for gas as they follow electric load. The changes in gas requirements can occur very quickly. Because electricity cannot be stored, it must be produced at the moment it is used. The customer demand for electricity reaches a peak in the summer in many areas of the country as it provides essential cooling services. Thus, power plants are increasingly consuming larger amounts of gas at the same time distribution

7 American Gas Association, "Policy Analysis Issues," Issue Brief 2002-02, May 7, 2002.

8 Oregon PUC Order No. 02-634, Stipulation Adopting Northwest Natural Gas Company Application for Public Purposes Funding and Distribution Margin Normalization (PUC of Oregon, September 12, 2003).

companies and others are attempting to fill seasonal storage.

These concerns have been the subject of considerable discussion and debate among industry participants. Recently, INGAA,[9] AGA,[10] and the APGA[11] developed a framework to discuss these issues.[12] The groups' stated goal is to "ensure the continuation of the historic reliability of the natural gas industry as gas demand grows particularly from the power generation sector." These evolving discussions among industry and government will need to continue to assure adequate, reliable, cost-effective natural gas service to all customers in the evolving natural gas marketplace.

Productivity Improvements Require R&D Investments

A measure of productivity in LDC operations is gas delivered per LDC employee. With an average drop in staffing levels of 4% per year since 1990, Figure 5-13 demonstrates the increased amount of gas delivered per distribution company employee, primarily as a result of implementation of new technologies. Much of this technology came from research and its correlated product and skill-set developments. However, expenditures for gas research have declined in the last five years, driven in large part by the reduction in funds collected through the FERC-mandated gas distribution surcharge. The collections of these funds will be completely eliminated by the end of 2004.

Research and development have provided and must continue to provide the new techniques and technologies to reduce costs and increase both the safety and reliability of distribution systems. Many LDCs believe government funding of research remains a critical need. In addition to state- and federal-sponsored R&D, many LDCs participate in and fund R&D. However, some distribution companies may operate under regulatory frameworks that discourage R&D. In such situations, LDC shareholders, finding themselves at risk to benefit, may be reluctant to support investment in the research and development needed to continue these productivity enhancements in the future. Given the inability of LDC shareholders to benefit from R&D investments in operations, the intervention of government may be required. State regulatory commissions should consider removing any barriers to LDC's participation in collaborative research. Similarly, DOE funding of gas utilization technology research must continue and, if possible, expand.

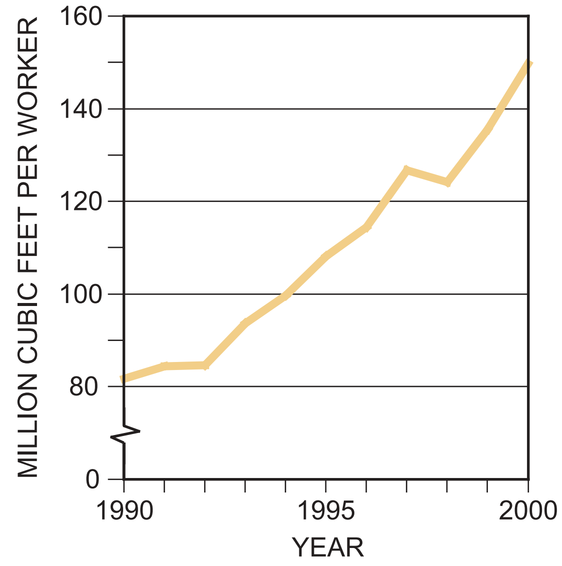


Figure 5-13. Gas Delivered per Worker

Storage

The ability to effectively store and retrieve large quantities of natural gas has been a key factor in the growth and development of the natural gas industry. At its most basic level, the storage function allows for the generally asynchronous supply and demand functions to be efficiently matched. Perhaps the most obvious example of this functionality involves satisfying the highly seasonal demand for natural gas for space-heating purposes in the residential and commercial sectors during the wintertime. Indeed, without the ability to build gas inventories in storage prior to the high-demand winter period, it is unlikely that natural gas would have become such a dominant space-heating fuel in these sectors. Without storage, the wintertime surge in demand would require that production be accelerated greatly for the winter season, then throttled back as temperature-driven demand waned. Huge

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[9] INGAA (Interstate Natural Gas Association of America) represents interstate pipelines.

[10] AGA (American Gas Association) represents investor-owned local distribution companies.

[11] APGA (American Public Gas Association) represents publicly owned natural gas local distribution companies.

[12] March 7, 2003, Letter to The Honorable Patrick H. Wood, III, Chairman of FERC from David N. Parker, President and CEO of the AGA.

amounts of pipeline capacity would have to be available to transport the gas to market areas, much of which would then be vastly underutilized at other times of the year. Thus, a major function of storage is to augment supply to satisfy seasonal demand increases.

A second major function of storage is the operational function of load balancing, usually associated with pipeline operations. In essence, the function of load balancing is operating the system in such a way that receipts of gas into the system roughly equal deliveries of gas from the system, within certain operating tolerances. Thus, interconnections to storage give the pipeline operator a place to inject excess gas when more is being received by the pipeline than delivered, as well as an incremental source for withdrawal of gas when more is being delivered to customers than is received by the pipeline.

A third major function for storage, which has gradually grown in prominence, is the rapid cycling or turnover of working gas storage inventory. This is most often associated with salt cavern storage facilities because of the ability to inject gas into and withdraw gas from these facilities at very fast rates relative to their storage capacities. This function also supports a wide variety of market-based uses, where the purpose of its use is primarily to obtain a profit as opposed to operational uses. Essentially, this function enables participants to profit from changes in gas prices over short time intervals, taking advantage of periods of high volatility in gas markets.

Overview

Natural gas may be stored in a number of different ways. It is most commonly held in inventory underground under pressure in three types of facilities. These are depleted oil and/or gas reservoirs, aquifers, and caverns developed in salt formations (see Figure 5-14).

Each type has its own physical characteristics (porosity, permeability, retention capability) and economics (site preparation costs, deliverability rates, cycling capability), which govern its suitability to particular applications. Two of the most important characteristics of an underground storage reservoir are its capability to hold natural gas for future use and the rate at which gas inventory can be injected and withdrawn – its deliverability rate. The distribution of storage facilities varies regionally by type within the U.S. lower-48, as can be seen in Table 5-1. It is important to note that while these data indicate total working gas

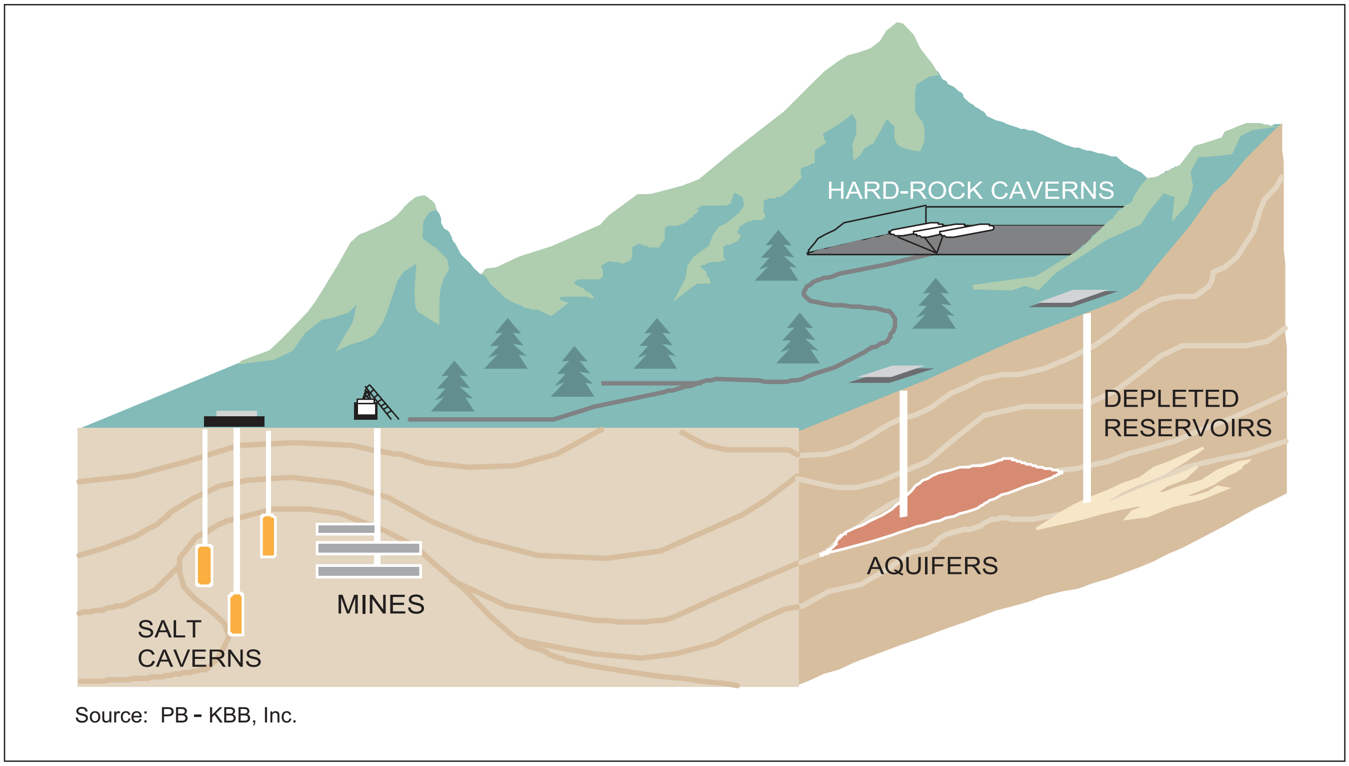


Figure 5-14. Types of Underground Natural Gas Storage Facilities

Region/State	Depleted Gas/Oil Fields		Aquifer Storage		Salt Cavern Storage		Total		
	Number of Sites	Working Gas Capacity (BCF)	Number of Sites	Working Gas Capacity (BCF)	Number of Sites	Working Gas Capacity (BCF)	Number of Sites	Working Gas Capacity (BCF)	Percent of Working Gas Capacity
Consuming East	242	1,722	34	354	4	5	280	2,081	46
Consuming West	31	606	6	38	0	0	37	644	14
Producing	74	1,087	*	*	24	138	98	1,226	27
Total U.S. Lower-48	**346**	**3,414**	**41**	**393**	**28**	**143**	**415**	**3,951**	**87**
Canada	11	598	0	0	1	4	12	602	13
Total North America	**357**	**4,012**	**41**	**393**	**29**	**147**	**427**	**4,553**	**100**

*Any aquifer facilities in this region have been counted as depleted gas/oil fields to preserve data confidentiality.

Notes: Regions are those used by the EIA in its Weekly Underground Storage Survey. BCF = billion cubic feet.

Table 5-1. Regional Distribution of Storage Facilities and Working Gas Capacity

capacity of over 4.5 TCF, the largest amount of inventory actually cycled in any year has been 2.9 TCF, and evidence suggests that storage capacity may be incapable, for a variety of reasons, of cycling more than that volume without extreme seasonal price variability.

In addition to the three primary storage types, industry participants also have a number of other options to satisfy the temporary spikes in demand generated by end-users – such as a surge in demand for space heating during an unusually cold period, or a sudden requirement for an electric utility to bring online a natural gas-fired generator – that can exceed the ability of traditional storage to handle. These storage options usually involve storing LNG, compressed natural gas, or liquefied petroleum gas (usually propane) in above-ground storage tanks, and have the capability to deliver natural gas or a propane-air mix into the local distribution system when required. These facilities are generally capable of relatively high deliverability but for short durations.

Following are brief descriptions of the characteristics of each of the major storage types. Depleted oil/gas reservoir storage facilities are the most widely distributed geographically. Aquifer facilities are found primarily in the Midwest, while most salt cavern storage has been developed in the salt formations along or near the Gulf of Mexico in Texas, Louisiana, and Mississippi.

Depleted Oil and Gas Reservoirs

Most existing gas storage in the United States is held in depleted natural gas or oil fields. Cycling in this type of facility (number of times a year the total working gas volume may be injected/withdrawn per year) is relatively low, and daily deliverability rates are dependent on the degree of rock porosity and permeability. These facilities are usually designed for relatively few injection and withdrawal cycles per year, and often for only one cycle.

Aquifers

Aquifers, which originally contained water, may be suitable for gas storage purposes if certain geologic criteria are met. In the United States, aquifers that are used for gas storage are found primarily in the Midwest. There are several reasons why an aquifer is the least desirable type of underground storage, many of which contribute to making aquifer storage more expensive to develop and maintain than depleted reservoir storage. First, it takes about twice as long to develop an aquifer storage site compared with an average depleted gas or oil field. Second, all new facilities must be installed, including wells, pipelines, dehydration facilities, and compressor operations. Third, no native gas is present in an aquifer formation. Thus, base or cushion gas must be acquired and injected into the reservoir to build and maintain deliverability pressure.

Once in operation, aquifer reservoirs have one potential advantage over depleted field storage. Because of the additional support of an aquifer's water (pressure) drive, in most instances, higher sustained deliverability rates than gas or oil reservoirs can be designed and attained. Injection and withdrawal activities generally are required to conform to a disciplined schedule, however, to avoid damage to the reservoirs or loss of gas. Therefore, aquifers only cycle once per year.

Salt Caverns

There are two basic types of geologic formations in which cavern structures used to store natural gas are developed: salt domes and bedded salts. Both are created by injecting water (leaching) into a salt formation and shaping a cavern. Caverns created in salt domes are large caverns as they are constructed within salt formations that can extend for thousands of feet.

A bedded salt storage cavern, on the other hand, is generally developed from a much thinner salt formation (hundreds of feet or less). As a result, the height-to-width ratio of the leached cavern in a bedded deposit is much less than for a cavern in a salt dome. Typically, bedded salt storage development and operation is more expensive than that of salt dome storage.

Because salt cavern storage facilities are essentially high-pressure storage vessels akin to underground tanks, their injection and withdrawal rates are very high and base gas requirements low. Their resulting ability to cycle working gas inventory numerous times during a year makes them ideal for meeting large demand swings.

LNG Storage

Liquefied natural gas is natural gas that has been cooled to approximately minus 260 degrees Fahrenheit for storage as a liquid. LNG storage accounts for a very small portion of the overall natural gas storage capability in the United States because LNG working gas storage capacity is just over 2% of the overall capacity. However, LNG storage facilities have relatively high deliverability rates that allow operators to deliver an amount equal to up to 14% of all underground storage. LNG storage can be grouped in two general categories: peak-shaving storage and marine terminals. Each of these categories has specific characteristics and utilization benefits.

Peak-shaving LNG storage has two main positive attributes: its high deliverability capability as compared to more traditional storage, and its flexibility with respect to where the storage can be located. However, peak-shaving LNG storage is more costly on the basis of dollars per million cubic feet of storage capacity, when compared to traditional storage.

Marine import terminals receive LNG shipments and have on-site storage. The LNG is stored in aboveground storage tanks until it can be regasified and injected into the pipeline grid. Additionally, the LNG can be stored until it is trucked, in liquid state, directly to customers. The principal operation of an import terminal is not for gas storage, but rather for receiving the waterborne LNG imports and then regasifying LNG for shipment via pipelines to customers.[13] Marine terminal storage can also function as peak-shaving storage; however, that is not its principal function.

Propane-Air Storage

Propane-air storage is another method by which gas utilities and industrial customers meet demand during the coldest days of the year. Propane is stored in aboveground tanks or underground caverns (usually granite) until needed. Because it vaporizes relatively easily, propane can enter the gas pipeline distribution systems with little difficulty. Generally, a propane-air mixture

[13] Energy Information Administration, *US LNG Markets and Uses,* January 2003.

containing 1,400 Btu per cubic foot has burning characteristics similar to natural gas. Although propane-air systems are common as a cheap alternative to pipeline capacity, there have been concerns over several failures for the propane to properly vaporize on especially cold days in the Midwest.

Historical Background and Statistics

Most of the nation's storage sites were developed between 1955 and the early 1980s. During this period, U.S. storage capacity increased over fourfold, from about 2.1 TCF in 1955 to 8 TCF in 1985.[14] The need for underground storage grew as consumption of natural gas increased significantly. The mix and requirements of consumers also changed as demand shifted toward the more weather-sensitive residential and commercial markets. Furthermore, in the mid- and late-1970s, the interstate market encountered supply and demand imbalance situations during several exceptionally cold winters, and as a result service curtailments were imposed. Since the mid-1980s, total storage capacity has remained at approximately 8 TCF, even with the recent surge in new storage development. However, the daily deliverability from storage has increased.

The volatile gas market during the late 1980s set in motion certain events that heightened interest in new storage facility development. Interest in new storage resurged as regulatory changes under FERC Orders 436 and 636 forced more competition into the marketplace. Storage became increasingly important as all pipeline services were unbundled and customers had to make their own storage arrangements. Between 1992 and 2002, deliverability from storage increased by 29%, from approximately 65 BCF/D to 83 BCF/D.

Results from the Study

The reference case analysis projects an increased demand for North American seasonal storage capacity of close to 1 TCF over the 22-year study period, relative to the demands on storage in the 1999-2002 period, which averaged 2.3 TCF per year. Recognizing that the base period (1999-2002) was characterized by relatively light demand on storage due to generally warm winters, it is estimated that the current storage infrastructure is sufficient to satisfy an increased average annual demand of approximately 300 BCF, leaving 700 BCF of demand that will need to be met by development of new capacity. As much as 150 BCF of this new capacity could be required in the very near term if there were a return to winter weather patterns closer to historical normal levels. As only 109 BCF of storage additions are projected to occur by 2005 (based on projects announced), most of any such near-term demand increase will need to be met through more efficient use of existing capacity, and measures to increase capacity and deliverability at existing facilities.

By 2015, total cumulative storage capacity additions will need to have approached 400 BCF, and by 2025, 700 BCF, to accommodate growth in the total gas market. While many of the best resources for gas storage (based on location and geology) have been developed, this rate of growth in the infrastructure is considered achievable provided that favorable market conditions exist to finance the additions. Conventional storage is expected to account for over 80% of the projected additions and high deliverability peak-shaving the remainder.

When discussing the adequacy of storage infrastructure, it must be kept in mind that demands on storage vary greatly, from year to year, depending on weather, and that even if the projected growth in capacity is achieved there will likely be winters when the system is unable to fully supply gas withdrawal requirements without some significant short-term reduction in gas demand, whether price induced or otherwise. A winter of significantly colder than normal winter weather can increase demand for storage capacity by as much as 25% relative to a normal year. It has been many years since North American storage capacity has been tested by such a winter and it is very likely that current storage capacity would be severely challenged to meet such demand, with potential for even greater price spikes and demand destruction than what was experienced in 2001 and 2003.

Storage additions for the U.S. lower-48 were evaluated on the basis of nodes within the nine census regions, while additions for Canada were split between nodes in eastern and western Canada.

In the U.S. lower-48, the need for near-term storage additions is greatest in the Pacific, East South Central, South Atlantic, West South Central, and Mid-Atlantic regions. Near-term storage additions for the Mountain

[14] Refers to total storage capacity. For depleted field and aquifer storage facilities, base gas typically occupies one-half or more of total storage capacity, with the remaining capacity available to store working gas.

region are projected to grow modestly. No near-term storage additions are projected for the West North Central or New England regions.

Projected additions to peak-shaving and conventional North American storage over the 2005-2025 period are 550 BCF. Nearly 80 BCF of the projected additions are for high deliverability peak-shaving storage facilities, with lower-48 additions accounting for 90% of this requirement. The need for this type of storage will be greatest in the South and Mid-Atlantic regions, collectively accounting for over 30% of the projected growth in peaking storage. Peak-shaving growth in the West South Central and Pacific regions are projected to grow at 9 BCF each. Eastern Canada will experience the need for peak-shaving additions as well; additions in this region are projected to be over 8 BCF.

Projected additions to conventional storage during 2005-2025 are largely concentrated in the lower-48 market area. Three regions in particular, East North Central, Mid-Atlantic, and South Atlantic, are projected to experience significant storage growth amounting to about two-thirds of the projected overall storage additions. Combined storage growth in these three regions is projected to be about 320 BCF, with the greatest additions to the East North Central at approximately 111 BCF (10% increase over current), followed by nearly 109 BCF (44% increase over current) and 99 BCF (23% increase over current) to the Mid-Atlantic and South Atlantic, respectively.

This increase in storage will require additional pipeline capacity to reach the market centers, particularly for storage developed to serve the Mid-Atlantic and Northeast markets, which lack suitable reservoirs for storage development within the region. Instead, the new storage capacity will have to be developed in the western portions of Pennsylvania and New York and eastern Ohio. This will result in the construction of incremental pipeline capacity of approximately 2 BCF/D from these storage sites to the coastal market centers, which include New York City, Boston, and Philadelphia.

The Mountain region is projected to require nearly 55 BCF of additional storage (17% growth), and the West North Central approximately 37 BCF (22% growth) of new storage capacity. Eastern Canada is projected to see growth of about 40 BCF, or about a 20% increase relative to current storage capacity.

Annual average North American daily loads adjusted for storage are projected to grow 19 BCF/D, from 71 BCF/D to 90 BCF/D, from 2005 to 2025. This growth will impact storage injection and withdrawal patterns in certain regions more than others, though in general, seasonal withdrawals will increase in response to growth in the residential and commercial sectors, and to some extent growth in power generation. In contrast, growth in the Industrial sector during this same period is projected to be virtually flat with likely no impact on storage usage patterns. Injection patterns will be impacted more due to growth in power generation than anything else.

Daily loads during the 10 highest demand days of the year are projected to increase from approximately 101 BCF/D to over 126 BCF/D during the study period, while loads during the 60 highest demand days are projected to grow from 92 BCF/D to 116 BCF/D. Storage plays a critical role in satisfying incremental load during peak use periods. The highest load periods occur during the heating season and storage withdrawals typically satisfy over 50% of the daily North American load during the highest demand days of the heating season. Two regions in particular stand out in this regard. In the East North Central region, the reference case projects demand during the 60 highest demand days of the year will be over 2.4 times the average daily load. A similar projection is evident for the West North Central where demand during the 60 highest demand days of the year is nearly twice that of the average daily demand. Under such circumstances, storage is ideally suited to satisfy these incremental seasonal loads, which are predominantly driven by space heating requirements in the residential and commercial sector.

Natural gas demand has always been seasonal, but a recent phenomenon is that, due to increased gas-fired generation implemented around the continent, a new summer season peak is also developing. Other than the industrial load, which has traditionally been steady on a daily and seasonal basis, the other major demand sectors (residential, commercial, and electric generation) are weather sensitive and have a high degree of variability. Demand in North America is projected to grow by 19% between 2003 and 2015, whereas industrial demand is projected to grow by only 3%. This would mean that the stable industrial demand sector is becoming a smaller percentage of total demand. This effect is more pronounced in the United States, where industrial demand is projected to decline by 6% from 2005 to 2015.

Demand for power generation, which will make up the majority of projected demand growth, is highly variable on an hourly, daily, and monthly basis. As can be seen in Figure 5-15 (historical 1997) and Figure 5-16 (projected 2025), power generation not only increases the number and magnitude of winter demand peaks, but it also creates a secondary demand peak in the summer. It also creates an hourly demand profile that is even more pronounced than that of a traditional residential/commercial load profile. The growing summer peak shortens the summer season gas storage injection period, primarily allowing for injections only in the off-peak electric demand hours of the day and thus requiring more volume to be injected into the shoulder (historically lower demand) months of April through June and September through October.

Projected near-term (2003-2005) demand for seasonal storage could grow by as much as 450 BCF, relative to the requirements of 1999-2002, with most of that increased demand being due to an assumption of a return to more normal weather. As much as 300 BCF of that demand growth may be accommodated by the existing infrastructure. Based on announced projects, it is expected that storage capacity will grow by only 109 BCF by 2005. Additions to working storage capacity in the U.S. lower-48 amount to 69 BCF, and consist of projects previously announced to the market.

Any remaining incremental near-term demand for storage will need to be met by more efficient utilization of existing capacity and short-term enhancements to the capacity and deliverability of existing facilities. There is a significant risk that any near-term return to more normal weather patterns could not be met by the existing infrastructure without some increase in seasonal gas price variability and volatility. The Pacific region will experience the largest near-term growth at over 29 BCF. The announced capacity expansion projects have an estimated cost of over $1 billion. Over 34 BCF of the near-term storage additions will be high deliverability salt cavern facilities located in the Mid-Atlantic, South Atlantic, West South Central, and Mountain regions, with a total estimated development cost of $211 million.

A mix of new salt cavern storage capacity and depleted reservoir storage projects in the Mountain and East North Central regions make up the remaining 4 BCF in the U.S. lower-48. The total cost associated with these additions is $38 million. Near-term additions to Canadian storage amount to 40 BCF, all of which are located in western Canada and involve new development in depleted reservoirs. The estimated cost associated with these additions is $100 million.

Projected North American storage infrastructure additions over the 2005-2025 period are approximately 550 BCF, 80 BCF of which will consist of high deliverability salt cavern facilities. In total, future North American storage infrastructure additions over the study period carry an estimated cost of nearly $5 billion.

On a regional basis, the development of 111 BCF of additional depleted reservoir and aquifer storage capacity is projected in the East North Central at an estimated cost of $905 million. Storage additions to the Mid-Atlantic region are forecast at 141 BCF, all of which will likely entail the conversion of depleted reservoirs, at an estimated cost of $1.3 billion.

Growth of storage in the South Atlantic is projected at about 99 BCF, with an estimated development cost of $804 million. The Mountain region is projected to need almost 55 BCF of additional conventional storage capacity with attendant development costs of $468 million.

The remaining additions to lower-48 storage capacity are projected at almost 87 BCF, at a total estimated cost of $1.07 billion. Projected additions to Canadian storage capacity are 56 BCF, including over 8 BCF of high deliverability storage. All but about 2 BCF of these additions are projected for eastern Canada. The total estimated cost of storage additions in Canada is $260 million. Table 5-2 shows the capacity additions and estimated costs in more detail.

It should be noted that these regional capacity addition estimates are based on model results that may not adequately reflect geological and other factors that favor construction of capacity in some regions relative to others. In particular, it is likely that more of this required capacity will be built in the major producing regions of the United States and Canada, and less in the market regions than is indicated in the discussion above.

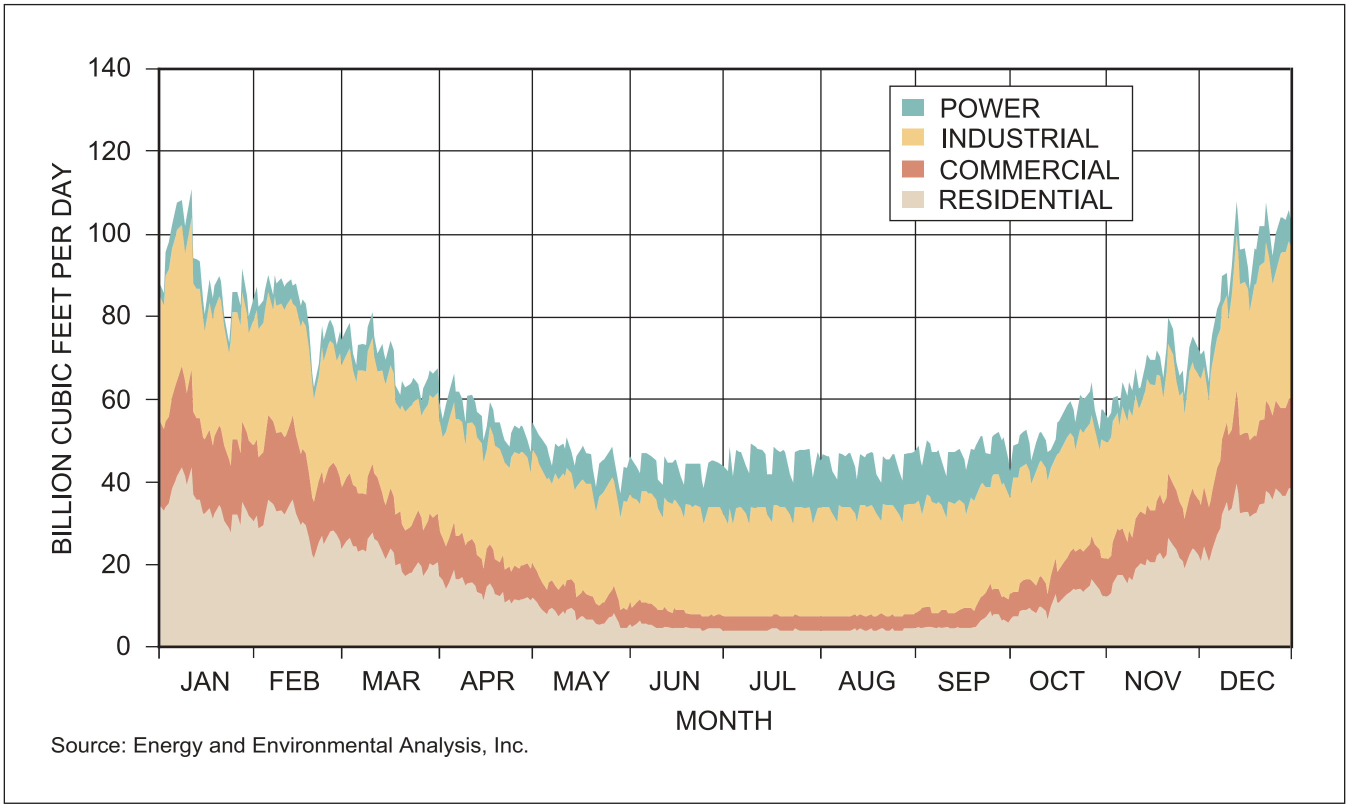


Figure 5-15. 1997 Daily Loads for the United States and Canada

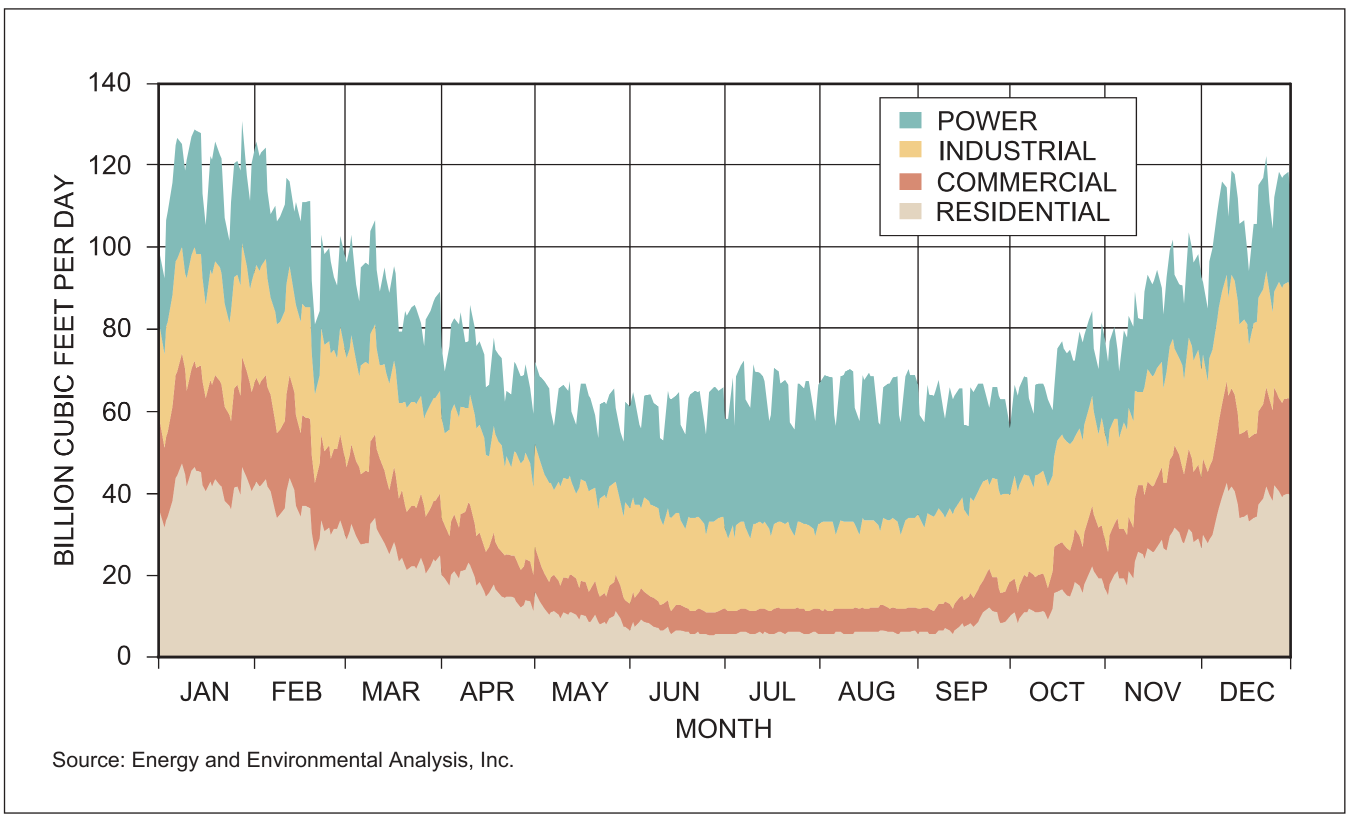


Figure 5-16. 2025 Daily Loads for the United States and Canada in Balanced Future Scenario

Region Number	Region Name	Announced 2003-2005	2003-2005 Est. Cost (MM$)	Additions (BCF) 2005-2025	2005-2025 Est. Cost (MM$)
1	New England	-	-	32.1	382
2	Middle Atlantic	5.0	47	108.9	914
3	East North Central	0.9	8	111.4	905
4	West North Central	-	-	36.9	332
5	South Atlantic	7.6	72	98.5	804
6	East South Central	16.0	149	6.0	227
7	West South Central	6.6	62	9.2	282
8	Mountain	3.2	30	54.3	468
9	Pacific	29.3	274	35.1	225
	Total U.S. Lower-48	**68.6**	**642**	**492.4**	**4,539**
10	Canada East	-	-	54.3	250
11	Canada West	40.0	100	1.8	10
	Total Canada	**40.0**	**100**	**56.1**	**260**
	Total North America	**108.6**	**742**	**548.5**	**4,799**

Notes: MM$ = millions of dollars. BCF = billion cubic feet.

Table 5-2. Projected Storage Capacity Additions and Costs by Region

The Outlook for Storage

In recent years there have been several occasions when winter/summer seasonal price spreads have declined to such low levels that seasonal storage of gas for price arbitrage purposes has been uneconomic. However, the operational need to store gas to balance winter and summer demand with relatively constant production of gas supplies has remained. In addition, the gas market's fluctuation on a day-to-day, week-to-week, and month-to-month basis demands quick turnaround of storage inventories. With credit concerns, i.e., cash flow, becoming an issue for many gas traders and marketers, storing gas without access to it for 6 to 8 months can be a risky proposition.

Electric generation demand in summer will compete with storage injection requirements during the summer cooling season. This issue has been in place for a number of years. Most multiple cycle storage operators are familiar with the double dipping of inventories due to cooling load in the summer and heating load in the winter. This is the effect of summer season generation demand on the pipeline infrastructure, and this effect continues to strengthen. If the pipeline infrastructure is strained due to peak summer loads, scheduled storage refills can be interrupted. As this phenomenon increases, there will be more and more of these refill interruptions.

Challenges to Building and Maintaining the Required Storage Infrastructure

The difficulty of siting storage facilities can be attributed to the need to find a site with the appropriate combination of geological features, pipeline proximity, and the ability to obtain land, rights, and permitting. Once a geologically suitable site is found at an acceptable location with respect to the natural gas pipeline infrastructure, the ability to obtain permitting, land, and development rights becomes critical. The primary access limitations on developing storage capacity are the difficulties in dealing with multiple governmental entities, limitations on emissions, and limitations on storage reservoir operating pressures.

The inconsistency in requirements for FERC and state facility certifications increases the time and cost to develop storage facilities. Proving necessity, i.e., market need, and tailoring implementation plans for minimization of environmental impact are two areas that can have widely varying meanings depending on the approval entity involved. When two or more governmental entities must be satisfied, the complexity involved in satisfying all parties increases exponentially.

The capital investments that would be required to add 700 BCF of additional working gas capacity by 2025 are significant, yet small relative to the potential capital requirements in other sectors of the natural gas industry. A more significant issue with regard to financing storage capacity growth is whether there will be adequate market signals to encourage such investment.

Storage development costs vary significantly from region to region and by facility type. Expansions of existing facilities have the potential to add approximately 200 BCF of incremental capacity at an average cost in the range of $5 million per BCF of working gas, while new projects will require $5 million to $10 million per BCF. Total financial requirements of adding 700 BCF of working gas capacity by 2025 are likely to be in the range of $4 billion to $6 billion.

Similar to pipeline transmission capacity, contracting practices for natural gas storage capacity are currently undergoing significant change, and it is not yet apparent how the market requirement for increased capacity will be translated into contractual arrangements to underpin investments. Until recently, the fastest growing segment of storage customers was the energy marketing companies who were primarily focused on price arbitrage opportunities. Over the last 18 months, a number of storage operators report a noticeable retreat from gas storage contracting on the part of energy marketing companies, due in no small part to the financial difficulties of this segment.

Also, market and regulatory trends of recent years have caused local distribution companies to become less active in contracting for long-term gas storage capacity. The introduction of customer choice programs and the uncertainties regarding the LDC's role as "supplier of last resort" (as discussed in the Distribution section of this chapter) have presented difficulties for LDCs in forecasting their future contractual requirements for gas supply, pipeline capacity, and storage capacity. At the same time, in the recent past there was a strong movement towards LDC reliance on energy marketing companies to manage contracted LDC storage capacity, often through short-term asset optimization arrangements between LDCs and marketers.

Coupled with market conditions that were characterized by relatively small summer/winter spreads throughout the first five months of 2003, these trends have resulted in what can be described by storage developers as a very soft market for the development of new gas storage capacity, notwithstanding the positive longer-term fundamentals as echoed herein. In order for gas storage capacity development to meet anticipated future demands, storage developers report they must see a revitalization of demand for multi-year gas storage contracts through some combination of customers such as LDCs and/or others with firm obligations to serve seasonal and peak-day market requirements for critical needs customers. Another possibility would be the emergence, or re-emergence, of a business sector capable of performing this service role while also in pursuit of price arbitrage opportunities.

Any access restrictions can have an even greater impact when the limited number of sites is considered. Depleted reservoirs, aquifers suitable for storage, and salt formations are all of limited extent in North America. Any target storage formation must first be reasonably close to a major pipeline before practical storage development can be considered. The mere presence of a candidate geologic formation for storage cavern development may not be sufficient to warrant practical storage development. For example, even though there are extensive bedded salt deposits in the Northeast United States, storage cavern development has been difficult to justify economically in the Northeast because there are few options for disposing (or otherwise utilizing) the massive salt brine volumes that naturally result from salt cavern development.

Comparison to Other Transportation Outlooks

An assessment of recent pipeline projects indicates that North American inter-regional pipeline capacity grew by 11.4 BCF/D from 1999 to 2002. This capacity growth exceeded the prediction of 8.7 BCF/D made in the 1999 NPC study. Most of the difference occurred in the Southeast and the Rocky Mountains. The growth in the Southeast was related to greater than expected market expansion (market pull), while the Rocky Mountain growth was in response to increased supply deliverability (supply push). The estimated average annual cost of this expansion was approximately $6.1 billion.[15] This compares to a 1990s average expenditure for the United States and Canada of $2.5 billion.[16]

The cost of pipeline construction per mile in the early to mid-1990s increased at an annual rate of 1.5% per year. Costs grew more rapidly from 1998 to 2000, averaging over 11% per year. Costs declined somewhat after the construction peak in 2000 because a smaller number of active projects led to lower prices for pipe, materials, and construction crews. However, despite the recent decline in construction activity, the growth rate in cost per mile increased by 3.1% per year from 1993 through 2002, which is twice the rate projected in the 1999 NPC study. The primary factors leading to larger than projected cost increases were higher expenses for right-of-way and labor.

Peak construction years for transmission pipelines in this study occur when Arctic pipelines are under construction (2008-2013). The overall construction estimates are lower than those that were projected in the 1999 NPC study, principally because of:

- Lower natural gas demand
- Lower production estimates from mature production regions
- Significantly higher imports of LNG directly into East and West Coast markets
- Utilization of existing pipeline infrastructure to transport gas from growing production regions.

Transmission, Distribution, and Storage Recommendations

Sustain and Enhance Natural Gas Infrastructure

Although the United States and Canada have an extensive pipeline, storage, and distribution network, additional infrastructure and increased maintenance will be required to meet the future needs of the natural gas market. The recommended actions listed below are required to ensure efficient pipeline, storage, and distribution systems:

- **Federal and state regulators should provide regulatory certainty by maintaining a consistent cost recovery and contracting environment wherein the roles and rules are clearly identified and not changing.** Regulators must recognize that aging infrastructure will need to be continuously maintained and upgraded to meet increasing throughput demand over the study period. They must also recognize that large investments will be required for the constructions of new infrastructure. To make the kinds of investments that will be required, operators and customers need a stable investment climate and distinguishable risk/reward opportunities. Changes to underlying regulatory policy, after long-term investments are made, increase regulatory and investment risk for both the investor and customers.

- **Complete permit reviews of major infrastructure projects within a one year period utilizing a "Joint Agency Review Process." Projects that connect incremental supply and eliminate market imbalances should be the highest priority and expedited.** Where available supply is constrained, FERC should expedite timely infrastructure project approvals that will help mitigate the current supply demand imbalance. Longer term, new project reviews should be expedited via continuing enhancement and increased participation in a Joint Agency Review Process, similar to that which FERC has utilized recently. A Joint Agency Review Process would require up-front involvement by all interested/concerned parties including appropriate jurisdictional agencies, allowing the decision process to proceed to approval and implementation more accurately, more timely, and at lower overall cost. The final FERC record should resolve all conflicts. The areas of greatest concern in this regard are requirements of the U.S. Army Corps of Engineers, Coastal Zone Management Act, and Section 401 of the Clean Water Act, all of which could hinder the orderly implementation of FERC certificates. This process must also assure that a project, which has used and successfully exited this process, may proceed per the direction received and will not be delayed by non-participating parties or other external regulatory standards or processes. This suggestion is a more-specific rendering of the 1999 NPC study's fifth recommendation:

[15] The INGAA Foundation, Inc., *Pipeline and Storage Infrastructure for a 30 Tcf Market – An Updated Assessment*, 2002.

[16] Ibid.

"Streamline processes that impact gas development." The NPC supports legislation that accomplishes the Joint Agency Review Process as described above. Regulators at federal, state, and local levels, with cooperation of all participating parties, should establish processes and timelines that would complete the regulatory review and approval process within 12 months of filing.

- **Regulatory policies should address the barriers to long-term, firm contracts for entities providing service to human needs customers.** Many LDCs will not enter into long-term contracts in today's market out of fear that regulators may subsequently deem them imprudent in the future. Similarly, power producers, especially those that provide peaking service, are reluctant to contract for firm pipeline service because charges for firm service cannot be economically justified in power sales. As discussed in Finding 9 in the Summary volume of this report, this practice is impairing the investment in infrastructure. The result is that regulatory practices that limit long-term contracts (prudence reviews and ratemaking) inhibit efficient markets and discourage the development and enhancement of pipeline infrastructure. The regulatory process must allow markets to transmit the correct price signals and enable market participants to respond appropriately. Regulators should encourage, at all levels of regulation, policies that endorse the principles of reliability and availability of the natural gas commodity. All regulatory bodies should recognize the importance of long-term, firm capacity contracts for entities providing service to human needs customers and remove impediments for parties to enter into such contracts.

- **FERC should allow operators to configure transportation and storage infrastructure and related tariff services to meet changing market demand profiles.** At the interstate level, FERC should continue to allow and expand flexibility in tariff rate and service offerings and continue to allow market-based rates for storage service where markets are shown to be competitive so that all parties can more accurately value services and make prudent contracting decisions. To ensure that existing and future transmission, distribution, and storage facilities can be adapted to meet the significantly varying load profiles of increased gas-fired generation, FERC and state regulators need to allow and encourage operators to optimize existing and proposed pipeline and storage facilities. In some cases, this will require significantly more flexible facility design based upon peak hourly flow requirements, and/or a modification to existing facilities to provide for optimizing storage injections in off-peak hours or in shoulder months.

- **Regulators should encourage collaborative research into more efficient and less expensive infrastructure options.** Funding for collaborative industry research and development is in the process of switching from a national tariff surcharge-funded basis to voluntary funding. Because of the benefits of reduced costs, system reliability, integrity, safety, and performance, DOE should continue funding for collaborative research. Regulators need to encourage and remove impediments regarding cost recovery of prudently incurred R&D by the operators to fund necessary collaborative research.

CHAPTER 6

MEXICO SUPPLY/DEMAND OUTLOOK

This chapter outlines the basic assumptions and outlook for Mexico's demand, supply, and associated infrastructure for natural gas.

Mexico consumes approximately seven quads (quadrillion Btu) of energy per year. Oil is the principal source of energy for Mexico, and is used primarily to provide heat for industrial applications, raw materials for chemical manufacturing, and fuel for power generation. Natural gas represents about 23% of Mexico's total energy demand, as shown in Figure 6-1. It is used primarily in chemical and manufacturing processes and has recently become the fuel of choice for new power generation facilities.

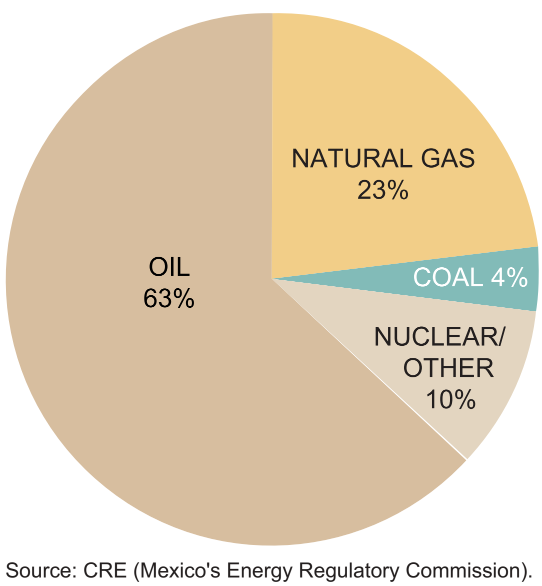


Figure 6-1. Primary Energy Consumption in Mexico

Mexico's gas demand of approximately 4.5 billion cubic feet per day (BCF/D) is met primarily by indigenous gas production augmented by pipeline imports from the United States. There are two gas transmission systems with about 6,000 miles of pipeline operated by Pemex that traverse the country north and south, as shown in Figure 6-2. Additionally, there are approximately 5,000 miles of distribution pipelines. The gas transmission and distribution system primarily serves industrial customers and the expanding power generation industry.

Background

Mexico continues to develop its natural gas industry to meet its burgeoning gas and power demand growth. Major natural gas policy objectives by the Fox Administration and Mexico's Energy Regulatory Commission (CRE) are as follows:

- Drive economic expansion by using natural gas for power generation and industrial growth
- Use natural gas to meet environmental standards in critical areas of the country, thereby decreasing consumption of fuel oil.

The country's natural gas sector is the most liberalized part of Mexico's energy system and portions of its pipeline and distribution infrastructure are open to private investment. However, energy investment spending by the state has traditionally focused on finding and developing new crude oil reserves for internal use and export. Several factors

Figure 6-2. Mexican Gas Transmission Systems

present significant challenges to the expansion of the gas market in Mexico:

- Limited capital is available to fund major new exploration and production projects, and foreign interests have been effectively excluded from petroleum exploration and production.
- There is a lack of gas pipeline infrastructure to move natural gas from the main producing regions in the south to the developing consuming regions in the north.
- The focus of reforms in Mexico's energy system has been primarily in the area of electricity generation.

Mexico's petroleum and natural gas resources have been held as property of the state since nationalization of the petroleum industry in 1938. Further, labor unions generally do not support foreign participation in the exploration and development of petroleum resources. Pemex retains exclusive rights to exploration and production of Mexico's natural gas according to Article 27 of the Constitution. In order to achieve the expansion of the gas supply required to meet future demand, the current administration has recently proposed a Multiple Services Contract (MSC) concept to allow limited foreign participation in exploration and production of oil and natural gas. Under the MSC concept, private companies bid to develop and operate production under a fee for services arrangement. It is as yet unclear whether this concept will attract sufficient interest and capital to achieve the desired growth objectives.

Economic Growth

Future demand for natural gas in Mexico will be determined by a number of factors. Economic growth, characterized by the change in gross domestic product (GDP), is a key factor influencing energy demand, including the demand for natural gas. Mexico's GDP growth averaged 3.7% per year from 1970 to 2002, generally declining over that period. Figure 6-3 shows annual GDP growth for Mexico, together with the GDP growth assumptions used in the NPC study to project natural gas demand. Mexico's projected GDP growth was developed in a manner consistent with the assumptions used in this study for the United States (3% per year) and Canada (2.6% per year). These assumptions reflect an economic rebound after the recent economic recession.

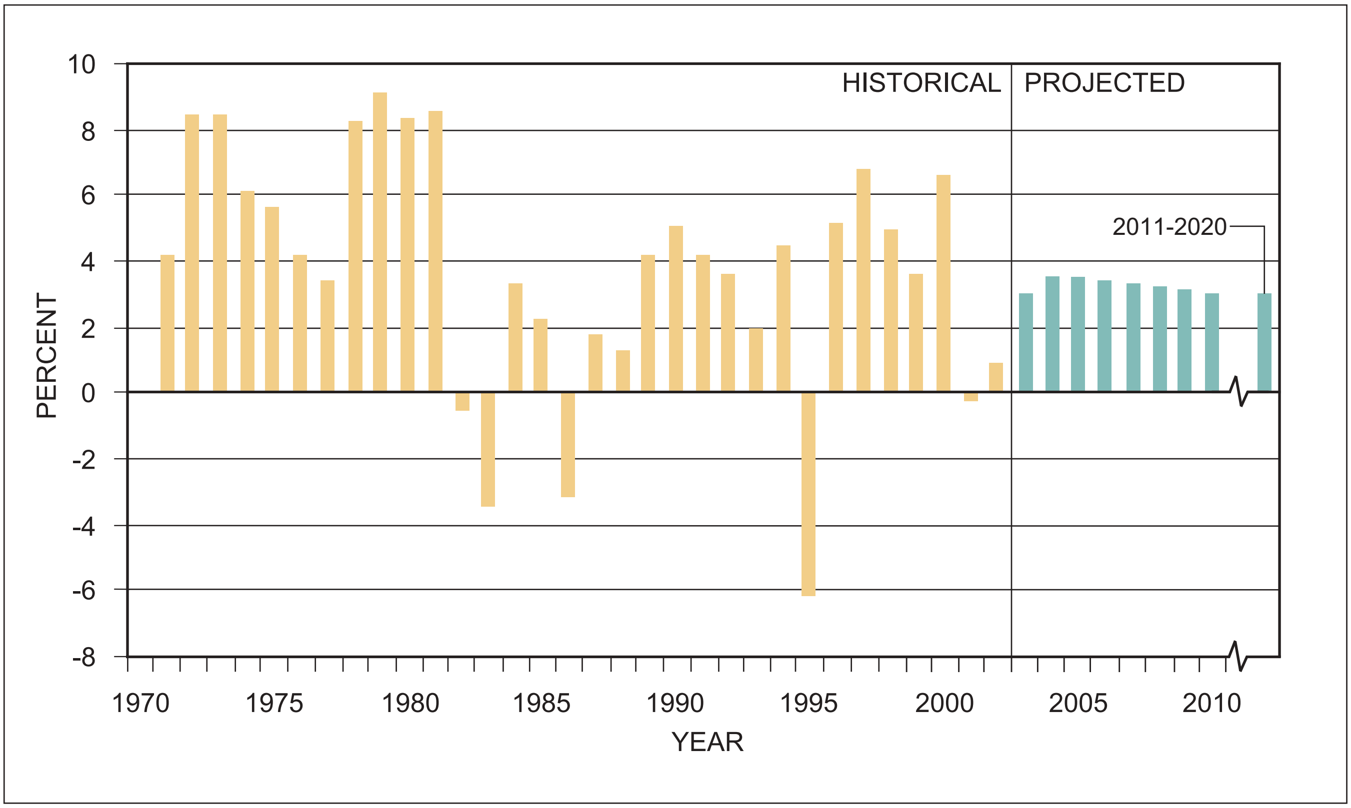


Figure 6-3. Mexican GDP Growth

However, given the uneven nature of the historical growth, the range of average future GDP growth in Mexico could be 2% to 4% per year.

The economic growth outlook for Mexico used in the NPC projections are summarized as follows:

- 2003 – GDP growth of 3.0%
- 2004 – GDP growth of 3.5%
- 2005 to 2010 – GDP growth of 3.5 to 3.0% per year
- 2011 to 2020 – GDP growth of 3.0% per year.

Natural Gas Demand

Mexico's natural gas demand reached 4.8 BCF/D in 2002 and has been growing at a rate of approximately 5% per year since 1992. Figure 6-4 shows historical demand for the major sectors of natural gas consumption. Growth rates for the 10-year period of 1993-2002 are also shown for each area. The largest sector of demand is petroleum-related activity associated with Pemex. Power generation is the highest growth segment, as gas-fired power technologies have been increasingly deployed in Mexico to satisfy growing power demand. Industrial demand for natural gas has shrunk since 1998 reflecting rising gas prices in North America. The significant drop in industrial natural gas demand in 2002-2003 illustrates the inter-relationships of Mexican industries with other industrial concerns in North America. Residential and commercial consumption is very small due to low space-heating requirements and the widespread use of liquefied petroleum gas (LPG) for home cooking.

Gas-fired power generation is likely to be the primary source of increasing gas demand in Mexico, as evidenced by recent growth in combined-cycle generation capacity from 5,700 megawatts in 2001 to 7,900 megawatts in 2002. Mexico remains short of electricity generation capacity, and virtually all new capacity additions are anticipated to be gas-fired.

The NPC study assumes natural gas demand will increase in Mexico to accommodate the general economic growth as well as the specific requirements of new gas-fired generation capacity. Historically, gas demand has been limited by the amount of indigenous supply made available by Pemex plus imports.

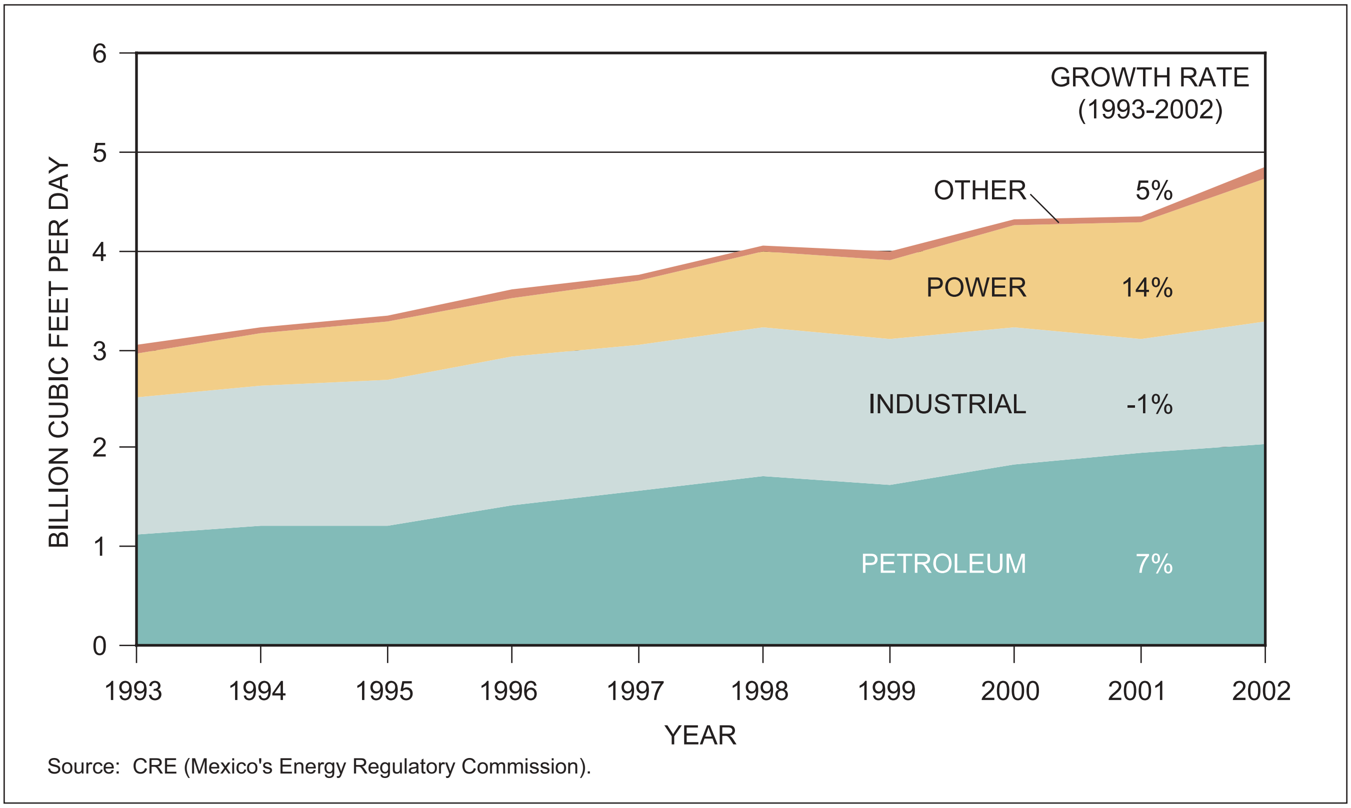


Figure 6-4. Mexican Gas Demand

It is unclear whether Pemex will be able to increase the rate of internal supply growth. Therefore, the level of pipeline and liquefied natural gas (LNG) imports will be a critical determinant in future demand.

Three cases have been developed to consider potential future demand for natural gas in Mexico:

- "High Demand Case," with overall natural gas demand growing at 6.0% per year, assuming natural gas-fired power generation grows at a rate of 14% per year, consistent with the outlook of SENER (Mexico's Energy Ministry).

- "Continued Trends," wherein demand grows at a historical rate of 4.7% per year

- "Low Demand Case," with overall natural gas demand growing at 2.9% per year, reflecting import supply limitations that could result from higher future natural gas prices ($4 to $6 per million Btu at Henry Hub).

Figure 6-5 shows the demand projections for these three cases. The outlook of the U.S. Energy Information Administration is also included for reference.

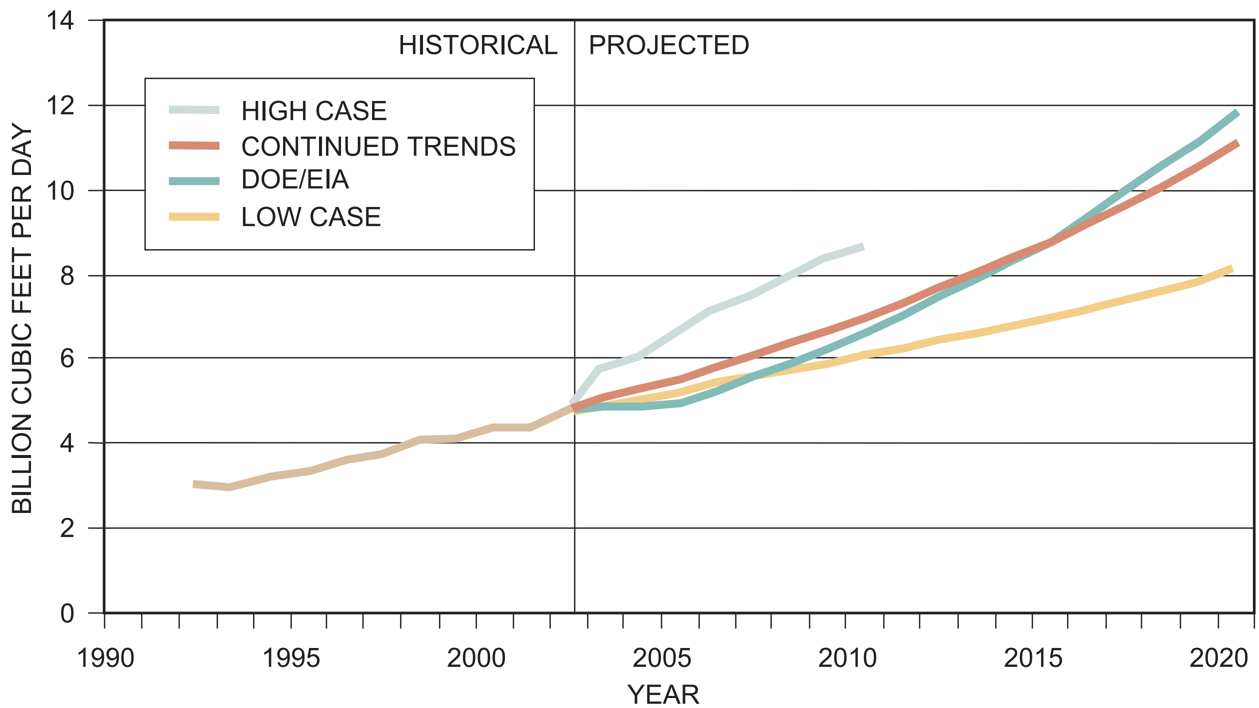
Natural Gas Supply

Current Production

Mexico currently produces approximately 4.5 BCF/D, primarily from the regions shown in Figure 6-6. About 70% of Mexico's natural gas is produced in association with oil, or "associated gas," with the remaining non-associated gas produced from gas fields.

Figure 6-7 shows Mexico's natural gas production since 1980. Production has been relatively flat since 1997 with declines in associated gas fields of the southern regions offset by increases in non-associated gas from northern fields. As productive capacity in the south continues to decline, most of the new supply will likely come from the northern areas of Mexico. The Pemex national pipeline system will need to adapt to these changes.

The NPC study assumes that production growth rates will be 3% per year for each of the three



Source: Historical data from CRE (Mexico's Energy Regulatory Commission).

Figure 6-5. Mexican Gas Demand Outlook

Figure 6-6. Major Natural Gas Producing Areas in Mexico

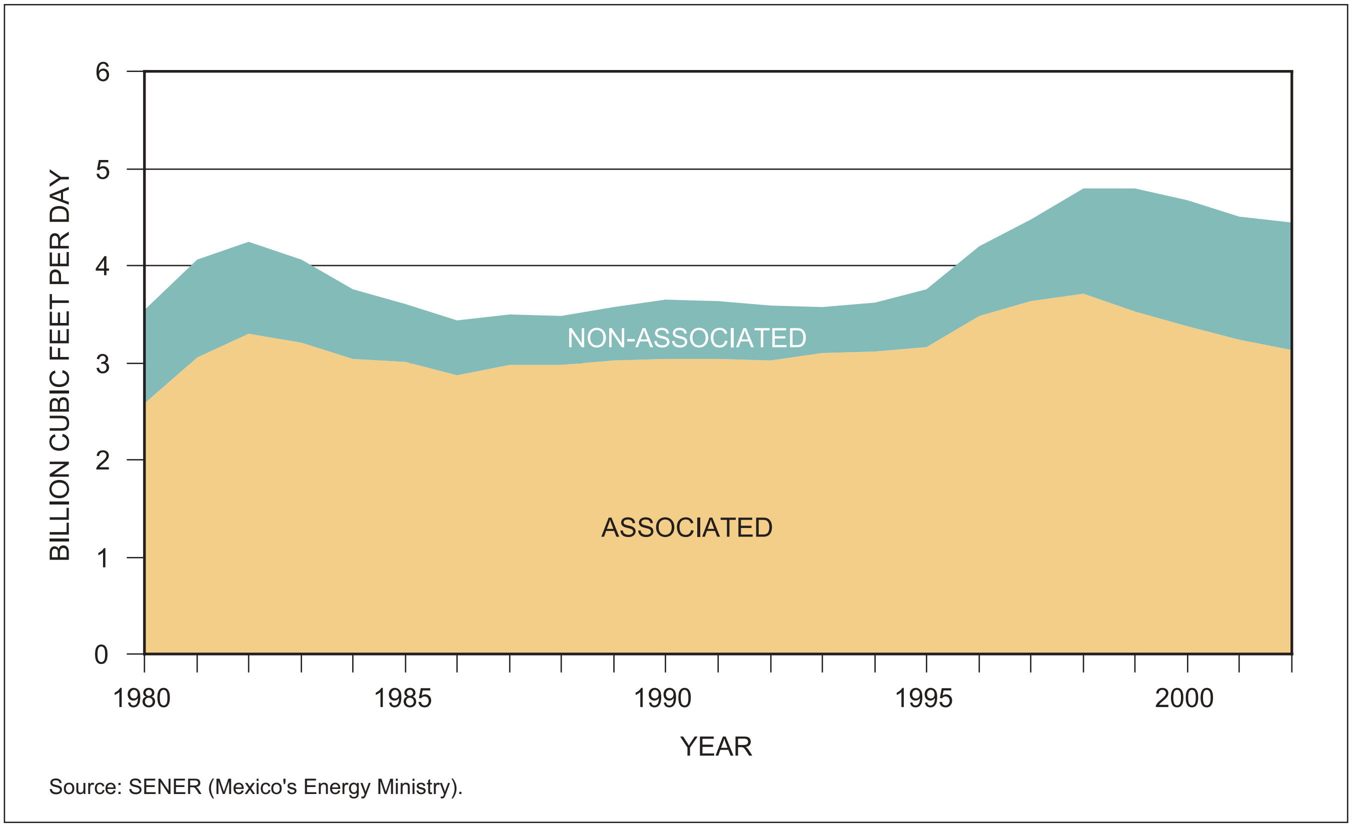


Figure 6-7. Historical Natural Gas Production in Mexico

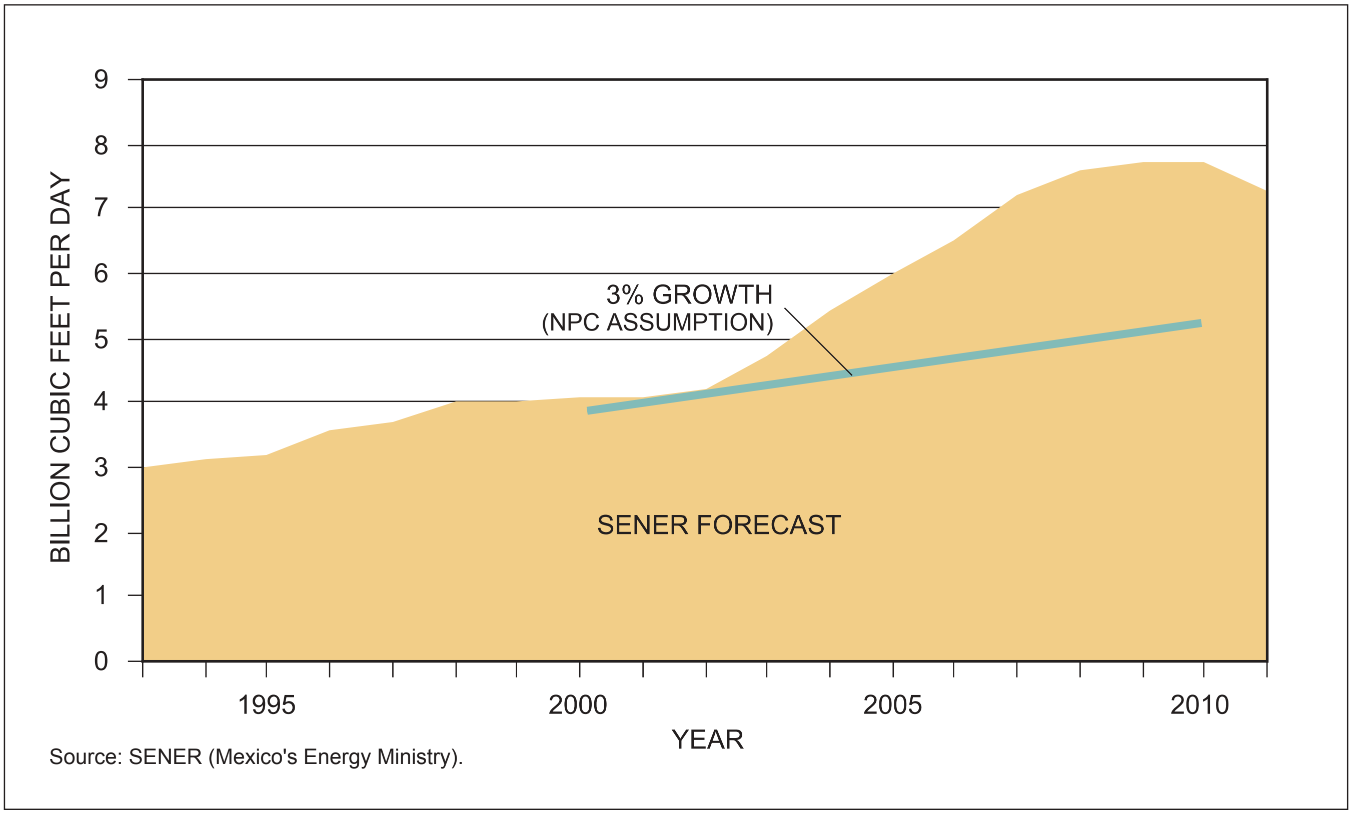


Figure 6-8. Production Outlook for Mexico

aforementioned cases ("High Case," "Continued Trends," and "Low Case"). Figure 6-8 shows the NPC projection of 3% per year overlaid on the projection of the SENER, which reflects an increase in natural gas production of 7% per year through 2012. The SENER projection is double the historical rate and will likely require a significant increase in the rate of investment. In this regard, the Fox Administration has doubled the resources channeled to exploration and production within the past two years.

Resource and Reserves Potential

Mexico has five regions with significant undiscovered gas: Sabinas, Burgos, Tampico-Misantla, Veracruz, and Sureste. All of the regions have onshore, shelf, and slope components except for Sabinas, which is exclusively onshore. These regions are shown in Figure 6-9. Water depth and drilling depth are keys to the economic potential of these areas.

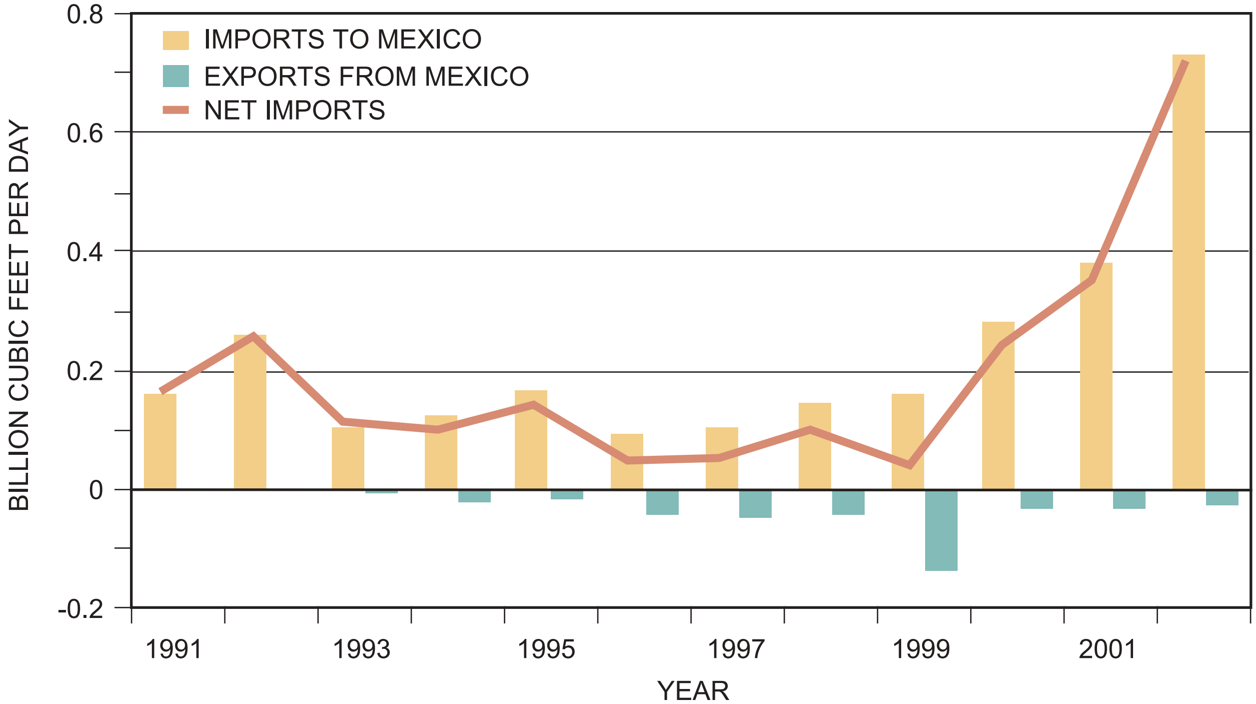
The NPC estimates 70 trillion cubic feet (TCF) of undiscovered gas in Mexico. The onshore and offshore Burgos Basin located adjacent to southern Texas is the most important non-associated gas basin in Mexico with undiscovered gas potential of 26 TCF. There is significant potential for growth of existing gas fields by infill drilling and reduced spacing in the onshore Burgos Basin. The other significant area is Sureste onshore and offshore with undiscovered gas of 23 TCF, which is mostly associated gas. The offshore Gulf of Mexico is lightly drilled compared to the U.S. Gulf of Mexico, particularly in the deepwater areas. Limited capital availability and long lead times to develop production tend to limit deepwater gas development activity.

Mexico has current proved gas reserves of 28 TCF and annual production of 1.3 TCF per year. Total remaining reserves including proved, probable, and possible reserves, are 51 TCF; of this total, 41 TCF is associated gas and 10 TCF is non-associated.

Natural Gas Import/Export Balance

The Mexican natural gas import/export balance has deteriorated over the past 10 years because indigenous supply has been unable to keep up with increased demand. As shown in Figure 6-10, the net balance increased to almost 800 million cubic feet per day (MMCF/D) in 2002 from the U.S. to Mexico.

Figure 6-9. Major Natural Gas Resource Areas in Mexico



Source: Energy Information Administration.

Figure 6-10. Historical U.S./Mexico Natural Gas Import/Export Balance

Major expansions of gas pipeline import capacity have been implemented with current capacity of 2.5 BCF/D.

Three cases have been developed to address potential pipeline and LNG imports under the three demand outlooks – High Demand, Continued Trends, and Low Demand cases. As discussed earlier, production is assumed to grow at the historical rate of 3% per year in each of these cases. Pipeline and LNG imports were varied to balance supply and demand. For the Continued Trends case, Mexico will likely have to rely on the United States to meet rapidly growing demand through 2005 with pipeline imports reaching 1.6 BCF/D. Longer term, pipeline imports from the United States decline to 1.1 BCF/D, reflecting declining South Texas supplies and the incentive to reduce foreign imports to minimum levels. Pipeline capacity limits of about 2.5 BCF/D would not appear to be a limiting factor. Additionally, pipeline imports could be expanded if supplies were available and Mexico were willing to manage the related trade balance with the United States. Figure 6-11 shows the U.S./Mexico import/export balance for the Continued Trends case. Significant LNG imports are implied by this case, and could be available.

Table 6-1 summarizes the pipeline imports assumed in each demand case.

Case	2010	2020
High Demand	1.1	1.1
Continued Trends	1.1	1.1
Low Demand	0.8	0.9

Table 6-1. Pipeline Imports from United States to Mexico, Excluding Baja (Billion Cubic Feet per Day)

Potential LNG Import Volumes

LNG imports are likely the least expensive of the supply options in the longer term. The Continued Trends case has been adopted as the base for

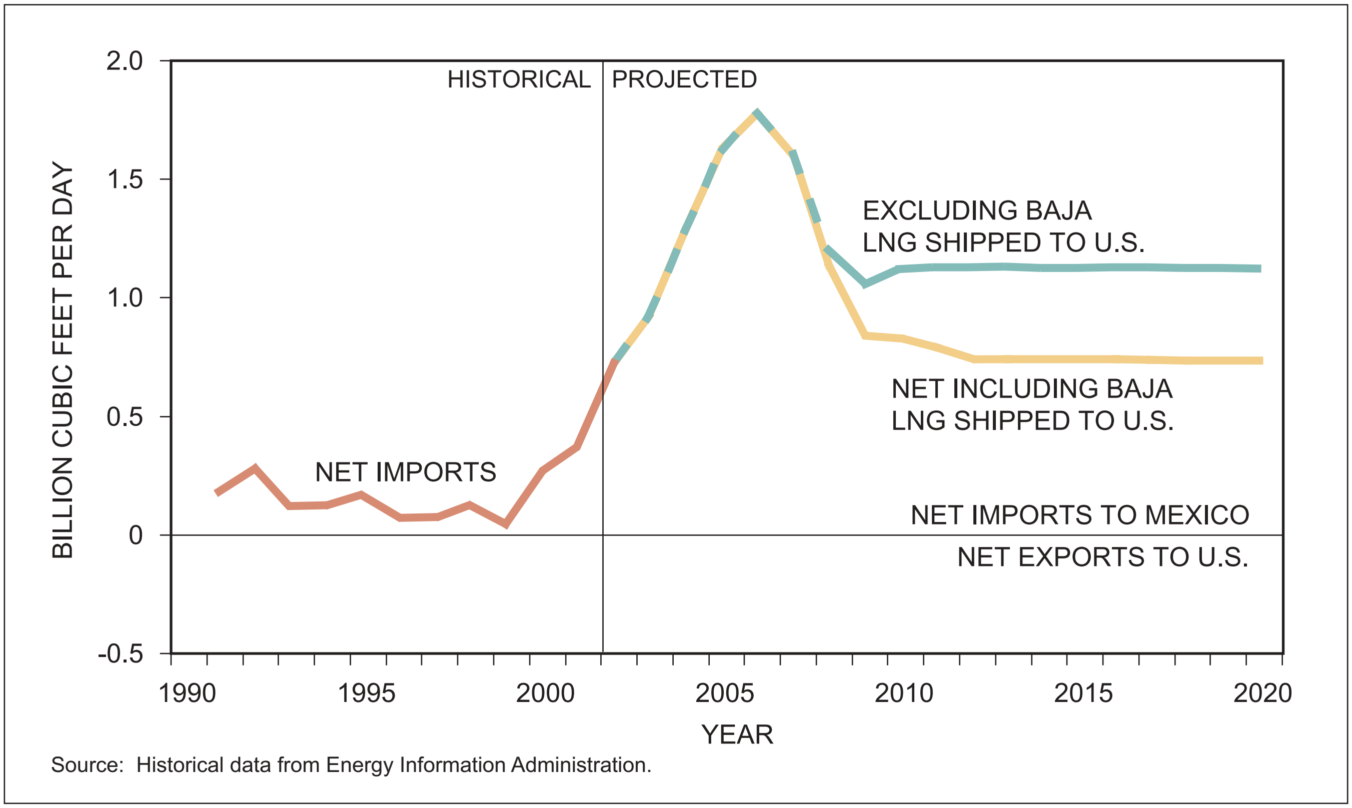


Figure 6-11. U.S./Mexico Natural Gas Import/Export Balance Assumptions

U.S./Mexico import/export imbalances and requires up to 2.9 BCF/D of LNG imports. The High Demand case would require up to 5.5 BCF/D of LNG imports. The Low Demand case requires no LNG imports due to the production growing at the same rate as demand growth. Figures 6-12, 6-13, and 6-14 show the pipeline and LNG imports for the various cases.

Pipeline Interconnection Capacities

There is 2.6 BCF/D of pipeline import capacity between the United States and Mexico. This is sufficient capacity to meet the forecast Mexico imports from the United States unless new LNG import facilities are not constructed. In the "No LNG Imports" case, Mexico could need up to 6 BCF/D of pipeline capacity. Figure 6-15 shows the pipeline interconnects.

LNG Import Terminals

LNG is expected to meet some of the growing Mexican demand, particularly for power generation in the eastern and Baja areas. There are proposals to develop LNG import facilities on the east and west coasts of Mexico. The CFE (Mexican Federal Electricity Commission) has proposed the construction of import facilities in Altamira for a major Independent Power Plant development. Foreign firms have shown interest in constructing import facilities on the Pacific coast to serve markets in Mexico and the Southwest U.S. LNG imports are important in that they will be designed to meet growing demand while not necessarily depending on the Pemex transmission system. For instance, the Baja LNG terminal will not necessarily be connected to the Pemex system. Also, the Altamira terminal will primarily serve a single generation facility. Figure 6-16 shows the proposed LNG import terminals.

The overall supply/demand balance could be significantly altered with varying LNG import profiles. LNG will have to compete with indigenous supply from Mexico and with U.S. imports. As such, it seems unlikely that Mexico will significantly increase its pipeline gas imports from the United States in the longer term while pursuing LNG imports. Also there will be large incentives for Mexico to fully develop its indigenous supply.

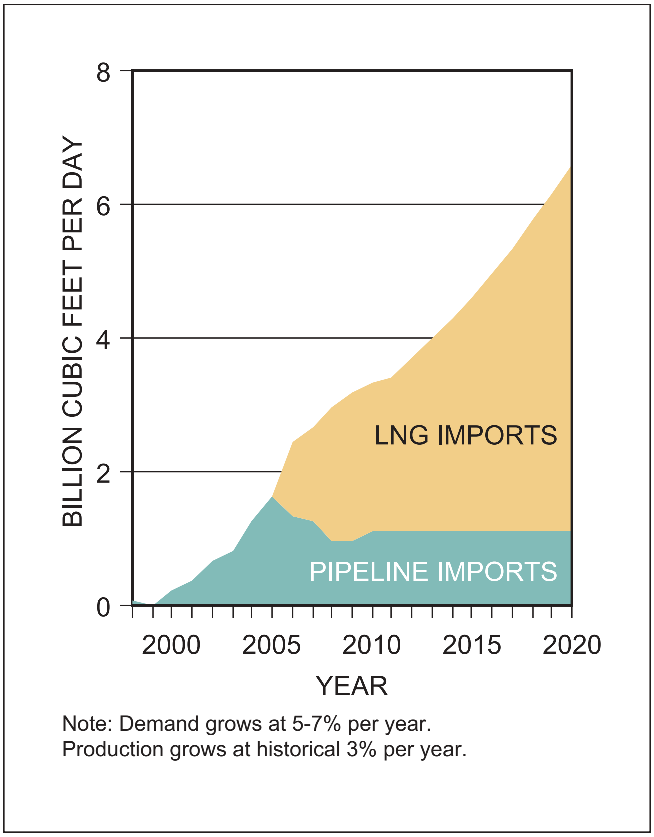


Figure 6-12. Mexico Imports – High Demand Case

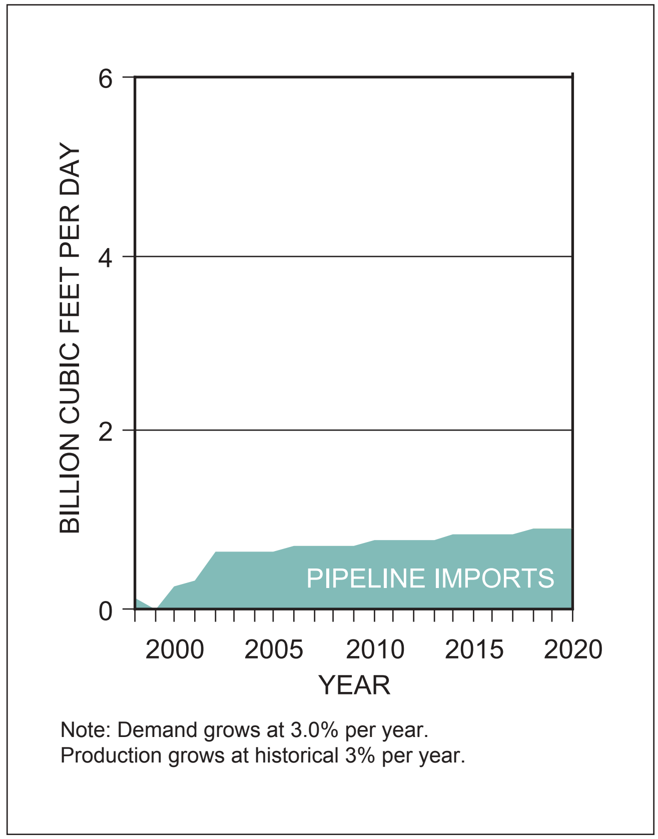


Figure 6-14. Mexico Imports – Low Demand Case

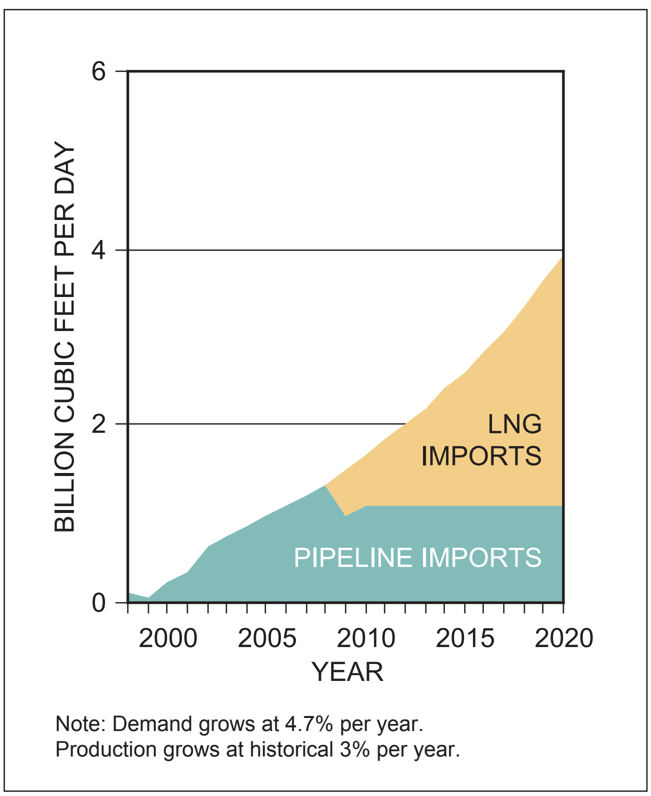


Figure 6-13. Mexico Imports – Continued Trends

Strategic Implications

Mexico remains an uncertainty in the North American gas balance. Unknowns related to both demand and supply give rise to widely varying potentials for import and exports to the United States. This balance ultimately rests on Mexico's stance relative to foreign participation in its exploration and production industries and its ability to attract LNG imports. Only with major increases in investment will Mexico be able to develop its supply resources at a pace different from history. Without new indigenous supplies, demand growth will be limited to what gas is produced and imported.

The NPC North American gas balance assumes the Continued Trends scenario with net pipeline imports from the United States to Mexico of approximately 1.1 BCF/D (excluding Baja LNG shipments of 400 MMCF/D to the United States via the Mexican peninsula).

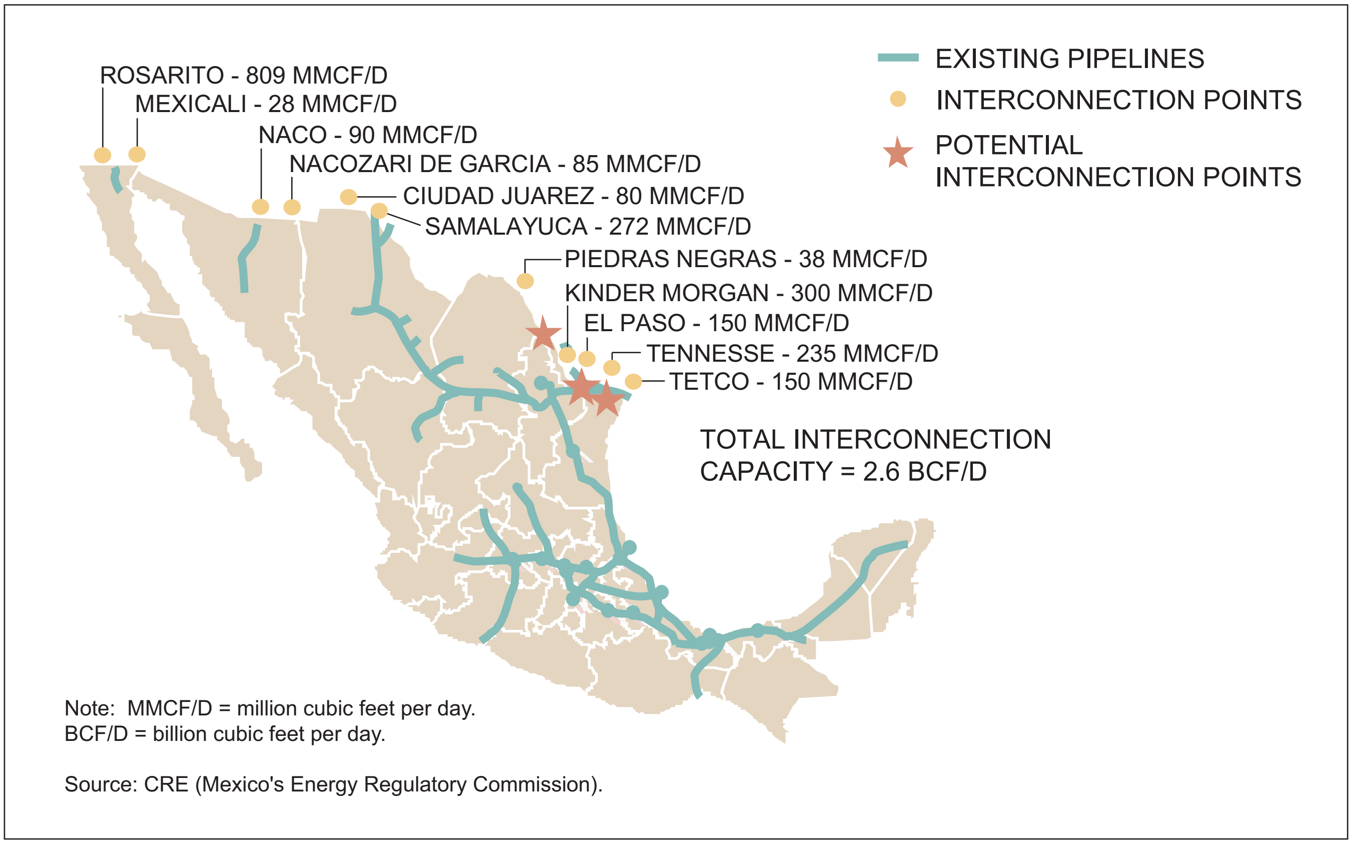


Figure 6-15. Current Mexican Interconnection Capacities

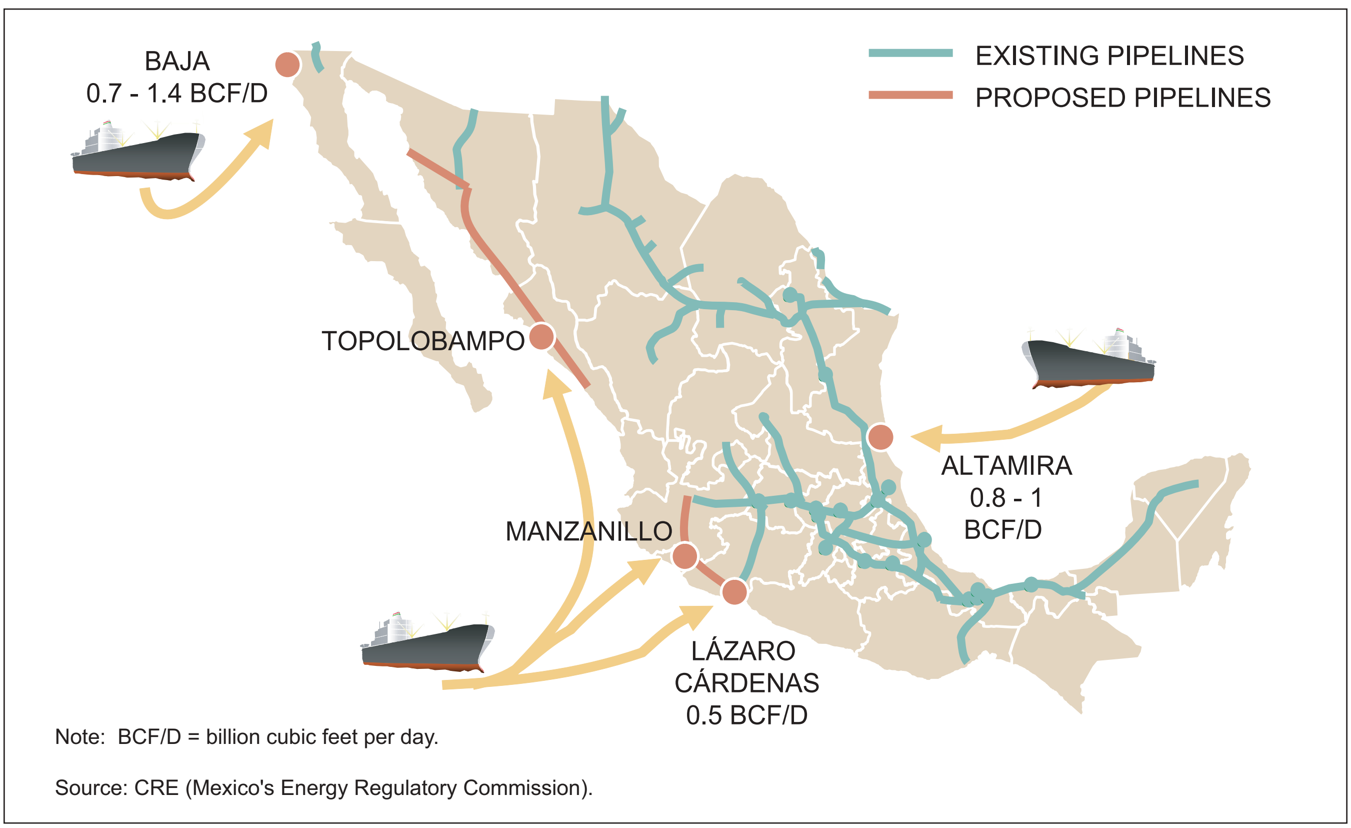


Figure 6-16. Proposed Mexican LNG Terminals

CHAPTER 7

NATURAL GAS MARKETS

Market-Related Issues

The North American natural gas market is the largest and most liquid gas market in the world, with hundreds of suppliers and thousands of major consumers including local distribution companies (LDCs), industrials, and power generators. The market is functioning efficiently with lessened government involvement following years of regulatory reform. The wholesale commodity and related financial instruments are not price regulated while the Federal Energy Regulatory Commission (FERC) does regulate interstate gas transmission and storage services. Furthermore, state public utilities commissions regulate the prudency of gas commercial practices and rates of local gas distribution companies.

Key characteristics of a healthy and well-functioning competitive North American gas market are a high degree of price transparency and overall market liquidity. Market participants must have reliable supply, demand, storage, pipeline capacity, and price information. They should be encouraged and be able to take appropriate actions in response to market signals, thereby optimizing the supply/demand balance from their individual perspective.

There have been significant changes in gas market participants since 2001. Several large marketing companies have exited the physical and financial gas trading business, and on-line trading operations have declined. The broad portfolio of financial products offered by these players has been reduced and the need to trade with creditworthy entities has been reinforced. These changes have highlighted a potential decline in market depth (e.g., number of players) particularly for long-term hedges, and therefore have contributed to a reduction in some customers' ability to manage long-term price volatility.

Price Transparency

Industry publications have reported monthly, weekly, and daily price indices for physical trades of gas at approximately 100 different locations for more than 10 years. These indices are based on the reported volumes traded at each location for actual fixed price physical contracts. In addition, the highly transparent New York Mercantile Exchange (NYMEX) futures contract for the Henry Hub, Louisiana physical delivery point is available for forward financial pricing and gas-related financial instruments. Industry and regulators have recently questioned the integrity of the physical index reported trade information. Some market participants have acknowledged improper reporting of trade information. There is a major effort headed by FERC and industry to improve the integrity of the process and to clarify and encourage accurate and adequate price reporting. The NPC supports FERC's efforts to increase market transparency and price reliability with minimal government intervention.

Physical Market Liquidity

Liquidity of the physical gas markets must be examined separately from that of the financial markets. Physically traded volumes of gas (first sales) have increased as supply and demand have grown over the 1986 to 2001 time period. In parallel, reported physical trade volumes of the largest natural gas marketers grew throughout the 1990s. At the peak in 2001-2002, the top ten marketer's volumes represented more than twice the average daily physical consumption of gas, as shown in Figure 7-1. This buying and reselling of gas tends to add liquidity and flexibility to the market. Gas

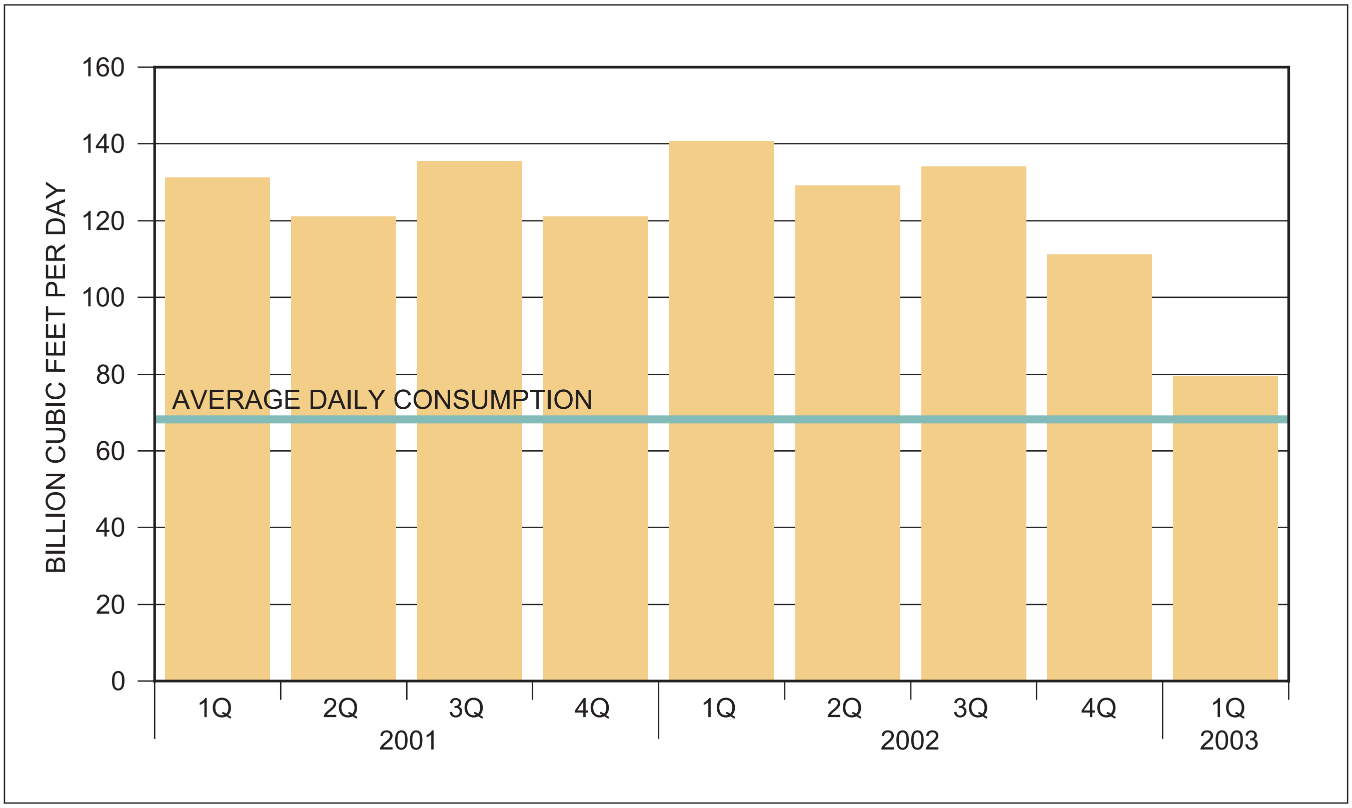


Figure 7-1. Quarterly Gas Volumes by Top Ten Marketers

marketer volumes declined in 2002 and continued to decline in 2003 with the restructuring of the merchant trading business.

Although physical flows have remained relatively constant, liquidity at some locations other than the major hubs is reduced from that of recent years, and reported trading volumes have declined from recent peaks. A number of factors may be contributing to this phenomenon, including the lack of a safe harbor for inadvertent mis-reporting of gas trade information. Industry and FERC efforts to improve reporting of trades are targeted to improve this issue. While industry lacks comprehensive historical data for trading liquidity, anecdotal evidence indicates that availability of buyers and sellers at various market hubs varies significantly depending on supply and demand factors. Some points are known to be highly liquid with very large volumes and hundreds of participants, while others are not. Prudent market participants should continue to develop sufficient market intelligence to guide commercial decisions and protect their interests. Buyers and sellers have the option to trade at larger, liquid points and make appropriate locational or price basis adjustments for other less liquid points.

Credit between counterparties has become a much more important issue than in the past. Market participants have high-graded their portfolio of trading parties and reduced overall credit risk.

Financial Market Liquidity

The rise in the use of financial products has been fairly dramatic since 1990. The trend in the use of NYMEX financial instruments is illustrated in Figure 7-2 and shows increasing open interest in NYMEX contracts through mid-2002. A decline is exhibited in 2003. Open interest is a measure of activity on NYMEX and gives some indication of overall market depth and liquidity.[1] Current levels of NYMEX trading at the Henry Hub are below the peak but above the overall range of the 1990s. Some of the peak activity was likely exacerbated by credit issues between counterparties that pushed transactions to the NYMEX in order to address the credit concerns as several large marketers exited the business.

[1] Open interest is defined as the number of open or outstanding contracts for which an individual or entity is obligated to the NYMEX because that individual or entity has not yet made an offsetting sale or purchase, an actual contract delivery, or, in the case of options, exercised the option.

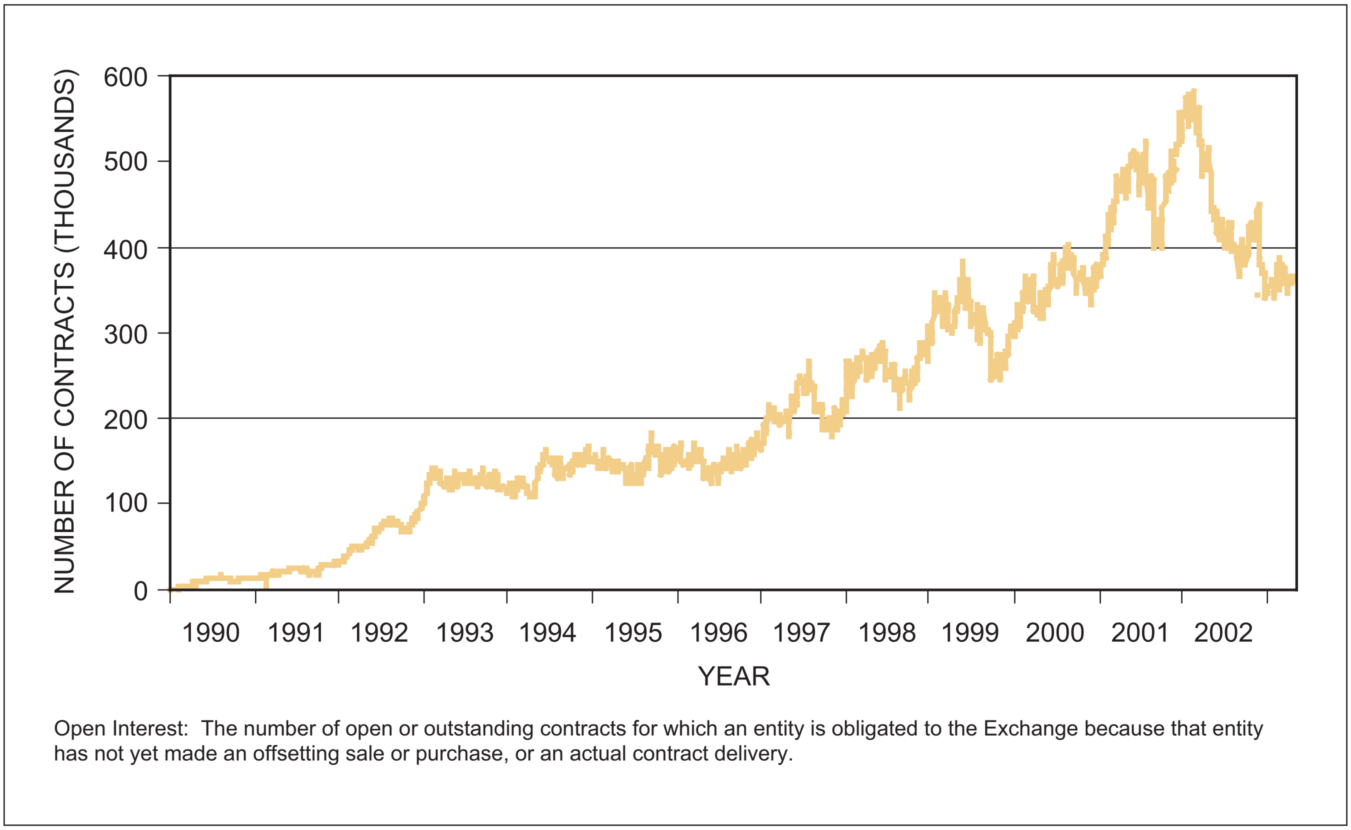


Figure 7-2. NYMEX Open Interest – Natural Gas Contracts

Marketers have traditionally been the major market makers and counterparties for a broad suite of NYMEX and over-the-counter financial tools (price swaps, forward price options, basis swaps, etc.) in addition to physical gas volumes. There are now fewer marketing entities offering these comprehensive services. The creditworthiness of the remaining parties and new entities entering the market (primarily banks) however has improved. This restructuring of the financial markets should be viewed as a positive trend.

Despite the recent changes in market participants, overall liquidity remains sufficient for parties to transact at multiple physical trading hubs and to access effective financial markets. Physical volumes at major hubs have been relatively constant throughout the period. The volume of financial trades has been variable and is down from peaks in 2001.

Continued enhancement of market liquidity and expanded market depth remain goals for industry, and the market is adjusting as appropriate. Government should allow free market forces to work, and markets will continue adjusting for an effective, efficient balance.

Natural Gas Price Volatility

Restructuring of the gas industry and the deregulation of the natural gas commodity has produced a competitive market with lower natural gas prices to consumers. Accompanying this deregulation has been greater variability in natural gas prices as market forces establish prices in the monthly and daily markets. Price volatility is a natural dynamic in a commodity market where supply and demand vary. Natural gas, electricity, crude oil, and oil product markets have all exhibited price volatility to varying degrees. Relatively large price changes (spikes and declines) occur in natural gas markets because supply and/or demand are not able to adjust quickly enough to cause a smooth price trend. Volatility tends to highlight inelasticity in some market segments.

The principal drivers behind volatility are supply and demand fundamentals, which include growth trends, weather, storage levels, and perceived market trends. Price volatility has a wide range of impact on market participants and there are several tools to manage the effects.

Finding: Price volatility is a fundamental aspect of a free market, reflecting the variable nature of demand and supply; physical and risk management tools allow many market participants to moderate the effects of volatility.

Price Volatility in the North American Market

The vast majority (80-90% by volume) of natural gas marketed in the United States and Canada is sold on a monthly basis. The remainder (10-20%) is bought and sold in the daily cash market and is primarily used to manage the overall supply/demand balance during the month. Volatility is a measure of the variation of price from its mean value over a period of interest (daily, monthly, or yearly). Volatility in the broadest sense is the "noise" around the long-term movement of price. Some industry participants tend to think of volatility either in terms of abnormally "high" or "low" prices, or specific upward or downward movement in prices. This is incorrect. Volatility is simply a measure of variability around a mean value, not a measure of the absolute price.

Price volatility is important to market participants in optimizing near-term operating decisions because the level of volatility establishes the cost of options in gas futures contracts on NYMEX. The annual variability of gas price, if it is sufficiently large, creates a "seasonal spread" that produces an incentive for storage of gas among merchant energy companies and producers. It is, however, the long-term price trend that drives major investment decisions in both the consuming and supply sectors.

Volatility Analysis

Gas prices exhibit a "log normal" distribution due to the fact that prices have no upside constraint, but are constrained on the downside by zero, as demonstrated in Figure 7-3. Therefore, a random distribution will be skewed positively around the mean price, the essence of log normality.

Although commodity prices follow a log normal distribution, changes in prices over specific periods can be either positive or negative, and approximate a normal distribution. Therefore the financial community looks at the log of the relative price changes to model historical and future price variations (see calculation methodology in box).

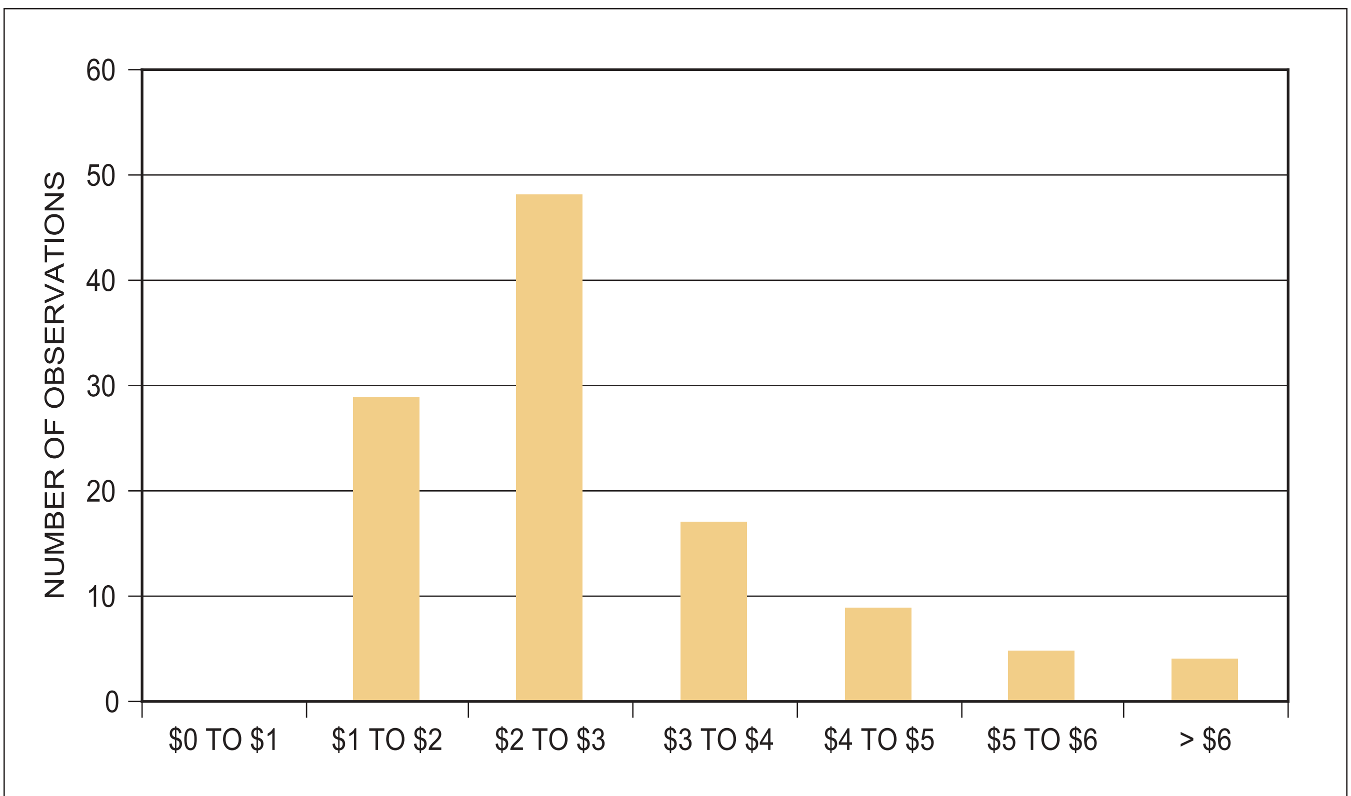


Figure 7-3. Frequency of Monthly Prices (1995 to 2003), Number of Observations in Price Range

Daily Gas Price Analysis

P_i = Price on a specific day
P_{i-1} = Price on prior day
Price Change $_i$ = Return $_i$ = $\text{Ln}(P_i / P_{i-1})$
Return average = $(\sum \text{Return}_i)/n$

Where: *n = total number of price observations*
Ln = natural log
$\sum$ represents "the sum" from 1 to n observations

Standard Deviation = Square root of variance
= $\text{SQRT}[\{\sum(\text{Return}_i - \text{Return}_{avg})^{*2}\}/(n-1)]$

Annualized Volatility = (Standard deviation) X (SQRT of # of prices in period)
Volatility is expressed as percentage. By convention, the number of prices or trading days in a year is 256 for daily prices.

For the purposes of this discussion, volatility is examined in a historical perspective. Implied forward volatility and forward NYMEX prices are financial tools that may be used to understand where the market is trading for future periods. The NPC recognizes that market participants may use the forward financial markets to buy and sell gas or enter into other hedging activities (e.g., puts and calls) to obtain price certainty and mitigate the impact of price volatility.

Historical Natural Gas Prices and Volatility

Henry Hub is a pipeline interchange in Louisiana where a number of interstate and intrastate pipelines connect through a header system. It is the standard delivery point for the NYMEX natural gas futures contract. There are two common price bases quoted for natural gas: 1) gas sold monthly and based on a first-of-month index price, and 2) gas sold on a daily cash basis. Figure 7-4 shows Henry Hub natural gas prices for both price bases.

North American gas prices have ranged since 1994 from less than \$2.00/MMBtu to \$10.00/MMBtu at the Henry Hub. The monthly index and daily cash prices follow each other closely. However, the daily cash price shows wider variability than the monthly market. This is particularly evident in the winters of 1995-1996 and 2000-2001.

Volatility of cash prices as calculated on a rolling 30-day basis has varied from 20% to 200% and has been highest during the late winter period, as shown in Figure 7-5. Periods of very high volatility reflect relatively inelastic demand during a peak winter period, usually exacerbated by abnormal weather, as shown in Figure 7-6. There is no correlation between volatility and the absolute price, because there are volatile periods with prices across the entire range.

Yearly average price volatility, as measured from the monthly index prices, is 60% over the 1995-2003 period, as shown in Figure 7-7. This volatility measure is related to the range of monthly prices that could be expected over a one-year period for longer-term investment decisions.

Comparison of Natural Gas Price Volatility vs. Crude Oil and Electricity

Figures 7-8 and 7-9 show the price trends for crude oil and electricity, respectively. Electricity price has volatility in the range of 200% and higher. Volatility in electricity price has been substantially higher than crude oil or natural gas. The primary drivers are the inability to store electricity and a declining reserve margin in key areas of the United States. Recent declines in volatility show, in part, the impacts of major gas-fired capacity additions creating a surplus of generation capacity above consumption requirements.

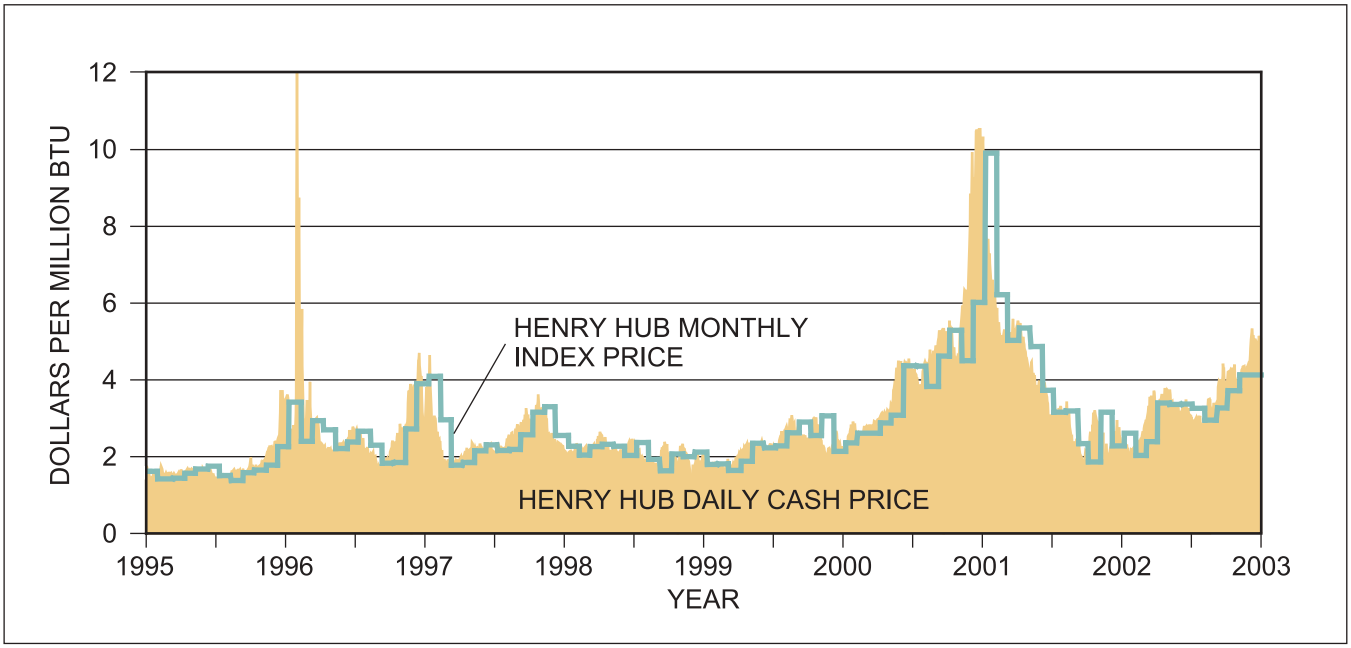


Figure 7-4. Henry Hub Natural Gas Prices

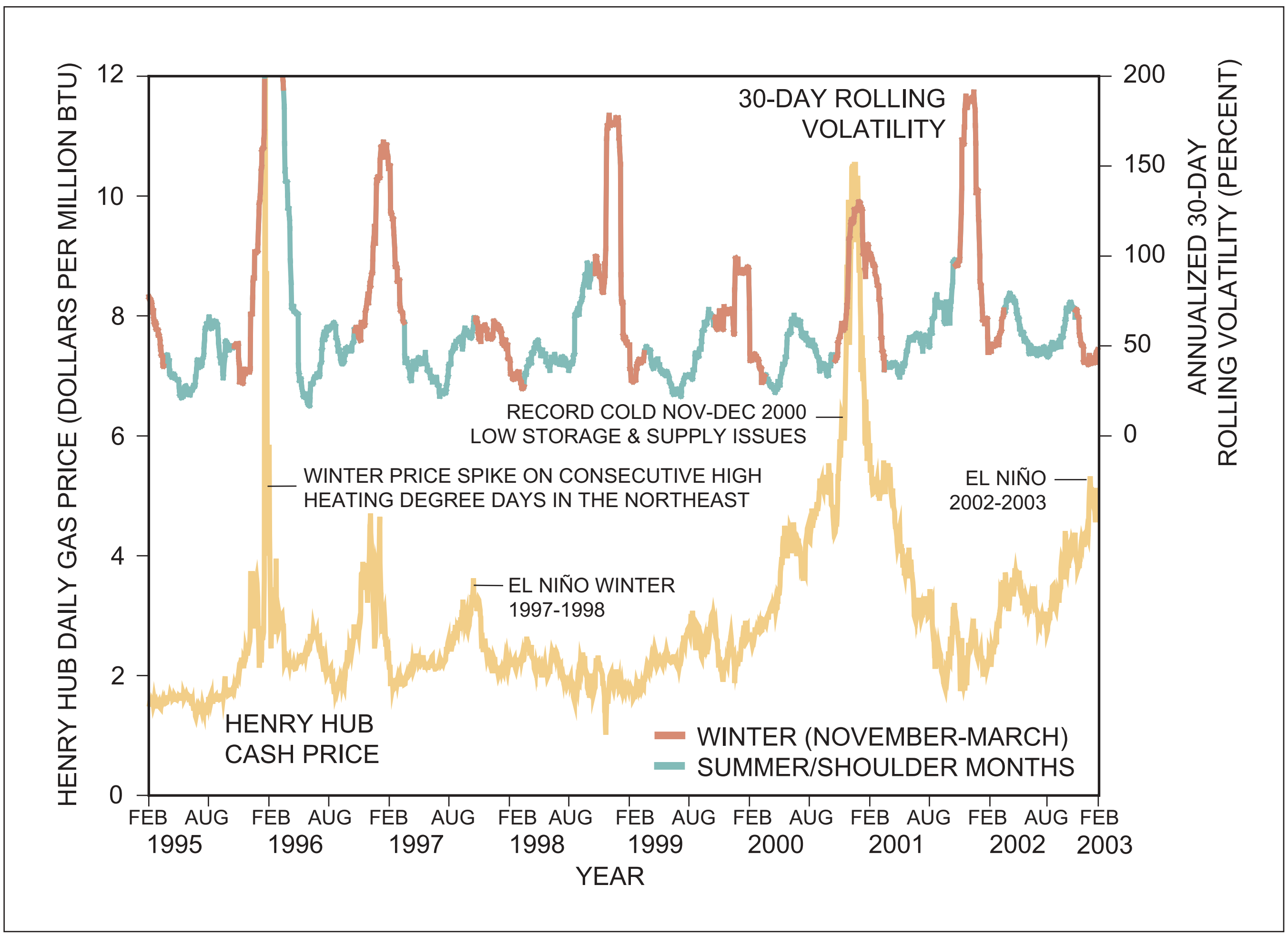


Figure 7-5. Natural Gas Price and Volatility

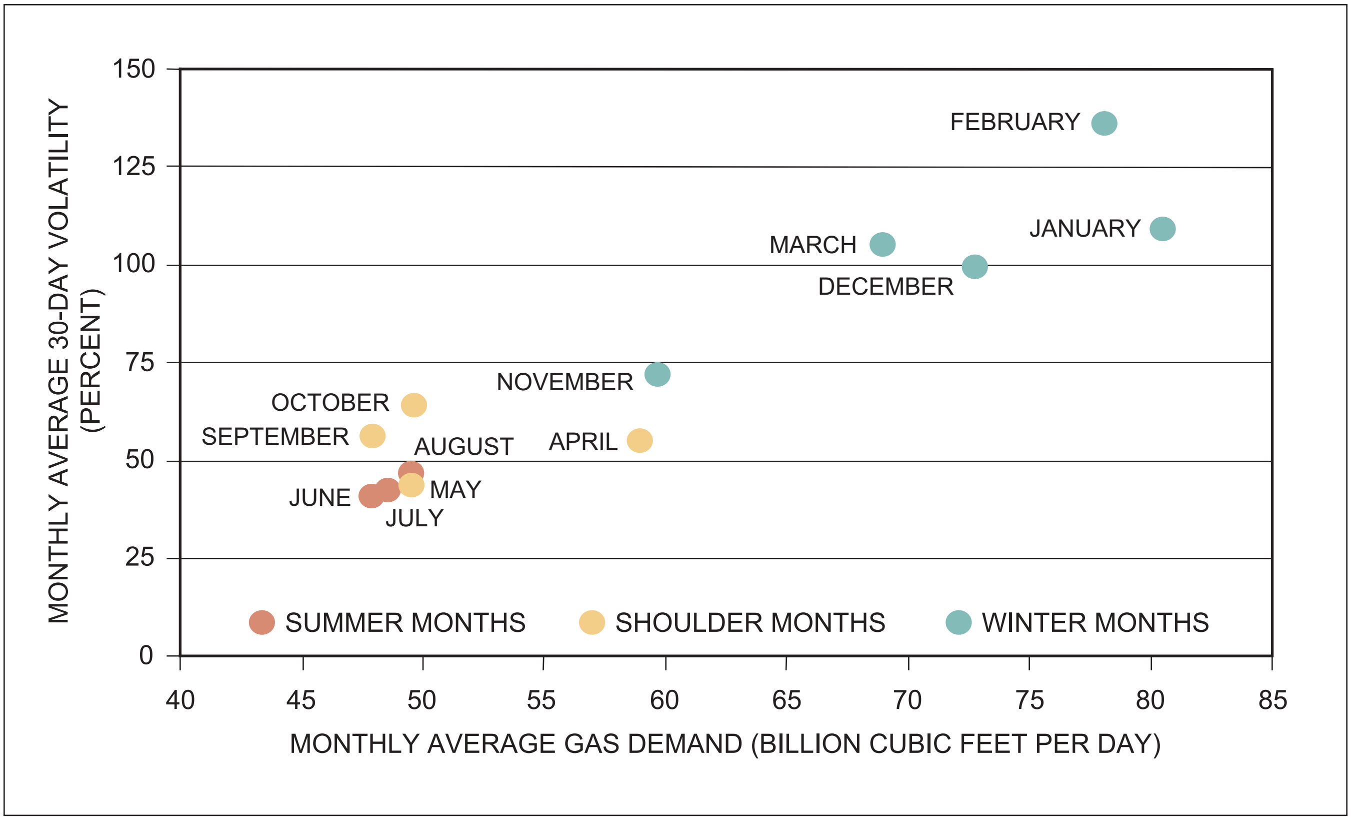


Figure 7-6. Relationship of Monthly Average Volatility and Gas Demand

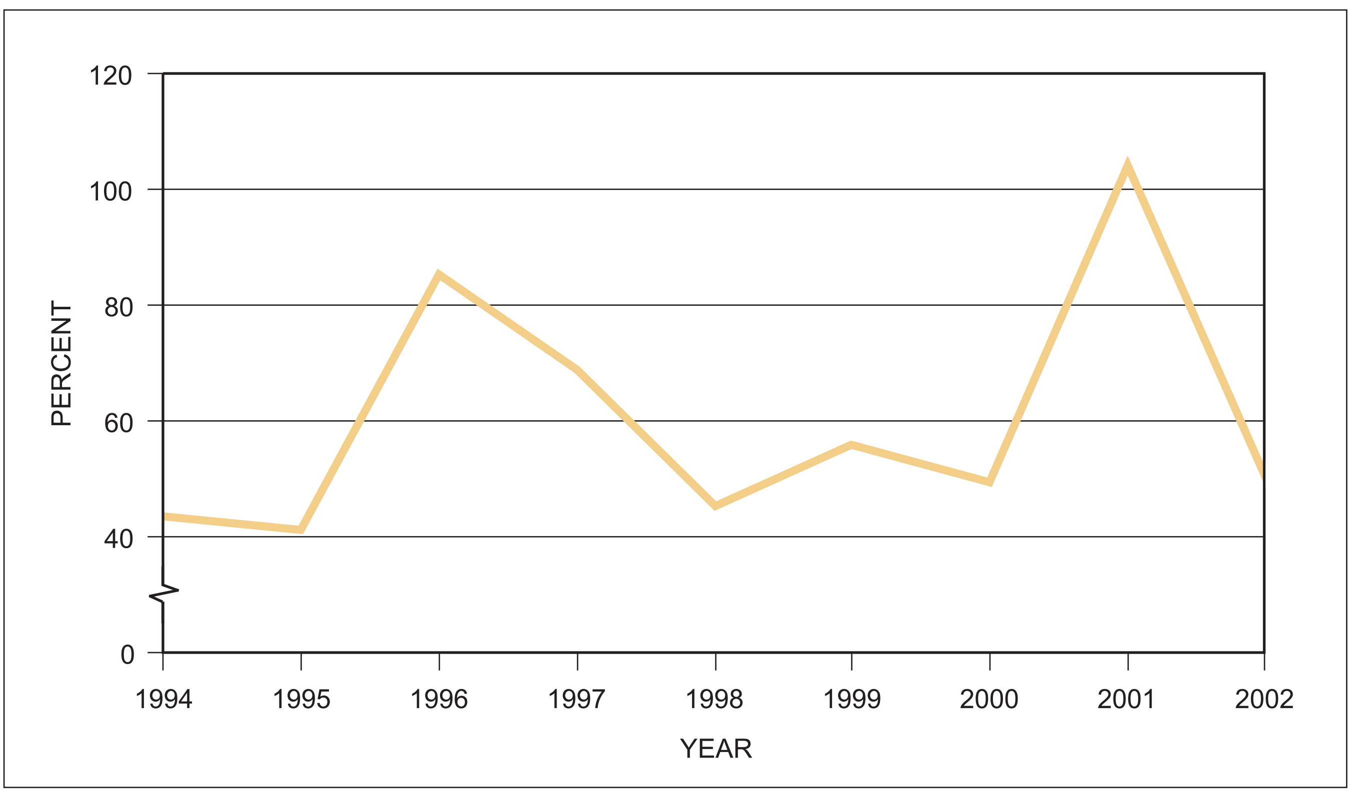


Figure 7-7. Henry Hub First of Month Index Volatility (Full Year Annualized)

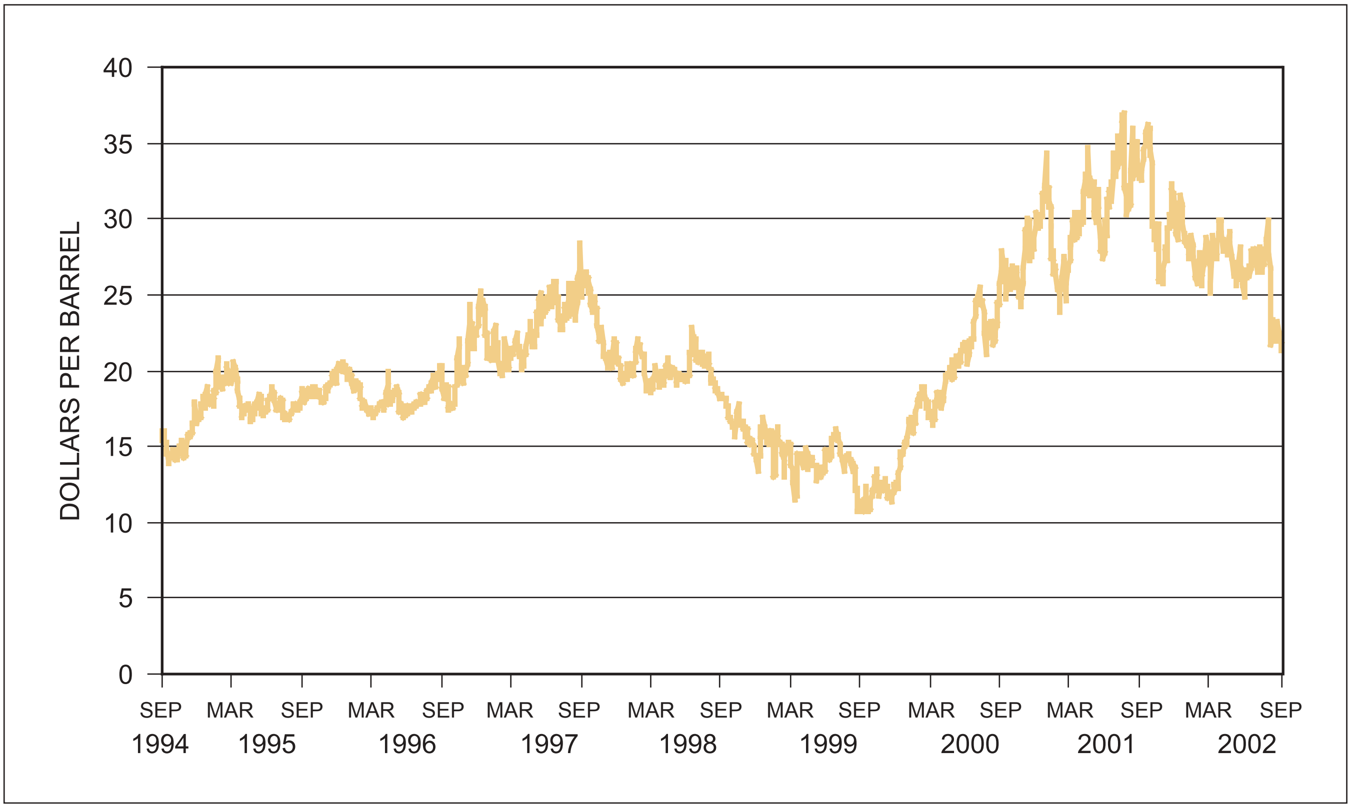


Figure 7-8. West Texas Intermediate Crude Oil Daily Cash Price

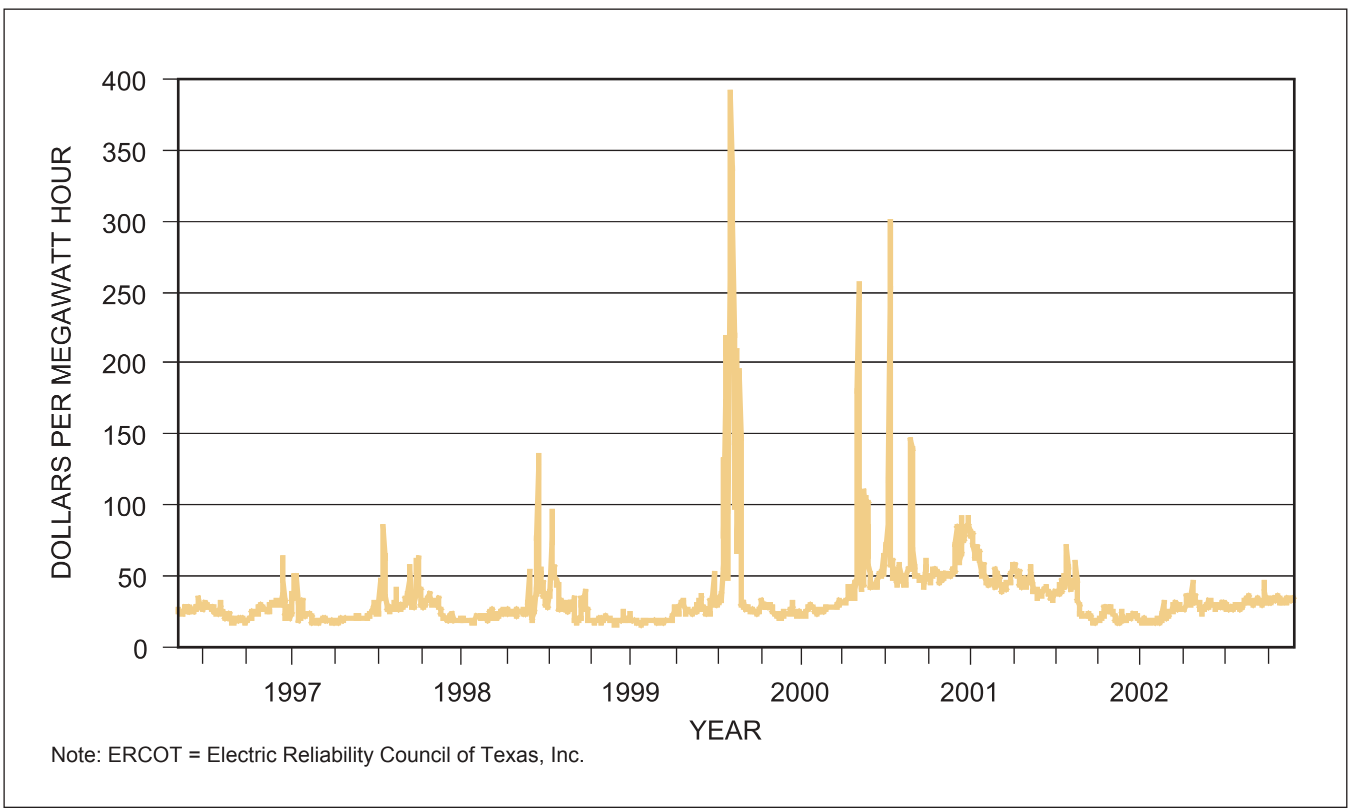


Figure 7-9. ERCOT Daily Peak Electricity Price

As shown in Figure 7-10, crude oil prices have exhibited lower volatility on average than natural gas, with yearly volatility averaging 40%. The stabilizing effect of OPEC and spare production capacity are the primary keys for the lower volatility.

Key Drivers of Natural Gas Price Volatility

	Affects Supply	Affects Demand
Weather	√	√
Inelasticity of Demand (during winter peaks)		√
Storage Levels	√	
Pipeline Capacity	√	
Operational Factors	√	
Lack of Timely, Reliable Information	√	√
Alternate Fuel Price Volatility		√

Gas consumption variability and inelasticity in the United States are primary drivers behind price fluctuations. The winter peak of 80+ BCF/D can be compared to the summer low of approximately 45 BCF/D. Gas storage facilities have been developed all over the United States to balance this market. During the summer period, gas is stored for use during the winter. The Energy Information Administration (EIA) estimates that about 4.2 TCF of gas storage capacity exists in the United States. On an annual basis, about 2 to 2.5 TCF of "working" gas is used to keep the market in balance, thereby mitigating seasonal price volatility.

Since the mid-1990s, the gas producers in North America have been producing at maximum rates throughout the year. The production profile has been relatively flat, as seen in Figure 7-11. Gas production in excess of demand is injected into storage in the summer and pulled from storage to meet the winter peak as shown by the shaded areas.

Supply and Demand Elasticity Effects

The gas supply in North America is inelastic in the short term. The ability to increase supply in the short term is limited to shutting down rich gas processing

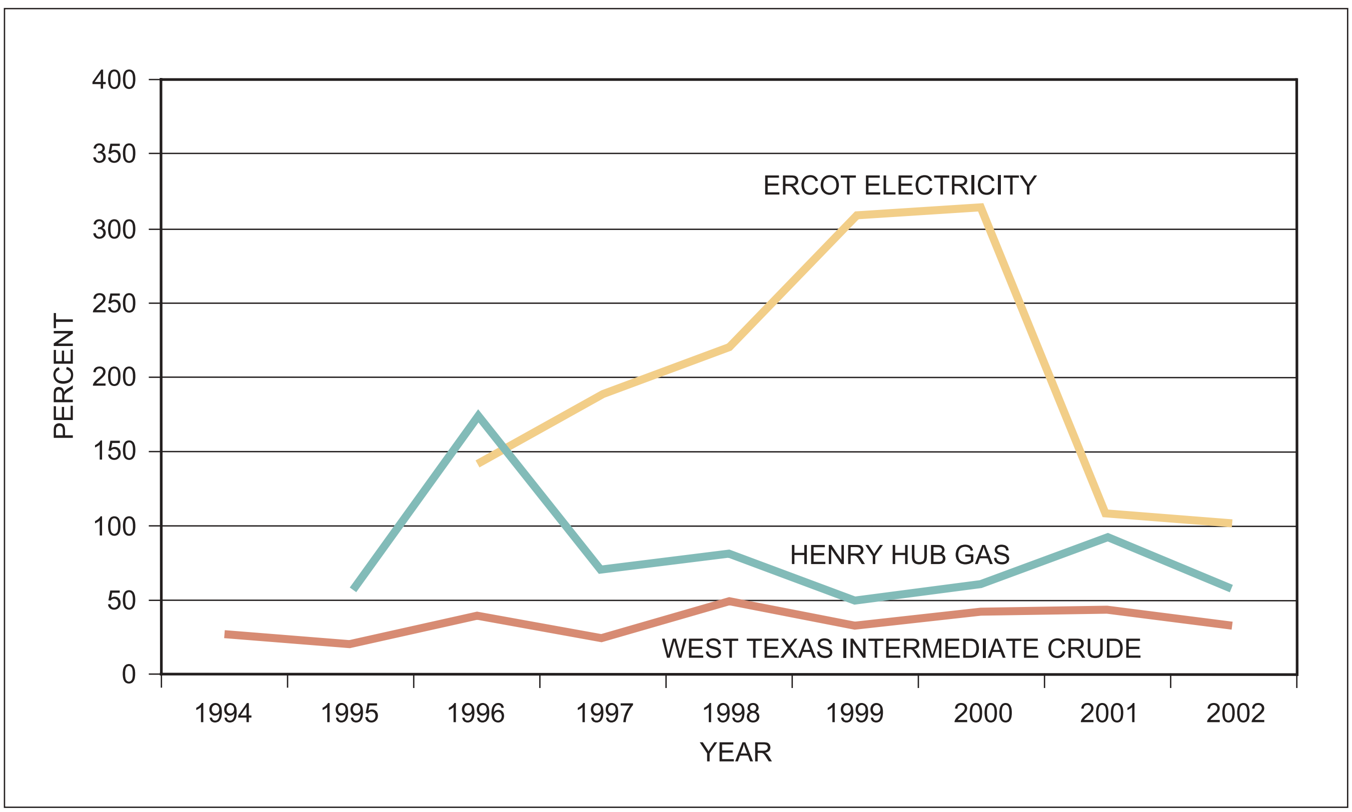


Figure 7-10. Energy Price Yearly Volatility Comparison – Daily Cash Prices (Yearly Period)

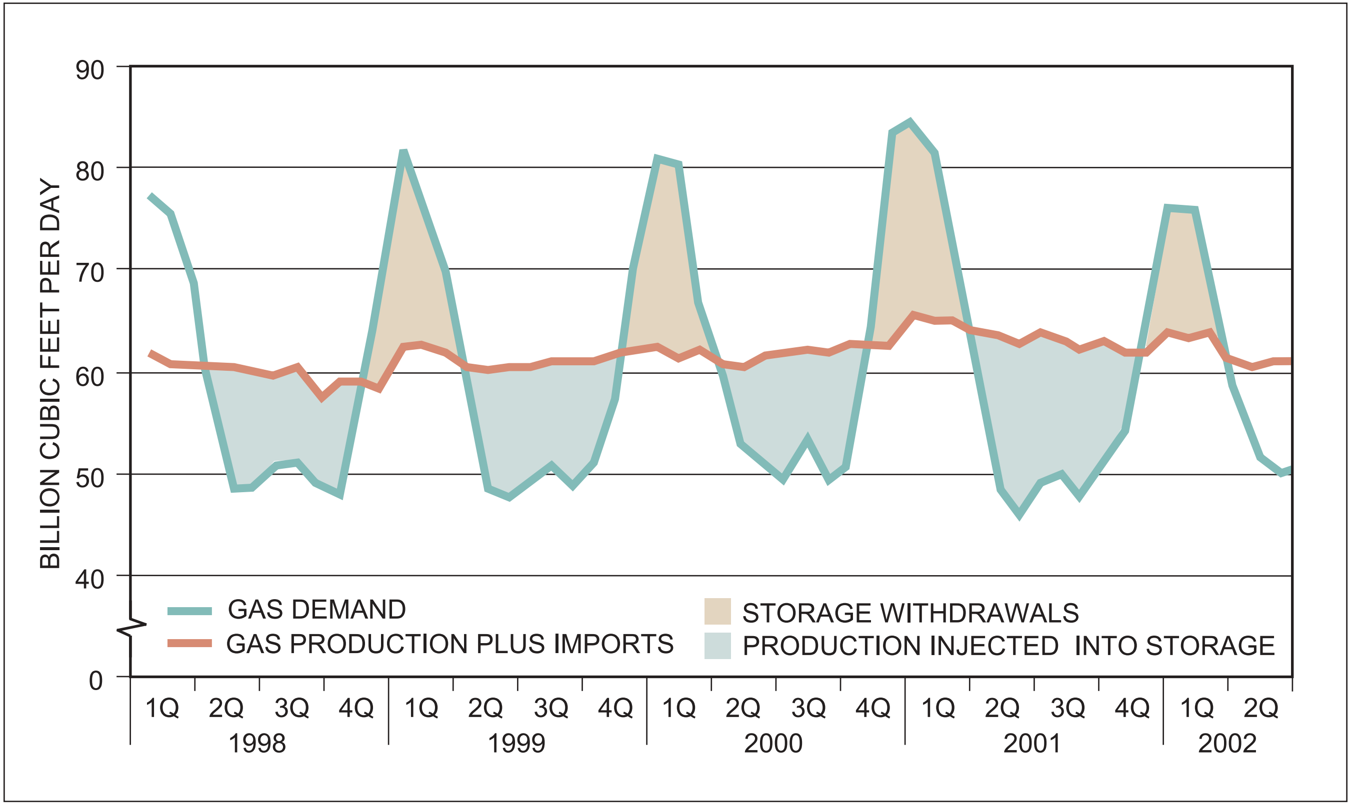


Figure 7-11. U.S. Natural Gas Consumption and Production

and/or gas injection for secondary oil recovery. Significant increases in supply have been difficult to achieve in recent times even with near record gas-directed drilling rig activity. Canadian gas imports have risen to 16% of total U.S. supply, as domestic production has not been able to keep up with demand. This short-term supply inelasticity contributes to price volatility. Supply is more elastic in the longer term with the potential to explore and develop new large supplies (e.g., deepwater Gulf of Mexico, Arctic, unconventional). However, the long lead times and large investments make short-term changes difficult.

For gas demand, the primary driver behind the seasonal consumption profile is space heating for the residential and commercial customers. This "LDC" demand is driven by the weather. In effect, the demand curve shifts to the right from summer to winter as shown in Figure 7-12. This dynamic shift in seasonal demand moves the equilibrium point between supply/demand upward and toward the steeper, less elastic portion of the demand curve. As a consequence, during a cold period in the winter when demand peaks, gas price can change very quickly as the market provides a price signal to consumers to curtail use or to switch to an alternate fuel (if possible). The rapid change in price leads to high volatility.

Pipeline Capacity and Operational Factors

Although the North American gas pipeline grid is well interconnected, there are constraints on the amount of gas that can be transported between the

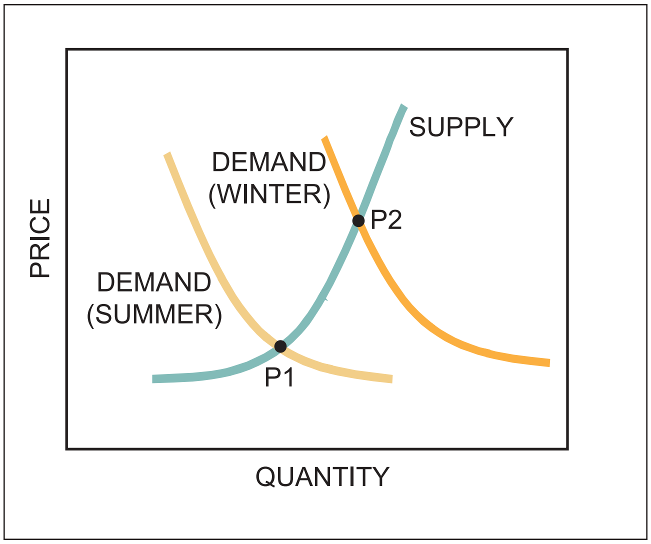


Figure 7-12. Price Elasticity Effects

supply areas and demand centers, particularly during the winter peak season. Therefore price differentials between areas, or a "basis," sometimes widen (or shrink) reflecting the availability of pipeline capacity. Pipeline capacity relative to demand impacts the delivered price and affects price volatility.

Price differentials reflect the value of transporting gas between regions and provide market signals and incentives for new pipeline capacity additions. In regions with excess capacity, the price basis may drop below the pipelines' published tariff rates for firm transportation. In regions where capacity is tight, the price basis may exceed the published tariff rates. Figure 7-13 shows the difference in price versus the Henry Hub for New York and Chicago citygates and the Rockies production area from 1998 to early 2003.

Citygate prices generally exceed wellhead prices, reflecting the value of transportation capacity between the production area and the market area. Between the Gulf Coast and New York, the basis variation has ranged as low as a few cents to over $2.00/MMBtu. Winter periods generally show the highest basis differentials due to pipeline capacity constraints. Chicago basis is lower than New York basis due to excess pipeline capacity from the Gulf Coast and Canadian producing areas to the Midwest. Prices in the Rockies production area are up to $2.00 less than the Henry Hub price, reflecting insufficient pipeline capacity to the market.

Lack of Timely, Reliable Information

The FERC and EIA publish demand and supply data on a monthly basis. EIA monthly reports attempt to document the overall U.S. supply and demand balance. However, due to the lack of complete data, the nearest 6 months are estimates. Information out to about 18 months is a combination of estimates and actual data, which are frequently revised (with large variations). The lack of reliable and timely information results in market uncertainty. On a daily basis, the market searches for the right clearing price. Uncertainty about demand and supply of gas is a contributing factor to these daily changes. The market has developed other indirect measurements of supply and demand to assist in understanding trends. For example, the market closely monitors gas in storage, drilling rig activity, and heating and cooling degree days, among other fundamentals. While helpful in some respects, these sources

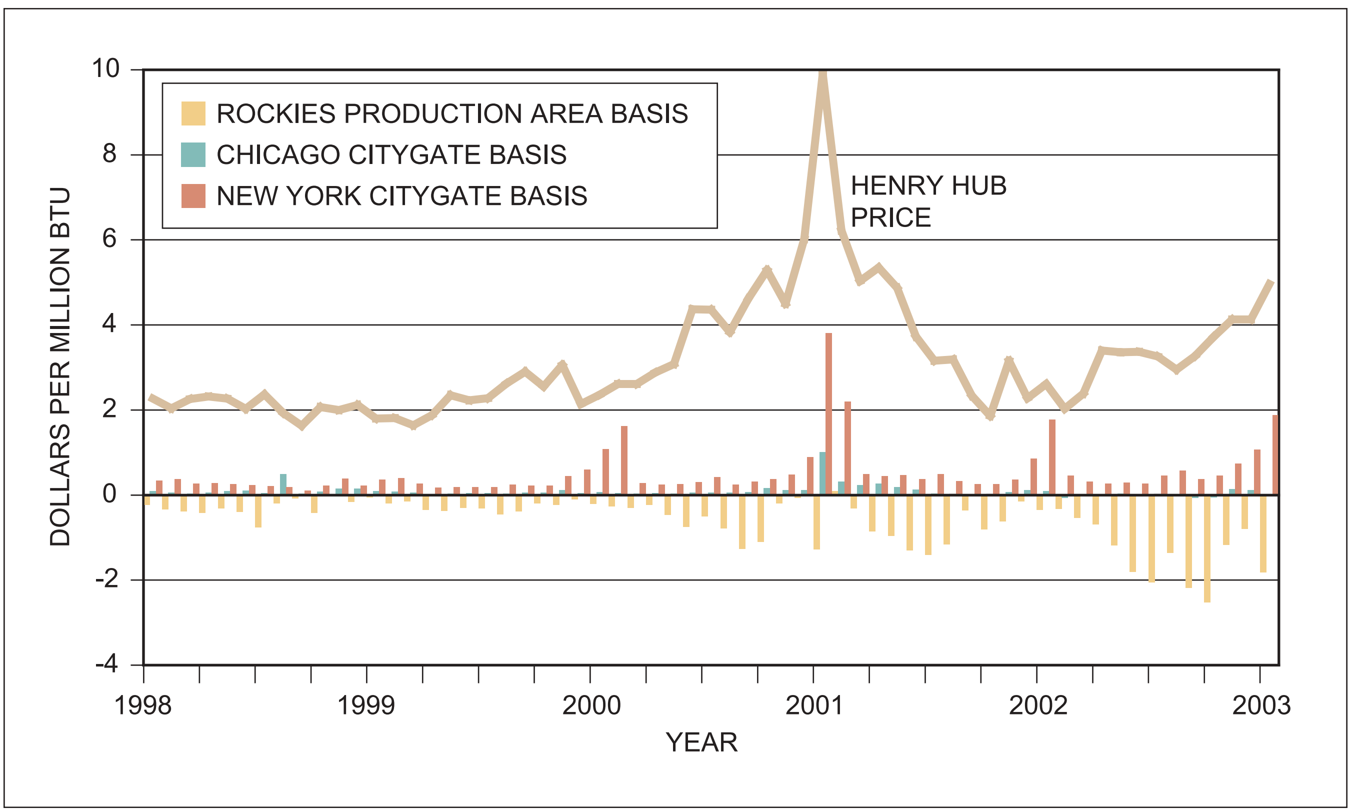


Figure 7-13. Market Basis to Henry Hub

of information are, at best, second-hand indications of true supply and demand trends.

Alternate Fuel Price Effects

Many industrial and utility customers have developed the ability to switch to an alternate fuel. The availability of this switchable load potentially decreases the upward price movement of gas for these customers when gas price exceeds alternate fuel parity and decreases downward price movement when below alternate fuel parity. Overall this has the potential to decrease natural gas price volatility during peak demand periods.

Factors that Mitigate Gas Price Volatility

- Gas storage
- Fuel switching
- Financial hedging (does not eliminate risk but does create price certainty)
- Excess production capability and pipeline capacity
- Long-term contracting
- Timely and reliable information

Exposure to Price Volatility and Its Effects

Retail and Commercial Customers

Most LDC firm-service customers are insulated from the day-to-day volatility in natural gas prices. Residential deliveries and approximately 60% of total commercial customers purchase natural gas at regulated rates from an LDC. The cost of natural gas to these customers is controlled by regulation, and generally reflects the rolled-in average cost of natural gas at the LDC citygate, plus the LDC distribution charge. The average cost of gas is adjusted on a going-forward basis, typically delayed by one to three months. In addition, many LDCs hedge gas prices on a portion of their requirements, either through physical means via natural gas storage, contractual means via longer-term (monthly and seasonal) gas purchase contracts, or a financial hedge. As a result, the gas prices faced by these users generally do not vary with short-term changes in energy market prices. However, persistent price changes do result in substantial price effects. Although prices to retail customers have varied over the past 10 years, only the upward movements tend to receive significant regulator and customer attention.

Industrial Customers

Industrial customers tend to be more exposed to volatility in energy prices. A vast majority of industrials (more than 80%) purchase gas in the daily or monthly markets and transport the gas to their facilities. The natural gas commodity is purchased either at market prices, or hedged through a third party.[2] In either case, industrial customers are exposed to market prices. Sales to industrial customers via LDCs at regulated prices account for only a small percentage (approximately 17%) of total sector requirements.

Industrial customers tend to have more options for reducing gas usage in response to price increases. Some industrial applications have dual-fuel capability, and can switch to residual fuel oil or distillate fuel oil when natural gas prices exceed fuel oil prices. When gas prices rise, industrial facilities may also choose to shut down production rather than use natural gas. During the peak price periods from 2000 to 2002, large amounts of ammonia production capacity shut down in response to higher natural gas prices.[3]

As a result, industrial customers tend to be more price sensitive than commercial or residential customers. This price sensitivity is reflected in both operational day-to-day decisions, and in long-term investment decisions in energy technologies. Price volatility can impact profitability for the industrial sector in positive and negative ways depending on the direction of natural gas price movement. Sustained (multi-month) price spikes may also cause business rationalization that cannot be easily or cost-effectively reversed. However, it is high absolute natural gas

2 The larger industrial consumers can consume enough natural gas to make direct price hedging attractive, hence providing some insulation from price changes.

3 Examples in 2002 include: Mississippi Chemical announced the permanent shutdown of its Donaldson, Louisiana urea facility because of pricing pressures – the complex has an annual capacity of one million tons of ammonia and 578,000 tons of urea synthesis. Missouri-based Farmland Industries indicated the prolonged downturn in fertilizer manufacturing resulted in a $183 million loss in 2002 and a Chapter 11 filing on May 31, 2002. Pennsylvania-based Air Products and Chemicals is planning to cease production of ammonia and methanol at its Pace Florida plant site, indicating 80% of ammonia and nitrogen feedstock costs are tied to natural gas prices. — Data per Natural Gas Week report on December 30, 2002.

prices (relative to its product sales prices) that tend to cause industrial customers to consider relocating from the United States to lower-cost supply regions elsewhere in the world.

Electric Power Generation

Natural gas has become a fuel of choice for new power generation because it optimizes installed cost and air emissions performance. Natural gas-fired generation is currently capturing almost 100% of new power capacity. Natural gas-fired combustion turbines can be installed more quickly, and have a lower upfront capital cost but higher variable cost (primarily fuel) relative to other technologies such as coal plants, and produce significantly lower CO_2 emissions than coal. The economics of natural gas-fired power generation, however, depend on future natural gas prices. As gas price and price volatility increases, the risks in major investments in gas-fired capacity increase relative to other fuels. Coal, for example, is expected to enjoy more stable fuel costs.

Relatively few new gas-fired power plants have dual-fuel capability, due in part to air emissions permitting constraints. Since the new gas-fired generation is more efficient than older plants, some of these less-efficient plants have been shut down. The older steam plants had liquid fuel alternatives (low-sulfur fuel oil and distillate), therefore the overall switching capability in the system has been reduced. This tends to decrease gas demand elasticity and increase price volatility.

Volatility in electricity price has the same impact as natural gas price volatility. Investors in potential powerplants must factor this risk into their "hurdle rate" [4] and adjust their investment decisions accordingly. In addition, volatility in gas prices – up or down – creates uncertainty in the planning process for both regulated utilities and merchant power companies.

Natural Gas Producers

Energy price volatility presents a number of significant challenges to the natural gas producers. Natural gas price volatility creates uncertainty around the future revenue of exploration or development projects. The primary risk to producers is the longer-term movement of gas prices and potential "boom-bust" investment cycles, rather than seasonal weather patterns or seasonal pricing variations.

These longer-term price risks for the producer and investors are incorporated into the effective financial "hurdle rate" for gas exploration and production projects. Thus, a typical gas producer will invest in new exploration and production projects only when the producer's expectation of the gas price rises to a level high enough to make the chances of reaching the target financial criteria acceptable. However, no investor's forecast is perfect, and the possibility of boom-bust gas price cycles remains.

While all energy prices will fluctuate, the impact is particularly significant to independent producers that do not have diversified sources of internally generated funds. A major investment decision taken in anticipation of future higher demand and higher prices can result in severe financial distress if the timing turns out to be incorrect.

Conclusions

- Price volatility is a natural dynamic in commodity markets where supply and demand vary. Gas price volatility has increased since deregulation. The overall tighter supply and demand balance and relative inelasticity of demand in the winter is the primary factor driving current volatility.

- Price levels provide consumers and suppliers with appropriate signals, and therefore cause rational actions. High volatility tends to increase uncertainty and decrease market efficiency (increased capital costs).

- Consumers and producers have a broad range of physical and financial tools to mitigate the effects of price volatility if they so choose. Many of the tools come at a cost. Use of financial tools may or may not reduce the cost or value of the natural gas product.

- Government policies should:
  - Promote free-market solutions to market issues.
  - Support transparency in market transactions.
  - Adopt emission regulations that promote customer alternate fuel options and switchability (particularly for new powerplant installations).
  - Provide safeguards against noncompetitive behavior and unfair market manipulation.
  - Foster timely and accurate information regarding supply, demand, and storage.

[4] The "hurdle rate" is the minimum acceptable expected return needed for a project to proceed.

CHAPTER 8

CAPITAL REQUIREMENTS

The NPC outlook incorporates all the expansion and efficiency projects for exploration, production, and infrastructure that are expected to provide acceptable financial returns based on free-market price signals. The investment criteria take into account today's low interest rate environment and Wall Street analysts' expectations of required returns on capital employed for various segments of the energy market. The cumulative amount of gas-related capital expenditures for the Reactive Path and Balanced Future scenarios are shown in Table 8-1. For the 2003-2025 period, total North American capital expenditures are $1.55 trillion in the Reactive Path scenario versus $1.45 trillion in the Balanced Future scenario.

The wide variety of capital spending envisioned in this outlook provides opportunity for a wide range of companies including small, private companies and large multinationals. Although there have been recent, notable bankruptcies and credit rating downgrades for companies linked to energy trading and merchant power activities, there is more than sufficient capital availability, liquidity, and participation from creditworthy companies to complete the projects with acceptable economic returns. It should be understood that the gas market is likely to experience periods of high/low prices, and there will be various degrees of risk and return inherent in these different types of investments. In markets where there is sufficient investor or consumer interest, there are financial mechanisms available to mitigate a significant portion of price risk.

Capital Investment

Financial Assumptions, Methodology

Long-term Wall Street projections currently suggest that Corporate America could grow earnings 6%-7% annually, have an approximate 40% dividend payout ratio, and realize average returns on equity of 13.0%-13.5%, with ongoing 50-50 debt-equity capital structures. In the opinion of Wall Street analysts, the natural gas industry needs to maintain these levels in order to remain competitive in the capital markets. We have structured our modeling assumptions accordingly.

A key set of assumptions to model this behavior is the expected cost of debt, the desired return on equity of the various market participants, and their desired debt-to-equity financing ratios. These assumed profitability levels are generally lower than in past years, reflecting in large part the lower inflation outlook.

Exploration and Production

Figure 8-1 shows that North American exploration and production capital expenditures are higher than they were in the past decade. The average annual expenditure for the forecast period (2003 to 2025) is approximately $15 billion higher than in the 1990s. In the early 1990s, the upstream sector was faced with lower gas prices resulting from a surplus of productive capacity. Increased gas demand over the past several years has used up this surplus, thus increasing prices. As a result, the level of exploration and production expenditures has increased, as shown in Figure 8-1, and is projected to stay in the $50-$60 billion per year range.

Natural Gas Infrastructure

Figure 8-2 shows that capital expenditures for infrastructure are expected to be consistent with the past several years. However, there will be a marked increase in certain years as important new supply areas in the Rockies and Arctic are brought on line.

	Reactive Path Scenario		
	United States	**Canada**	**North America†**
Supply	1,010,214	314,915	1,325,129
Gathering	15,999	5,888	21,886
Interstate & Intrastate Pipelines	48,872	14,788	63,660
LDC	110,887	10,759	121,646
Storage	8,441	1,045	9,486
LNG*	5,058		5,058
Total Capital Expenditures	**1,199,471**	**347,395**	**1,546,866**

	Balanced Future Scenario		
	United States	**Canada**	**North America†**
Supply	991,442	239,034	1,230,477
Gathering	14,450	4,597	19,047
Interstate & Intrastate Pipelines	50,632	13,929	64,561
LDC	110,887	10,759	121,646
Storage	8,441	1,045	9,486
LNG*	6,558		6,558
Total Capital Expenditures	**1,182,410**	**269,364**	**1,451,775**

*LNG figures reflect only U.S. regasification costs.

†Does not include Mexico.

Table 8-1. Total Capital Expenditures from 2003 to 2025 (Millions of 2002 Dollars)

Over time, a higher percentage of pipeline expenditures will be devoted to maintenance and enhancement of existing infrastructure in order to maintain system integrity.

As shown in Figure 8-3, the average of projected storage capital expenditures will be consistent with historical averages. The projected growth in gas fired power generation has resulted in greater need for storage capacity to meet peak power needs during periods of high seasonal demand. From 2003 to 2025, working gas storage increases by 700 BCF, or approximately 16%.

As shown in Figure 8-4, capital expenditures for LNG regasification in the United States increase significantly in both the Reactive Path and Balanced Future scenarios. LNG imports grow to 15 BCF/D in the Balanced Future scenario versus almost 12.5 BCF/D in the Reactive Path scenario.

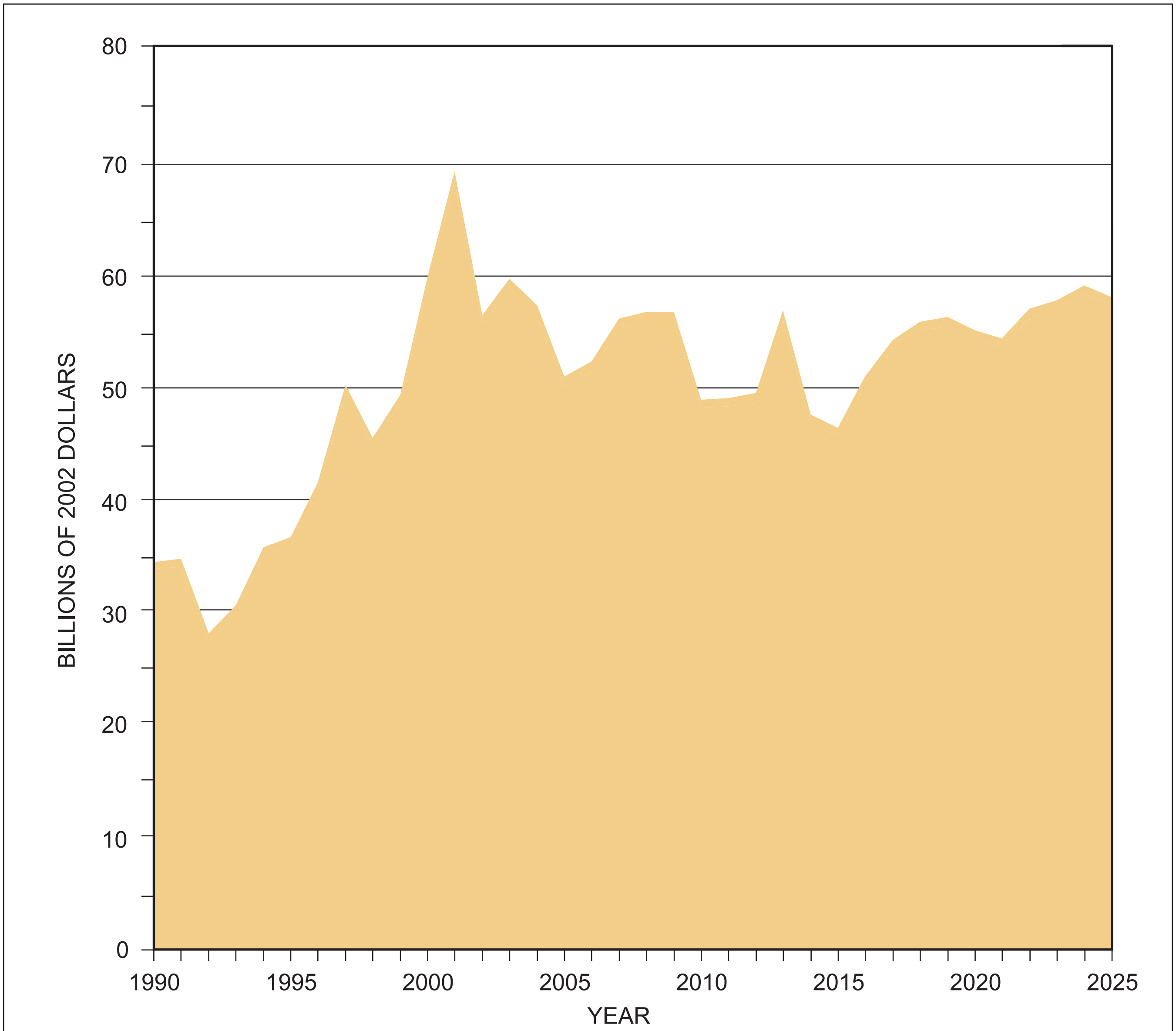
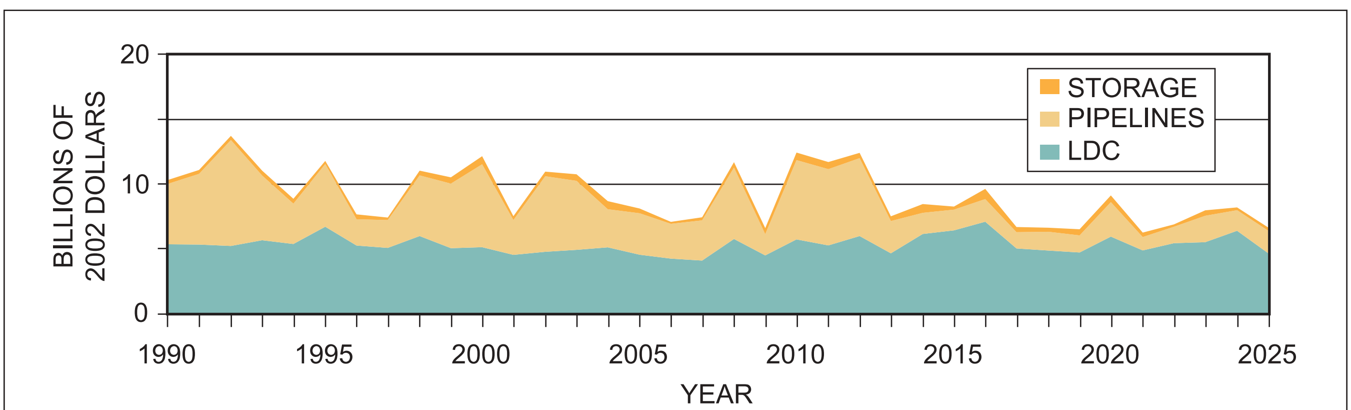


Figure 8-1. North American Upstream Expenditures – Balanced Future Scenario



Note: This figure is a revision of Figure 53 in Volume I of this report.

Figure 8-2. North American Infrastructure Expenditures – Balanced Future Scenario

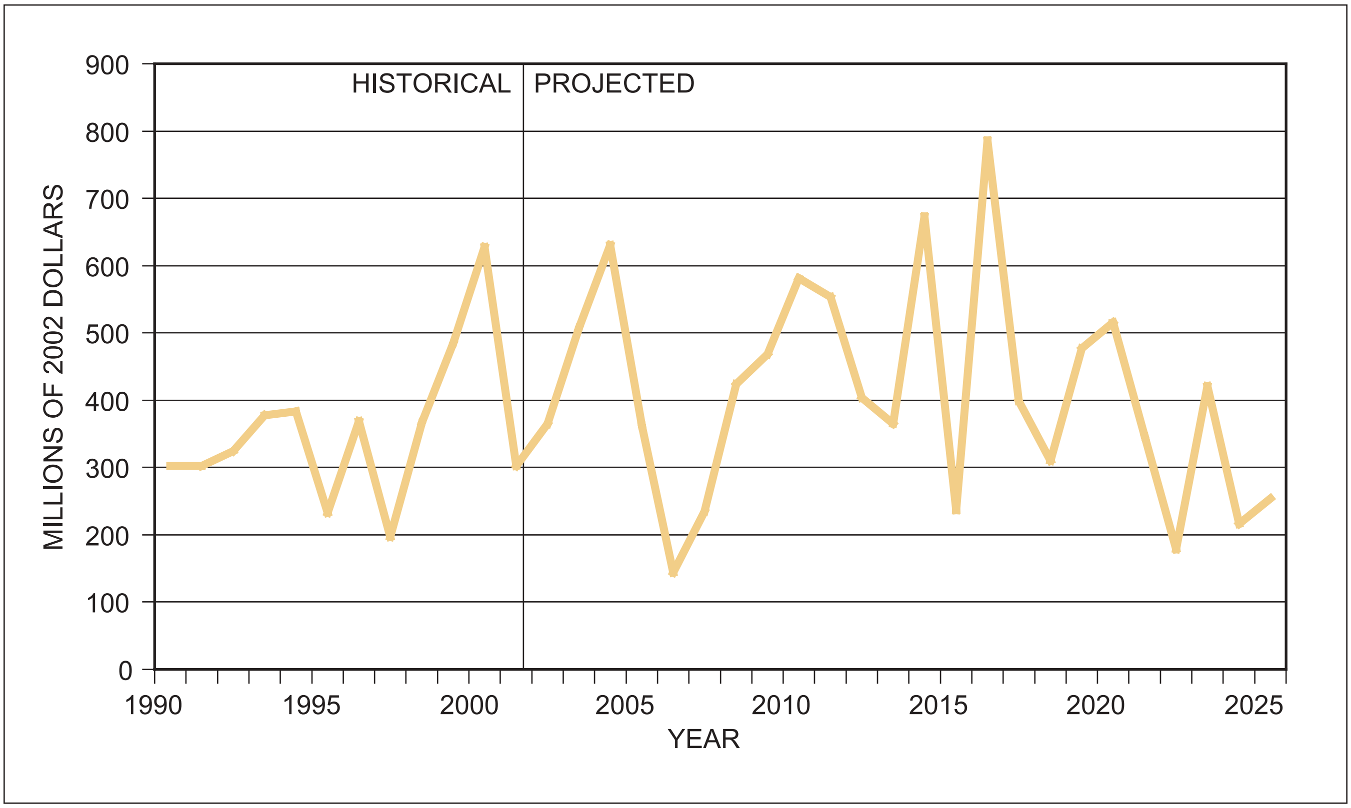


Figure 8-3. North American Storage Capital Expenditures

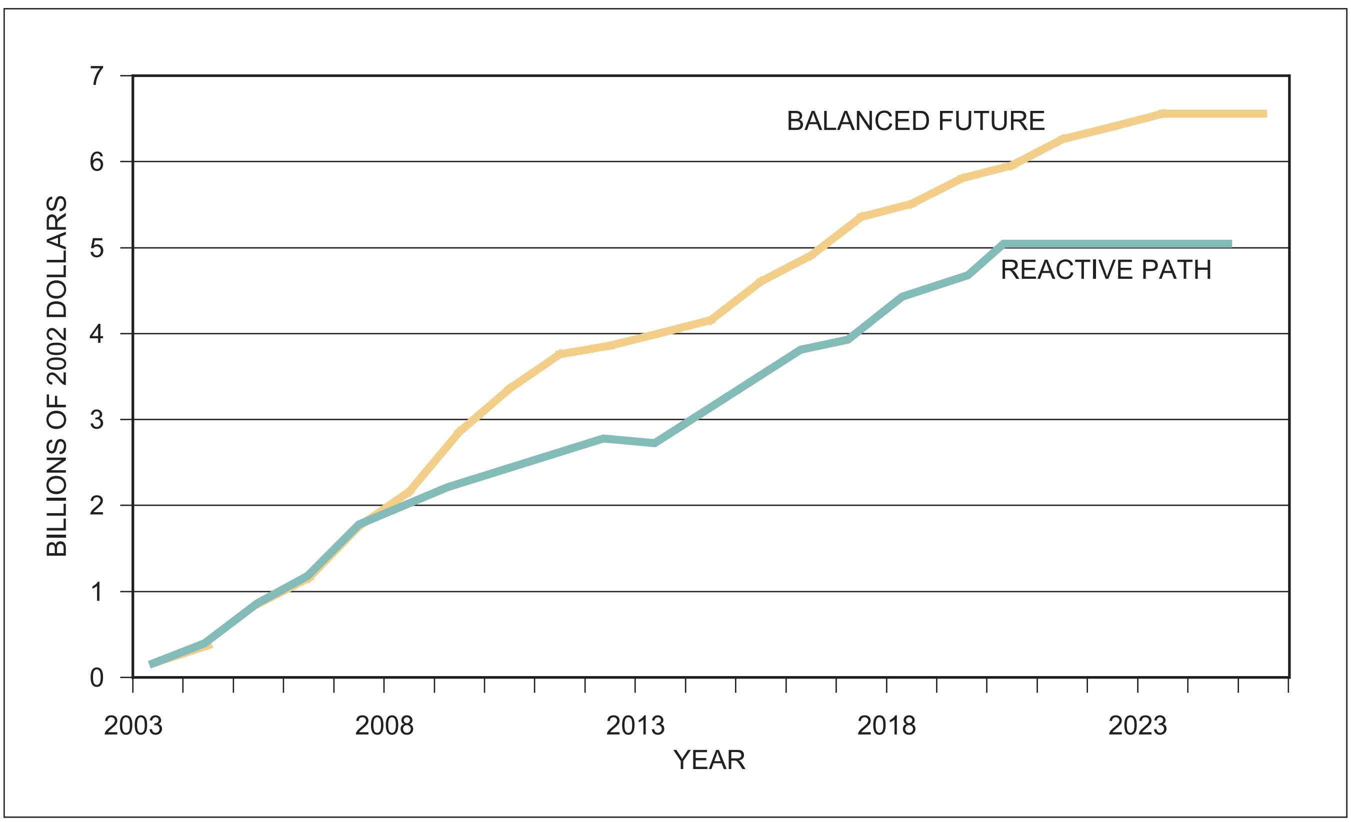


Figure 8-4. Cumulative U.S. LNG Regasification Expenditures

CHAPTER 9

SENSITIVITY ANALYSIS

The NPC considered the many factors that drive overall supply and demand and created consistent input data sets for the forecasting models. The NPC also evaluated alternative assumptions to test how the natural gas market might` evolve under different conditions. Those alternative assumptions addressed the general economic environment, government policies affecting supply and demand, natural resource size, upstream technological trends, weather, end-use efficiency improvements, and other factors.

Figure 9-1 is a highly simplified schematic showing supply and demand versus price for North America. The blue circle in the middle represents an initial projection of natural gas prices and volumes for a given year or period. That "solution point" is the combined result of many assumptions that affect natural gas supply and other assumptions that affect the demand for natural gas. Alternative views of those factors would lead to a different solution point. There are, of course, thousands of potential solution points that

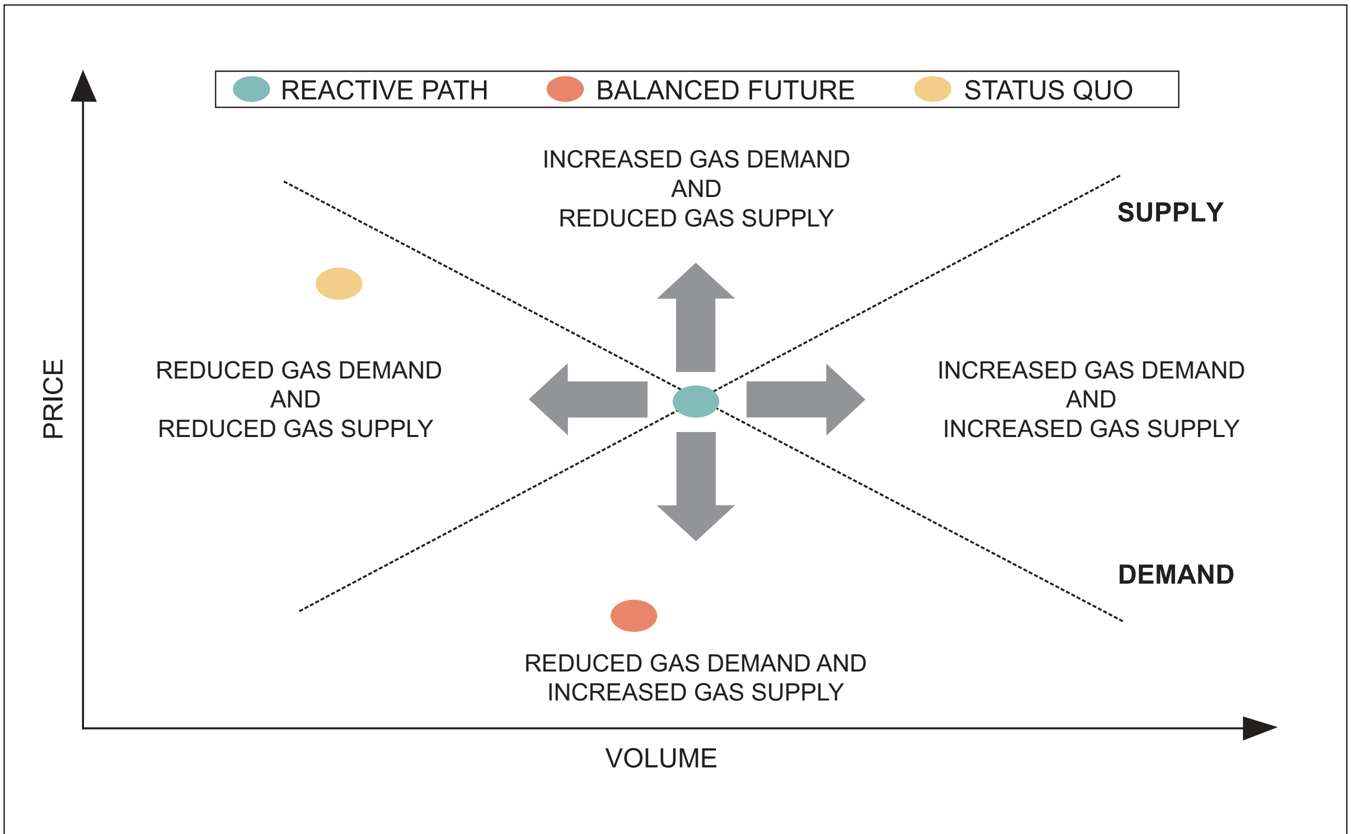


Figure 9-1. Price-Volume Schematic

could be created with different combinations of assumptions.

As is shown in Figure 9-1, those alternative points can be represented as falling around the initial solution point depending on whether and by how much various supply/demand assumptions are changed. If the blue circle is taken to represent the Reactive Path scenario, then the orange circle can represent the Balanced Future scenario in which additional supplies and more flexible uses of fuels combine to reduce natural gas prices. Likewise the gold circle can represent the Status Quo scenario in which supply is less available, thus increasing prices, even though natural gas demand is reduced to a certain degree.

Examples of the model "factors" that were adjusted in creating NPC scenarios and sensitivities are shown in Table 9-1. Among the factors that increase natural gas demand are gas-favoring environmental regulations, higher economic growth, less end-use fuel efficiency, less fuel flexibility, higher oil prices, and more extreme weather. Those same factors can be set in the opposite direction to create cases in which natural gas demand could be lower. For example, slower economic growth would tend to reduce overall energy needs and the demand for natural gas. The key gas supply drivers shown in Table 9-1 include integration of Arctic gas, LNG imports, Rockies and offshore land access, upstream technological advances, the underlying resource endowment, and tax and royalty policies. Each of these factors can be set in a manner that tends to increase natural gas availability or reduce it.

In the preparation of this report, approximately 100 integrated supply/demand model runs were made using the EEA models. There were several sets of preliminary or "strawman" cases that were prepared as the study group members investigated various issues and settled on reasonable and consistent assumptions. Out of this process came the over thirty "final" cases that are presented in the report and in supporting documentation. This collection of case analyses serves many purposes, including:

- Examining the effects of government policies on supply and demand
- Quantifying the effects of "fuel flexibility" policies on consumer costs and other outcomes
- Quantifying the effects of land access polices on consumer costs and other outcomes

GAS DEMAND	GAS SUPPLY
Increased Demand	**Reduced Supply**
• Gas-Favoring Environmental Regulations	• No/Less Arctic Gas
• Higher Economic Growth	• Reduced LNG Imports
• Less End-Use Efficiency	• Reduced Access
• Less Fuel Flexibility	• Lower Technology Evolution
• Higher Oil Prices	• Lower Resource Potential
• Colder Winters/Hotter Summers	
Reduced Demand	**Increased Supply**
• Gas-Neutral Environmental Regulations	• Increased Arctic Gas
• Lower Economic Growth	• Greater LNG Imports
• Greater End-Use Efficiency	• Increased Access
• Enhanced Fuel Diversity	• Greater Technology Evolution
• Lower Oil Prices	• Increased Resource Potential
• Warmer Winters/Cooler Summers	• Higher Oil Prices

Table 9-1. Sensitivity Factors

- Illustrating the growing importance of large-scale pipeline and LNG projects on natural gas markets
- Exploring the critical linkages between economic activity and the demand for electricity and natural gas
- Measuring the impacts of end-use efficiencies on electricity demand and natural gas markets
- Illustrating the uncertainty inherent in factors such as resource endowment and upstream technological advances
- Exploring the effects of weather variability on demand swings and price volatility.

The major elements that went into the various scenarios and sensitivities presented in this report are discussed below by subject area starting with general economic factors, going then to demand drivers, supply drivers, pipeline and other infrastructure assumptions, and finally liquefied natural gas investments.

Factors Related to the Economic Environment

The general economic environment is represented in EEA's Gas Market Data and Forecasting System through inputs such GDP growth rates and industrial production growth rates in the United States and Canada and prevailing world oil prices. Alternative scenarios and sensitivities were created by varying general (GDP) growth rates and additional sensitivities were made in which just the industrial sector's growth rates were adjusted. There was also one sensitivity made with higher oil prices set at $28.00 per barrel for West Texas Intermediate crude oil.

Demand-Related Factors

Many of the demand drivers adjusted by the NPC to create alternative scenarios related to electricity demand and power generation. Adjustments were also made to inputs for the industrial, residential, and commercial sectors.

Electricity Sales as a Function of Economic Growth

For the purpose of the study, electricity sales were defined as on-grid deliveries of electricity to retail customers, and do not include electricity consumed at the source of generation or direct sales. The projections for electricity sales were base on an assumed elasticity relationship between GDP and electricity sales. The starting elasticity for all cases was 72%; that is, for every one percent increase in GDP, electricity sales increase by 0.72%. For the base projection, it was assumed that the elasticity will gradually decrease due to increasing energy efficiency. By 2025, the GDP-to-electricity sales elasticity decreases to 62% in the Reactive Path projection. In the Balanced Future scenario, it decreases at a slightly faster rate to 60% by 2025. In the Low Electricity Elasticity case, elasticity was decreased to 52%, and in the High Electricity Elasticity case it was held constant at 72%.

Industrial/Power Generation Fuel Switching

The Reactive Path assumption for the industrial sector is that there is limited expansion of oil/gas switching capability. In the Balanced Future scenario, there is an increase in the switching capability of industrial boilers from the 2003 level of about 5% to 28%, as well as a doubling of gas price elasticities for industrial process heat by 2025.

The Reactive Path assumption for power generation fuel switching was that the amount of switching from gas to oil would be limited by environmental constraints. Fuel switching was severely limited in the Northeast and West Coast, and allowed to expand slightly in other areas. In the Balanced Future scenario, the amount of time that dual-fuel units were allowed to switch to oil was increased by approximately 7%.

Existing Fossil-Fuel Generating Capacity

The Reactive Path assumption was that the majority of existing fossil capacity would continue to operate throughout the forecast time frame. It was assumed that due to economic competition with newly constructed combined-cycle and combustion turbine capacity, 21.5 gigawatts of oil/gas steam capacity would be retired between 2003 and 2008. Oil/gas steam capacity was held constant after 2008. To meet upcoming restrictions on mercury emissions, it was assumed that 21.1 gigawatts of coal capacity would be retired between 2008 and 2010. In the Balanced Future scenario, there were no retirements of either coal or oil/gas steam capacity between 2003 and 2010.

New Fossil-Fuel Generating Capacity

In all cases, construction of new capacity was determined by an analysis using busbar cost curves and production simulations. The busbar cost curves were used to determine appropriate capacity factor operating ranges for each type of capacity. The costs include fuel costs, construction costs, financing costs, taxes, operations and maintenance expenses, and all the other costs of owning and operating a power plant. The production simulations determined if the newly added units are operating in those ranges. In the production simulation, the newly added units were integrated with the existing fleet and all units were dispatched to meet load. In the base case, additional restrictions were applied as to where certain types of capacity could be construction and how much could be constructed per year. For example, no new coal capacity could be built in the Northeast or West Coast, and coal capacity additions were limited to 12 gigawatts per year. In the Balanced Future scenario, some of these restrictions were relaxed to allow a more favorable environment for constructing coal- and oil-fired capacity.

Nuclear Capacity

The Reactive Path assumptions for existing nuclear capacity were that all currently operating plants would receive one 20-year extension of their operating license, and that incremental improvements would increase the operating capacity of the existing fleet by a total of 2% by 2011. In the Balanced Future scenario, the operating capacity of the existing fleet was increased by a total of 10% by 2013.

Nuclear capacity was allowed to compete as an option for new capacity in all cases. However, the long lead-time for planning and construction of nuclear plants made them economically uncompetitive in all but the Carbon Reduction sensitivity case.

Renewable Capacity

Costs for new renewable capacity were represented by wind turbines, which is currently the most economic non-hydroelectric renewable energy technology. In the Reactive Path scenario, renewable generation was assumed to increase at a rate of 11% per year. In the Balanced Future scenario, renewable generation was assumed to increase at approximately 15% per year.

Industrial Production and Energy Intensity

Alternative cases were created in which the efficiency improvement by industrial sectors was varied. In one case, the growth rate of energy-intensive industries was increased and in a second case it was lowered. These cases were intended to illustrate how energy use could vary in the industrial sectors based on which industry groups were expanding.

Residential/Commercial Energy Efficiency

The Balanced Future scenario and several other cases were run with assumptions of greater energy efficiency in the residential and commercial use of natural gas.

Domestic Supply-Related Factors

The main factors that were adjusted to create the alternative cases were resource access, resource base size, and upstream technological advances.

Resource Access

Access to indigenous resources is essential for reaching North America's full supply potential. New discoveries in mature North American basins represent the largest component of the future supply outlook, including potential contributions from imports and Alaska. However, the trend towards increasing leasing and regulatory land restrictions in the Rocky Mountain region and the Outer Continental Shelf (OCS) is occurring in precisely the areas that hold significant potential for natural gas production. In the Rocky Mountain areas, previous studies have evaluated the effects of federal leasing stipulations.

Leasing moratoria in the Eastern Gulf of Mexico, Atlantic Coast, and the Pacific Coast currently prohibit access to these areas of the OCS.

Resources are classified in EEA's Hydrocarbon Supply Model under three categories:

- Accessible under standard lease terms
- Accessible but higher cost due to restrictions
- Inaccessible.

Seven resource access cases were developed. Four cases evaluated increased access and three cases looked at decreased access. Rockies and offshore access scenarios were evaluated separately, and then together, in both increased and decreased access scenarios.

Resource Base Sensitivities

The quantity of available undiscovered oil and gas is one of the key factors in modeling future activity and production. Because there is inherent uncertainty in assessing undiscovered resources, it is necessary to evaluate this range of uncertainty through model sensitivities. Two resource base sensitivity runs were evaluated: High Resource Base sensitivity (also called P10) and Low Resource Base sensitivity (also called P90).[1] The Supply Subgroup developed resource base specifications for these model runs and examined a range of uncertainty from minus 30% to plus 35% of the reference resource. This range was determined through industry discussions and comparisons with other published assessments.

A uniform change to all resources in the model was used for both cases. For the Low Resource Base case, all undeveloped and undiscovered resources were reduced by 30% relative to the Reactive Path resource base. For the High Resource Base case, all undeveloped and undiscovered resources were increased by 35%. These multipliers were applied to Canada as well as the United States. This approach differs somewhat from that used in the 1999 study, in which only the resources in specific regions were varied to create the low and high resource base cases.

Upstream Technological Advancements

Technology is a critical driver for the growth of the gas industry in North America. This is dictated by the nature and complexity of the undiscovered resource base, which is generally characterized by deeper drilling, deepwater, and nonconventional reservoirs. Continued development of improved exploration and development technologies and cost reductions for drilling and platform construction will be critical to improving the economics of future gas supply.

In EEA's Hydrocarbon Supply Model, supply technologies are represented in three categories:

- Improved exploratory success rates
- Cost reductions in platform, drilling, and other costs
- Improved recovery per well.

These factors are input into the model by region and type of gas and represent several dozen actual parameters. The Reactive Path scenario includes assumptions for all upstream technology parameters based upon analysis of past industry trends. Three technology sensitivities were developed versus the base technology assumptions: High Supply Technology, Low Supply Technology, and Static Supply Technology (no improvement).

LNG Assumptions

It was determined early in the study process that LNG import projects would be highly influenced by U.S. regulatory processes, the policies of the source countries, and long-term investment decisions by private industry. Therefore LNG volume and timing assumptions were developed collectively and input exogenously to the model.

The Reactive Path assumption for LNG imports has seven new terminals added and imports reach 4.6 TCF per year (12.5 BCF/D) by 2025. After existing import facilities are utilized to full capacity and then expanded, new import facilities are built in the Gulf of Mexico and the Northeast.

The High LNG Imports case adds nine new import terminals and imports reach a total of 5.4 TCF per year (14.8 BCF/D) by 2025. The High LNG Imports case adds facilities in south Florida, offshore Texas, and northern California in addition to those already built in Northeast and Gulf of Mexico in the base scenario. The Balanced Future scenario uses the High LNG Imports assumption of 5.4 TCF per year, as do many cases that use the Balanced Future scenario as a starting point.

The Low LNG Imports case adds only two new import terminals for a total of 2.4 TCF per year (6.5 BCF/D) by 2025. All existing LNG facilities still are fully utilized but there are no new import facilities built in the Northeast and only one new Gulf of Mexico import facility is added.

The LNG Stress Test case for Balanced Future adds an additional 547 BCF (1.5 BCF/D) to the High LNG level for a total of 6.0 TCF LNG imports by 2025. This additional LNG is added in the Gulf of Mexico, where sufficient pipeline capacity exists to move it to market.

Assumptions for Pipeline Construction

The cost of expanding pipelines throughout the United States and Canada are inputs into the model.

[1] Resource base estimates are often represented on a cumulative probability scale that goes from 100 percent chance of X TCF or more resource to a near-zero percent chance of Y TCF or more resource. The resource read at the point "P10" means that there is a 10% probability that the actual resource endowment is that much or more. The resource read at point "P90" means that there is 90% chance that the actual resource base is that big or less. The resource base read at "P50" indicates the point at which there is an equal likelihood that the real resource base is higher as it is lower.

These data are used along with "rules" by which the decision to expand capacity will be made as the model case is developed. The rules specify what basis differential must be realized before a pipeline project will be started and how many years it will take to permit and implement the project. These costs and rules were not varied among the cases except for the Accelerated and Delayed Rockies Pipeline Development cases, in which pipelines out of the Rockies were, respectively, accelerated or delayed.

A natural gas pipeline from the Alaska North Slope to serve lower-48 demand was not modeled using decision rules. Instead, its timing and size were set by Arctic Subgroup guidance. Most cases were run assuming a 2013 in-service date for the Alaska pipeline and a throughput (after an initial ramp-up period) of 4 BCF/D. There was also a case in which the Alaska pipeline was delayed for five years and two cases in which the Alaska natural gas pipeline was not built at all. One case was also run assuming that the Alaska natural gas pipeline is expanded by 1 BCF/D to a total of 5 BCF/D in 2020.

Construction of the NPC Cases

Cases were constructed by selecting and combining the factors discussed above. Table 9-2 shows in a summary fashion how the 32 main cases were constructed. Each row on the table represents a separate case and each column represents a category of assumptions that could be changed among the cases. The assumptions are shown in the table as changes relative to the Reactive Path scenario. Therefore, when assumptions are the same as the Reactive Path scenario, that will be indicated as a blank box in the figure.

The Balanced Future scenario is presented in this report as the primary alternative to the Reactive Path scenario. As is shown in the second row of Table 9-2, the Balanced Future scenario contains different assumptions:

- Increased access to Rockies and offshore lands for oil and gas development
- A more favorable regulatory environment for LNG and greater amounts of investment in LNG for U.S. markets
- More efficient use of natural gas in residential and commercial sectors
- More efficient use of electricity in all sectors
- Greater fuel flexibility in the industrial and power generation sectors
- A more favorable regulatory environment to preserve existing oil- and coal-fired steam powerplants and to build new ones
- Greater increases in the capacity of existing nuclear power plants
- More renewable capacity for power generation.

These assumptions are indicated by the gray boxes in Table 9-2. Some of these same assumptions were used in other cases. For example, the case appearing in row 24 is the Fuel Flexibility case. It contains all of the same assumptions as the Balanced Future scenario, with the exception of land access, which is kept the same as in the Reactive Path scenario. Row 25 contains the LNG Stress Test case, which has the same assumptions as the Balanced Future scenario with the exceptions of higher LNG imports.

Most of the sensitivity cases appearing in this report were run off of the Reactive Path scenario. For example, rows 3 and 4 of Table 9-2 show the economic growth sensitivities, which contain the same assumptions as the Reactive Path scenario for everything but the economic environment. The same pattern of change in only one column appears for:

- Two cases related to the income elasticity of electricity demand (rows 5 and 6)
- High and low LNG cases (rows 7 and 8)
- Seven land access cases (rows 9 to 15)
- Three Alaska natural gas pipeline cases (rows 16 to 18)
- Three upstream technology sensitivities (rows 19 to 21)
- Two industrial production cases (rows 22 and 23)
- Accelerated and delayed Rockies pipeline development cases (rows 26 and 27)
- High and low resource base sensitivities (rows 28 and 29).

Two other scenarios were also created and are shown in rows 30 and 31 of Table 9-2. The Carbon Reduction case contained limitations of carbon emissions from powerplants that were met by reduced use of coal and more use of natural gas and nuclear power. The Status Quo scenario represented what might happen if some of the regulatory hurdles to additional gas supplies and alternative fuel use were not eased even to the degree anticipated in the Reactive Path scenario. This was represented in the EEA models as the combined effect of decreased access to land, no Alaska natural gas pipeline, low LNG imports, and delayed construction of coal powerplants. Because of the high natural gas and electricity prices produced in this case, expected feedback effects of reduced electricity consumption and more renewables use were also made part of the Status Quo scenario.

In addition to the cases represented in Table 9-2, EEA ran a large number of weather sensitivity cases based on the Reactive Path and Balanced Future scenarios. This was done by changing the heating degree days and cooling degree days by region and month in various future years. The purpose of these weather cases was to measure the degree of stress on the natural gas transmission and storage infrastructure caused by extreme weather and how natural gas price levels and volatility are affected.

Summary Results of the NPC Cases

Some of the results of the NPC scenarios and sensitivities are presented elsewhere in this Integrated Report and more details are provided in the Task Group Reports. This section provides a broad overview of the major NPC cases.

Figure 9-2 presents some of the supply-side sensitivity cases that were run based on the Reactive Path scenario. It shows the Henry Hub price differences (Y-axis) and the U.S. plus Canadian gas supply/demand differences (X-axis) averaged over the 15-year period of 2011 to 2025. The black circle at the center is the Reactive Path scenario and, by definition, is at zero on both axes. Results to the upper left of that point are cases for which available suppliers are reduced. The reduced supplies tend to drop the overall supply/demand balance point and increase prices. Cases that appear to the right and below the Reactive Path are those for which supplies are increased, leading to lower natural gas prices. The two most extreme points in Figure 9-2 are defined by the two resource base sensitivities: the Low Resource Base sensitivity produced the greatest price increases and largest demand/supply drops, while the greatest price reductions and largest demand/supply gains resulted from the High Resource Base sensitivity.

The combined results of the supply-side sensitivities to the Reactive Path scenario trace out a "demand

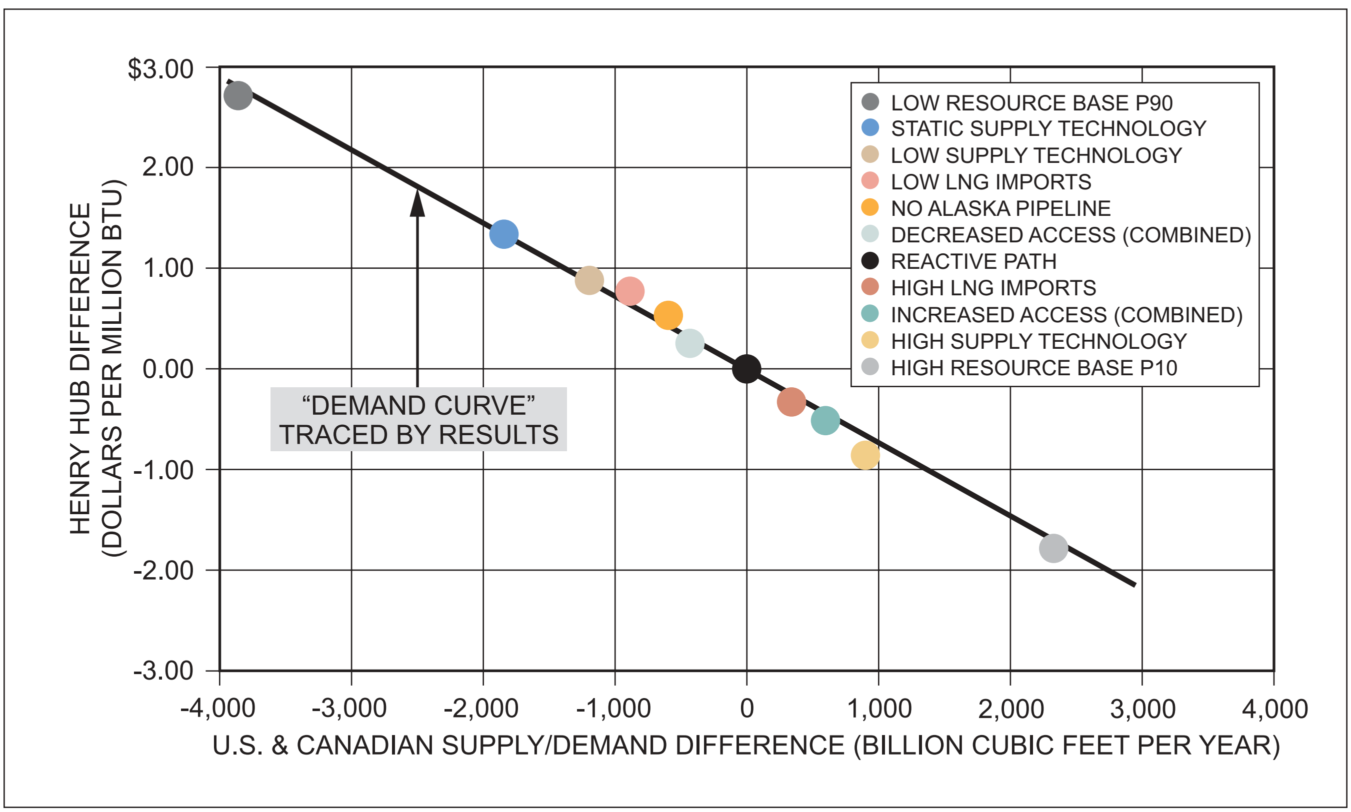


Figure 9-2. Selected Supply Sensitivities – United States and Canada (2011-2025 Averages)

	Case	Economic Environment	Land Access for Gas Production	Gas Supply Technology & Resource Base	Gas Transmission Infrastructure	LNG Investment	Residential/ Commercial Efficiency
1	Reactive Path						
2	Balanced Future		Increased Access			Higher LNG	Greater Efficiency
3	Low Economic Growth	Slower GDP Growth					
4	High Economic Growth	Faster GDP Growth					
5	Low Electricity Elasticity						
6	High Electricity Elasticity						
7	High LNG Imports					Higher LNG	
8	Low LNG Imports					Low LNG	
9	Increased Access (Combined)		Increased Access (Rockies & Offshore)				
10	Increased Offshore Access		Increased Offshore Access				
11	Increased Rockies Access (Gradual)		Gradual Rockies Access				
12	Increased Rockies Access (Full Effect)		Full Effect Rockies Access				
13	Decreased Rockies Access		Decreased Rockies Access				
14	Decreased Offshore Access		Decreased Offshore Access				
15	Decreased Access (Combined)		Decreased Access (Rockies & Offshore)				
16	No Alaska Pipeline				No Alaska Pipeline Built		
17	Delayed Alaska Pipeline				Alaska Pipeline Delayed 5 Years		
18	Expanded Alaska Pipeline				Expanded Alaska Pipeline in 2020		
19	Low Supply Technology			Low Technological Advances			
20	High Supply Technology			High Technological Advances			
21	Static Supply Technology			No Technological Advances			
22	Low Industrial Production	Lower Industrial Production Growth					
23	High Industrial Production	Higher Industrial Production Growth					
24	Fuel Flexibility						Greater Efficiency
25	LNG Stress Test – Balanced Future		Increased Access			Highest LNG	Greater Efficiency
26	Accelerated Rockies Pipeline Development				Quick Rockies Build Logic		
27	Delayed Rockies Pipeline Development				Slow Rockies Build Logic		
28	High Resource Base P10			High Resource Base			
29	Low Resource Base P90			Low Resource Base			
30	Carbon Reduction						
31	Status Quo		Decreased Rockies Access		No Alaska Pipeline Built	Low LNG	
32	WTI $28 Oil Price						

Table 9-2. Summary of Cases (Shown as Changes from Reactive Path Assumptions)

	Case	Income Elasticity of Electricity Sales	Industrial & Power Generation Fuel Switching	Fossil Generation	Nuclear Capacity	Renewable Capacity and Generation	Other Items
1	Reactive Path						
2	Balanced Future	Increased Efficiency Yields Lower Income Elasticity	Great Flexibility	More Favorable to Coal & Oil	Increased Uprates of Existing Units	More Growth in Capacity	
3	Low Economic Growth						
4	High Economic Growth						
5	Low Electricity Elasticity	Increased Efficiency Yields Lower Income Elasticity					
6	High Electricity Elasticity	Less Efficiency Yields Higher Income Elasticity					
7	High LNG Imports						
8	Low LNG Imports						
9	Increased Access (Combined)						
10	Increased Offshore Access						
11	Increased Rockies Access (Gradual)						
12	Increased Rockies Access (Full Effect)						
13	Decreased Rockies Access						
14	Decreased Offshore Access						
15	Decreased Access (Combined)						
16	No Alaska Pipeline						
17	Delayed Alaska Pipeline						
18	Expanded Alaska Pipeline						
19	Low Supply Technology						
20	High Supply Technology						
21	Static Supply Technology						
22	Low Industrial Production						
23	High Industrial Production						
24	Fuel Flexibility	Increased Efficiency Yields Lower Income Elasticity	Greater Flexibility	More Favorable to Coal & Oil	Increased Uprates of Existing Units	More Growth in Capacity	
25	LNG Stress Test – Balanced Future	Increased Efficiency Yields Lower Income Elasticity	Greater Flexibility	More Favorable to Coal & Oil	Increased Uprates of Existing Units	More Growth in Capacity	
26	Accelerated Rockies Pipeline Development						
27	Delayed Rockies Pipeline Development						
28	High Resource Base P10						
29	Low Resource Base P90						
30	Carbon Reduction			High Retirement Rates for Steam; No New Conventional Coal Plants	New Nuclear Units Added After 2012	More Growth in Capacity	Carbon Emissions Constrained
31	Status Quo	Increased Efficiency Yields Lower Income Elasticity		Delayed Construction of New Coal Capacity		More Growth in Capacity	
32	WTI $28 Oil Price						Oil Price is $28 for WTI

Table 9-2. Summary of Cases (Continued)

curve" of sorts, which shows how much natural gas demand would exist in the United States and Canada at various price levels. This is shown as a black line in Figure 9-2. The solution point on that curve that is reached by any case depends on what supply-side assumptions are made, since price will adjust in a free market to make demand equal supply. However, the "demand curve" that is traced by the cases is not perfectly smooth because there are time-dependant perturbations that result from the various assumptions and regional price variability that cannot be captured in a simple two-dimensional plot.

Figure 9-3 presents the same type of information for the demand-side sensitivities. It is possible to trace out a "supply curve" off of the Reactive Path demand-side assumptions. The black line in Figure 9-3 shows the points that result from keeping the supply assumptions the same, but varying demand-side factors. For example, the solution point furthest down on the curve is the Fuel Flexibility case. By allowing other fuels to compete more effectively with natural gas, the Fuel Flexibility case achieves the largest gas price reductions given the Reactive Path supply-side assumptions. The point furthest up on the curve is the High Economic Growth case. This adds the greatest amount of natural gas demand and reaches the highest price increase given Reactive Path supply-side assumptions.

All 32 of the major NPC cases are plotted in Figure 9-4 using the same conventions as Figure 9-2 and 9-3. The implied demand and supply curves from the Reactive Path scenario are shown as blue lines labeled D1 and S1. The solution point for the Balanced Future scenario is Point 2 at the intersection of the two green lines that represent supply and demand curves for that scenario. Likewise, the solution point for the Status Quo scenario is Point 31 at the intersection of the two red lines. Because only one supply-side sensitivity was run based on the Balanced Future scenario (LNG Stress Test), the demand curve for that case cannot be traced very fully. However, one can surmise from Figure 9-4 that additional supply-enhancing assumptions, such as improved upstream technologies, would drop prices further as the solution point moved further down from Point 2 on the D2 curve.

Figure 9-5 is a graphical representation of the impact of selected sensitivity cases.

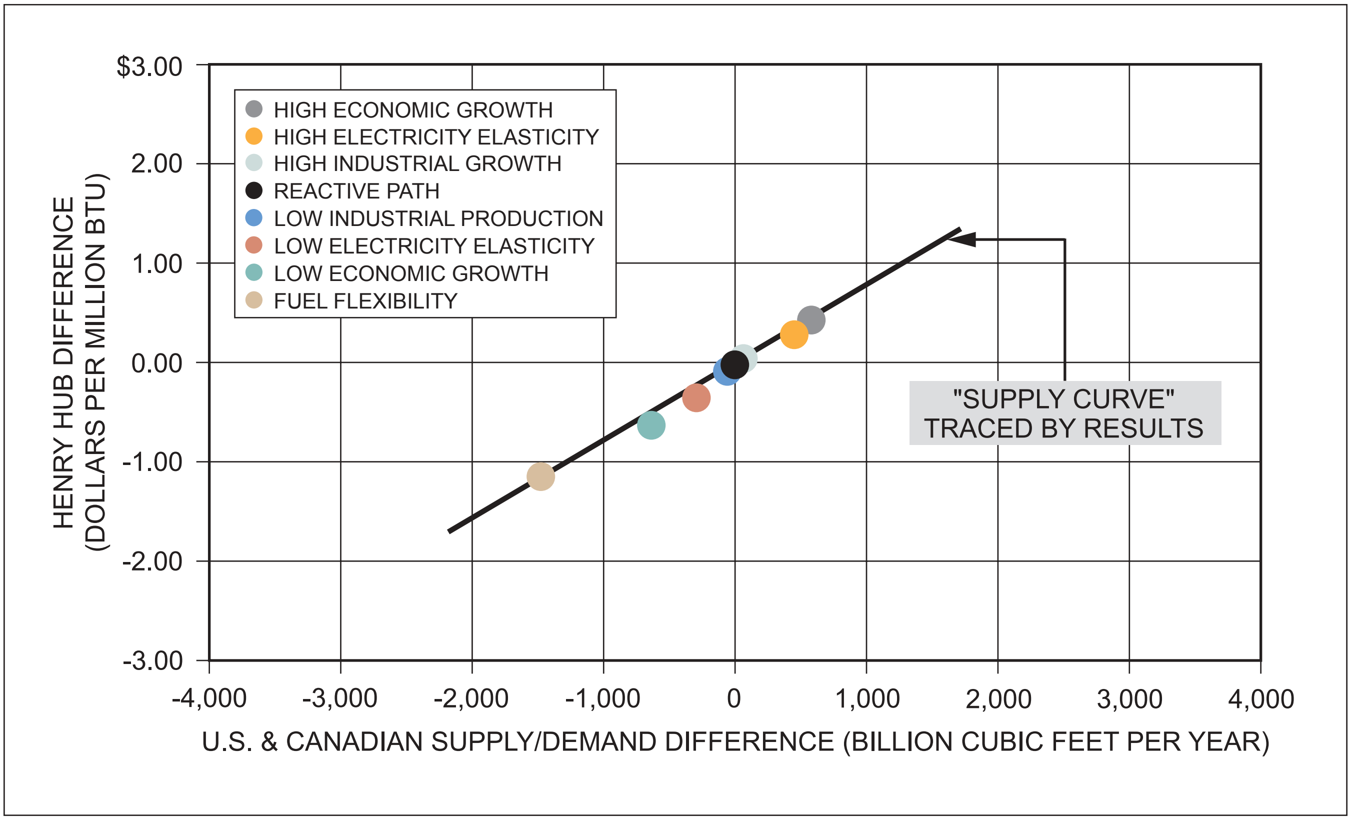


Figure 9-3. Selected Demand Sensitivities – United States and Canada (2011-2025 Averages)

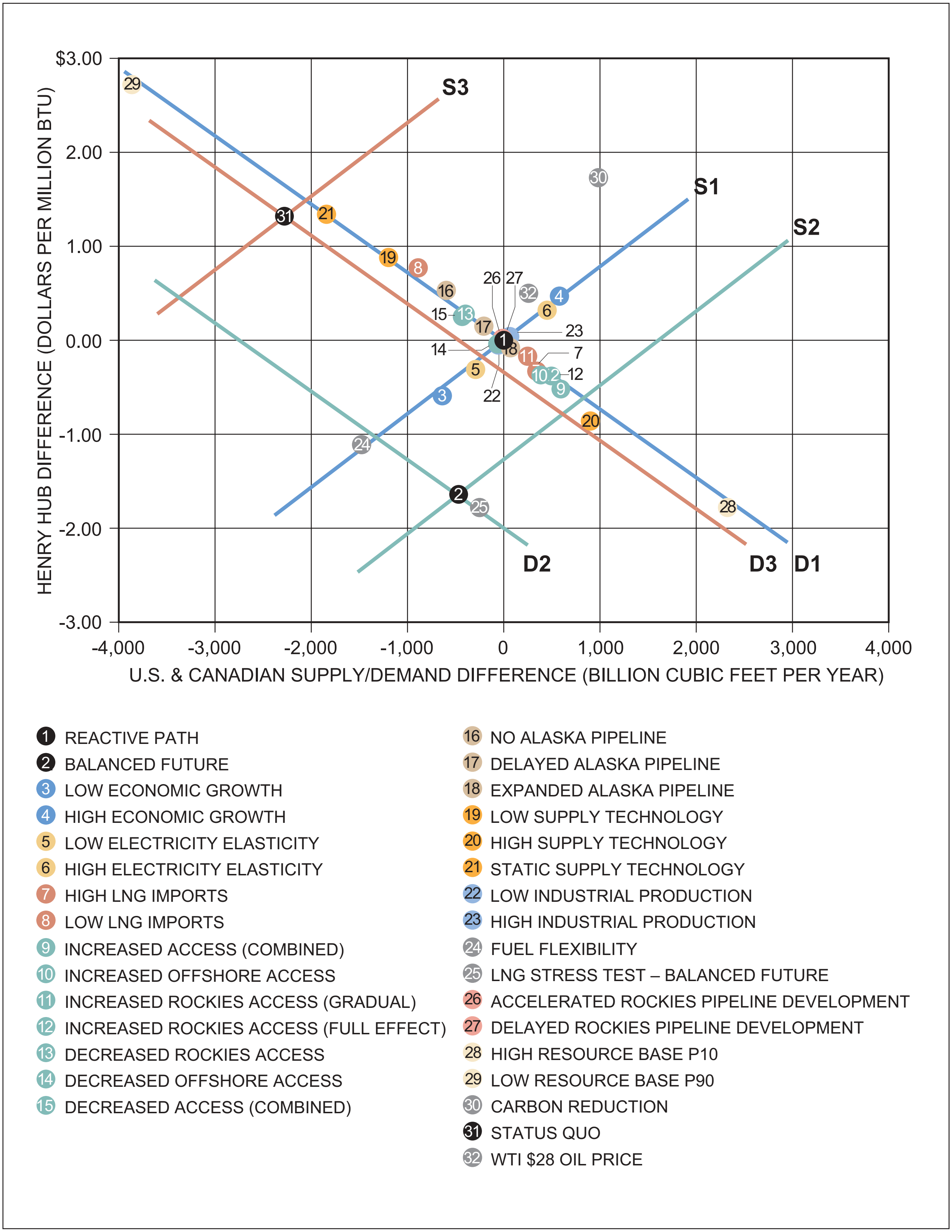


Figure 9-4. Selected Cases – United States and Canada (2011-2025 Averages)

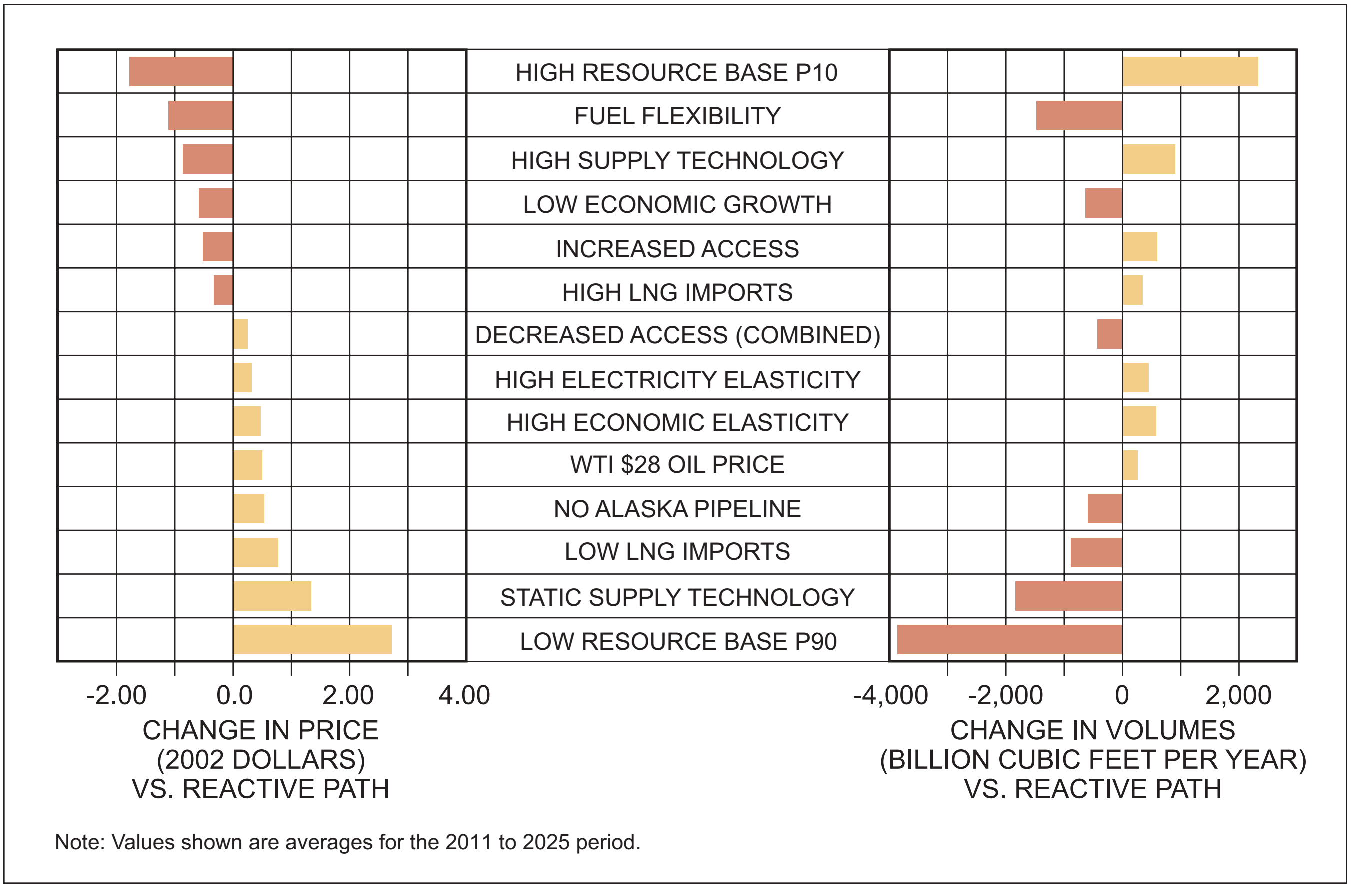


Figure 9-5. Price and Volume Impacts of Selected Sensitivities

Further Information on Cases

This chapter was intended only to introduce the full range of cases explored in this study. Please see the individual Task Group Reports for additional details on these cases including regional production and demand trends, pipeline construction and flow patterns, changing basis differentials, and consumer cost impacts.

CHAPTER 10

MODELING METHODOLOGIES

This chapter describes the natural gas market modeling methodologies used by the NPC. The modeling framework developed and maintained by Energy and Environmental Analysis, Inc. (EEA) formed the basis of gas market outlooks in the current study. Additional work was conducted to apply data and develop underlying assumptions for models by Altos Management Partners. Further information is available in the Task Group Reports.

In the course of this study, the NPC developed databases related to resource base quantities and developing and operating costs, gas pipeline capacity and rates, and characterizations of gas demand volumes versus price. It is the intent of the NPC to make these data available to government agencies and other interested parties. The NPC also will continue working with government agencies, such as the USGS, to determine the feasibility of updating, utilizing, and maintaining the resource, engineering, and cost data developed by the NPC.

The EEA Models

Models licensed from Energy and Environmental Analysis, Inc. (EEA) for this study included the Hydrocarbon Supply Model (HSM) and the Gas Market Data and Forecasting System (GMDFS). The HSM models supply on an annual basis, while the GMDFS simulates monthly market behavior, and the models are operated in an integrated manner. The primary inputs from the HSM into GMDFS are gas deliverability data, and the primary data going back from GMDFS to the HSM are gas production levels and prices.

The EEA models solve using a "market simulation" methodology, meaning the decisions are simulated on a period-by-period basis using foresight assumptions set by the user. As such, the EEA models produce results that match history and provide insight into the future natural gas market.

Earlier versions of the HSM were used in both the 1992 and 1999 NPC studies. The GMDFS also was used in the 1999 study. Several changes were made to those models since the 1999 study, both independently by EEA and in consultation with the NPC. The major changes for the 2003 NPC study, in contrast to earlier studies, include:

- New, more disaggregated regions in the supply model
- Use of play-level resource description for new field resources
- Revised field appreciation (growth) data and resource estimate
- Revised data and more flexible methodology for treating land access in the United States and Canada
- Updated performance parameters for well recoveries, find rates, etc.
- Revised decline rates for existing and new reserves
- New upstream factor costs for wells, platforms, etc.
- Modeling of ethane rejection in gas processing as a supplement to natural gas supplies
- New gas pipeline corridors to accommodate new regions

- Updated existing pipeline capacities
- New costs for pipeline construction
- Expanded industrial gas demand model
- New cost and performance factors for multiple power generation technologies
- Extended forecast horizon to the year 2030
- Enhanced outputs in Microsoft Excel and Access format.

Gas Market Data and Forecasting System

The Gas Market Data and Forecasting System has the capability to track and analyze the performance of North American natural gas markets on a monthly basis. At the heart of the system is a comprehensive gas transmission network that solves for natural gas supply and demand in the United States, Canada, and northern Mexico. Specifically, the model solves for monthly natural gas production and demand, storage injections and withdrawals, pipeline flows, natural gas prices, location, and seasonal basis for a very detailed natural gas pipeline network comprised of over 100 nodes (or market hubs). Results are described at the node level. In the power generation sector, the GMDFS solves for monthly U.S. electricity demand, power generation by type of fuel, and fuel use.

The GMDFS model simulates monthly gas market performance to 2030, considering the impact of a wide range of variables. Inputs include: growth rates for economic drivers, such as GDP and industrial production; projected prices of crude oil and alternative fuels; power generating capacity by technology and fuel supply; weather and hydrological conditions; pipeline and storage expansions; LNG imports and exports; and other annual and seasonal factors.

Overall, the model solves for monthly natural gas market clearing prices by considering the interaction between supply and demand relationships at each of the model's nodes. On the supply side, prices are determined by short-term production and storage price curves that reflect prices as a function of production and storage utilization. Prices are also influenced by "pipeline discount" curves, which reflect the change in basis or the marginal value of gas transmission as a function of load factor. On the demand side, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes in the model at the market clearing prices determined by the shape of the supply and demand curves. EEA maintains this model by doing significant "backcasting" (calibration) of the model's curves and relationships on a monthly basis to make sure that the model reliably reflects historical gas market behavior, instilling confidence in the projected results.

The NPC provided input assumptions for weather, economic growth, and oil prices, among other variables. EEA performs market reconnaissance and keeps the model up to date with generating capacity, near-term gas supply deliverability, storage and pipeline expansions, and the impact of regulatory changes in gas transmission.

Since the GMDFS solves on a monthly basis, EEA's Daily Demand model was used to determine daily gas demands. The Daily Demand model is an offshoot of the GMDFS. It is based on the same nodal structure and demand modules used by the GMDFS, but runs for each day of a given historical or future year. The output of the Daily Demand model is daily residential, commercial, industrial, and power generation gas demand at each model node, and daily fossil generation for each of the model's power dispatch regions. The Daily Demand model was used by the NPC to project peak-day demands, assess the need for high-deliverability storage, and identify possible pipeline constraints.

In contrast to the GMDFS, which solves for the full supply and demand balance at each node to arrive at natural gas market clearing prices, the Daily Demand model uses the gas prices from a GMDFS model run to determine daily demand at each node. Once a GMDFS model run is complete, the Daily Demand routine is run using the same inputs as the GMDFS, plus the gas price outputs from the GMDFS model run. The daily temperatures used in the Daily Demand model are adjusted to match the total monthly heating and cooling degree-day values used as input for the GMDFS. This allowed the NPC to model the demand variability within each month and distribute the monthly load over the days of the month.

Hydrocarbon Supply Model

The Hydrocarbon Supply Model is an analytical framework designed for the simulation, forecasting, and analysis of natural gas, crude oil, and natural gas liquids supply and cost trends in the United States and Canada. It is a process-engineering model with a detailed representation of potential gas resources and the technologies with which those resources can be proven and produced. The degree and timing by which resources are proven and produced are determined in the model through discounted cash flow analyses of alternative investment options and behavioral assumptions in the form of inertial and cash flow constraints and the logic for setting producers' market expectations (i.e., future gas prices).

The model covers the U.S. lower-48, Alaska, and Canada. The lower-48 states are represented in 28 onshore regions and 11 offshore regions. Alaska is divided into seven regions, and Canada is divided into ten regions. All regions are further broken out into subregions or "intervals." Each of these "intervals" represents some combination of drilling depths, water depth, or geographic areas.

Resources in the Hydrocarbon Supply Model are divided into three general categories: new fields/new pools, field appreciation (growth), and nonconventional gas. For conventional resources in the United States, there are 220 region/interval categories that are modeled with over 10,000 prototypical field development plans. Old-field appreciation is modeled in approximately 525 categories. Nonconventional gas is represented by 261 "cells" that, for the United States, correspond to the "continuous plays" of USGS resource assessments.

The Hydrocarbon Supply Model has a large number of factors that can be changed to produce alternative cases. These include:

Resource Base

- Undiscovered New Field Resources
- Initial Old Field Growth
- Unconventional Gas Resources

Policies

- Taxes and Royalties
- Land Access
- Environmental Regulations

Exploration, Development, and Production Costs

- Drilling Costs
- Environmental Compliance Costs

Technologies

- New Field Exploration Efficiency
- Field Development, Gas Processing
- Recovery Factor Improvement

Producer Behavior

- Oil and Gas Price Expectations
- Rate-of-Return Criteria

Model output includes annual forecasted number of wells drilled by type, reserve additions, production, end-of-year reserves, and various cash flow accounts. Outputs can be in viewed in Microsoft Excel and Access format and include details by type of natural gas and by model regions/intervals.

The Altos Models

In order to develop additional tools to supplement the EEA forecasting model, the NPC also licensed the North American Regional Gas (NARG) model and the North American Regional Electricity (NARE) model from Altos Management Partners. All characterizations of North American gas and electric power markets incorporated into the Altos model were developed by a modeling team that was part of the NPC natural gas study. Although significant progress was made developing input to the model, there was insufficient time during this study to thoroughly review the results with industry representatives and build this feedback into the model. At the time of publication, some changes were felt to be appropriate. The modeling frameworks and their associated algorithms are described below.

The NARG Model

For the purposes of the 2003 NPC study, 230 natural gas supply nodes and 72 demand regions were defined. The supply regions were aggregated from over 700 plays, and the demand regions were segmented into residential, commercial, chemical industry, other industry, and power generation. The model was configured through 2045. Because results are computed and reported annually, NARG does not incorporate gas storage, or the seasonal load variations.

The NARG model assumes the existence of a competitive, transparent market, and seeks an economically optimum solution over the investment life cycle that allows investors in all segments of the market to achieve their target rates of return.

Users of NARG must specify supply and demand nodes, and pipeline infrastructure connections, called links, as follows:

- Supply, or "resource," nodes require cost-of-supply curves, which characterize the increasing marginal cost of bringing new gas to market. Cost-of-supply curves are derived from resource availability, production decline profiles, and cost data.

- Demand nodes require specification of demand volumes, price elasticity, and other variables such as income, weather, and population.

- Pipeline links, processing plants, and LNG terminals require capacity and tariff specification. The model constructs new capacity when user-defined economic criteria are met.

The NARE Model

The NARE model includes a database of every generating unit in North America (capacity, fuel-type, costs, etc.), along with utility demand projections. It uses a "zero-arbitrage" solution to dispatch units within each region and across regional boundaries. Users must define the capital and operating costs of new capacity, which will be allowed to compete with existing capacity. Dispatch of existing fleet capacity is based on competitive economics.

Gas prices reported as output from the NARG model were input to the NARE model to project gas consumption based on economic dispatch of the generation. An iterative process was used to reach convergence of price and demand between the two models.

Modeling Methodology

The NPC modeling team comprehensively customized the NARG and NARE models. The most important features incorporated into the NPC version of the models are outlined as follows.

Resources and Supply

Initially, the team modeled cost-of-supply curves for all geologic plays in North America. However, in order to simplify the computational load and improve model performance, the cost-of-supply data for proved reserves, proved growth, and undiscovered resources from over 700 plays were aggregated into 230 supply nodes.

Technical Resource. The technical resource included proved reserves, growth, and undiscovered resource assessments. The resource was also segmented into conventional gas (non-associated and associated gas) and nonconventional gas (shale gas, coal bed methane, and tight gas). Total resource assessments were adjusted to reflect current access restrictions.

Cost-of-Supply Curves. For each node and gas reservoir type, full development and operating costs were used for proved reserves growth and undiscovered resources, while only operating cost curves were used to define continued production of proved reserves. All costs were provided by an upstream cost estimating team within the Supply Task Group. As of the release of this report, the cost-of-supply curves had not been reviewed and analyzed by the Supply Task Group, and some changes were viewed to be appropriate to achieve consensus within the Supply Task Group on the cost-of-supply input to the Altos model. Detailed pre-processing spreadsheet models were developed to calculate the cost-of-supply input needed by the NARG model. The NRG Associates database was used to statistically estimate the Estimated Ultimate Recovery per well for each play.

The team developed a Monte Carlo simulation to forecast the size order of future discoveries. This "discovery process model" was used to estimate the expected size of the three representative undiscovered fields in each play needed to define a cost-of-supply curve. Technology improvement factors were used for both the capital and operating cost curves.

LNG Imports. Nodes were defined to represent existing and new LNG terminal capacity; the costs of landing and regasification were defined for each of these nodes. The model then computed import volumes that would be economic depending on local market price.

Arctic Gas. Alaska gas was assumed to be available in 2013 and Mackenzie Delta gas was assumed to be available in 2009, with initial pipeline capacities of 4 BCF/D and 1 BCF/D, respectively.

Pipelines

Existing Pipelines. Every major pipeline in North America was characterized by its capacity and fixed and variable tariff rates. Discounting based on load factor was incorporated.

Expansions and New Capacity. Potential expansions or new-build capacity were specified by year of availability, capital costs, operating costs, and capacities. The model then computed whether to utilize capacity based on the overall economics of transportation and regional price differentials. Near-term planned expansions were explicitly modeled.

Demand

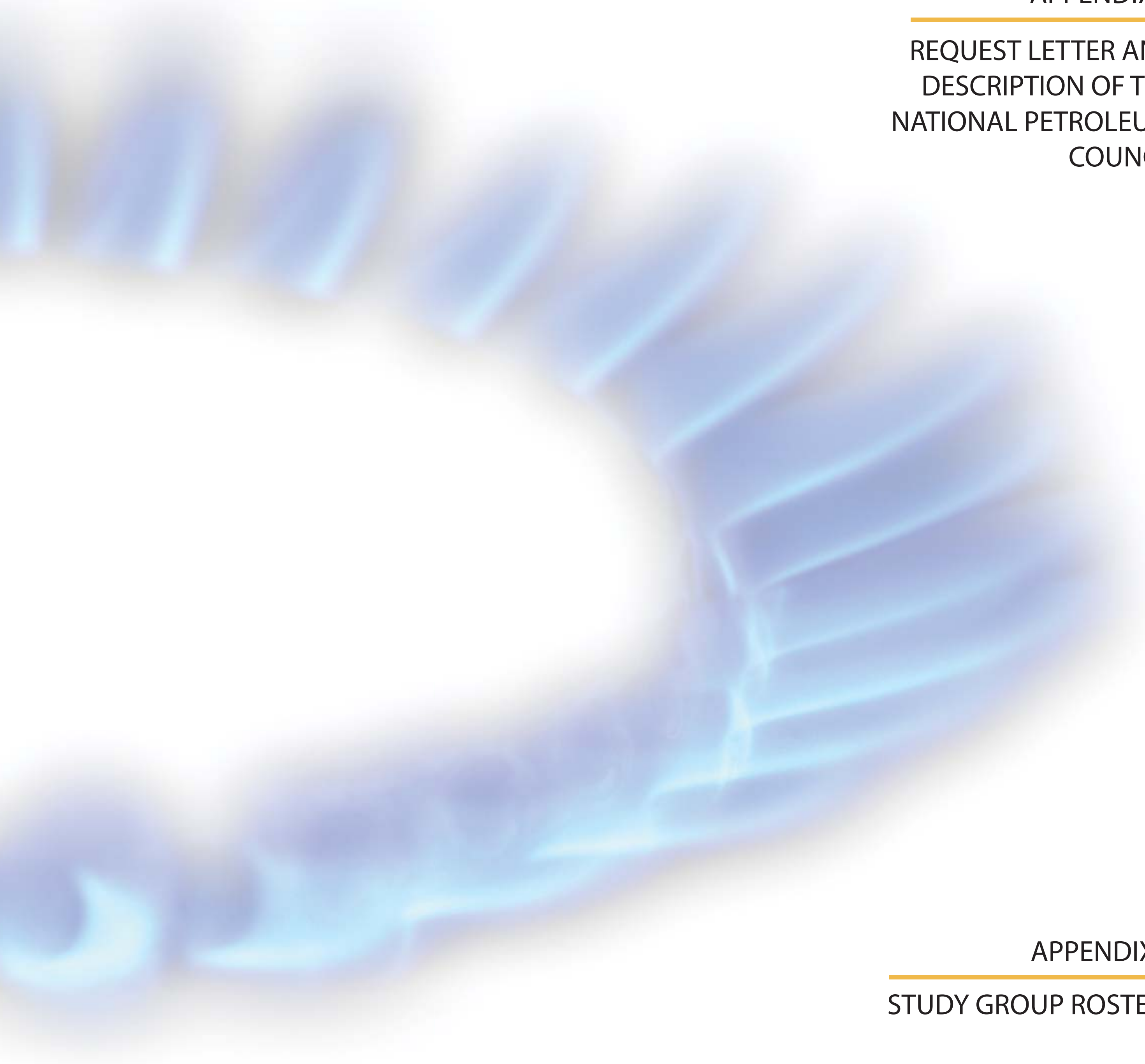
Dynamic elasticity of demand was incorporated in the residential, commercial, chemical, and other industrial sectors. The power generation sector was modeled using NARE, and thus was characterized structurally rather than econometrically.

- The demand model incorporated exogenous factors such as economic growth, weather, and population.
- Gas demand was a model output for the residential, commercial, electric power generation, chemical, and other industrial sectors.
- For residential and commercial demand, price and income elasticity, as well as the influence of population and weather, were econometrically estimated from historical data.
- For chemicals and other industrial demand, price and income elasticity were estimated from projected price and consumption consistent with the detailed analysis undertaken by the NPC using expanded industrial model developed by EEA.
- For electric power gas demand, the results of NARE were input into NARG. The NARE model contained new-build power generation capacity assumptions.
- Specific model upgrades, such as integration into the World Gas model, increased industrial demand granularity, incorporating a price/income feedback loop, etc., are addressed in the Demand Task Group Report.

Further Altos Modeling Work

The NPC modeling team will continue working with the USGS to determine the feasibility of the USGS updating and maintaining the resource, engineering, and cost data used in the cost-of-supply pre-processor developed by the NPC.

APPENDICES



APPENDIX A

REQUEST LETTER AND DESCRIPTION OF THE NATIONAL PETROLEUM COUNCIL

APPENDIX B

STUDY GROUP ROSTERS

The Secretary of Energy
Washington, DC 20585

March 13, 2002

Mr. William A. Wise
Chairman
National Petroleum Council
1625 K Street, NW
Washington, DC 20006

Dear Chairman Wise:

In the last decade, the National Petroleum Council conducted two landmark studies on natural gas, the 1992 study ***Potential of Natural Gas in the United States*** and the 1999 study ***Meeting the Challenges of the Nation's Growing Natural Gas Demand***. These studies provided valuable insights on the potential contribution of natural gas to the Nation's economic, energy and environmental future, and the capabilities of industry to meet future natural gas demand and changing market conditions.

Considerable change has occurred in natural gas markets since the Council's 1999 study, among these being new concerns over national security, a changed near-term outlook for the economy, and turbulence in energy markets based on perceived risk, price volatility, fuel switching capabilities, and the availability of other fuels. The Nation's reliance on natural gas continues to grow, with U.S. consumption projected to increase by 50 percent in the next 20 years. However, the availability of investment capital and infrastructure, the pace of technology progress, access to the Nation's resource base, and new sources of supplies from Alaska, Canada, liquefied natural gas imports, and unconventional resources such as methane hydrates are factors that could affect the future availability of natural gas supplies.

Accordingly, I request that the Council conduct a new study on natural gas in the United States in the 21st Century. Such a study should examine the potential implications of new supplies, new technologies, new perceptions of risk, and other evolving market conditions that may affect the potential for natural gas demand, supplies, and delivery through 2025. It should also provide insights on energy market dynamics, including price volatility and future fuel choice, and an outlook on the longer-term sustainability of natural gas supplies. Of particular interest is the Council's advice on actions that can be taken by industry and Government to increase the productivity and efficiency of North American natural gas markets and to ensure adequate and reliable supplies of energy for consumers.

I am designating Mr. Robert G. Card, Under Secretary for Energy, Environment and Science, and Mr. Carl Michael Smith, Assistant Secretary for Fossil Energy, to represent me in the conduct of this important study. I offer my gratitude to the Council for its efforts to assist the Department in defining the scope of the study request and I recognize that refinements may be necessary after the study starts to ensure that the most critical issues affecting future natural gas demand, supplies, and delivery are addressed.

Sincerely,

Spencer Abraham

Secretary Abraham

DESCRIPTION OF THE NATIONAL PETROLEUM COUNCIL

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council (NPC) on June 18, 1946. In October 1977, the Department of Energy was established and the Council was transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by the Secretary, relating to oil and natural gas or the oil and gas industries. Matters that the Secretary of Energy would like to have considered by the Council are submitted in the form of a letter outlining the nature and scope of the study. The Council reserves the right to decide whether it will consider any matter referred to it.

Examples of studies undertaken by the NPC at the request of the Secretary of Energy include:

- *Factors Affecting U.S. Oil & Gas Outlook (1987)*
- *Integrating R&D Efforts (1988)*
- *Petroleum Storage & Transportation (1989)*
- *Industry Assistance to Government – Methods for Providing Petroleum Industry Expertise During Emergencies (1991)*
- *Short-Term Petroleum Outlook – An Examination of Issues and Projections (1991)*
- *Petroleum Refining in the 1990s – Meeting the Challenges of the Clean Air Act (1991)*
- *The Potential for Natural Gas in the United States (1992)*
- *U.S. Petroleum Refining – Meeting Requirements for Cleaner Fuels and Refineries (1993)*
- *The Oil Pollution Act of 1990: Issues and Solutions (1994)*
- *Marginal Wells (1994)*
- *Research, Development, and Demonstration Needs of the Oil and Gas Industry (1995)*
- *Future Issues – A View of U.S. Oil & Natural Gas to 2020 (1995)*
- *Issues for Interagency Consideration – A Supplement to the NPC's Report: Future Issues – A View of U.S. Oil & Natural Gas to 2020 (1996)*
- *U.S. Petroleum Product Supply – Inventory Dynamics (1998)*
- *Meeting the Challenges of the Nation's Growing Natural Gas Demand (1999)*
- *U.S. Petroleum Refining – Assuring the Adequacy and Affordability of Cleaner Fuels (2000)*
- *Securing Oil and Natural Gas Infrastructures in the New Economy (2001).*

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of the oil and gas industries and related interests. The NPC is headed by a Chair and a Vice Chair, who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

NATIONAL PETROLEUM COUNCIL

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ACRONYMS AND ABBREVIATIONS

AEO	EIA's Annual Energy Outlook
AFUE	annual fuel utilization efficiency
AGA	American Gas Association
ANGTS	Alaska Natural Gas Transportation System
ANWR	Arctic National Wildlife Refuge
API	American Petroleum Institute
BCF	billion cubic feet
BCF/D	billion cubic feet per day
BLM	U.S. Bureau of Land Management
Btu	British thermal unit
CCGT	combined-cycle gas turbines
CEQ	Council on Environmental Quality
CERI	Canadian Energy Research Institute
CFE	Comision Federal de Electricidad (Mexico's Federal Electricity Commission)
CGPC	Canadian Gas Potential Committee
CHP	combined heat and power
CO_2	carbon dioxide
COAs	conditions of approval
CRE	Comision Reguladora de Energia (Mexico's Energy Regulatory Commission)
CZM	Coastal Zone Management
D&C	drilling and completion
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
E&P	exploration and production
EEA	Energy and Environmental Analysis, Inc.
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
EUR	estimated ultimate recovery
FERC	Federal Energy Regulatory Commission
FPC	Federal Power Commission (forerunner of FERC)
GDP	gross domestic product
GMDFS	EEA's Gas Market Data and Forecasting System
GRI	Gas Research Institute
GSR	EEA's Gas Supply Review
HSM	EEA's Hydrocarbon Supply Model

HVAC	heating-ventilation-air conditioning systems
IHS	IHS Energy Group
INGAA	Interstate Natural Gas Association of America
IP	initial production rate
ISTUM	Industrial Sector Technology Use Model
JAS	API's Joint Association Survey
LDC	local distribution company
LIHEAP	Low Income Home Energy Assistance Program
LNG	liquefied natural gas
MCF	thousand cubic feet
MM	million
MMBtu	million British thermal units
MMCF	million cubic feet
MMCF/D	million cubic feet per day
MMS	Minerals Management Service
MOU	memorandum of understanding
MSC	Multiple Services Contract
MTA	million tons per annum
NAICS	North American Industry Classification System
NEB	National Energy Board of Canada
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NGL	natural gas liquid
NGPA	National Gas Policy Act
NGV	natural gas vehicle
NOx	nitrogen oxides
NOAA	National Oceanic and Atmospheric Administration
NPC	National Petroleum Council
NPRA	National Petroleum Reserve, Alaska
NYMEX	New York Mercantile Exchange
OCS	Outer Continental Shelf
Pemex	Petroleos Mexicanos
POLR	provider of last resort
PSAC	Petroleum Services Association of Canada
psi	pounds per square inch
PUC	Public Utility Commission
PURPA	Public Utility Regulatory Policies Act of 1978
quads	quadrillion Btu
RACC	refiner acquisition cost of crude oil
R&D	research and development
ROE	return on equity
R/P	reserves to production (ratio)
RTOs	Regional Transmission Organizations
RPS	Renewable Portfolio Standards
SENER	Secretaria de Energia (Mexico's Energy Ministry)
SIC	Standard Industrial Classification
SOLR	supplier of last resort
SOx	sulfur oxides
SO_2	sulfur dioxide
TCF	trillion cubic feet
USGS	United States Geological Service
WCSB	Western Canada Sedimentary Basin
WTI	West Texas Intermediate crude oil

INTEGRATED REPORT

GLOSSARY

Access
The ability to drill and develop oil and natural gas resources, build associated production facilities, and construct transmission and distribution facilities on either public and/or private land.

Basis
The difference in price for natural gas at two different geographical locations reported for the same time period.

British Thermal Unit (Btu)
A Btu is the amount of heat required to change the temperature of one pound of water one degree Fahrenheit, and is the common energy measurement for natural gas. One cubic foot of natural gas contains approximately 1,000 Btu.

Capacity, Peaking
The capacity of facilities or equipment normally used to supply incremental gas or electricity under extreme demand conditions. Pipeline peaking capacity is generally available for a limited number of days at maximum flow rate while electric peaking capacity is generally available whenever market price conditions cover all variable costs and startup expenses for such capacity.

Capacity, Pipeline
The maximum physical 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 contract service conditions.

Citygate
The point at which interstate and intrastate pipelines sell and deliver natural gas to local distribution companies.

Cogeneration
The production of electricity and useful thermal energy from the same initial energy source. Natural gas is a favored fuel for combined-cycle cogeneration units, where it directly produces electricity from a combustion turbine and the resultant waste heat is converted to steam for process use and for generating electricity in a heat steam recovery generator (HSRG).

Commercial
A sector of customers or service defined as non-manufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, retail stores, and health, social, and educational institutions.

Compressed Natural Gas (CNG)
Natural gas cooled to a temperature below 32°F and compressed to a pressure ranging from 1,000 to 3,000 pounds per square inch in order to allow the transportation of large quantities of natural gas.

Cost Recovery
The recovery of permitted costs, plus an acceptable rate of return, for an energy infrastructure project subject to rate regulations.

Cubic Foot
The most common unit of measurement of gas volume; the amount of gas required to fill a volume of one cubic foot under standard conditions of temperature, pressure, and water vapor.

Distribution Line
Natural gas pipeline system, typically operated by an LDC (local distribution company), for the delivery of natural gas to end-users.

Elasticity
An economic metric that typically measures the magnitude of changes in supply or demand as a function of changes in price.

Electric
A sector of customers or service defined as generation, transmission, distribution, or sale of electric energy.

End-User
An entity that actually consumes energy, as opposed to one who sells or re-sells it.

Federal Energy Regulatory Commission (FERC)
The federal agency that regulates rates and terms of service for interstate gas pipelines and interstate gas sales and for wholesale electric power transactions under federal energy statutes.

Feedstock
The use of one product as an ingredient to produce another, such as using natural gas as a feedstock to produce ammonia or methanol.

Firm Customer
A customer who has contracted for firm service.

Firm Service
Service offered to customers under schedules or contracts that anticipate no interruptions, except for force majeure.

Fuel Switching
Substituting one fuel for another based on price and availability. Large industries and power generators often have the capability of using either oil or natural gas to fuel their operation and of making the switch on short notice.

Fuel-Switching Capability
The ability of an end-user to readily change fuel type consumed whenever a price or supply advantage develops for an alternative fuel.

Gigawatts
One billion watts, or one thousand megawatts.

Gross Domestic Product (GDP)
A dollar measure of total output of goods and services in the nation. Note that GDP can be measured in nominal or current dollars or in real dollars, which removes the effects of inflation.

Henry Hub
A pipeline interchange near Erath, Louisiana, where a number of interstate and intrastate pipelines interconnect through a header system operated by Sabine Pipe Line. The standard delivery point for the New York Mercantile Exchange natural gas futures contract.

Industrial
A sector of customers or service defined as manufacturing, construction, mining, agriculture, fishing, and forestry.

Kilowatt
One thousand watts.

Liquefied Natural Gas (LNG)
The liquid form of natural gas, which has been cooled to a temperature –256°F or –161°C and is maintained at atmospheric pressure. This liquefaction process reduces the volume of the gas by approximately 600 times its original size.

Load Profiles
Gas or electric power usage over a specific period of time, usually displayed as a graphical plot.

Local Distribution Company (LDC)
A company that obtains the major portion of its natural gas revenues from the operations of a retail gas distribution system and that operates no transmission system other than incidental connections within its own or to the system of another company. An LDC typically operates as a regulated utility within a specified franchise area.

Megawatts
One million watts or one thousand kilowatts.

Marketer (natural gas)
A company, other than the pipeline or LDC, that buys and resells gas or brokers gas for a profit. Marketers also perform a variety of related services, including arranging transportation, monitoring deliveries and balancing. An independent marketer is not affiliated with a pipeline, producer or LDC.

New Fields
A quantification of resources estimated to exist outside of known fields on the basis of broad geologic knowledge and theory; in practical terms, these are statistically determined resources likely to be discovered in additional geographic areas with geologic characteristics similar to known producing regions, but are untested by actual drilling.

Nominal Dollars
Dollars that have not been adjusted for inflation.

Nonconventional Gas
Natural gas produced from coalbeds, shales, and low permeability reservoirs. Development of these reservoirs can require different technologies than conventional reservoirs.

Peak-Day Demand
The maximum daily quantity of gas or power used during a specified 24-hour period and evaluated over a specific period such as a year.

Peak Shaving
Methods to reduce the peak demand for gas or electricity or to meet those peaks with alternate delivery sources or methods. Examples would be price-controlled interruptions for demand reduction or propane-air and distributed LNG for alternate resources.

Proved Reserves
The most certain of the resource base categories representing estimated quantities that analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Generally, these gas deposits have been "booked," or accounted for as assets on the SEC financial statements of their respective companies.

Real Dollars
Dollars in a particular year that have been adjusted for inflation to make financial comparisons in different years more valid.

Refiner Acquisition Cost of Crude Oil (RACC)
The cost of crude oil, including transportation and other fees paid by the refiner. The composite cost is the weighted average of domestic and imported crude oil costs. Note: The refiner acquisition cost does not include the cost of crude oil purchased for the Strategic Petroleum Reserve (SPR).

Regional Transmission Organization (RTO)
A regulatory-recognized organization of electric transmission owners, transmission users, and other entities interested in coordinating transmission planning, expansion, and use on a regional and interregional basis.

Residential
The residential sector is defined as private households that consume energy primarily for space heating, water heating, air conditioning, lightning, refrigeration, cooking, and clothes drying.

Revenue
The total amount of money received by a firm from sales of its products and/or services.

Shipper
One who contracts with a pipeline for transportation of natural gas and who retains title to the gas while it is being transported by the pipeline.

Terrawatts
One trillion watts.

Watt
The common U.S. measure of electrical power.