

Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy

Volume I Summary of Findings and Recommendations

**A Report of the
National Petroleum Council**

September 25, 2003

This is a working document solely for the review and use of the participants in the National Petroleum Council's Natural Gas Study. Data, conclusions, and recommendations contained herein are preliminary and subject to substantive change. This draft material has not been considered by the National Petroleum Council and is not a report nor advice of the Council.

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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." (See Appendix A for the complete text of the Secretary's request letter.)

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,

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

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, 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, financiers, 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 (Electric Power, Industrial, Commercial/Residential, and Economics/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 thirteen 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 (FERC), and the Energy Information Administration (EIA).

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, of course, 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, which clearly identified basins that are maturing and those where production growth potential remains. This analysis helped condition the forward-looking assumptions used 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.

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 (TCF) 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 be 220 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 (MMS) 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.

Executive Summary

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. The solution is a balanced portfolio 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. The following is a summary of key findings and of recommendations that will help achieve a balanced future for natural gas.

ALTERNATIVE SCENARIOS

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.

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. To achieve even the Reactive Path outcome, the following actions must be taken:

- Continue improvements in energy efficiency and conservation.
- Enact enabling legislation for the Alaskan gas pipeline.
- Overcome local siting opposition to new LNG terminals.
- Streamline permitting processes to allow increased drilling and development activity in the Rocky Mountains.

- Implement a Joint Agency Review process for new infrastructure.
- Clarify New Source Review requirements for industrial and power plant facilities.

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.

This scenario allows for a balanced future by:

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

It is important to note that there are uncertainties, which could significantly impact the supply/demand balance for each scenario. These uncertainties include, but are not limited to, weather, oil price, economic growth, and potential treatment of carbon dioxide (CO₂) emissions.

This report analyzes supply, demand, and the infrastructure for natural gas in North America in the near, mid, and long term (through 2025). Recommendations from this analysis are intended to preserve the critical benefits of natural gas to the North American economy and environment.

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.

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.

Infrastructure

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

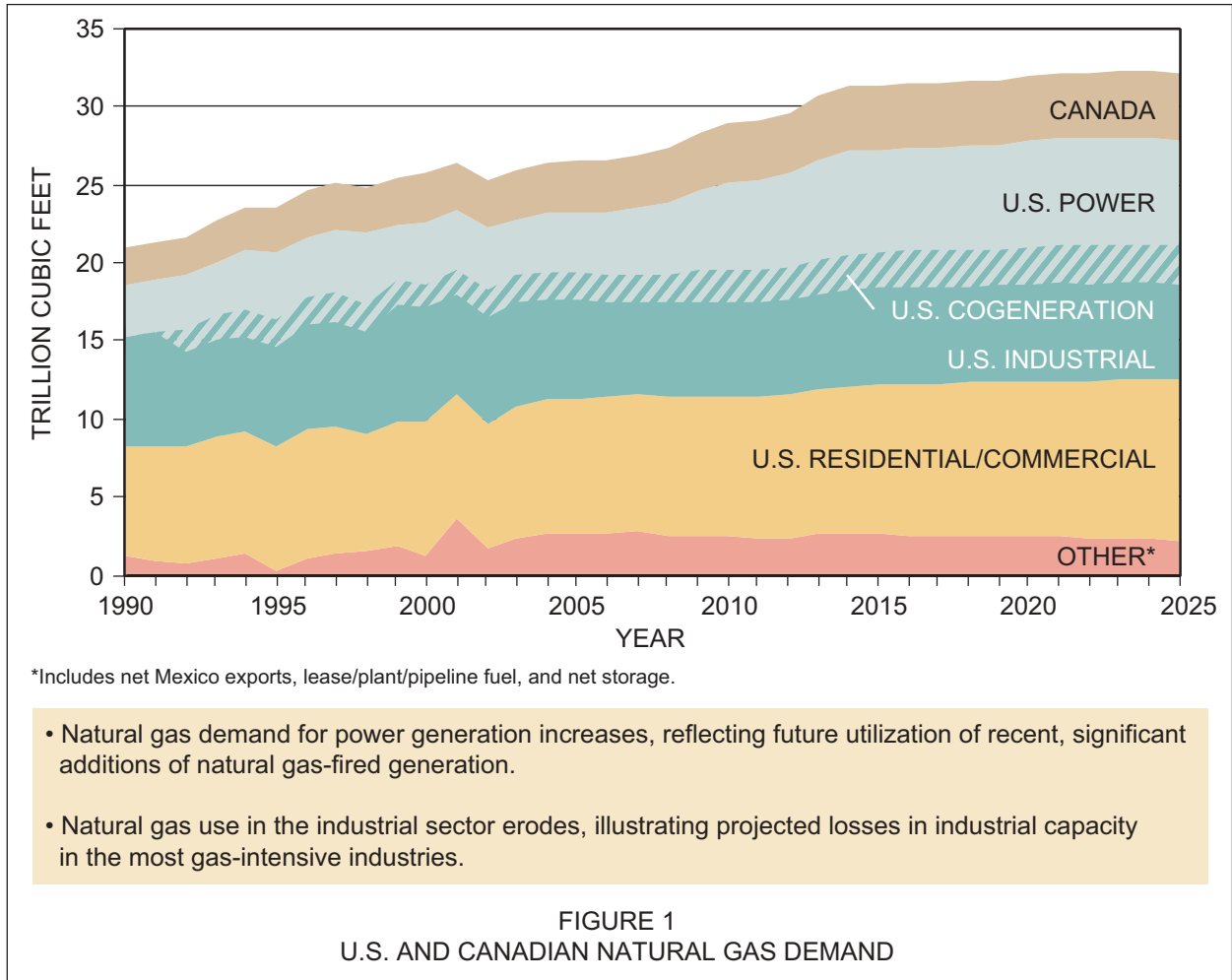
Regulatory barriers to long-term contracts for transportation and storage impair infrastructure investment.

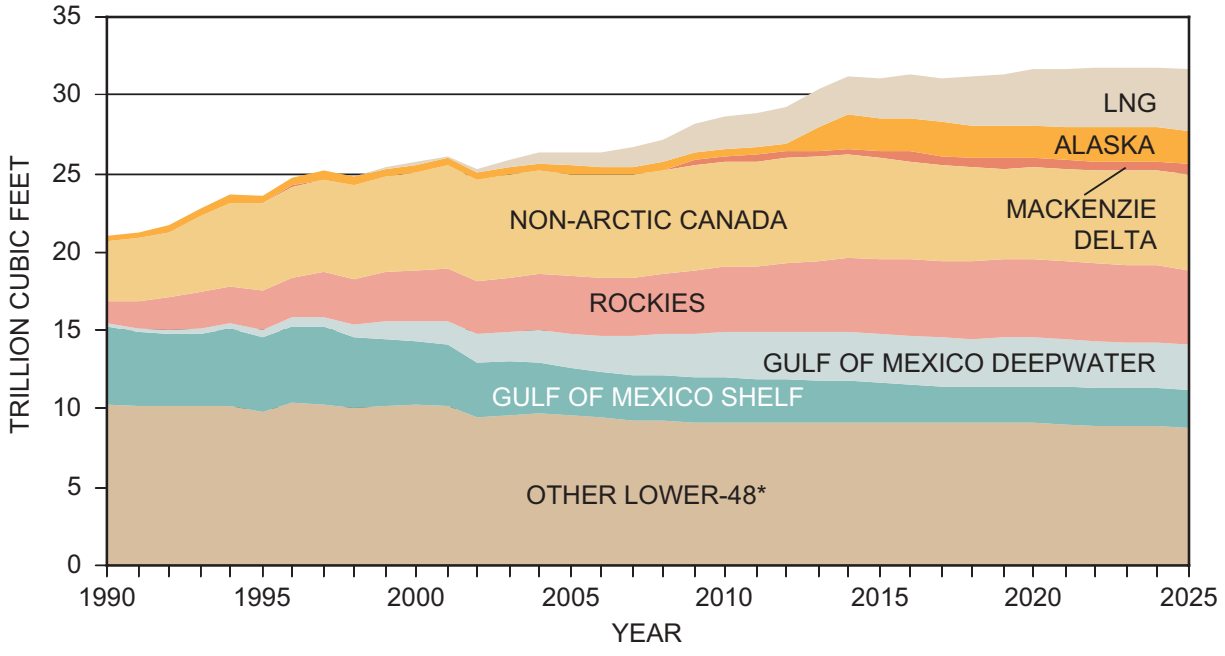
Markets

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.

National Petroleum Council projections of future demand and supply are illustrated in Figures 1 and 2. These figures illustrate some of the key attributes of the NPC outlooks.





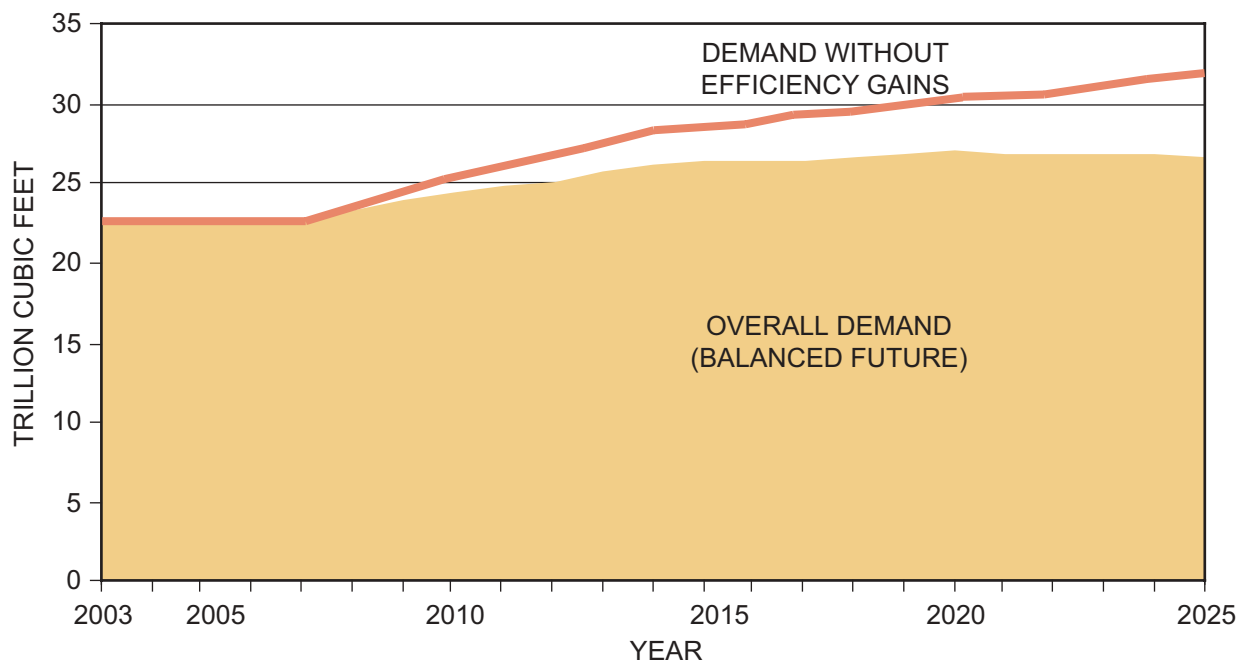
* Includes lower-48 production, ethane rejection, and supplemental gas.

- 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 2
U.S. AND CANADIAN NATURAL GAS SUPPLY

NATURAL GAS DEMAND

Natural gas supplies approximately 25% of U.S. energy, generating about 19% of electric power, supplying heat to over 60 million households, and providing over 40% of all primary energy for industries. The NPC assessed future demand in each of the key consumer sectors – residential/commercial, power generation, and industrial. These assessments focused on the increased capability to consume natural gas in power generation and the effect of higher prices on industrial consumers, commercial establishments, and residential consumers. These analyses incorporate the effects of energy efficiency improvements in each of these consumer sectors, as shown in Figure 3. Figure 4 shows the diverse nature of natural gas demand in North America, on both a geographic and sectoral basis.



* Energy efficiency gains in NPC modeling of future gas demand are principally from: decreased electric power demand intensity; increased efficiency in gas-fired power generation, industrial boilers, and industrial process heat; and efficiency gains in commercial and residential gas consumption.

FIGURE 3
ENERGY EFFICIENCY EFFECT ON GAS CONSUMPTION*

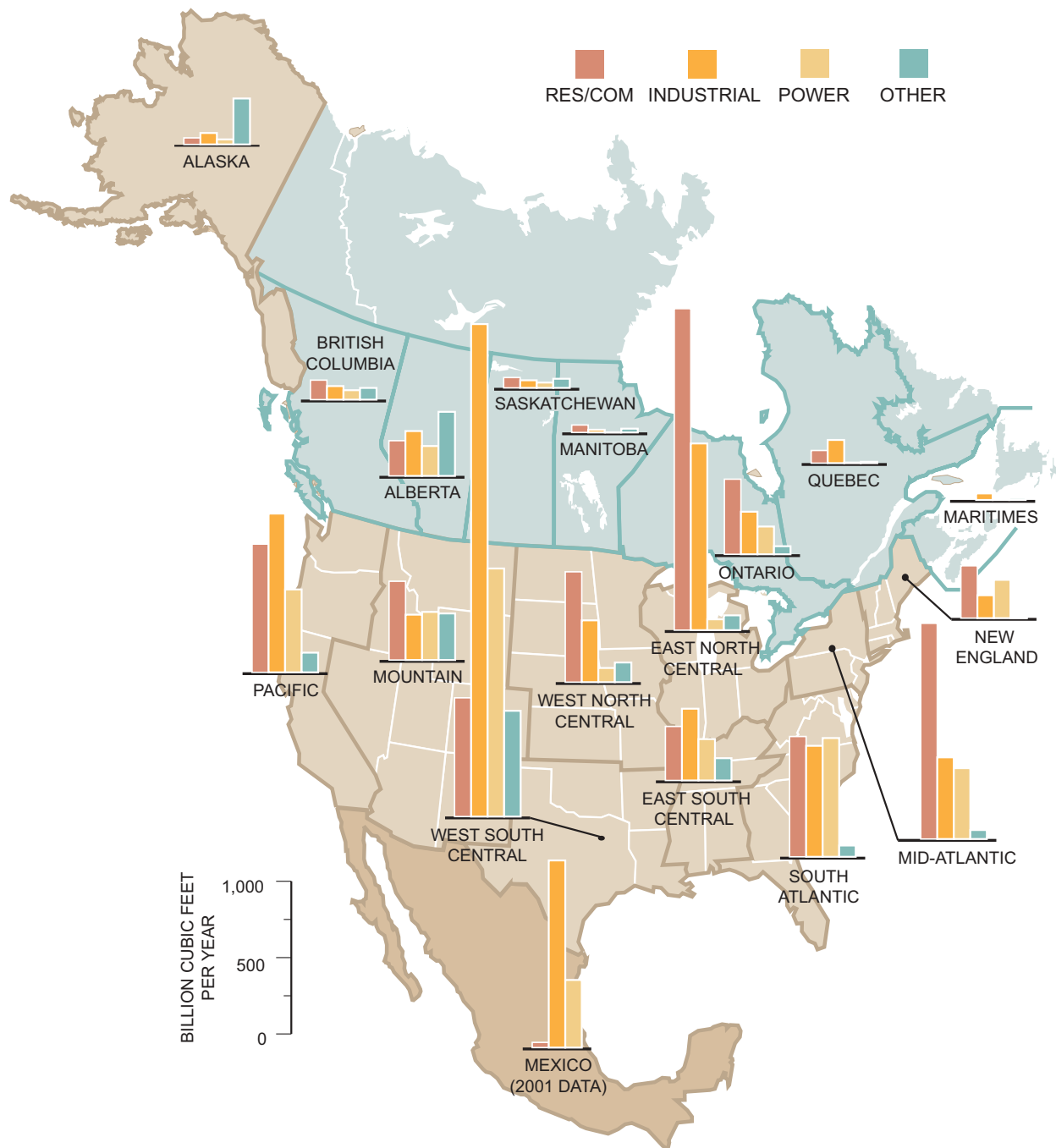


FIGURE 4
U.S. AND CANADIAN NATURAL GAS DEMAND BY SECTOR, 2002

NATURAL GAS SUPPLY

Abundant natural gas resources exist in North America and worldwide. 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 in supply from areas such as the deepwater Gulf of Mexico, the Rockies, Arctic regions, and imported LNG.

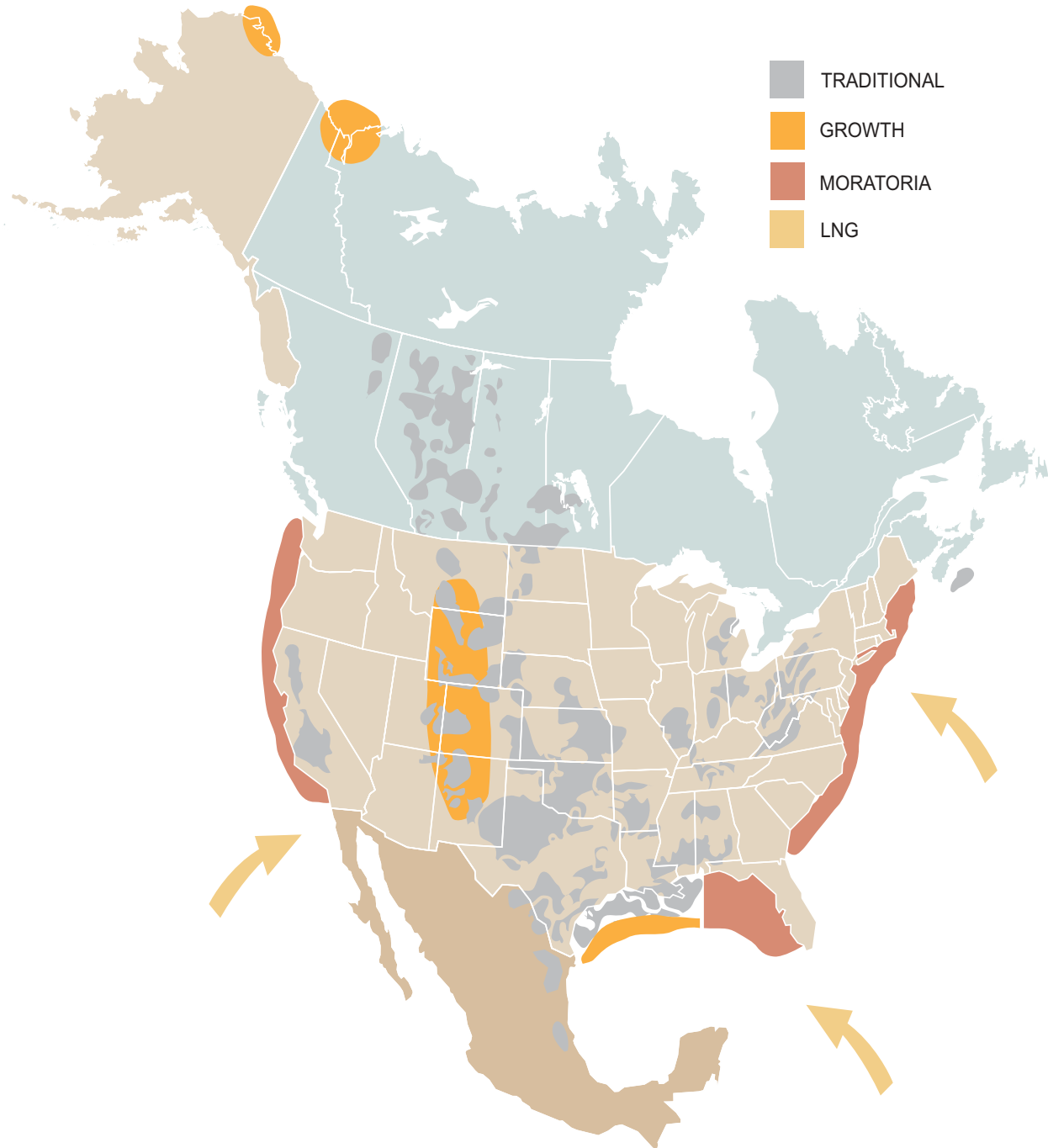


FIGURE 5
SOURCES OF NATURAL GAS SUPPLY

RANGE OF POTENTIAL PRICES

Supply and demand will balance at a higher range of prices than historical levels. That price range will be primarily driven by demand response through efficiency and fuel flexibility, the ability to increase conventional and nonconventional supply from North America including the Arctic, and increasing access to world resources through LNG. National Petroleum Council price ranges for the alternate scenarios are illustrated in Figure 6. These are not status quo scenarios. They both require significant initiative by policy makers and industry stakeholders to implement the recommendations of this report in order to achieve a balanced future.

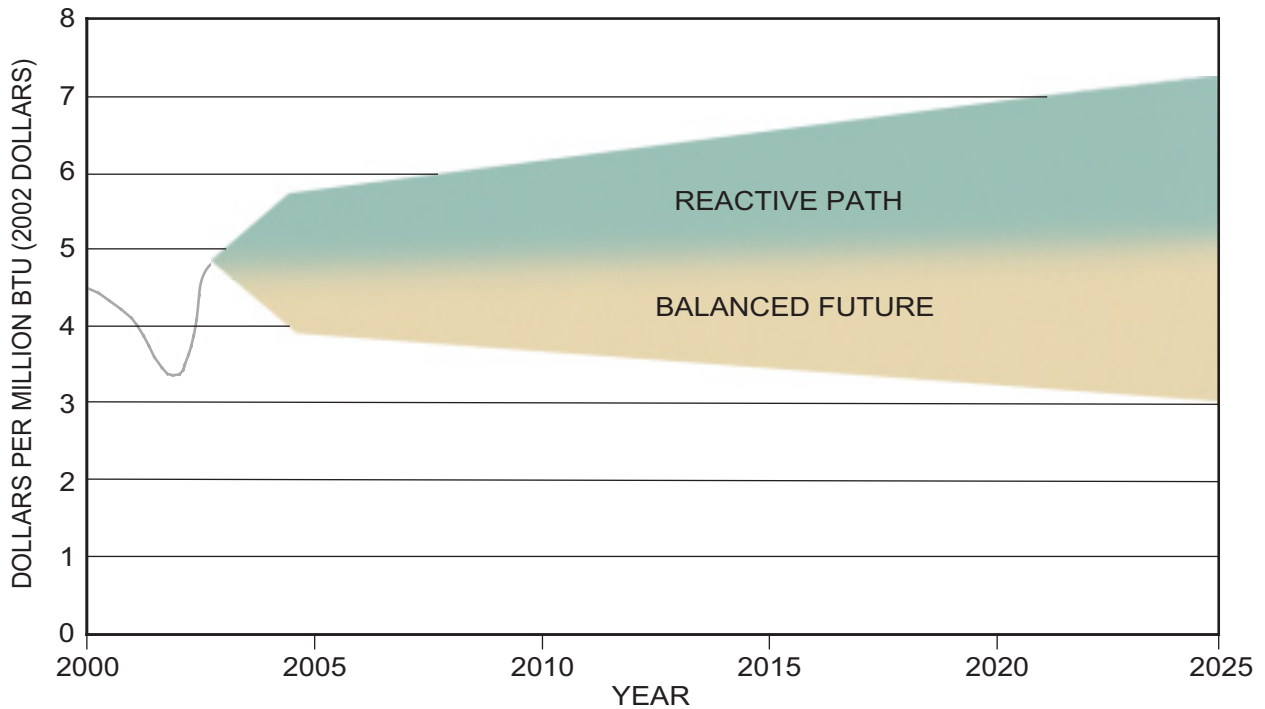


FIGURE 6
AVERAGE ANNUAL HENRY HUB PRICES

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

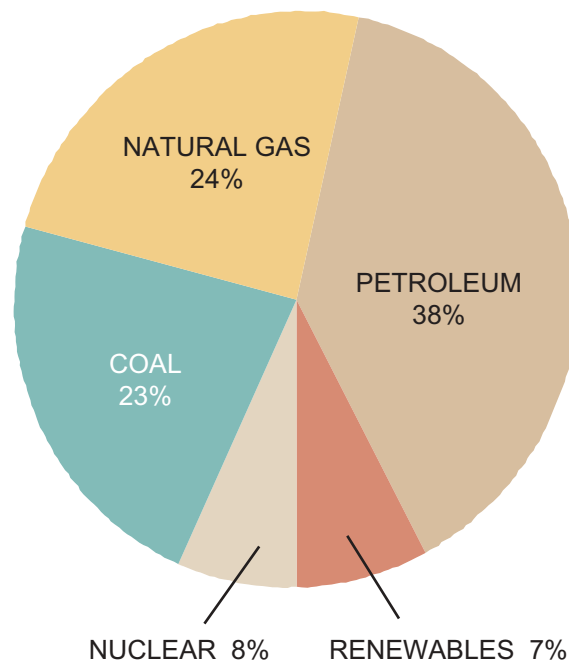
Improve transparency of price reporting.

Expand and enhance natural gas market data collection and reporting.

Overall, this comprehensive NPC report provides a number of recommendations, all of which require action and are required to achieve the Balanced Future, thus creating a more favorable outcome for consumers and the economy.

Introduction

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 requirements² 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 7 illustrates the contribution of natural gas to U.S. energy needs, and Figure 8 shows gas use by sector.



Source: Energy Information Administration.

FIGURE 7
AVERAGE ANNUAL ENERGY USE, 1997-2001
97 TCF PER YEAR (EQUIVALENT)

² Data from Energy Information Administration, Monthly Energy Review, April 2003.

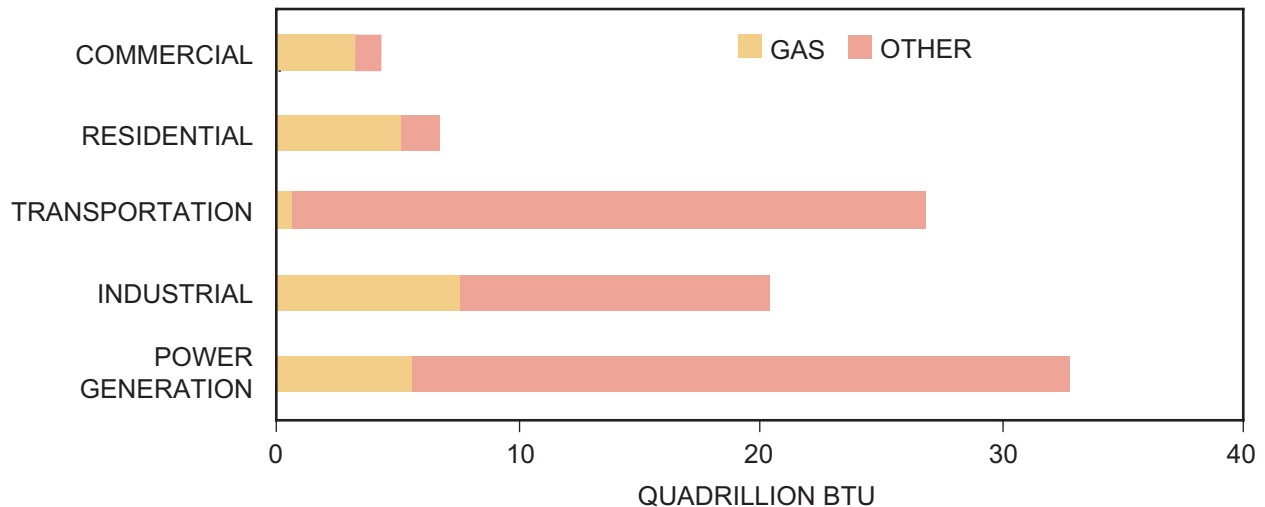


FIGURE 8
U.S. PRIMARY ENERGY USE BY SECTOR, YEAR 2002

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.

From the 1930s until the 1980s most of the interstate natural gas industry was highly regulated. Many of these regulations were in conflict. Low, regulated prices constrained supply growth while demand grew rapidly. During the 1970s these policies resulted in gas shortages. Additional regulations in the late 1970s attempted to allocate and curtail gas deliveries to some customers, such as industrial consumers and electric generators. These regulations exacted an enormous cost on U.S. industry and consumers, and ultimately on the U.S. economy. Price controls on natural gas were effectively removed in the late 1980s and gas futures trading on the NYMEX began in April 1990.

Today, many regulations and policies affecting natural gas are in conflict. Public policies are promoting 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 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.

In order to illustrate the findings and recommendations of this study, the NPC developed two contrasting scenarios that represent plausible and feasible future trends in North American natural gas markets. All of the Task Groups were involved in the development of these scenarios, including representatives of producers, pipelines, distributors, final consumers, power companies and government agencies. These scenarios and their results should not be considered as forecasts but as internally consistent frameworks for analyzing choices open to the principal stakeholders in North American gas over the study time period.

Each of the two scenarios has different assumptions regarding some of the key variables related to supply and demand responses to public policy choices. These key variables include 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. The names of the two scenarios are “Reactive Path” and “Balanced Future.” The full details of the assumptions used in each of Reactive Path and Balanced Future can be found in the NPC Study Integrated Report.

Reactive Path assumes current laws remain in effect, and governmental policies at federal, state/provincial, and local levels continue to broadly encourage gas usage while discouraging access to lower-48 gas resources. However, in addition to these broad policies, the assumptions built into this case acknowledge that resultant high 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. Thus, the Reactive Path is not a status quo outlook. 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. Overall demand levels from both NPC scenarios are lower than other outlooks, resulting in less upward pressure on the supply/demand balance. Even with uncertainty surrounding air quality regulations, the modeling effort projects construction of new, state of the art, emission controlled coal 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 results of the Reactive Path show that, even though consumers and producers act rationally within this policy framework, impediments to growing natural gas supply, and lack of flexibility of fuel consumption, inevitably lead to higher prices, which, in turn, bring negative impacts on gas intensive industries and the economy as a whole. Price volatility remains a consistent feature of gas markets in this scenario. Perhaps 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 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. On the supply side, barriers to development of new natural gas sources are progressively lowered, both for domestic and imported natural gas. The result, with enhanced supply and more flexible demand, would be a market with lower gas prices and less potential for upward price spikes. This case is a better outcome for North American consumers than the continuing market tightness associated with 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 considers the effect of not developing major new LNG import facilities or the Arctic gas pipelines; neither scenario considers actions that might severely limit CO₂ emissions or the permitted carbon content of fuels; neither scenario attempts to speculate on ground-breaking new technology that could fundamentally alter demand patterns or supply potential. The NPC did not consider such possibilities as being likely outcomes to be modeled in the base scenarios. However, each base scenario was tested against variabilities in many of the major underlying assumptions, such as 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 directional 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 robust competition among energy alternatives and the lowest cost for consumers and the nation are to be achieved. 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.

The findings of the National Petroleum Council described in this volume of the report represent the conclusions of the Council from the detailed analysis undertaken over the past year. 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.

The National Petroleum Council has identified the following key findings based on its analysis of the natural gas market:

- 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.
- 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.
- 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 \$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.
- 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.
- 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 consumers 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.

Findings

FINDING 1: 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.

During the 1990s, environmental standards and economic growth were the forces driving the demand for natural gas in North America. Historically, in North America drilling activity has responded quickly to market signals and, together with increasing supplies from Canada, has yielded sufficient production to meet demand. Figure 9 shows U.S. and Canadian production. It now appears, however, that natural gas productive capacity from accessible basins in the United States and Western Canada has reached a plateau. Recent experience shows steeper decline rates in existing production and a lower average production response to higher prices from new wells in these areas. This trend is expected to continue. As a result, markets for natural gas have tightened to a degree not seen in recent experience and prices have increased well above historical levels. These higher prices have been accompanied by significant price volatility, as illustrated in Figure 10.

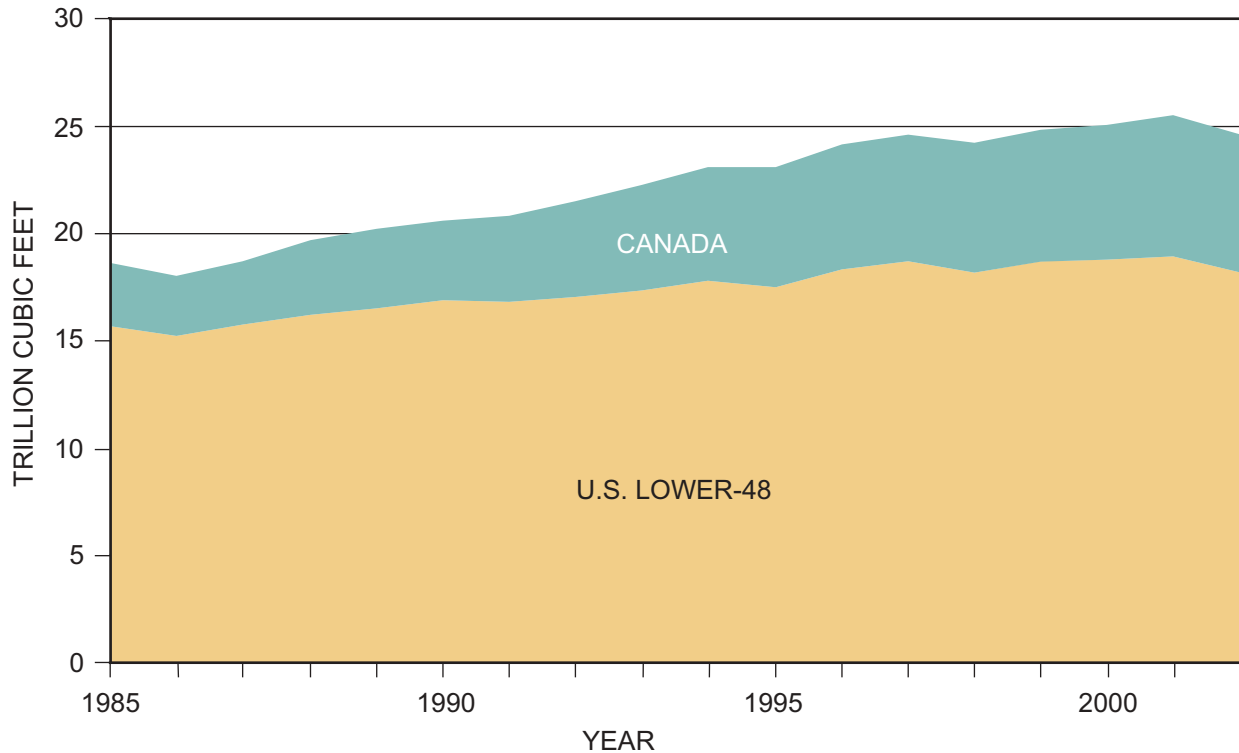
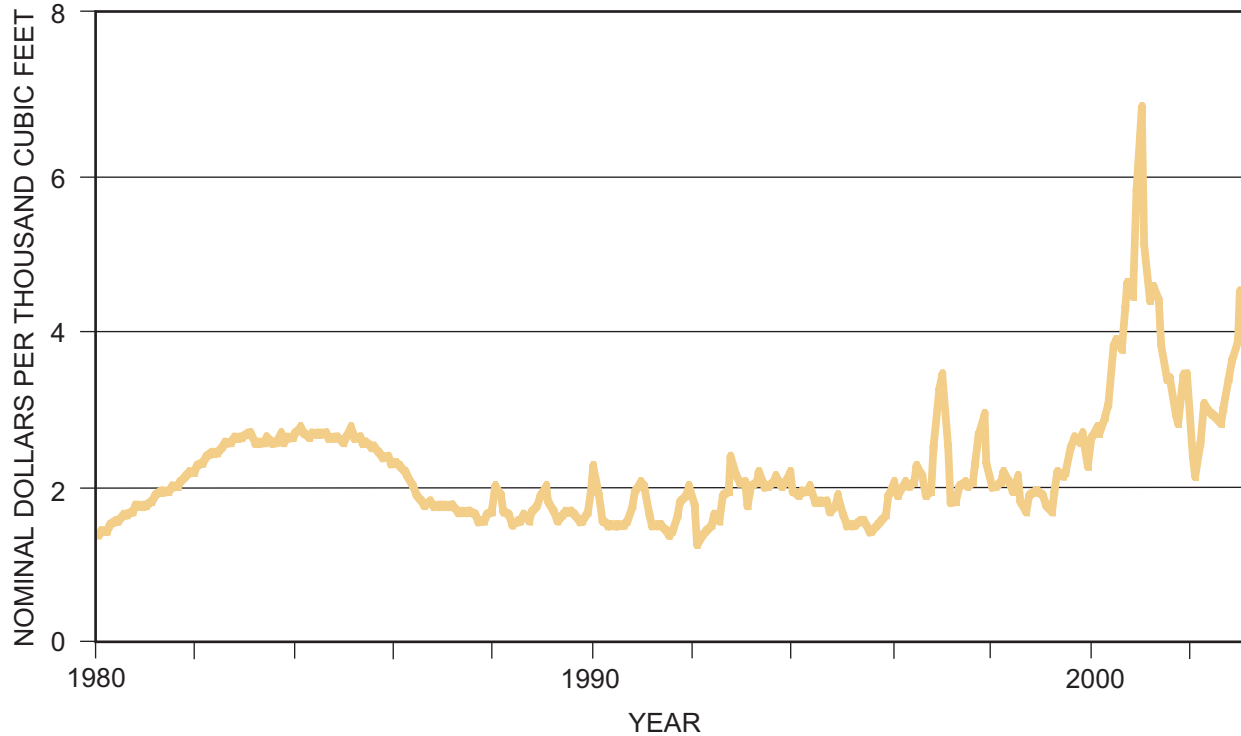


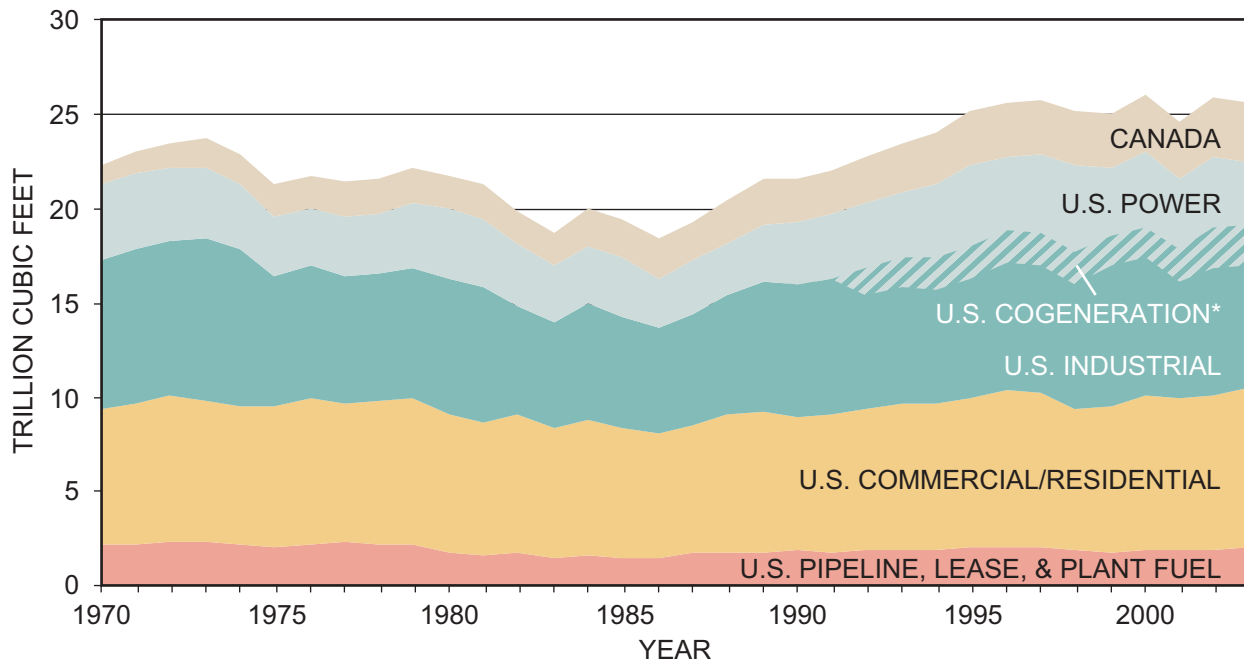
FIGURE 9
U.S. LOWER-48 AND CANADIAN NATURAL GAS PRODUCTION



Source: Energy Information Administration.

FIGURE 10
U.S. WELLHEAD GAS PRICE

Natural gas demand grew by more than 40% between 1986 and 1997, from 16 TCF/year to 23 TCF/year, as illustrated in Figure 11. While overall demand has persisted between 22 TCF/year and 23 TCF/year since 1997, the market has fundamentally changed. Natural gas used for power generation has grown while industrial use has declined. Today, it is productive capacity, including established import capacity, that drives the tight supply/demand balance; the resulting higher prices are limiting the ability of natural gas demand to grow.



* Energy Information Administration reports cogeneration beginning 1989.

FIGURE 11
U.S. AND CANADIAN NATURAL GAS DEMAND

This is in contrast to the “gas bubble” environment of the late 1980s and 1990s that was characterized by a surplus of supply and weak demand. This “bubble” kept prices low and dampened price volatility. This market was influenced by a succession of since-modified legislative and regulatory decisions beginning with the Powerplant and Industrial Fuel Use Act of 1978 (PIFUA) and the Natural Gas Policy Act of 1978 (NGPA). While the PIFUA placed restrictions on industrial and power generation uses of natural gas, the NGPA set in motion a process that encouraged gas supply growth. Amendments in 1987 to the PIFUA removed restrictions on the use of gas in power generation, and the Natural Gas Wellhead Decontrol Act of 1990 removed wellhead price controls.

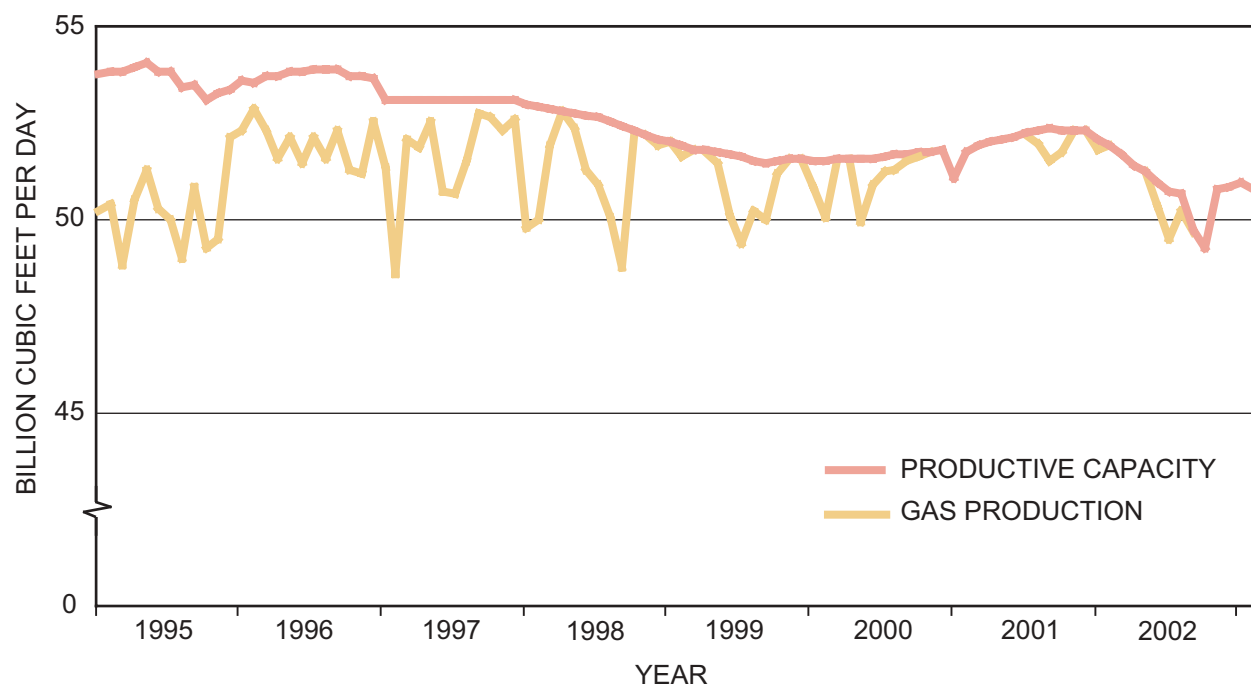
Thus, a responsive market developed in the early 1990s for the supply and trade of natural gas. This market grew out of deregulation of supply and demand, and was reinforced by a series of FERC Orders creating an unbundled and more flexible transportation system. The excess productive capacity of North America, combined with storage capability for meeting seasonal demand surges meant that there was sufficient supply to meet daily, seasonal, and annual gas requirements, including those driven by weather and/or economic growth.

The capability to consume natural gas continues to increase. The number of residential natural gas customers grew from 48 million in 1987 to 60 million in 2001.³ Of the 220,000 megawatts of new powerplant capacity recently constructed or about to be placed in operation

³ U.S. Energy Information Administration.

over the next few years, well over 90% are fueled with natural gas.⁴ Industrial consumption, including cogeneration applications, grew by almost 48% from 1986 to 2001.

The combination of growing demand and limited supply has resulted in a disappearance of the “gas bubble,” as shown in Figure 12. It has created an overall tightening of the market and led in recent years to higher gas prices and price volatility. The market is less able to absorb changes in supply or demand without a significant swing in price. This dynamic will continue until additional supplies are brought to market and more demand flexibility is achieved.



Source: Energy and Environmental Analysis, Inc.

FIGURE 12
LOWER-48 DRY GAS PRODUCTION VS. DRY GAS PRODUCTIVE CAPACITY

⁴ Daniel Yergin Speech before the Natural Gas Summit in Washington, DC, June 26, 2003.

FINDING 2: GREATER ENERGY EFFICIENCY AND CONSERVATION ARE VITAL NEAR-TERM AND LONG-TERM MECHANISMS FOR MODERATING PRICE LEVELS AND REDUCING VOLATILITY.

Improved efficiency of energy use has been a major feature of the U.S. economy since the 1970s. For the past 30 years, the amount of gas used in the production of a dollar's worth of economic output has continued to decrease. Since 1974, the industrial sector alone has reduced its energy use for fuel and power consumption per unit of output by nearly 40%. Residential consumers reduced natural gas use per customer by 16% from 1980 to 2001, primarily as a result of more-efficient space heating and improved housing characteristics.⁵ The power generation industry has also achieved significant efficiency gains through the introduction of highly efficient combustion turbines, combined heat and power configurations, and combined cycle applications. Between 1997 and 2001, the net effect of these innovations has been a 15% increase in efficiency of gas consumed to produce power.

Continued energy conservation and more efficient use of existing equipment can ease short-term market pressures. Natural gas conservation and efficiency measures in residences and commercial establishments – which collectively represent over 40% of total U.S. demand – can contribute substantially to higher efficiencies. For example, electricity conservation can reduce the demand on regional power systems, minimizing the operation of “peaking” capacity that is often supplied by gas-fired facilities. Electric power generators can also reduce natural gas demand by ensuring higher utilization of combined-cycle units instead of less-efficient gas-fired boilers.

The economy has generally become more efficient in its use of natural gas and other energy sources, even during periods of low prices, due to technological innovation, the ongoing shift to less energy-intensive industries, and government policies. Figures 13, 14, and 15 illustrate efficiency gains in natural gas utilization for the industrial, electric power, and residential and commercial sectors, respectively. These historical gains will generally be sustained due to historical and future changes in capital stock, and as new construction incorporates more-efficient building codes and standards. These continuing improvements in the efficiency of electricity and natural gas consumption are assumed in both the Reactive Path and Balanced Future scenarios, and are illustrated for the Balanced Future scenario in Figure 16. The increased residential and commercial energy efficiencies in the Balanced Future scenario are assumed to be the result of market mechanisms that provide clear natural gas and power price signals to consumers, by consumer education, and by appropriate changes to building standards.

⁵ American Gas Association, Energy Analysis EA 2003-01, June 16, 2003.

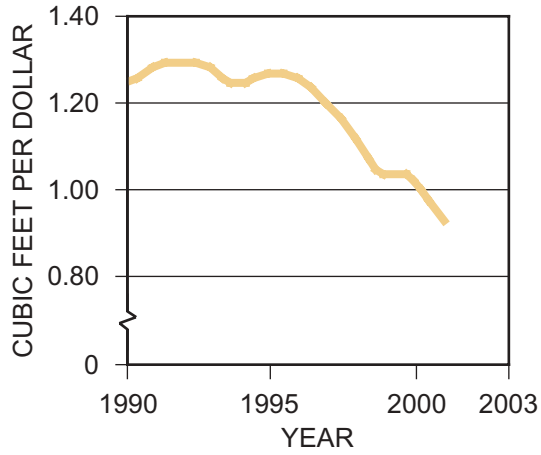


FIGURE 13
 AVERAGE INDUSTRIAL GAS INTENSITY
 (CUBIC FEET OF GAS CONSUMED
 PER DOLLAR OF INDUSTRIAL OUTPUT)

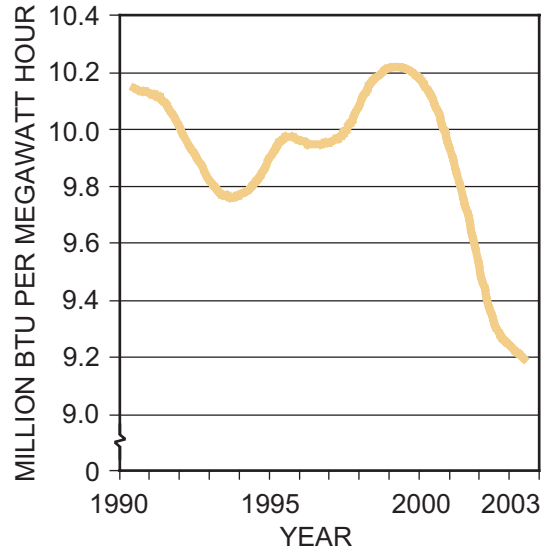


FIGURE 14
 GAS-FIRED GENERATION HEAT RATE

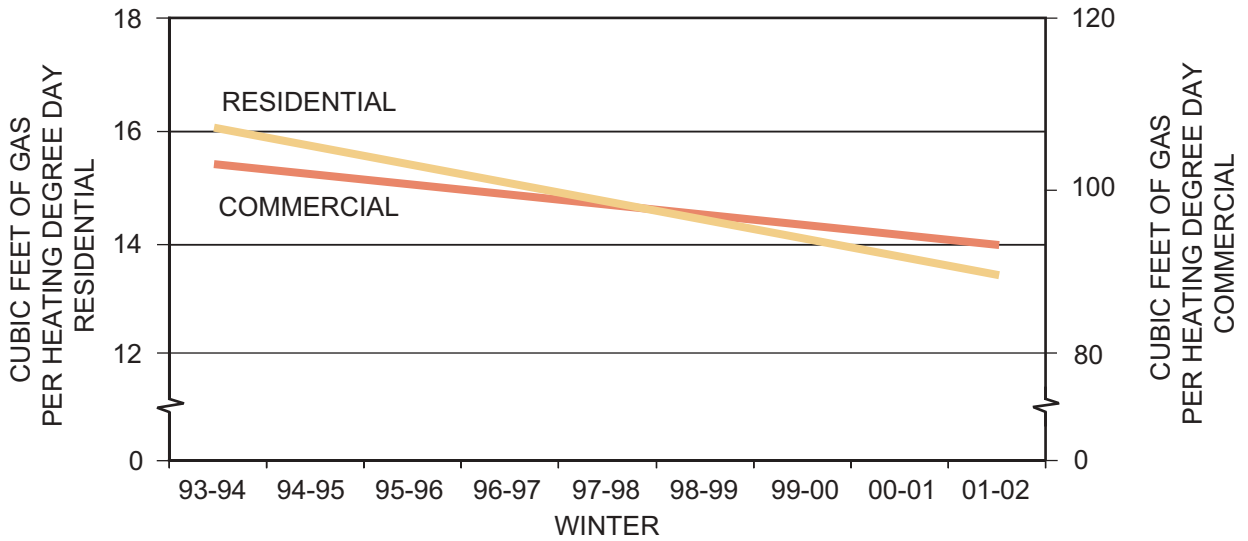
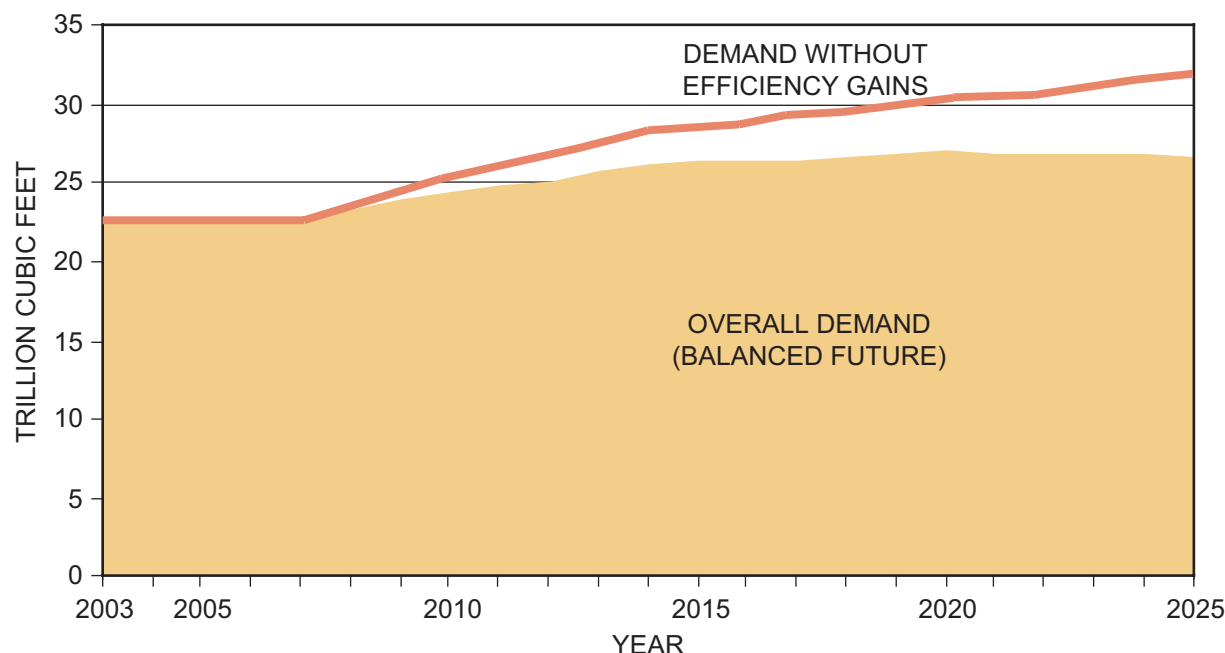


FIGURE 15
 RESIDENTIAL AND COMMERCIAL GAS USE INTENSITY



* Energy efficiency gains in NPC modeling of future gas demand are principally from: decreased electric power demand intensity; increased efficiency in gas-fired power generation, industrial boilers, and industrial process heat; and efficiency gains in commercial and residential gas consumption.

FIGURE 16
ENERGY EFFICIENCY EFFECT ON GAS CONSUMPTION*

FINDING 3: 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.

For the past 15 years, industrial consumers and power generators have become increasingly dependent on natural gas-based technologies for meeting their energy requirements and for satisfying more-stringent air quality standards. These consumers have chosen gas-fired equipment based on the following factors:

- **Life-cycle economics.** Gas-fired applications generally have lower capital costs. Gas-fired combustion turbines used in power generation and industrial cogeneration require shorter construction lead times and are available in convenient modular designs. This saving in capital costs was especially attractive in the late 1980s and 1990s when gas prices were consistently below the equivalent liquid fuel prices.
- **Environmental performance.** Improved air emissions performance of natural gas-based technologies has favored investments in facilities that use natural gas. In many instances, power generators and industrial consumers made investment decisions favoring natural gas in order to achieve compliance with “New Source Performance Standards” and/or as a condition of a “New Source Review” proceeding.

- **Land use.** Gas applications generally require less land and are less intrusive than other fossil fuel applications. Modular gas-fired generation facilities have been used to meet increased electric power demand frequently as an alternative to extending power transmission lines to certain areas.

As shown in Figure 17, natural gas demand for power generation (including industrial-based generation) grew by more than 50% in the 15 years ending in 2002. Despite recent declines in demand from the industrial sector – particularly portions of the chemical industry and metals manufacturers – overall industrial gas demand is greater today than 15 years ago.

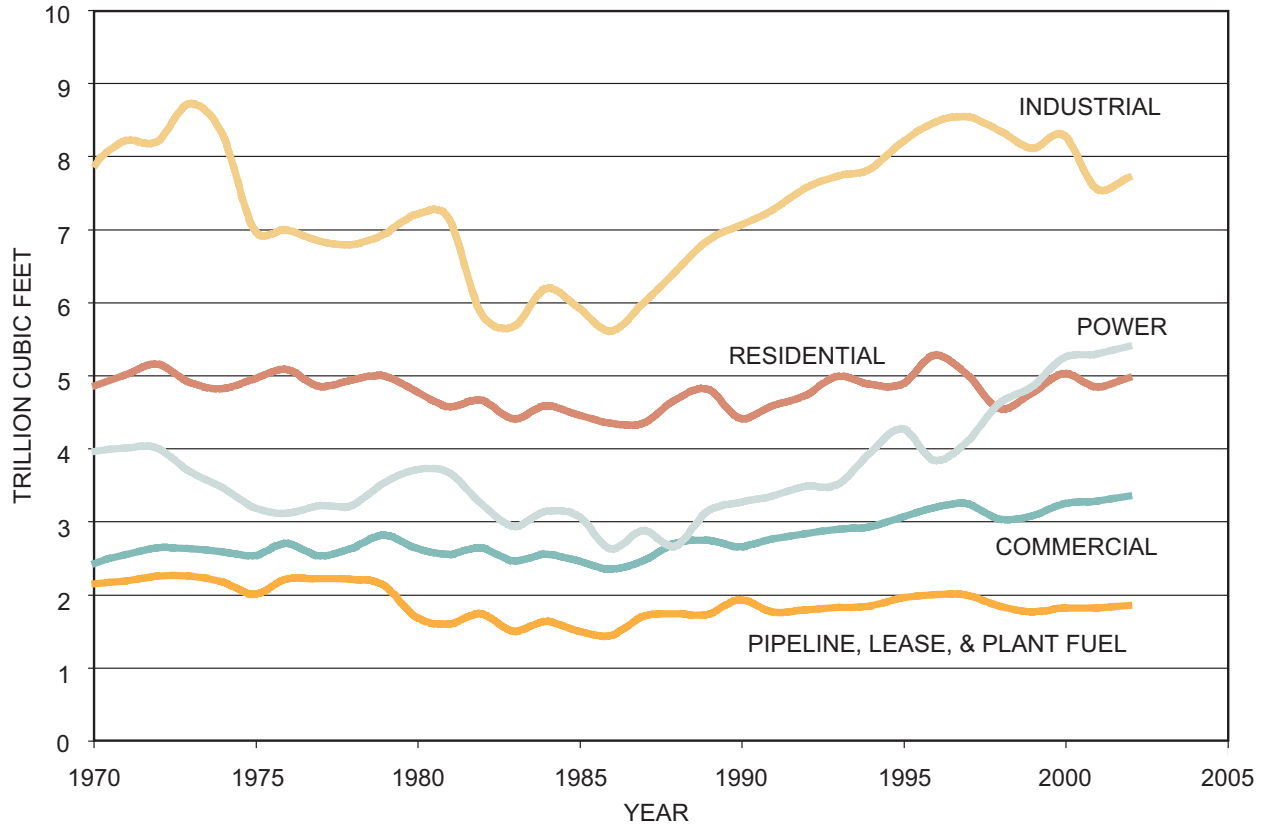


FIGURE 17
NATURAL GAS CONSUMED BY SECTOR

At the same time, the stock of gas-fired power generation and industrial equipment became less flexible in its ability to operate with alternate fuels. This loss of flexibility has been driven in part by an array of governmental policies such as local siting restrictions on fuel backup and New Source Review proceedings. World economic and competitive forces provided the incentive for energy consumers to seek industrial process efficiencies and control costs. For example, existing burners are “tuned” to maximize operational and environmental efficiency when operating solely with natural gas. Power generators and industrial gas users have retired or mothballed boilers and other equipment capable of using dual fuels, such as oil and gas. In addition, not using oil or coal in current or retiring processes yielded the emission credits that were needed for plant expansions or new process construction. Some plant sites, once capable of

using dual fuels now lack the permits to burn fuels other than natural gas and/or lack both the infrastructure and the physical storage capacity for using alternative fuels.

Figure 18 approximates the current short-term flexibility of U.S. power generation and industrial capacity for responding to changes in natural gas prices, as considered in NPC modeling. This indicates that about 6 billion cubic feet per day (BCF/D) of fuel-switching or demand suppression would be expected to occur at prices up to \$6.50/MMBtu, and up to 10 BCF/D at prices of \$8.00/MMBtu.

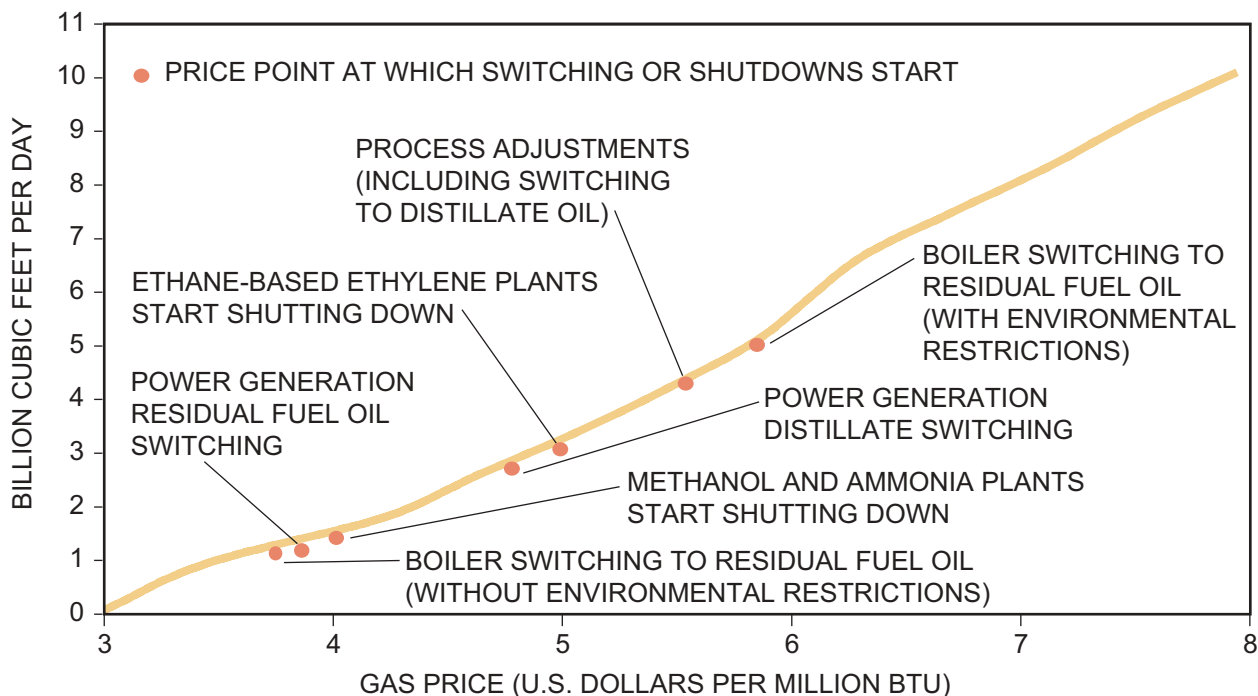


FIGURE 18
INDUSTRIAL AND POWER GENERATION
NATURAL GAS FLEXIBILITY, JULY 2003

Through at least 2008, natural gas-based technologies will represent about one-third of U.S. generation capacity. Subject to significant variation due to the weather, natural gas should supply between 15% and 20% of the electricity generated during this time. In contrast, oil/gas boiler generation capacity is about 12% of total U.S. capacity, and will provide about 2% of the electricity generated. Figure 19 shows the relative shares of oil and gas used in power generation.

Boiler fuel for steam generation represents 25%-30% of industrial gas consumption. An industry-wide survey by the Department of Commerce for the period 1994-1998, suggested that up to 28% of industrial boilers at the end of that period were fuel-switchable. However, one finding of the workshops conducted by the Demand Task Group and the many gas-intensive industrial users was that the practical level of boiler fuel-switching capability is much lower today; only approximately 10% of the total – or approximately 200 BCF/year; some industrial consumers reported it to be as low as 5%.

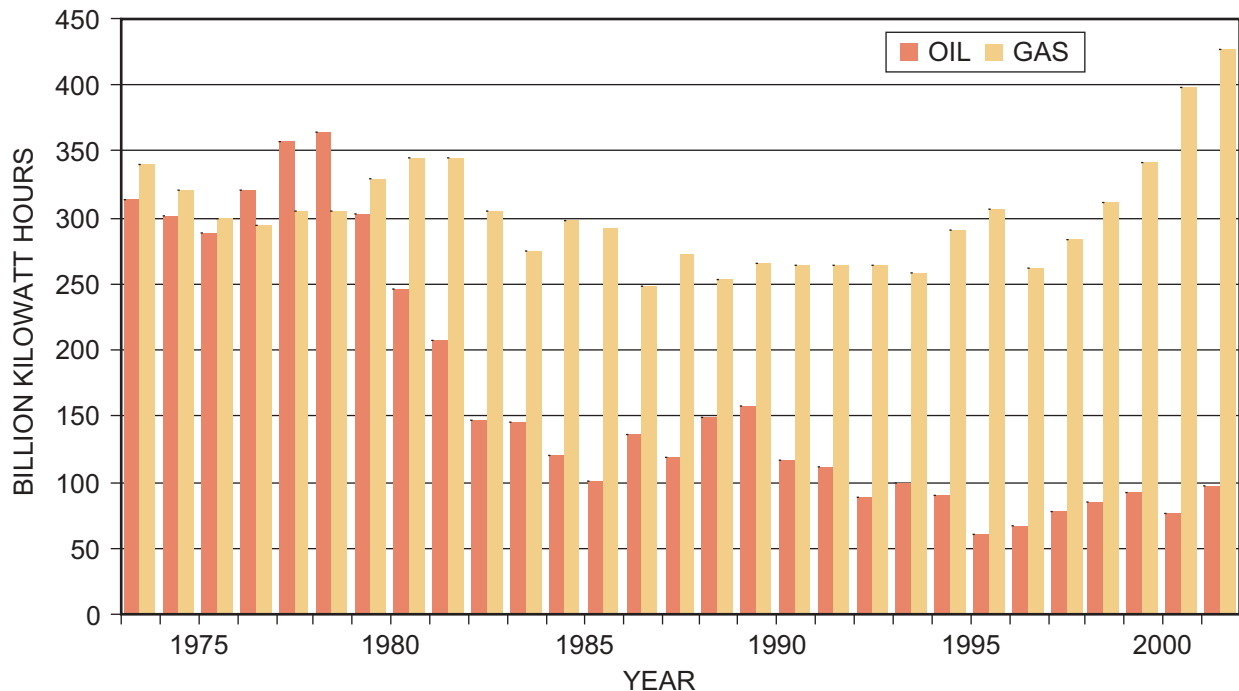


FIGURE 19
U.S. ELECTRICITY GENERATED, BY OIL AND GAS

FINDING 4: 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.

Long-term natural gas demand is expected to increase due to economic growth and increased environmental regulations, fundamental changes in energy usage patterns and in investments in gas-intensive equipment. Influenced heavily by short-term weather cycles, these increases will be driven by changing demographic patterns, and by actions taken by power generators and industrial consumers to comply with increasing air quality standards. This growth will be slowed by higher prices that will principally affect energy-intensive consumers in the industrial sector – chemicals, refining, and metals – that, unlike power generators, generally compete in world markets.

Future U.S. and Canadian natural gas demand is reflected in Figure 20 for the Reactive Path case. This figure shows an overall increase of about 23% by 2025 from 2002. The Reactive Path and the Balanced Future cases both assume average annual U.S. GDP growth from 2005-2025 of 3%, and annual Canadian GDP growth of 2.6%, based on historical averages. The cases also assume weather conditions at the average of the past 30 years. Each case assumes future air regulations will conform to current law; but the cases differ in their expectations for coal plant shutdowns due to mercury emission rules. The Balanced Future assumes deliberate

introduction of fuel flexibility in power generation and industrial applications, as well as increased energy efficiency in the commercial and residential sector. Demand in the Balanced Future is not greatly different to that of the Reactive Path, because the offsetting effects of greater energy efficiency and greater use of alternate fuels assumed in the Balanced Future would tend to reduce demand, but would be offset by the effects of lower prices, which tend to increase demand.

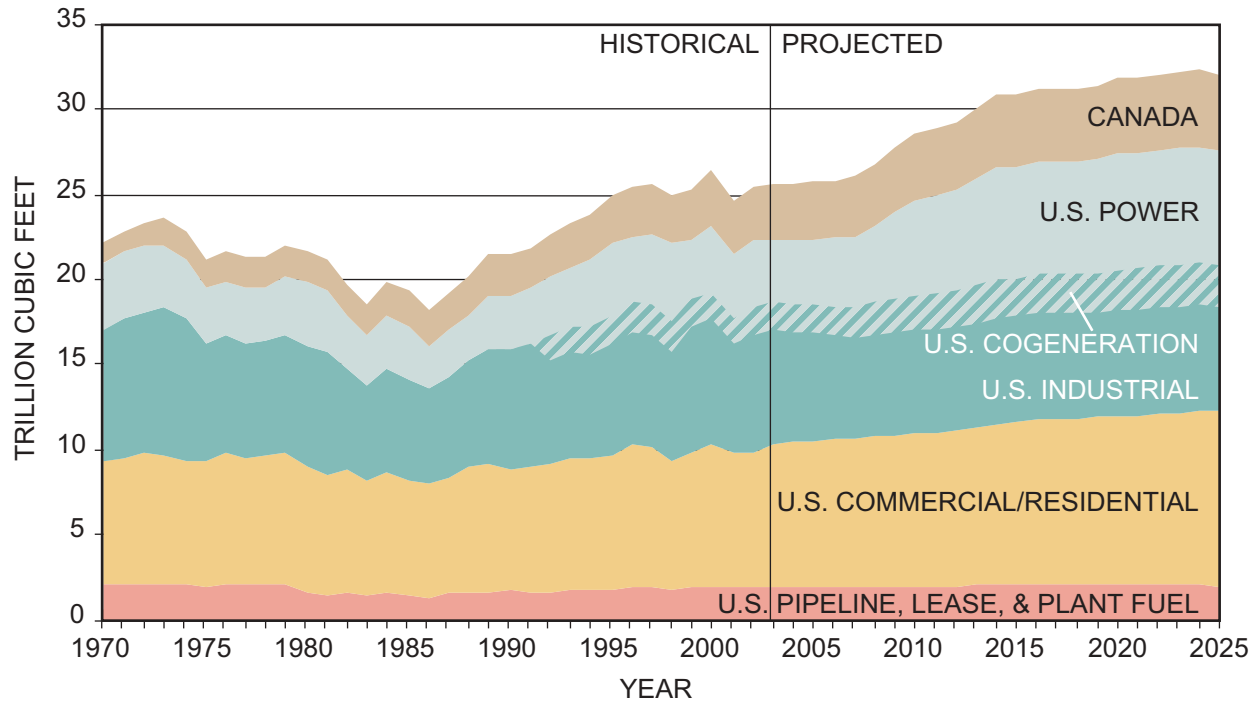


FIGURE 20
HISTORICAL GAS DEMAND AND "REACTIVE PATH" PROJECTION

Power Generation

U.S. electricity demand grew 31% from 1990 to 2002, and the increase in U.S. gas supply directed to power generation increased from 22% to 30%. The rapid buildup of gas-based generation capacity starting in the 1990s reflects investment efficiencies, environmental performance, operational flexibility, siting ease, and production costs for these facilities. The outlook for natural gas in power generation is defined by the following factors.

- Electricity demand.** Electricity demand has steadily grown in relation to GDP growth, and the NPC expects this growth to continue. U.S. electricity demand has grown an average of 2.5%/year since 1973. In the Reactive Path scenario, electricity demand is assumed to grow an average of 1.9%/year through 2025, while in the Balanced Future scenario growth of 1.7%/year is assumed. Although each scenario assumes similar GDP growth as in the past three decades, power demand growth is forecast to be lower, reflecting greater energy efficiency.

- Power generation capacity.** The scenarios assume: (a) in the Reactive Path scenario, retirement or mothballing of 18 gigawatts (GW) of oil- and gas-fired steam boiler units through 2010, and retirement of 21 GW of smaller coal-fired units in 2007-2009 due to the Maximum Achievable Control Technology (MACT) standards for mercury; (b) lower levels of oil/gas and coal retirements in the Balanced Future scenario; (c) continued exclusion of new coal-based technology from the U.S. west coast and from ozone non-attainment areas of the U.S. east coast; (d) continued development of renewable technology, reflecting a combination of tax incentives and efficiency increases over time, with 73 GW constructed through 2025 in the Reactive Path scenario, and 155 GW in the Balanced Future scenario; (e) competitive coal-based technology – using all required environmental controls – with over 100 GW of capacity likely to be constructed, primarily after 2015; (f) continued operation of existing nuclear capacity through at least 2025, but no new nuclear capacity due to overall costs and perceived investment risks associated with waste disposal; and (g) some increase in hydroelectric generation in Canada, none in the United States.

Figure 21 shows future U.S. generation capacity, by fuel source, as projected in the Reactive Path scenario. Figure 22 illustrates the quantities of electricity generated by fuel type. Because short-term weather cycles will have a significant effect on electric power demand, the NPC also conducted sensitivity analyses, which indicated that these cycles could markedly change natural gas requirements for power generation in any given year.

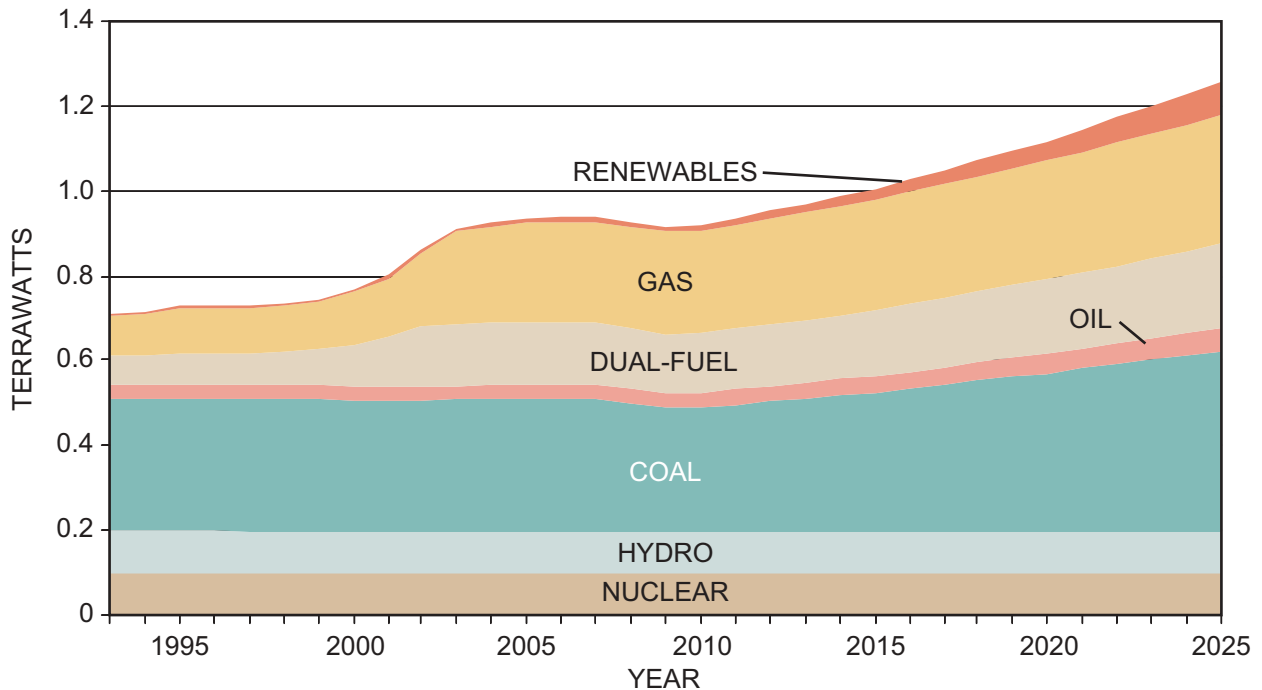


FIGURE 21
ELECTRIC POWER GENERATION CAPACITY BY FUEL TYPE

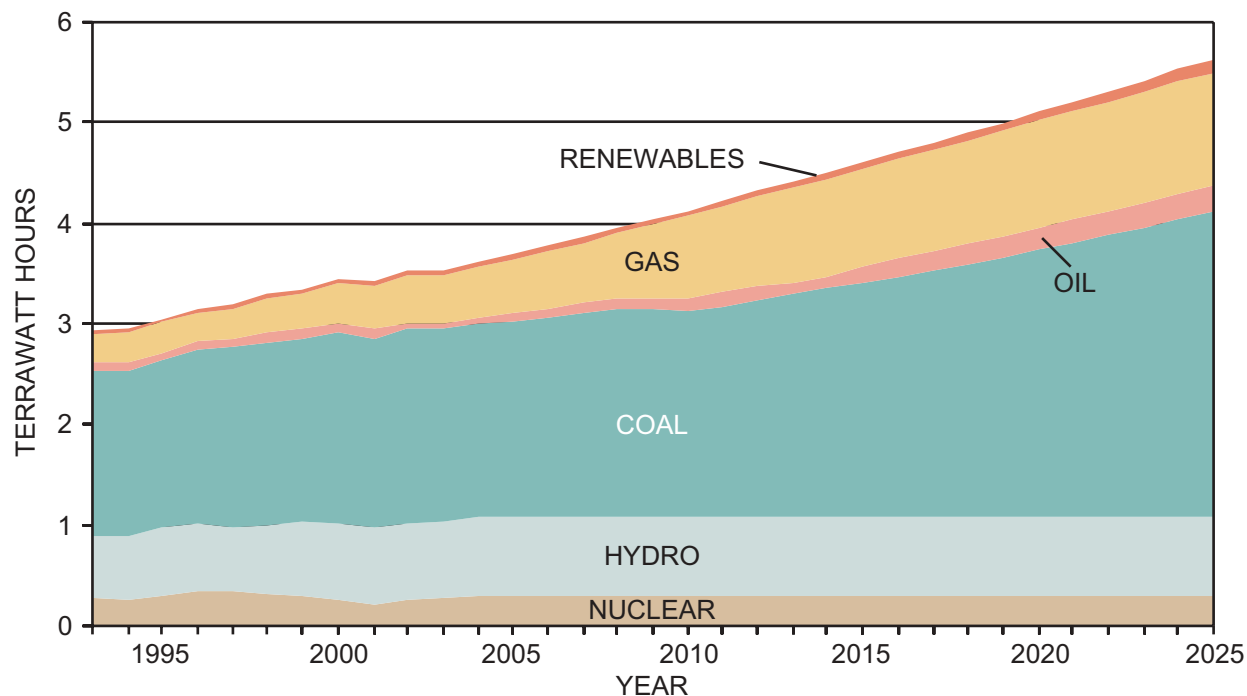


FIGURE 22
ELECTRICITY GENERATED BY FUEL TYPE

Industrial Use

U.S. industries derive 40% of their primary energy from natural gas. Natural gas and/or the ethane produced in association with natural gas are the key raw materials in the manufacture of ammonia, methanol, ethylene, and the hydrogen that is produced outside of petroleum refining processes. Natural gas usage was analyzed for key categories of industrial consumers – chemicals, refining, primary metals, paper, stone/clay/glass, food/ beverage, and other industries.

The potential demand for natural gas by industrial consumers in a Reactive Path scenario is illustrated in Figure 23; Figure 24 shows gas use by principal industrial application. In this case, industrial demand would be most affected in the near-term, as higher natural gas prices increase the pressure on gas-intensive industrial consumers to discontinue some operations and limit investments in North American chemical process capacity. Manufacturers of ammonia, methanol, petrochemicals, and metals would be most affected.

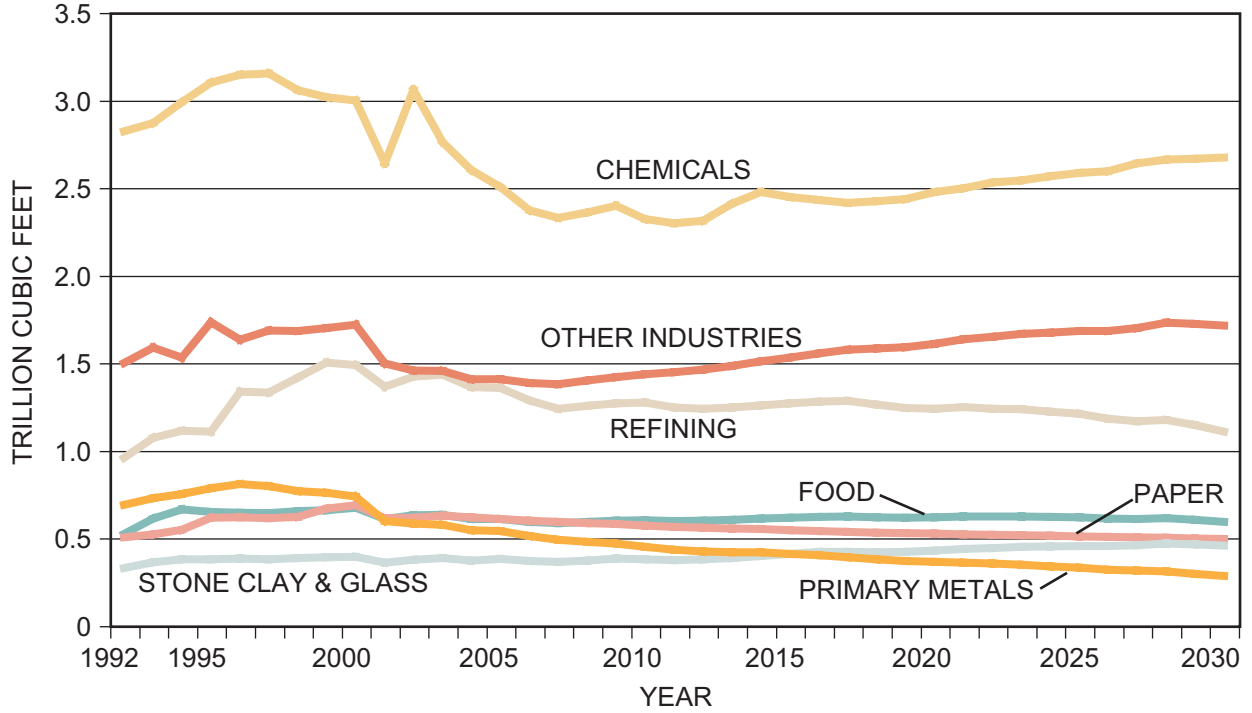


FIGURE 23
INDUSTRIAL GAS CONSUMPTION BY INDUSTRY IN REACTIVE PATH SCENARIO

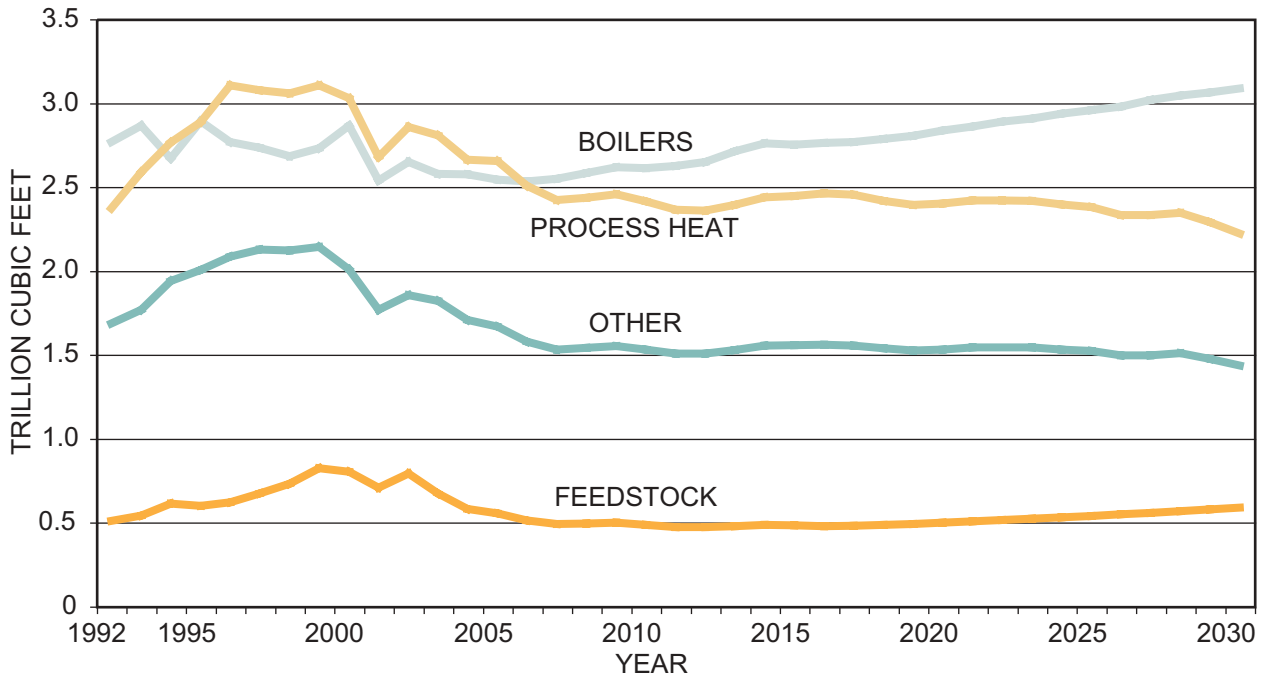


FIGURE 24
LOWER-48 INDUSTRIAL GAS DEMAND BREAKDOWN
(NEW COGENERATION AFTER 1998 NOT INCLUDED)

In the Reactive Path scenario, the most gas-intensive industries are likely to experience little-to-no growth, and would be at risk of permanent relocation to regions of the world that have less-expensive gas supplies. The NPC attempted to understand the implications for gas demand of potential economic dislocations by doing sensitivity analyses of different industrial production rates in the chemicals and primary metals industries. These analyses indicated that a reduced production in these industries would result in reduced natural gas demand. Conversely, an increase in production in these industries, perhaps caused by high economic growth in the U.S. relative to other areas of the world, would result in increased natural gas demand.

In the Balanced Future scenario, industrial demand would still be reduced in the near-term, as higher natural gas prices continue to induce gas-intensive industrial consumers to discontinue some operations and limit investments in North American industrial process capacity. However, if investments in fuel-flexibility and enhanced supplies were facilitated by government policies, industrial consumers in North America would be more competitive on a world scale. There would be less demand erosion, and the financial incentive would exist for construction of additional industrial capacity in North America.

Commercial and Residential Use

Over 60 million U.S. households use natural gas, and over 40% of commercial energy requirements are met by natural gas. Commercial and residential demand growth will reflect demographic shifts, penetration of gas-based technologies, growth in floor space, and levels of energy efficiency. To forecast future natural gas demand in the commercial and residential sectors, the NPC used both an econometric model and a model of capital stock employed. These models considered many variables, including the weather, demographic trends, population growth, responsiveness of these sectors to gas price increases, residential housing stock, the efficiency of the capital stock, commercial floor space, and penetration of gas-based technology.

Commercial and residential natural gas demand is expected to increase in both the Reactive Path and Balanced Future scenarios, due to penetration of gas-based technology, population growth, and growth in floor space, only partially offset by continuing gains in energy efficiency. Energy efficiency is one of the key differences between the two scenarios, with the Balanced Future having greater efficiency gains in residential appliances, commercial equipment, and building standards.

Mexico

Rapidly growing Mexican gas demand and lagging domestic production development will result in Mexico continuing to rely on U.S. gas imports through at least 2005 and likely through 2025. Significant unknowns related to both demand and supply give rise to widely varying potentials for imports and exports. This balance ultimately rests on Mexico's success in attracting foreign participation in its exploration and production industries and its ability to attract LNG imports. Therefore Mexico's impact on the North American gas balance remains uncertain. Both the Reactive Path and Balanced Future outlooks assume that Mexico will import up to 1.6 BCF/D from the United States in the near term and a net of 700 MMCF/D in the longer term, as illustrated in Figure 25.

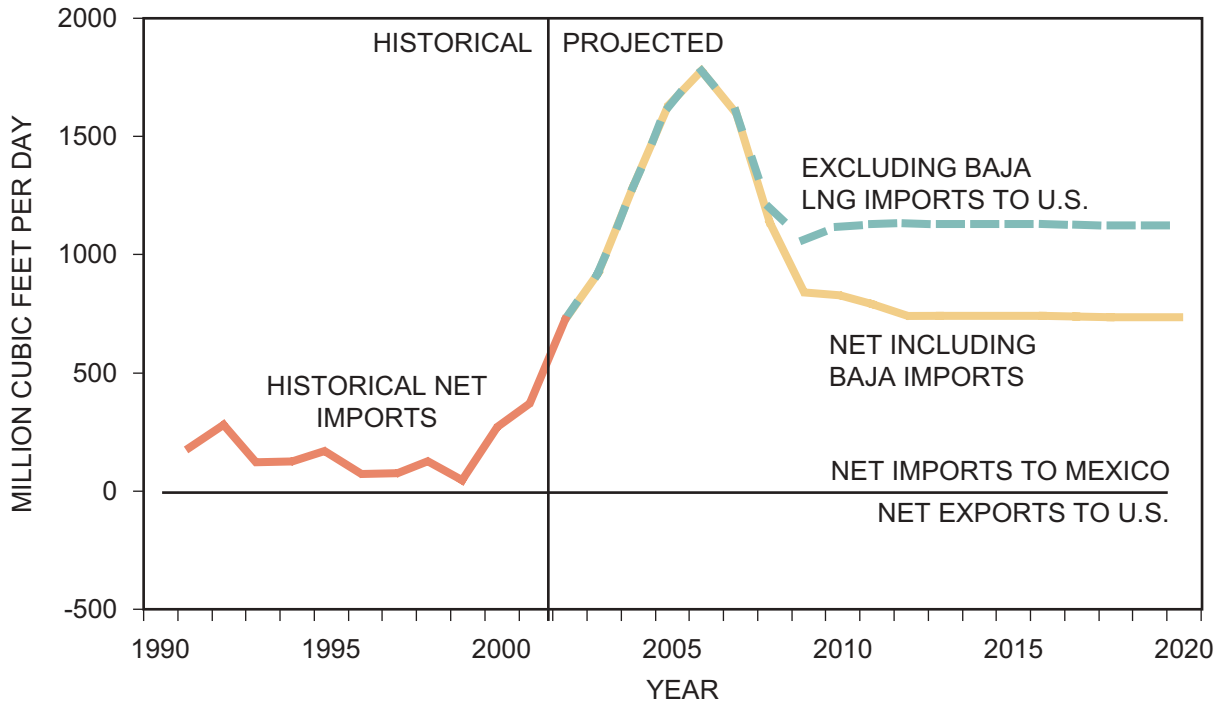


FIGURE 25
MEXICO IMPORT/EXPORT BALANCE

Key Uncertainties in Natural Gas Demand

Natural gas demand varies seasonally, and grows or decreases from year-to-year based on a wide number of factors that were considered in the modeling of both the Reactive Path and the Balanced Future scenarios. The respective effects of key uncertainties were evaluated with sensitivity analyses, and are discussed in the Integrated Report. Those factors with the largest impact on the demand for natural gas are weather cycles, North American and worldwide economic activity, crude oil prices, and changing regulations including the potential for limits on carbon dioxide emissions.

FINDING 5: TRADITIONAL NORTH AMERICAN PRODUCING AREAS WILL PROVIDE 75% OF LONG-TERM U.S. GAS NEEDS, BUT WILL BE UNABLE TO MEET PROJECTED DEMAND.

The NPC undertook a comprehensive review of the North American resource base. As described in earlier studies, there is a large North American gas resource base that will play a key role in providing future natural gas supply. A key aspect of this review, and a stepout from previous NPC studies, was a detailed analysis of production performance over the past ten years. Evaluating historical performance is one way to gain an understanding of current production and to build a sound basis for establishing future projections. This review used historical well production data from the lower-48 states and western Canada to analyze initial production rates, production decline rates, and total well recoveries for each major producing basin.

The key finding from this analysis was that, on average, initial production rates from new wells have been sustained through the use of advancing technologies; however, production declines from these initial rates have increased significantly, and recoverable volumes from new wells drilled in mature producing basins have declined over time, as shown in Figure 26.

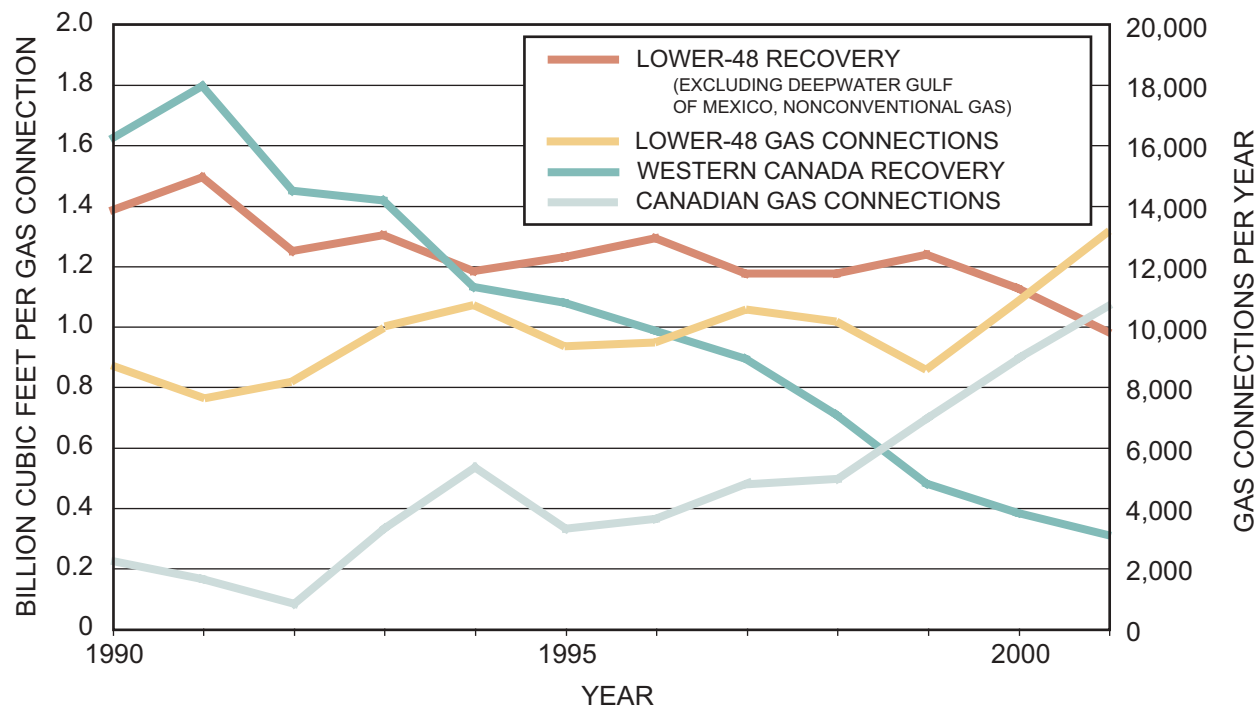


FIGURE 26
RECOVERY PER GAS CONNECTION

Declining well recoveries and higher initial decline rates for new wells are characteristics of many producing basins. This is the underlying reason that the annual rate of decline for North American production continues to increase, and why it is often said that producers are “running harder to stay even.” Figure 26 also shows how drilling activity has increased, a trend that has tended to offset the effect of the declining well recoveries.

Without the benefit of new drilling, indigenous supplies have reached a point at which U.S. production declines by 25-30% each year, as shown in Figure 27. In other words, new wells must make up that volume each year before any growth from prior year levels can be achieved. Figure 28 shows how the lower-48 base production is expected to decline and the level of new production that must be achieved from future drilling in the Reactive Path case. Eighty percent of gas production in ten years will be from wells yet to be drilled. The future gas wells that are required for this production outlook are shown in Figure 29. Small, independent producers, who account for about 70% of U.S. production, will drill most of these wells.

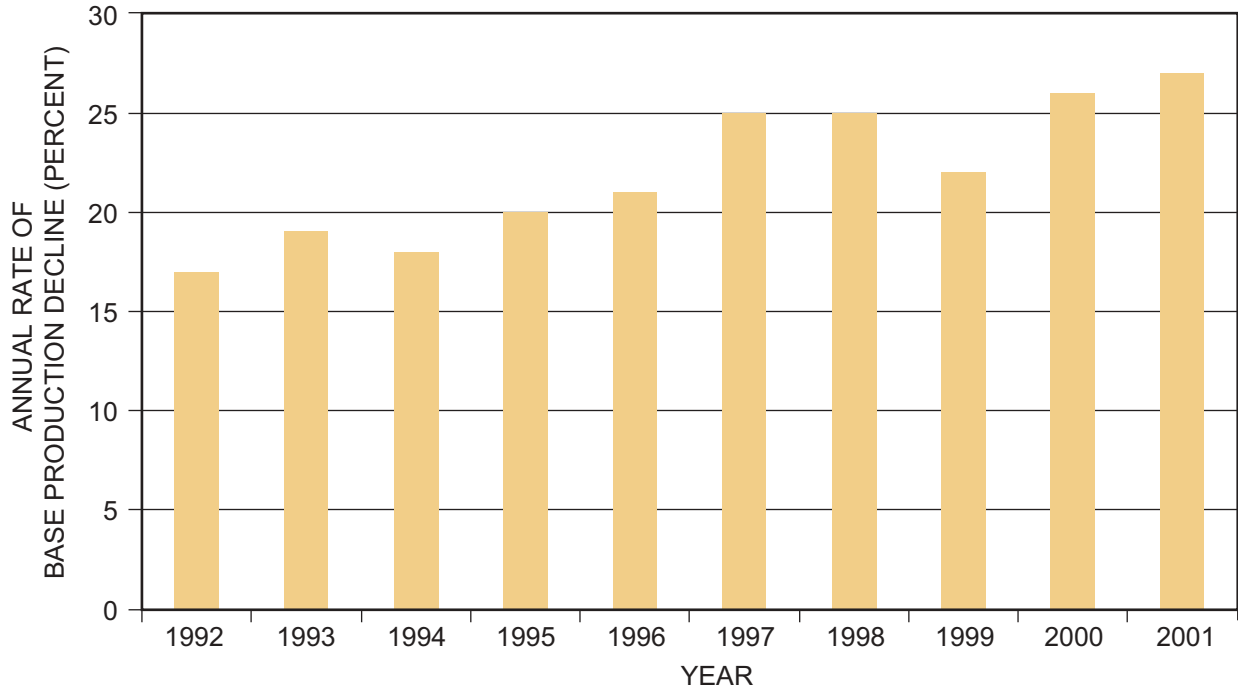


FIGURE 27
LOWER-48 BASE DECLINE RATE

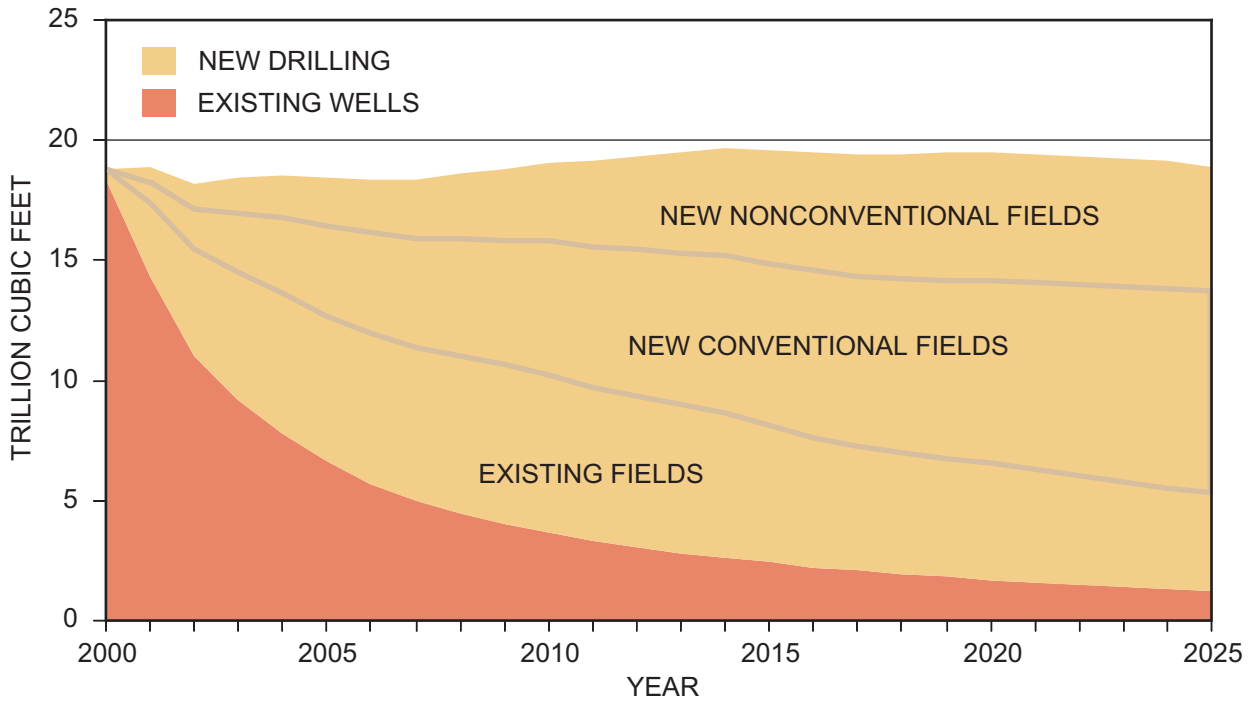
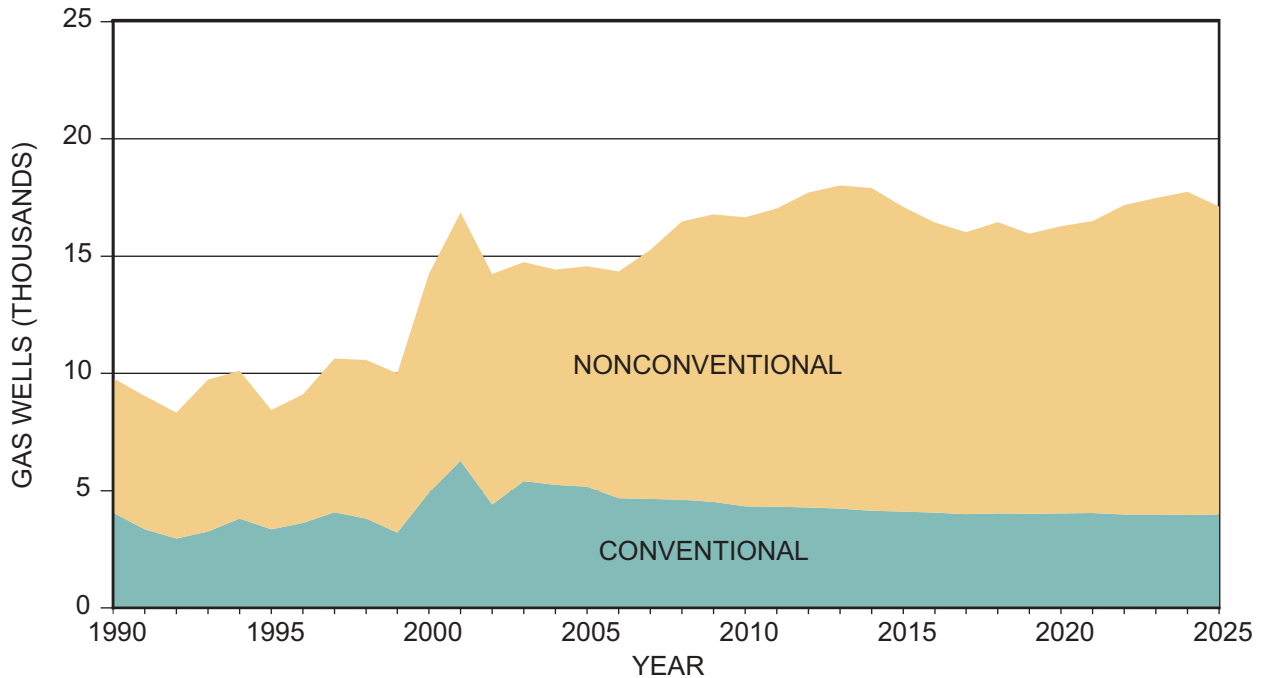


FIGURE 28
LOWER-48 PRODUCTION, EXISTING AND FUTURE WELLS



Note: Historical splits are estimated.

FIGURE 29
LOWER-48 ONSHORE GAS WELLS

The gas drilling activity projected is an increase from the levels of the 1990s, but is consistent with the levels industry has operated at over the past few years. In this outlook, the number of nonconventional wells drilled is increasing, offsetting the projected decline in conventional wells. Given the shorter drilling time for nonconventional wells, this results in a relatively flat outlook for gas drilling rigs during the study period.

This production outlook not only requires a continued high level of drilling activity, but also assumes continued improvement in technologies that increase recovery, reduce costs, and improve drilling success rates. The resources to be found and developed over the next 25 years will be more technologically challenging. These resources will come from reservoirs that are smaller, deeper, and/or lower in permeability. Technology will play a key role in commercializing these resources. Of the projected production in 2025, 14% is attributable to expected advances in technology. This contribution is discussed in detail in the Technology section of the Supply Task Group Report.

To understand the effects of increased drilling activity, the NPC analyzed the supply response from the lower-48 states associated with the doubling of rig activity in 2000/2001. There were limited opportunities in more prolific areas. Most of the additional drilling occurred in basins where low initial rates and low well recoveries were to be expected. Thus, the supply response was less than 5% of lower-48 production even with a doubling of rig activity. In addition, production levels quickly fell when rig activities declined. Figure 30 shows the limited supply increase in response to the doubling of drilling activity.

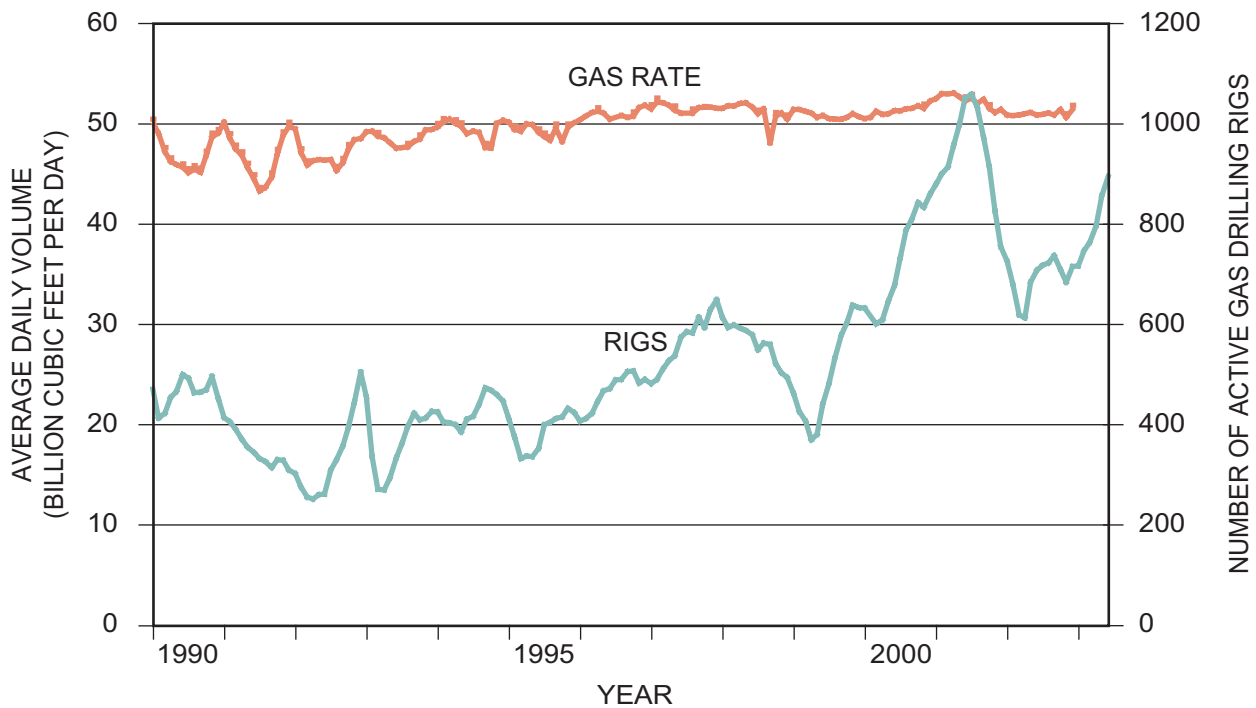


FIGURE 30
MONTHLY LOWER-48 DRY GAS PRODUCTION

Based on analysis of the lower-48 and Canadian resource base and on production performance data, the NPC has concluded that conventional gas production will inevitably decline, and that the overall level of indigenous production will be largely dependent on industry’s ability to increase its production of nonconventional gas. Nonconventional gas includes gas from tight formations, shales, and coal seams. Given the relatively low production rates from nonconventional wells, the analysis further suggests that even in a robust future price environment, industry will be challenged to maintain overall production at its current level. This conclusion is reached even though new discoveries in mature North American basins represent the largest contribution to future supplies of any component of this supply outlook. Figures 31 and 32 show projections of the Reactive Path case for production by resource type and from each of the key producing regions.

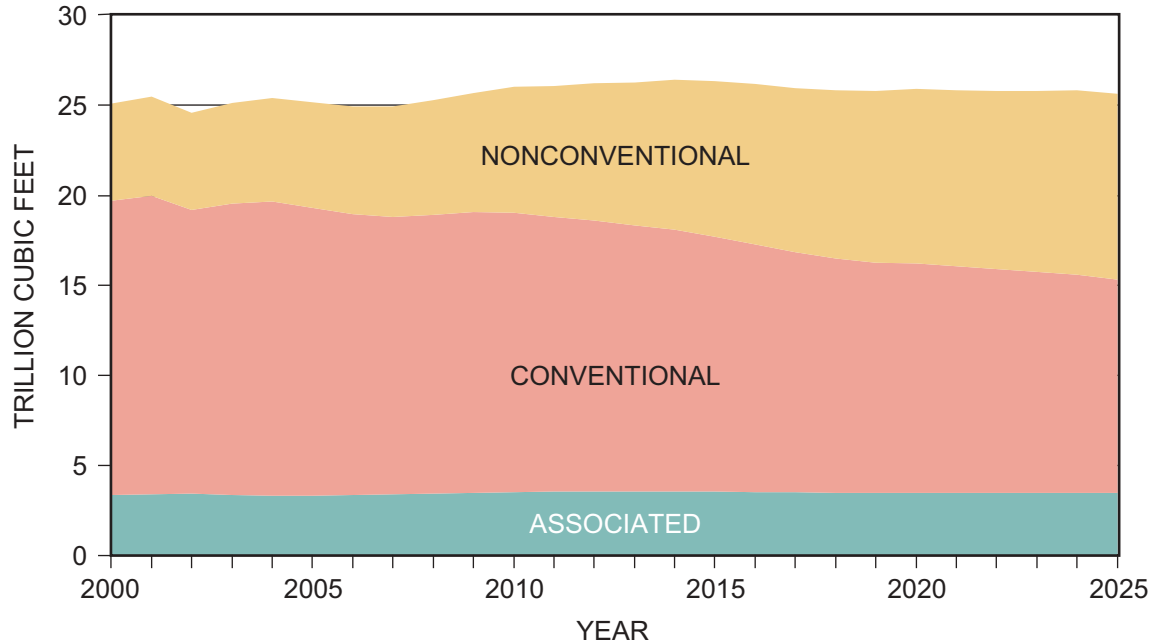


FIGURE 31
U.S. LOWER-48 AND NON-ARCTIC CANADIAN GAS PRODUCTION BY TYPE

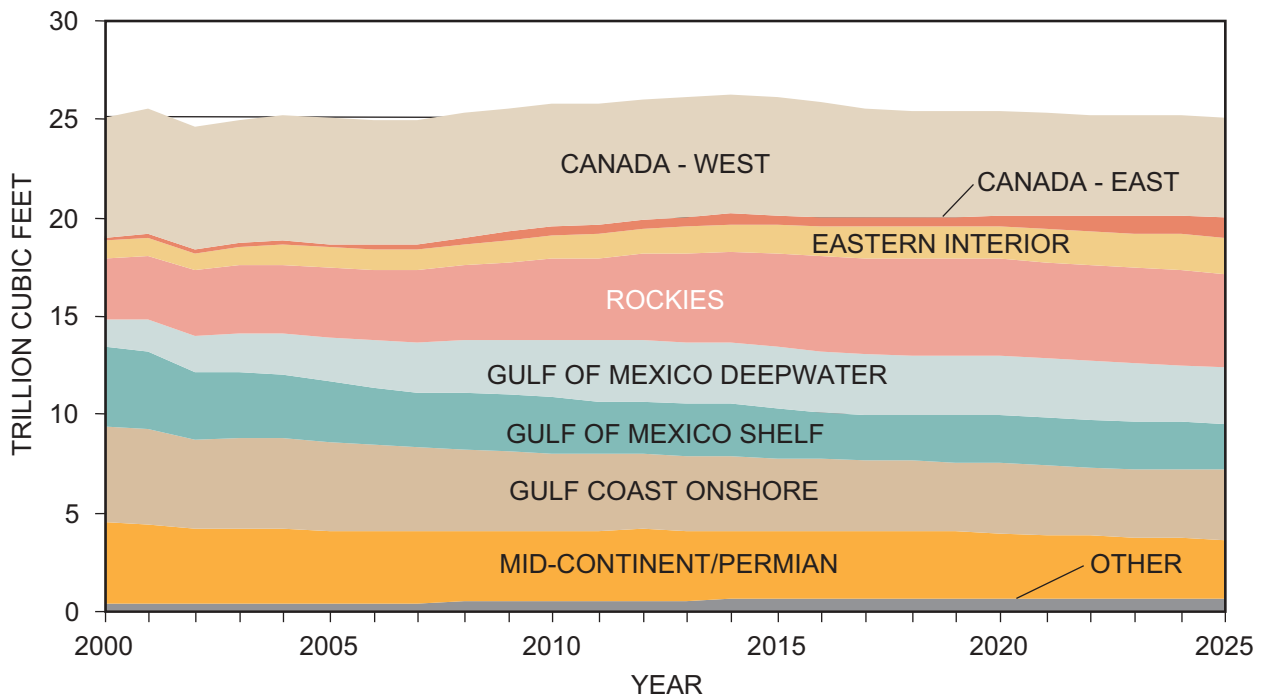


FIGURE 32
U.S. LOWER-48 AND NON-ARCTIC CANADIAN GAS PRODUCTION BY REGION

Although most of the regions are expected to continue to decline with time, some key areas are likely to grow enough to partially offset this decline. Notably, growth in production should occur from the deep waters of the Gulf of Mexico slope, which effectively offsets decline in the more mature, shallower waters of the Gulf of Mexico shelf. In addition, significant growth

is expected in production of nonconventional gas, principally in the Rocky Mountains, which effectively offsets declines in other areas.

The NPC estimates that production from the lower-48 states and non-Arctic Canada can meet 75% of U.S. demand through 2025. However, these indigenous supplies will be unable to meet the projected natural gas demand.

FINDING 6: INCREASED ACCESS TO U.S. RESOURCES (EXCLUDING DESIGNATED WILDERNESS AREAS AND NATIONAL PARKS) COULD SAVE \$300 BILLION IN NATURAL GAS COSTS OVER THE NEXT 20 YEARS.

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. This study expanded those evaluations to include post-leasing conditions of approval on both public and private lands to more fully quantify the effect of regulatory processes on resource development. The NPC created a comprehensive model incorporating key wildlife habitat and simulated the effects of regulatory processes on development activities. The results of this analysis are summarized for four key basins in Figure 33.

| CATEGORY | GREEN RIVER | UINTA PICEANCE | POWDER RIVER | SAN JUAN |
|--|-------------|----------------|--------------|-----------|
| NO LEASING (% RESOURCE) | 7% | 4% | 4% | 5% |
| PROHIBITIVE CONDITIONS OF APPROVAL (%) | 36% | 17% | 34% | 6% |
| ADDED COSTS PER WELL (THOUSANDS) | \$55 - 100 | \$55 - 110 | \$20 - 60 | \$35 - 55 |
| TIME DELAY PER WELL (MONTHS) | 12 - 22 | 8 - 13 | 7 - 14 | 6 - 8 |

FIGURE 33
EFFECT OF CONDITIONS OF APPROVAL ON ROCKY MOUNTAIN RESOURCE DEVELOPMENT

Overall, restrictions from conditions of approval were found to be more of an impediment to development than leasing stipulations. For example, in the Green River basin, 7% of the area was unavailable for leasing. A further 36% of the area was available for leasing, but was “effectively” off-limits to development due to prohibitive conditions of approval, bringing the

total area not available to development to 43%. In addition, conditions of approval added cost and time delays.

In total, the study found that 69 TCF, or 29%, of the Rocky Mountain area technical resource base is currently “effectively” off-limits to exploration and development, and that access-related regulatory requirements impacted an additional 56 TCF of potential resource with added costs and delays to development. The details of the methodology used to develop this assessment are included in the Access section of the Supply Task Group Report.

Leasing moratoria in the Eastern Gulf of Mexico, Atlantic Coast, and the Pacific Coast currently prohibit access to these areas of the OCS. The NPC has estimated that 80 TCF of technically recoverable resources potentially underlie these moratoria areas. It should be noted that limited data have been acquired in these areas due to the moratoria so the range of uncertainty with regard to the size of this resource is large. Figure 34 shows the major regions of the lower-48 states with such access constraints and the volume of technical resource restricted from exploration and development.

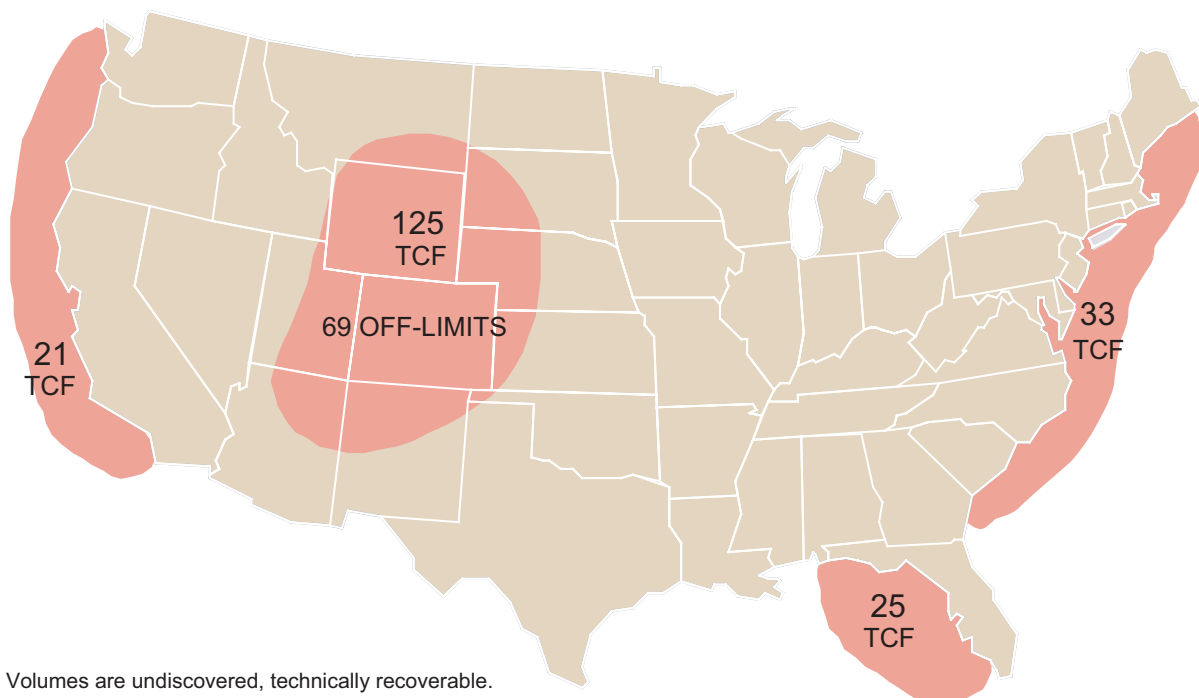


FIGURE 34
LOWER-48 TECHNICAL RESOURCE IMPACTED BY ACCESS RESTRICTIONS

The NPC evaluated the effect of removing the OCS moratoria and of reducing the impact of conditions of approval on the Rocky Mountain areas. These changes could potentially add 3 BCF/D to production by 2020. In addition, this increased production was found to reduce average price projections by \$0.60/MMBtu (nominal dollars), which translates into a reduction in the cost of natural gas to consumers of about \$300 billion over a 20-year period. This outlook is reflected in the Balanced Future case, and can play an important role, along with other new supply sources, in meeting the projected natural gas demand.

FINDING 7: 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.

With the outlook for production from the U.S. lower-48 and non-Arctic Canada flat to declining, new sources of supply will be required to meet the projected growth in natural gas demand. Both the Reactive Path and Balanced Future cases project liquefied natural gas and Arctic gas to become major supply sources, providing 20-25% of U.S. demand by 2025. These new sources also diversify the natural gas supply beyond traditional indigenous sources, and provide access to the rapidly developing global LNG market.

Liquefied natural gas is already a significant supply source for many countries in the world, including Japan, South Korea and several west European nations. Fortunately, the world's gas resource base is large. The NPC analysis concludes that significant quantities of LNG will need to be imported into the United States in the future to meet the expected demand for natural gas. LNG has a proven safety record with 33,000 carrier voyages covering 60 million miles with no major accidents over a 40-year history. Historically, LNG imports into the United States have contributed less than 1% to U.S. supply, primarily due to low gas prices and the relatively high cost of LNG. This situation has changed. New technology has reduced the cost of making and transporting LNG. New LNG supply sources have also begun to enter the market and, because of higher gas prices, are now competitive in the North American market. Figure 35 illustrates the diverse global natural gas supply sources for LNG.

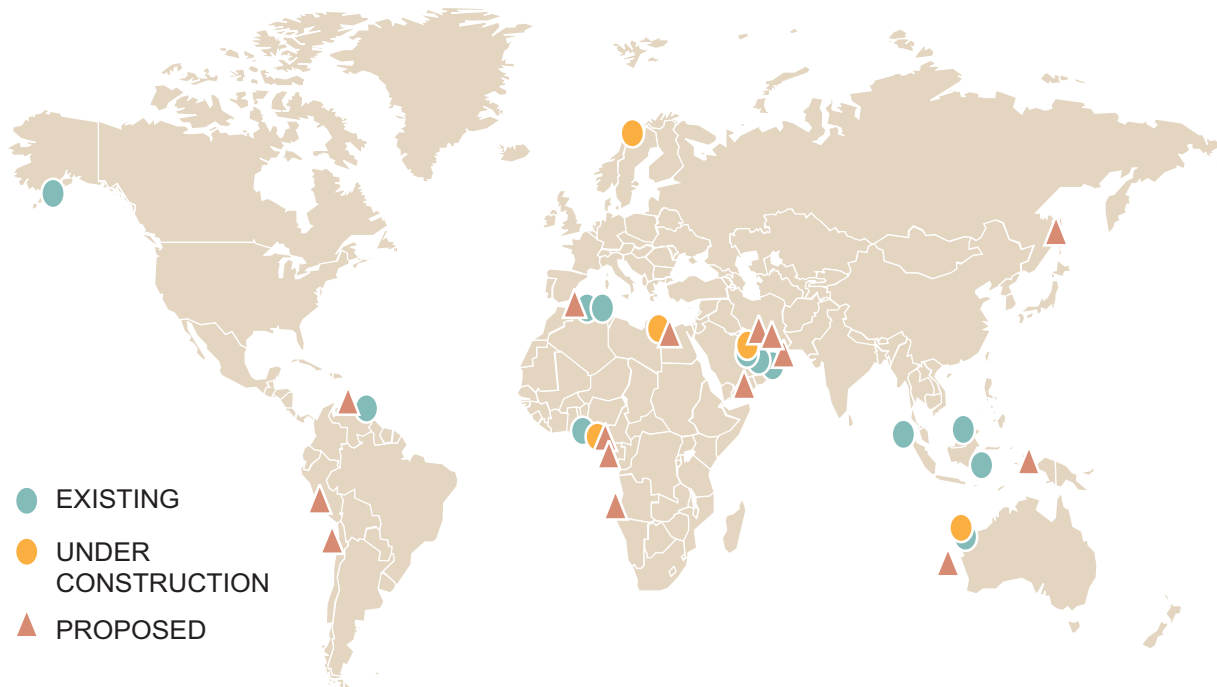


FIGURE 35
GLOBAL LNG SUPPLY

The Reactive Path case assumes the four existing U.S. regasification terminals will be fully utilized by 2007, and that seven additional regasification terminals (and seven expansions) will be built in North America to meet gas demand through 2025. This would result in a total LNG import capacity of 12.5 BCF/D, with LNG providing 14% of the U.S. supply of natural gas by 2025. In the Balanced Future case, projects are permitted more quickly and two additional terminals and two additional expansions are assumed built. This increases total LNG import capacity to 15 BCF/D or 17% of the U.S. supply of natural gas by 2025. Figure 36 shows the locations of existing and potential new LNG terminals, and Figure 37 shows the projected volume contribution from LNG.



FIGURE 36
NEW NATURAL GAS SUPPLY SOURCES

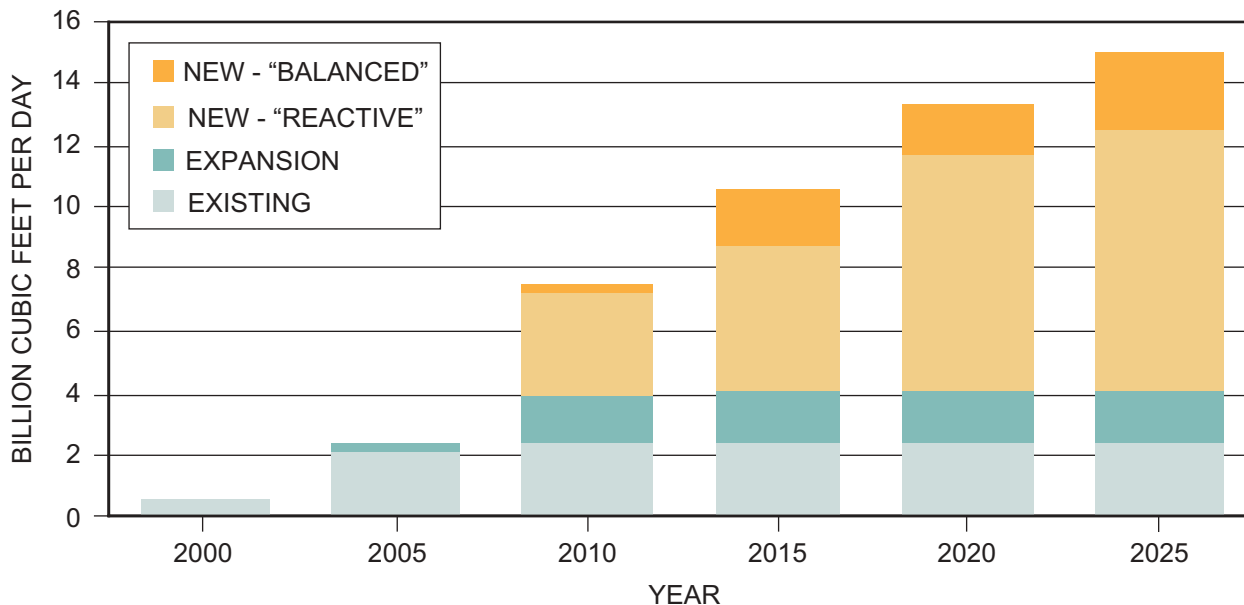


FIGURE 37
NORTH AMERICAN LNG IMPORTS

While there is clear potential for LNG imports to fall short of these projections due to market uncertainties and possible opposition to siting of LNG regasification terminals, the upside potential, while significant, is also uncertain. One implication of natural gas price projections in the Reactive Path case is that even larger quantities of imports might be attracted. However, LNG developments will also be subject to the risk of lower North American demand due to higher prices, as well as competition from other North American sources of natural gas production.

The assumptions in either case represent a major undertaking, since developing a large, new LNG import capability in North America will not be easy. LNG imports require alignment of the entire supply chain from development of foreign source gas reserves, to liquefaction of the supply, to construction of specialized LNG carriers, to regasification and delivery into the North American transmission infrastructure. Capital requirements for a typical LNG development from source to an interconnection with an existing pipeline grid are on the order of \$5-\$10 billion per BCF/D of capacity. For the Reactive Path case, the estimated capital requirements for LNG during the study period are over \$90 billion, and nearly \$115 billion for the Balanced Future case.

The typical regasification terminal in the United States is estimated to take over five years from initial permit application to commencement of imports. Under current regulations, permitting can take from one year (offshore terminals) to over two years (onshore terminals) assuming minimal resistance and a well-coordinated permitting process. The Reactive Path case assumed a permitting time of two years, while the Balanced Future case assumed one year.

Recently, the U.S. government implemented two policy changes to facilitate development of new LNG import regasification terminals. First, the Deep Water Port Act was amended to include natural gas/LNG/CNG; this resulted in two significant changes for offshore LNG import

terminals. Such terminals will now be under the jurisdiction of the United States Coast Guard, and permit applications will have a discrete timeline. Second, the Federal Energy Regulatory Commission, which has the jurisdictional authority for onshore LNG import regasification terminals, ruled that two such terminals will be treated similarly to gas processing plants, no longer requiring open-access regulation. The latter policy allows companies to develop integrated LNG projects, which is important in reducing the risk associated with these large, complex, projects.

These efforts, while encouraging new LNG import terminal development, will not overcome all the hurdles faced by the industry. New terminals may face substantial local opposition. Permits for new terminals, particularly onshore terminals, will only be issued in a timely fashion with the support of local governments and communities. A continued leadership role, as demonstrated by FERC in the recent reactivation of the Cove Point and Elba Island facilities, will be needed to move the permitting process forward in a timely manner. Any setbacks from what the NPC projects as substantially successful development of LNG supply would reduce projected supplies and increase gas prices.

To evaluate the impact of potential setbacks, a sensitivity case was evaluated in which only two new LNG terminals were constructed due to permitting difficulties. In this case, LNG import capacity was reduced by 6 BCF/D and the average gas price increased by 10%. Clearly the ability to import increasing volumes of LNG is important to achieving a more comfortable supply/demand balance.

A second source of significant potential new supplies is Arctic gas. This includes gas from the Alaska North Slope and the Mackenzie Delta region in Canada (illustrated in Figure 36) where substantial quantities have already been discovered, but require long, new pipelines to be developed.

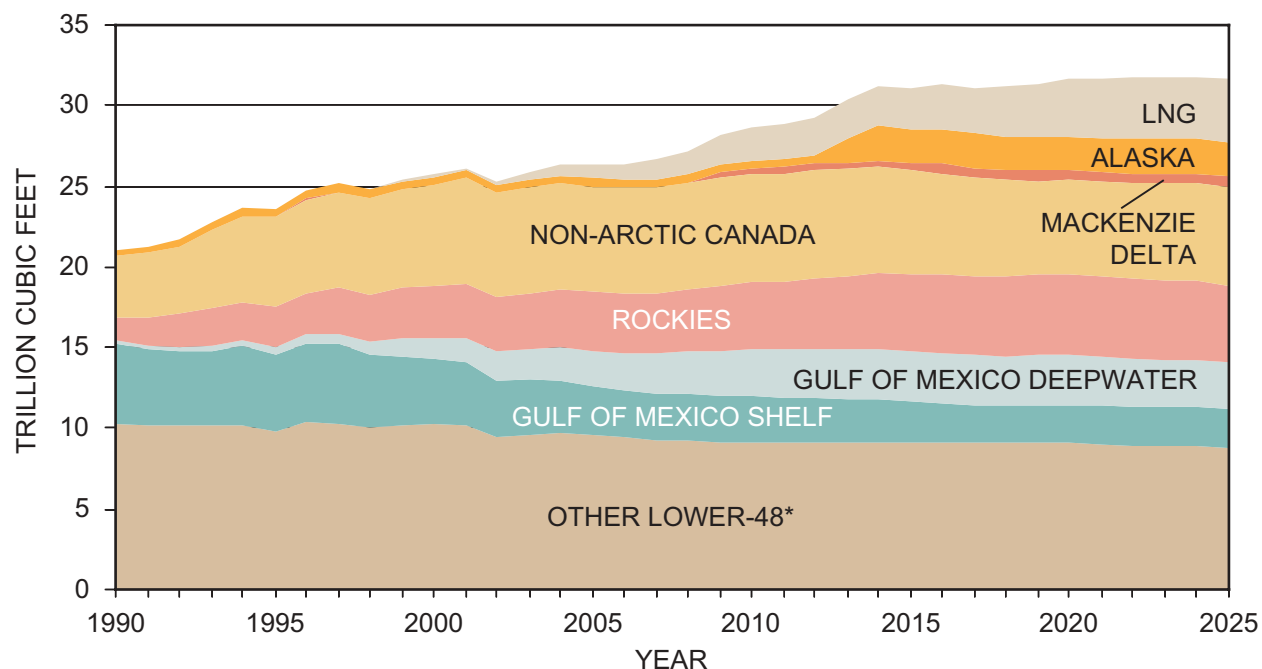
Efforts have been underway by industry for over 30 years to commercialize Alaskan gas. Major hurdles for commercializing this resource include costs, permitting, state fiscal uncertainty, and market risks. The companies involved in oil and gas production at Prudhoe Bay, Alaska estimate the cost to bring Alaskan gas to U.S. markets to be on the order of \$20 billion with a lead time of ten years, assuming construction of full pipeline infrastructure south of Alberta to U.S. markets. The NPC study analysis indicates some capacity may be available in existing infrastructure, potentially reducing the amount of new pipeline construction required.

Industry is working to advance new technology that could reduce the capital cost. However, securing all the necessary permits in a timely manner from various jurisdictions in the United States and Canada represents a significant challenge. Another hurdle is the uncertainty regarding how royalty and tax payments to the state of Alaska will be calculated over the life of a pipeline project. Conditions must be particularly strong to support an investment of this magnitude considering the long lead-time and the inherent risks. The NPC has assumed that these challenges will be overcome, and that conditions will support an Alaska gas pipeline start-up in the 2013-14 time frame. This would contribute 4 BCF/D, about 6% of U.S. supply, through the remaining years of the study period.

Given the commercial, regulatory, and cost-related risks associated with this project, a sensitivity case was run in which it was assumed that the Alaska gas pipeline will not be built. This increased gas price projections by roughly 8% over the period from 2015 to 2025, putting further stress on the economy and illustrating the importance of this project to the overall outlook.

Similar issues confront a proposed pipeline from the Mackenzie Delta in Canada. Although that project is smaller, and most of the gas will probably find a market in Canada, there will be an effect on the U.S. gas supply. A Canadian regulatory process is evolving to address First Nations' rights as well as other local and federal issues in a timely manner. The NPC has assumed that permits can be secured and market conditions could support start-up of a Mackenzie Delta pipeline in 2009 at a rate of 1 BCF/D, with an expansion in 2015 to 1.5 BCF/D.

All of these projects face barriers to development and have very long lead times. Thus these potential sources of supply will not affect the short-term fundamentals of the current market environment. Figure 38 shows the relationship of these new supply sources to other sources of supply in the Reactive Path case.



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

FIGURE 38
U.S. AND CANADIAN NATURAL GAS SUPPLY

The NPC also evaluated potential new supply sources that require technology advances to be commercially competitive. These new sources, including methane hydrates are viewed as unlikely to make material contributions prior to 2025, but they do represent potential longer-term supply sources. Additional details can be found in the Technology section of the Supply Task Group Report.

FINDING 8: PIPELINE AND DISTRIBUTION INVESTMENTS WILL AVERAGE \$8 BILLION PER YEAR, WITH AN INCREASING SHARE REQUIRED TO SUSTAIN THE RELIABILITY OF EXISTING INFRASTRUCTURE.

Figure 39 illustrates expected capital expenditures for infrastructure through 2025 for the Balanced Future case (the results of the Reactive Path case are very similar). Through 2025 it is anticipated that in the United States, \$35 billion (\$1.5 billion per year) will be invested in new and expanded pipeline and storage infrastructure to provide deliveries of new supply sources to the marketplace. Additionally \$12 billion in pipeline and storage infrastructure expenditures is projected for Canada. Nearly \$70 billion (\$3 billion per year) will be required for distribution facilities in the United States (twice the rate for pipeline and storage).

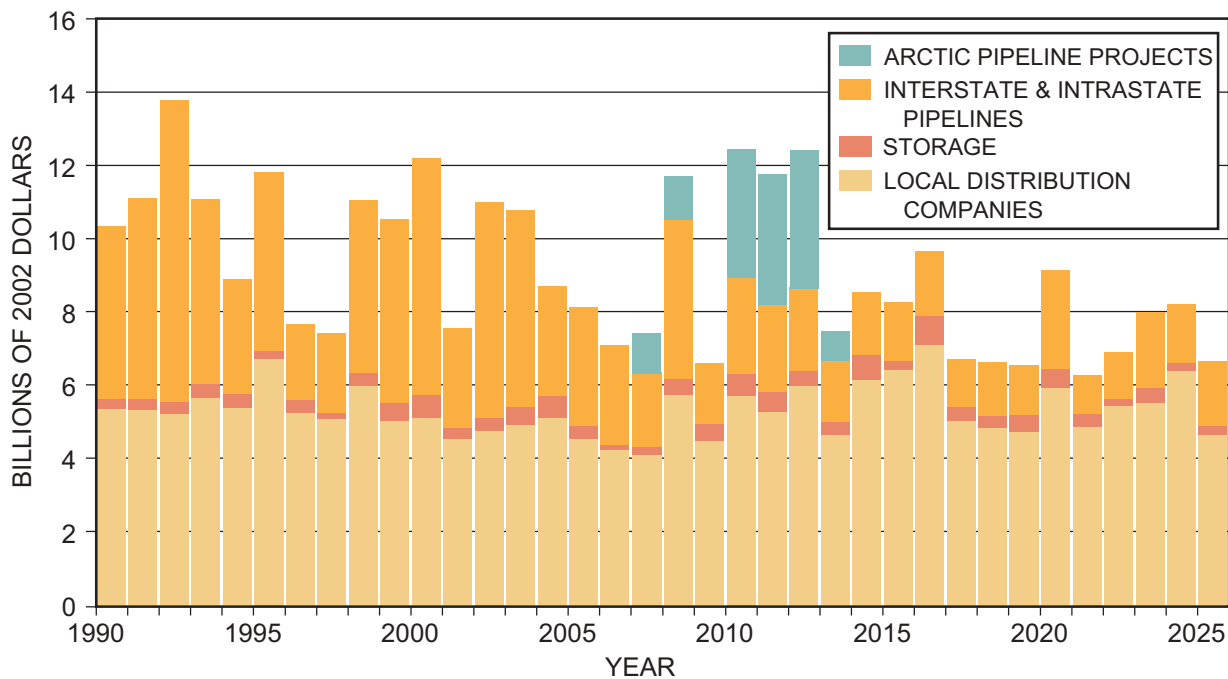


FIGURE 39
NORTH AMERICAN CAPITAL EXPENDITURES FOR TRANSMISSION, DISTRIBUTION, AND STORAGE

As can be seen, the projected need for capital for new infrastructure is decreasing in the future while sustaining capital is becoming an increasing percentage of total capital requirements. It is anticipated that over the next 22 years \$70 billion of expenditures will be needed in sustaining capital for the existing pipeline and distribution infrastructure in the United States, and \$3 billion in Canada. 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.

As discussed previously, growth in onshore production in the lower-48 states is effectively limited to the Rocky Mountain region. Major new sources of gas will have to come

from outside the lower-48 states and will rely on the existing network of nearly 290,000 miles of high-pressure pipelines to transport the gas to markets. Figure 40 shows the anticipated new pipeline transmission requirements in the Balanced Future case by 2025.



FIGURE 40
NEW PIPELINE AND LNG CAPACITY
(MILLION CUBIC FEET PER DAY) CHANGE FROM 2003 TO 2025

Major new pipeline infrastructure will be needed to bring Arctic production to the Alberta hub. The additional capacity needed to move the Arctic gas away from the Alberta hub is a function of the rate of decline of Western Canadian Sedimentary Basin (WCSB) production,

which is anticipated to continue its decline as the Arctic gas comes on line, and growth in demand for gas in Canada, including an increasing gas demand for oil sands development. Currently, there is about 15 BCF/D of pipeline capacity from western Canada and it is about 85%-utilized in transporting WCSB gas to downstream markets. The NPC analysis suggests that an additional 0.5 to 2 BCF/D of new or expansion capacity will be required with the remainder moving on existing pipeline infrastructure.

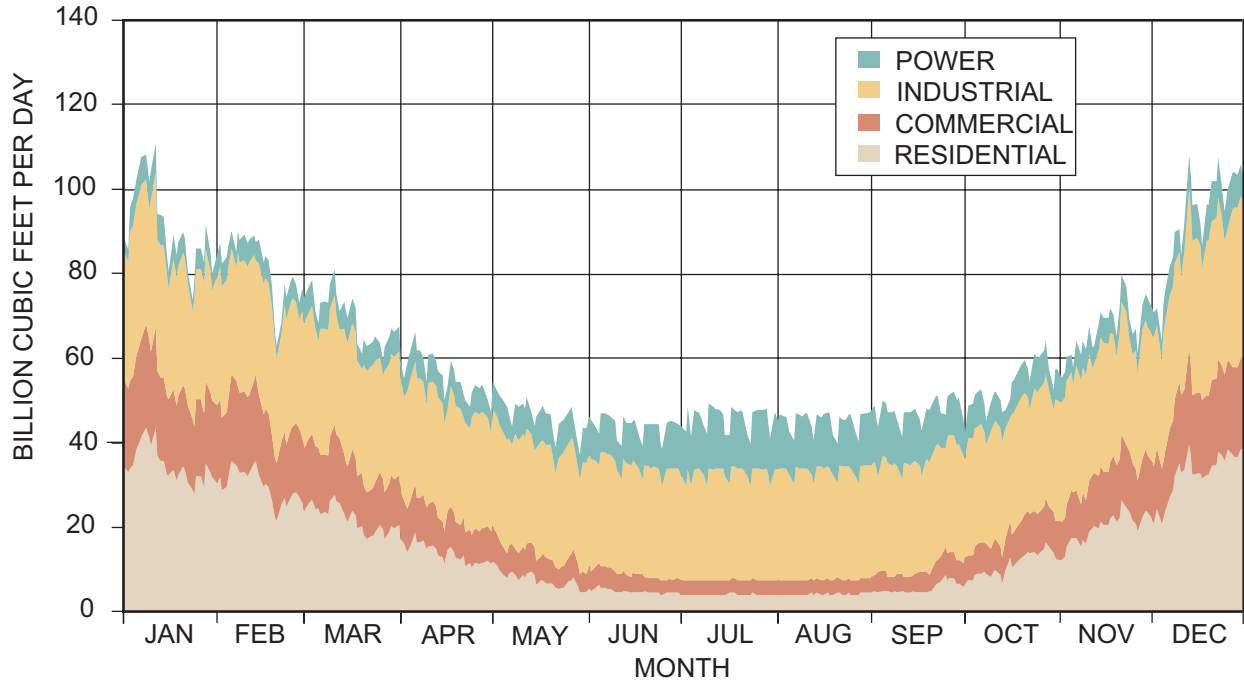
The NPC outlook indicates that LNG import terminals are a critical element needed to meet demand on the east and west coasts. To the extent that these LNG regasification terminals can be sited close to demand centers, additional pipeline infrastructure investment may be minimized, particularly where existing capacity is made available by declines in domestic production. If such terminals cannot be sited in market regions, however, additional pipeline infrastructure and greater reliance on the existing pipelines from the Gulf Coast may be needed to deliver LNG to major markets. This will result in higher basis between Henry Hub and the market and higher costs for consumers.

Additional pipeline take-away capacity will also be needed from the Rocky Mountains, deep waters of the Gulf of Mexico, and Eastern Canada offshore. This new capacity will be limited to that needed to interface the existing pipeline grid. From there, it is expected that the gas will move on existing pipeline systems to access markets throughout the lower-48 states.

Capacity must also be constructed to transport gas from storage to market centers. Mid-Atlantic and Northeast markets will require additional storage. Since the lack of suitable reservoirs restricts the potential development of this storage capacity to the western portions of Pennsylvania and New York and Eastern Ohio, incremental short-haul pipeline capacity of approximately 2 BCF/D will have to be constructed to the major northeastern market centers, which include New York City, Boston, and Philadelphia.

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 is fairly 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, industrial demand is projected to grow by only 3%. This means 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 Figures 41 and 42, 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 and unpredictable than that of a traditional residential/commercial load profile. The growing summer peak impacts 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 storage during the shoulder months of April through June and September through October, historically lower demand.



Source: Energy and Environmental Analysis, Inc.

FIGURE 41
1997 DAILY LOADS
FOR THE UNITED STATES AND CANADA

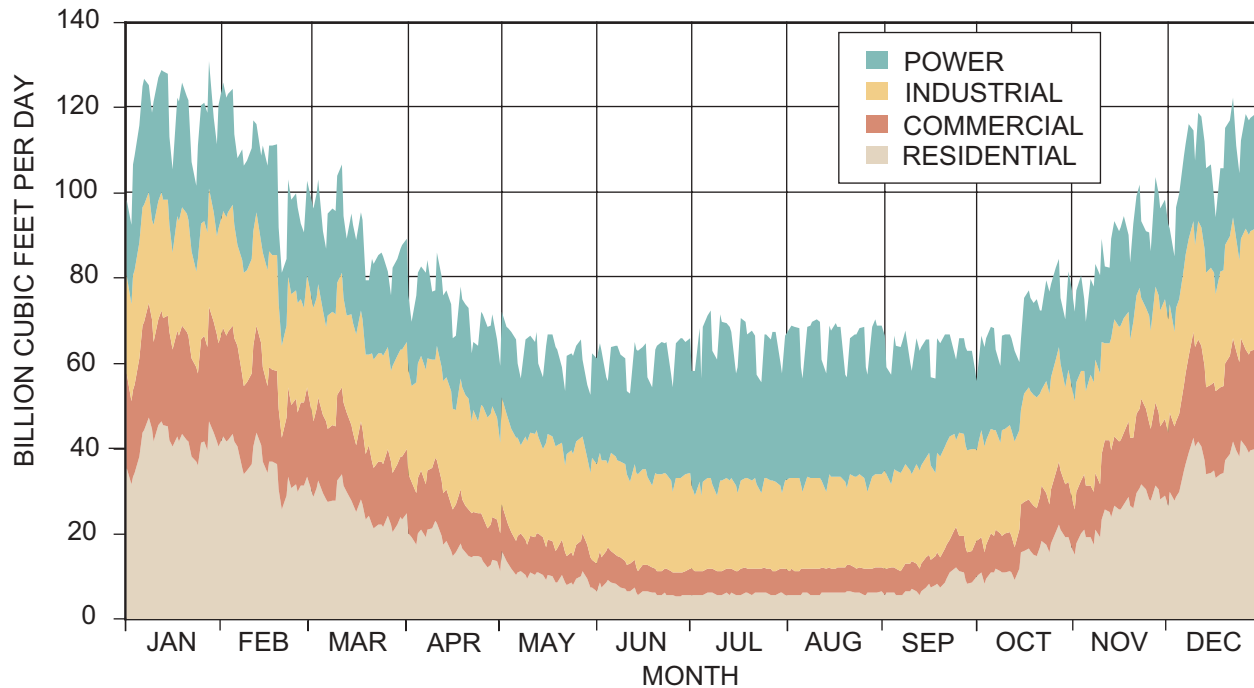


FIGURE 42
2025 DAILY LOADS
FOR THE UNITED STATES AND CANADA

Regardless of the growing power generation needs in the summer months, local distribution companies (LDCs) will need to fill their market area storage to be able to meet their customer's winter consumption requirements reliably. The growing divergence of the two sectors' needs will require storage operators to construct additional storage capacity and increase the flexibility of their current facilities.

Construction of significant new LDC facilities will also be required to meet customer demands. These facilities include main reinforcements, main extensions, and the construction of services to bring the gas into an individual home or business. New and even more environmentally sensitive and lower cost construction techniques are needed. Better technologies for locating existing underground facilities will enhance the safety and operation of existing facilities⁶ and reduce the costs of new construction. A 1% annual gain in productivity from technological advances was assumed in this study. Such a gain would result in reduced customer costs of \$300 to \$400 million per year, over the costs of the previous year. Therefore, continued R&D is needed to provide new techniques and technologies to minimize these future costs while assuring safe and reliable operation of distribution systems.

Existing Infrastructure

Gas transmission and distribution has been the safest mode of energy transportation. Use of the existing pipeline and distribution infrastructure is anticipated to increase as many lines reverse flow, and others increase in utilization. Significant ongoing expenditures will be required to undertake additional preventative measures to maintain safe and reliable operations. Pipeline and storage companies operate over 290,000 miles of transmission pipe and approximately 16,000,000 horsepower. Of the 290,000 miles, 255,000 miles, or 88%, was installed prior to the 1970s. Figure 43 shows the North American pipeline grid.

⁶ "Third party damage" where someone other than an LDC hits the distribution pipe is the leading cause of damage to the distribution system.



FIGURE 43
NORTH AMERICAN PIPELINE GRID (24" DIAMETER AND GREATER)

Congress enacted in 2002 the Pipeline Safety Improvements Act, which has significantly increased pipeline testing and reporting requirements for the transmission and distribution industries. In addition to improving the “one call” systems used by the states and requiring enhanced operator qualifications, the Act mandates updated maintenance programs and continuing inspections of all pipelines located in population centers. These mandates will increase costs to consumers several ways. Additional costs will arise because facilities will need to be temporarily taken out of service to perform the mandated testing. This may cause deliverability constraints during testing periods due to reduced capacity. Costs will also increase as a result of the direct costs of integrity inspections and the required modifications of pipeline and distribution facilities. Both of these costs will tend to put upward pressure on gas transportation rates.

Because of the decreasing life expectancy of the installed horsepower and pending and potential environmental mandates, significant horsepower will have to be replaced over the study period. If operators were to replace all horsepower over the next 50 years, 320,000 horsepower would need to be replaced each year. Similarly if all pipe was replaced over the next fifty years, 5,800 miles of pipe would need to be replaced each year. 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 as 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. The basis for using the lower number is that it better matches the historical level of replacement. Because of the impacts of the Pipeline Safety Improvements Act, however, we doubled the historical levels for the purposes of the study. If pipelines aren't able to retire the pipe and/or compression in the future due to continuing need or otherwise, sustaining capital could be significantly higher. At some point in the future, however, the progressive aging of pipelines and compressors will result in further significant increases in the miles of pipe and horsepower replaced per year.

FINDING 9: REGULATORY BARRIERS TO LONG-TERM CONTRACTS FOR TRANSPORTATION AND STORAGE IMPAIR INFRASTRUCTURE INVESTMENT.

The average transportation contract term on pipelines has shortened. New pipeline and storage infrastructure are generally financially supported by long-term contracts for a period of ten to twenty years. Companies are less willing to invest dollars in new infrastructure if contract durations for existing or new pipeline/storage capacity are shortened by the impact of regulatory policies. In a free market, shippers make long-term commitments when they see the need for the service that will be provided. If barriers exist to shippers making long-term commitments, investment in new infrastructure is impacted. This affects both new and existing pipelines. As shown in Figure 44, the average contract term on gas pipelines is being shortened. Pipeline operators believe a significant factor is the regulatory policies on contracting practices by some federal and state regulatory agencies. As a result, even though the pipelines were carrying basically the same amount of gas to serve the same markets, the revenue stream is viewed as more short-term in nature and less likely to support long-term infrastructure investments.

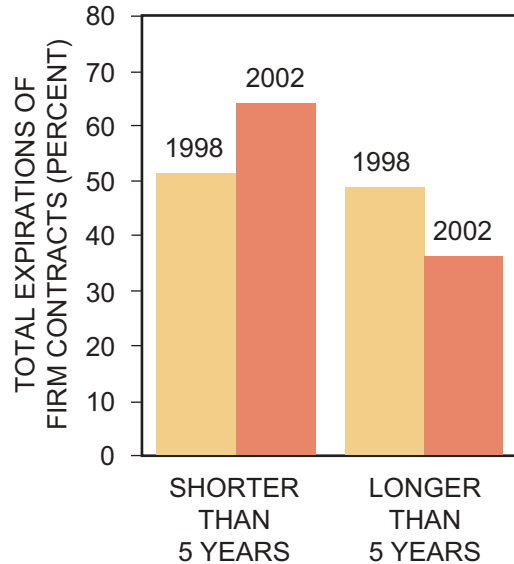


FIGURE 44
FIRM CONTRACT EXPIRATIONS

From the beginning of the transmission industry until recently, LDCs were the dominant parties contracting for long-term pipeline and storage capacity. Their contracts were crucial for the development of new pipelines and the expansion of existing ones because they provided the financial underpinning necessary to raise the required capital. This role began to change in the late 1990s as a result of regulatory changes at the federal and state level. Regulatory changes associated with a competitive market that resulted in the growth of independent marketing companies as sellers of gas to both utilities and to end users gave LDCs more supply options and incentives to contract for less capacity and to hold shorter-term capacity contracts.

Marketing companies saw rapid growth in the early 1990s as they provided the intermediary function between producers and consumers that arose as the pipeline sales function disappeared. LDCs and major industrial consumers became responsible for purchasing their own gas supplies. Most began by buying gas in the production area directly from producers and transporting it to market via their existing contracts. Over time, marketing companies began to offer city gate sales service to LDCs and large end-users by efficiently packaging portfolios of transportation and storage contracts obtained from the original contract holders either through agency agreements, contract releases or, in the later stages, by direct contract ownership. Marketers desired to hold transportation and storage contracts similar in term to their associated sales agreements to lower their financial exposure. Many of the marketers' sales contracts were relatively short term. Some marketer's portfolios held some long term capacity contracts but it was for a much smaller proportion of their portfolio than was common for pipeline customers in the pre-restructuring period. Thus, as illustrated in Figure 44, although the pipelines were carrying basically the same amount of gas to serve the same end-uses, their average contract term shortened.

A contributing factor in the shortening of pipeline contracts was the restructuring of many LDC businesses in the 1990s. The opening of LDC distribution system capacity to transport by third parties was developed as a means to increase competition and lower prices. By

the end of the 1990s, restructuring was complete in many states for gas in the industrial and electric generation segments and was underway in the residential/commercial sector. Although retail choice programs are in place in many states, to date the vast majority of residential customers have elected to remain with their original utility. Nevertheless, a directive from some states is that LDCs should not contract for the long term in pipeline, storage, or upstream capacity since their share of the future market was unknown and subject to considerable risk in the face of developing competition. Generally, LDCs are not willing to contract for long-term capacity and take the risk of being second-guessed in future prudence reviews.

Today, the turmoil of the gas marketer business segment has almost eliminated independent and affiliated marketers from the list of prospective purchasers of existing and/or proposed pipeline transmission capacity. Even if such firms wanted to contract for capacity, their creditworthiness may make them too great a risk for pipelines and downstream customers to consider without the gas marketer providing significant credit assurances.

Many LDCs will not enter into long-term contracts with marketers in today's market out of fear that regulators may subsequently deem them imprudent. 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. The result is that regulatory barriers may be inhibiting efficient markets and discouraging the financial incentives to develop and maintain pipeline infrastructure.

FINDING 10: 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.

Since the 1980s, the natural gas market has continuously evolved following FERC and Congressional actions to implement the free market system for the trade of natural gas. Accompanying this deregulation has been greater variability of gas prices as market forces worked to establish prices in the monthly and daily markets. Price volatility is a natural phenomenon in a market where supply and demand vary on a daily/hourly basis. The principal drivers behind price volatility are supply and demand fundamentals, which include demand variability, weather effects, supply and storage levels, the cost of competing fuels, and overall market trends. Relatively large price changes can and have occurred when supply and/or demand sectors are unable to quickly adjust to unexpected changes in market conditions. Figure 45 shows Henry Hub monthly prices for the last ten years. Natural gas prices have been more volatile than crude oil prices but significantly less volatile than electricity prices. Many consumers and producers have access to a broad range of physical and risk management tools to manage its effects.

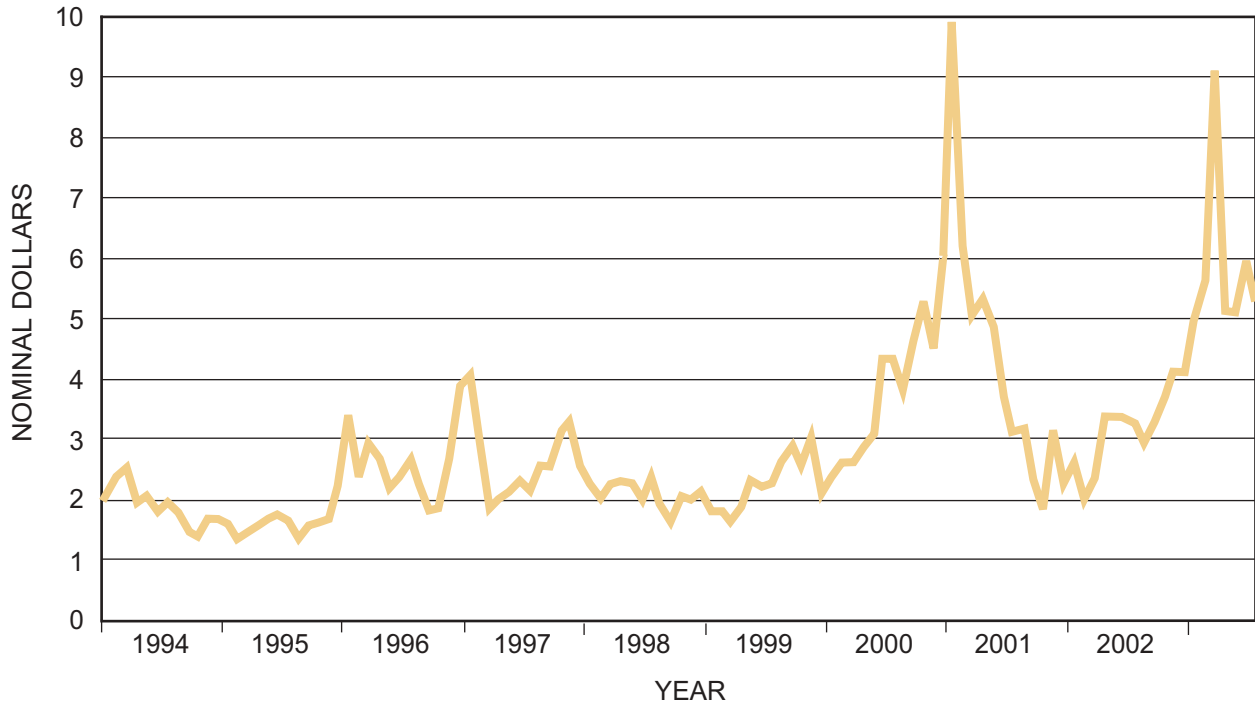


FIGURE 45
HENRY HUB MONTHLY INDEX PRICES

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 LDCs, industrials, and power generators. The market is functioning efficiently with lessened government involvement following years of regulatory reform. In a free market, participants need price signals in order to make rational decisions about whether to produce or consume more gas. Customers who want gas, even in the highest demand periods, get their gas if they contract for delivery in advance – or alternatively pay the market price on the day. Additionally, producers respond to price signals for increased supply by increasing their exploration and drilling efforts.

Most residential and commercial customers served by LDCs are insulated from day-to-day price volatility, through state or local regulation with periodic adjustments reflecting the average cost of gas purchased over a longer period. Ultimately consumers' bills reflect price level changes.

Industrial gas consumers tend to be more exposed to short-term price effects since they usually buy gas in the monthly and daily markets, and therefore have been most affected by rising prices (this also makes them the first to benefit from falling prices). Rising gas prices have caused some industrial plant shutdowns and relocations of some manufacturing to foreign locations with lower cost natural gas. Industries most affected are the fertilizer, methanol, steel and chemicals.

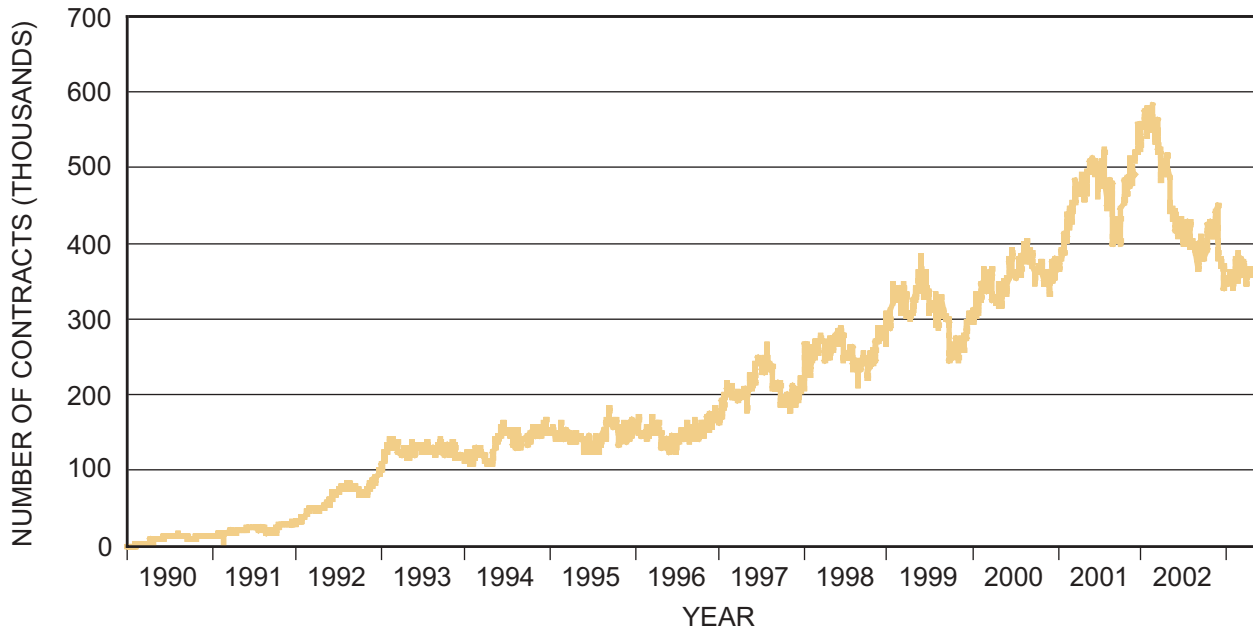
There are several steps that market participants and regulators can take to mitigate price volatility. These include: 1) contracting for firm transportation and storage; 2) switching to lower cost alternate fuels; 3) using financial hedges – a strategy that does not eliminate risk, but

does create price certainty; 4) contracting under long-term fixed price agreements; and 5) making available timely and reliable information regarding supply, demand, and storage levels. Items 1-4 require a cost-to-benefit analysis to determine whether they should be adopted by individual market participants. Item 5 is best facilitated by government action.

Exposure to price volatility to a great extent is about choices that market participants make. Participants may choose to buy or sell in the short-term daily market and not contract for storage or transportation capacity – this exposes them to increased volatility. Others may choose to contract under long term arrangements for the purchase or sale of gas and hold firm transport capacity thereby reducing their exposure to price volatility. Additionally the futures market may be used to manage forward pricing. In summary, tools are available to help manage the risk of price volatility, but they come at a cost.

There have been major changes in gas market participants over the past two years. Several large marketing companies have exited the physical and financial gas trading business, and on-line trading operations have declined. The number of participants offering a broad portfolio of financial products has been reduced and the need to trade with credit-worthy 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.

The rise of financial products has been fairly dramatic since 1990. The trend in the use of NYMEX financial instruments is illustrated in Figure 46 and shows increasing open interest in NYMEX contracts through mid 2002. Open interest is a measure of activity on NYMEX and gives some indication of overall market depth and liquidity. Current levels of NYMEX trading at the Henry Hub are below the 2002 peak but above the overall range of the 1990s. Marketers have traditionally been the major market makers and counter parties 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 as they now also have fewer parties to transact with and mitigate exposures.



Open Interest: The number of open or outstanding contracts for which an entity is obligated to the Exchange because that entity has not yet made an offsetting sale or purchase, an actual contract delivery.

FIGURE 46
NYMEX OPEN INTEREST – NATURAL GAS CONTRACTS

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. 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. 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.

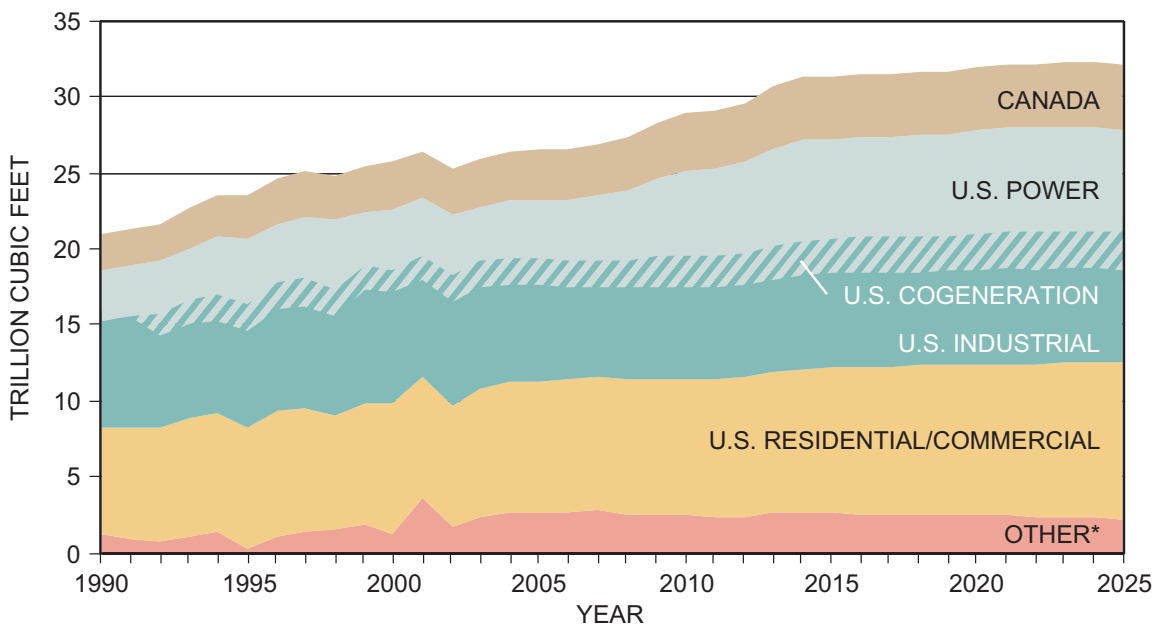
FINDING 11: A BALANCED FUTURE THAT INCLUDES INCREASED ENERGY EFFICIENCY, IMMEDIATE DEVELOPMENT OF NEW RESOURCES, AND FLEXIBILITY IN FUEL CHOICE COULD SAVE \$1 TRILLION IN U.S. NATURAL GAS COSTS OVER THE NEXT 20 YEARS. PUBLIC POLICY MUST SUPPORT THESE OBJECTIVES.

Competitive markets are the most effective means to ensure that consumers get the greatest benefit from the use of our natural gas resource endowment. These benefits are significantly affected by policy choices at all levels of government. The most difficult task faced by the NPC was to assess the future balance of consumption and new supplies in the face of a tight market for natural gas. On the demand side, the ability and likelihood of consumers to switch to lower-cost fuels was comprehensively evaluated, as was the potential for more stringent environmental regulation – a course that could lead to an even greater demand for gas.

On the supply side, consideration was given to the uncertainties in estimating the size of the indigenous North American resource base, the rate of technology development, as well as regulatory actions that might accelerate or delay development of domestic and foreign sources of supply.

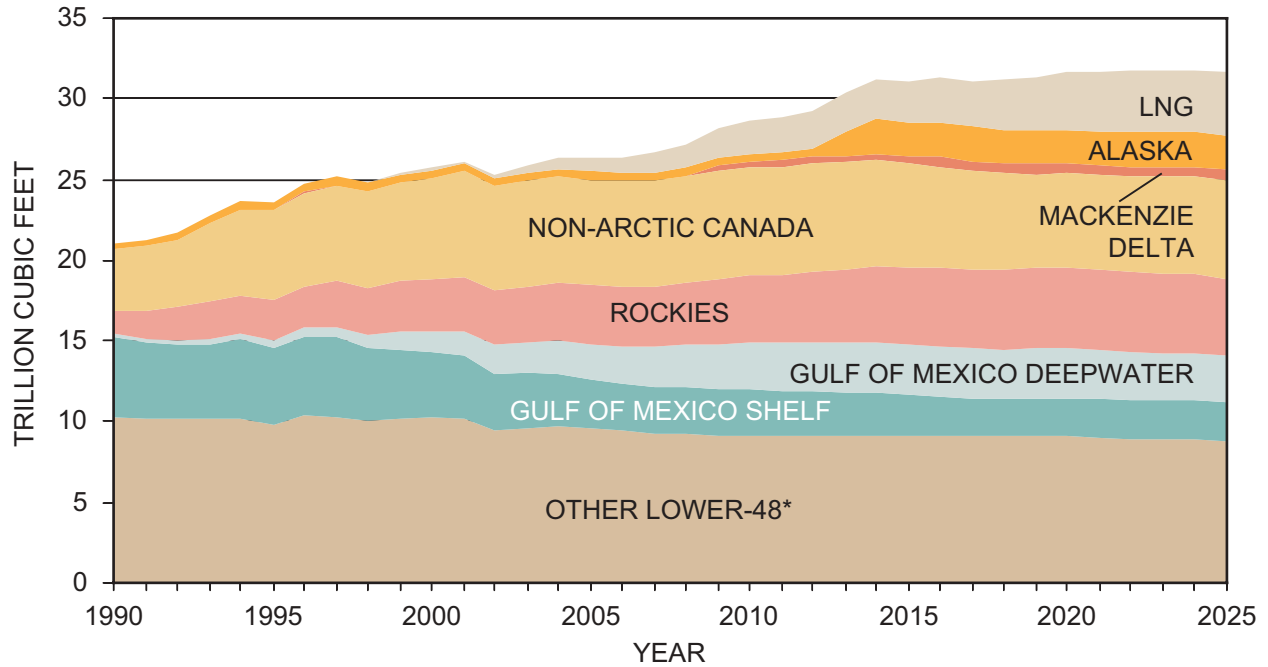
As previously described, two primary scenarios were used to evaluate the long-range outlook. The Reactive Path case was modeled based on existing environmental regulations and policies for both production and consumption of natural gas. This case continues the current limitations on fuel switching and the use of alternative fuels, as well as the restrictions to supplies, particularly in the Rocky Mountain region and offshore lower-48 states. Despite these limitations, the Reactive Path case assumes industry will be able to discover and develop significant new quantities of gas in the lower-48 states and Canada, import very large volumes of LNG, and commercialize Arctic gas in a timely manner. The Reactive Path case also assumes that there is no major new environmental law or initiative that significantly reduces the ability of coal, nuclear, and hydroelectric power to provide electricity.

Even with these potentially optimistic assumptions, the Reactive Path outlook still results in a very tight balance of supply and demand. Overall natural gas demand continues to grow largely as a result of strong new power generation needs. Industrial demand is lower in response to higher prices and the tight supply and demand balance. Increasing natural gas demand is met primarily with growing LNG imports and Arctic gas developments, while robust prices are required to maintain production levels from indigenous lower-48 and Canadian sources. After development of Arctic resources, the value of gas relative to alternate fuels continues to grow in the Reactive Path case, implying a structural change in price projections for natural gas. The demand and supply components for the Reactive Path case are shown in Figures 47 and 48. The price range outlooks for the Reactive Path and Balanced Future cases are shown in Figure 49.



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

FIGURE 47
U.S. AND CANADIAN NATURAL GAS DEMAND — REACTIVE PATH



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

FIGURE 48
U.S. AND CANADIAN NATURAL GAS SUPPLY — REACTIVE PATH

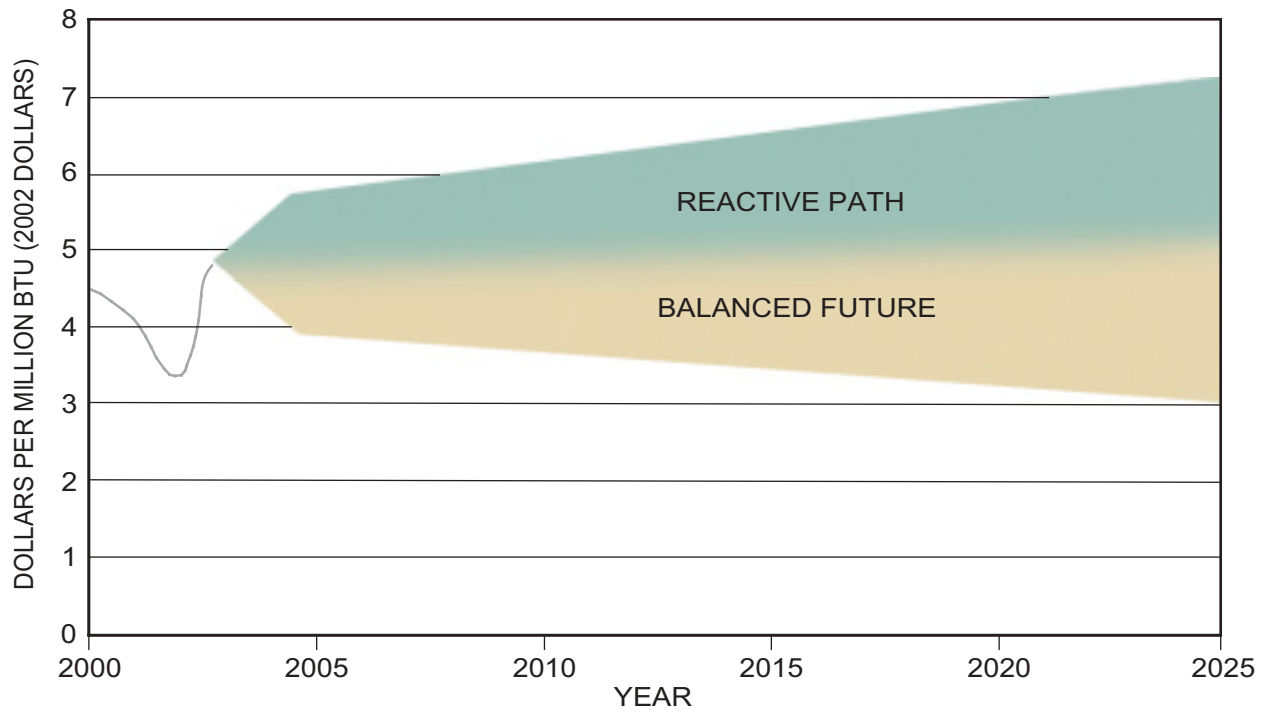


FIGURE 49
AVERAGE ANNUAL HENRY HUB PRICES

This outlook raises many questions and concerns. Many believe that market forces should better balance supply and demand, and that our inexperience with such a sustained high-price environment may be affecting our ability to model the response of supply and demand. For example, it is possible that such price signals could lead to periods of oversupply, as numerous high-volume, long-lead-time supply projects come on stream, potentially in an environment in which demand has been reduced by high prices. However, given the supply and demand assumptions inherent in the Reactive Path case, the NPC was unable to develop a credible case for such a balance without policy actions that encourage supply and give industrial consumers and power generators more options in their choice of fuel.

To evaluate these policy choices, the Balanced Future case was developed. This case incorporates government policies that encourage a more diverse but environmentally sound future fuel mix, and which would relieve some of the pressure placed on gas by existing regulations. As a result, this case increases renewable, coal, and oil generation capacity. This assumes a regulatory regime with respect to mercury that reduces retirements of coal-fired capacity, increases the output of existing nuclear facilities, and reduces retirement of existing oil/gas switchable capacity. Additionally, this case assumes a systematic re-introduction of fuel flexibility in both industrial and power generation applications; 25% of existing gas-fired capacity is retrofitted for oil backup, 25% of new gas-fired capacity includes oil backup capability, and industrial boilers return to the fuel-switching level of 28% by 2025. These assumptions incorporate control technologies to assure continued compliance with existing air quality regulations. Finally, this case assumes enhanced efficiencies in residential and commercial sectors due to enhanced building codes, smart controls, and efficient market mechanisms such as real-time pricing.

On the supply side, the Balanced Future case assumes that improvements will be made in permitting processes and access to resources, which allow an increased supply outlook to be achieved, both through indigenous production and more timely, increased LNG imports (an additional 2.5 BCF/D). Lower-cost domestic production is achieved through lifting of the OCS moratoria and by reducing the effect of access restrictions caused by restrictive conditions of approval in the Rocky Mountain area by 50% over a 5-year period. The net effect of these policy-related changes is to reduce the cost to consumers of providing similar quantities of gas. Figures 50, 51, and 49 show the demand, supply, and price range projections, respectively, for the Balanced Future case.

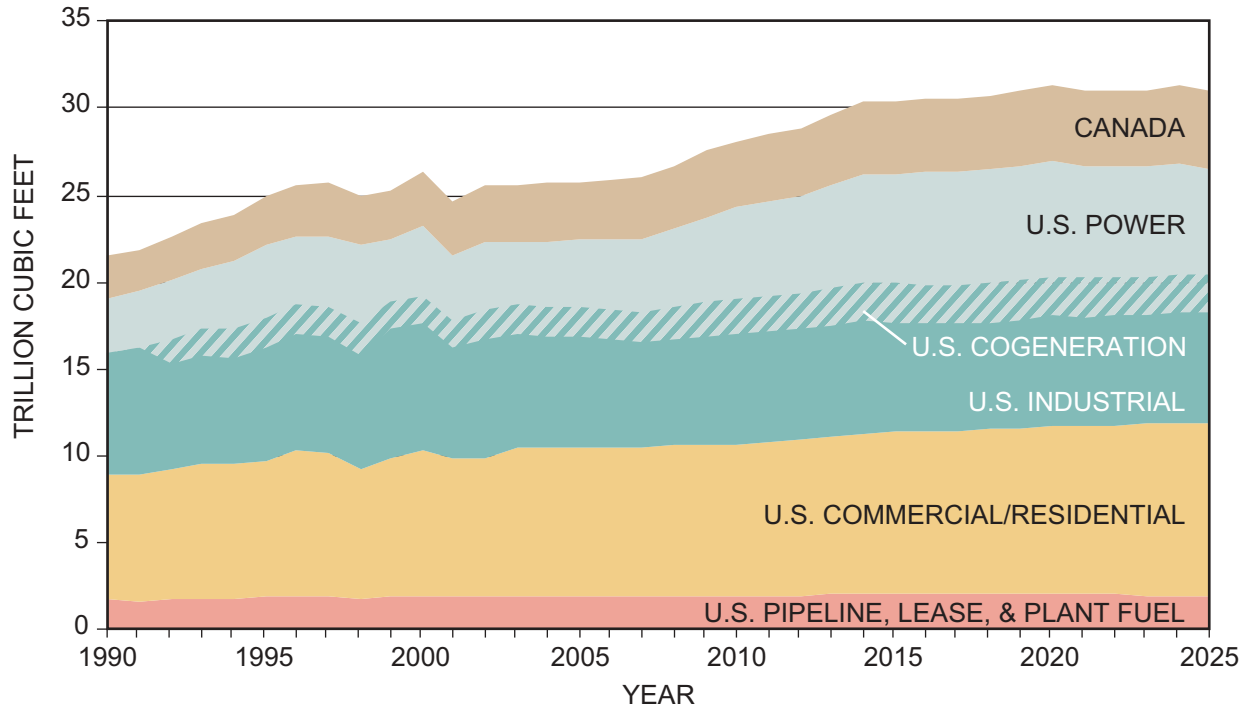


FIGURE 50
U.S. AND CANADIAN NATURAL GAS DEMAND — BALANCED FUTURE

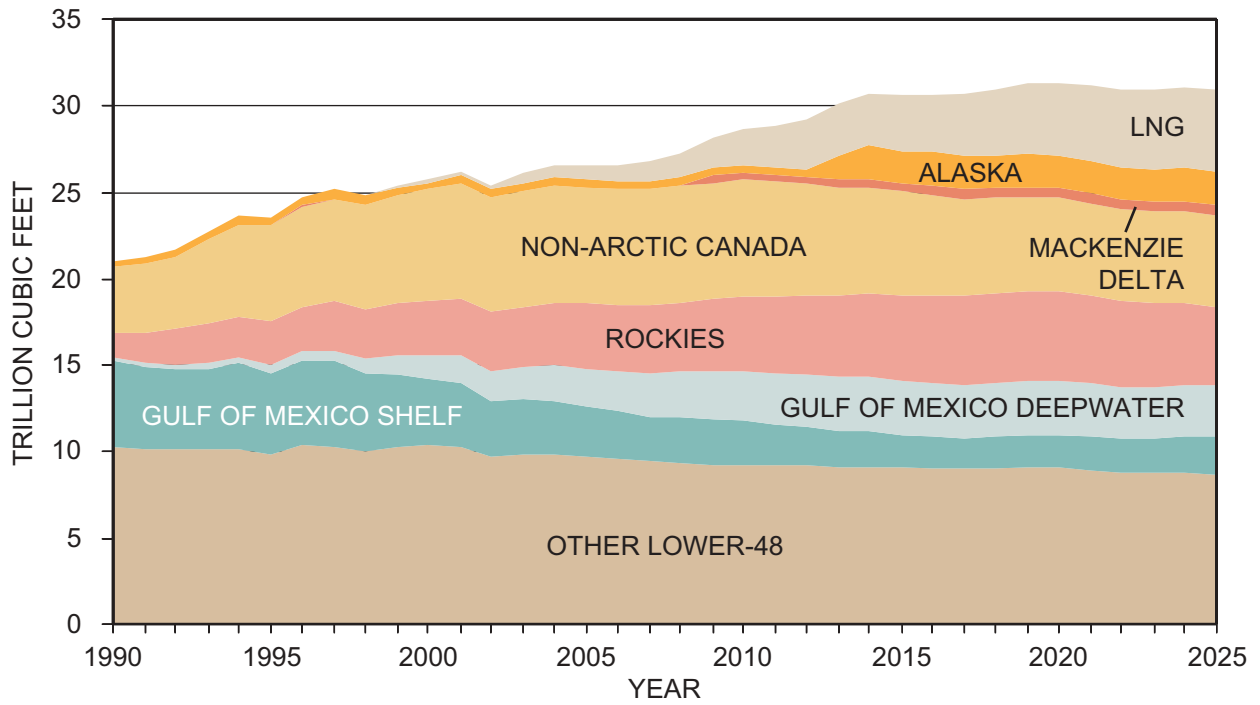


FIGURE 51
U.S. AND CANADIAN NATURAL GAS SUPPLY — BALANCED FUTURE

With lower cost supplies being made available, more demand can be satisfied, recognizing some demand being met by alternate fuels. It is particularly significant that more industrial demand for gas is satisfied in the Balanced Future case. Relatively small adjustments can make a big difference in achieving a comfortable supply/demand balance.

The NPC also evaluated cases that reflect even more difficult futures than the Reactive Path case, such as controls on carbon emissions and more limited access to gas resources. These evaluations are described in the Integrated Report. These assumptions clearly entail very high demand for gas, very tight supplies, and significant upward pressure on prices.

The NPC recognizes that this kind of analysis is sensitive to changes in assumptions. Any of a number of key variables – including economic growth, oil prices, resource base size, and technology development – can dramatically influence the outlook for future gas markets. Even recognizing those sensitivities, the fundamentals of the current situation are evident, especially for the next five years or so: indigenous supply is flat to declining, demand is growing, and there will be upward pressure on prices.

Capital Requirements

The NPC also evaluated the capital requirements of these outlooks. Almost \$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 & production sector (\$1.2 trillion) with the remaining 15% (\$0.2 trillion) spent on pipelines, storage, and distribution, as can be shown in Figures 52 and 53. These expenditures represent a significant increase over the 1990-2000 period for the exploration & 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.

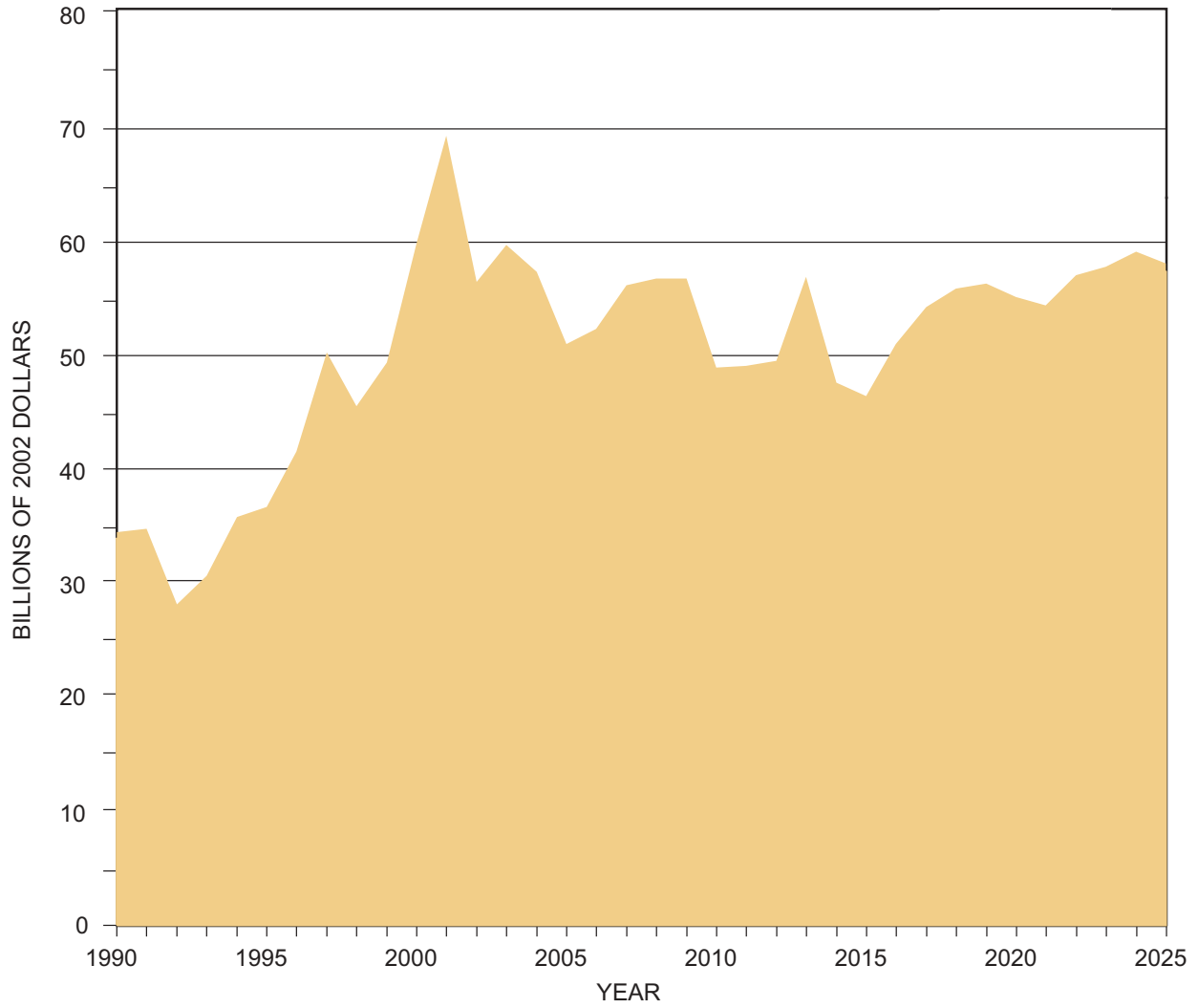


FIGURE 52
 U.S. AND CANADIAN EXPLORATION AND PRODUCTION
 CAPITAL EXPENDITURES — BALANCED FUTURE SCENARIO

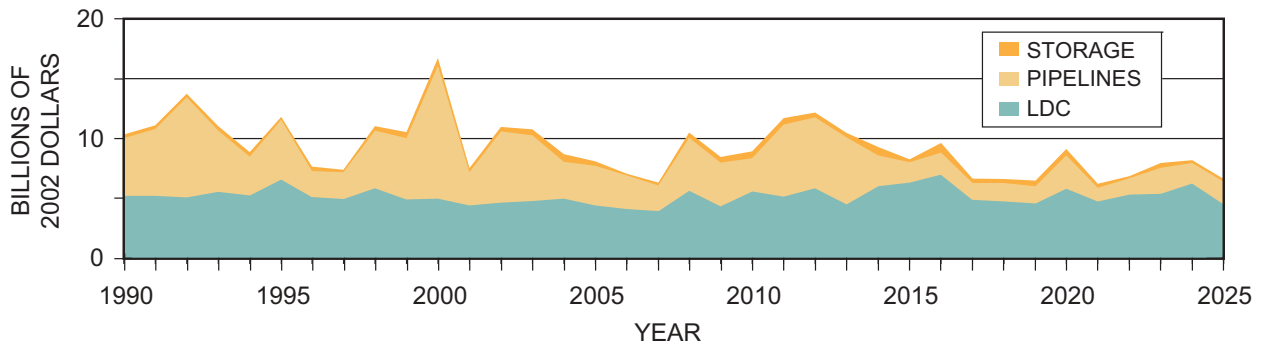


FIGURE 53
 U.S. AND CANADIAN INFRASTRUCTURE
 CAPITAL EXPENDITURES — BALANCED FUTURE SCENARIO

While a majority of the required capital will come from reinvested cash flow, industry will continue to need capital from the markets to fund the growth. To achieve this level of capital investment, industry must compete with other investment opportunities and deliver returns equal to or better than other S&P 500 companies. Some industry segments have not achieved this in the past and this presents a challenge for the future.

However, the 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 credit-worthy companies to complete the projects with acceptable economic returns.

Clearly a broad spectrum of industries and consumers will be affected by the policy choices ahead. The NPC's recommendations on how to achieve a Balanced Future are listed in the section that follows.

Recommendations

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. Key recommendations to assure long-term supply and a balanced fuel portfolio at reasonable cost fall into four strategic themes highlighted and summarized here:

- **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
- **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
- **Sustain and enhance natural gas infrastructure**
 - Provide regulatory certainty by maintaining a consistent cost-recovery and contracting environment and remove regulatory barriers to long-term capacity contracting and cost recovery of collaborative research
 - Permit projects within a one-year period using a "Joint Agency Review Process"
- **Promote efficiency of natural gas markets**
 - Improve transparency of price reporting
 - Expand and enhance natural gas market data collection and reporting.

North American natural gas resources have historically provided stable supplies, and will continue to supply the vast majority of the continent's needs. However, future needs will not be met by continued development of these resources alone, and a significant share of demand will be met with Arctic and global LNG resources. Natural gas provides about 25% of the continent's total energy needs and will be one of the vehicles for continued air quality improvements. However, as part of the balance between supply and demand, flexibility in current fuel use and diversity in future industrial and power generation fuels will be required. Following are details of NPC recommendations.

RECOMMENDATION 1: 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 recommendations 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 which were previously adopted to ensure 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 Organization (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 lowest cost and system reliability requirements.
- **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 Utilize 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 greater 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 sulfur oxides (SO_x), nitrogen oxides (NO_x), 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 SO_x and NO_x emissions, and provide phase-in timeframes 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 power plant 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 PUCs should provide rate treatment to recover fuel costs and increased fuel operating & 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 policies of state permitting agencies encourage liquid fuel back up 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 CO₂ 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 CO₂ 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 CO₂ emissions in industrial processes and power generation. The most significant impact of CO₂ 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 CO₂. 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 CO₂ 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, as well as efficient use of natural gas should also be supported.

RECOMMENDATION 2: INCREASE SUPPLY DIVERSITY

The lower-48 states currently supply about 80% of the natural gas consumed in the United States. Imports, primarily from Canada, provide about 20%, with LNG currently accounting for about 1% of total U.S. demand. While North America has very sizable natural gas resources, supplies from them are unlikely to meet projected demand growth. As a result, new sources of supply must enter the market, and government policies must remove impediments that inhibit delivery of the additional supplies.

These new supply sources can be broadly characterized as:

- Lower-48 resources that are currently restricted or face permitting impediments
- North American Arctic gas
- Increased global 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 summarized below.

Increase Access and Reduce Permitting Impediments to Development of Lower-48 Natural Gas Resources

Land-use policies of federal, state, and local governments have not kept pace with technological advances that allow for exploration and production while protecting environmentally sensitive areas by reducing the number and size of onshore drilling sites and offshore production facilities.

In addition, the federal government has continued to set federal lands off-limits to development through legislation, executive orders, and regulatory and administrative decisions. Moreover, an increasingly complex and costly maze of statutory and regulatory requirements effectively places a significant portion of additional lands off-limits to development, even though they are technically available for leasing.

The trend toward increased land restrictions and set-asides has been especially troublesome in the Rocky Mountain area. The NPC estimates that 25% of the remaining technical resource in the lower-48 underlies the Rocky Mountain area, and that 29% (70 TCF) is currently off-limits to exploration and development, either due to statutory leasing withdrawals or to the cumulative effect of conditions of approval associated with exploration and development activities. Set asides are common in the OCS, where virtually the entirety of the Atlantic and Pacific coasts are off limits due to executive order and most of the Eastern Gulf of Mexico is off limits due to administrative decisions. Most recently, further restrictions were set in place when the original boundaries of the 2001 OCS Lease Sale 181 were reduced to include only 25% of the originally proposed acreage.

Experience shows that natural gas development in areas similar to those restricted in the United States can be undertaken with appropriate environmental safeguards. The use of state-of-the-art drilling and production technologies plays a key role in those developments. Mountainous areas of western Canada, which face fewer federal and provincial barriers to access, have been successfully developed without compromising the environment. The OCS of Eastern Canada is being successfully and safely developed, and the governments of British Columbia and Canada are reviewing the potential to open offshore Western Canada for exploration and development.

The NPC recognizes and supports the obligations of state and federal governments to protect endangered species, historical resources, and the environment. At the same time, the NPC sees the need for government to balance those considerations with the need to increase supplies of natural gas.

The following public-policy recommendations are designed to foster balance by streamlining processes, improving communications, enhancing cooperation, acknowledging proven technological advances, and reducing unnecessary costs and delays for the industry and the various government agencies and non-governmental organizations involved with addressing these issues. The recommendations are segregated into onshore and offshore.

Onshore – Increase Access (Excluding Wilderness Areas and National Parks) and Reduce Permitting Costs/Delays 50% over Five Years

The following recommendations will reduce permitting response time by streamlining processes, instituting performance metrics, clarifying statutory authority, and ensuring adequate agency resourcing.

- **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 (NEPA).** 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 establish 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

Resources in the Eastern Gulf of Mexico and off the Atlantic and Pacific coasts are currently not accessible due to leasing moratoria. The following recommendations are proposed for these stranded resources:

- **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.

Currently accessible areas of the Gulf of Mexico provide the United States with 23% of its natural gas supply. The following recommendations are proposed to ensure the continued supply of this critical resource:

- **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.

Enact Enabling Legislation in 2003 for an Alaska Gas Pipeline

The Arctic regions of Alaska and Northwestern Canada contain significant volumes of discovered gas resources, which have the potential to supply North America with 8% of projected demand in 2015. While these resources were discovered over 30 years ago, several hurdles (costs, permitting, state fiscal certainty, market risks) have prevented their development. 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.

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.

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.

Process LNG Project Permit Applications Within One Year

The North American resource base has met the natural gas demands of Canada, Mexico, and the United States to date. However, this is not expected to continue and increased imports of LNG will be required to meet growing demand. LNG provides access to the global supply of natural gas, which has been estimated to contain over 30 times the resource volume of North America. Advances in liquefaction and transportation technologies have driven down the unit cost of LNG by 30% over the past decade and LNG is now viewed as cost competitive with domestic supplies. To meet future demand, the NPC is projecting LNG imports will grow to become 10-15% of the U.S. natural gas supply by 2020. This will require the construction of seven new regasification terminals and expansions of three of the four existing terminals.

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 FERC (positive changes on regulatory process, active leadership role in recent reactivation of Cove Point and Elba Island, and implementation of Memorandums of Understanding [MOUs] 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 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 (OEMs). 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 forty 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 team 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-related 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.

RECOMMENDATION 3: 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 construction 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 Using a “Joint Agency Review Process.” Projects that Connect Incremental Supply and Eliminate Market Imbalances Should Be the Highest Priority and Be 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 would require the up-front involvement by all interested/concerned parties including appropriate jurisdictional agencies. This will allow 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: "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" of this report, this practice is impairing the investment in infrastructure. The result is that regulatory practices that limit long-term contracts 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 a significantly more flexible facilities design based upon peak hourly flow requirements, i.e., 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 expenses by the operators who fund necessary collaborative infrastructure research.

RECOMMENDATION 4: PROMOTE EFFICIENCY OF NATURAL GAS MARKETS

North American natural gas markets are relatively efficient and effective but can be improved. Government should allow market forces to work in addressing the efficiency of markets, particularly as related to liquidity. Recommendations to improve the market's efficiency and effectiveness are summarized below.

Improve Transparency of Price Reporting

Federal and state regulators should support transparency in market transactions by encouraging market participants to report transactions voluntarily to price reporting services. The Council recognizes and supports the FERC's ongoing efforts to improve market transparency and voluntary price reporting.

Expand and Enhance Natural Gas Market Data Collection and Reporting

- DOE's Energy Information Administration should coordinate efforts with state and other federal agencies (MMS) to improve data-collecting processes such that accurate monthly production and consumption data are available within three months.
- DOE/EIA should extend the weekly natural gas storage survey to encompass all storage fields to ensure adequate data necessary to analyze the changing nature of peak demands in winter and power-driven demand in the summer. The current survey method is predicated on reservoir size and omits too many salt dome facilities with their high cycling capability.
- DOE/EIA should reduce the lag in their reported natural gas data series by one month, with a target of storage data one month in arrears and two months for supply and demand data. Involvement of the MMS to provide timely production data is critical given the key role Gulf of Mexico production plays in the total U.S. supply.

STEWARDSHIP OF RECOMMENDATIONS

In order to monitor the progress of implementing the NPC study recommendations, it is proposed that the DOE lead a workshop by May 2004 with government stakeholders and industry representatives. This workshop would review the steps taken for each of the study recommendations and identify additional actions required to achieve the objectives of the study.

It is also proposed that the DOE lead a workshop by year-end 2004 to review actual supply and demand performance and compare with the study outlook. This workshop would highlight any performance deviations from the study projections and identify potential implications for any such changes.

FUTURE WORK AND STUDIES

The NPC study was a comprehensive analytical review of the North American natural gas market, including detailed assessments of supply sources, demand outlooks, and infrastructure requirements. While conducting the study, opportunities for additional activities were identified that could build on the study analysis and position the NPC in the event another major study of North American natural gas is undertaken. Areas for future work include the following.

Resource Base Assessment

- **Rockies Nonconventional Assessment.** There currently exist significant differences between published assessments of the Rockies nonconventional resource. This is the region of the lower-48 states with the largest remaining resource potential and also the largest range of uncertainty. It is proposed that a study be initiated in 2004, involving the DOE, USGS, and industry, to better understand the differences in assessments and see if a more consistent assessment can be developed.
- **Resource Assessment Methodology.** Resource assessments are conducted by many organizations using various methodologies. The resource is generally categorized as proved reserves, future appreciation of the proved reserves in producing fields, and undiscovered resource potential. It is proposed that a study be initiated in 2004, involving the DOE, USGS, MMS, and industry to improve the understanding of the various methodologies with an objective of establishing a preferred approach for future assessments. This would include methodologies for assessing both the technical and commercial resource base.
- **Resource Base Collaboration.** The USGS and MMS conduct periodic assessments of the U.S. resource base. During development of the NPC study resource base, the benefits of industry and government collaborating on such assessments was a key learning and it is proposed that such collaborations continue for future updates to improve alignment. In addition, since the last complete assessment of the U.S. resource base by the USGS is from 1995, it is suggested that the USGS establish a new comprehensive reference assessment utilizing the recent regional updates.
- **DOE/EIA Energy Outlooks.** The DOE's EIA conducts annual energy outlooks for the United States, utilizing a methodology with common components to the NPC study. It is proposed that appropriate findings from the NPC study be incorporated into future annual energy outlooks to improve alignment of outlooks. Initial collaboration is currently underway and is expected to continue past the completion of the study.

Econometric Modeling Efforts

As part of the study, a modeling team was created to construct a comprehensive dynamic equilibrium model of the North American natural gas and power markets. This work advanced the NPC's ability to model the natural gas market. To build on these efforts, the following are proposed:

- **Model Availability.** Work is expected to continue by the modeling team beyond the completion of the study to finalize the modeling effort and to make the model available to NPC members and potentially the DOE if desired.
- **Data Maintenance.** Extensive efforts went into building the supply components of the model. It is proposed that the USGS assume responsibility for maintaining the resource assessments and supply curves in the model as updates become available.

Gas and Power Demand Data Collection and Reporting for Industrial Processes and Power Generation

- **EIA Surveys.** The EIA should conduct two annual surveys, one for power generation and one for industrial applications. These surveys should target the underlying attributes of the industry's physical ability to switch fuel and its actual practice in switching. Units that can switch should be categorized. For example, the EIA should modify its Form 860 to:
 - Reflect most recent date any alternate fuel was consumed for purposes other than testing and which of the listed fuels was consumed
 - Indicate whether alternate fuel usage is limited by permit; and if so, the approximate number of hours capable of being used annually
 - Specify oil storage capability and average inventory when it is categorized as the alternate fuel.
- **North American Reliability Council Reliability Assessments.** The North American Reliability Council should add natural gas supply issues to its regional assessments for reliability purposes.
 - Alternate fuel capabilities should be identified and reported.
 - Gas-fired only capacity should be identified as to percentage of megawatt capacity with firm transportation contracted.

LNG Global Assessment

Given the importance of LNG in North America's natural gas future, DOE should sponsor a follow-on study to assess the worldwide market dynamics for LNG, and the inter-relationships with North American supply and demand. Work should focus on developing a better understanding of the resource bases, prospects for development of various overseas supplies, cost competitiveness, and the possible role for government policies to encourage market-driven development. The LNG summit planned by DOE for this fall would be an appropriate starting point for such an effort, which should aim for a Fall 2004 delivery.

Appendices

Appendix A

**Request Letter
and**

**Description of the
National Petroleum Council**



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.

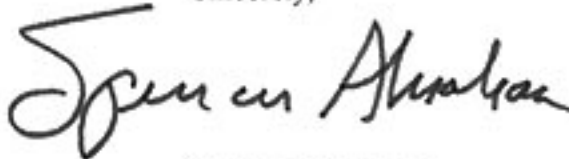
Considerable change has occurred in natural gas markets since the Council's 1999 study, among these being new concerns over national security, a changed near-term outlook for the economy, and turbulence in energy markets based on perceived risk, price volatility, fuel switching capabilities, and the 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,

A handwritten signature in black ink, appearing to read "Spencer Abraham". The signature is written in a cursive, flowing style with a large initial "S".

Secretary Abraham

NATIONAL PETROLEUM COUNCIL BACKGROUND INFORMATION ON 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 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 include:

- *U.S. Arctic Oil & Gas* (1981)
- *Environmental Conservation – The Oil & Gas Industries* (1982)
- *Third World Petroleum Development: A Statement of Principles* (1982)
- *Petroleum Inventories and Storage Capacity* (1983, 1984)
- *Enhanced Oil Recovery* (1984)
- *The Strategic Petroleum Reserve* (1984)
- *U.S. Petroleum Refining* (1986)
- *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.

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Appendix B

Study Group Rosters

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- Modeling Team
- Communications Team

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- Power Generation Subgroup
- Residential & Commercial Subgroup
- Industrial Utilization Subgroup

Supply Task Group

- Resource Subgroup
- Technology Subgroup
- Environmental/Regulatory/Access Subgroup
- LNG Subgroup
- Arctic Subgroup

Transmission & Distribution Task Group

- Transmission Subgroup
- Distribution Subgroup
- Storage Subgroup

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The National Petroleum Council wishes to acknowledge the numerous other individuals and companies who participated in some aspects of the work effort through workshops, outreach meetings and other contacts. Their time, energy, and commitment significantly enhanced the study and their contributions are greatly appreciated.

Acronyms and Abbreviations

| | |
|-----------------|--|
| APD | application for permit to drill |
| BCF | billion cubic feet |
| BCF/D | billion cubic feet per day |
| Btu | British thermal unit |
| CNG | compressed natural gas |
| CO ₂ | carbon dioxide |
| DOE | U.S. Department of Energy |
| EEA | Energy and Environmental Analysis, Inc. |
| EIA | Energy Information Administration |
| FERC | Federal Energy Regulatory Commission |
| GDP | Gross Domestic Product |
| GW | gigawatts |
| LDC | local distribution company |
| LNG | liquefied natural gas |
| MACT | Maximum Achievable Control Technology |
| MM | million |
| MMBtu | million British thermal units |
| MMCF | million cubic feet |
| MMCF/D | million cubic feet per day |
| MMS | Minerals Management Service |
| MOUs | Memorandums of Understanding |
| NEPA | National Environmental Policy Act |
| NGL | natural gas liquid |
| NGPA | National Gas Policy Act |
| NO _x | nitrogen oxides |
| NPC | National Petroleum Council |
| OCS | Outer Continental Shelf |
| PIFUA | Powerplant and Industrial Fuel Use Act of 1978 |
| PUC | Public Utility Commission |
| RTOS | Regional Transmission Organizations |
| SO _x | sulfur oxides |
| TCF | trillion cubic feet |
| USGS | United States Geological Service |
| WCSB | Western Canadian Sedimentary Basin |

Glossary

Access

The legal right to:

1. Drill and develop oil and natural gas resources
2. Build associated production facilities
3. Build transmission and distribution facilities

on either public and/or private land.

Basis

The difference in price for natural gas at two different geographical locations.

Capacity, Peaking

The capacity of facilities or equipment normally used to supply incremental gas or electricity under extreme demand conditions. Peaking capacity is generally available for a limited number of days at maximum rate.

Capacity, Pipeline

The maximum throughput of natural gas over a specified period of time for which a pipeline system or portion thereof is designed or constructed, not limited by existing service conditions.

City Gate

The point at which interstate and intrastate pipelines sell and deliver natural gas to local distribution companies.

Cogeneration

The sequential production of electricity and useful thermal energy from the same energy source, such as steam. Natural gas is a favored fuel for combined-cycle cogeneration units, in which waste heat is converted to electricity.

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.

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 stated conditions of temperature, pressure, and water vapor.

Distribution Line

Natural gas pipeline system, typically operated by a local distribution company, for the delivery of natural gas to end users.

Electric

A sector of customers or service defined as generation, transmission, distribution, or sale of electric energy.

End-User

One who actually consumes energy, as opposed to one who sells or re-sells it.

FERC (Federal Energy Regulatory Commission)

The federal agency that regulates interstate gas pipelines and interstate gas sales under the Natural Gas Act.

Firm Customer

A customer who has contracted for firm service.

Firm Service

Service offered to customers under schedules or contracts that anticipate no interruptions, regardless of class of service, except for force majeure.

Fuel Switching

Substituting one fuel for another based on price and availability. Large industries 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.

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.

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 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 specified franchise area.

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 which are as yet untested with the drillbit.

Nonconventional Gas

Natural gas produced from coalbed methane, shales, and low permeability reservoirs. Gas production from these environments typically requires a different, sometime higher, level of technology than gas production from conventional reservoirs.

Peak-Day Demand

The maximum daily quantity of gas used during a specified period, such as a year.

Peak Shaving

Methods to reduce the peak demand for gas or electricity. Common examples are storage and use of LNG.

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.

Regional Transmission Organization (RTO)

Voluntary organization of 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 household establishments which consume energy primarily for space heating, water heating, air conditioning, lightning, refrigeration, cooking, and clothes drying.

Revenue

The total amount 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.