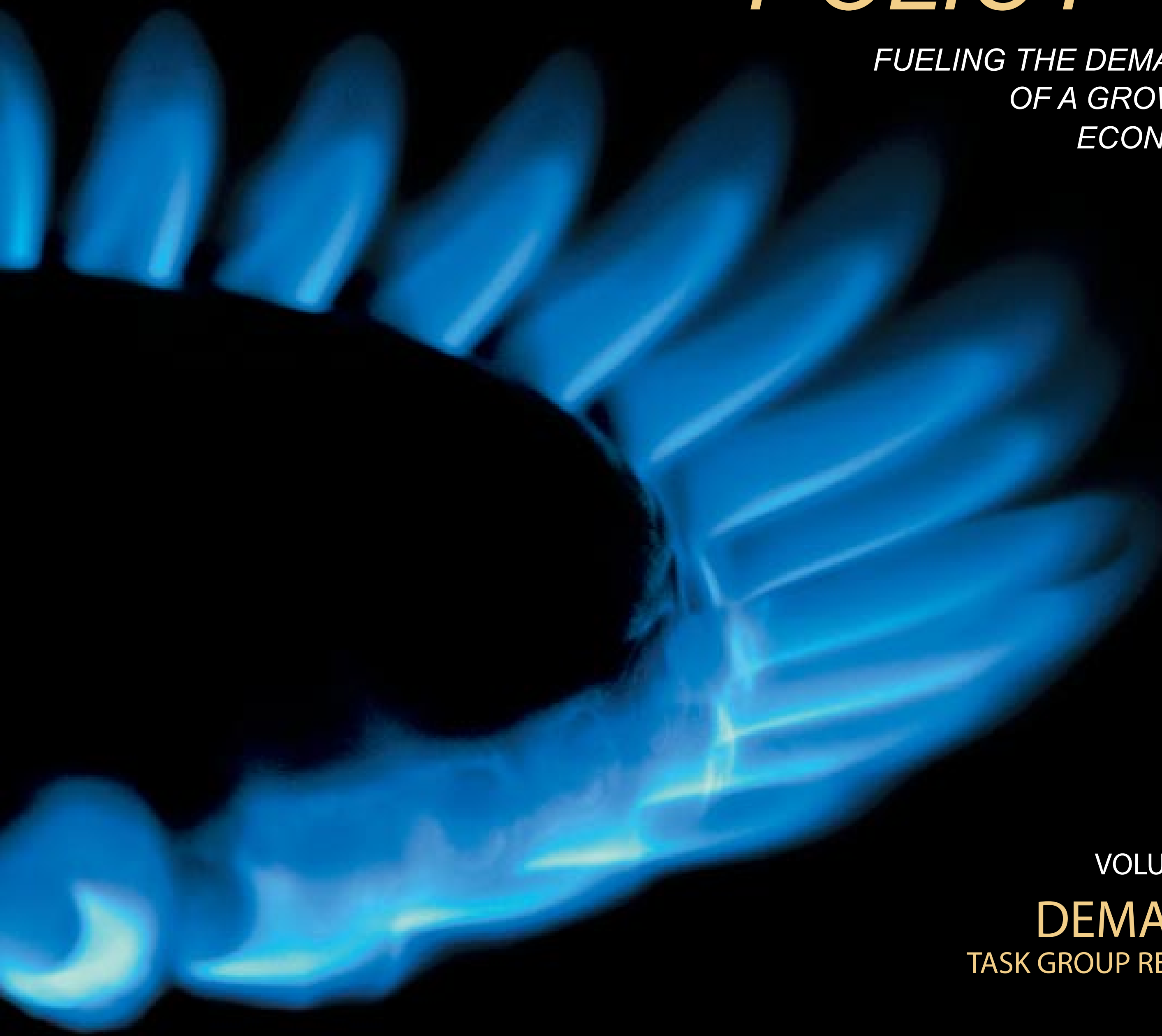
BALANCING NATURAL GAS POLICY

FUELING THE DEMANDS OF A GROWING ECONOMY



VOLUME III

DEMAND

TASK GROUP REPORT

NATIONAL PETROLEUM COUNCIL

SEPTEMBER 2003

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

NATIONAL PETROLEUM COUNCIL

Bobby S. Shackouls, *Chair*
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U.S. DEPARTMENT OF ENERGY

Spencer Abraham, *Secretary*

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

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PREFACE

Study Request

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

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

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

Study Organization

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

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

This volume of the report was prepared by the Demand Task Group and its subgroups. David J. Manning, Senior Vice President, KeySpan Corporation, chaired the Demand Task Group, and Mark R. Maddox, Principal Deputy Assistant Secretary, Fossil Energy, U.S. Department of Energy, served as Government Cochair. The Demand Task Group was assisted by four subgroups:

- Economics and Demographics Subgroup
- Power Generation Subgroup
- Residential and Commercial Subgroup
- Industrial Utilization Subgroup.

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

Study Approach

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

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

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

The Transmission & Distribution Task Group analyzed existing and potential new infrastructure. Their analysis was based on the work of three subgroups (Transmission, Distribution, and Storage). Industry participants undertook an extensive review of existing and planned infrastructure capacity in North America.

Their review emphasized, among other things, the need to maintain the current infrastructure and to ensure its reliability. Participants in the Transmission & Distribution Task Group included representatives from U.S. and Canadian pipeline, storage, marketing, and local distribution companies as well as from the producing community, the Federal Energy Regulatory Commission, and the Energy Information Administration.

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

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

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

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

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

- A detailed play-based approach to assessment of the North American natural gas resource base, using regional workshops to bring together industry experts to update existing assessments. This was used in two detailed descriptive models, one based on 72 producing regions in the United States and Canada, and the other based on 230 supply points in the United States, Canada, and Mexico. Both models distinguished between conventional and nonconventional gas and between proved reserves, reserve growth, and undiscovered resource.

- Cost of supply curves, including discovery process models, were used to determine the economically optimal pace of development of North American natural gas resources.

- An extensive analysis of recent production performance history, 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.

Study Report

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

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

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

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

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

  – Volume III, *Demand Task Group Report*, provides in-depth discussions and analyses of economic and demographic assumptions; consumption in the industrial, residential, commercial, and electric power sectors; and uncertainties/sensitivities.

  – Volume IV, *Supply Task Group Report*, provides in-depth discussions and analyses of resource assessment, cost methodology, production performance, technology improvements, access issues, and arctic developments.

  – Volume V, *Transmission & Distribution Task Group and LNG Subgroup Reports*, provides in-depth discussions and analyses of LNG imports and transmission, distribution, and storage infrastructures. (While the LNG Subgroup operated under the Supply Task Group, its report is provided with that of the Transmission & Distribution Task Group due to the interrelationship of their infrastructures and issues.)

– *CD-ROMs* are available as part of the documentation of the Task Group Reports. One CD contains further input/output on a regional basis for the study's principal modeling activities. That CD also contains digitized maps, which were used in assessing the potential impact of conditions of approval for access to key Rocky Mountain resource areas. Another CD contains the input data developed by the NPC for use in the study's supplemental modeling activities.

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

Retrospectives on 1999 Study

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

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

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

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

CHAPTER 1

INTRODUCTION

This volume describes the methods used and results obtained by the Demand Task Group in developing an outlook for North American natural gas demand as part of the overall, integrated NPC effort. The work of the Demand Task Group was performed in concert with the Supply and Transmission & Distribution Task Groups, as well as the several issue-specific working groups constituted in the process of the NPC study of natural gas. This was done to ensure that demand for natural gas was assessed within the context of its interaction with supply and the effects of both infrastructure and energy markets – importantly, for natural gas, "competing" fuels, and electric power.

The Demand Task Group was led, and its activities coordinated, by representatives of KeySpan Corporation. The study effort was carried out through four basic working groups: Economics and Demographics, led by Shell Trading Gas and Power; Power Generation, led by American Electric Power; Industrial Consumers, led by Process Gas Consumers; and Residential and Commercial Consumers, led by KeySpan Corporation.

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

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

The Economics and Demographics Subgroup developed critical assumptions necessary to conduct econometric and other analyses for the Demand, Supply, and Transmission & Distribution Task Groups. These assumptions included major North American economic growth parameters and alternate fuel prices, mainly U.S. coal and oil prices. This group reviewed interim and final modeling results for logic and consistency and identified alterations to key assumptions.

The Power Generation Subgroup focused its efforts on understanding the factors that are likely to drive capacity and utilization decisions of existing and new generation. A variety of electric power generators from various regions was represented or consulted in this analysis, and workshops were held in New Orleans, Phoenix, and Baltimore. A suite of cost factors was developed for the construction and utilization, or dispatch, of generation capacity by fuel type. The team performed extensive analyses on investment criteria;

likely technology advances; outlooks for coal, nuclear, and hydroelectric capacity; the potential effects of Regional Transmission Organizations; the effects of state, provincial, and local regulations and standards; and practices governing the flexibility of power generators to substitute fuels.

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

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

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

I. The Role of Natural Gas in the North American Economy

Natural gas has played a key role in the North American energy picture during the last 50 years. Natural gas was about 16% of the total energy consumption in the early 1950s. As it became a widespread fuel for home heating, and a significant fuel and feedstock in industrial applications, its share of total energy grew to nearly 32% in the early 1970s. During the early 1980s, however, natural gas use as a percentage of total energy consumption dropped to about 23%. Gas consumption declined due, in part, to a period of relatively high gas prices, gas shortages, and curtailments that led to government policies discouraging the use of gas for certain applications. Since the mid-1980s, natural gas has maintained approximately a 25% share of total energy consumption while its use has grown by about 2.1% per year. Figure D1-1 shows natural gas in relation to the other primary sources of energy for the United States.

Gas is a major source of energy in every sector of the economy except the transportation sector, as depicted in Figure D1-2. It has become a highly desirable fuel and enjoys significant market share due to its ease of use, historical competitive costs, and most recently its desirable environmental impact characteristics of low emissions.

Over the past decade, the power generation sector has been increasing its demand for natural gas. The drivers for this growth include increasing electricity demand, the rapid buildup of gas-fired generating capacity, greater efficiency due to technological advances in gas-fired generation, and more stringent environmental policies favoring the relatively cleaner-burning gas-based generation. Figure D1-3 shows historical power generation capacity additions, including assumptions for 2004 and 2005. The large quantity of natural gas-fired generation capacity installed between 1998 and 2005 underpins the

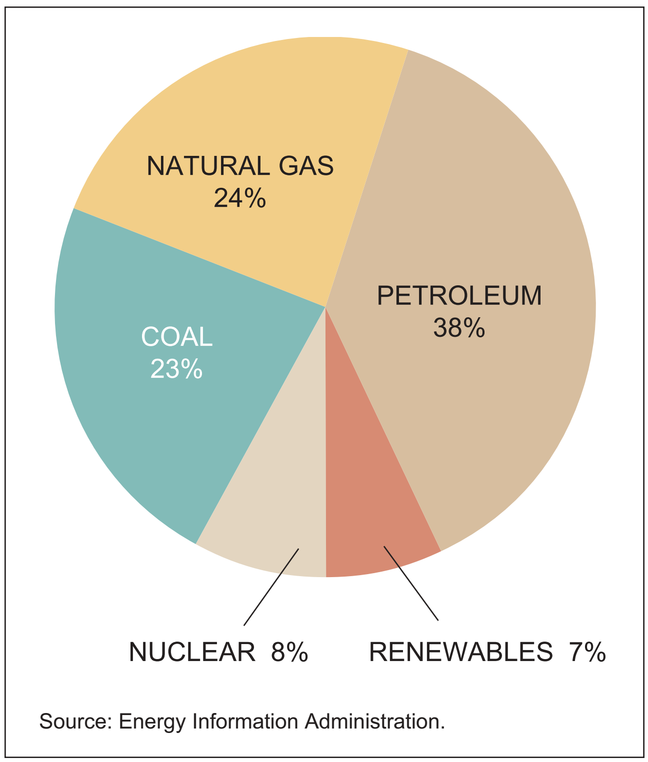


Figure D1-1. Average Annual Energy Use, 1997-2001
97 Trillion Cubic Feet per Year (Equivalent)

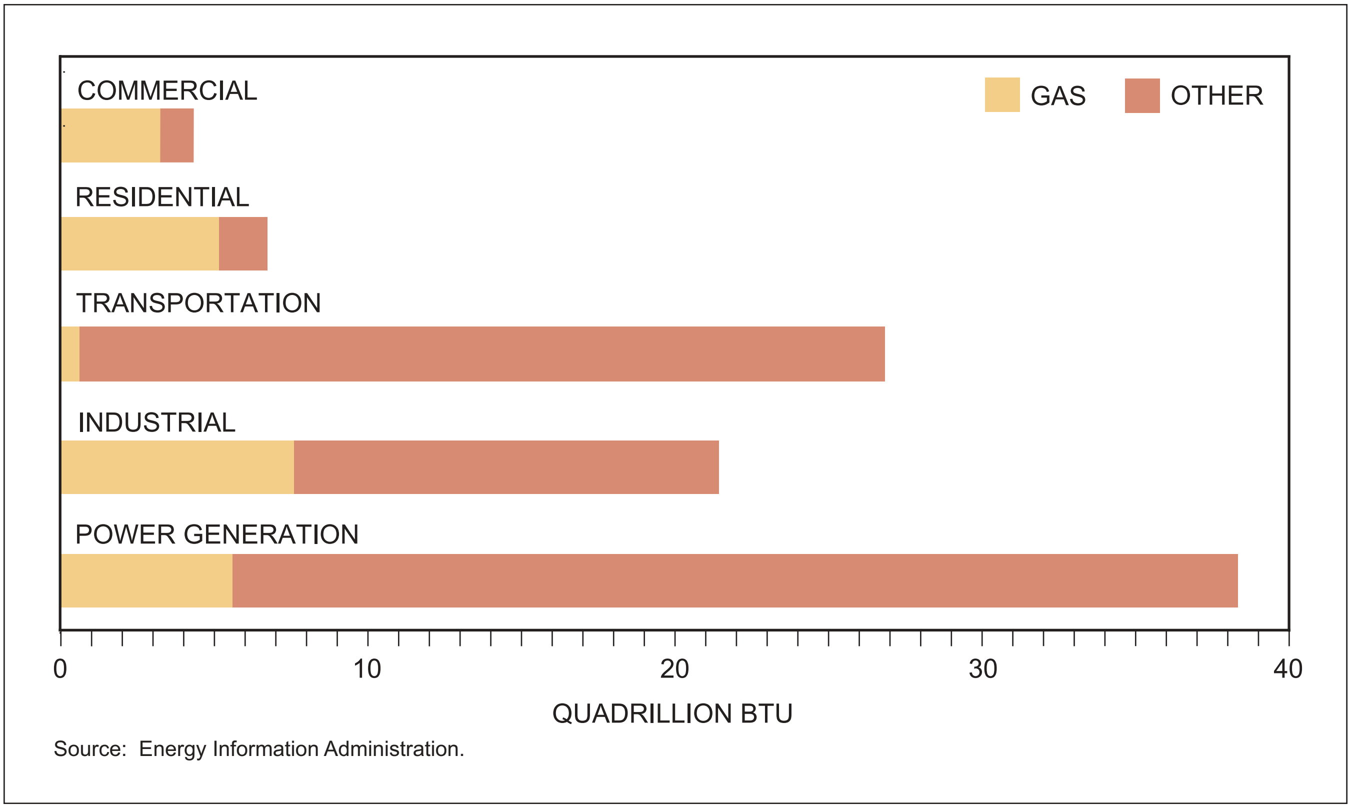


Figure D1-2. U.S. Energy Use by Sector, 2002

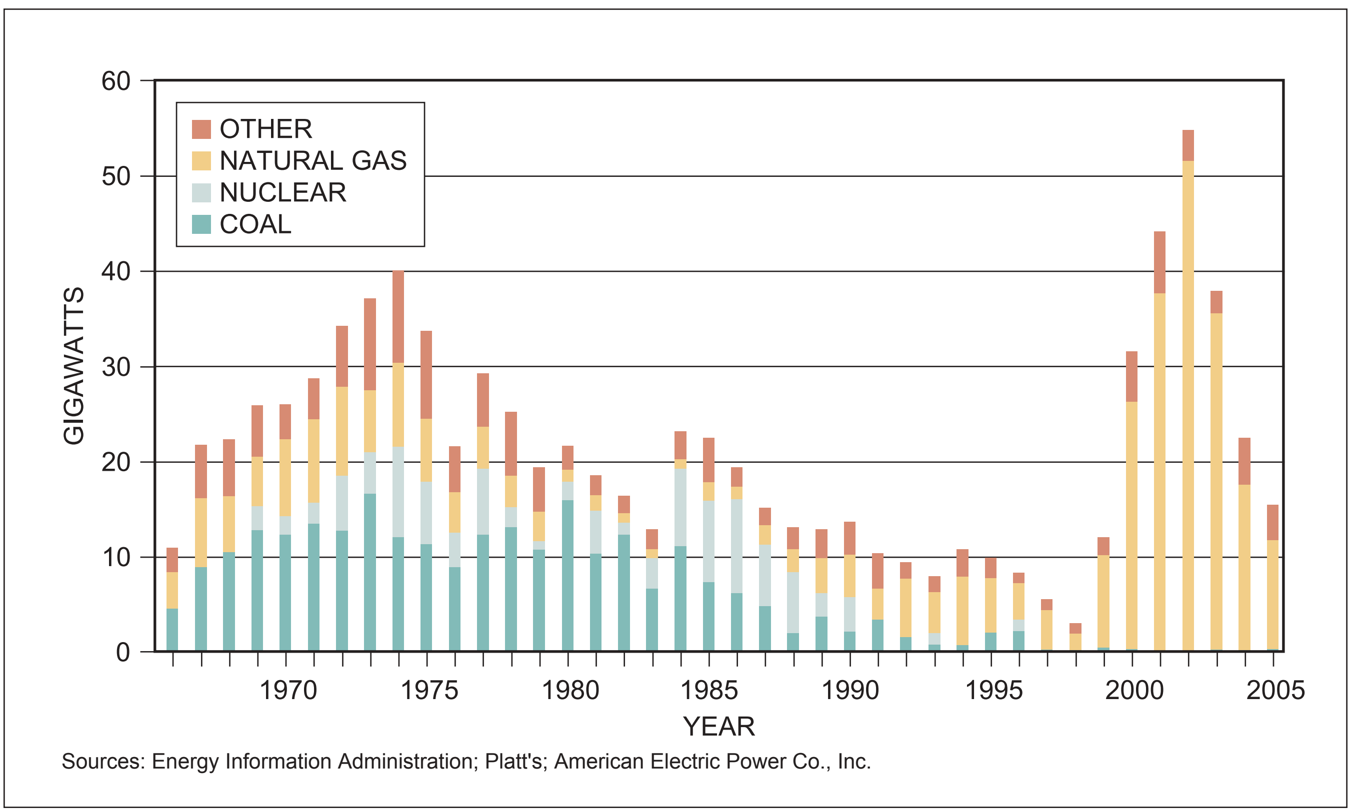


Figure D1-3. Electric Power Generation Capacity by Fuel Type outlook for significant gas demand growth over much of the 2005-2025 period, as depicted in Figure D1-4 for the Reactive Path scenario.

II. Key Study Results

The NPC study participants used the modeling framework of EEA to describe the behavior and interactions of supply, demand, and infrastructure. The overall study effort incorporated a "bottom-up" analysis of each sector, in which data and information were developed and/or assessed to validate the behavior of these sectors. After testing these models, the NPC study participants chose to develop outlooks for future supply, demand, and infrastructure through the use of two "base case" scenarios, described below, and multiple sensitivity analyses, described in Chapter 6 of this volume and Chapter 9 of the Integrated Report. It is through the "lens" of these scenarios and sensitivity analyses that the results of this study, and the demand-related aspects in this volume, should be considered and used.

The two "base case" scenarios of future supply and demand move beyond what the NPC study participants considered the "status quo" because a status quo approach to natural gas policy would not be sustainable. In the view of the study participants, a "status quo" approach would discourage economic fuel choice, new supplies from traditional basins and Alaska, and new LNG terminal capacity. Both "base case" scenarios require actions by policy makers to remove impediments to rational economic choices and by industry stakeholders to effect change.

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

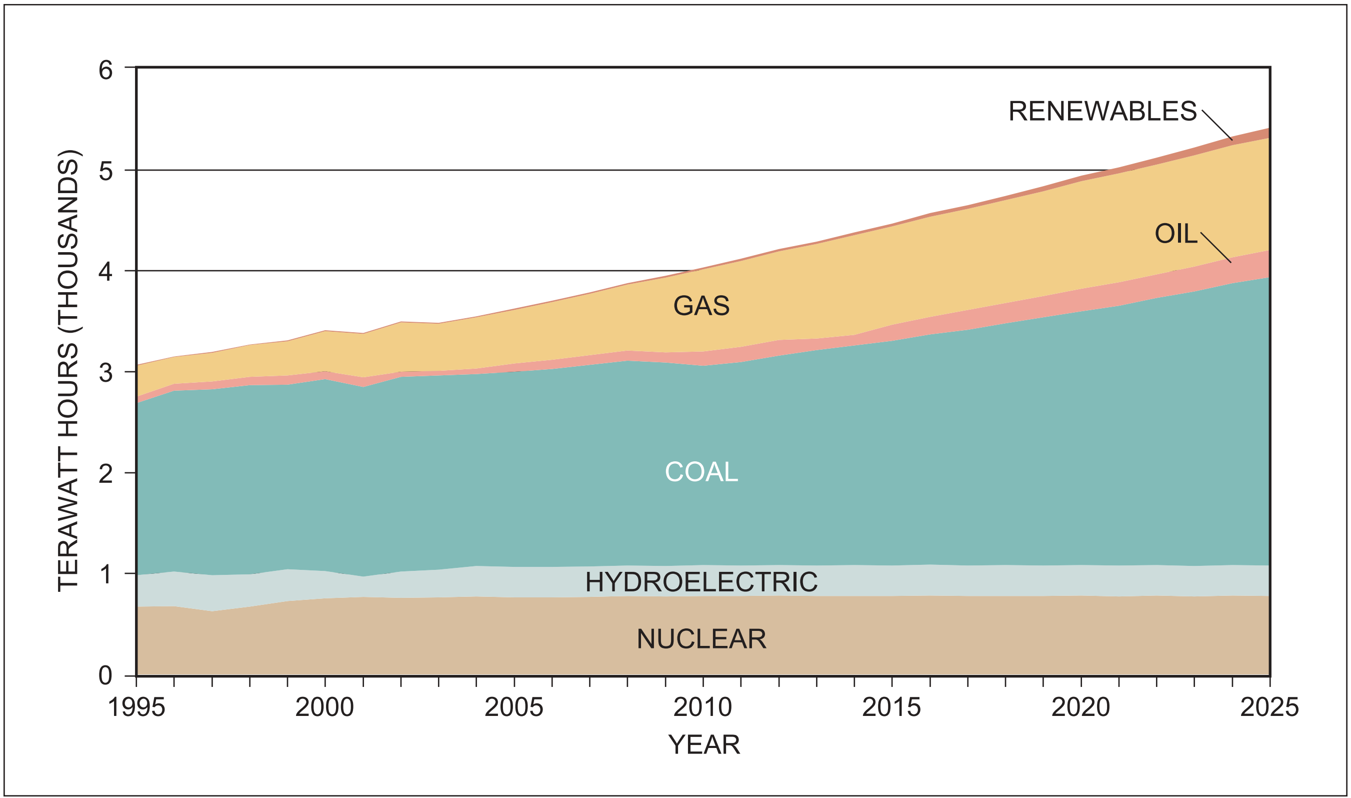


Figure D1-4. Electricity Generated by Fuel Type – Reactive Path Scenario

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

The basic assumptions of the two "base case" scenarios are summarized as follows:

Reactive Path Scenario

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

Balanced Future Scenario

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

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

Federal Reserve Board Chairman Alan Greenspan characterized 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 while adhering to current environmental standards. On the supply side, barriers to development of new natural gas sources are progressively lowered, both for domestic and imported natural gas. The result is a market with lower gas prices and lower volatility due to enhanced supply and more flexible demand. This scenario results in a better outcome for North American consumers than the "Reactive Path."

It would be possible to construct many different scenarios, or visions of the future, to illustrate the NPC analysis. For example, neither the Reactive Path nor the Balanced Future scenario reflects the effect of *not* developing major new LNG import facilities or the Arctic gas pipelines; neither scenario reflects actions that might severely limit CO_2 emissions or the permitted carbon content of fuels; and neither scenario attempts to speculate on ground-breaking new technology that could fundamentally alter demand patterns or supply potential. The NPC did not consider such possibilities as being likely enough to be integrated into the base scenarios. However, each scenario was tested against variabilities in these and other major underlying assumptions through the use of sensitivity analyses. Major assumptions tested in these sensitivity analyses included weather patterns, economic growth, the price of competing fuels, the size of the domestic gas resource base, timing of infrastructure implementation, and the role of other electric generation technologies such as nuclear and hydroelectric plants. These sensitivity analyses provide additional insight to the conclusions reached from the base scenarios and reinforce the study findings and recommendations.

In either scenario, it is clear that North American natural gas supplies from traditional basins will be insufficient to meet projected demand; choices must be made immediately to determine how the nation's natural gas needs will be met in the future. The best solution to these issues requires actions on multiple paths.

Flexibility in fuel use must be encouraged, diverse supply sources must be developed, and infrastructure must be made to be as reliable as possible. Policy choices must consider domestic and foreign sources of supply, large and small increments of production, and the use of other fuels as well as gas for power generation. All choices face obstacles, but all must be supported if we are to achieve robust competition among energy alternatives and the lowest cost for consumers and the nation. The benefits of the Balanced Future scenario to the economy and environment unfold over time. But, it is important that these policy changes be implemented now; otherwise, their benefits will be pushed that much farther into the future, and the tight supply/demand balance of recent years will continue.

Efficiency

Efficiency is an important aspect of the behavior of each consuming sector. The Demand Task Group worked with EEA to assess historical trends for efficiency effects, as well as future potential for efficiency gains within the two "base case" scenarios. The assumptions incorporated into these scenarios were tested with consumers through the workshop and outreach processes of the industrial consumer and power generation working groups. Figures D1-5 and D1-6 illustrate the hypothetical reductions in energy demand implied by the efficiency assumptions in the Reactive Path and Balanced Future scenarios, respectively. Appendix C provides details of the effects of efficiency deduced in the two base scenarios, by sector.

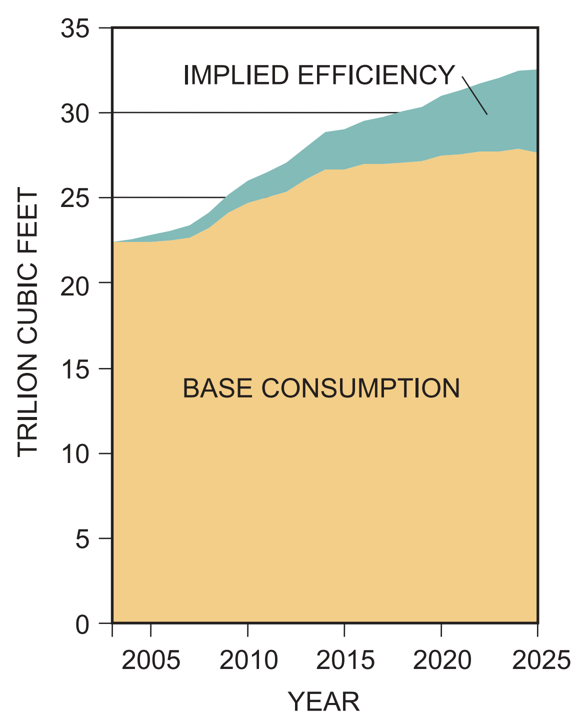


Figure D1-5. Efficiency and Conservation Improvements in Reactive Path Scenario

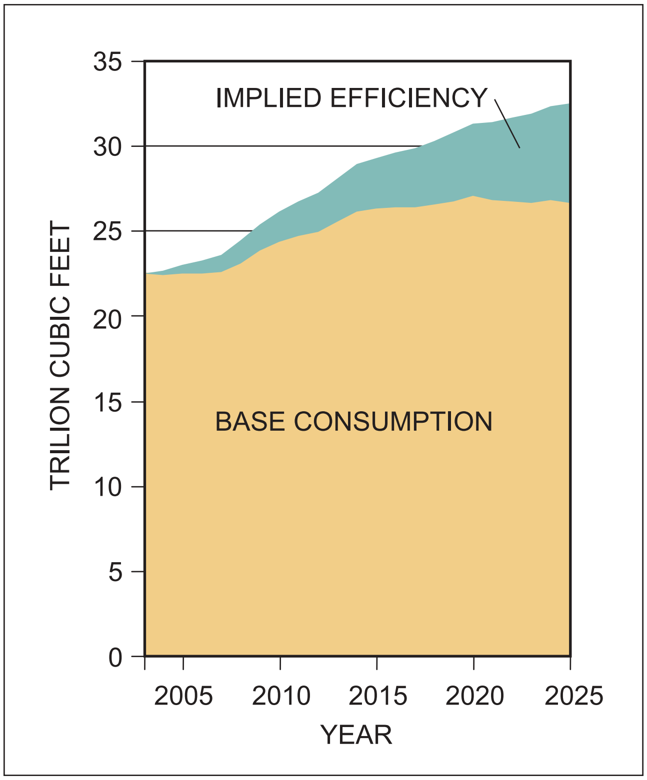


Figure D1-6. Efficiency and Conservation Improvements in Balanced Future Scenario

III. Implications for Natural Gas Demand

To achieve our nation's economic goals and meet our aspirations for the environment, natural gas will play a vital role in a balanced energy future. Stable and secure long-term supply, a balanced fuel portfolio, and reasonable costs will be enabled by a comprehensive solution composed of key actions facilitated by public policy at all levels of government. The following demand-related recommendations describe actions that can facilitate this outcome.

Recommendation Related to Natural Gas Demand

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

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

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

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

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

- **Educate consumers.** All levels of government should collaborate with non-governmental organizations to enhance and expand public education programs for energy conservation, efficiency, and weatherization.

- **Improve conservation programs.** DOE should identify best practices utilized by states for the low-income weatherization programs and encourage adoption of such practices nationwide.

- **Review and upgrade efficiency standards.** DOE, state energy offices, and other responsible state and local officials should review the various building and appliance standards that were previously adopted to ensure that decisions reached under cost/benefit relationships are valid under potentially higher energy prices.

- **Provide market price signals to consumers to facilitate efficient gas use.** FERC, Regional Transmission Organizations (RTOs), and state utility commissions should facilitate adoption of market-based mechanisms and/or rate regimes, coupled with metering and information technology to provide consumers with gas and power market price signals to allow them to make efficient decisions for their energy consumption.

- **Improve efficiency of gas consumption by resolving the North American wholesale power market structure.** FERC and the states/provinces, and if necessary congressional legislation, should improve wholesale electricity competition in the United States, Canada, and interconnected areas of Northern Mexico. FERC should mitigate rate and capacity issues at the seams between adjoining RTOs to maximize efficient energy flows between market areas.

- **Remove regulatory and rate-structure incentives to inefficient fuel use.** FERC, RTOs, and state regulators should ensure central dispatch authority rules, procedures and, where applicable, cost recovery mechanisms, require dispatch of the most efficient generating units while meeting system reliability requirements and minimizing cost.

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

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

An additional consideration with regard to efficiency is the continued role of research and development. The Demand Task Group identified the following consideration as relevant:

- **Encourage research and development to achieve new levels of energy efficiency.** To encourage increased efficiency and conservation through market-oriented initiatives and consumer education, public or ratepayer investments have in the past been made in increased efficiency end-use equipment that exceeds efficiency requirements of current regulations. Increased-efficiency, lower-emissions end-use equipment in traditional natural gas markets of residential and commercial applications for furnaces, water heaters, and cooking equipment and the industrial steam generation and process heating markets can provide breakthroughs that would enhance market initiatives and education and maximize the benefits. Stakeholders – including state and federal regulators, local distribution companies, other retail gas suppliers, large industrial and power generation consumers, and research & development entities – must develop workable funding mechanisms to facilitate such efforts, so that the technology needed to exceed current efficiency regulations is not delayed by years from being developed and reaching the marketplace. Examples of the needed technology include fully condensing, low-cost residential water heaters, with 92% efficiency; residential and commercial gas heat pumps that can provide heating efficiencies of over 120% and cooling Coefficient of Performance (COP) of over 0.80; industrial boilers with efficiencies of over 93%; and distributed generation/combined heat and power (CHP) technologies that have efficiencies of over 50% for electricity generation and over 80% for combined CHP applications.

Increase Industrial and Power Generation Capability to Use Alternate Fuels

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

Most facilities that would consider installing non-gas fueled capacity tend to be large and energy intensive. Therefore, increasing fuel diversity will have a large cumulative effect on natural gas consumption over the period of this study. Recommendations of the NPC in this area of natural gas consumption are:

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

There are additional actions and policy initiatives that bear focus and consideration. Some actions may be undertaken to create a more flexible and efficient consumer environment for natural gas, while assuring environmental goals are achieved. Other actions may create a more harmful supply/demand balance environment for consumers. The NPC identified the following key considerations in the area of natural gas consumption:

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

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

- **Potential Limits on Carbon Dioxide Emissions.** Ongoing policy debates include discussion of carbon reduction, including potential curbs on CO_2 emissions. Many actions would constitute the market's response to such limitations, including shutdown and/or re-configuration of industrial processes, additional emissions controls including carbon sequestration, or the shifting of manufacturing to other countries. Natural gas has lower CO_2 emissions than other carbon-based fuels. Therefore, natural gas combustion technologies are likely to be a substantial aspect of the market's response to limitations on CO_2 emissions in industrial processes and power generation. The most significant impact of CO_2 emission curbs would likely be restrictions in operation of much of the coal-fired power generation, since coal-combustion processes tend to emit the highest levels of CO_2. Depending on the level of emission restrictions, the requirements for natural gas in power generation alone could increase substantially. Alternatives to natural gas would be additional nuclear power and/or coal-fired generation employing carbon sequestration technologies that are unproven on a large scale. Renewable electric generation capacity is likely to play a growing role in the future, but has not demonstrated the ability to have a large impact. This study tested the impacts on natural gas demand and the resulting market prices, by performing sensitivity analyses; the impact on gas demand could be significant, as discussed elsewhere in this study, depending on the degree to which carbon intensity might be reduced. Natural gas consumption for power generation would clearly increase under any CO_2 reduction scheme during the time frame of this study, placing enormous demand pressure on natural gas. This would likely lead to much higher natural gas prices and industrial demand destruction.

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

IV. Summary

The NPC was asked by the Secretary of Energy to provide insights into the North American natural gas market, address and assess the implications of several issues influencing these markets, and to make recommendations for government and industry. To respond to the Secretary's request, the NPC study group analyzed and documented the many factors affecting gas supply, demand, and infrastructure. The NPC study group developed an analytically based view of how various components of the market behave, and are likely to behave in the future, using EEA's modeling framework as a key tool. Recognizing the many factors that will shape future natural gas markets, and the associate uncertainties, the NPC study group modeled two contrasting "base" scenarios to draw insights, assess various implications, and for the basis of recommendations.

The two "base" scenarios and many sensitivity analyses support a view that natural gas demand for the next 3-5 years will be persistent near present levels, but not grow significantly. This near-term view reflects a combination of competing factors, including the prospect of higher natural gas prices placing general downward pressure on demand, continued economic growth placing upward pressure on consumption among residential and commercial consumers, and the general lack of short-term alternatives to natural gas-based process energy and raw materials for industrial consumers. While steadily increasing amounts of electric power are expected to be generated with natural gas-based technologies, continued penetration of highly efficient combined cycle gas turbines will likely mute near-term growth in natural gas demand in the electric power sector.

For the longer period assessed by this study, through 2025, these analyses suggest natural gas demand will grow, but not at the same pace as in the recent past. Industrial demand – on an overall basis – is likely to persist near current levels during the period addressed by this study (through 2025), reflecting growth in some industrial sectors, balanced with continued penetration of process efficiencies, and likely substantial reductions in natural gas usage in the most gas-intensive industries, such as methanol and ammonia production. Power generation demand for natural gas is likely to continue to grow, with much of the increase coming from higher utilization of generation capacity that has already been built. However, this study found that competing forms of generation, most notably coal-fired technologies and renewables, will likely grow significantly. Additionally, this study found that energy efficiency and the amount of flexibility in fuel use, particularly liquid fuel backup for gas-based power and industrial applications, are the most significant factors for consumers to affect natural gas prices. Finally, the study found that uncertainty of air quality regulation, and the potential for control of carbon emissions are both factors that could materially impact natural gas demand.

The solution is a balanced portfolio of actions that includes increased energy efficiency and conservation; alternate energy sources for industrial consumers and power generators, including renewables; gas resources from previously inaccessible areas of the United States; liquefied natural gas (LNG) imports; and gas from the Arctic.

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

The following chapters and associated appendices describe analytical approach and evaluations of natural gas consumption in North America.

CHAPTER 2

ECONOMICS AND DEMOGRAPHICS

Changes in natural gas demand are driven by a host of factors that include macroeconomic variables, demographic changes, fuel use regulations, energy prices, weather, technology, regulatory structures governing energy use, and many others. The Demand Task Group formed an Economics and Demographics (E&D) Subgroup to provide background information to the broader NPC study group on the variables that have shaped natural gas supply, demand, and infrastructure in North America; to analyze variables that are likely to affect future gas demand, supply and infrastructure; and to determine the primary macroeconomic assumptions to be used in modeling of natural gas demand and supply. Additionally, the E&D Subgroup was involved in vetting model runs to ascertain consistency of various assumptions, and to analyze whether the various scenarios and sensitivities required different macro economic assumptions.

The E&D Subgroup accomplished its objective by researching economic and industry literature; by analyzing trends in macroeconomic variables; by discussions with other economists and industry analysts; and by employing third-party econometric models to test assumptions. The E&D Subgroup consisted of veteran economic and industry analysts from the petroleum producing and energy-consuming companies (see Appendix B for the Economics and Demographics Subgroup Roster).

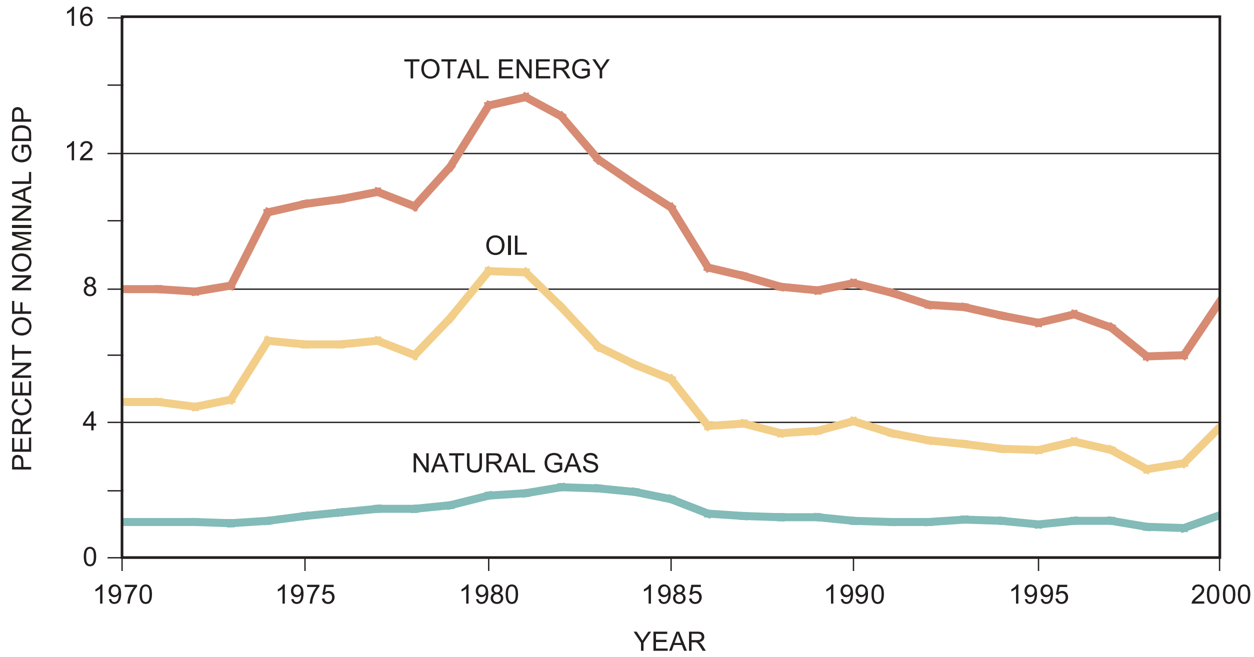
I. Energy and the Economy

Energy is used in the manufacturing and distribution of virtually all products. It is particularly important to the viability of many industrial consumers, which in aggregate use about one-third of total U.S. energy. Natural gas is the preferred fuel of the industrial sector, accounting for about 40% of primary fuel consumption by industrial consumers. The chemical industries are particularly sensitive to natural gas prices because they use gas as both an energy source and a feedstock for their products. Bulk chemical manufacturers, for example, spend more than 20% of the value of their shipments on energy. As shown in Figure D2-1, energy expenditures in the U.S. today represent about 8% of U.S. gross national product. However, energy's importance to the economy goes far beyond its share of GDP.

Residential and commercial consumers also use energy for heating and cooling, lighting, cooking, and transportation. There are approximately 65 million customers using gas in the United States and 126 million customers using power.

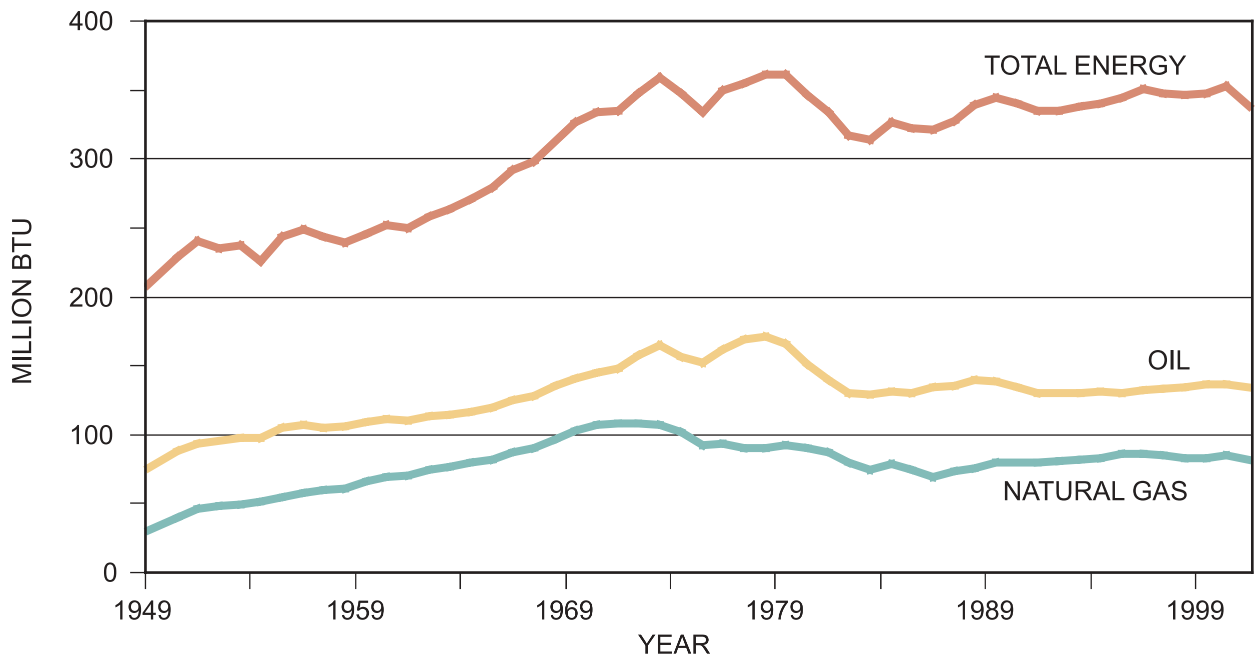
In response to the energy price shocks in 1973-74 and 1979, energy expenditures as a share of the U.S. economy have fallen by over 40% since the peak in 1981, when they represented 14% of GDP. Since 1981, energy expenditures have declined as a share of GDP as a result of the 70% decline in real oil prices between 1981 and 1999, the shift in the U.S. from a manufacturing to a less energy-intensive service economy, and from fuel and equipment efficiency improvement in the aftermath of the energy price shocks.

Figure D2-2 shows that energy consumption per capita in the United States has actually been increasing since 1986. This resulted from the combination of relatively low energy prices and rising incomes. For example, as income grows, people tend to buy larger



Sources: Energy Information Administration; U.S. Department of Commerce – Bureau of Economic Analysis.

Figure D2-1. Energy Expenditure Share of the U.S. Economy



Sources: Energy Information Administration; U.S. Department of Commerce – Bureau of Economic Analysis.

Figure D2-2. Energy Consumption per Person houses that require more heating and cooling, buy larger cars and more appliances, and travel more. An additional factor is the significant growth in electricity consumption, which requires more energy as a result of transformation and transmission losses.

In the past few years, energy balances have tightened considerably, and energy prices have been rising. In particular, natural gas prices rose to record-high levels after 1999. Energy expenditures rose relative to GDP over the 2000-2003 period. The U.S. economy flourished after the mid-1980s due in part to relatively low energy prices. The results of this study suggest that the U.S. economy is likely to face an extended period of higher, and potentially more volatile natural gas prices.

II. Energy and Natural Gas

Natural gas has played a critical role during the last 50 years in total U.S. energy consumption. As seen in Figure D2-3, natural gas was about 16% of the total energy consumption in the early 1950s, when it was a predominately a fuel and feedstock in industrial applications, and grew to nearly 32% in the early 1970s as other market uses developed. During this period, natural gas demand grew rapidly in residential and commercial use, primarily for space and water heating, attendant with the development of an increasingly more integrated interstate pipeline system and local distribution networks. Natural gas use grew from 5 trillion cubic feet (TCF) in 1949 to 22 TCF in 1972.

During the second half of the 1970s and early 1980s natural gas use declined, both in actual terms and as a percentage of total energy consumption. Gas consumption declined due, in part, to a period of relatively high gas prices and from government policy prohibiting the use of gas for certain applications. Since the mid-1980s, natural gas's share of total energy consumption remained quite stable while its use has grown by about 2.1% per year.

Natural gas as a fuel source continues to demonstrate a unique value compared to other fuels. Figure D2-4 shows energy use by fuel type along with its principal application. Most fuels have a primary application, whereas natural gas has been more versatile. Natural gas has wide application for space and water heating, power generation, and both an industrial raw

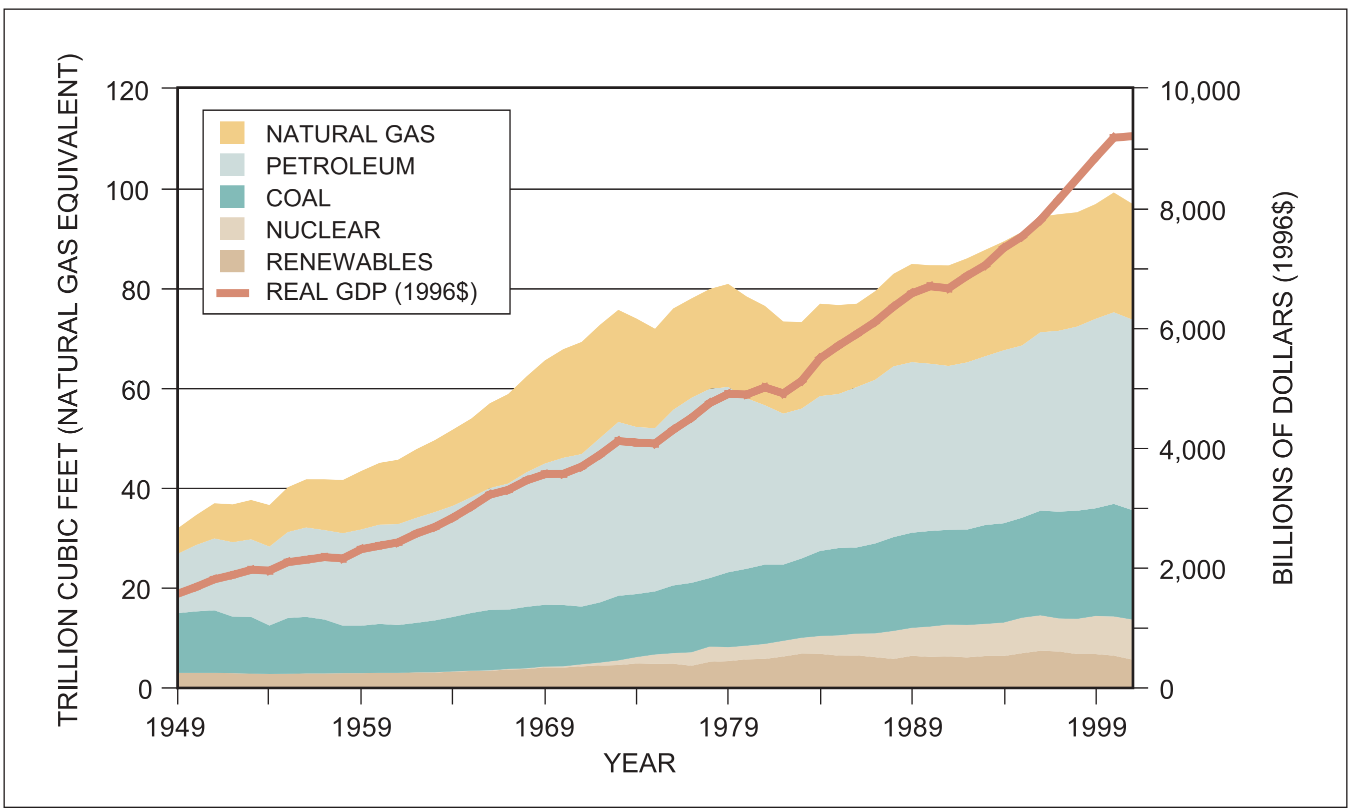


Figure D2-3. Total U.S. Energy Consumption

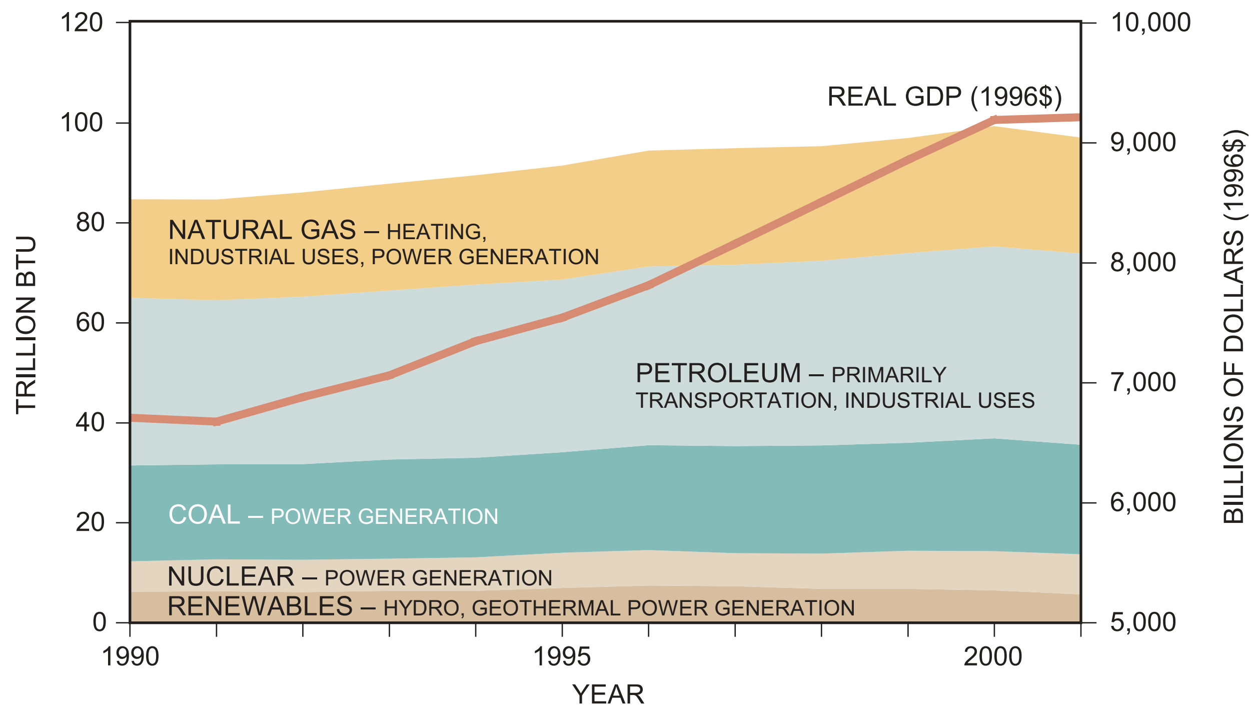
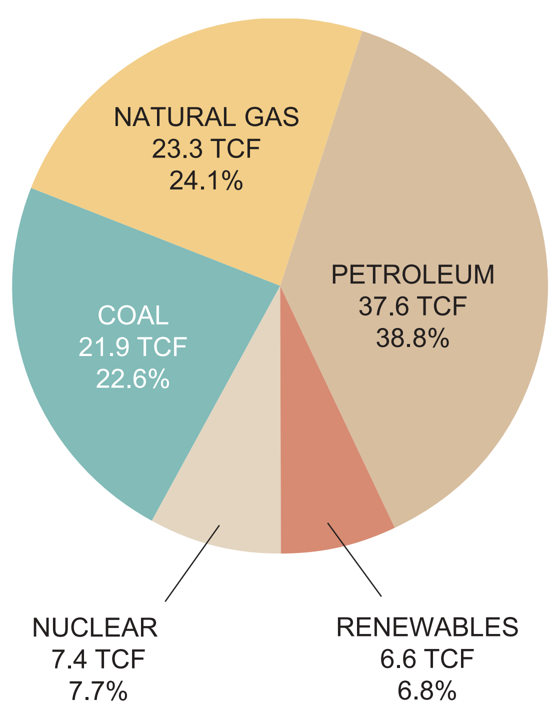


Figure D2-4. Total U.S. Energy Consumption

material and fuel. The integrated transportation and distribution systems for natural gas make it widely available within the United States.

Natural gas also has important environmental benefits. For example, when natural gas is burned in combustion turbines, it produces about one-third the volume of greenhouse gases per kilowatt-hour compared to a coal-fired boiler. Overall, environmental performance has been a major factor in the growth of natural gas for power generation. In the industrial sector, petroleum represents 42% of primary energy use while natural gas accounts for 38%. Natural gas is preferred in many applications because of its clean burning qualities.

By the late-1990s, U.S. natural gas use grew more quickly than any other energy source, primarily from its use in electricity generation by independent or merchant power producers. Natural gas consumption grew to nearly one-quarter of total U.S. energy consumption by 1999 (see Figure D2-5). Natural gas became the "fuel of choice" because it was widely distributed, had clean burning qualities, and was priced at a discount, on a dollar per Btu basis, compared to oil and its derivative fuels.



Source: Energy Information Administration.

Figure D2-5. Average Annual Energy Use, 1997-2001
97 Trillion Cubic Feet per Year (Equivalent)

Gas use from 1990 to 2002 for each major sector is shown in Figure D2-6. Gas consumption among residential and commercial customers has grown by slightly more than one percent per year; gas consumed in electric generation (including combined heat and power) increased at a 4.6% annual pace; and industrial gas demand (for fuel and feedstock) saw growth through the mid-1990s before declining in response to higher natural gas prices. Natural gas accounts for about 73% of primary energy use in the residential sector, about 77% of primary commercial use, nearly 40% of industrial use, and about 18% of electricity utility generation. The wider use of gas has been offset to a small degree by improvements in its utilization efficiency, particularly in power generation. However, annual use is highly dependent on weather. Between 1996 and 1998, for example, a warm weather cycle known as El Nino significantly reduced winter demand for gas.

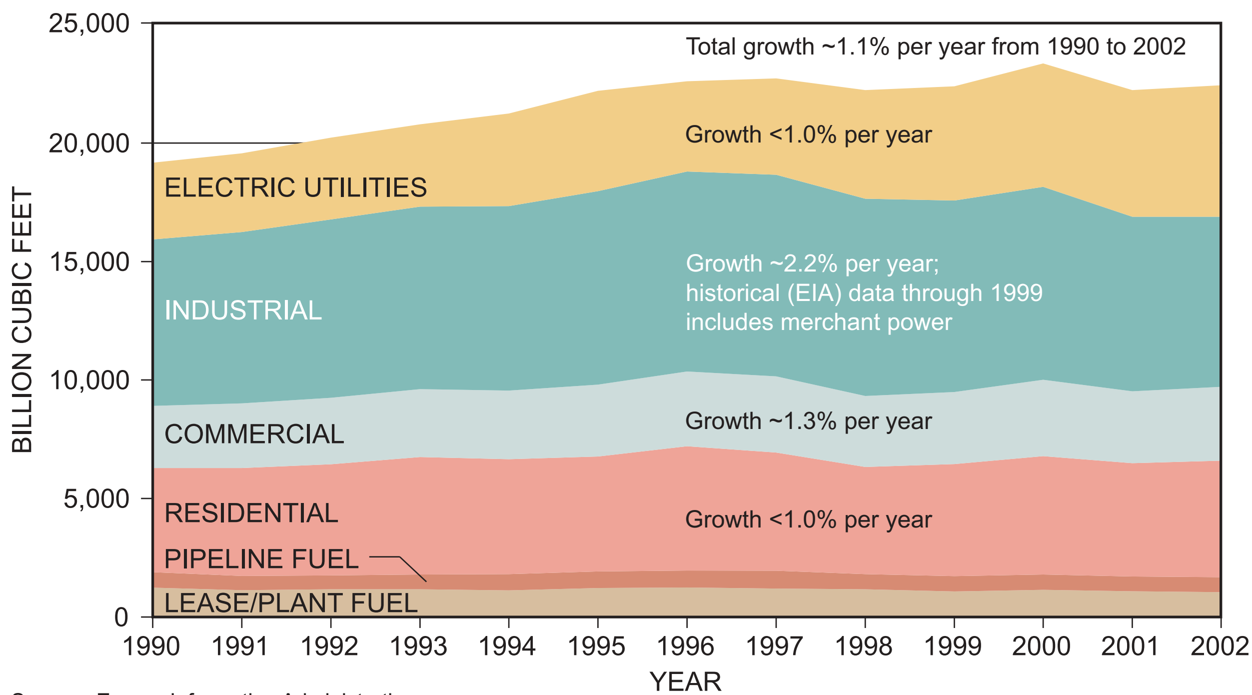
The industrial sector's gas use rose strongly during the first half of the 1990s, peaking at nearly 10 TCF in 1997. By 2003 industrial gas use had fallen to 8.3 TCF per year, due in part to higher natural gas prices and to lower economic growth. With the higher natural gas prices suggested by this study, industrial gas use is unlikely to rebound to levels seen during the 1990s.

The fastest growth gas-consuming sector over the past decade has been electric power. Beginning around 1990, independent power developers created a new class of gas users promoting the application of highly efficient gas-fired combustion turbines. This wave of new construction was prompted by low natural gas prices and by policies that facilitated the licensing of these new facilities on the federal, state, and local levels. In 2002 gas consumed by the electric power sector totaled 5.6 TCF, up from 3.2 TCF in 1990.

Other uses of gas include lease and plant fuel, and transportation. Lease and plant gas use has remained relatively stable over the past decade and currently accounts for about 5% total gas consumption. Gas used in the transportation sector is mainly as a pipeline fuel. Pipeline fuel use accounts for roughly 3% of total natural gas consumption. A minor amount of natural gas is also used in vehicles.

III. Effects of Energy Policies

Policies that affect gas prices and supplies also affect economic activity. Economic theory and empirical evidence suggest that low energy prices enhance GDP growth, while higher energy prices tend to inhibit economic growth. While most of the research was on oil



Source: Energy Information Administration.

Figure D2-6. U.S. Natural Gas Consumption price increases, similar effects are likely to apply to natural gas price increases.

Examples of policies that affect gas supply and price include environmental, health, and safety policies; regulations by the FERC and state public service commissions that affect market entry and market activities of gas pipelines and LDCs; and federal, state, and local regulations that limit or delay gas production (or imports) including rules that restrict access to attractive drilling areas, pipeline routes, or other gas infrastructure such as storage facilities or LNG import terminals. Policies that limit or delay supply tend to increase natural gas prices, which impact economic activity.

Rules that artificially limit fuel substitutability and increase gas demand have similar effects. Generally, any policies that limit the flexibility of consumers will decrease their ability to respond to price increases, resulting in greater price volatility and attendant negative economic effects.

A. Economic Growth Effects

The literature on the impact of changes in energy prices on the U.S. economy primarily addresses the impacts of oil price shocks, although some of the impact may have been from increases in natural gas prices as well. As Figure D2-7 shows, episodes of sharply rising oil prices (shown as the highlighted portions of oil price) have preceded nine of the ten post-World-War II recessions in the United States. While economists offer many reasons for the negative impact of oil price shocks on the economy, the main reasons are that oil price increases raise the cost of production and reduce disposable personal income. The net effect is that U.S. aggregate demand is reduced.[1]

Reasons why oil price shocks seem to have a disproportionately large effect on economic activity vary, but include inappropriate monetary policies, high adjustment costs arising from either energy-intensive capital stock or sectoral imbalances, and coordination problems when individual firms lack information on the permanence of price changes. Finally, uncertainty about future oil prices tends to reduce investment.[2] Consumer purchases of housing, automobiles, and appliances may also be deferred as a result of instability in energy markets. Energy prices are highly visible (e.g., prices posted at the gasoline pump) and price run-ups may have a disproportionately large impact on business and consumer confidence. The economy would most likely perform better with stable or predictable energy prices than when the price of energy fluctuates greatly.[3]

The relationship between oil prices and aggregate economic activity has lessened since the 1970s as a result of declining energy intensity described previously. Brown and Yucel estimate that the U.S. economy was about one-third less sensitive to oil price fluctuations in 2000 than it was in the early 1980s, and about one-half as sensitive as it was in the early 1970s.[4] It is also possible that the experience of previous price shocks will reduce adjustment costs, coordination problems, uncertainty, and financial stress.

Natural gas price impacts are broadly similar to but not identical to oil price impacts. Gas consumption is only about two-thirds of oil consumption and domestic gas production is higher than domestic oil production. Natural gas consumption patterns are also different from oil consumption patterns. Figure D2-8 indicates that transportation and industrial account for most oil use whereas residential/commercial and power generation account for most gas use.

The U.S. petrochemical industry appears more exposed to natural gas prices than to oil prices, due to feedstock needs (both natural gas and/or natural gas liquids). Much of the foreign competition is more exposed to oil prices because oil is the most common feedstock. That puts North American chemical producers at a competitive disadvantage when gas prices are high relative to oil prices. North American ammonia and methanol industries are the most exposed to gas prices because of their overwhelming dependence on gas as a feedstock. High gas prices may force temporary or permanent plant closures and layoffs in these industries.

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1 Stephen P.A. Brown, Mine K. Yucel, and John Thompson, Federal Reserve Bank of Dallas, *Business Cycles: The Role of Energy Prices.* Encyclopedia of Energy, Cleveland Cutler, editor, Academic Press, forthcoming.

2 Ibid.

3 U.S. Department of Energy, Energy Information Administration, *Energy Price Impacts on the U.S. Economy,* April 2001.

4 Brown and Yucel, op. cit.

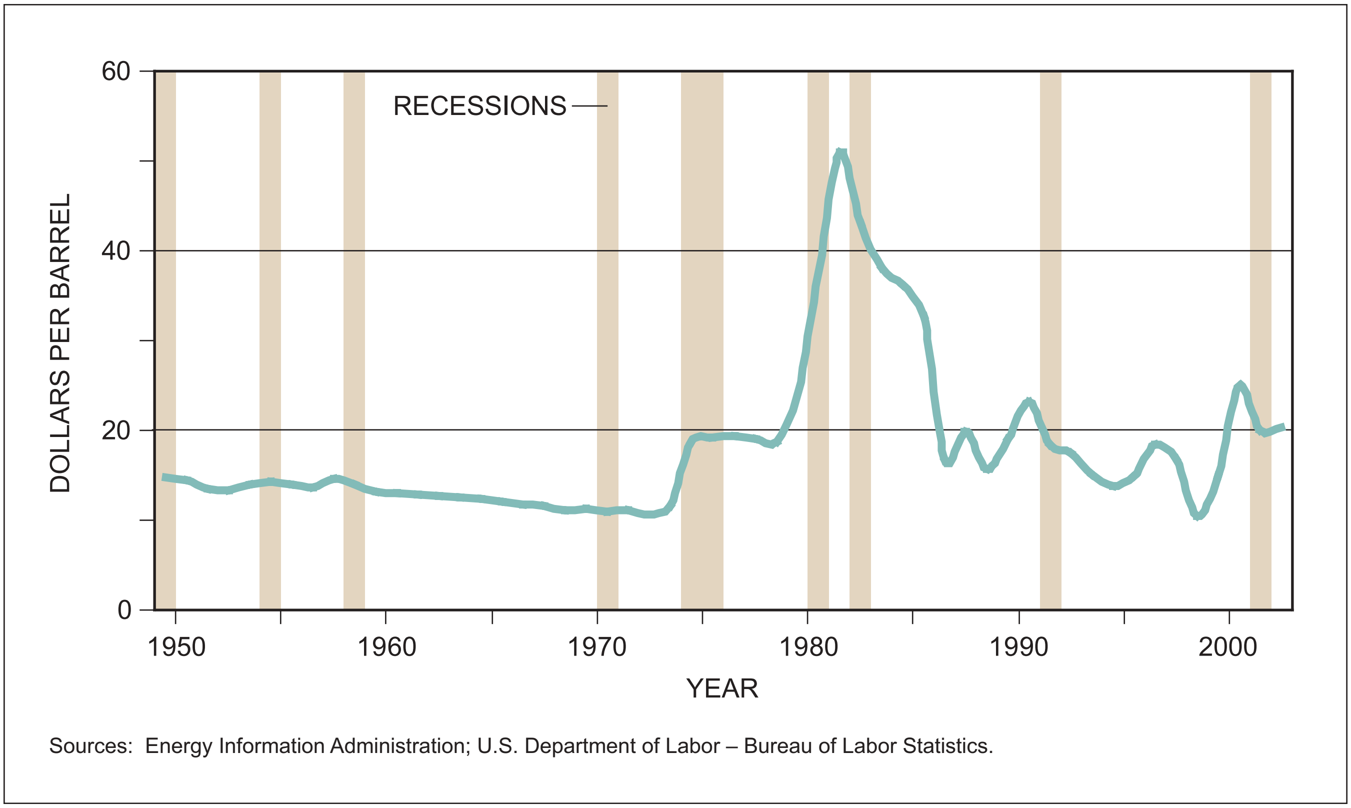


Figure D2-7. Real Oil Prices and U.S. Recessions

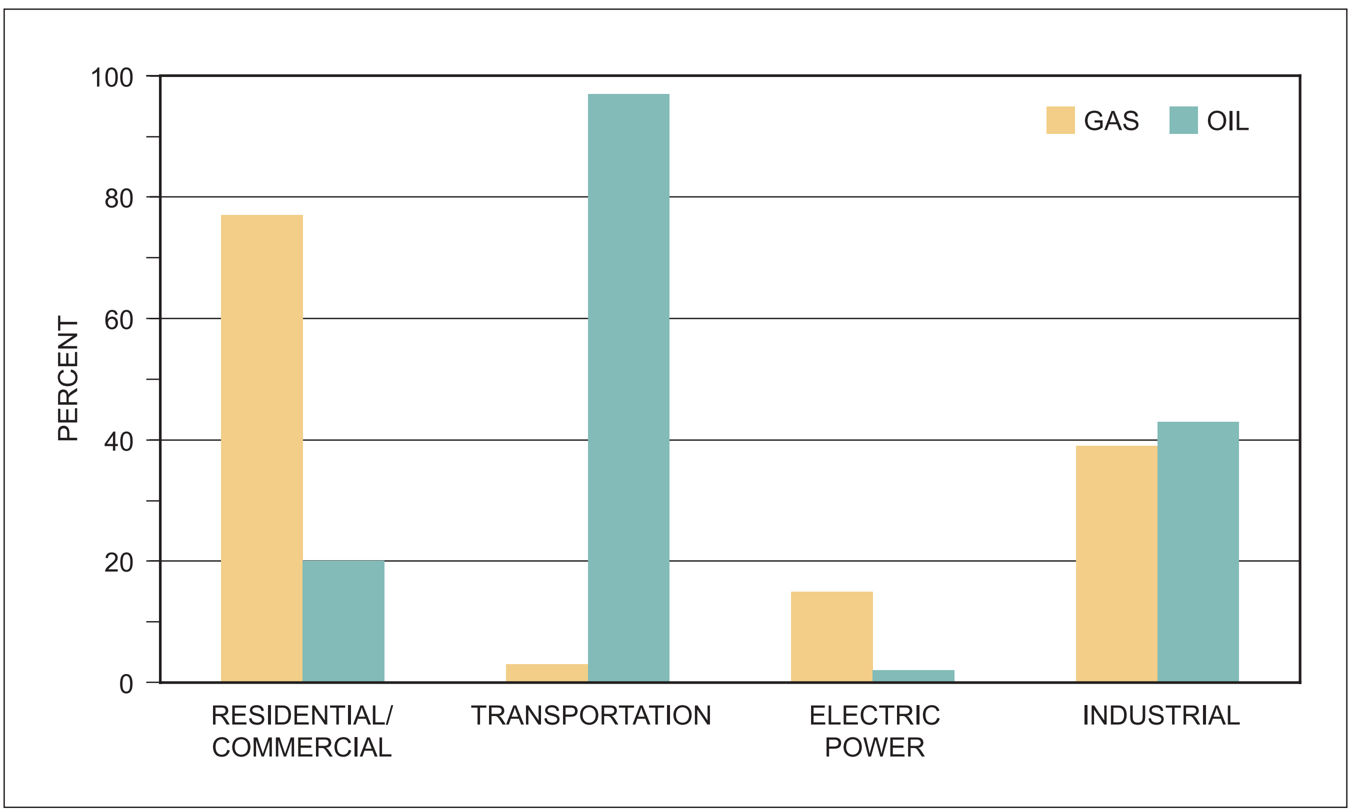


Figure D2-8. Gas and Oil Consumption Patterns

Oil price impacts may occur more quickly than natural gas price impacts following price increases. Gasoline accounts for nearly half of oil consumption. Gasoline prices are highly visible and changes are quickly transmitted to consumers because they purchase it frequently. Residential and commercial natural gas consumers are more insulated from price changes due to regulatory lags and monthly billing cycles.

Power generators and industrial users respond quickly to gas and oil price changes when they have alternate fuel capability. Both see the changes quickly though they may have the opportunity to purchase either oil or gas under long-term contracts or to hedge their purchases. Fuel switching, where important, typically does not occur instantaneously. Indirect fuel switching between gas and other fuels in power generation can take place relatively quickly as output shifts among the many plants on line at a given time.

B. Regulations and Regulatory Framework

The U.S. and Canadian natural gas market is complex and natural gas permeates most sectors of the North American economy. From its beginning more than 150 years ago as manufactured gas from coal, the gas industry and gas consumption has been shaped by a combination of government regulations and competitive markets. Between 1954 and the mid-1980s, federal, state, or local governments regulated practically all segments of the natural gas value chain – exploration, production, marketing, transmission, and distribution. The primary decontrol process began in the late 1970s with the Natural Gas Policy Act of 1978; ultimately leading to a competitive marketplace for many segments of the gas industry.

Beginning in 1954 and continuing on into the mid-1980s, the regulation of wellhead natural gas prices distorted consumer and producer behavior, ultimately leading to severe shortages. In 1961, the Federal Power Commission (FPC) set wellhead prices for interstate supplies lower than what in many cases was required by exploration and production (E&P) companies to continue to explore and drill for natural gas. By the late mid-1970s, the lack of drilling activity resulted in severe gas shortages and rapid price increases. Fears surrounding the lack of available natural gas reserves caused legislators to set the price on a path that led to artificially high prices and more drilling activity and at the same time passed the Powerplant and Industrial Fuel Use Act, which decreased demand. These actions contributed to a surplus of natural gas that took more than a decade to dissipate.

Today most residential and commercial gas purchases still fall under utility-type regulations, where the consumer costs are bundled and cover the price of the commodity, transmission, and distribution. In contrast, larger gas consumers are often able to negotiate separately with the different participants in the value chain. During the 1990s the non-regulated segments grew into a well-functioning market, one where many buyers and sellers determined prices, and one where various financial instruments could be used for price risk mitigation – futures, puts, calls, etc.

The flourishing and financially liquid market for scores of different gas price financial products suffered a setback post 2000 as a result of problems in the California market and the bankruptcy of industry's largest trader at the end of 2001. Financial markets today have not rebounded to their previous levels of activity, but there are sufficent liquidity and financial product offerings to manage price risk and volatility for a majority of gas industry buyers and sellers.

1. Regulatory Framework to 1978

In 1954, a landmark Supreme Court decision declared that the Natural Gas Act of 1938 required regulation of not only pipeline rates, but also required regulation of the prices received by gas producers, known as wellhead prices. Wellhead prices for gas moving in interstate commerce was set by the FPC, based on historical finding and development costs and did not distinguish between various producing regions. Starting in 1961, wellhead prices set by the FPC were no longer rising and no longer providing sufficient incentive to producers to increase production. Figure D2-9 shows that natural gas prices were set well below the CPI after 1961.

Since the gas price received by producers was low, drilling declined. Figure D2-10 shows how the number of development and exploratory wells drilled decreased between 1961 and 1971. According to the U.S. Department of Energy, the number of successful natural gas wells drilled dropped during this period by nearly 40% (from 5,486 to 3,971). As the number of wells drilled dropped, the production rate leveled off and eventually began to decline. Figure D2-11 shows natural gas production leveling off in 1971, and beginning to decline in 1974.

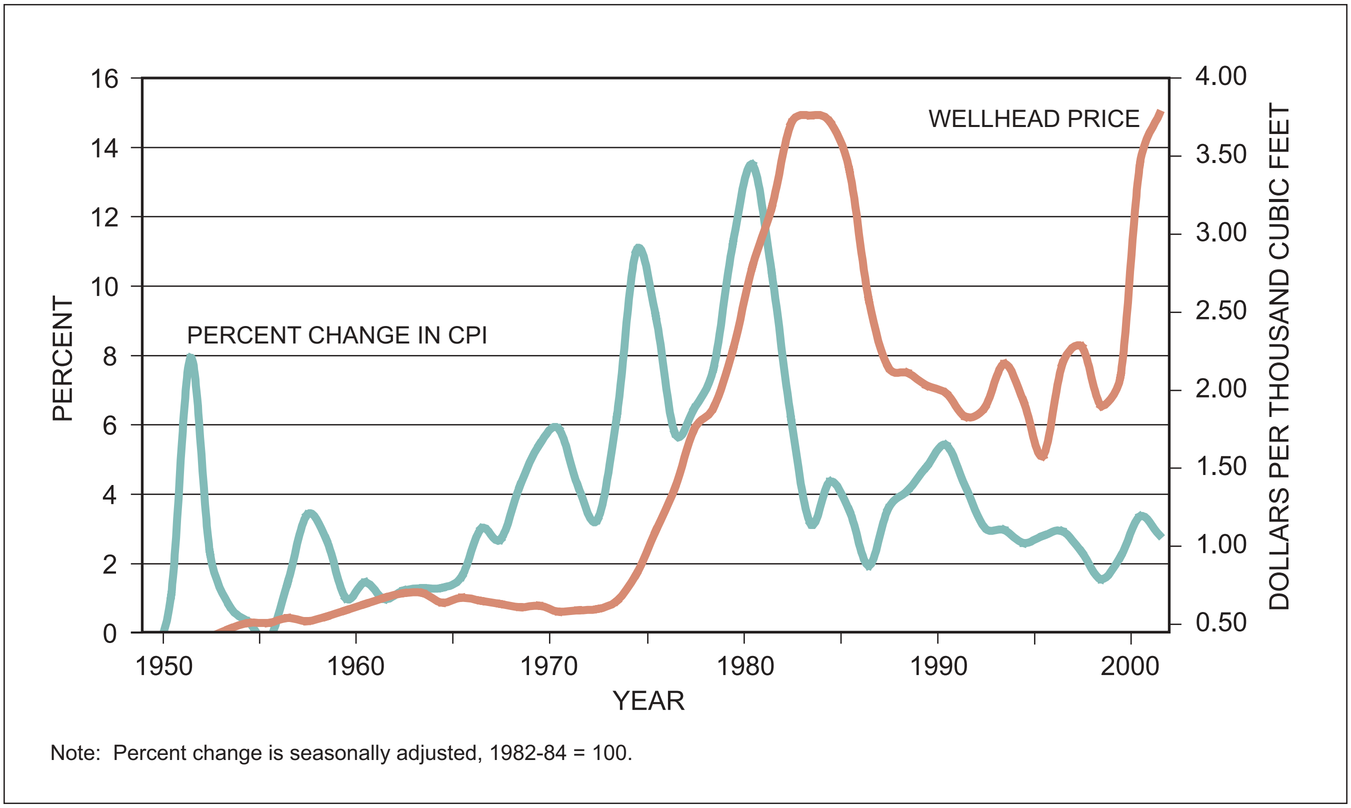


Figure D2-9. Annual Change in CPI and Wellhead Gas Price (1996$)

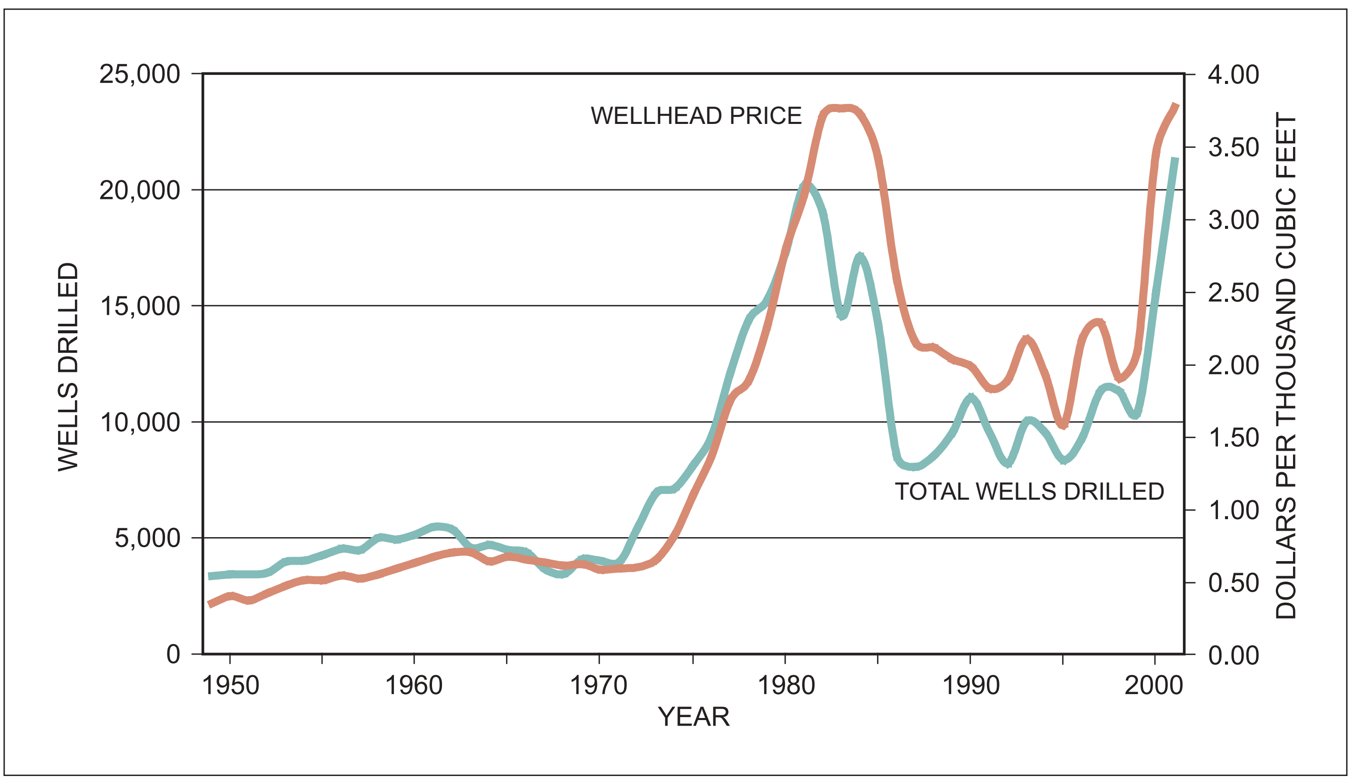


Figure D2-10. Successful Natural Gas Exploratory and Development Wells Drilled and Wellhead Gas Price (1996$)

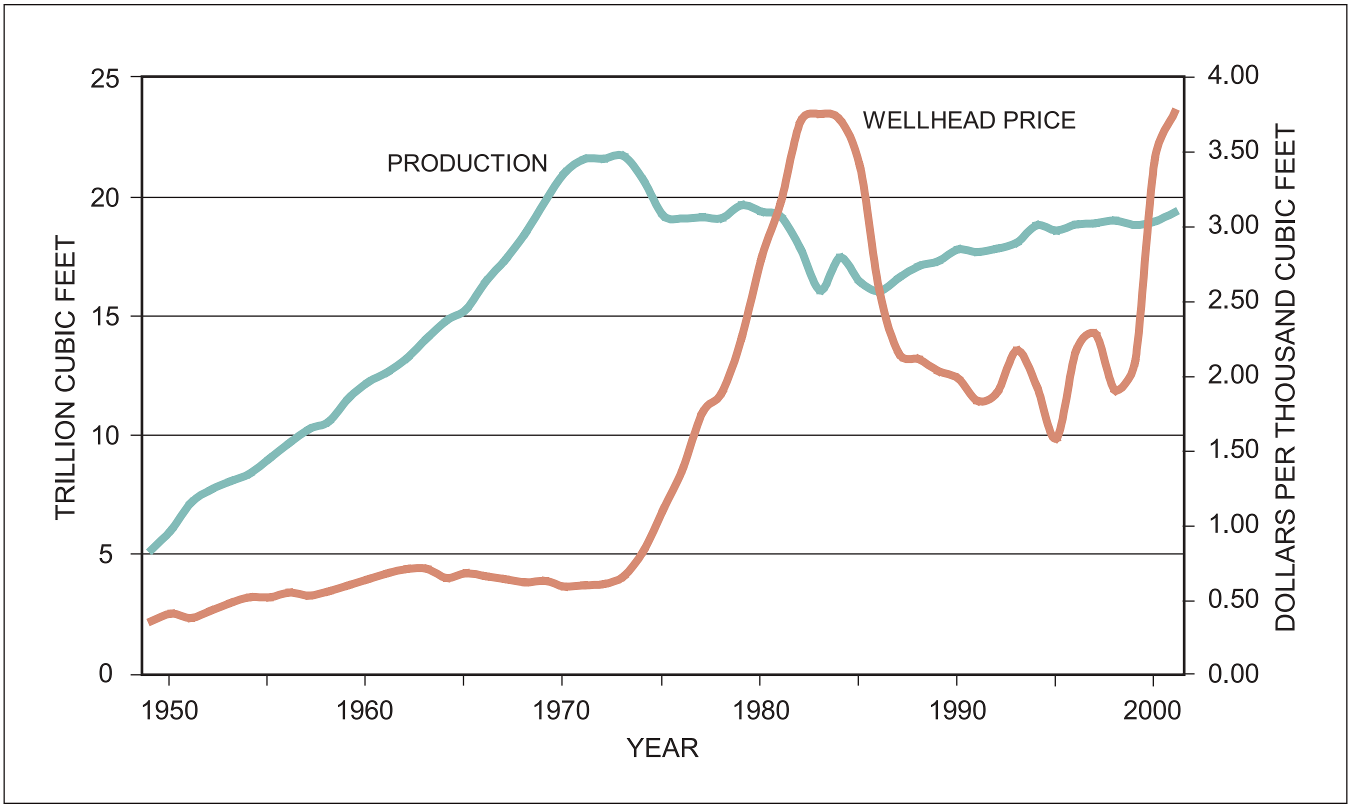


Figure D2-11. Natural Gas Production and Wellhead Gas Price (1996$)

By the late 1960s, the FPC realized that the wellhead prices were too low and began to increase prices. However, the increases were still insufficient to encourage production. In response to this situation, producers moved their sales to the unregulated intrastate natural gas market. This market was not under FPC regulation and could pay higher prices for natural gas. As a result of this higher-priced sales outlet, wellhead prices began to increase in 1971. By 1972, E&P companies were drilling development and exploration wells again since they again had the price required to provide an acceptable rate of return.

Even though drilling was beginning to increase again, proved reserves were still declining. As shown in Figure D2-12, reserves had dropped from 293 TCF in 1967 to 209 TCF in 1977. With reserves and production declining, and producers fetching higher prices from intrastate pipelines, interstate pipelines were finding it difficult to supply gas to their customers. Shortages began to occur in states without natural gas production and many power generation facilities and industrial users installed fuel-switching capabilities to avoid shutdowns. The federal government adopted policies to reduce gas demand to match the perceived lower natural gas supply, despite strong evidence that the supply shortage was created by wellhead price controls.

After a decade of declining natural gas reserves and the inability of interstate pipelines to deliver gas to consumers, the federal government, convinced that there was a natural gas shortage, passed the Natural Gas Policy Act of 1978 (NGPA) and the Powerplant and Industrial Fuel Use Act of 1978 (PIFUA).

2. Regulatory Framework Post 1978

The objective of the NGPA was to provide a phased decontrol of natural gas wellhead prices. The NGPA placed wellhead price caps on several categories of natural gas, which had escalation factors to allow them to rise to a level competitive with other fuels. Rather than remedying the situation, the complexities of the NGPA increased the problem. The escalation clauses were developed under the assumption that oil prices would continue to rise steeply. Price caps for the categories of gas subject to these escalators grew to be priced considerably above, rather than below, the market. These high prices spurred exploration and development. This resulted in high reserve additions, while at the same time the high prices were having a dampening effect on

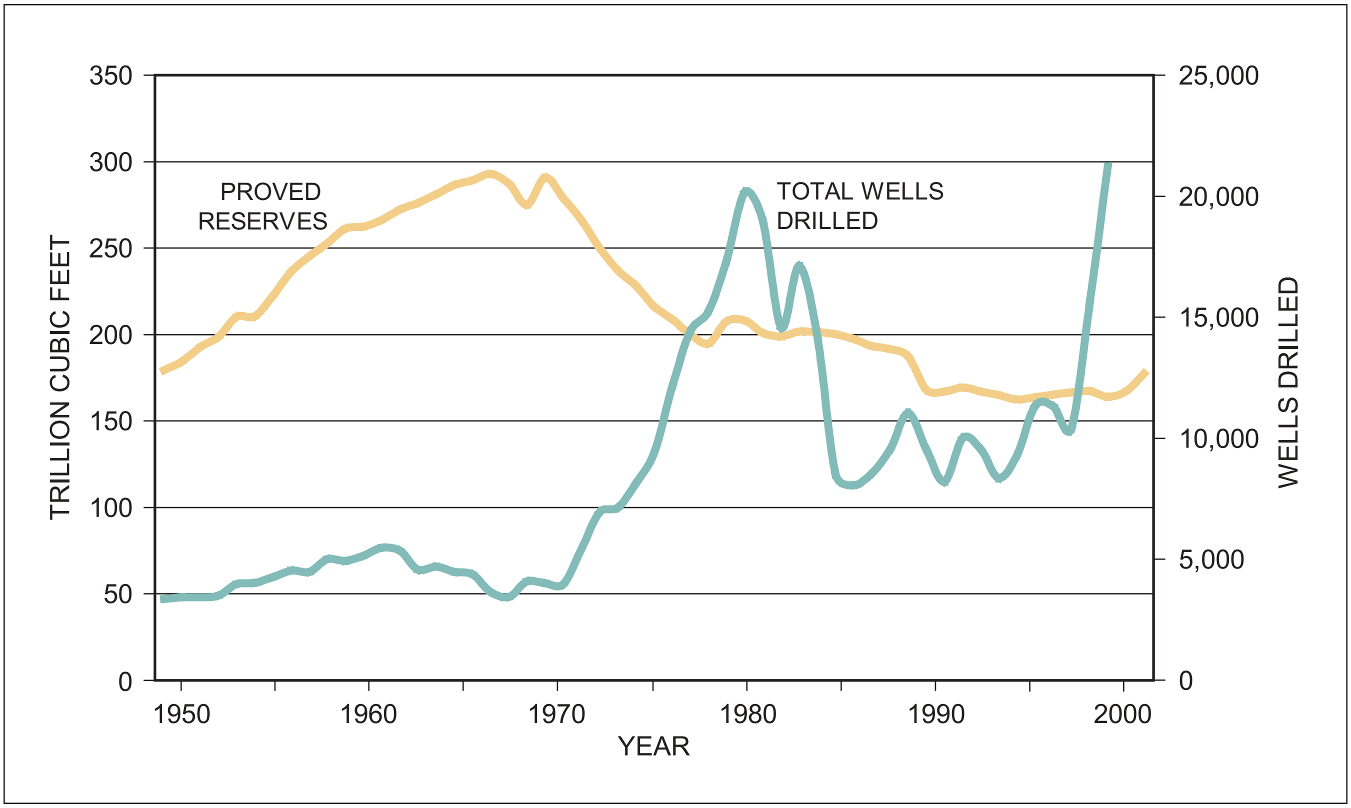


Figure D2-12. Successful Natural Gas Wells Drilled and Proved Gas Reserves

demand. By the early 1980s, the shortage of natural gas had been replaced with a surplus, often referred to as the "gas bubble."[5] It took more than a decade to work off the surplus and rebalance the market.

It is difficult to judge how instrumental PIFUA was in curtailing natural gas demand since industry and power generators were already taking action to reduce their consumption of natural gas. Several industrial end-users and power generators had begun to install dual-fuel capabilities before PIFUA was passed. By 1978, demand for natural gas had been declining for five years, especially in the industrial and power generation sectors as shown in Figure D2-13.

During the PIFUA era, consumption of natural gas continued to decline. Industrial and power generation customers were using more fuel oil, which meant interstate pipelines were allocating more natural gas costs to residential users. In response to the higher prices, residential users began to use less natural gas. Also, several states prohibited the expansion of LDC distribution systems, which further hindered residential and commercial use of natural gas. State regulators increased rates for industrial customers to help subsidize residential users, which continued to decrease the industrial community's appetite for natural gas. According to EIA data, the consumption of natural gas dropped from 20.2 TCF/year in 1979 to 17.2 TCF in 1987, the year that the PIFUA was repealed. In 1987, industrial end-users consumed 14% less than gas than they did in 1979, and 31% less than they did in 1973.

The drop in gas consumption and the eventual decline in gas price caused producers to substantially reduce natural gas oriented drilling. Figure D2-14 shows that exploratory drilling declined steeply after 1981. Once the PIFUA was repealed in 1987, the decline in the number of gas wells being drilled was halted.

After the repeal of PIFUA, demand for natural gas increased as prices settled into a lower range and production increased as the opportunity for new demand and market-based prices provided incentives to natural gas producers to invest in additional drilling. This surplus of gas that NGPA instigated eased fears that the

[5] Mary J. Hutzler, Before the Committee on Energy and Natural Resources, U.S. Senate, June 26, 2000.

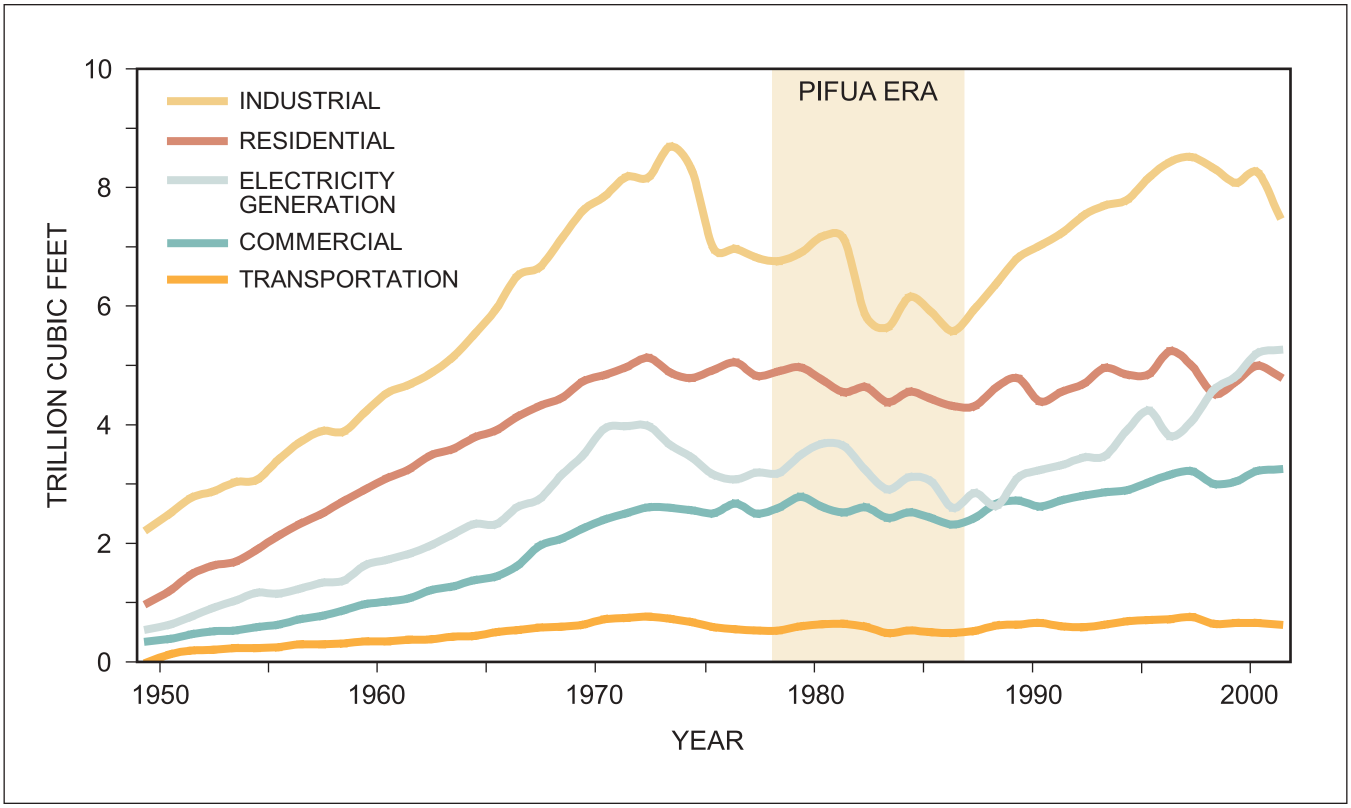


Figure D2-13. Consumption of Natural Gas

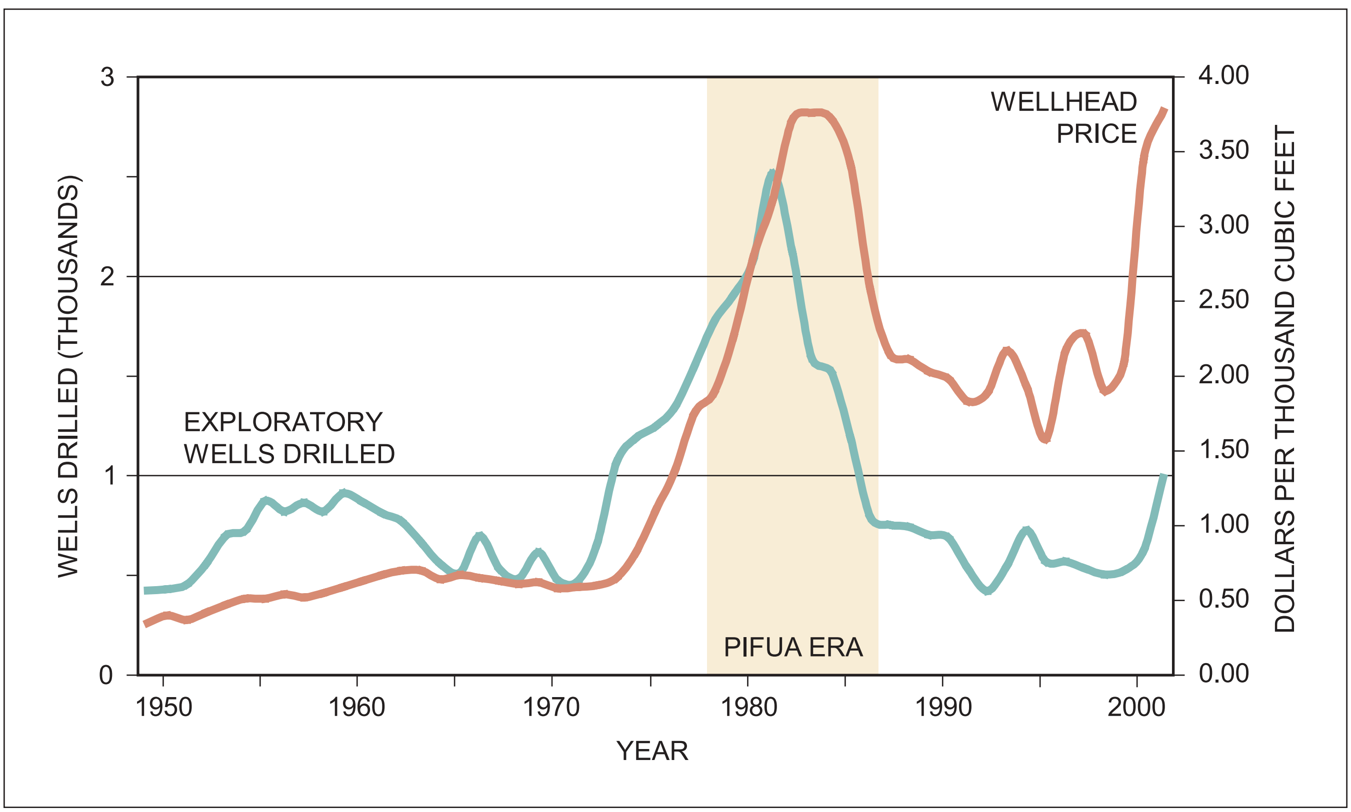


Figure D2-14. Successful Natural Gas Exploratory Wells Drilled and Wellhead Gas Price (1996$)

United States was running out of natural gas but and at the same time, raised concerns the PIFUA was limiting the use of a clean-burning and economically producible fuel source.

Both the NGPA and PIFUA were repealed because they produced unintended consequences that distorted the market and created inefficiencies. The legacy of these experiments is that regulated prices will rarely work to keep markets balanced because they will invariably send the wrong price signals to producers and consumers, and result in supply shortages or surpluses. An initial regulatory act often leads to a series of regulatory acts to correct the adverse consequences of the previous actions. For example, the low controlled prices of the 1960s to 1970s decreased exploration and drilling activity to the point of causing a supply shortage. Instead of lifting price controls and allowing the free market forces to balance the market, the federal government instead set policy that would decrease demand to match the lower supplies. This action reduced drilling activity, requiring an additional regulation to fix that problem.

Since higher prices were extremely effective signals to reduce the demand for natural gas, it is not clear that the PIFUA was even necessary. As proven in the early 1970s, fuel switching is an economic decision made by companies based on their outlook for various fuels and the ability to obtain and store those fuels. The incentive for fuel switching does not require government intervention. However, it does require that government policies not create impediments to economically rational investment decisions to install alternate fuel capability.

IV. Modeling Assumptions

The NPC study group used macroeconomic and demographic assumptions to model future U.S. and Canadian natural gas demand and supply. These assumptions, which are largely independent of natural gas volumes and price, are commonly referred to as exogenous variables. As described in Chapter 6 of this Demand Task Group Report, several of these assumptions were tested with sensitivity analyses. There are several broad categories of these assumptions.

Macroeconomic variables describe overall economic activity. These variables include economic growth, industry structure, financial indicators, and other drivers that are dictated by the behavior of the U.S. and world economic system. The following primary macroeconomic assumptions were utilized:

- U.S. GDP growth of 2.8% 2002-2005 and 3.0% thereafter
- Overall Industrial Production growth of 3.0% 2003-2025
- Canadian GDP 2.4% 2002-2005 and 2.6% thereafter
- Rates of return of 7% on debt and 12% on equity, BFIT
- Inflation rate of 2.5%, as measured by the GDP Price deflator.

The price of other fuels describes the market where natural gas competes. In large part these fuel prices are determined independent of U.S. natural gas prices. For example, crude oil and petroleum product prices are determined in world markets. The following fuel price assumptions were utilized:

- Crude oil (WTI-NYMEX) prices were trended down to \$20.00/barrel (in 2002 dollars) by 2005, from those prevailing in early 2003, and were assumed to average \$20.00/barrel thereafter
- Refiner acquisition costs (RAC) would equal 90% of WTI
- Average utility coal prices in 2002 dollars were assumed to decrease 1% annually.

It is important to note that most of the assumptions used in the models – assumptions that drive gas demand, supply and price – have exhibited significant variability over time. Annual GDP growth over the past half-century ranged from negative 2% to over 9% per year. The past quarter century saw annual WTI prices range from \$15/barrel to nearly \$70/barrel (in 2002 dollars). Weather has also been highly variable with some of the warmest winters this century occurring over the past 5 years; while November–December 2000 was one of the coldest two-month periods on record. The assumptions used in the two NPC base-case scenarios – the Reactive Path and the Balanced Future – are longer-term averages, which hide this variability and the price volatility it can engender.

History has shown that the neither the economy nor prices move in a steady or predictable pattern. Longer-term growth projections rarely coincide with the current environment. Nonetheless, long-term averages are useful when considering forecasts of 5, 10, or 20+ years. They are also useful in examining how U.S. natural gas balances might be affected by changes in key macroeconomic variables.

A. Economic Activity

The overall level of domestic economic activity influences the demand for natural gas because natural gas is an important input to many production and consumption processes. U.S. Gross Domestic Product (GDP) is a commonly used official measure of overall economic activity.[6] For purposes of this study, it was assumed that U.S. GDP increases (in constant dollars) at an average of 2.8% from 2002 through 2004 and by 3.0% from 2005 through 2025. These GDP growth rate assumptions were based on (1) historical data on U.S. GDP itself, (2) historical data on the U.S. labor force and its productivity, and (3) the projections published by major economic research firms.

1. GDP Data

The historical GDP data are summarized in Figure D2-15. For the years 1950 through 2001, the average of the annual changes in constant dollar U.S. GDP is +3.5%. From 1970 to 2001, the average annual change is +3.0%. The average of the annual changes for the decades of the 1970s, 1980s, and 1990s are +3.3%, +3.0%, and +3.0%, respectively.

2. U.S. Productivity and Labor Data

Overall economic activity in the United States can be broken apart for more detailed analysis in many ways. One important way is to observe that overall output is the product of output per hour worked (productivity) and number of hours worked (and thus that the GDP growth rate is approximately the sum of the productivity growth rate and growth rate of hours worked). Figure D2-16 illustrates the growth rate of productivity.

The average productivity growth over the period 1950 through 2001 is 2.2%. The average for the period 1960 through 2001 is 2.0%. The average for the decades of the 1970s, 1980s, and 1990s are 1.9%, 1.4%, and 1.8%, respectively. The literature discussing productivity growth identifies several shifts since 1950. Productivity growth averaged nearly 3% from the early 1950s to the early 1970s; only about 1.4% from 1974 to 1995; and more than 2% in the late 1990s. There is disagreement, of course, about which period (or periods) best represents a basis for making assumptions about future productivity growth; the late 1990s rebound in productivity growth is thought to have resulted from strong capital formation and the adoption of new computation and communication technologies. Although productivity growth is not an explicit input to the modeling effort, the study's assumption of a 3.0% rate of GDP growth is amply supported by recent productivity data.

The population growth rate charted in Figure D2-17 shows steady declines toward 1% in 1990 and then further projected declines to between 0.8% and 0.9% at the end of the study period. The labor force is a fraction of the total population. The labor force growth rate rose from between 1% and 2% in the 1950s to more than 2% in the 1970s as the baby boom generation came of working age and the labor force participation rate for females rose significantly. The labor force growth rate declined to about 1% during the 1990s as the working age population grew more slowly and the female participation rate approached that of males.

In addition to population growth rates becoming lower, the age structure of the U.S. population is projected to change during the study period. Figures D2-18 and D2-19 illustrate this phenomenon. These data suggest that while the number of people in the United States that are of working age will continue to increase during the study period, the fraction of the population in this age category will decline.

A continuation of the recent labor force and productivity growth rates of about 1% and 2%, respectively, would result in about 3% growth in real GDP. The available data seem to support this idea.

B. Industrial Production

Implicit in the U.S. GDP growth assumption is a 3% annual increase in overall Industrial Production. Historically the industrial sector has been the largest

[6] Gross domestic product (GDP) is the sum of the value (prices multiplied by quantities) of all goods and services purchased by final consumers. For purposes of computing GDP, final goods and services produced domestically are partitioned into those purchased by domestic consumers ("consumption"), those purchased by domestic firms ("investment"), those purchased by domestic governmental organizations ("government"), and those sent outside the U.S. less those produced outside the U.S. but purchased by domestic consumers, firms, or governments ("net exports").

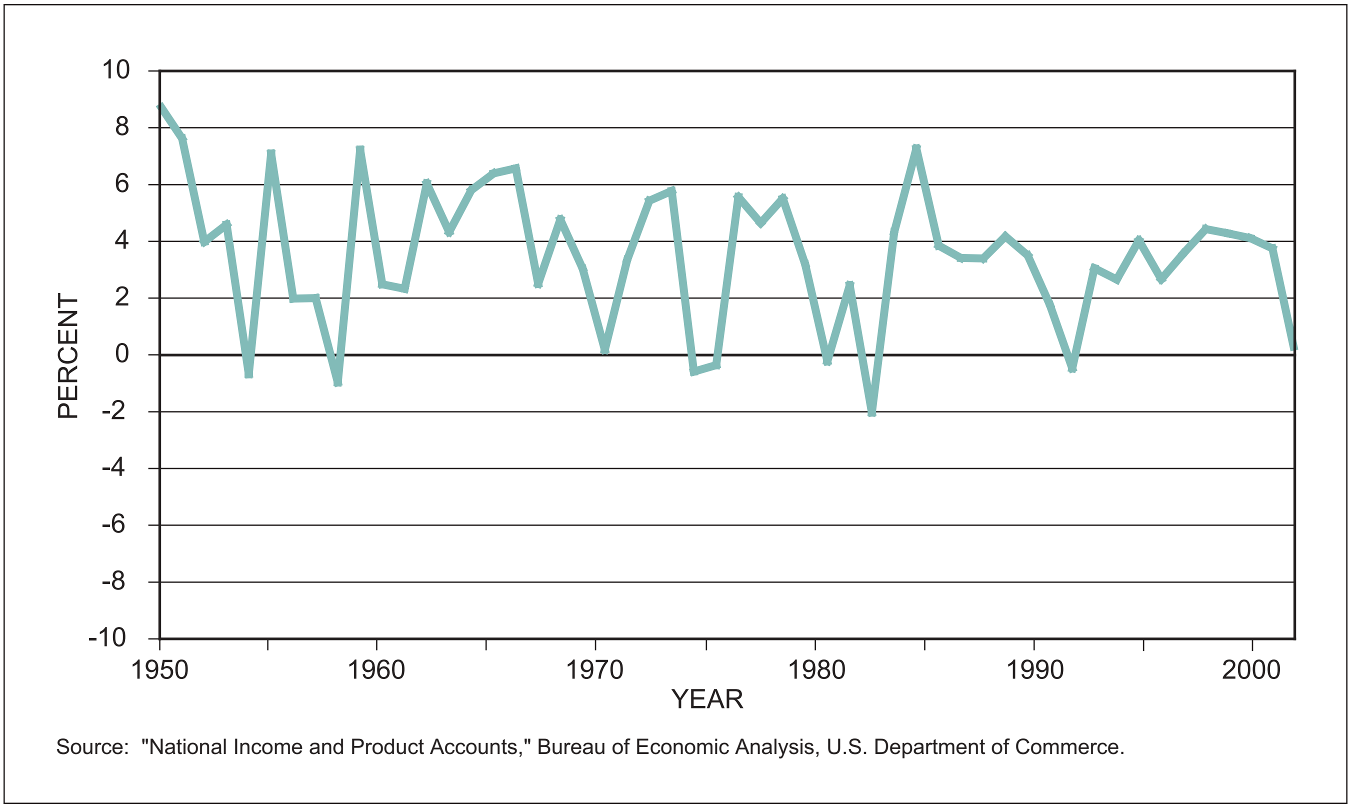


Figure D2-15. U.S. GDP – Annual Change in Constant Dollars

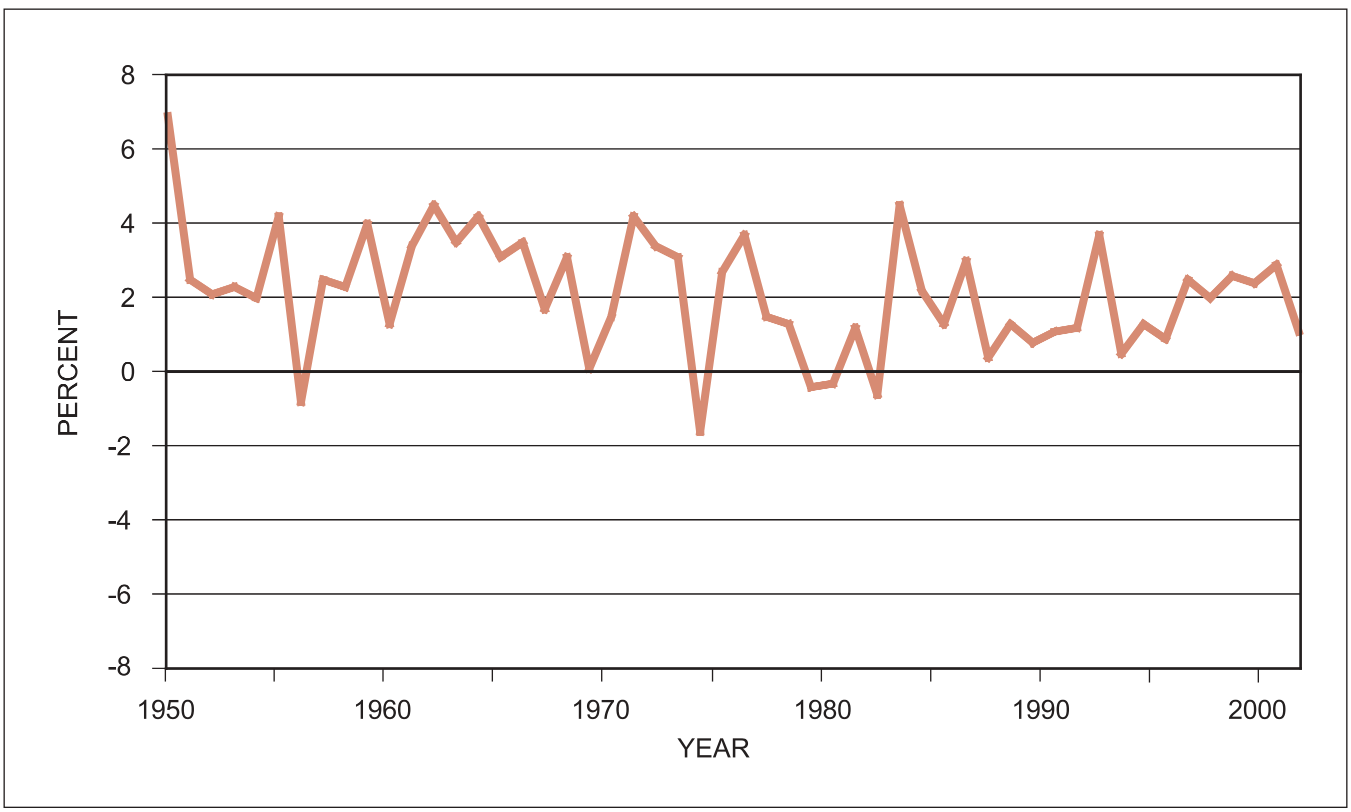


Figure D2-16. U.S. Productivity – Annual Change in Output per Hour of Work, Non-Farm Business

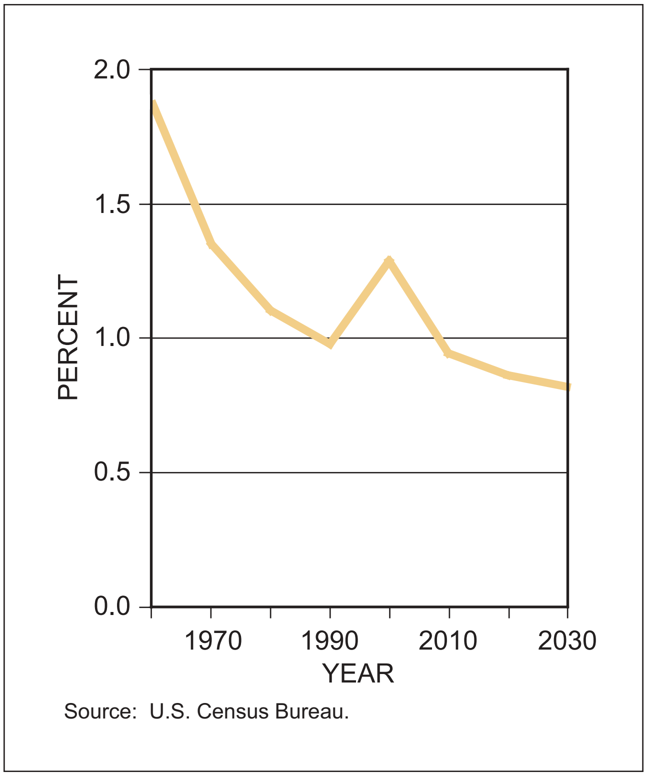


Figure D2-17. U.S. Population – Historical and Projected Annual Average Growth Rate

consumer of natural gas. However, the Demand Task Group observed significant changes in the components of U.S. industrial production that could decrease the intensity of gas use. Therefore, as described in detail in Chapter 3 of this Demand Task Group Report, the industrial sector was evaluated and modeled in a manner that allowed the behaviors of the most gas-intensive industries to be described; thus, the NPC study group was able to gain insights into industrial gas use, assess implications of various factors affecting natural gas consumption, and make recommendations accordingly.

The composition of North American industry appears to be changing from raw material and heavy manufacturing to a high-tech and high value-added structure. Gas and other energy-intensive manufacturing are shrinking. For example, ammonia and methanol companies have moved operations to economically favorable locations over the past decade. An increasing portion of basic chemicals is coming from overseas, rather than from domestic-sourced manufacturers. High value-added manufacturing will often require energy in the form of electricity rather the direct use of natural gas or liquid fuels. Also, a growing service industry tends to be more electricity driven.

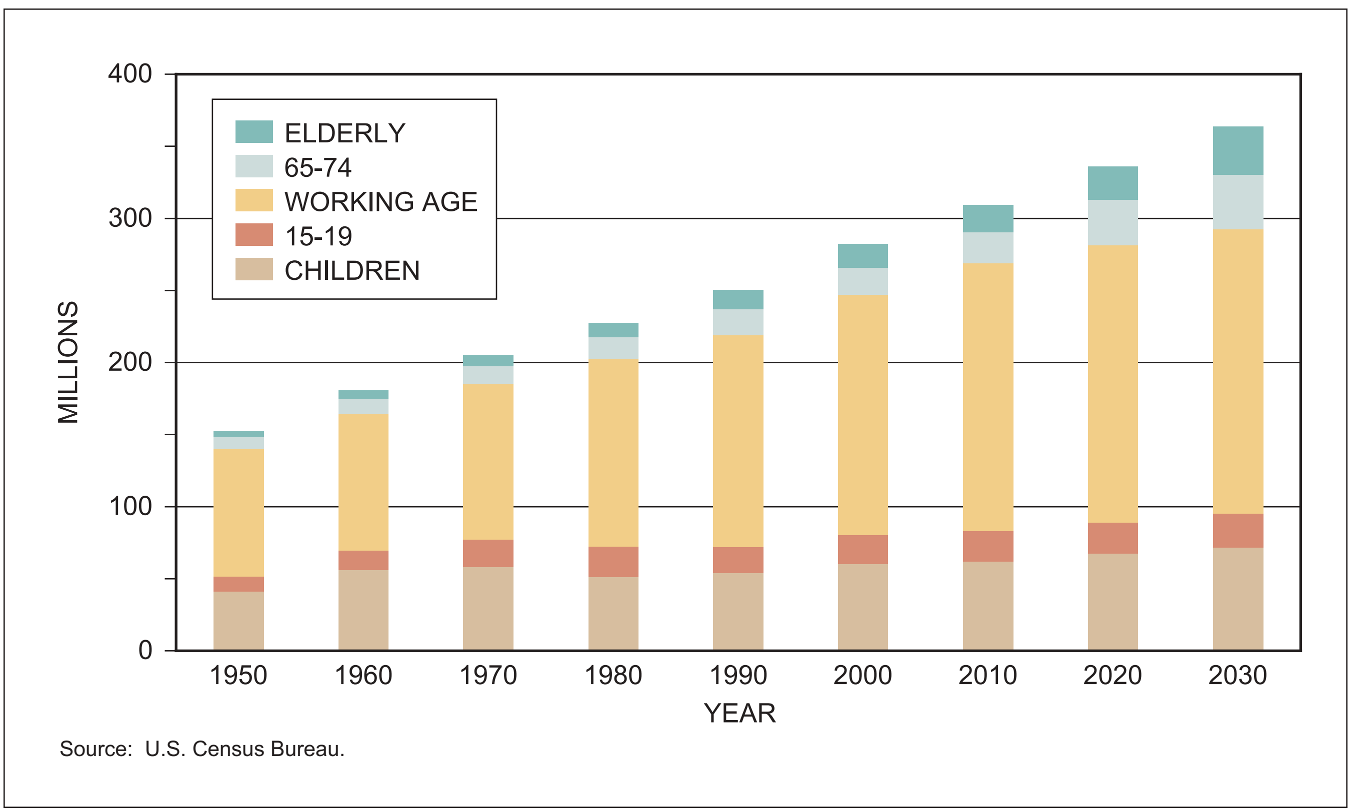


Figure D2-18. U.S. Population by Age – Historical and Projected

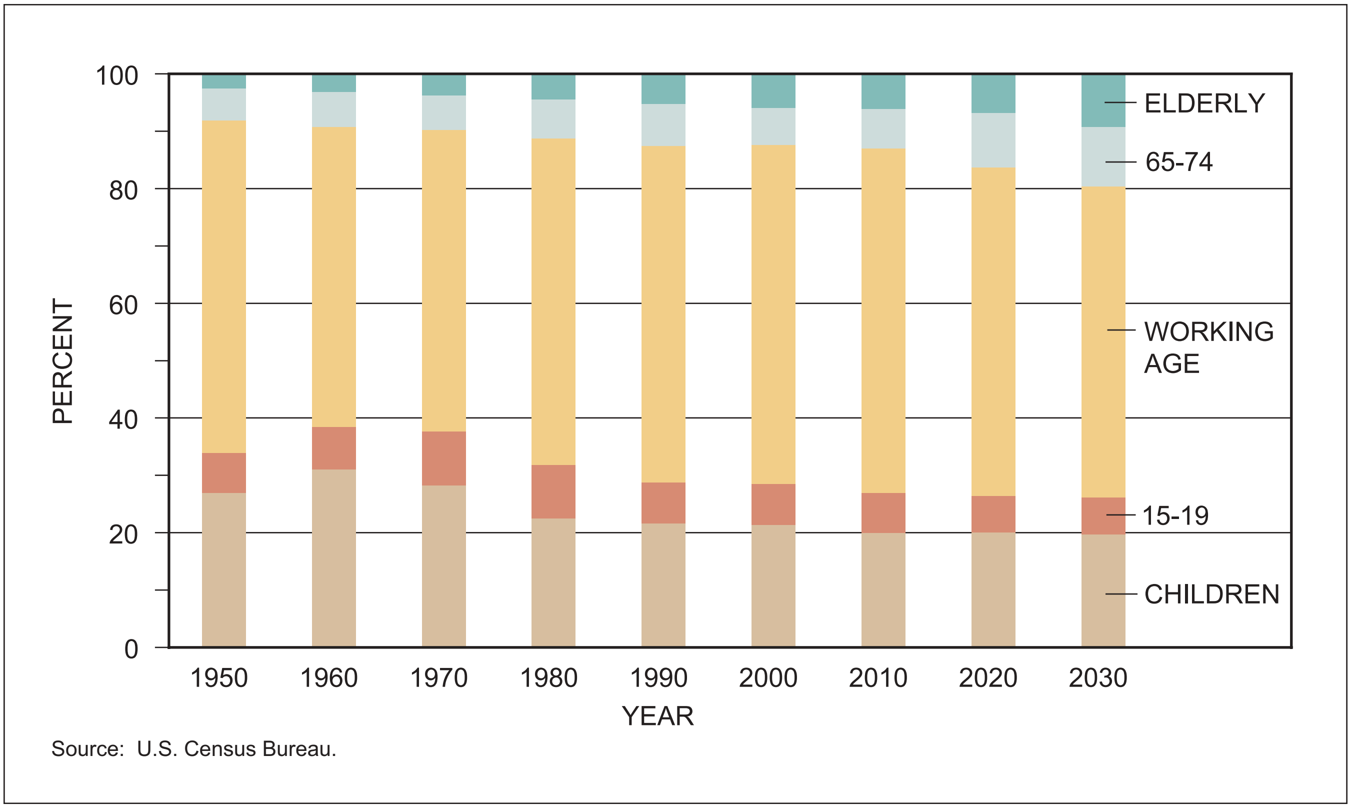


Figure D2-19. U.S. Population Distribution by Age – Historical and Projected (Fraction of Total)

Figure D2-20 shows annual growth in U.S. industrial production from 1960 to 2002. Over the whole period, U.S. Industrial Production increased at an average of 3.3% annually. For more recent periods, average annual rates were as follows: 1980-2002, 2.6%; 1990-2002, 2.9%; and 1995-2002, 3.4%. For the 2003-2025 period, the Task Group assumed that an assumption of 3.0% annual growth in Industrial Production was consistent with recent trends and other assumptions on the structure of the U.S. economy. And, as described in Chapter 3, individual industry sectors were assumed to have different, industry specific Industrial Production factors.

C. Inflation

For purposes of this study, the Task Group assumed that fiscal, monetary, and environmental policy would be consistent with U.S. and Canadian GDP growth assumptions. In particular, monetary policies would prevent growth from averaging much above the 3% U.S. number, and both monetary and fiscal policies would prevent any sustained periods of economic growth much below 3%. From 1995 to 2001, inflation (as measured by the GDP Implicit Price Deflator) increased at an average rate of 1.9%, due in large part to above-average productivity increases in the second half of the 1990s. The study team assumed that an inflation rate of 2.5% per year was consistent with expected policy and productivity trends.

D. Rates of Return

For purposes of this study, the average rate of return on corporate bonds was assumed to be 4.5% in constant dollars and the average rate of return to corporate equity was assumed to be 9.5% in constant dollars. (Given the inflation assumption, these are 7% and 12%, respectively, in current dollars.)

E. Canadian Economic Growth

Canada is the largest trading partner of the United States, accounting for about one-fifth of total U.S. trade. The level of overall economic activity in Canada is closely integrated with that of the United States and therefore received special consideration in the study. The Canadian historical data are summarized in Figure D2-21.

For the years 1962 through 2001 (the period over which consistent data were readily available) the

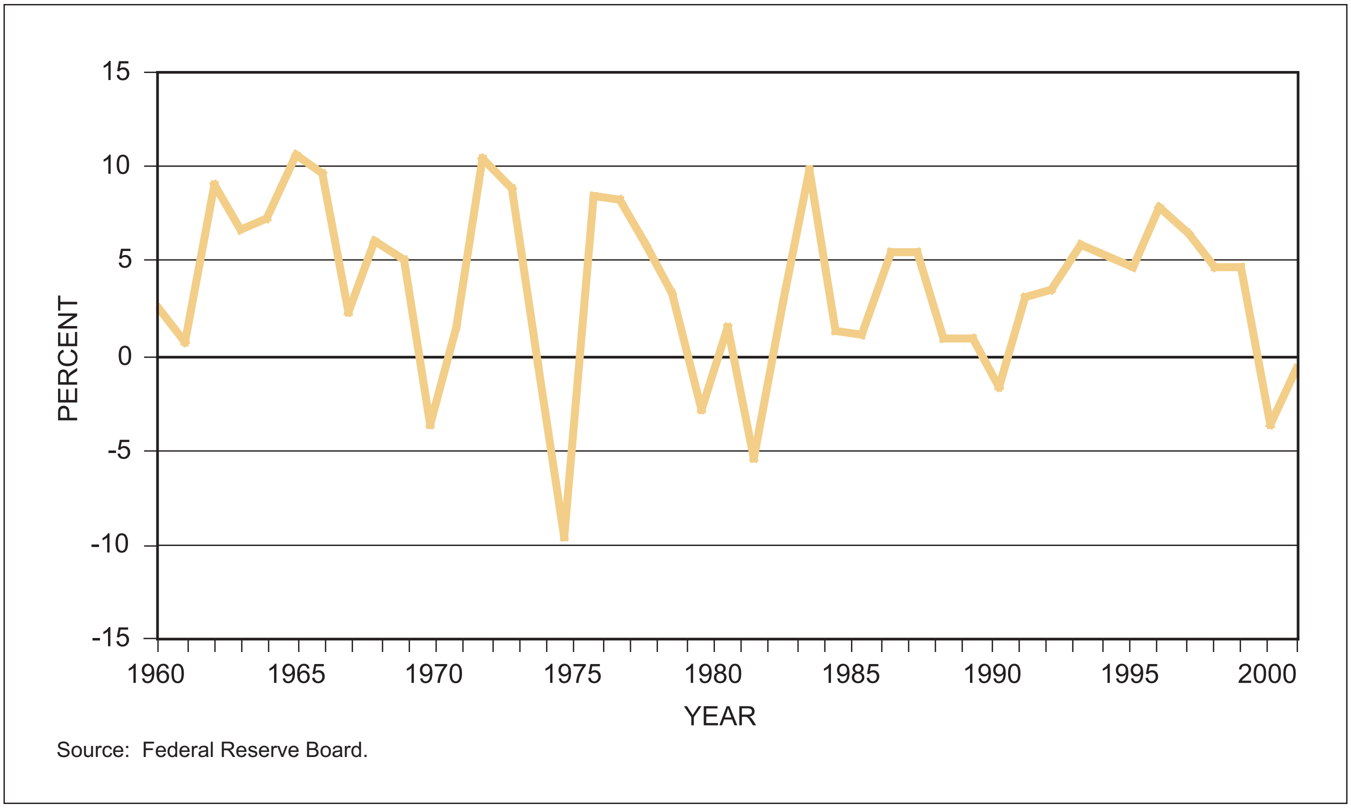


Figure D2-20. U.S. Industrial Production – Annual Changes

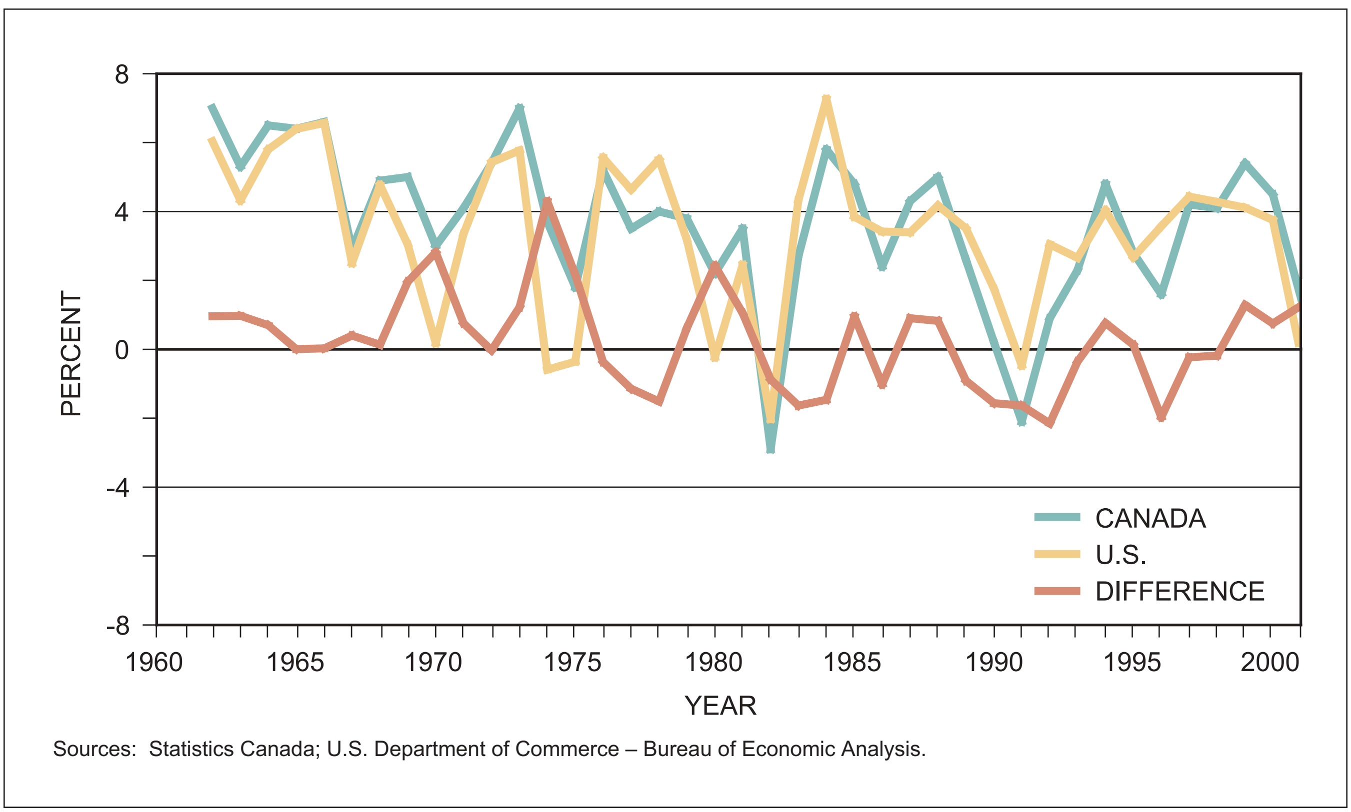


Figure D2-21. GDP in Canada and U.S. – Annual Change in Constant Dollars average annual change in constant dollar GDP was 3.7%, falling to 3.2% from 1970 to 2001 the average annual change is +3.2%. The average of the annual changes for the decades of the 1970s, 1980s, and 1990s are +4.0%, +3.2%, and +2.4%, respectively.

The study team also considered tying its Canadian number to its U.S. number. Figure D2-21 also illustrates the difference between U.S. and Canadian GDP changes. Over the period 1962-2001, the average of annual Canadian GDP growth has been 0.3 percentage points above the average annual U.S. GDP growth and for the decade of the 1990s, annual Canadian growth has averaged 0.4 percentage points below average U.S. annual growth.

The above analysis resulted in the study team assuming that Canadian GDP (constant dollar) would grow an average of 2.4% over the 2002-2004 period and 2.6% thereafter.

F. Alternate Fuels

The price of alternate fuels is expected to influence long-term gas demand. Depending on the timeframe and end use technology, principal alternate fuels to gas over the study period are likely to be crude oil-derivative fuels and coal. However, alternate fuel economics are complex and dynamic with variables that include the relative thermal efficiency of the energy conversion process and emissions issues with use of alternative fuels. Petroleum products refined from crude oil – mainly gasoline, distillate fuel oil, and residual fuel oil – are used for a variety of applications including transport, heat, power, and feedstock. Coal, on the other hand, is used almost exclusively to generate power.

With crude oil the dominant worldwide energy commodity, its price will be a significant factor in influencing future natural gas prices in North America. Figure D2-22 shows that oil prices have been quite volatile over the past decade. The real price (2002 dollars) of West Texas Intermediate crude oil (a benchmark U.S. crude oil that is traded on the NYMEX) averaged $22.76/barrel over the 1990-1999 period, and the 2000-2002 average was about $26.00/barrel. These averages are higher than the $20.00/barrel real price that this study assumes over the 2005-2025 period.

The Demand Task Group assumed that crude oil prices would revert to levels seen over much of the 1990s. Higher crude oil prices since 1999 study have been primarily the result of an unusual degree of

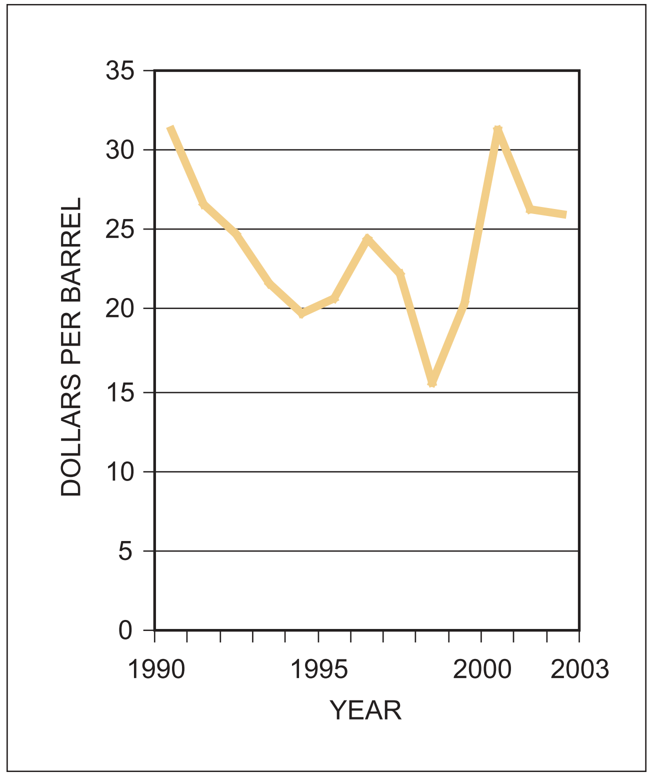


Figure D2-22. West Texas Intermediate Crude Oil (NYMEX) – Real Price (2002$)

OPEC discipline and an unusual period of disruptions in oil flows. This study did not explicitly look at worldwide costs for finding, developing, and producing oil; however, there is no evidence to suggest that there has been any upward movement in these costs in recent years. Beyond 2005, current proved reserves, combined with new discoveries and continued technological innovation (including anticipated market penetration of fuel-efficient hybrid vehicles) are expected to be sufficient to meet growing demand without significantly higher prices. Global proved reserves have been rising in recent years, particularly non-OPEC reserves.

In other oil-related assumptions this study assumed that average refiner acquisition cost of crude oil (RACC) would average 90% of WTI (NYMEX). RACC has averaged approximately 91% of WTI since 1990. The price of residual fuel oil is assumed to average 85% of RAAC over the 2005-2025 period, and the distillate fuel price is assumed to be 140% of RACC.

Delivered coal prices to all consumers were assumed to be $1.46 per MMBtu decreasing at 1% annually (in 2002 dollars). The premise for decreasing coal prices in real terms is that productivity increases will exceed increases in labor and capital costs. Additionally, there will be competition among coal plants and coal imports. Another premise is that savings in coal transportation (lower freight rates) will also reduce real prices.

G. Electricity – GDP Elasticity

The relationship between electricity consumption and overall economic activity (GDP) was a critical assumption in the modeling of the electric generating sector. This sector is expected to see the bulk of the growth in natural gas consumption over the study period.

In the United States, the amount of electricity consumed per unit of overall economic activity began to fall in 1975 after having climbed for several decades. Except for a 5-year period in the late 1980s, this measure of the electricity intensity of the U.S. economy has continued to decline (see Figure D2-23). This decline was assumed to continue through the study period. In particular, it was assumed that by 2025, electricity intensity will have fallen to about the same level it was at in the early 1960s – about 33 kilowatt-hours for every hundred dollars of GDP (1996 dollars). This decline is less rapid than occurred during the most recent 10-year period, 1991-2001, but more rapid than the average experienced over the 25-year period 1976-2001.

The relationship between electricity consumption and the level of overall economic activity can also be stated in terms of the ratio of the percent change in electricity consumption to the percent change in GDP. This ratio is an income elasticity of demand for electricity. With GDP assumed to grow at 3% per year, the rate of growth in electricity demand begins the 2005-2025 period at 2.16% and falls to 1.86% by the end of the period. Income elasticity of electricity demand falls from a current value of about 0.72 to a value of 0.62 in 2025.

Since 1950, the energy intensity of the U.S. economy has been falling, from about 20 thousand Btus per dollar of GDP (1996$) in 1950 to about 10 today. This is due to both (1) increased efficiency in energy use; and (2) more rapid growth in sectors of the economy that are not energy-intensive (such as services) and less rapid growth in the more energy-intensive sectors of the economy. The fraction of total energy that is consumed as electricity, however, has increased throughout this 50-year period, though at a slower pace beginning in the mid-1980s. These trends, shown in Figure D2-24, are also projected to continue.

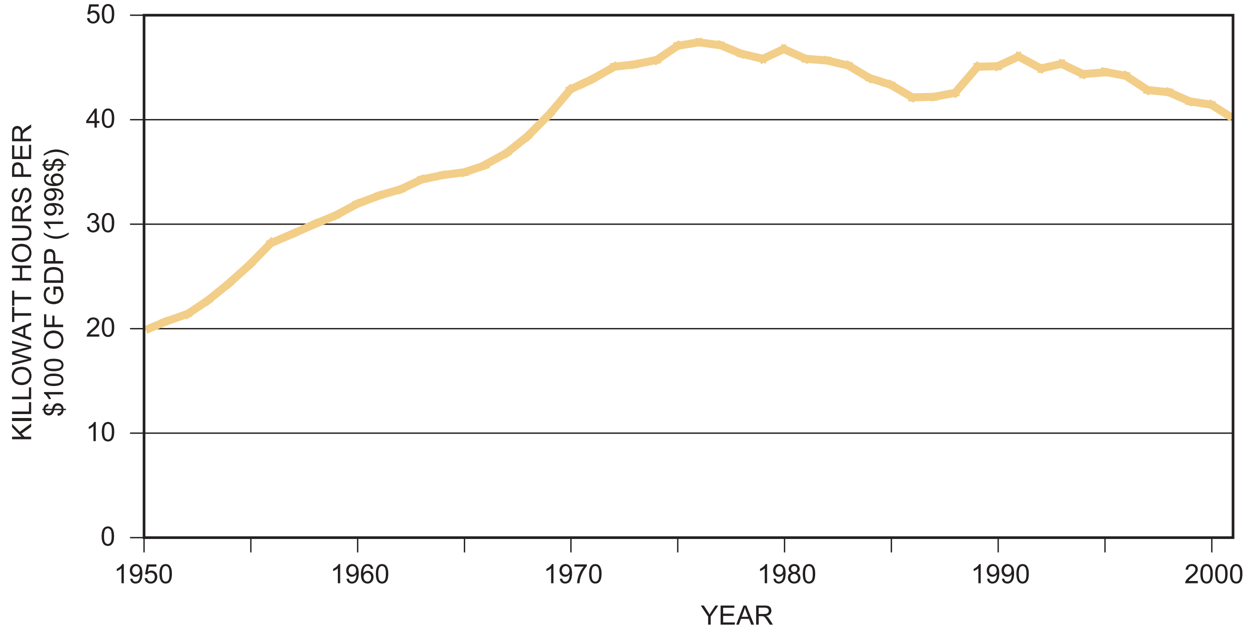
H. Scenario Differences

Given the uncertainty surrounding the continuing evolution of the gas industry in the United States – particularly from an energy policy standpoint – two primary scenarios were analyzed. The Reactive Path scenario assumes continued conflict between natural gas supply and demand policies – policies that tend to support natural gas usage but discourage supply development. For the Balanced Future scenario, policies were assumed that increase fuel use flexibility and choice, as well as supporting supply development. Most of the macroeconomic and price assumptions discussed above were the same for both scenarios.

In deciding to use the above assumption in the **Reactive Path** scenario, a path that shows a future with much higher natural gas prices that in the past, the study group considered information from an analysis performed by Global Insight.[7] In the analysis, the Demand Task Group requested that Global Insight compare its own macroeconomic outlook against a case that used this study's oil price assumption and natural gas prices developed by the EEA model in an early version of the Reactive Path scenario. The results of this analysis are shown in Table D2-1 and the entire report is in Appendix D. While absolute levels of GDP and Industrial Production would be lower under sustained levels of high gas prices, growth rates in these macroeconomic variables from 2005-2025 would not be significantly different from the above assumptions. Some of the salient conclusions from the Global Insight report include:

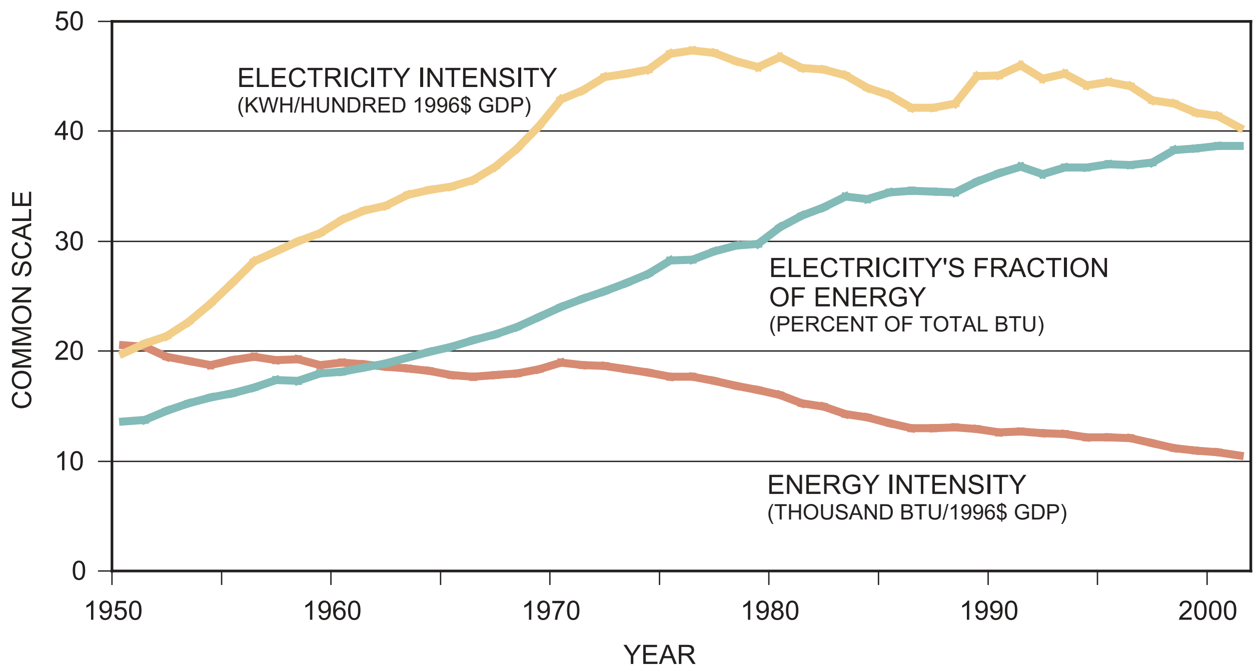
> Higher natural gas costs translate into lower spending, lower economic output and higher unemployment. At the peak impact year GDP is 1.1% lower, industrial production is 2.6% lower, employment is 1.2 million lower and inflation is 1.2% higher versus the Global Insight base case.
>
> Sustained higher natural gas prices would result in changes in production patterns and processes. As with previous oil shocks, inflation would increase, economic activity would be reduced, and unemployment would rise. Since natural gas is used in the production of all goods and services, all other prices would rise as well, depending on the energy content of that product.

[7] Global Insight Inc., 24 Hartwell Avenue, Lexington, MA 02421-3158.



Sources: Energy Information Administration; U.S. Department of Commerce – Bureau of Economic Analysis.

Figure D2-23. U.S. Electricity Intensity



Sources: Energy Information Administration; U.S. Department of Commerce – Bureau of Economic Analysis.

Figure D2-24. Energy and Electricity in the U.S. Economy

ECONOMIC EFFECTS	2005	2010	2015	2020	2025
Economic Impacts (% Difference from Global Insight Base)					
Economic Indicators					
Real GDP	-1.1%	-0.6%	-0.2%	-0.3%	-0.4%
Employment, Establishment	-0.9%	-0.4%	-0.1%	-0.2%	-0.3%
Manufacturing	-1.4%	-0.6%	-0.5%	-0.8%	-0.9%
Non-Manufacturing	-0.8%	-0.3%	-0.1%	-0.2%	-0.2%
Employment, Establishment (Difference)	-1.21	-0.53	-0.15	-0.38	-0.51
Manufacturing	-0.22	-0.10	-0.08	-0.13	-0.16
Non-Manufacturing	-0.99	-0.43	-0.07	-0.25	-0.35
GDP Price Deflator	1.0%	1.2%	1.0%	0.9%	0.4%
PPI	3.0%	3.4%	3.2%	3.3%	3.0%
Fed. Funds Rate	-0.22	-0.21	-0.23	-0.32	-0.50
INDUSTRY EFFECTS	**2005**	**2010**	**2015**	**2020**	**2025**
(% Decline by Industry)					
Industry					
Agricultural Chemicals	16.32	8.09	25.33	33.17	28.97
Chemical Fertilizer	14.09	6.38	21.32	27.70	23.55
Other Metal Mining	13.03	5.36	17.54	22.21	18.43
Chemical Products	11.51	4.83	16.55	20.64	16.59
Blast Furnaces and Steel Mills Product	9.37	4.15	11.68	14.79	12.46
Nonferrous Metal Product	5.87	2.50	6.63	7.93	6.20
Pulp, Paper, and Paperboard Mill Product	5.75	2.47	7.34	9.22	7.52

Table D2-1. Comparison of Global Insight Cases

Higher prices impose a burden on the U.S. economy – workers and producers must adjust to an environment with radically different relative prices. For businesses, the rising price of natural gas hurts their profitability, discourages their use of natural gas and encourages the use of more energy-efficient capital equipment and some additional labor to produce their products. Businesses respond by shifting towards other fuels; with a net effect of higher costs is and a loss of competitiveness.

Consumers face an increase in the cost of natural gas and electricity, encouraging them to reduce their expenditures on energy. Some workers lose their jobs through a weaker economic environment, while other workers lose well-paying manufacturing jobs, and find only lower wage service jobs. All workers face a slowing in their real wage growth. Further, real disposable income falls due to reduced employment and lower wages.

In addition, the economy is worse off as the increase in natural gas prices pushes up inflation and interest rates. Higher interest rates reduce housing starts, vehicle sales, and business investment. With a lower level of productive capital stock, fewer people are employed and real GDP is smaller.

Significant losses in output are projected for industries that are gas-intensive. As natural gas prices rise, industry attempts to reduce use of this fuel. For gas-intensive industry, it is projected that there would be some movement of production to other countries with lower gas costs. The loss of output from these two effects would cause a ripple through the rest of the economy.

Macroeconomic and alternate fuel prices were similar in the **Balanced Future** scenario. An exception was that policies were assumed that would increase efficiency and conservation relative to the Reactive Path scenario. The most significant change in assumptions was in the electricity demand income elasticity. Whereas income elasticity of demand for electricity falls from a current value of about 0.72 to a value of 0.62 in 2025 in the Reactive Path scenario, the Balanced Future scenario steepens the trend to a value of 0.55 in 2025. Smaller effects were applied to the other sectors.

V. Price Relationships between Natural Gas and Alternate Fuels

The results of this study show that U.S. natural gas prices will likely average higher than in the past. In the Reactive Path scenario, Henry Hub natural gas prices increase from $5.17 in 2005 to $7.23 in 2025 (2002 dollars). This is in sharp contrast to the $2.43 average price of Henry Hub gas from 1990-1999. However, the real price of oil is assumed to average only $20.00/barrel from 2005 to 2025.

Historically, whenever energy prices were high consumers switched to cheaper fuels and conserved energy while producers quickly raised supply. The price of natural gas rarely strayed much above low sulfur petroleum products, because consumers switched to lower priced fuels. This study does not expect gas prices to follow this historical pattern for several reasons:

- Low natural gas prices during the 1990s were primarily a result of the unraveling of price controls that produced surplus gas (the Gas Bubble).
- The ability of consumers to switch to alternate fuels has been significantly diminished due to federal, state, and local restrictions.
- Environmental regulations have made natural gas a preferred fuel because of its clean-burning characteristics.
- Gas Producing basins in North America have matured, raising the costs of finding and developing new supplies.
- The buildup of facilities to import lower cost overseas LNG will take a long time due to long lead-times for terminal construction and for overseas liquefaction projects, as well as siting issues, and competition for LNG from Europe and Asia.
- Increasingly stringent restrictions on sulfur content in petroleum products may increase their price versus the price of crude oil.
- New gas-fired combined-cycle electric generating plants are significantly more efficient than many existing oil-fired steam generating plants, allowing generators to pay a higher price for natural gas and still be competitive against oil-burning plants.

Throughout the 1990s, the wholesale price of natural gas on a Btu basis generally varied between residual and distillate fuel oil but well above the delivered price of coal to powerplants (Figure D2-25). This price dynamic made natural gas a preferred fuel to meet more stringent environmental regulations and for the rapid growth in electric generation. In the late 1990s, as the gas bubble dissipated, natural gas prices moved up towards distillate fuel oil equivalency.

Since the late 1990s, there has been a structural change in the cost of producing natural gas in North America. The traditional gas resource base is mature and much of the easily found and low cost gas has been produced. To find additional gas producers are forced to drill higher cost wells – wells below 10,000 feet, wells in water over 1,000 feet deep, wells with lower deliverability and wells requiring sophisticated and high-cost technology. These are permanent changes in the U.S. supply cost equation, changes that require a significantly higher price to produce the same volume of gas as in the 1990s.

Similarly, there have been structural changes in the gas demand equation. Policies on the federal, state, and local levels have been highly effective in causing new investment decisions for combustion applications to choose natural gas rather than alternate fuels such as coal and petroleum products. Since the late 1980s, large investments have been made in gas-burning equipment by industrials and power generators to meet emission regulations. Advancements in technology now allows combined-cycle gas turbines to produce electricity 30-50% more efficiently than in steam-generating plants. For coal and oil to compete with natural gas in many stationary applications now requires significant capital investments in environmental controls for sulfur and

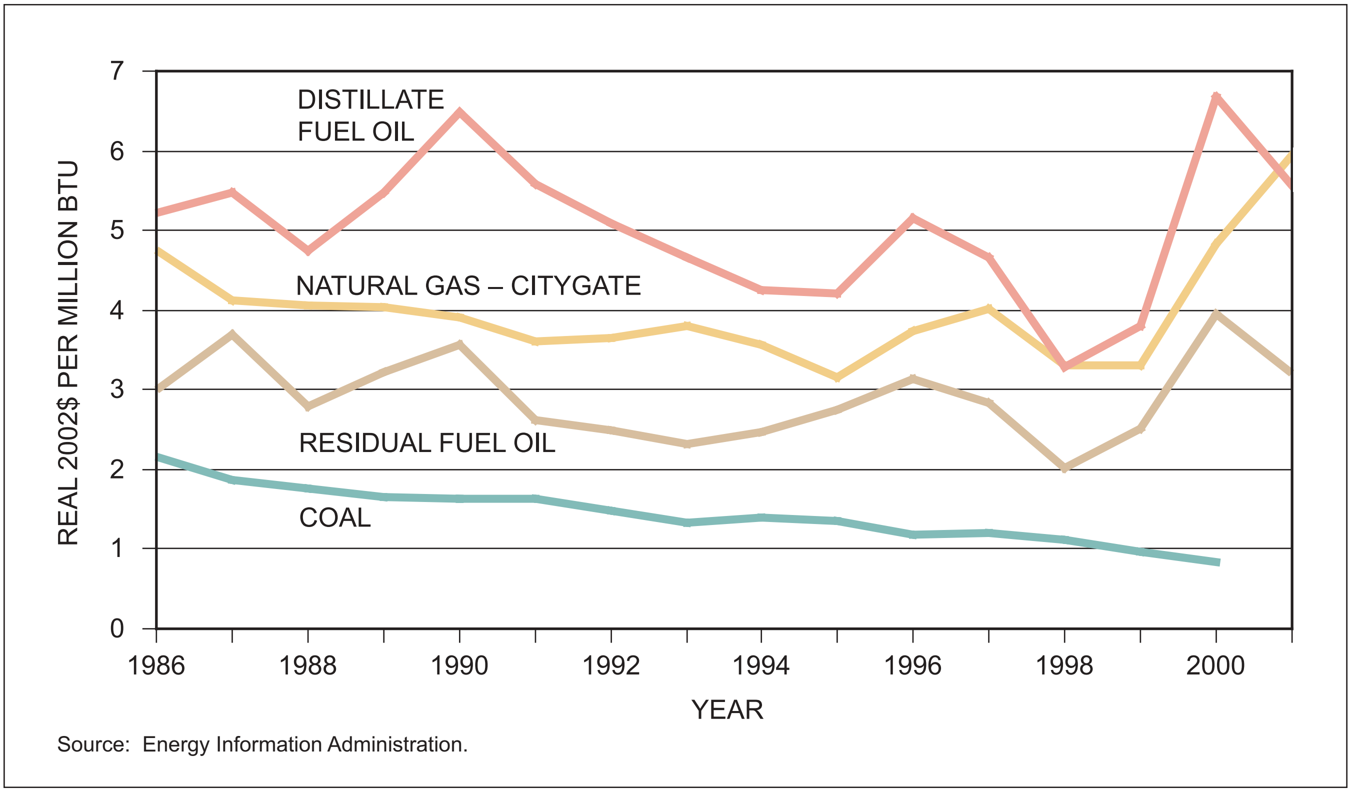


Figure D2-25. Cost of U.S. Wholesale Fuels

nitrogen emissions with the potential additional costs to control mercury and carbon sequestration. These incremental costs are factored into the price that consumers are willing to pay. These dynamics have raised the gas demand curve for the foreseeable future.

The costs of imported LNG tend to be below the price level anticipated in this study. If North America could import unlimited volumes of LNG, then gas prices would fall to the marginal LNG costs. However, LNG is becoming a worldwide commodity, the demand for which is growing; terminals are difficult to site in North America; the LNG supply chain involves billions of dollars; and LNG terminals have limited throughput and storage capacities. These characteristics will likely limit the number of terminals that can be built over the 2003-2025 period. The United States must compete for LNG with growing and well-established markets in Europe and Asia where LNG is priced in parity or higher against alternative fuels or oil. However, in North America, LNG imports will likely be a "price taker," receiving prices similar to North American gas in the region they are delivered.

With these shifts in both the natural gas demand and supply relationship, North America can expect gas prices to average above the levels experienced throughout the past two decades. While significant changes in policies and regulations can be mitigating factors, this study suggests that they will be unable to reverse this higher gas price track. Existing policies, regulations, and long-term facility investments limit the alternatives to natural gas for many consumers. Although capital and new technologies will likely allow oil-burning and potentially coal-burning facilities to operate at very low emission levels, the additional capital costs as well as investment in oil storage is likely to put an economic premium on natural gas in many applications.

It is also likely that the price of fuels against which natural gas will compete will be rising in the future. While crude oil prices are expected to remain constant in real terms the price of low sulfur fuels may be on a rising trend. Environmental rules are becoming more stringent in both the United States and rest of the world. Regulations on sulfur levels in fuels are increasing, which puts additional burdens on refiners and increases the costs of producing these low-sulfur fuels. Figure D2-26 depicts a rising trend in the cost of residual fuel oil relative to RACC for U.S. electric

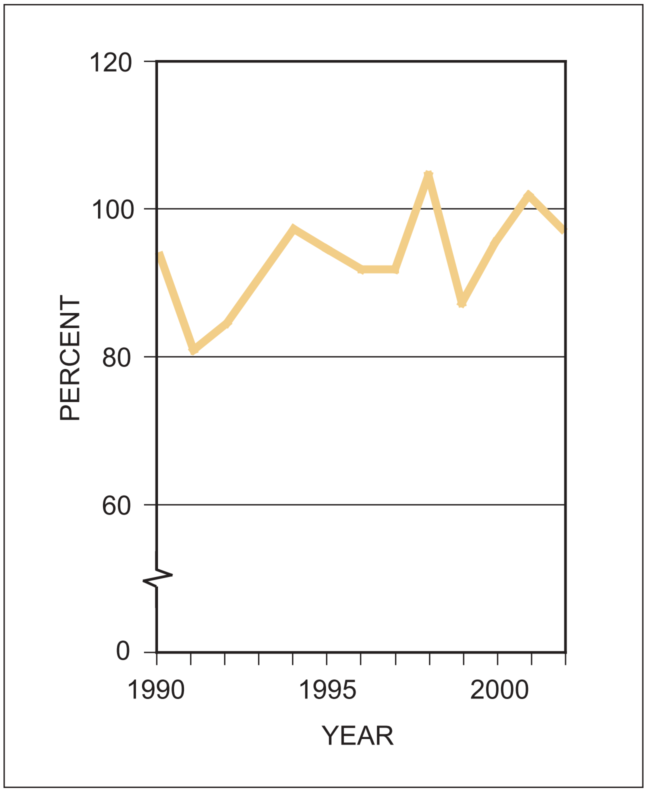


Figure D2-26. Residual Price vs. RACC (Cost to Electric Generators)

generation. Lower sulfur diesel regulations may affect distillate fuels in a similar manner.

Most regions of North America have seen a significant increase in gas-fired generation since the mid-1990s. To a large extent these additions have been highly efficient combined-cycle gas turbines (CCGT), capable of generating electric power at heat rates around 7,000 Btus/Kwh. In contrast, older dual-fuel (oil and natural gas) steam generation plants have lower efficiencies (greater than 10,000 Btus/Kwh). Given a choice to operate either a new CCGT plant or older dual-fuel steam facilities based solely on fuel costs, the CCGT plant could pay 40% more for natural gas than for oil (on a Btu basis) and still generate lower cost electric power – creating an incentive to pay a higher price for natural gas in some periods.

The two base-case scenarios suggest that natural gas will be able to sell at a premium to crude oil through 2025. In addition to CCGT technology, other primary demand drivers for this new price relationship are more stringent clean air standards, the great difficulty in building new coal-fired or nuclear powerplants, and the steady domestic shift from a heavy industrial base to a more service- and information-based economy that places a higher value on reliable electricity.

A. Energy Market Structure

In efficient markets, buyers and sellers see price signals that convey information. If prices are low, this is generally a signal for consumers to increase consumption and for producers to reduce output. High prices signal the opposite behavior. For the gas industry, clear market signals essentially began in the early 1990s, when Henry Hub natural gas began trading on the NYMEX. This established a transparent price that allowed all buyers and sellers to see the same signals at the same time.

The growth of gas trading at Henry Hub led to additional locations where gas buyers and sellers entered into short- and longer-term contracts. Dozens of trading points were established in Texas, California, Illinois, Wyoming, New York, etc. Many non-industry participants were attracted to these markets, providing additional liquidity (creating large enough pool to prevent a single participant from significantly influencing the market). Market liquidity and number of transaction declined after 2000, following market turmoil caused by bankruptcies, accounting scandals and government investigations.

The cost of entering into long- and short-term gas contracts is higher than it was at the height of market liquidity. With fewer market participants, risks are higher, requiring higher margins between the bid and ask price. Lack of transparent prices and constraints on trading gas and derivative products inhibit transactions and do not provide appropriate signals. The result is that both buyers and sellers may not be making the most efficient decisions.

Government needs to encourage a fair and liquid market for physical hubs, natural gas futures and other financial instruments to ensure an efficient market. Industry regulators, collectively the FERC, the CFTC, and the state public utility commissions, all need to cooperate in the regulation of energy, energy infrastructure and energy trading through existing laws and regulations, with an emphasis on the development of efficient and competitive energy markets and legal certainty of the enforceability of energy derivatives. They have and should continue to use their broad panoply of powers to bring enforcement actions against those firms who violate laws and regulations.

VI. Price Volatility

Restructuring of the gas industry and the deregulation of the natural gas commodity has produced a competitive market with lower natural gas prices to consumers. Accompanying this deregulation has been greater variability in natural gas prices as market forces establish prices in the monthly and daily markets. Price volatility is a natural dynamic in a commodity market where supply and demand vary. Natural gas, electricity, crude oil, and oil product markets have all exhibited price volatility to varying degrees. Relatively large price changes (spikes and declines) occur in natural gas markets because supply and/or demand are not able to adjust quickly enough to cause a smooth price trend. Volatility tends to highlight inelasticity in some market segments.

The principal drivers behind volatility are supply and demand fundamentals, which include growth trends, weather, storage levels, and perceived market trends. Price volatility has a wide range of impact on market participants and there are several tools to manage the effects. However, 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. Price Volatility in the North American Market

The vast majority (80-90% by volume) of natural gas marketed in the United States and Canada is sold on a monthly basis. The remainder (10-20%) is bought and sold in the daily cash market and is primarily used to manage the overall supply/demand balance during the month. Volatility is a measure of the variation of price from its mean value over a period of interest (daily, monthly, or yearly). Volatility in the broadest sense is the "noise" around the long-term movement of price. Some industry participants tend to think of volatility either in terms of abnormally "high" or "low" prices, or specific upward or downward movement in prices. This is incorrect. Volatility is simply a measure of variability around a mean value, not a measure of the absolute price.

Price volatility is important to market participants in optimizing near-term operating decisions because the level of volatility establishes the cost of options in gas futures contracts on NYMEX. The annual variability of gas price, if it is sufficiently large, creates a "seasonal spread" that produces an incentive for storage of gas among merchant energy companies and producers. It is, however, the long-term price expectation that drives major investment decisions in both the consuming and supply sectors.

B. Volatility Analysis

Gas prices exhibit a "log normal" distribution due to the fact that prices have no upside constraint, but are constrained on the downside by zero, as demonstrated in Figure D2-27. Therefore, a random distribution will be skewed positively around the mean price, the essence of log normality.

Although commodity prices follow a log normal distribution, changes in prices over specific periods can be either positive or negative, and approximate a normal distribution. Therefore the financial community looks at the log of the relative price changes to model historical and future price variations (see calculation methodology in box on facing page).

For the purposes of this study, volatility was examined in a historical perspective. Implied forward volatility and forward NYMEX prices are financial tools that may be used to understand where the market is trading for future periods. The NPC study group recognized that market participants may use the forward financial markets to buy and sell gas or enter into other hedging activities (e.g., puts and calls) to obtain price certainty and mitigate the impact of price volatility.

C. Historical Natural Gas Prices and Volatility

Henry Hub is a pipeline interchange in Louisiana where a number of interstate and intrastate pipelines connect through a header system. It is the standard delivery point for the NYMEX natural gas futures contract. There are two common price bases quoted for natural gas: (1) gas sold monthly and based on a first-of-month index price, and (2) gas sold on a daily cash basis. Figure D2-28 shows Henry Hub natural gas prices for both price bases.

Natural gas prices at the Henry Hub have ranged from less than $2.00/MMBtu to $10.00/MMBtu since 1995. The monthly index and daily cash prices follow each other closely. However, the daily cash price shows wider variability than the monthly market. This is particularly evident in the winters of 1995-1996 and 2000-2001.

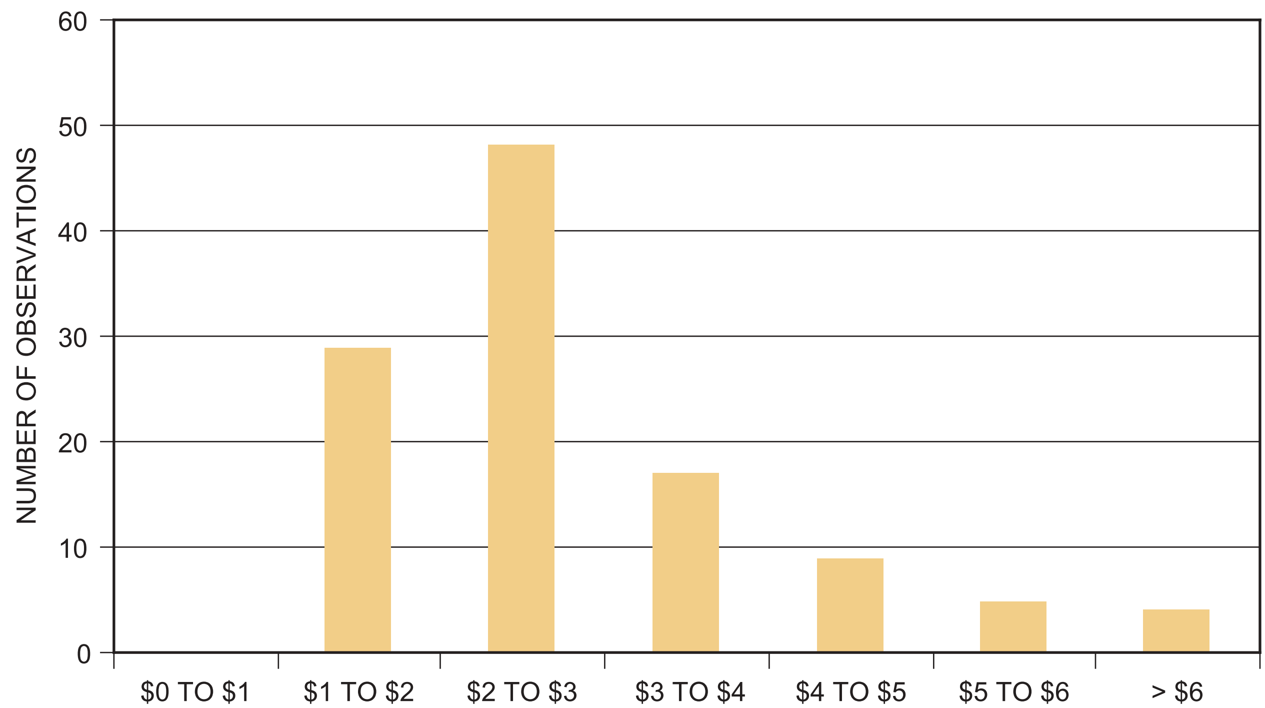


Figure D2-27. Frequency of Monthly Prices (1995/2003), Number of Observations in Price Range

Volatility of cash prices as calculated on a rolling 30-day basis has varied from 20% to 200% and has been highest during the late winter period, as shown in Figure D2-29. This is also illustrated in Figure D2-30, where periods of very high volatility reflect relatively inelastic demand during a peak winter period, which would be exacerbated by abnormal weather. There is no correlation between volatility and the absolute price, because there are volatile periods with prices across the entire range.

Daily Gas Price Analysis

P_i = Price on a specific day
P_{i-1} = Price on prior day
Price Change $_i$ = Return $_i$ = $\mathrm{Ln}(P_i / P_{i-1})$
Return average = (Σ Return $_i$)/n

Where: *n = total number of price observations*
Ln = natural log
Σ represents "the sum" from 1 to n observations

Standard Deviation = Square root of variance
= SQRT[{Σ(Return $_i$ – Return $_{avg}$)* ^{2}}/(n-1)]

Annualized Volatility = (Standard deviation) X (SQRT of # of prices in period)
Volatility is expressed as percentage. By convention, the number of prices or trading days in a year is 256 for daily prices.

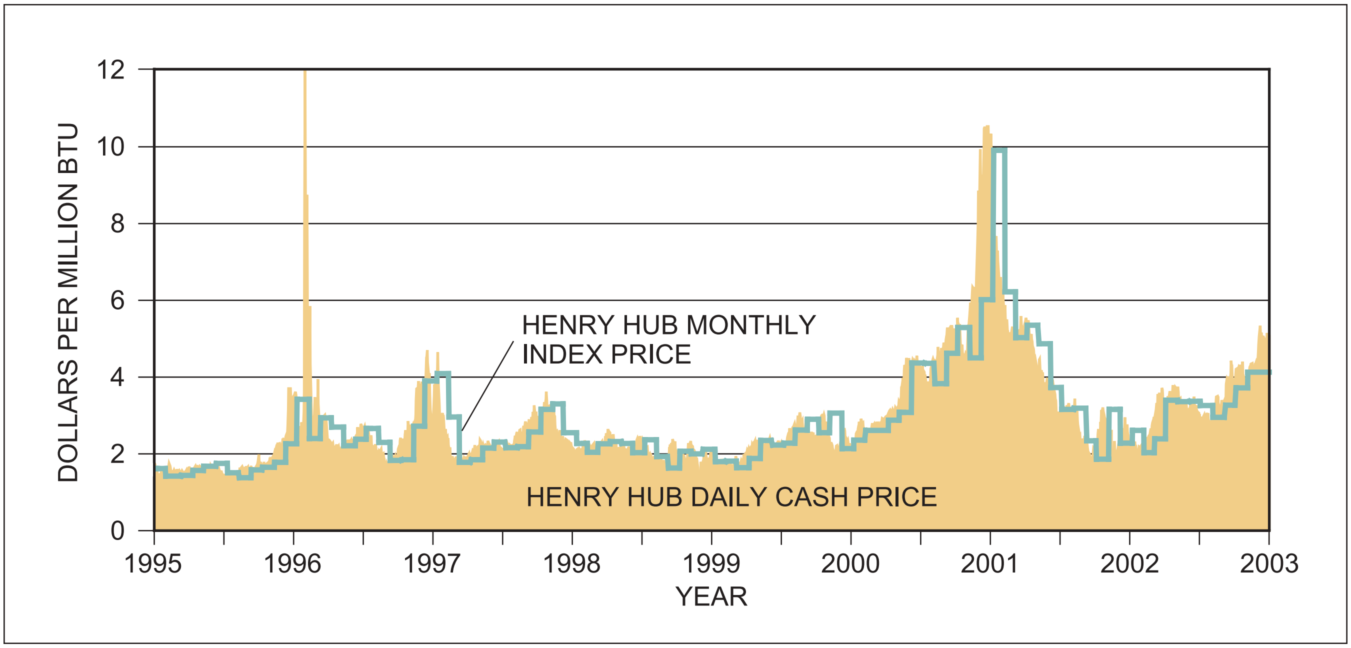


Figure D2-28. Henry Hub Natural Gas Prices

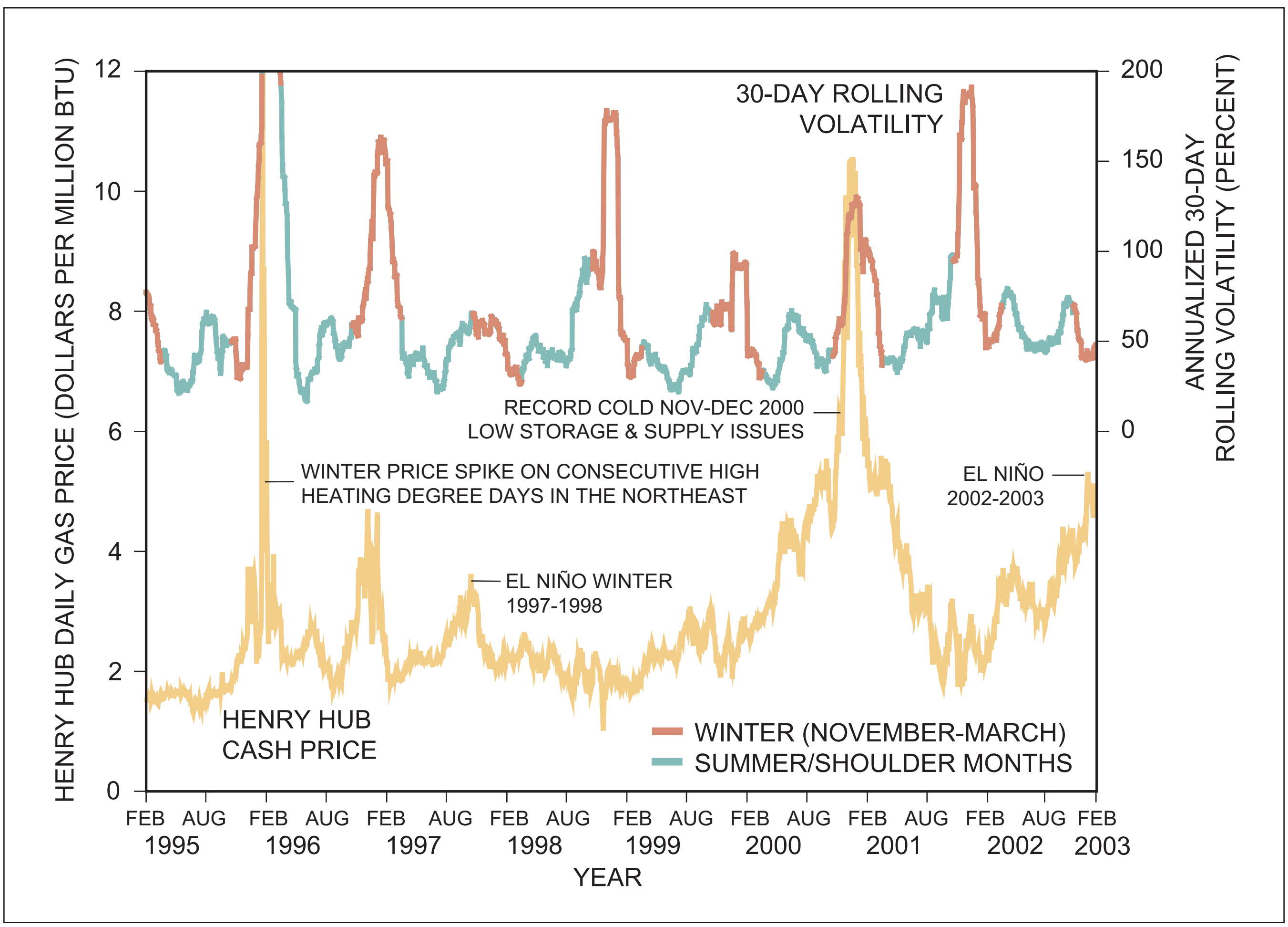


Figure D2-29. Natural Gas Price and Volatility

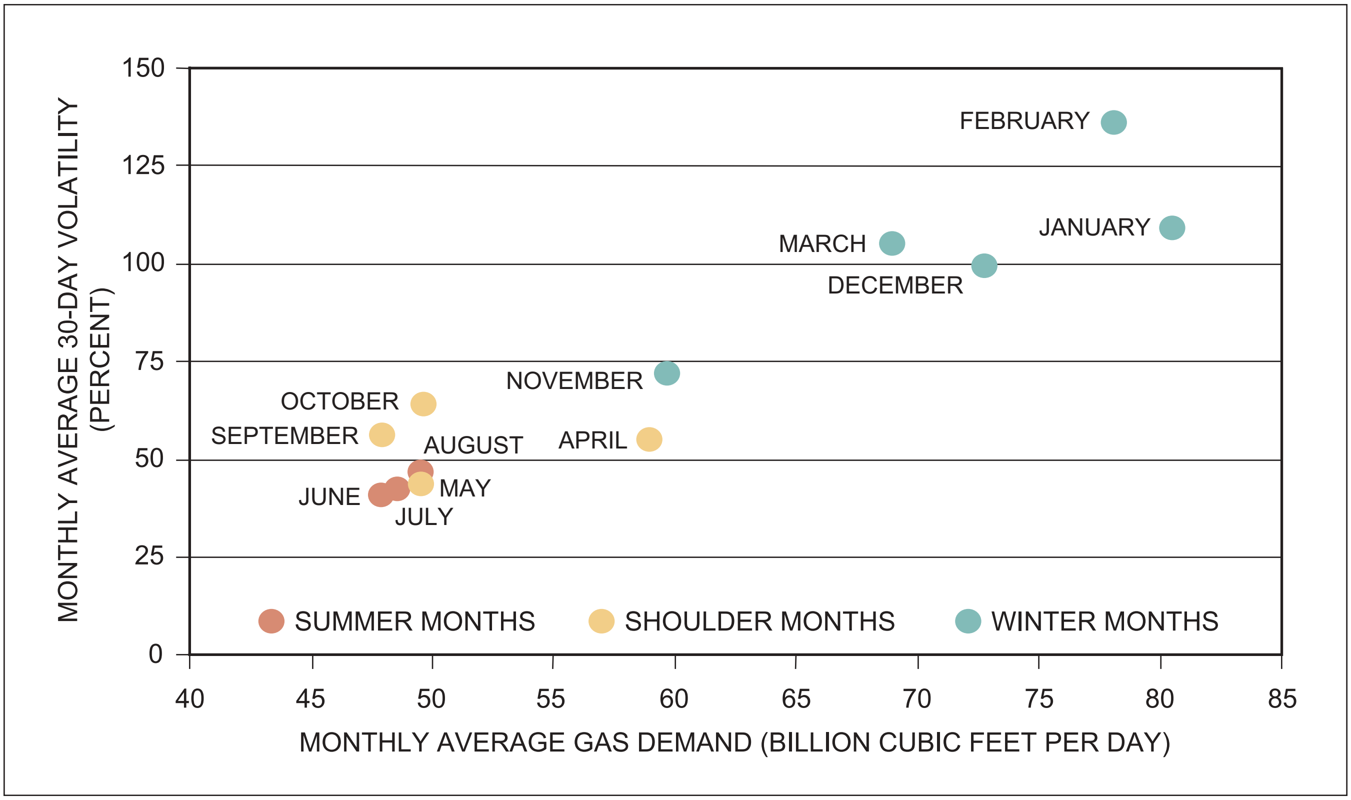


Figure D2-30. Relationship of Monthly Average Volatility and Gas Demand

Yearly average price volatility, as measured from the first-of-month index prices, is 60% over the 1994-2002 period, as shown in Figure D2-31. This volatility measure is related to the range of monthly prices that could be expected over a one-year period for longer-term investment decisions.

D. Comparison of Natural Gas Price Volatility vs. Crude Oil and Electricity

Figures D2-32 and D2-33 show the price trends for crude oil and electricity, respectively. Electricity price has experienced volatility greater than 200%, particularly prior to the substantial capacity buildup in 2000-2003. Volatility in electricity price has been substantially higher than crude oil or natural gas. The primary drivers are the inability to store electricity and its own regional supply demand balance for installed capacity needed to meet super peak demands for a few hours or days in the entire year. Recent declines in electricity volatility, trending towards a convergence with natural gas volatility, illustrates both the impacts of major gas-fired capacity additions creating a surplus of generation capacity above consumption requirements and the increased number of hours that gas is the marginal fuel setting wholesale power prices.

As shown in Figure D2-34, crude oil prices have exhibited lower volatility on average than natural gas, with yearly volatility averaging 40%. The stabilizing effect of OPEC and spare production capacity are the primary keys for the lower volatility.

E. Key Drivers of Natural Gas Price Volatility

	Affects Supply	Affects Demand
Weather	√	√
Inelasticity of Demand (during winter peaks)		√
Storage Levels	√	
Pipeline Capacity	√	
Operational Factors	√	
Lack of Timely, Reliable Information	√	√
Alternate Fuel Price Volatility		√

Gas consumption variability and inelasticity are primary drivers behind price fluctuations in the United

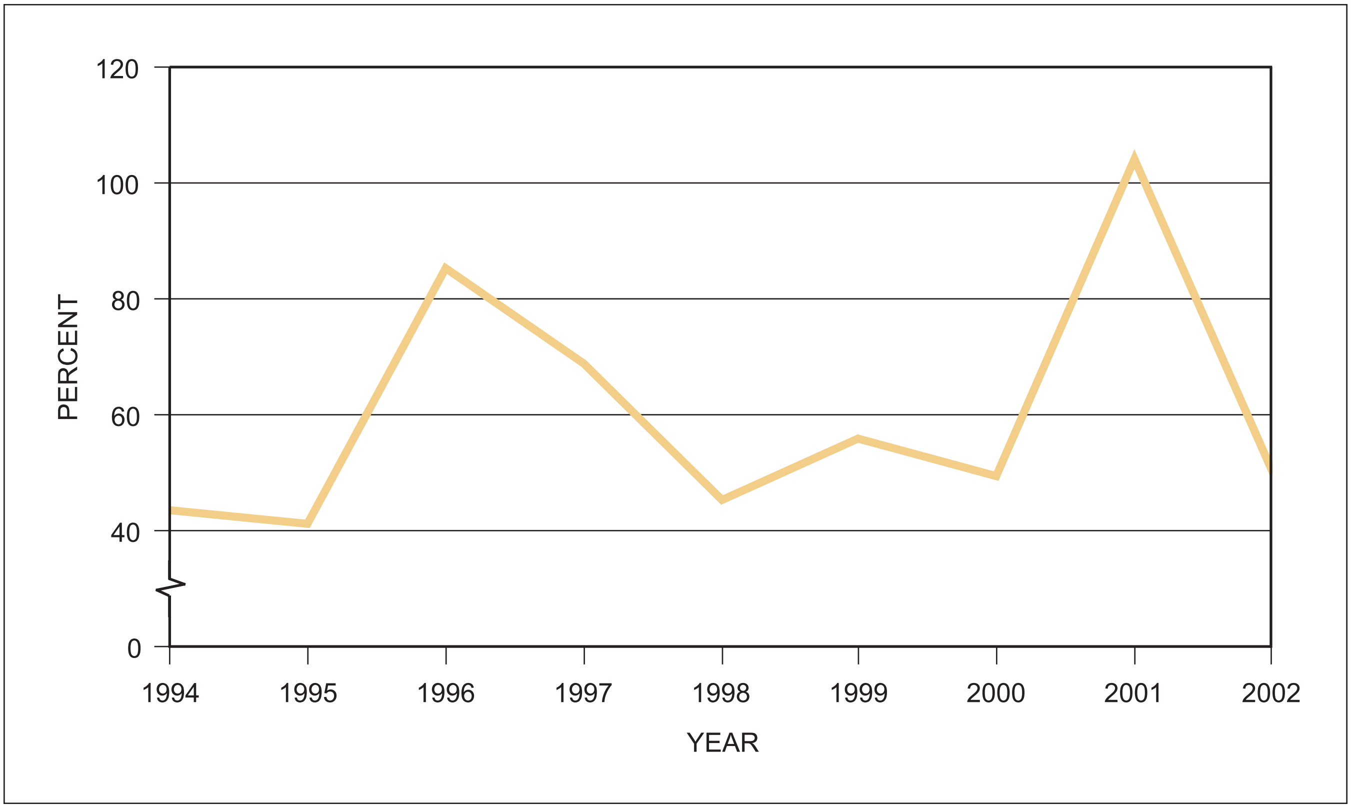


Figure D2-31. Henry Hub First of Month Index Volatility (Full Year Annualized)

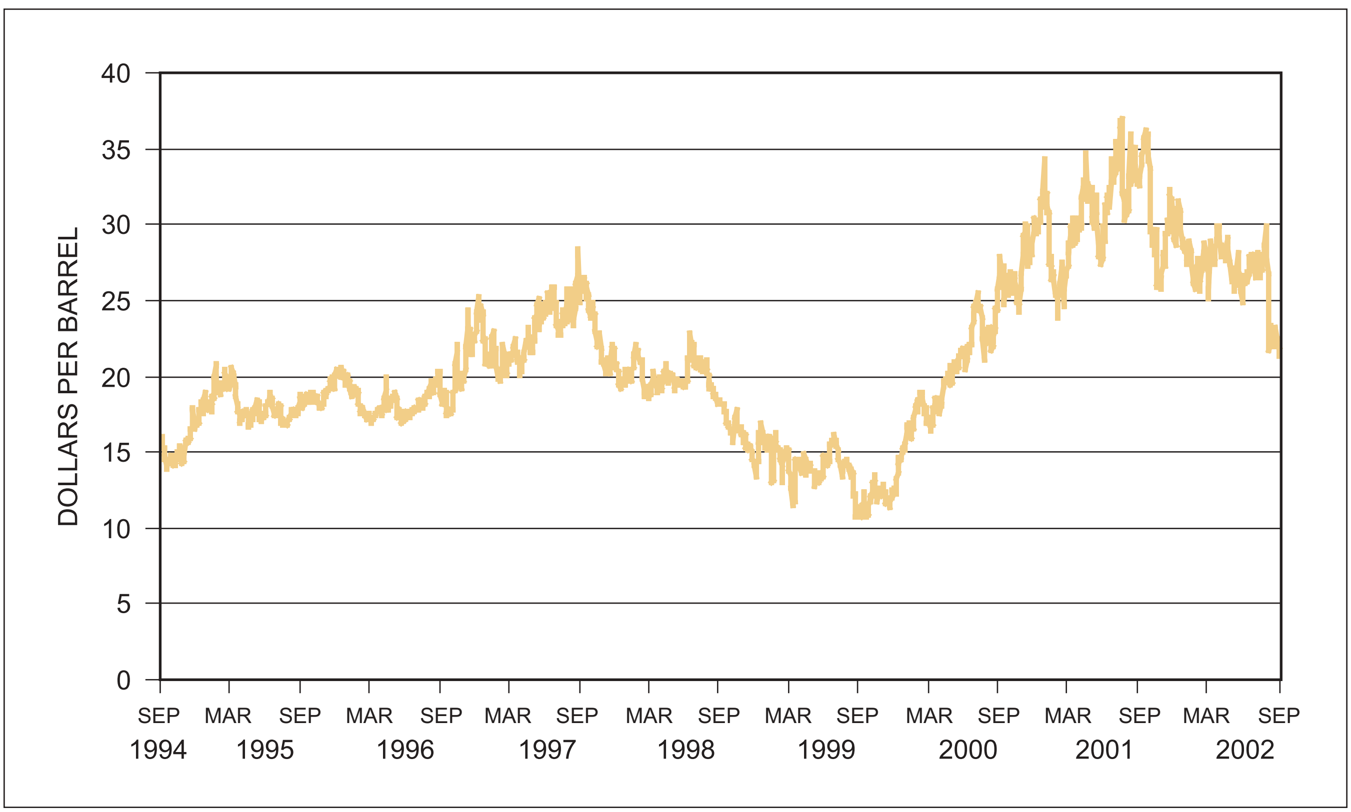


Figure D2-32. West Texas Intermediate Crude Oil Daily Cash Price

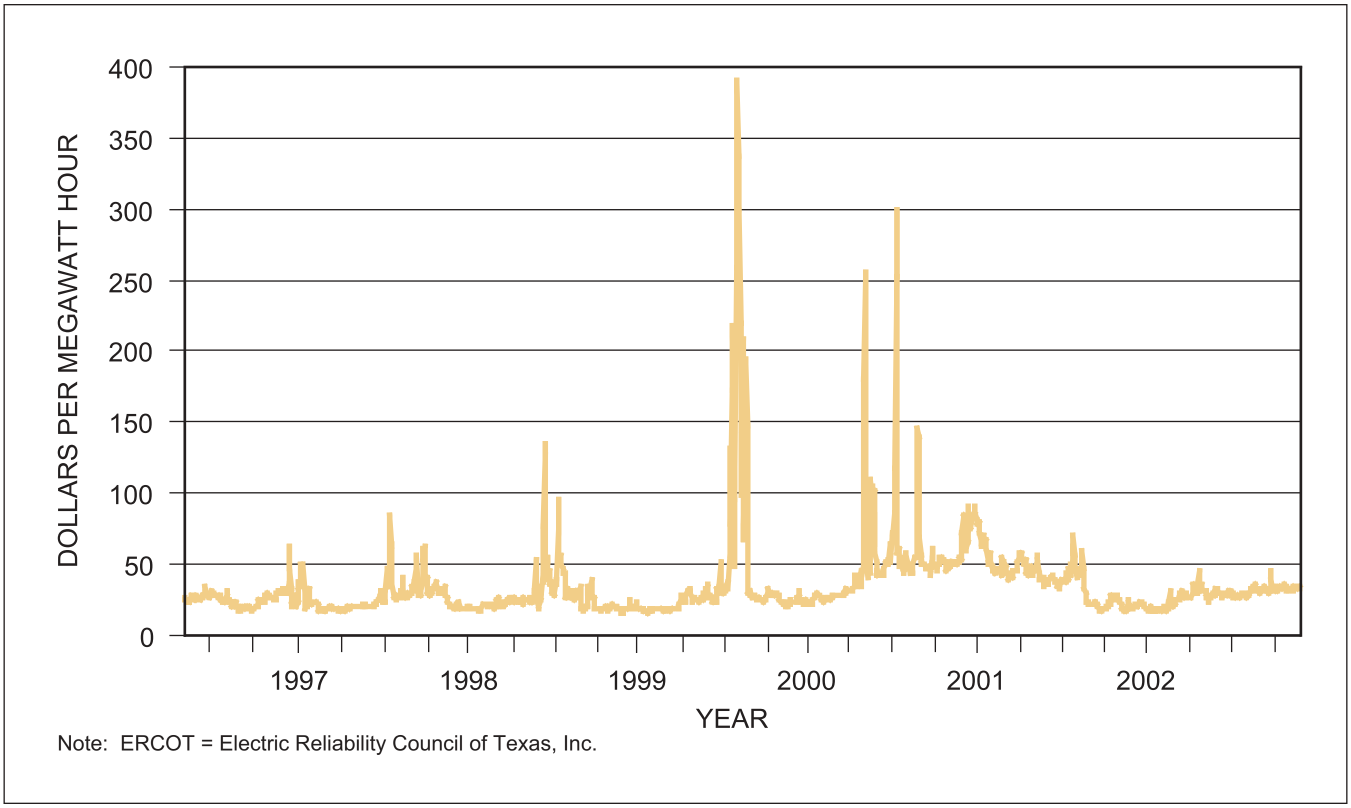


Figure D2-33. ERCOT Daily Peak Electricity Price Volatility

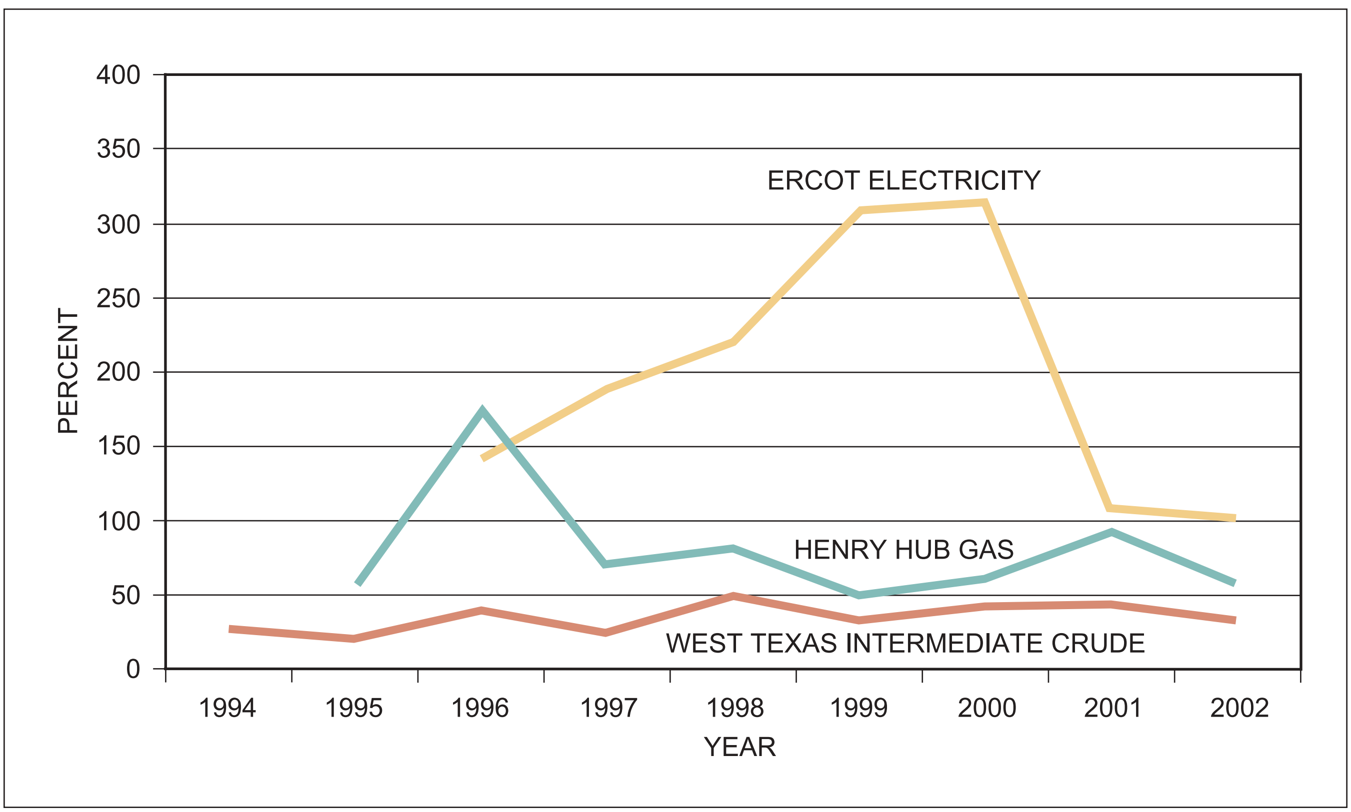


Figure D2-34. Energy Price Yearly Volatility Comparison – Daily Cash Prices (Yearly Period)

States. The winter peak demand can average 80+ BCF/D for January with one-day peaks exceeding 100 BCF/D, which can be compared to the summer low of approximately 45 BCF/D. Gas storage facilities have been developed in most regions of the United States to balance this market. Natural gas is typically stored between April and October for use in meeting winter demands from November through March. The Energy Information Administration (EIA) provides data that about 4.2 TCF of working gas storage capacity exists in the United States. This capacity may overstate what is readily available to the market, since weekly EIA natural gas storage has only recorded working gas storage above 3.2 TCF on five separate weeks going into the winters of 2001 and 1998. On an annual basis, about 2 to 2.5 TCF of "working" gas is used to keep the market in balance, thereby balancing seasonal demand with relatively constant supply and partially mitigating seasonal price volatility.

Since the mid-1990s, the gas producers in North America have been producing at maximum rates throughout the year. The production profile has been relatively flat, as seen in Figure D2-35. Gas production and imports in excess of demand is injected into storage in the summer and pulled from storage to meet the winter peak as shown by the shaded areas.

1. Supply and Demand Elasticity Effects

The gas supply in North America is inelastic in the short term. The ability to increase production in the short term is limited to shutting down rich gas processing and/or gas injection for secondary oil recovery. Increased LNG imports could occur since the four existing terminals are not operating at maximum capacity, but shipping, liquification facilities, and existing contractual arrangements for deliveries to other countries are the binding constraint to short-term increases. Significant increases in supply have been difficult to achieve in recent times even with near record gas-directed drilling rig activity. Canadian gas imports have risen to 16% of total U.S. supply, as domestic production has not been able to keep up with demand. This short-term supply inelasticity contributes to price volatility. Supply is more elastic in the longer term with the potential to explore and develop new large supplies (e.g., deepwater Gulf of Mexico, Arctic, unconventional, LNG). However, the long lead times and large investments make short-term changes difficult.

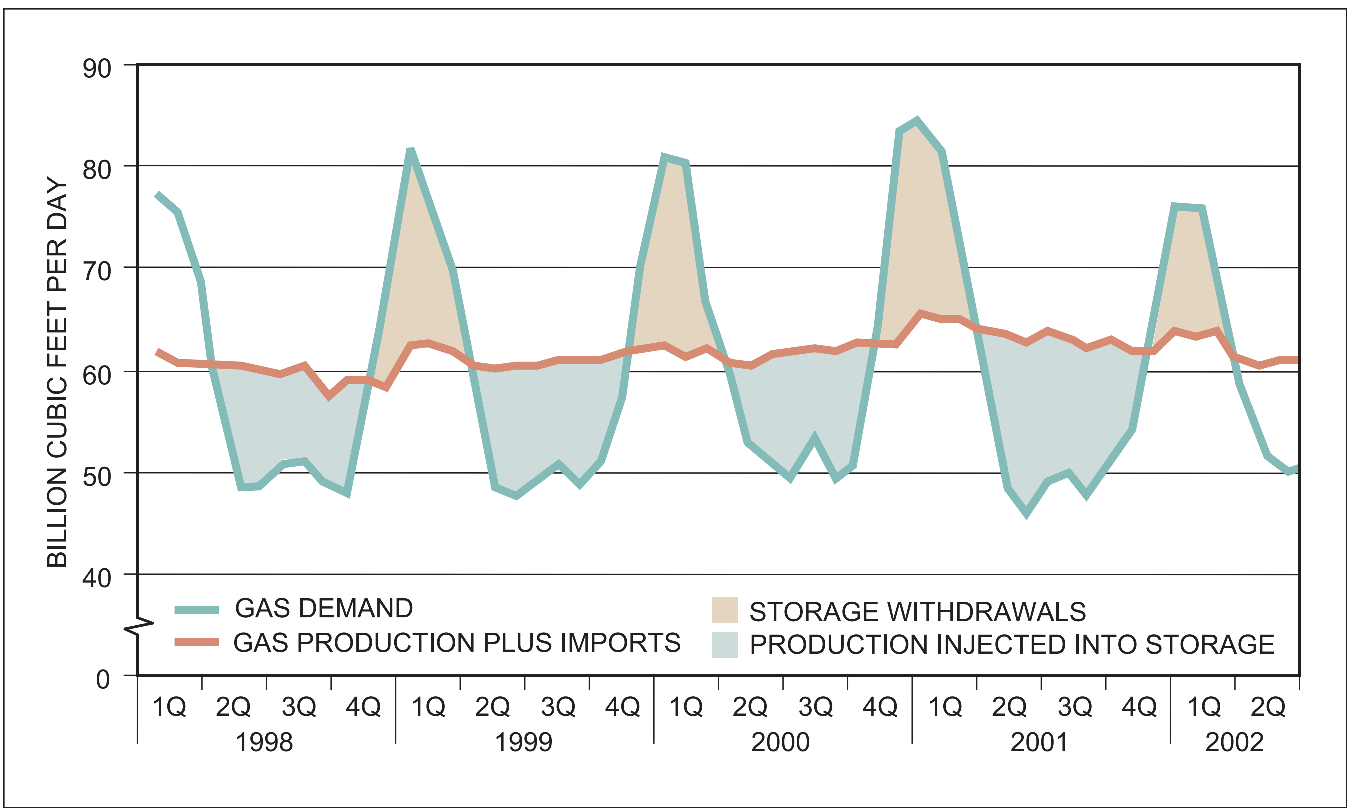


Figure D2-35. U.S. Natural Gas Consumption and Production

For gas demand, the primary driver behind the seasonal consumption profile is space heating for the residential and commercial customers. This "LDC" demand is driven by the weather. In effect, the demand curve shifts to the right from summer to winter as shown in Figure D2-36. This dynamic shift in seasonal demand moves the equilibrium point between supply/demand upward and toward the steeper, less elastic portion of the demand curve. As a consequence, during a cold period in the winter when demand peaks, gas price can change very quickly as the market provides a price signal to consumers to curtail use or to switch to an alternate fuel (if possible). The rapid change in price leads to high volatility.

2. Pipeline Capacity and Operational Factors

Although the North American gas pipeline grid is well interconnected, there are constraints on the amount of gas that can be transported between the supply areas and demand centers, particularly during the winter peak season. Therefore price differentials between areas, or a "basis," sometimes widen (or shrink) reflecting the availability of pipeline capacity. Pipeline capacity relative to demand impacts the delivered price and affects price volatility.

Price differentials reflect the value of transporting gas between regions and provide market signals and incentives for new pipeline capacity additions. In regions with excess capacity, the price basis may drop below the pipelines' published tariff rates for firm transportation. In regions where capacity is tight, the price basis may exceed the published tariff rates. Figure D2-37 shows the difference in price versus the Henry Hub for New York and Chicago citygates and the Rockies production area from 1998 to early 2003.

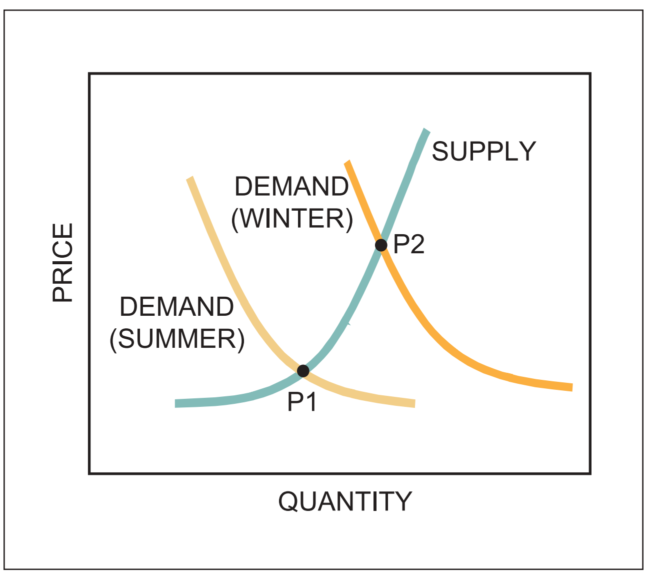


Figure D2-36. Price Elasticity Effects

Citygate prices generally exceed wellhead prices, reflecting the value of transportation capacity between the production area and the market area. Between the Gulf Coast and New York, the basis variation has ranged as low as a few cents to over \$2.00/MMBtu. Winter periods generally show the highest basis differentials due to pipeline capacity constraints. Chicago basis is lower than New York basis due to excess pipeline capacity from the Gulf Coast and Canadian producing areas. Prices in the Rockies production area have been up to \$2.00 less than the Henry Hub price, reflecting insufficient pipeline capacity to the market.

3. Lack of Timely, Reliable Information

The FERC and EIA publish demand and supply data on a monthly basis. EIA monthly reports attempt to document the overall U.S. supply and demand balance. However, due to the lack of complete data published information back about 18 months is a combination of estimates and actual data, which are frequently revised (with large variations). The lack of reliable and timely information results in market uncertainty. On a daily basis, the market searches for the right clearing price. Uncertainty about demand and supply of gas is a contributing factor to these daily changes. The market has developed other indirect measurements of supply and demand to assist in understanding trends. For example, the market closely monitors gas in storage, drilling rig activity, and heating and cooling degree days, among other fundamentals. While helpful in some respects, these sources of information are, at best, second-hand indications of true supply and demand trends.

4. Alternate Fuel Price Effects

Some industrial and utility customers have the ability to switch to an alternate fuel. The availability of this switchable load potentially decreases the upward price movement of gas for these customers when gas price exceeds alternate fuel parity and decreases downward price movement when below alternate fuel parity. Overall this has the potential to decrease natural gas price volatility during peak demand periods.

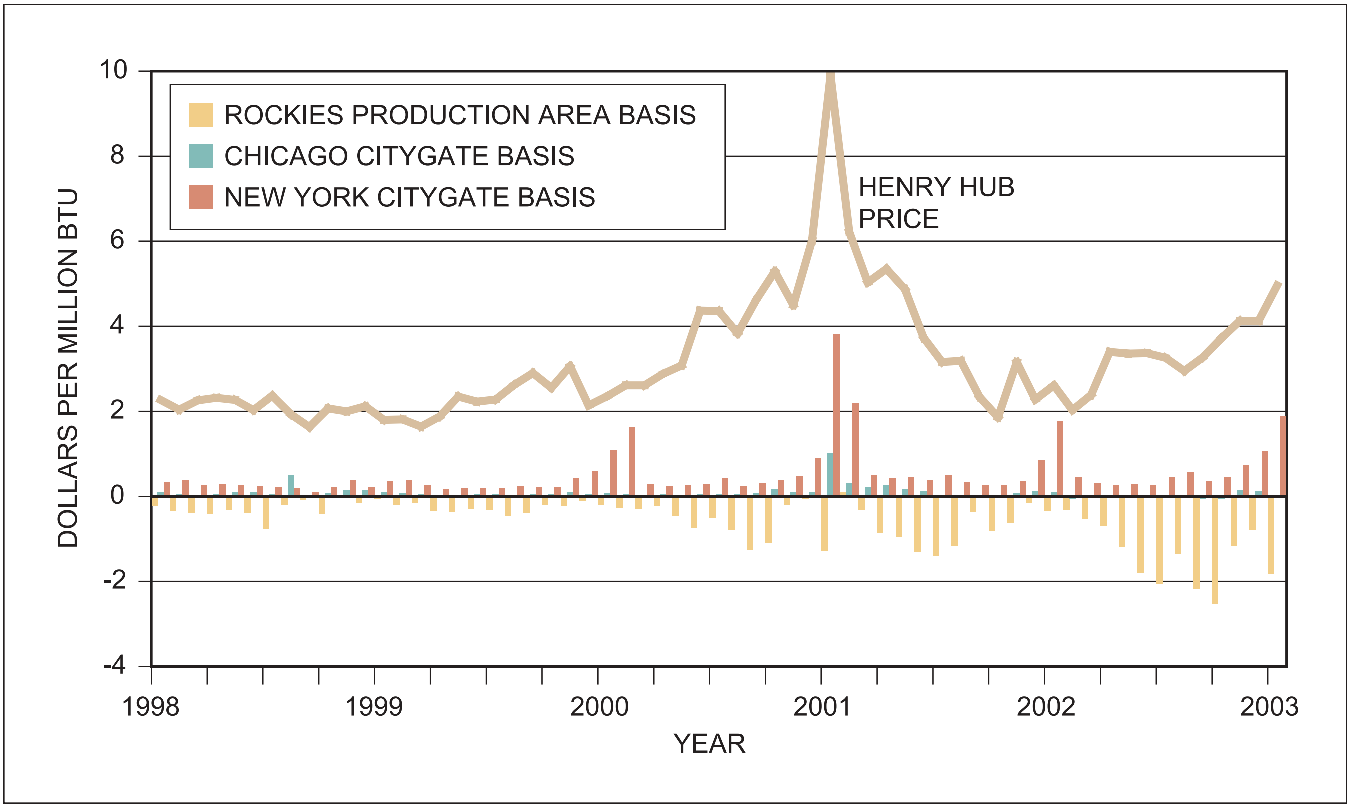


Figure D2-37. Market Basis to Henry Hub

F. Factors that Mitigate Gas Price Volatility

- Gas storage
- Fuel switching
- Financial hedging (does not eliminate risk but does create price certainty)
- Excess production capability and pipeline capacity
- Long-term contracting
- Timely and reliable information

H. Exposure to Price Volatility and Its Effects

1. Retail and Commercial Customers

Most LDC firm-service customers are insulated from the day-to-day volatility in natural gas prices. Residential deliveries and approximately 60% of total commercial customers purchase natural gas at regulated rates from an LDC. The cost of natural gas to these customers is controlled by regulation, and generally reflects the rolled-in average cost of natural gas at the LDC citygate, plus the LDC distribution charge. The average cost of gas is adjusted on a going-forward basis, typically delayed by one to three months. In addition, many LDCs hedge gas prices on a portion of their requirements, either through physical means via natural gas storage, contractual means via longer-term (monthly and seasonal) gas purchase contracts, or a financial hedge. As a result, the gas prices faced by these users generally do not vary with short-term changes in energy market prices. However, persistent price changes do result in substantial price effects. Although prices to retail customers have varied over the past 10 years, only the upward movements tend to receive significant regulator and customer attention.

2. Industrial Consumers

Industrial consumers tend to be more exposed to volatility in energy prices. A vast majority of industrials (more than 80%) purchase gas in the daily or monthly markets and transport the gas to their facilities. The natural gas commodity is purchased either at market prices, or hedged through a third party.[8] In

8 The larger industrial consumers can consume enough natural gas to make direct price hedging attractive, hence providing some insulation from price changes.

either case, industrial customers are exposed to market prices. Sales to industrial customers via LDCs at regulated prices account for only a small percentage (approximately 17%) of total sector requirements.

Industrial consumers tend to have more options for reducing gas usage in response to price increases. Some industrial applications have dual-fuel capability, and can switch to residual fuel oil or distillate fuel oil when natural gas prices exceed fuel oil prices. When gas prices rise, industrial facilities may also choose to shut down production rather than use natural gas. During the peak price periods from 2000 to 2002, large amounts of ammonia production capacity shut down in response to higher natural gas prices.[9]

As a result, industrial consumers tend to be more price sensitive than commercial or residential customers. This price sensitivity is reflected in both operational day-to-day decisions, and in long-term investment decisions in energy technologies. Price volatility can impact profitability for the industrial sector in positive and negative ways depending on the direction of natural gas price movement. Sustained (multi-month) price spikes may also cause business rationalization that cannot be easily or cost-effectively reversed. However, it is high absolute natural gas prices (relative to its product sales prices) that tend to cause industrial customers to consider relocating from the United States to lower-cost supply regions elsewhere in the world.

3. Electric Power Generation

Natural gas has become a fuel of choice for new power generation because it optimizes installed cost and air emissions performance. Natural gas-fired generation is currently capturing almost 100% of new power capacity. Natural gas-fired combustion turbines can be installed more quickly, and have a lower up-front capital cost but higher variable cost (primarily fuel) relative to other technologies such as coal plants, and produce significantly lower CO_2 emissions than coal. The economics of natural gas-fired power generation, however, depend on future natural gas prices. As gas price and price volatility increases, the risks in major investments in gas-fired capacity increase relative to other fuels. Coal, for example, is expected to enjoy more stable fuel costs.

Relatively few new gas-fired power plants have dual-fuel capability, due in part to air emissions permitting constraints. Since the new gas-fired generation is more efficient than older plants, some of these less-efficient plants have been shut down. The older steam plants had liquid fuel alternatives (low-sulfur fuel oil and distillate), therefore the overall switching capability in the system has been reduced. This tends to decrease gas demand elasticity and increase price volatility.

Volatility in electricity price has the same impact as natural gas price volatility. Investors in potential powerplants must factor this risk into their "hurdle rate"[10] and adjust their investment decisions accordingly. In addition, volatility in gas prices – up or down – creates uncertainty in the planning process for both regulated utilities and merchant power companies.

4. Natural Gas Producers

Energy price volatility presents a number of significant challenges to the natural gas producers. Natural gas price volatility creates uncertainty around the future revenue of exploration or development projects. The primary risk to producers is the longer-term movement of gas prices and potential "boom-bust" investment cycles, rather than seasonal weather patterns or seasonal pricing variations.

These longer-term price risks for the producer and investors are incorporated into the effective financial "hurdle rate" for gas exploration and production projects. Thus, a typical gas producer will invest in new exploration and production projects only when the producer's expectation of the gas price rises to a level high enough to make the chances of reaching the

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[9] Examples in 2002 include: Mississippi Chemical announced the permanent shutdown of its Donaldson, Louisiana urea facility because of pricing pressures – the complex has an annual capacity of one million tons of ammonia and 578,000 tons of urea synthesis. Missouri-based Farmland Industries indicated the prolonged downturn in fertilizer manufacturing resulted in a $183 million loss in 2002 and a Chapter 11 filing on May 31, 2002. Pennsylvania-based Air Products and Chemicals is planning to cease production of ammonia and methanol at its Pace Florida plant site, indicating 80% of ammonia and nitrogen feedstock costs are tied to natural gas prices. — Data per Natural Gas Week report on December 30, 2002.

[10] The "hurdle rate" is the minimum acceptable expected return needed for a project to proceed.

target financial criteria acceptable. However, no investor's forecast is perfect, and the possibility of boom-bust gas price cycles remains.

While all energy prices will fluctuate, the impact is particularly significant to independent producers that do not have diversified sources of internally generated funds. A major investment decision taken in anticipation of future higher demand and higher prices can result in severe financial distress if the timing turns out to be incorrect.

I. Conclusions

- Price volatility is a natural dynamic in commodity markets where supply and demand vary. Gas price volatility has increased since deregulation. The overall tighter supply and demand balance and relative inelasticity of demand in the winter is the primary factor driving current volatility.

- Price levels provide consumers and suppliers with appropriate signals, and therefore cause rational actions. High volatility tends to increase uncertainty and decrease market efficiency (increased capital costs).

- Consumers and producers have a broad range of physical and financial tools to mitigate the effects of price volatility if they so choose. Many of the tools come at a cost. Use of financial tools may or may not reduce the cost or value of the natural gas product.

- Government policies should:
  - Promote free-market solutions to market issues.
  - Support transparency in market transactions.
  - Adopt emission regulations that promote customer alternate fuel options and switchability (particularly for new powerplant installations).
  - Provide safeguards against noncompetitive behavior and unfair market manipulation.
  - Foster timely and accurate information regarding supply, demand, and storage.

CHAPTER 3

INDUSTRIAL CONSUMERS

This chapter provides details on the outlook for natural gas use by industrial consumers. It includes a review of the historical determinants of industrial use of natural gas, as well as the factors that will affect its future use in the United States and Canada. Finally, this chapter contains projections of industrial use of natural gas through 2025 for the Reactive Path and Balanced Future scenarios.

Industrial consumers are a pivotal element in the future for natural gas demand. Since 2000, the price of natural gas has raised significantly, attendant with concerns about its continued viability for some industrial applications. The higher price for natural gas alone changes the competitive environment for many industrial consumers. The price of natural gas relative to other fuels is also a key factor in future industrial gas demand.

Industrial consumers used 7.2 trillion cubic feet (TCF), or about 32% of total U.S. gas consumption in 2002. Industrial consumers use natural gas for energy and as a raw material or feedstock. Figure D3-1 illustrates regional energy use for U.S. industrial consumers in 2002. Figure D3-2 provides a basic description of the use of natural gas as a raw material.

The industrial "sector" is large and diverse, and very difficult to evaluate. In both of the base-case scenarios assessed by the NPC study group, as well as in virtually every sensitivity analysis, this study found that future natural gas demand by industrial consumers is influenced by many competing factors. Among these are economic growth, technology advancement, worldwide competition, flexibility to use alternate fuels, and many other considerations. As a result, demand is likely to be little changed from today's levels on an *overall* basis. However, individual components of the industrial sector will behave differently. The overall levels of industrial consumption foreseen by this study are lower than the nearly 9 TCF used by the industrial sector in the late 1990s.

Natural gas use in the industrial sector has developed significantly over the last 60 years, during which time industrial consumers have made considerable investment in capital equipment for preferential use of natural gas. Natural gas in industrial applications offers flexibility, controllability, and low emissions. Table D3-1 summarizes the characteristics of natural gas and competing fuels. Except for a few periods, natural gas has been a widely available, cost-effective fuel and feedstock. Historically, natural gas on a heat content (dollars per Btu) basis has been less expensive than all other fuels except for coal.

The importance of natural gas in the industrial sector relative to other energy sources is shown in Figure D3-3. Natural gas is the primary fuel for boilers, cogeneration, and process heating. It is also an important feedstock. The operational characteristics of natural gas are as good or better than other energy sources that are typically more expensive per delivered unit of energy (e.g., distillate or electricity). Natural gas is widely available, easy to transport, and requires no on-site storage. Natural gas can be used in a wide variety of applications to provide a high degree of control without negatively affecting product quality; for example, in contact heating and drying processes.

The use of alternate fuels has historically been important for industrial consumers. For example,

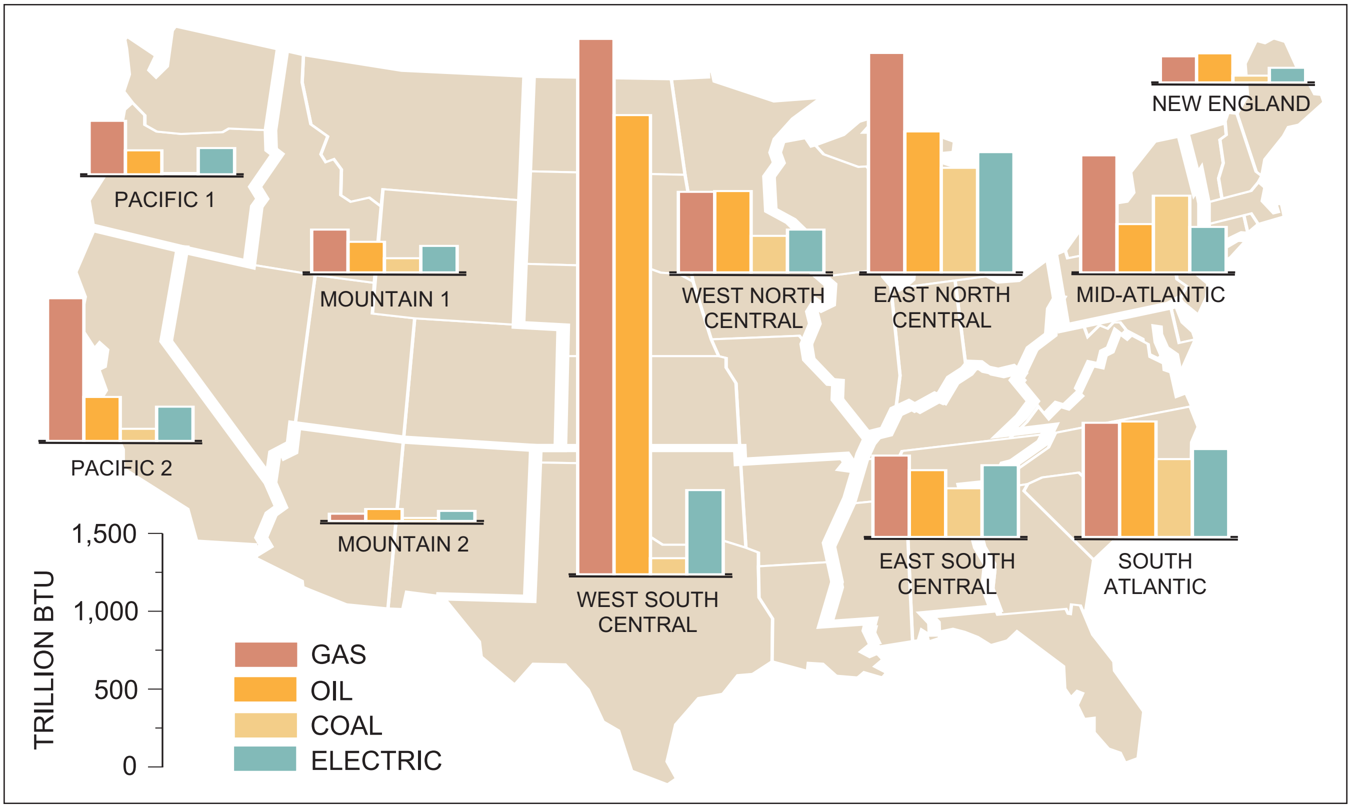
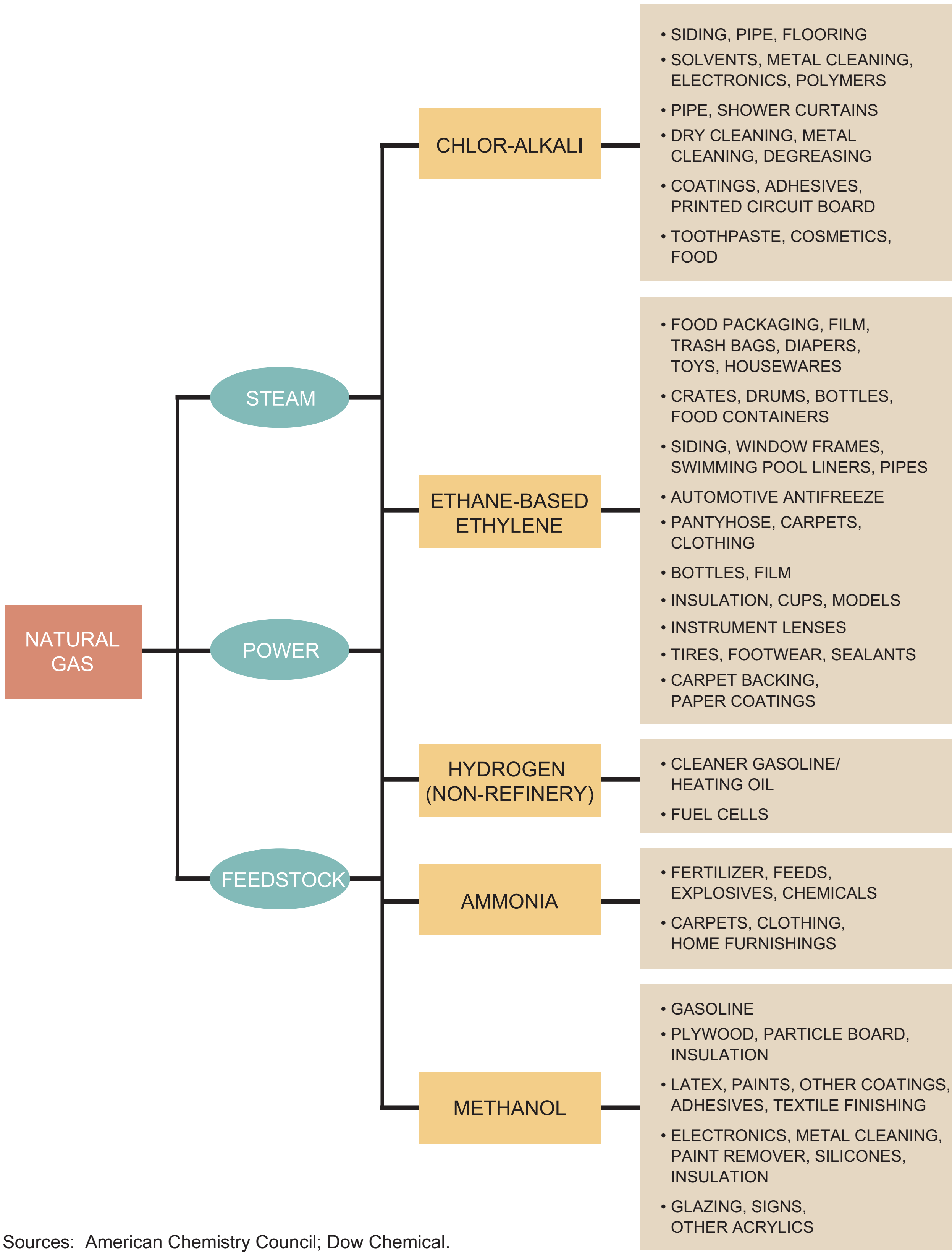


Figure D3-1. U.S. Industrial Energy Use in 2002

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

Table D3-1. Characteristics of Industrial Fuels



Sources: American Chemistry Council; Dow Chemical.

Figure D3-2. Simplified Diagram of Natural Gas Use in Selected Chemical Processes

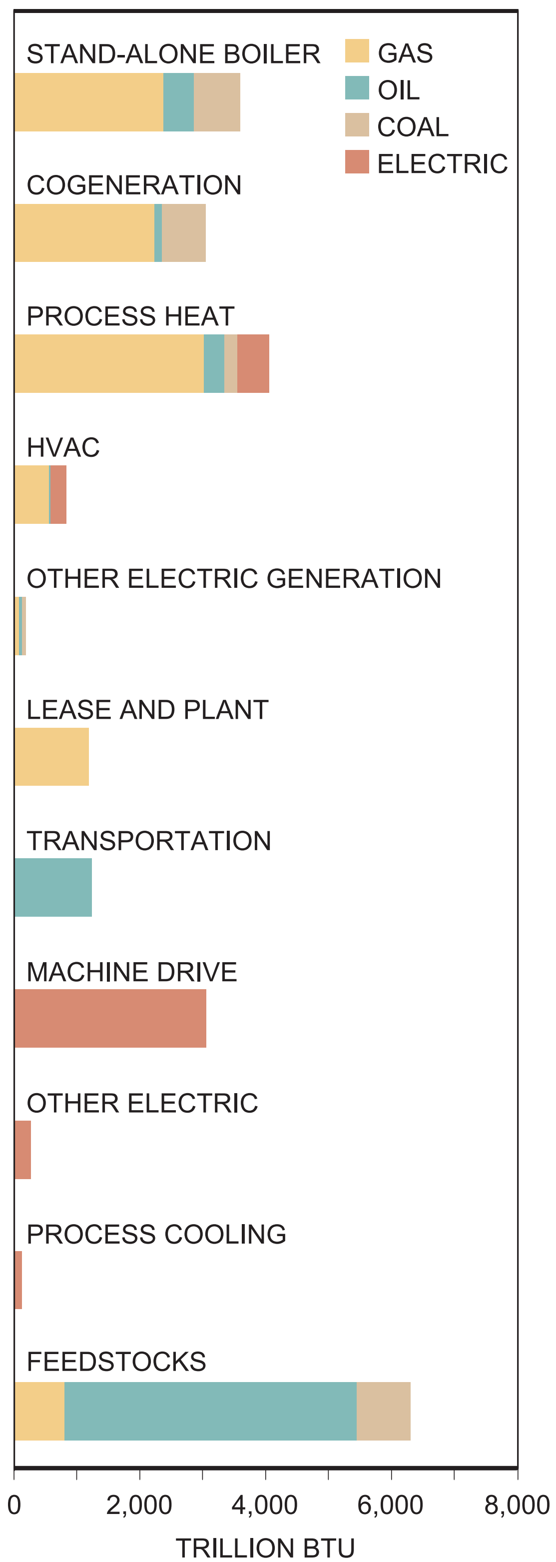


Figure D3-3. U.S. Industrial Energy Consumption by End Use in 2001

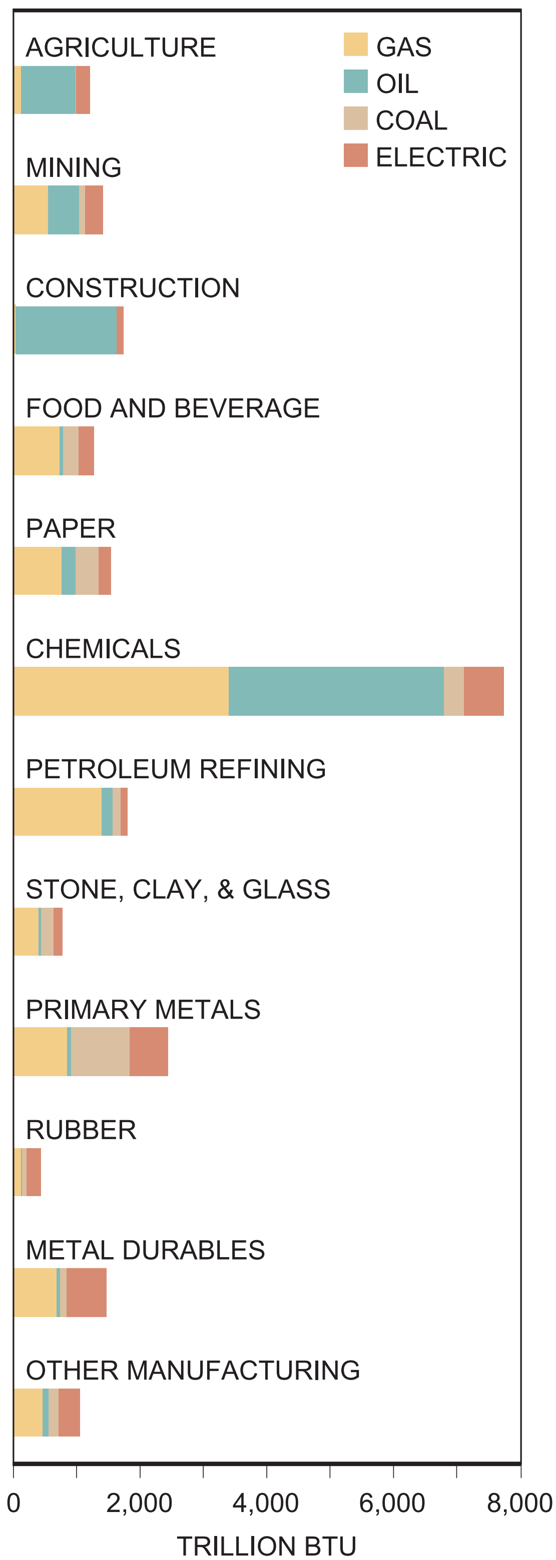
periodically when gas prices were high relative to alternate fuels, facilities capable of switching to another less-expensive fuel had important competitive advantages for these operations. That role has diminished during the last decade, however, as fuel-switching capability has dwindled due to the combination of regulatory and operational factors.

Natural gas is used in most parts of the industrial sector. In order to adequately describe likely future natural gas demand by industrial consumers, the Demand Task Group focused on the most significant, or "gas-intensive" users of energy, and natural gas in particular. Figure D3-4 shows that 72% of industrial energy and 80% of industrial natural gas is consumed in six of the most gas-intensive industries:

- Chemicals
- Petroleum Refining
- Primary Metals
- Food and Beverage
- Paper
- Non-Metallic Product Industries (Stone, Clay, and Glass).

These key industries were evaluated by the Demand Task Group to develop outlooks for the overall industrial demand for natural gas. Due to the potential magnitude of industrial natural gas usage for bitumen extraction and processing in Alberta, this particular application was assessed separately with the six most gas-intensive industries.

Publicly available data on alternate fuel use and capability of industrial consumers, such as those collected by governmental entities, are not current. Therefore, the NPC modeling was based upon information from work sessions of the Demand Task Group, outreach efforts with industrial consumers, and consulting support from Energy and Environmental Analysis, Inc. (EEA). A basic parameter describing industrial activity, and the related natural gas demand in this study is industrial production (IP). Industrial production is a measure of changes in the output of production versus a baseline year. In contrast to past NPC studies of natural gas, this analysis placed an emphasis on the relation between potential future gas prices and future IP.



Source: Energy and Environmental Analysis, Inc.

Figure D3-4. U.S. Industrial Energy Consumption by Sector in 2001

Key drivers for industrial energy utilization, and natural gas uses in particular, are as follows:

Production Growth. IP is a key factor in describing the driving forces for total U.S. energy and gas demand. Many factors determine production growth, including growth in the U.S. and global economies and the competitiveness of U.S. industries in global markets. High relative energy prices can reduce industry competitiveness, potentially lowering the demand for energy and gas.

Industry Mix. Long-term trends in industry mix impact energy demand. Over the last 30 years, many traditional manufacturing industries have declined in the United States due to foreign competition or other factors. The United States has evolved to more technology and service industries, which consume less energy per dollar of gross domestic product (GDP) generated. Some basic energy-intensive industries, such as primary metals and fertilizer, have experienced sizable temporary and permanent declines.

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

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

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

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

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

As shown in Figure D3-5, industrial natural gas consumption grew steadily up to the early 1970s and peaked at 8.7 TCF in 1973. After the "oil shock" of that year, industrial gas demand dropped more or less continuously to a low of 5.6 TCF in 1983. Many factors contributed to the decline in natural gas demand beginning in the early 1970s, as listed here (and described in Chapter 2):

- Government interventions, specifically, the Powerplant and Industrial Fuel Use Act (PIFUA)
- General economic downturns during the period
- Foreign competition
- Evolution toward technology and service industries
- Major increases in efficiency and implementation of new technologies.

As the overall economy improved in the late 1980s, IP grew. Many industries became more competitive and increased production. Adapting to new environmental regulations, companies became more efficient by employing gas-based technologies. Cogeneration grew very rapidly during this period. Amendments in 1987 to the PIFUA removed restrictions on the use of gas in power generation and industrial applications, and the Natural Gas Wellhead Decontrol Act of 1990 removed wellhead price controls. In response to these trends and events, industrial gas consumption rebounded to 8.9 TCF by 1996.

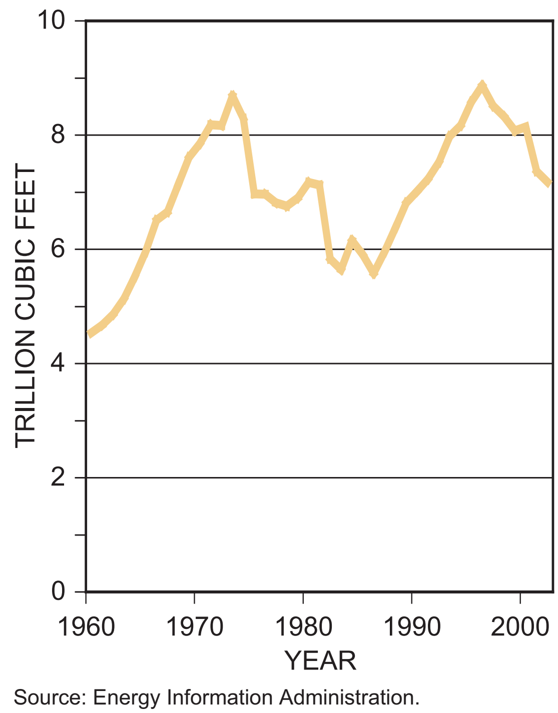


Figure D3-5. Industrial Natural Gas Consumption

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

The following sections address the analytic approach taken by the Demand Task Group to develop outlooks for industrial natural gas demand and the attendant projections of natural gas demand in this sector in the Reactive Path and Balanced Future scenarios. These sections also contain descriptions of the most gas-intensive industries and insights on natural gas demand for those industries. Since natural gas usage for bitumen extraction and processing from the Alberta oil sands has become significant in recent years, this area of industrial natural gas demand is also separately addressed.

I. Analytic Approach and Projections of Industrial Demand

A. Overview of Modeling Approach

The North American industrial sector is comprised of a diverse mix of consumers, many of which have different gas consumption needs, economic and environmental drivers, fuel-switching capabilities, and price elasticity dynamics. Previous NPC studies estimated natural gas demand for the overall U.S. industrial sector in aggregate, but did not articulate demand for the various industry groups. For this study, the Demand Task Group sought a deeper understanding of industrial demand, through a modeling approach that would be transparent for others who would use – and subsequently improve upon – the work of the NPC. Therefore, an adequate representation of the sector required a "bottom-up" approach to modeling for the NPC study.

For purposes of this study, "industrial demand" includes industrial consumption of natural gas outside of oil and gas lease operations and natural gas plants. The exception to this is natural gas used in the extraction and processing of bitumen from Alberta's oil sands, which is modeled as part of the industrial and power generation natural gas demand in Canada. Natural gas consumed in lease and natural gas plant operations is specifically projected by the EEA modeling framework, and accounts in detail for the demand associated with pipeline capacities, compressor horsepower requirements, ongoing system expansions and equipment upgrades, and other relevant factors.

The Demand Task Group recognized that it faced barriers in data quality and timeliness. For the United States, the last comprehensive study of industrial consumption completed by the Department of Commerce and the DOE's Energy Information Administration (EIA), was the Manufacturing Energy Consumption Survey (MECS) for the period ending in 1985-1994. While survey data have been collected for the subsequent period through 1998, and EIA is incorporating various improvements to the MECS process, an updated MECS survey had not been completed at the time of this report. In contrast to energy and natural gas demand data for industrial consumers are other aspects of the supply/demand picture: demand information for residential and commercial consumers is both current and relatively reliable due to the role of local distribution companies (LDCs) and their regulatory reporting responsibilities; electric power demand and fuel use data are current and relatively reliable due to reporting requirements and data collection by state regulatory bodies and/or Independent System Operators; data on infrastructure capacities and other characteristics are relatively well-documented and up-to-date; and supply information is relatively reliable and timely due to various reporting requirements. Therefore, industrial demand was modeled as described in this section. U.S. industrial demand was described using a new modeling framework developed for this study; Canadian industrial demand was modeled as described below; and Mexico's industrial demand was not specifically modeled, rather, it was assessed as part of an overall evaluation of Mexico's natural gas picture as described in Volume II, the Integrated Report.

For Canadian industrial demand, government data gathering has historically grouped gas-based electric power generation with industrial demand. Consistent with this publicly available data, the EEA model framework combines these two segments of Canadian natural gas demand. Therefore, the Demand Task Group worked with the EEA modelers to disaggregate Canadian gas-fired power demand from industrial demand in post-processing analyses to allow the study team to better interpret results and guide additional modeling. Additionally, EEA and the Demand Task Group created distinct model inputs for natural gas demand in Alberta oil sands extraction and processing.

The NPC study group worked with EEA to develop a model to forecast U.S. industrial natural gas demand by taking into account various demand drivers such as IP, energy prices, and technology changes. The model assessed demand for 26 industries (aggregated into 10 groups), 11 regions (U.S. census regions), and four end-use categories (boilers, process heat, feedstocks, and other). Because of its size, complexity, and importance to gas consumption trends, the chemical industry was further disaggregated into components critical to natural gas demand: ammonia, methanol, hydrogen, ethane-based ethylene, and other chemicals.

The model was designed to explicitly capture changes and improvements in technology including improvements in energy efficiency, short- and long-term fuel switching and global competition in critical industries such as ammonia, methanol, and ethane-based ethylene production. In order to develop input parameters and to validate the results, the Demand Task Group formed an Industrial Utilization Subgroup, with representatives from a variety of gas-intensive industrial companies involved in the production of methanol, ammonia, other bulk chemicals, specialty chemicals, glass, copper, paper products, olefins, aluminum, and other products. Additionally, the Industrial Utilization Subgroup conducted outreach meetings and workshops with representatives of key gas-intensive industries to aid in the understanding of emerging trends and key drivers.

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

B. Major Drivers of Industrial Natural Gas Demand

The main drivers of industrial gas demand are industrial production activity, natural gas and other energy prices, changes in processes, and penetration of more efficient equipment. The main drivers assessed by the Demand Task Group, and modeled in the EEA modeling framework, are discussed below.

1. Industrial Production

The industrial activity characterized in the level and mix of industrial production (IP) greatly affects industrial gas consumption. An increase in IP can reflect increased activity that will spur direct growth in gas consumption. Likewise, a drop in IP can reflect reduced consumption. Nevertheless, a robust growth in IP may indirectly encourage the investment and installation of more efficient equipment that require less energy to run. As production increases, equipment turnover also may increase. Older equipment is then replaced with newer and generally more efficient equipment that then partially counterbalances the increased energy consumption due to increased production.

Six energy-intensive and gas-intensive industries account for over 80% of total non-lease and plant natural gas consumption in the industrial sector. Thus, these industries are critical in analyzing and forecasting industrial gas demand. The energy-intensive industries are:

- Chemicals
- Petroleum Refining
- Primary Metals
- Food and Beverage
- Paper
- Non-Metallic Product Industries (Stone, Clay, and Glass).

These industries are individually represented in the model, and some (primary metals and chemicals) are further disaggregated.

2. Energy Prices

Although energy cost is a relatively small component of total production cost for most manufacturers, energy prices are still an important driver of energy consumption, and its consideration is significant in investment decisions. Thus, absolute and relative fuel prices are important in determining industrial gas demand. An increase in absolute gas price, for example, can increase energy conservation or can also cause certain industries to temporarily or permanently shutdown. In end-uses where fuels compete over the short-term (such as boilers), an increase in the relative price of gas over a competing fuel (typically residual fuel oil) can decrease the share of gas consumed. Over the long-term, higher natural gas prices can drive manufacturer's investment decisions to invest in other alternate-fuel-based processes and technologies. The impact of these latter type of investments would be the slow, albeit firm, displacement of natural gas processes. Conversely, lower natural gas prices can have the opposite effect.

For some industries, natural gas can be a major component of the total production costs. Principal among these industries are the production of ammonia, hydrogen, and methanol. Furthermore, ammonia and methanol industries compete on a global scale and thus, permanent loss of capacity in these industries is possible during prolonged periods in which North American natural gas prices are higher than the cost of natural gas feedstocks elsewhere in the world. Ethane-based ethylene production, although it does not require substantial amounts of natural gas, is also affected by global competition. Ethane is a major feedstock in the production of ethylene in the United States. Ethane, being a natural gas liquid, is priced relative to the price of natural gas. During the periods of higher natural gas prices in the 2000-2003 period, ethane prices increased as well, thus motivating at least a temporary reduction in the utilization of domestic ethylene capacity.

Electricity prices have become increasingly dependent on natural gas costs, due to natural gas-based generation capacity being the marginal source of generation in many areas of North America. Therefore, industrial consumers for which electricity costs are a major component of production costs – such as aluminum smelters and chloralkali facilities – are also impacted by natural gas prices.

3. Process Changes

The penetration of new technologies due to process changes (and not directly due to energy prices) can also increase the use of the fuel of the incoming technology and decrease the fuel of the outgoing technology. The penetration of new technologies can therefore either increase or decrease the use of natural gas. These process changes may be driven by environmental regulations, change in raw materials, or changes in product demand or product quality. An example of this is the successful penetration of electric-arc furnace (EAF) in steelmaking. The success of EAFs, which displaced a significant fossil-fuel based integrated mill capacity in the steel industry, reflects its lower capital requirement and production costs.

4. Regionality

The West South Central and East North Central regions represent over half of industrial non-lease and plant natural gas consumption. The West South Central region accommodates a large share of the capacity of basic chemicals and petroleum refiners. The historically abundant supply of low-cost natural gas in this region has allowed natural gas to dominate this region over other fuels. In the East North Central region, easy access to natural gas as well as the large presence of food manufacturers, petroleum refiners, chemicals, and metals industries has resulted in substantial amounts of natural gas consumed in the region. Other major gas-consuming regions include Pacific 2 (essentially, California), Middle Atlantic, and South Atlantic regions.

5. Seasonality

A large portion of natural gas in the industrial sector is used for space heating, either through steam-based systems or direct-fired gas space heating equipment. Also, some industries such as agriculture are seasonal in terms of production activities. Thus, industrial natural gas consumption experiences some seasonal cycles. This is important especially when modeling monthly gas demand.

C. Industrial Modeling Approach

To capture the complexities inherent in modeling energy demand of industrial consumers (as discussed above), a new industrial model developed for this study by EEA in consultation with the Demand Task Group incorporated the most important drivers and factors of industrial natural gas demand. Table D3-2 summarizes the representation of the sector in the model.

The six energy- and gas-intensive industry groups are individually represented in the model. The chemical and primary metals industries are further disaggregated into important subgroups. The chemical industry is disaggregated into five sub-industries: ammonia, methanol, hydrogen, ethane-based ethylene, and other chemicals. The ammonia, methanol, and hydrogen industries are the primary gas feedstock consumers in the sector. Ethane-based ethylene is also modeled separately since it is an important user of natural gas and it is relatively gas-price sensitive due to the relationship between natural gas and ethane. The primary metals industry is subdivided into three industries: iron and steel, aluminum, and other primary metals. The use of natural gas and regional location are different among them, so it was deemed necessary to disaggregate the industry.

The "Other Manufacturing" industry group includes the rest of the manufacturing sector. The most important feature of this sector is its low gas intensity, higher value of products, and fast production growth. The fastest growing sectors over the last decade has been the computer, electronics, and telecommunications

Industry Groups
Food
Paper
Chemicals
Ammonia
Methanol
Hydrogen
Ethane-Based Ethylene
Other Chemicals
Petroleum Refining
Stone, Clay, and Glass
Primary Metals
Iron and Steel
Aluminum
Other Primary Metals
Other Manufacturing
Non-Manufacturing
End-Uses
Process Heat
Boilers
Feedstock
Other (includes space heating and cogeneration)
Regions
New England
Middle Atlantic
East North Central
West North Central
South Atlantic
East South Central
West South Central
Mountain 1
Mountain 2
Pacific 1
Pacific 2

Table D3-2. Industrial Sector Representation in the Industrial Model

industry, as well as plastics and rubber; these industries are in this "Other Manufacturing" industry group. Non-manufacturing industries include agriculture, mining, and construction. The mining sector is the largest user of natural gas among these three industries, primarily for enhanced oil recovery.

The new industrial model was developed by EEA to forecast monthly industrial natural gas demand. The model was designed to be computationally simple to be run as part of the larger integrated modeling system, but still with sufficient detail to represent important gas demand drivers and patterns. The industrial sector includes some very gas-intensive processes in certain industries, which are too complex to be modeled explicitly in the model. Moreover, there are gas-intensive industries in the sector, which are usually exposed to global markets that are at risk of market loss when gas prices are high. The industrial demand model designed for this NPC study uses various modeling techniques and approaches to handle these important issues.

Figure D3-6 presents an overview flowchart of the industrial model. The figure shows the main model inputs (IP, energy prices, others), outputs, and components (boilers, process heat, feedstock, other use). These are discussed in detail below.

1. Industrial Production

Growth in IP by industry group is a fundamental input to the model. Except for the chemical industry, IP is exogenous in the model. In the modeling process, growth rates are externally developed, and entered for the industry groups listed in Table D3-3.

The model performs an extra calculation step to calculate the IP projections for the industrial machinery and the electrical equipment industries. These industries include the manufacturing of products related to computer, electronics, and telecommunications industries. During the 1990s, these industries experienced a significant amount of productivity improvement. Thus, the Demand Task Group agreed with recommendations from EEA, and determined that historical efficiency trends, which are used in the process heat and other use categories for the other industries, would not be appropriate for these industries. As a result, an adjustment was made on the IP for these industries in the NPC scenarios, changing the IP growth rates of these industries to a lower rate,

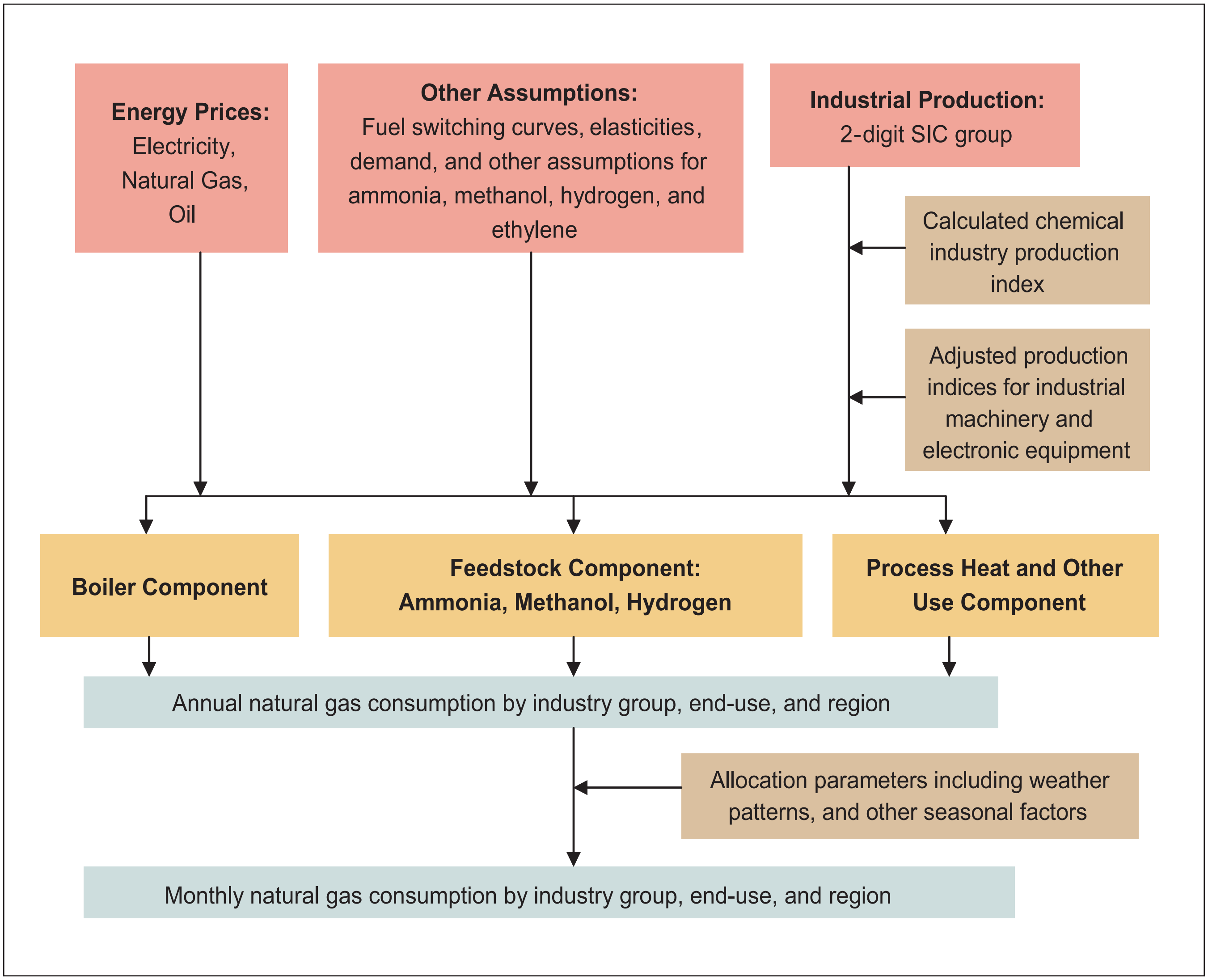


Figure D3-6. Overview of Industrial Model

thus mimicking a production growth rate more in step with gas use in these industries.

Because the basic chemical segment of the chemical industry is more critical in modeling gas demand in the chemical industry than other segments, and because some portions of the industry (aside from ammonia, methanol, hydrogen, and ethane-based ethylene industries) are relatively more sensitive to gas prices, it was deemed necessary to endogenously forecast the production in the chemical industry. The model is a simple log-linear regression model that relates the chemical industry production index with GDP and natural gas prices. The regression equation is:

$$ln(chem\ IP\ index) = 3.4228 + 0.5137*ln(GDP) - 0.2703*ln(natural\ gas\ price)$$

This relationship was estimated using production, GDP, and natural gas price annual historical data from the Federal Reserve Board, Bureau of Economic Analysis, and EIA.

2. Energy Prices

The industrial demand model requires four exogenous energy price forecasts: purchased electricity, natural gas (average), natural gas (boiler), and residual fuel oil. The purchased electricity price forecast from the other parts of the EEA modeling framework is used in the calculation of production costs of ammonia, methanol, and ethylene. Average natural gas prices are used in the calculation of production costs of ammonia, methanol, and ethylene, as well as in the process heat and other use model components. Natural gas

Industry Groups
Agriculture – Crop
Agriculture – Livestock
Mining – Energy
Mining – Non-Energy
Construction
Food
Tobacco
Textile
Apparel
Lumber and Wood
Furniture
Paper
Printing
Petroleum Refining
Rubber and Plastics
Leather
Stone, Clay, and Glass
Primary Metals – Iron and Steel
Primary Metals – Aluminum
Primary Metals – Other
Fabricated Metals
Industrial Machinery
Electrical Equipment
Instruments
Miscellaneous Manufacturing

Table D3-3. List of Industries

boiler and residual fuel oil prices are used in the boiler component.

3. Boiler Component

Figure D3-7 provides an overview of the boiler component of the industrial model. Appendix E provides additional information on process energy, which includes boilers and process heat. To forecast industrial gas demand in boilers, the model projects steam generation from natural gas boilers and uses boiler fuel-switching curves to determine the share of boilers that consume gas, and then subsequently estimate the amount of gas consumed by applying boiler efficiency assumptions. Appendix F contains these boiler-switching relationships for each census region, as used in the model. To forecast steam generation from boilers, the model begins with year 2001 values of the amount of steam generation by dual-fired boilers (in trillion Btu) by industry group and region. After 2001, steam generation is modeled to grow based on IP growth for the given industry, coupled with an assumed steam efficiency improvement of 1% per year. Once total steam generation from dual-fired boilers is determined, the share of the steam generated from dual-fired boilers that are switchable (based on gas/oil prices) is calculated by applying the variable called "Maximum Boiler Switching Capacity." This variable differs by region, and is exogenous to the model. It is represented as the percentage of switchable (based on gas/oil prices) dual-fired boilers, over the total capacity of dual-fired boilers in the region. This is an important consideration since a large part of boilers capable of using both natural gas and liquid fuels cannot switch away from natural gas due to environmental and technical constraints. Gas consumption from the non-switchable dual-fired boilers is calculated by applying an average boiler efficiency of 70%.

The boiler fuel-switching curves estimate the share of natural gas consumption in boilers that are capable of switching between gas and residual fuel oil, as a function of the difference between boiler gas and residual fuel oil prices. The share of natural gas is then applied to the switchable portion of the total steam generations. The average efficiency of gas boilers (70%) is then applied to calculate gas use in switchable boilers. Gas use from dual-fired switchable boilers and from dual-fired non-switchable boilers is then added to calculate total gas use in boilers.

The boiler switching curves show the relationship between gas share and the price difference between natural gas and residual fuel oil. The curves are updated from a fuel-switching study performed by EEA in 1993 for the Gas Research Institute.[1] The curves try to capture the differences across regions, thus, there is one curve for each region. Industries are assumed to react similarly; therefore, the curves do not differ by industry.

4. Feedstock Component

The feedstock component of the model consists of three subcomponents: ammonia, methanol, and hydrogen. These are discussed on the following pages.

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1 Gas Technology Institute (formerly Gas Research Institute), *Fuel Switching Issues in the Industrial Sector,* GRI-93/0286, December 1993 (prepared by Energy and Environmental Analysis, Inc.).

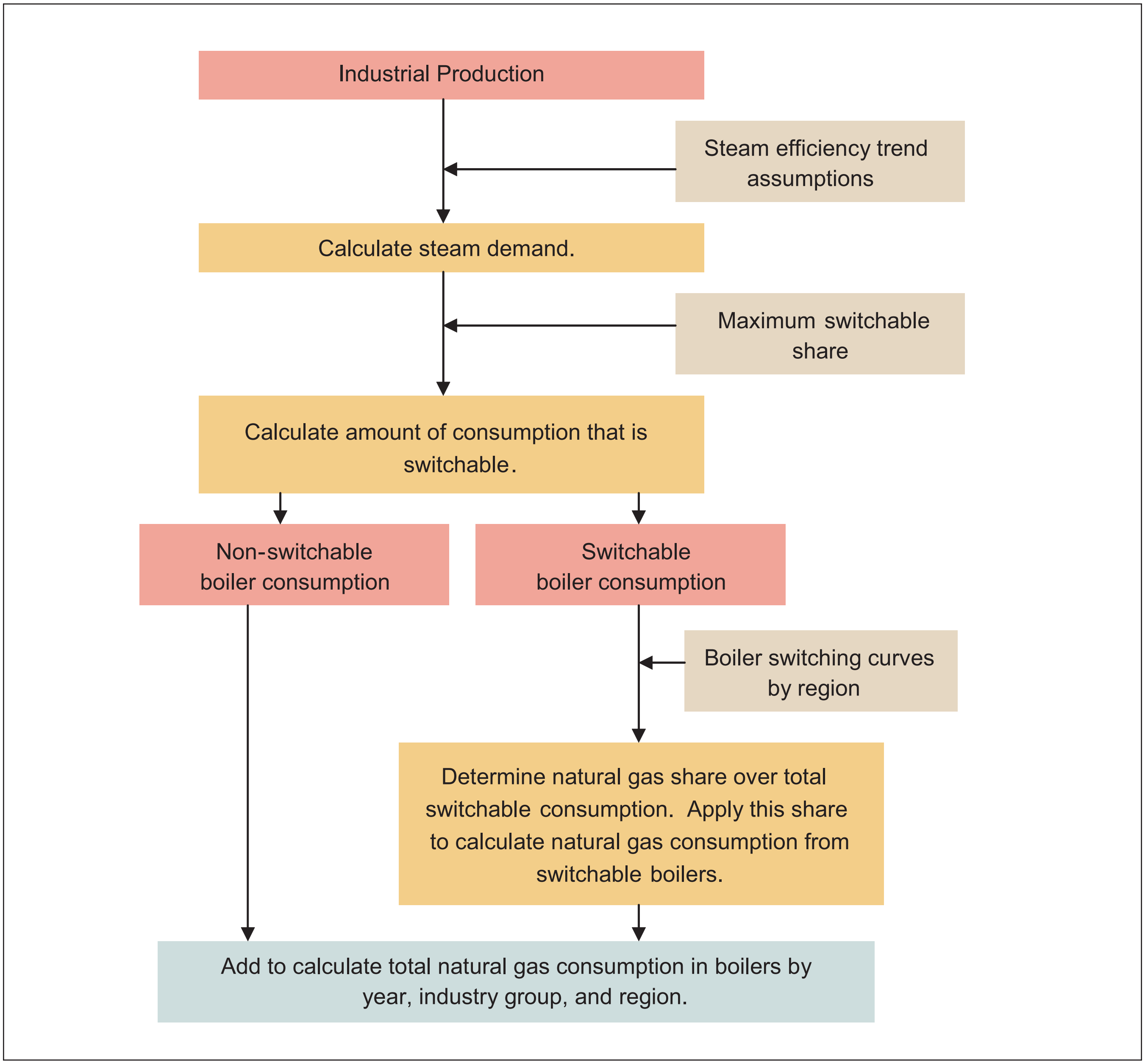


Figure D3-7. Boiler Demand Modeling

a. Ammonia Model

The feedstock component of the industrial model has an ammonia model that projects domestic ammonia production and the subsequent gas demand for this product. Figure D3-8 shows an overview of the ammonia model.

The domestic ammonia industry is affected significantly by higher natural gas prices. Natural gas accounts for a substantial share of its total production costs. Further, the industry is exposed to global market competition, so it is subject to the possibility of a permanent loss of domestic production capacity due to increased imports. The model attempts to take these factors into account.

In the model, domestic ammonia production is primarily driven by the domestic demand for ammonia, the cost of domestic ammonia production, and the price of ammonia imports. The model starts with a given exogenous domestic ammonia demand and then compares the cost of producing ammonia domestically and the price of imported ammonia. Based on the difference between these costs, the amount of domestic ammonia production is calculated by using a linear relationship between the cost

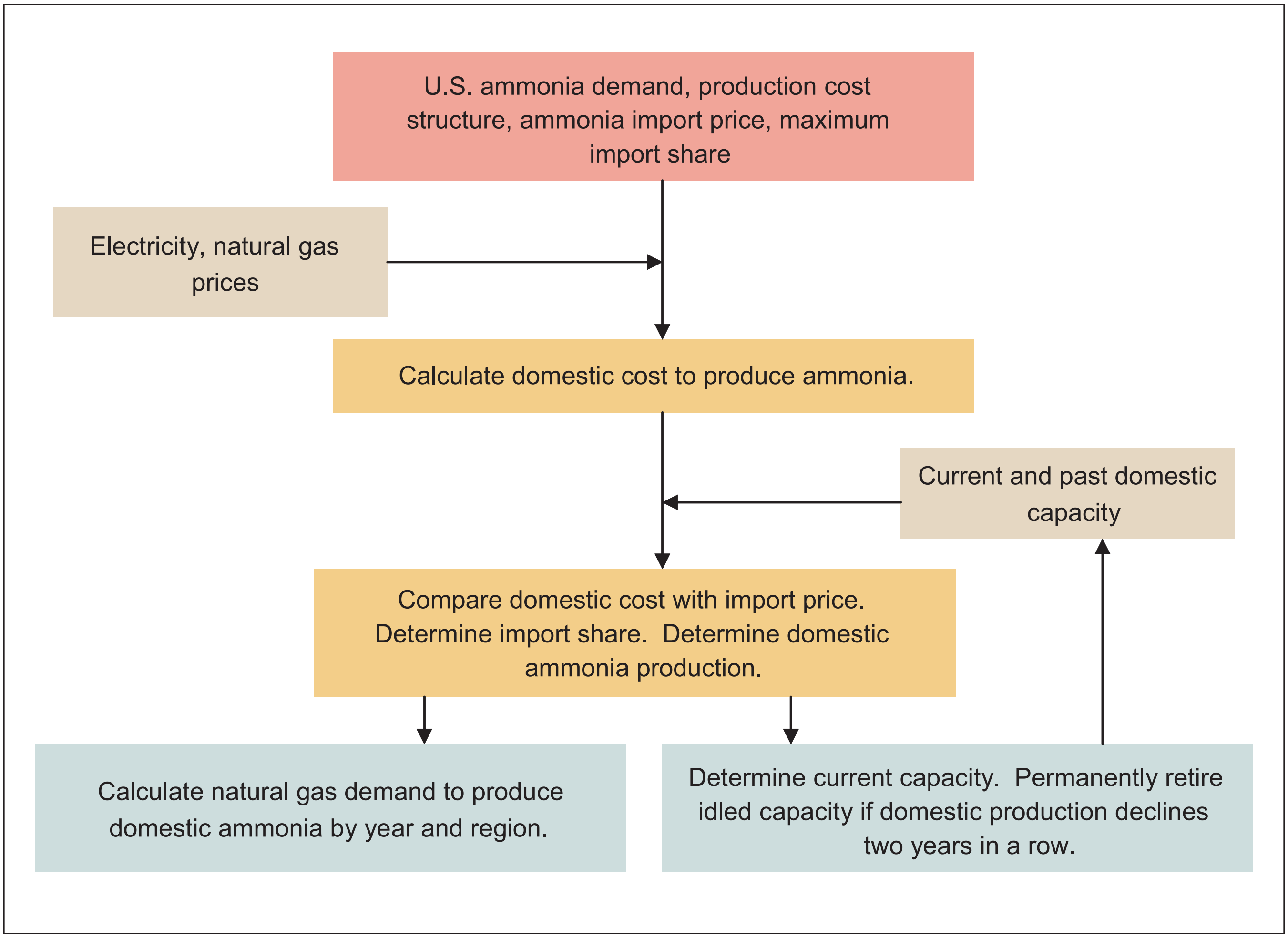


Figure D3-8. Ammonia Demand Modeling

difference and share of imported ammonia. Thus, the model defines an amount of capacity that is temporarily shut down. The model also takes into account the potential for permanent capacity shutdown by assuming existing capacity will be permanently shut down after two consecutive years of decline in domestic ammonia production. Only capacity in the West South Central and South Atlantic regions is allowed to permanently shut down because of the easier penetration of imports in these regions. Capacity in the other regions is assumed to continue to supply domestic ammonia demand regardless of natural gas prices. This is because the Demand Task Group assumed that the high transportation costs to deliver imported ammonia to these regions will continue to make imported ammonia less competitive. After the amount of modeled domestic ammonia production is determined, the total demand for natural gas in the ammonia industry is calculated.

The calculation of production costs for ammonia incorporates not only feedstock (natural gas) costs but also other energy costs (for fuel and power), fixed plant costs, capital charges, and other expenditures.[2] The costs are allowed to increase over time based on an assumed escalation rate of 3% per year. Other inputs to the model are:

- Projection of domestic ammonia demand (thousand metric tons)
- Maximum import share

2 The data used in the production cost model were taken from the *Methodology/Technical Documentation DRI Chemical/GRI Energy Model Linkage,* Gas Technology Institute (formerly Gas Research Institute), March 1991 (prepared by DRI/McGraw-Hill). The data were then revised, updated, and calibrated by Energy and Environmental Analysis, Inc.

- Projection of average ammonia import price, f.o.b. Caribbean ($/ton).

The values for these three inputs were derived from recent historical trends assessed by EEA, and agreed to for use in the model by the Demand Task Group.

b. Methanol Model

The feedstock component of the industrial model also has a methanol model that projects domestic methanol production and the subsequent gas demand for this production. Figure D3-9 shows an overview of the methanol model that is similar to the ammonia model. Natural gas also accounts for a substantial share of methanol production costs. And like ammonia, the domestic methanol industry is constantly threatened by methanol imports and thus, the methanol model takes into account possible temporary or permanent shutdowns when gas prices are high.

Domestic demand for methanol, cost of domestic methanol production, and price of methanol imports drive domestic methanol production. Similar to the ammonia model, the methanol model compares the cost of producing methanol domestically and the price of imported methanol. Based on the difference between these costs, the amount of domestic methanol production is calculated by using a linear relationship between the cost difference and share of imported methanol over total demand for methanol. The model takes into account temporary capacity that is shut down due to price competition. The model also defines permanent capacity shutdown by assuming a certain amount of existing capacity to be permanently shut down after two consecutive years of decline in domestic methanol production. Like the ammonia model, only capacity in the West South Central and South Atlantic regions is allowed to shutdown permanently. Capacity in the other regions is assumed to continue to supply domestic methanol demand regardless of natural gas prices.

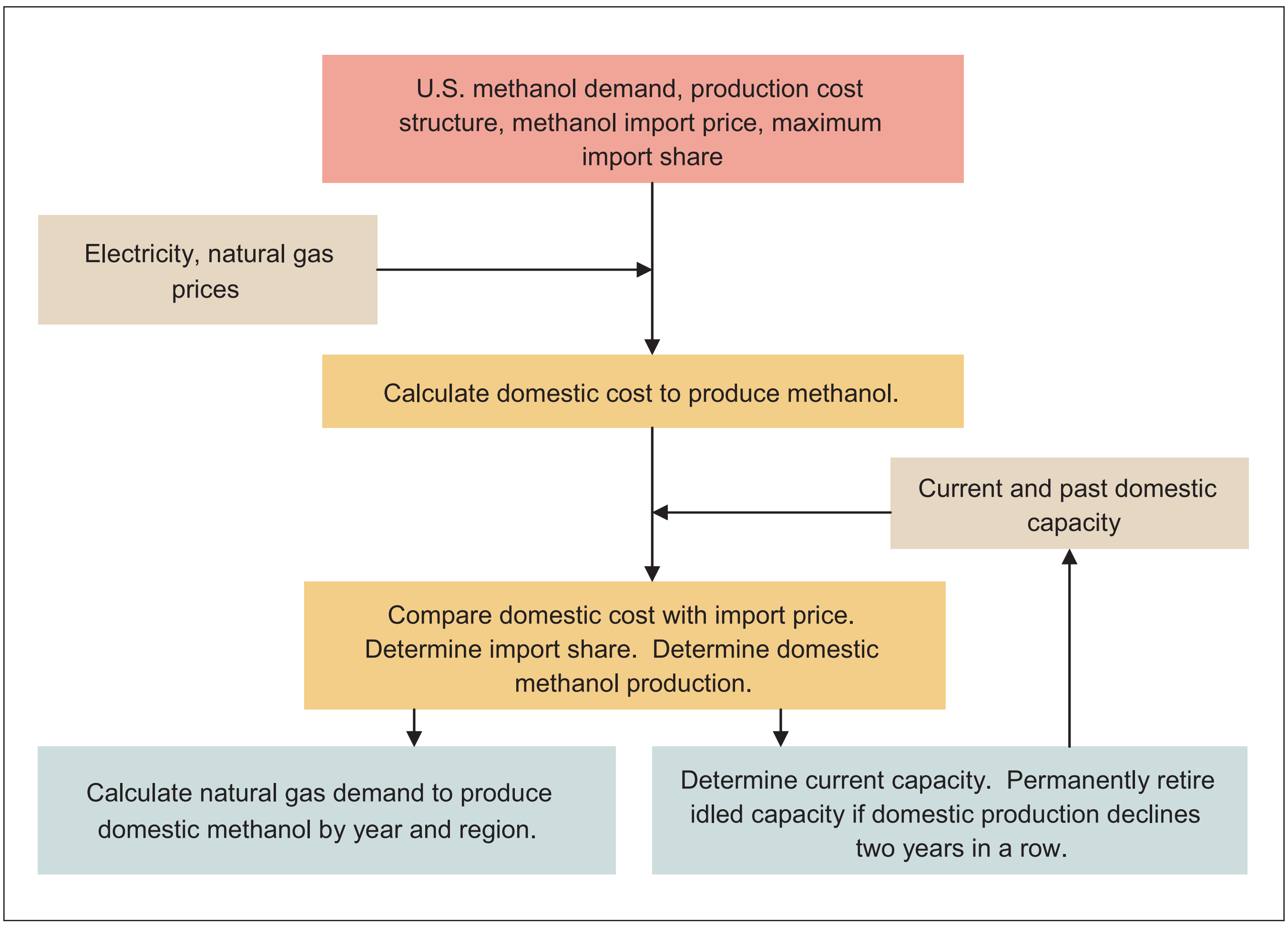


Figure D3-9. Methanol Demand Modeling

The methanol model calculates methanol production costs by including feedstock (natural gas) costs, other energy costs (for fuel and power), fixed plant costs, capital charges, and other expenditures.[3] The costs are allowed to increase over time based on an assumed inflation rate of 3% per year. Other inputs to the methanol model are:

- Projection of domestic methanol demand (billion gallons)
- Projection of average world methanol price ($/gallon)
- Maximum import share.

The values used for the above three inputs were derived from recent historical data assessed by EEA, and agreed to for use in the model by the Demand Task Group.

c. Hydrogen Model

The third feedstock component of the industrial model is the hydrogen model. Hydrogen is one of the fastest growing markets for natural gas. It is used in refinery operations and other industrial processes. If fuel cells successfully penetrate the transportation and distributed generation markets, then the demand for hydrogen could grow even faster than projected in this study. The industrial model used by the NPC in this study has a hydrogen model that only includes hydrogen production outside a refinery. Hydrogen production in refineries is included in the process heat model, as gas consumption in the refining sector. Thus, the non-refining hydrogen model includes merchant hydrogen producers that may supply hydrogen to refineries, as well as other producers that supply to other users of hydrogen.

The hydrogen model is straightforward. Unlike the methanol and ammonia industry, international competitors, because of the technical barriers to shipping the product, do not directly influence domestic hydrogen producers. Thus, it is assumed that domestic manufacturers will supply all domestic hydrogen demand. In the model, domestic hydrogen demand is entered as an exogenous variable. Gas demand for hydrogen production is calculated based on this demand and the unit requirement for gas per unit of hydrogen produced.

5. Process Heat and Other Use Components

Figure D3-10 gives an overview of the "process heat" and "other use" components of the industrial demand model. The figure shows that these two end-uses are modeled the same way. However, the "other use" component has another subcomponent, which is the ethane-based ethylene model.

The process heat end-use includes all uses of energy that involve direct heating (instead of indirect heating like steam) while the "other use" includes all the other uses, including non-boiler cogeneration, on-site electricity generation, and space heating. The Demand Task Group decided to approach both end-use categories by using EEA's large and detailed industrial model called the Industrial Sector Technology Use Model (ISTUM-2), described in Appendix G. ISTUM-2 projects industrial energy consumption by 2-digit SIC, and is more detailed for some industries, by energy service categories, technology, fuel, and region. EEA has used ISTUM-2 for a variety of projects including GRI's baseline projections.

To calibrate the new industrial model, ISTUM-2 was run twice, once with a base case gas price scenario and once with a higher gas price scenario. The IP assumptions used for the base case run were taken from EIA's 2003 Annual Energy Outlook IP assumptions. The higher gas price scenario assumed gas price to be 1.5 times the price used in the base case. Based on the results from these two runs, gas-use intensity elasticity on gas prices was calculated by industry. These elasticities, which differ by year, were then used in the new industrial model (the model developed for this study) to capture the change in gas use intensity given a change from the base case gas prices. The calculated gas-use intensity was then used to calculate gas demand given the IP for each industry. The model assumes the same elasticities for process heat and other use.

a. Ethane-Based Ethylene Model

The United States dominates the global production of ethylene. This dominance in world ethylene production has been fostered by North America's large

[3] The data used in the production cost model were taken from the *Methodology/Technical Documentation DRI Chemical/GRI Energy Model Linkage,* Gas Technology Institute (formerly Gas Research Institute), March 1991 (prepared by DRI/McGraw-Hill). The data were then revised, updated, and calibrated by Energy and Environmental Analysis, Inc.

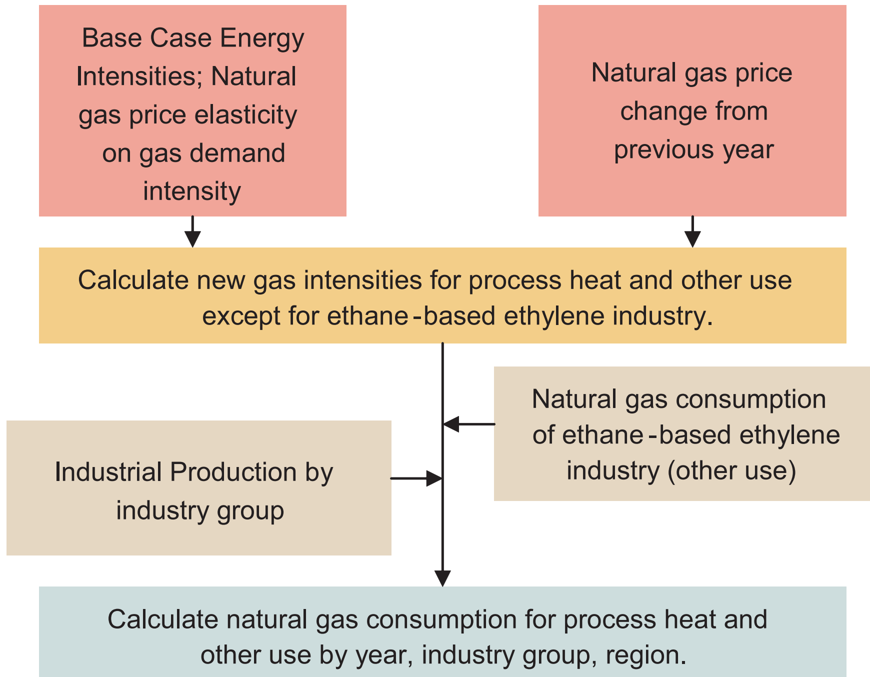


Figure D3-10. Modeling of Process Heat and Other Uses

demand for ethylene and its intermediate products, the historical availability of low-cost natural gas supplies, and an efficient infrastructure to store and transport the products. The United States has 27% of total world ethylene capacity; six of the ten largest ethylene plants in the world are in the U.S. Gulf Coast region.

The United States is a major producer of ethylene for both domestic and export markets. Ethylene production uses a variety of feedstocks, including ethane, propane, butane, naphtha, and gas oils. Among all the feedstock used in ethylene production, ethane is the most sensitive to gas price. The low levels of gas prices in the past have allowed ethane to be the primary ethylene feedstock in the United States. However, with gas prices today higher than in the past, ethane-based ethylene producers are negatively impacted and have become less competitive in the global market for ethylene.

The industrial model has a separate component that forecasts ethylene production by ethane-based producers, and the subsequent consumption of natural gas. The model is similar to the ammonia and methanol models. Figure D3-11 shows an overview of the ethane-based ethylene model.

The domestic production of ethane-based ethylene is driven by overall domestic demand for ethylene, the cost of domestic ethylene production from ethane, and the price of ethylene imports. Similar to the methanol and ammonia models, the model compares the cost of producing ethane-based ethylene domestically and the price of imported ethylene. Based on the difference between these costs, the amount of domestic ethane-based ethylene production is calculated by using a linear relationship between the cost difference and share of imported ethylene. Thus, the model accounts for temporary capacity shutdown. The ethane-based ethylene model also takes into account permanent capacity shutdown by assuming a certain amount of existing capacity to be permanently shut down after two consecutive years of decline in domestic ethylene production. Like the ammonia and methanol models, only capacity in the West South Central and South Atlantic regions is allowed to shut down permanently. Capacity in the other regions is assumed to continue to supply domestic ethylene demand regardless of natural gas prices. High transportation costs to deliver imported ethylene to these regions make imported ethylene less competitive in these regions.

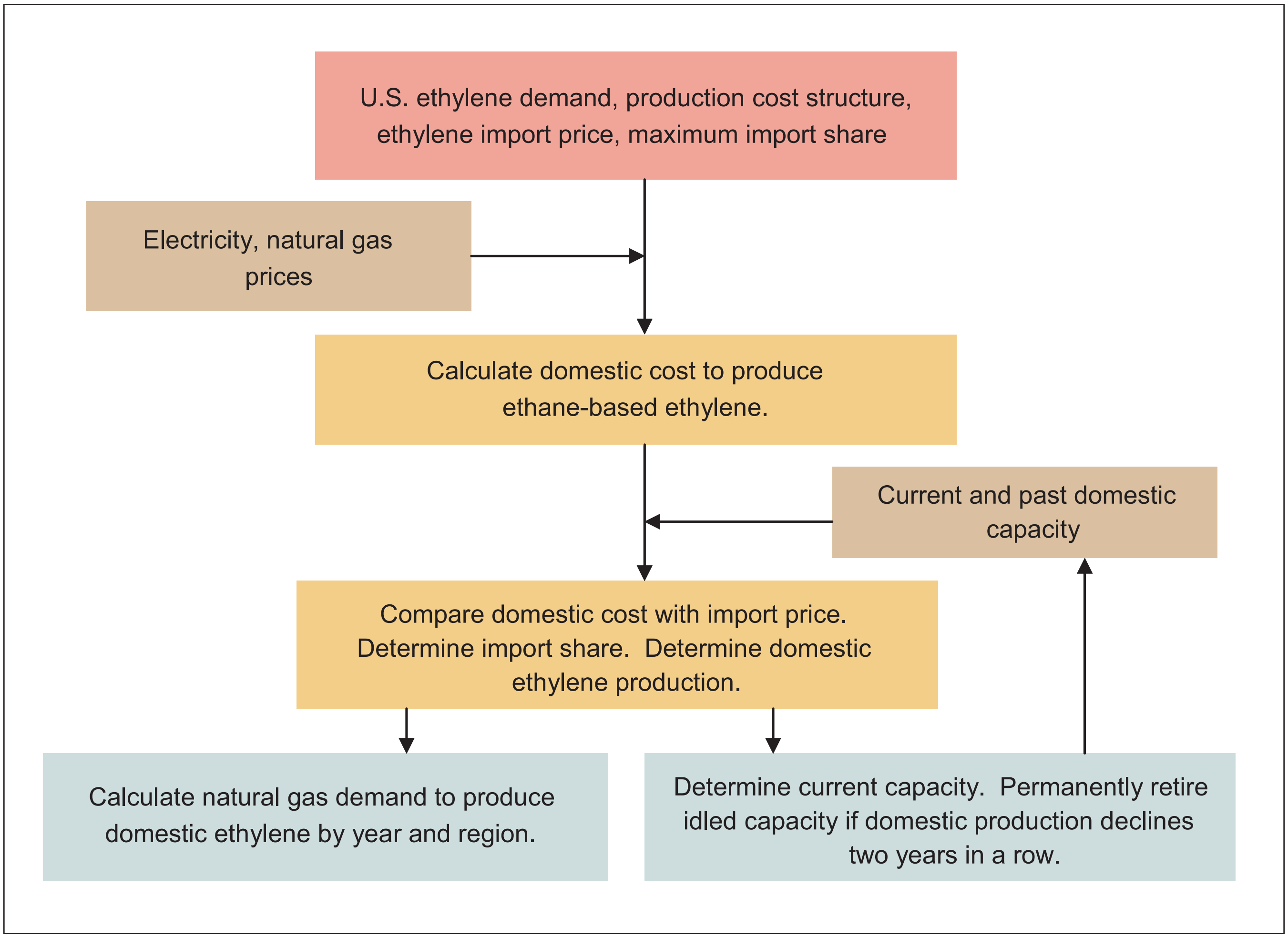


Figure D3-11. Ethane-Based Ethylene Modeling

The calculation of production costs of ethane-based ethylene incorporates feedstock (ethane) costs, other energy costs (for fuel and power), fixed plant costs, capital charges, and other expenditures.[4] The costs are allowed to increase over time based on an assumed escalation rate of 3% per year. Other inputs to the ethane-based ethylene model are:

- Projection of domestic ethylene demand (million lb)
- Projection of average world ethylene price (cents/lb)
- Maximum import share of ethane-based ethylene.

The values used for the three inputs were derived from recent historical data assessed by EEA, and agreed to for use in the model by the Demand Task Group.

6. Model Outputs

The industrial model used by the NPC study group forecasts industrial gas consumption by industry, end-use, and region. The model first calculates annual gas demand and then uses seasonality factors to derive monthly gas demand.

a. Summary of Modeling Approach

As mentioned earlier in this chapter, the NPC study group worked with EEA to develop a model to forecast U.S. industrial demand for 26 industries, 11 regions, and 4 end-use categories (boilers, process heat, feed-stocks, and other) reflecting economic growth

4 The data used in the production cost model were taken from the *Methodology/Technical Documentation DRI Chemical/GRI Energy Model Linkage,* Gas Technology Institute (formerly Gas Research Institute), March 1991 (prepared by DRI/McGraw-Hill). The data were then revised, updated, and calibrated by Energy and Environmental Analysis, Inc.

assumptions and a range of natural gas prices. Because of its size, complexity, and importance to gas-consumption trends, the modeling of the chemical industry was further disaggregated into ammonia, methanol, hydrogen, and other chemical industry products. The model was designed to explicitly capture changes and improvements in technology including improvements in energy efficiency, short- and long-term fuel switching, and global competition. In order to develop input parameters and to validate the results, outreach seminars were conducted with representatives of key gas-intensive industries to capture emerging trends and major drivers of industrial natural gas consumption.

Adjustments for competitive and price elasticity effects were made in interim post-processing analyses to better reflect demand in each sector. Particular focus was placed on gas price elasticity dynamics because model price outputs were on the upper end of historical norms, and there was little data to calibrate sustained demand response to higher prices and greater global competition.

Figures D3-12 and D3-13 summarize the analysis process for non-chemical and chemical industry demand, respectively. These figures show that the projection of gas demand for each sector is made in a multi-step process. Historical energy consumption and industrial production data are used to calculate historical "gas energy intensity" values for each sector. Future gas energy intensity values are projected reflecting:

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

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

b. Projections of Industrial Demand

As described in the preceding sections, the NPC projection of industrial gas demand addressed key factors affecting gas-intensive industries. These include:

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

Industrial production growth is the most significant driver of gas consumption in the NPC scenarios. Table D3-4 lists the growth factors used in the projections compared to recent historical data (1992-1998). This shows that IP for gas-intensive industries grew at a slower rate than for other industries. In some cases, energy consumption was projected to grow at a slower rate than production due to better energy efficiency.

As referenced elsewhere in this chapter, the 1992-1998 period was assessed by EEA to determine behavior of industrial consumers of natural gas and was used as a "baseline" period for future demand elasticity. During the 1992-1998 period, overall energy consumption grew at only 1.3% per year. Compared to other fuels, gas consumption grew at a faster rate, particularly from growth in gas-intensive processes. Industrial consumers reported in outreach work sessions with the Demand Task Group that one of the key factors for the growth in gas-intensive processes was the ease of environmental permitting and compliance actions for gas-based technologies and applications relative to those for facilities and/or equipment using other fuels. In particular, New Source Review (NSR) proceedings, and the reported uncertainty associated with the enforcement with regard to NSR, was a major factor in biasing their investment decisions toward gas. These consumers also acknowledged that the relatively low-priced outlook for natural gas was also a major factor in such decisions.

New cogeneration during this period also contributed to the increase in gas consumption. Gas consumption grew by 2.4% per year when cogeneration was excluded.

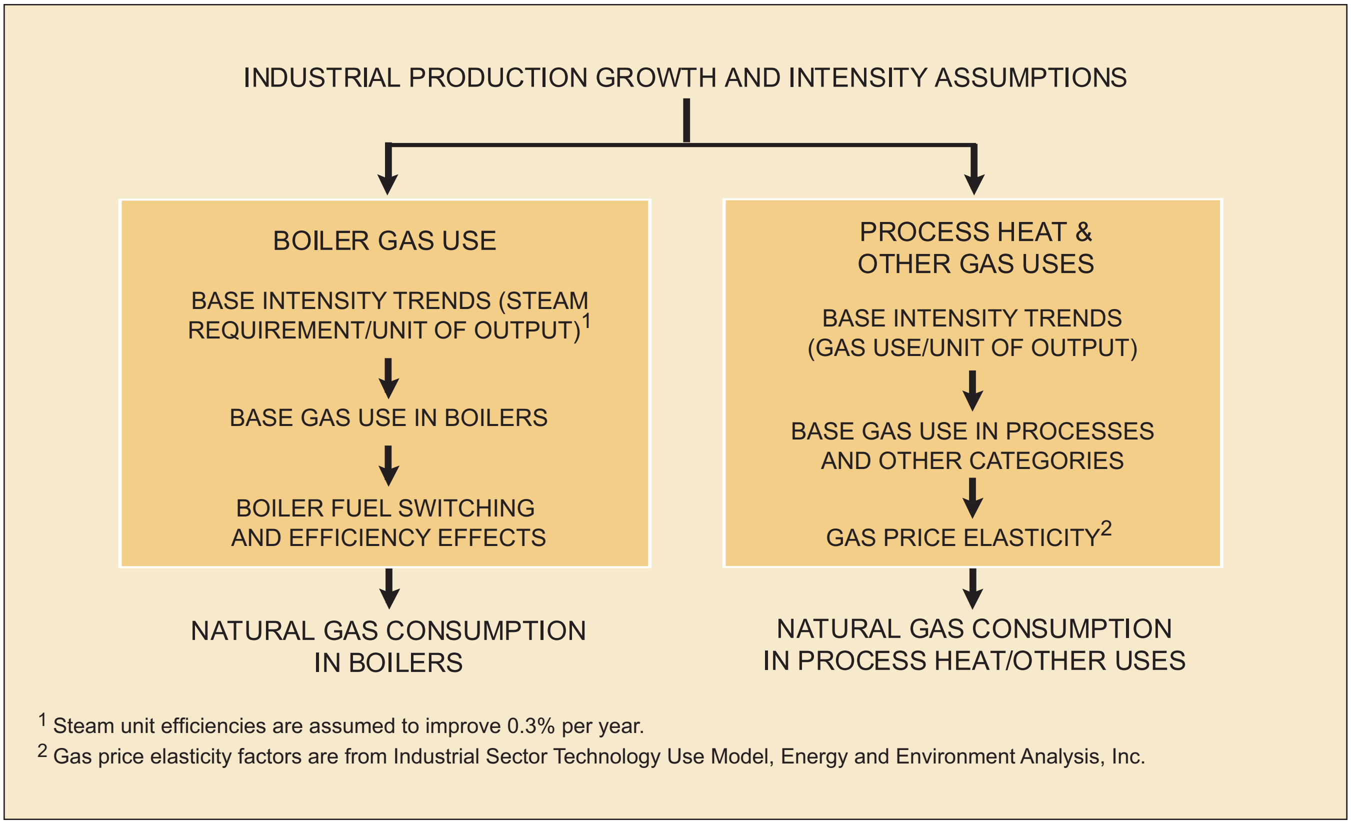


Figure D3-12. Industrial Demand Analysis – Non-Chemical Uses

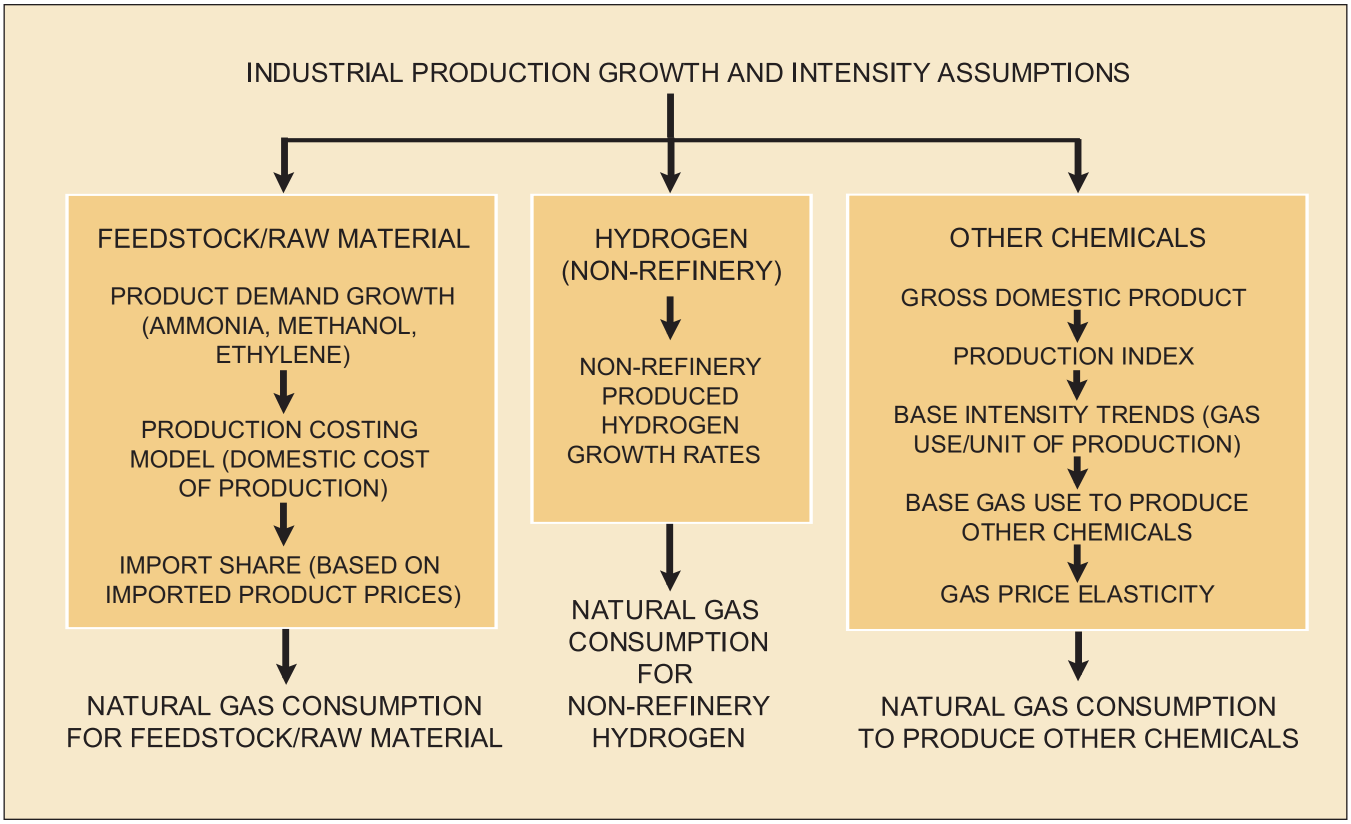


Figure D3-13. Industrial Demand Analysis – Chemical Uses

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

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

Table D3-4. Growth Factors (Percent)

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

The principal differences between the Reactive Path and the Balanced Future scenarios with regard to industrial consumers are assumptions for fuel-switching capability, both short-term and long-term, and assumptions for efficiency improvement, each of which is greater in the Balanced Future scenario. To model fuel-switching behavior of industrial consumers, boiler-switching relationships were developed for each region of the United States and Canada. An example of these relationships is shown by Figures D3-14 and D3-15, the boiler-switching capability modeled in the Reactive Path and Balanced Future scenarios, respectively, for the West South Central region of the United States. In the Balanced Future scenario, the percentage of industrial boilers that would be able to fuel-switch was increased from a low in 2003 of between 2% and 8%, depending on the region, to a high of 28% in all regions by 2025. The 28% figure was assumed as an "end point" by the Demand Task Group on the logic that the last MECS survey, addressing the 1985-1994 period, reflected this high a level of fuel-switching capability in U.S. industries. Therefore, the Demand Task Group determined that such a number was reasonable in historical context, and would provide users of this study with perspectives on the potential impact of steps that might be taken by government and industry to facilitate and/or achieve additional fuel flexibility.

Since the switchable boilers cannot operate 100% on oil due to operational constraints, the maximum oil percentage for the switching curves was varied to account for the differences in boiler capabilities by region.

The aggregate results modeled for industrial boiler switching and the attendant fuel utilization are illustrated in Figures D3-16 and D3-17 for the Reactive Path scenario, and in Figures D3-18 and D3-19 for the Balanced Future scenario. To further apply the process described earlier, the NPC study group developed price elasticity relationships. Base elasticity trends were taken from the ISTUM-2 model, developed by EEA; these were modified to reflect the major industry

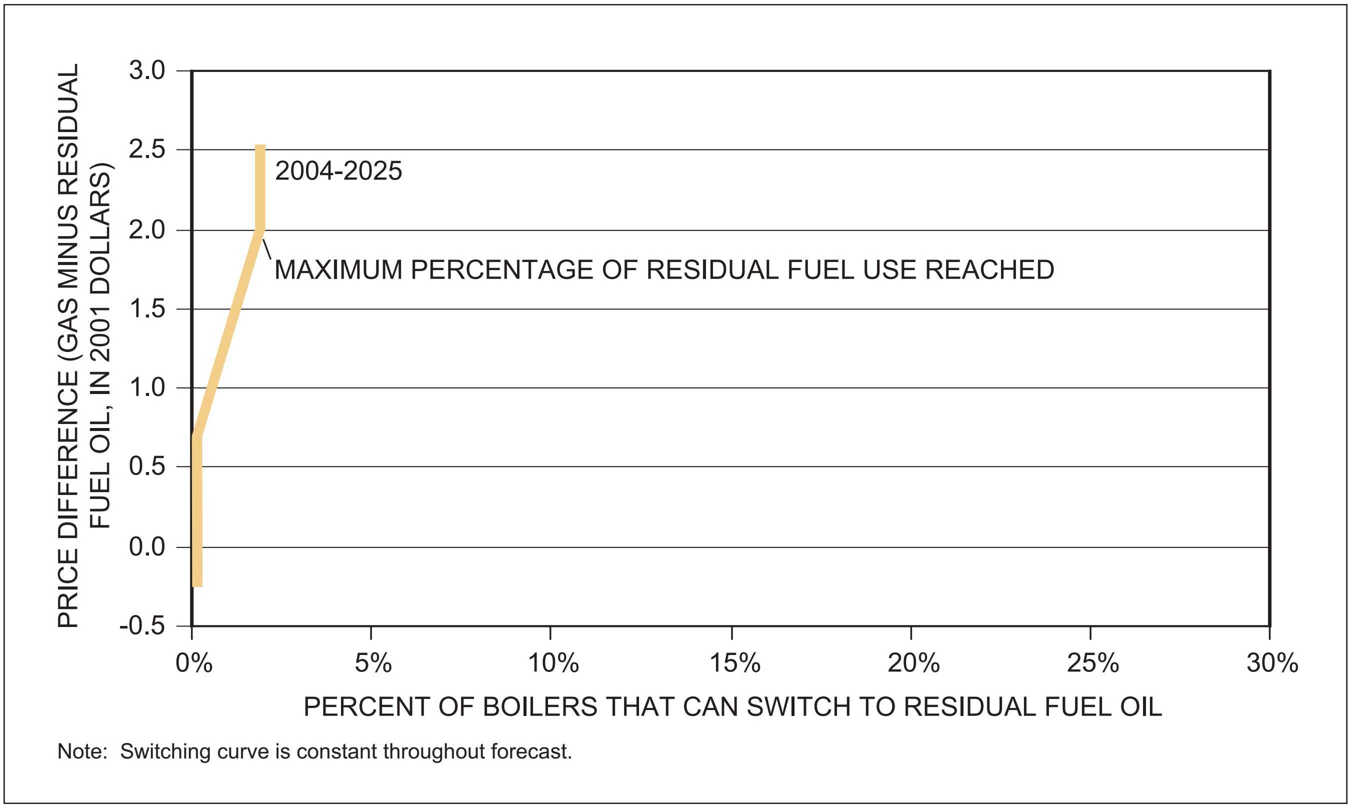


Figure D3-14. Industrial Boiler Switching Curve Used for West South Central Region of United States in Reactive Path Scenario

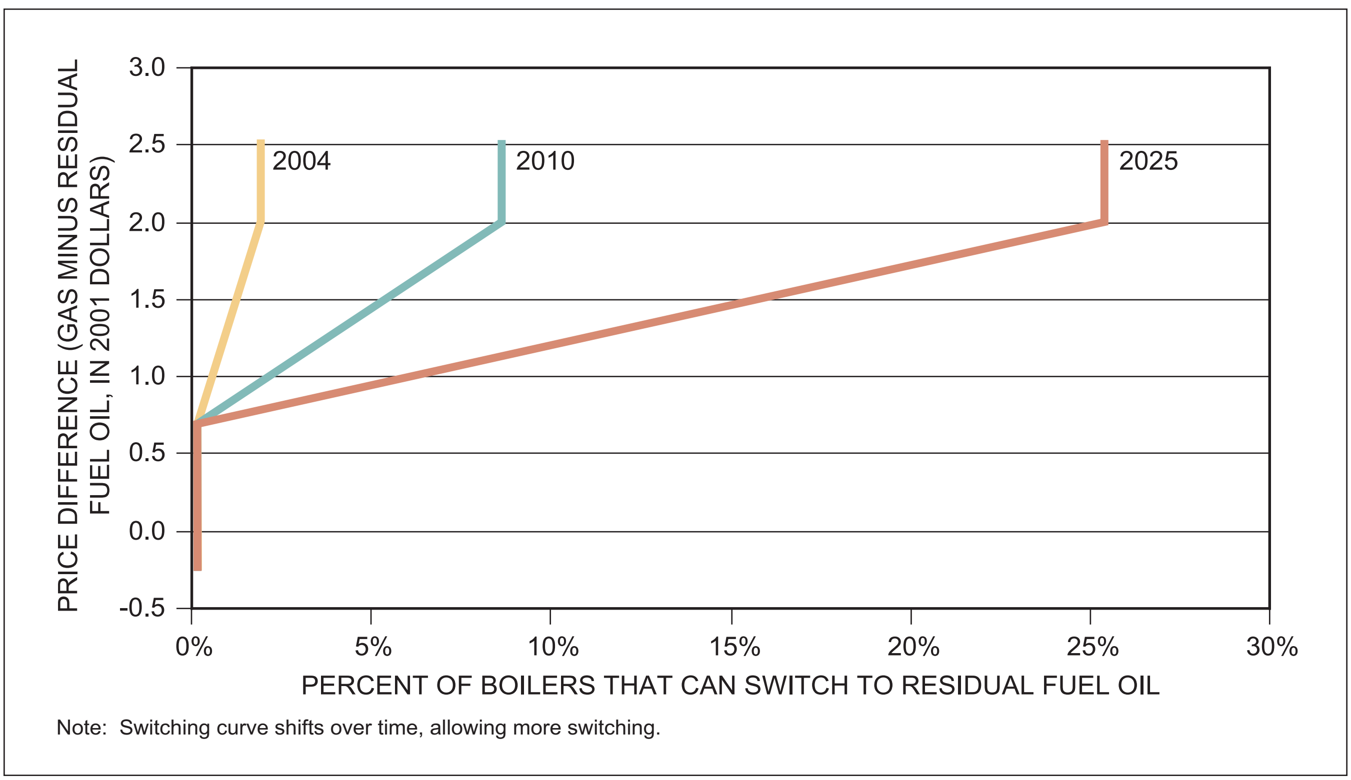


Figure D3-15. Industrial Boiler Switching Curve Used for West South Central Region of United States in Balanced Future Scenario

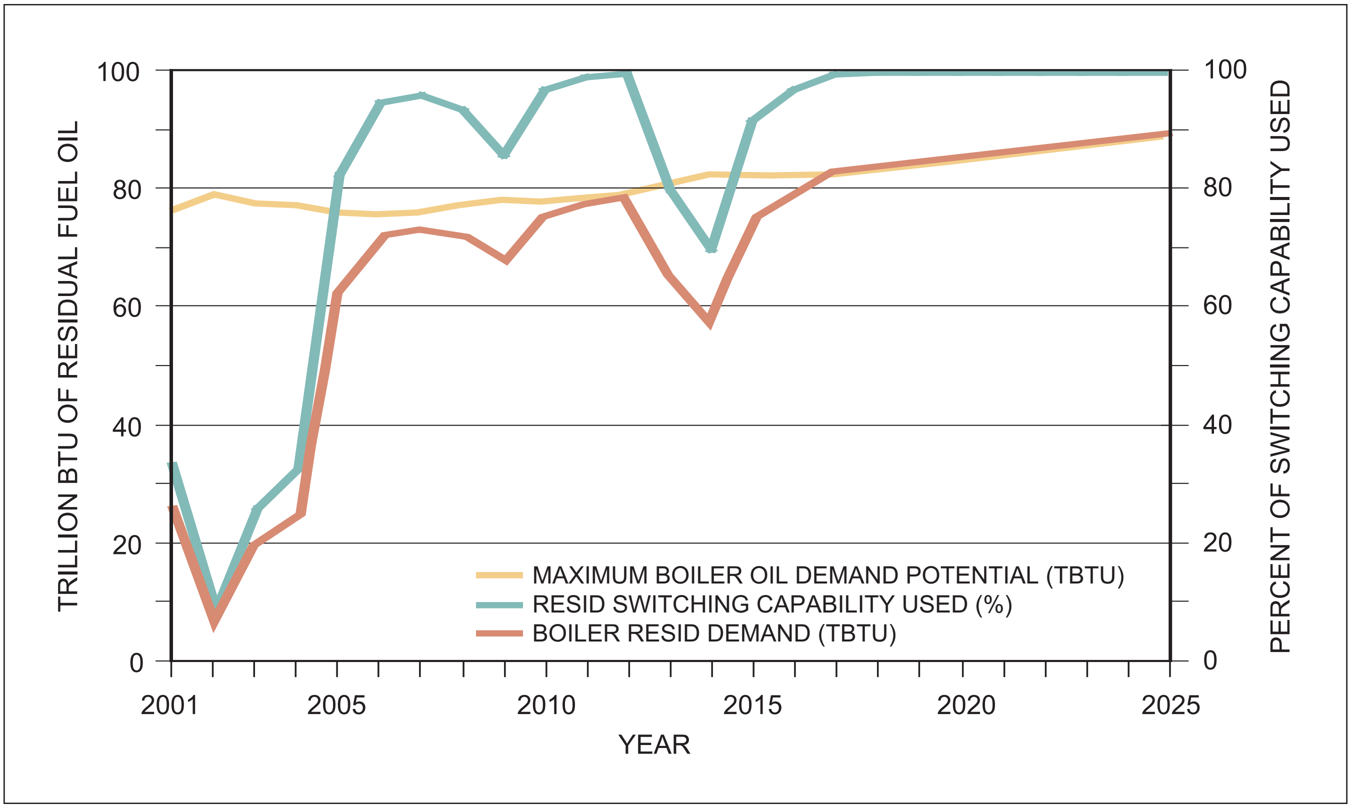


Figure D3-16. Industrial Boiler Switching in Reactive Path Scenario

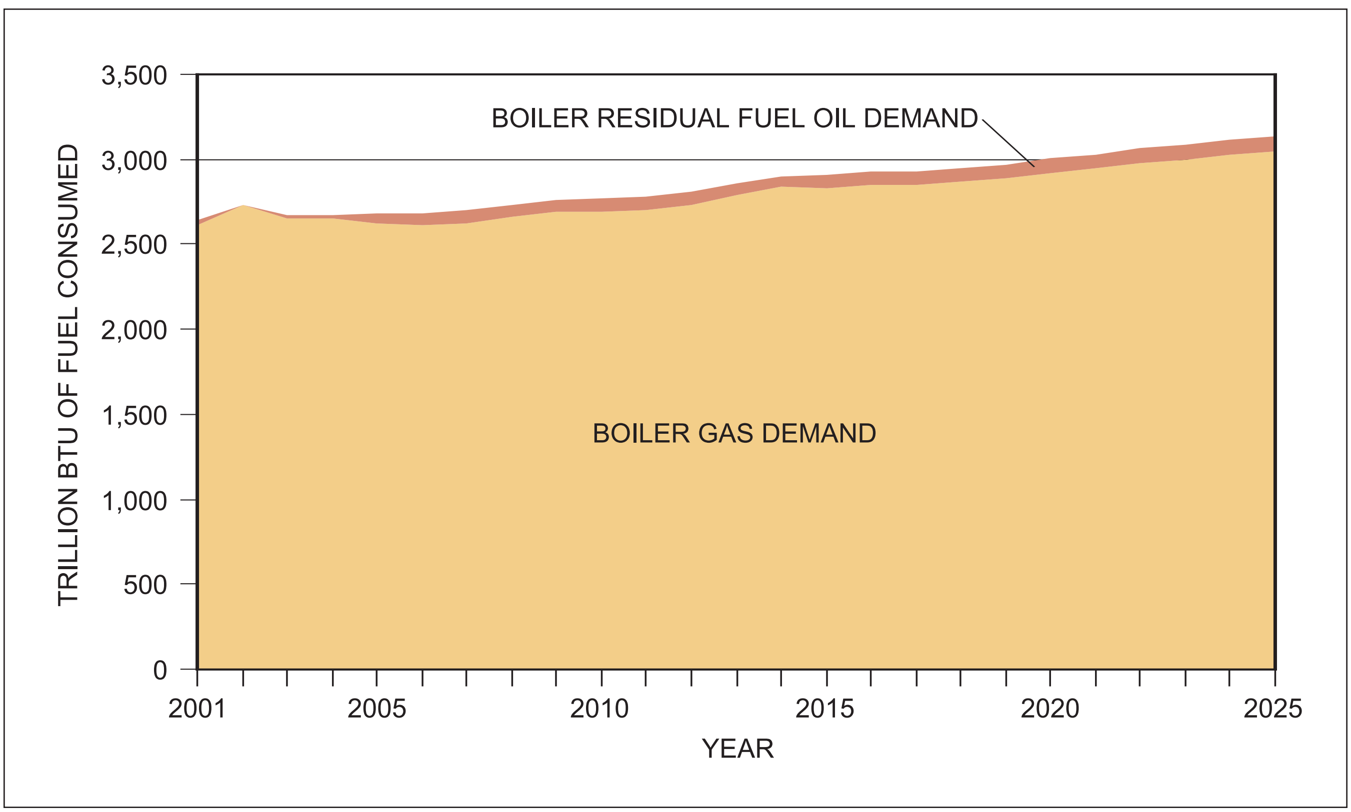


Figure D3-17. Industrial Boiler Fuel Use in Reactive Path Scenario

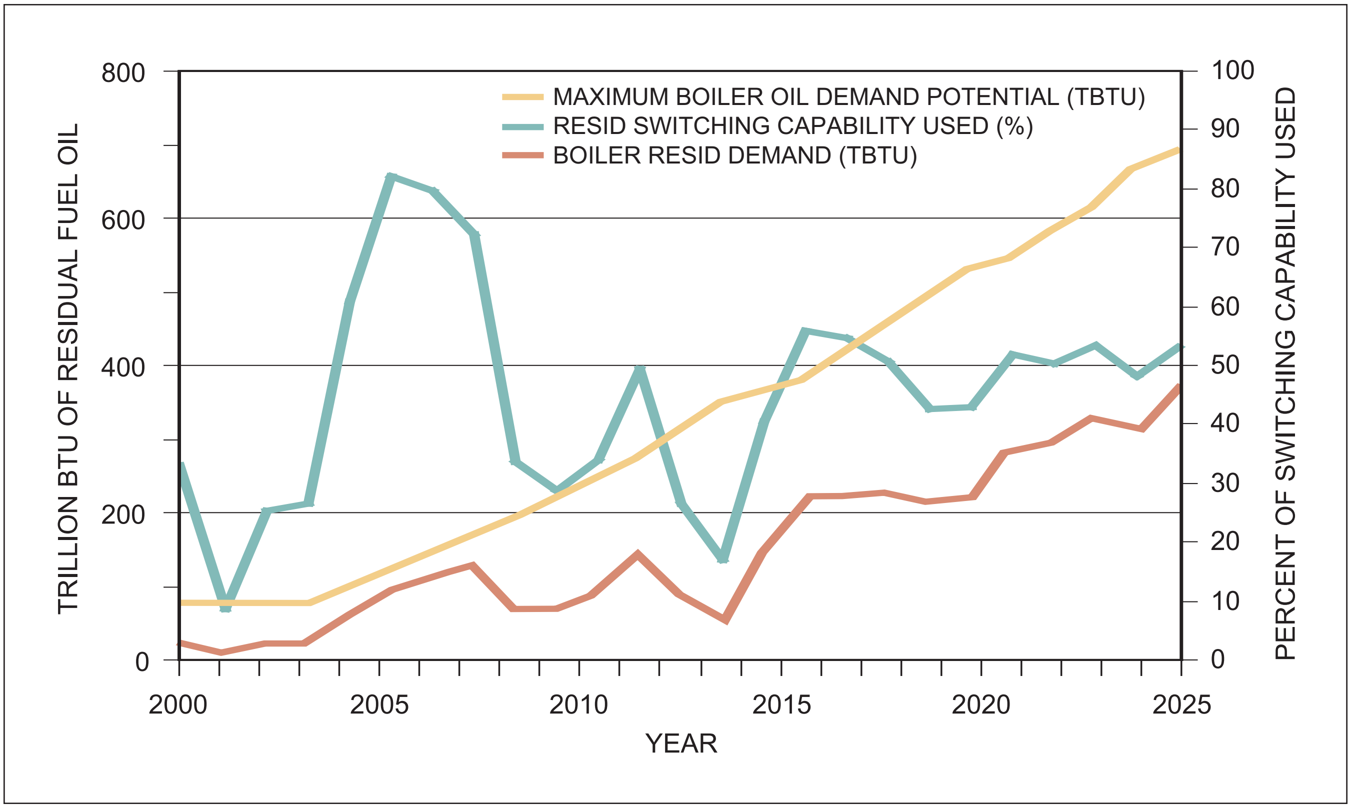


Figure D3-18. Industrial Boiler Switching in Balanced Future Scenario

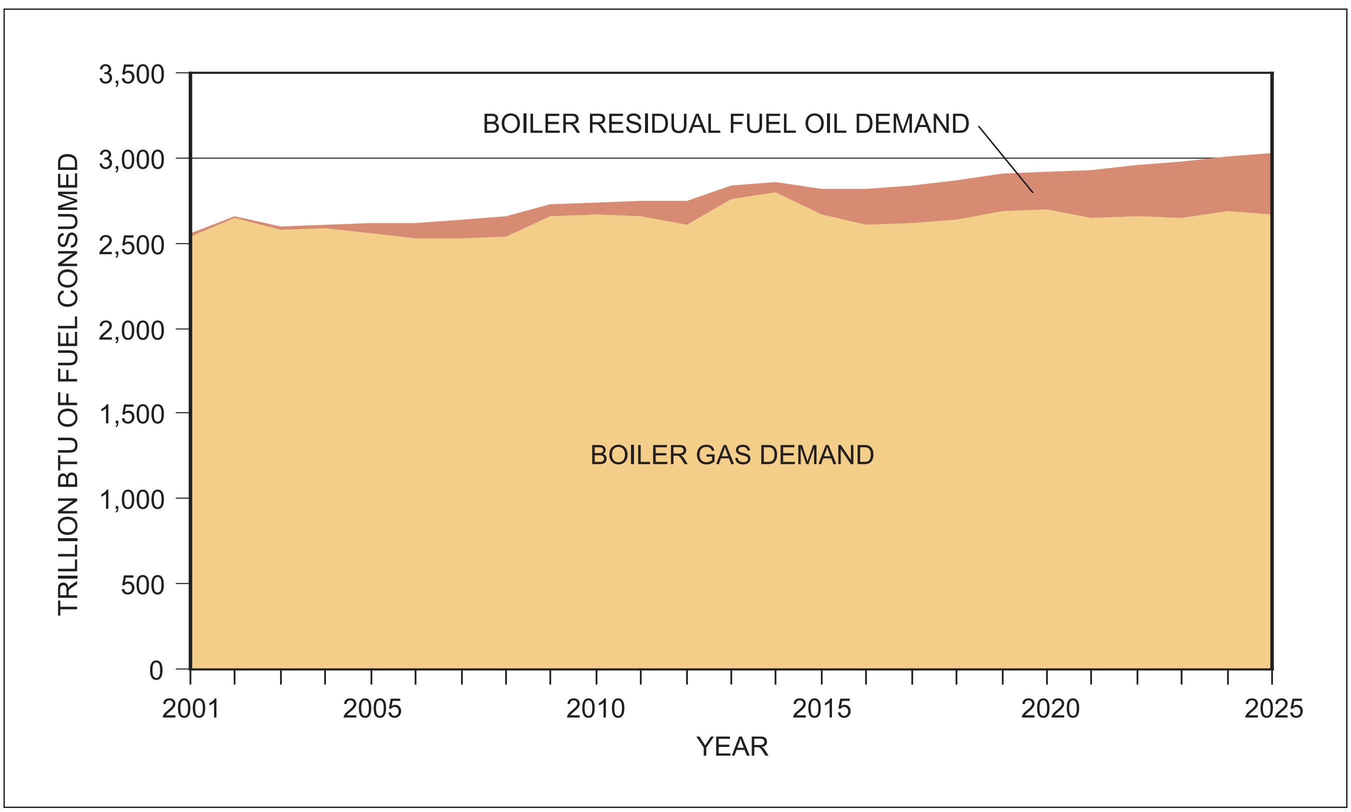


Figure D3-19. Industrial Boiler Fuel Use in Balanced Future Scenario groupings analyzed by the NPC study group, and are shown in Table D3-5. Further, energy intensity price elasticity factors were taken from ISTUM-2, modified to reflect the major industry groupings, and then developed for both the Reactive Path and Balanced Future scenarios; Tables D3-6 and D3-7 contain these factors. Figures D3-20 and D3-21 show an example of these relationships for the petroleum refining industry, as modeled in the Reactive Path and Balanced Future scenarios, respectively.

The resulting industrial gas demand projected for the Reactive Path scenario is shown in Figure D3-22. This suggests a continuation of the current decline in gas demand from the 1997 high downward to about 7 TCF per year in about 2007. Overall industrial gas demand in both scenarios is forecast thereafter to be relatively flat to 2013, after which a small increase is reflected in the Reactive Path scenario, consistent with the lower natural gas prices of the scenario in that year. Figure D3-23 shows the historical and projected gas demand by industry, illustrating both the trajectory and overall magnitude of gas consumption in each industry. The chemicals industry is projected to remain the largest industrial gas consumer, although its consumption drops significantly from the levels of recent years in the Reactive Path scenario. This projected decline is largely due to likely loss of market share to global competition at the projected gas prices. The volume of natural gas feedstock is projected to drop for ammonia and methanol, as is ethane used for ethylene production.

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

Figure D3-24 shows the Balanced Future forecast of overall industrial gas demand. Figure D3-25 provides this information for each industry segment modeled by the NPC. These projections show a decline from current levels, though not quite as much as in the Reactive Path scenario. The projection fluctuates around the 7 TCF per year level over most of the forecast period. Although more fuel-switching capability is in this scenario, gas consumption is actually higher. The Balanced Future reflects the potential for fuel switching to reduce peak demands, and thus price volatility, without large effects on annual gas load. Further, the increased flexibility in the Balanced Future scenario progressively lowers gas prices relative to the Reactive Path scenario, and allows industrial consumers to rely on natural gas to a greater degree.

II. Chemicals

The chemical industry (SIC 28 or NAICS 325) – or "the business of chemistry" – is the most significant industry group in the United States and Canada in terms of natural gas demand. Natural gas is used in the chemical industry as both a fuel and as a raw material. Natural gas is used directly as the basic building block of various chemicals, most notably ammonia and methanol. Additionally, natural gas liquids (NGLs), including ethane, propane, and butane, are major petrochemical feedstocks. The products from these chemical processes contribute to the creation of a host of other consumer goods, such as plastics, pharmaceuticals, and electronic materials.

In 2002, the chemical industry consumed 6.5 quadrillion Btu for fuel, power, and feedstocks. Energy used for fuel, power, and electricity generation accounted for 3.1 quadrillion Btu, nearly 50% of the total. Natural gas accounted for 1.8 quadrillion Btu or 59% of the industry's total energy requirements.

A. Role of Chemicals in the U.S. Economy

The chemical industry converts certain petroleum products, natural gas, and other naturally occurring raw materials into a wide variety of basic chemicals. These basic chemicals (including petrochemicals such as ethylene, propylene, and butadiene) are then converted by other sectors of the business into chemical intermediates (polyethylene, polypropylene, styrene, vinyl chloride, etc.) and final chemical products such as plastics, synthetic fibers, and rubber. In turn, these chemistry products are fabricated by many different industries into thousands of industrial and consumer products. In fact, the chemical industry makes many of

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

Table D3-5. Base Energy Intensity Trends (Indexed, 2001 = 1.000)

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

Table D3-6. Energy Intensity Price Elasticity for Reactive Path Scenario (Change in Energy Intensity per Change in Gas Price)

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

Table D3-7. Energy Intensity Price Elasticity for Balanced Future Scenario (Change in Energy Intensity per Change in Gas Price)

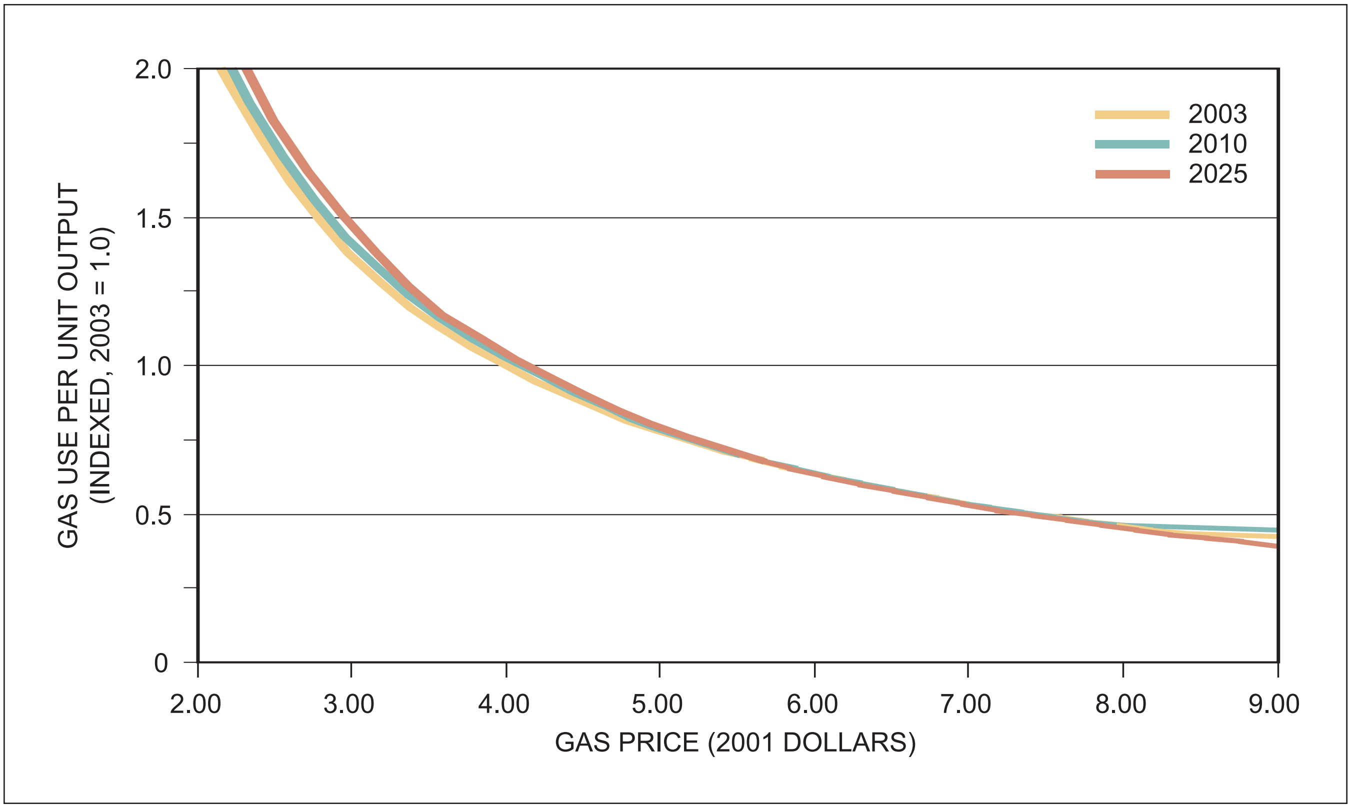


Figure D3-20. Change in Energy Intensity for Petroleum Refining Sector in Reactive Path Scenario

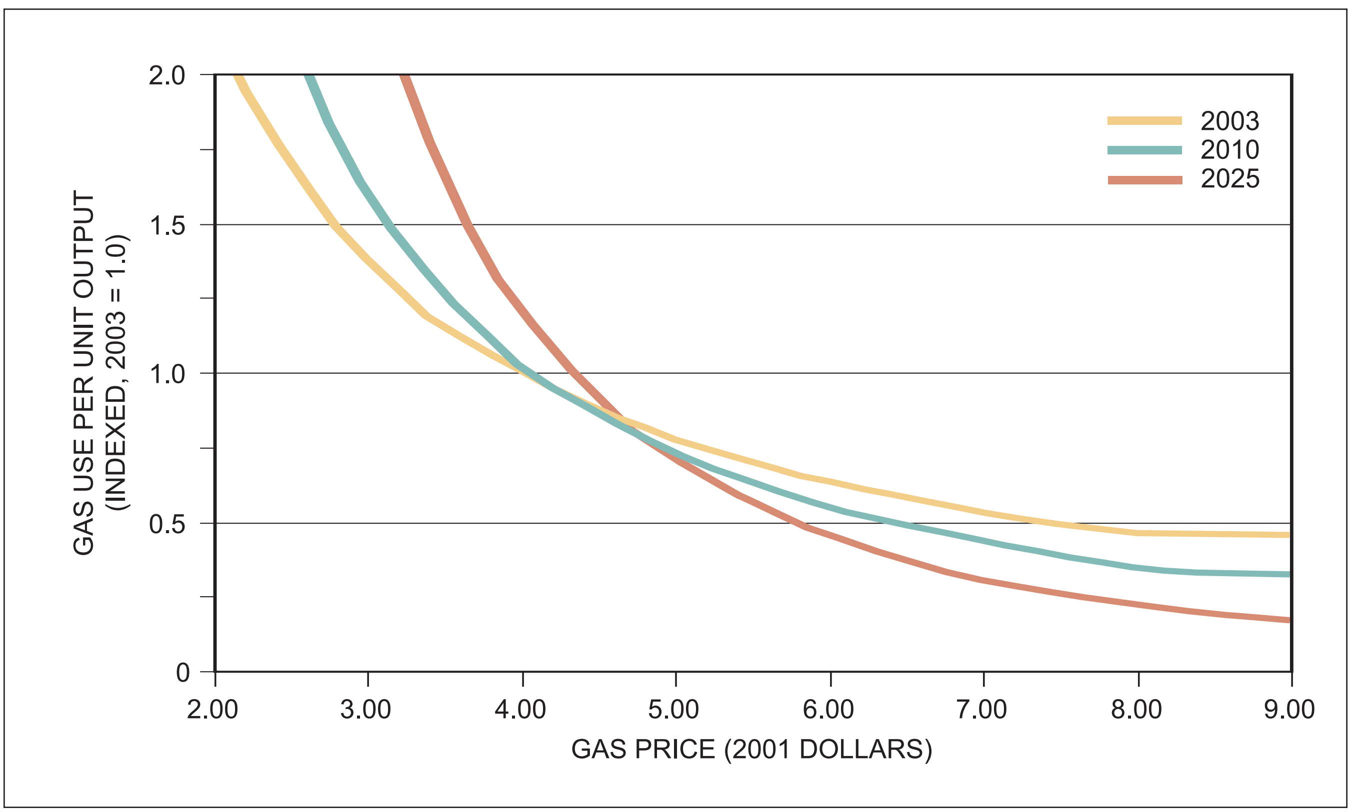


Figure D3-21. Change in Energy Intensity for Petroleum Refining Sector in Balanced Future Scenario

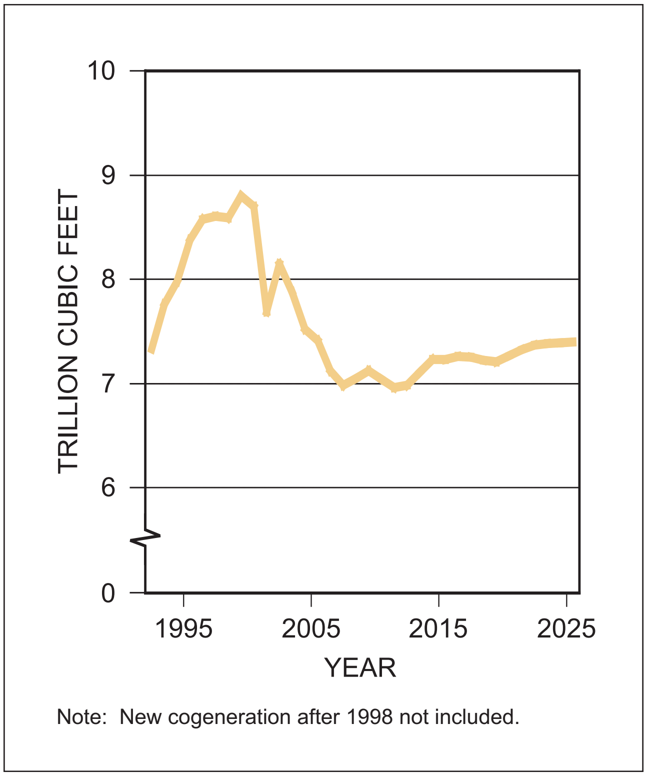


Figure D3-22. U.S. Industrial Gas Demand in Reactive Path Scenario

the products that help save energy throughout the entire economy, including energy-saving polymers to insulate homes and enable cars to be more energy-efficient. Representatives of the chemical industry stressed that this industry is the only part of the economy that transforms hydrocarbon molecules into products of value rather than deriving value by combusting them for energy.

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

[5] American Chemistry Council.

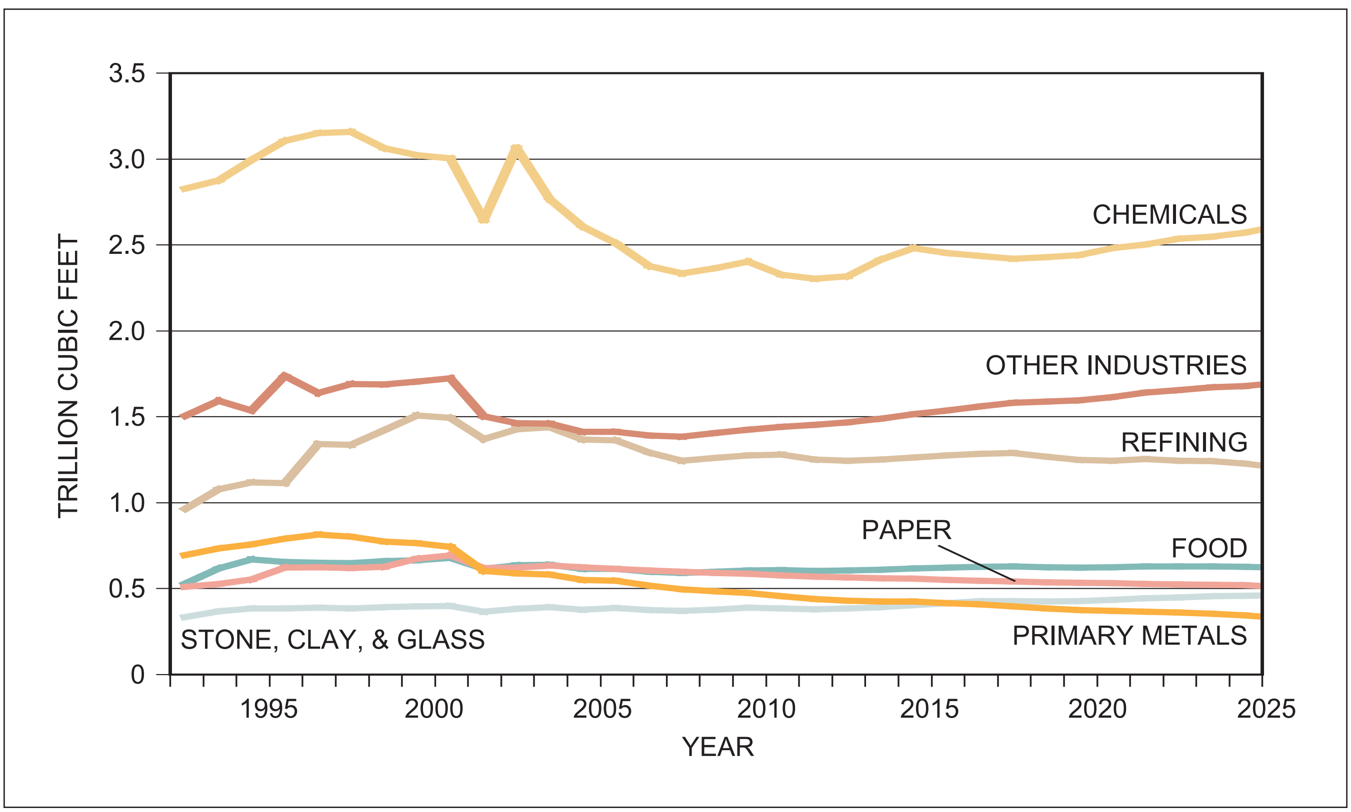


Figure D3-23. U.S. Industrial Gas Consumption by Industry in Reactive Path Scenario

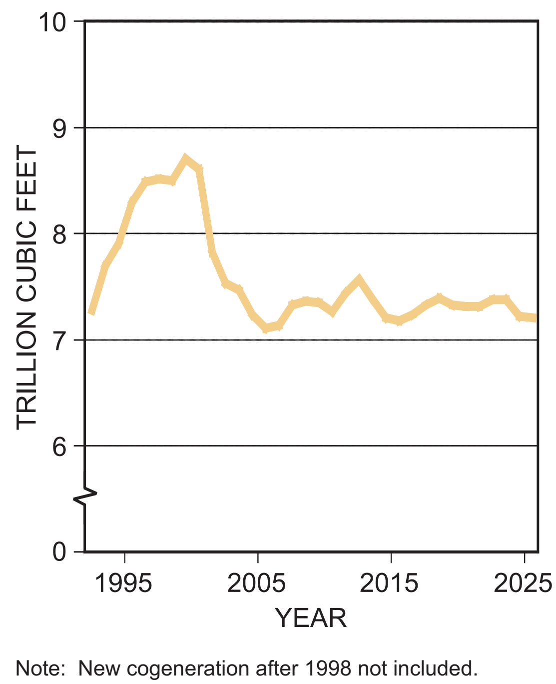


Figure D3-24. U.S. Industrial Gas Demand in Balanced Future Scenario

companies are often simultaneously suppliers, customers, and competitors.

The business of chemistry also requires constant innovation, and is knowledge-intensive. The American Chemistry Council reports that the chemical industry employs more knowledge workers than any other manufacturing industry, that chemical companies spend over $31 billion annually on research and development, and that these companies generate one-seventh of patents granted in the U.S. annually.

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

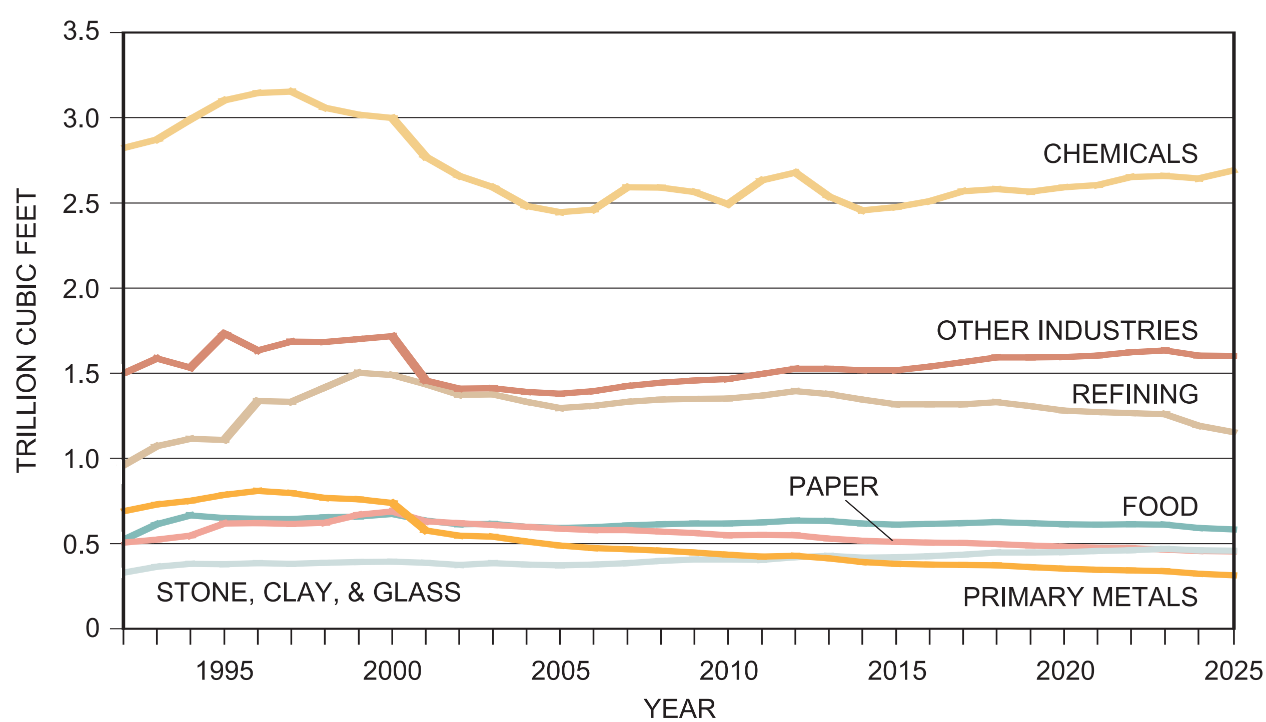


Figure D3-25. U.S. Industrial Gas Consumption by Industry in Balanced Future Scenario

North America was an early leader in developing a chemical industry. The industry has gone through several growth phases, the first of which began around 1900. The most recent period of rapid growth began during World War II. Much of this growth in the basic chemicals (and petrochemicals) segment of the industry has been concentrated along the U.S. Gulf Coast, where natural gas and other petroleum raw materials have been historically abundant. Much of basic chemical production is still concentrated in the Gulf Coast area, with Texas and Louisiana producing about 70% of all primary petrochemicals in the United States. The conversion of these basic chemicals into plastics, synthetic fibers, rubber, and other chemical products is more geographically dispersed covering all 50 states. For example, the majority of total synthetic fiber production occurs in the Southeast, while production of other chemical products such as plastics, pharmaceuticals, consumer products, and fertilizers is even more widely dispersed among the states.

The regions and states of the United States are economically interdependent. Each state's economy depends on the continuing availability of goods and services from other states and on its ability to sell its goods and services throughout the nation. Every state is dependent on the products of chemistry to support its manufacturing, agricultural, service, and/or other industries. Nearly every state hosts some form of chemical production. The majority of the U.S. production of basic industrial chemicals, however, occurs in relatively few states. In rank order, the ten leading states in shipments of chemical products are:

1. Texas
2. Louisiana
3. New York
4. New Jersey
5. California
6. North Carolina
7. Pennsylvania
8. Illinois
9. Ohio
10. Indiana.

Combined, the chemical industry in these ten states directly employed 621,900 people in 2001 and these states accounted for 61% of total chemical industry employment. Figures D3-26 and D3-27 illustrate where the business of chemistry is located. Figure D3-28 illustrates the concentration of chemical industry jobs by state. Appendix H lists additional statistics for all 50 states and the District of Columbia.

B. Global Chemicals Market

Among the major industrial nations of the world, the U.S. chemical industry is the largest exporter of chemicals. The chemical industry is worldwide in scope, and is large, mature, and highly fragmented, with numerous suppliers and customers. The bulk of the world's $1.72 trillion chemical output, however, is accounted for by a handful of industrialized nations. The top ten countries combined accounted for about 70% (or $1.21 trillion) of total world chemical output in 2001. The United States alone produced $454 billion, over 26% of the total. As illustrated in Figure D3-29, the top ten chemical-producing countries in 2001 were:

1. United States ($454 billion)
2. Japan ($213 billion)
3. Germany ($119 billion)
4. China ($109 billion)
5. France ($74 billion)
6. Italy ($60 billion)
7. South Korea ($53 billion)
8. United Kingdom ($51 billion)
9. Brazil ($38 billion)
10. Belgium/Luxembourg ($34 billion).

Combined, the chemical industries of the world employ some 10 million people.

The business of chemistry in each of these industrialized nations typically produces a wide variety of chemicals ranging from commodity industrial chemicals used to make other products, to specialty chemicals that are tailored for unique applications. Each of these countries has a large body of technological knowledge in research and process engineering, abundant capital and management skills, and skilled and technically competent labor forces. Many of these industrialized developed nations have historically maintained trade surpluses in chemicals. In 2001, the United States was the largest exporter ($80.2 billion), followed by the Germany ($72.9 billion), Belgium/Luxembourg ($45.3 billion), France ($45.0 billion),

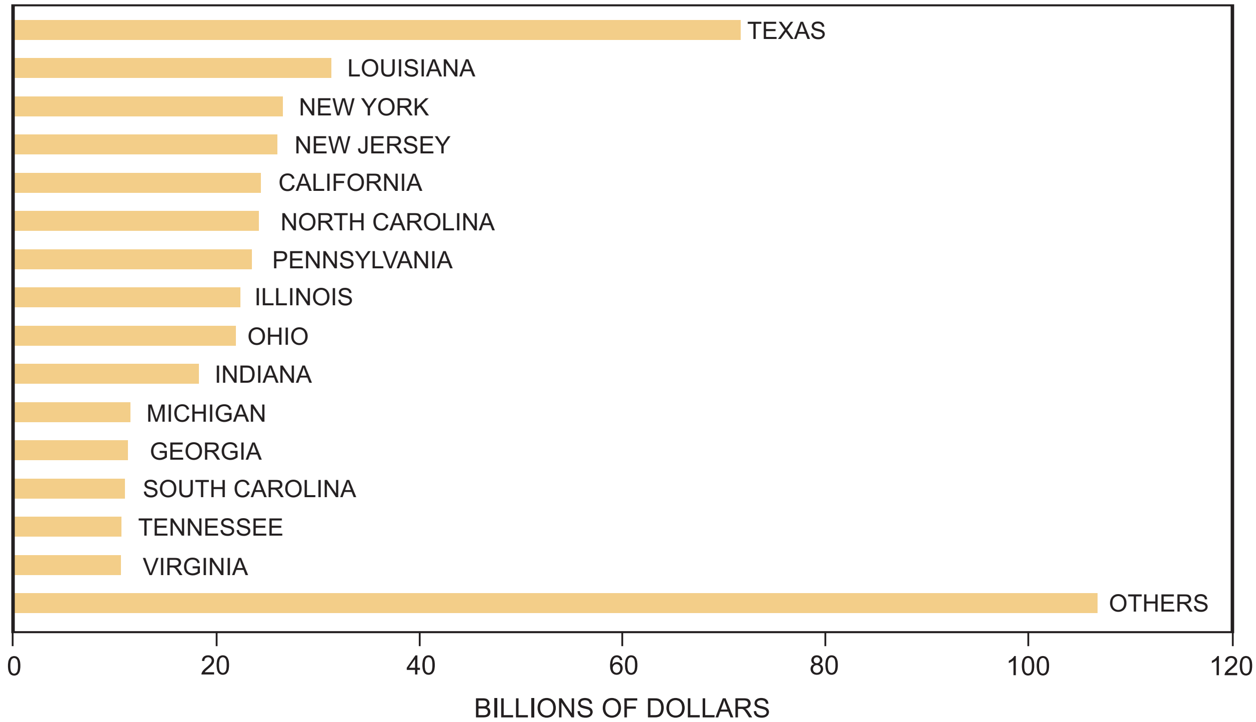
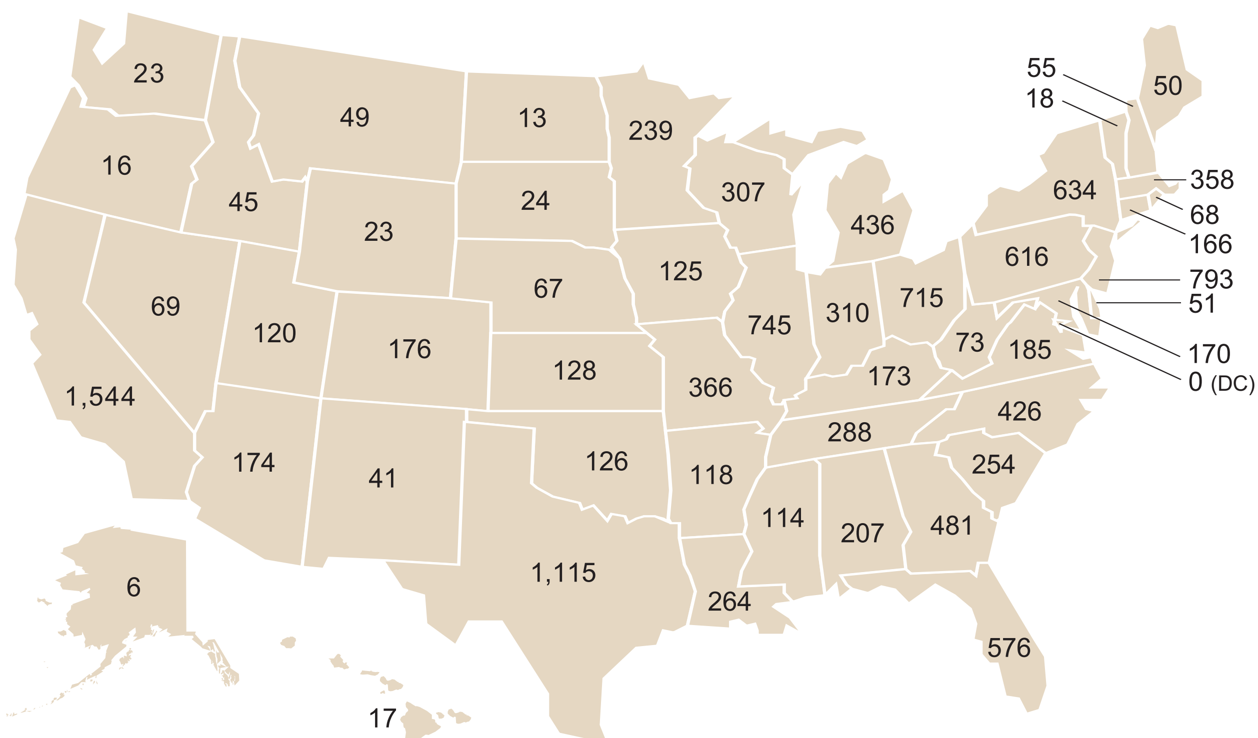


Figure D3-26. Value of Chemical Industry Shipments by State



Source: U.S. Census Bureau.

Figure D3-27. Number of Chemical Industry Establishments (1997)

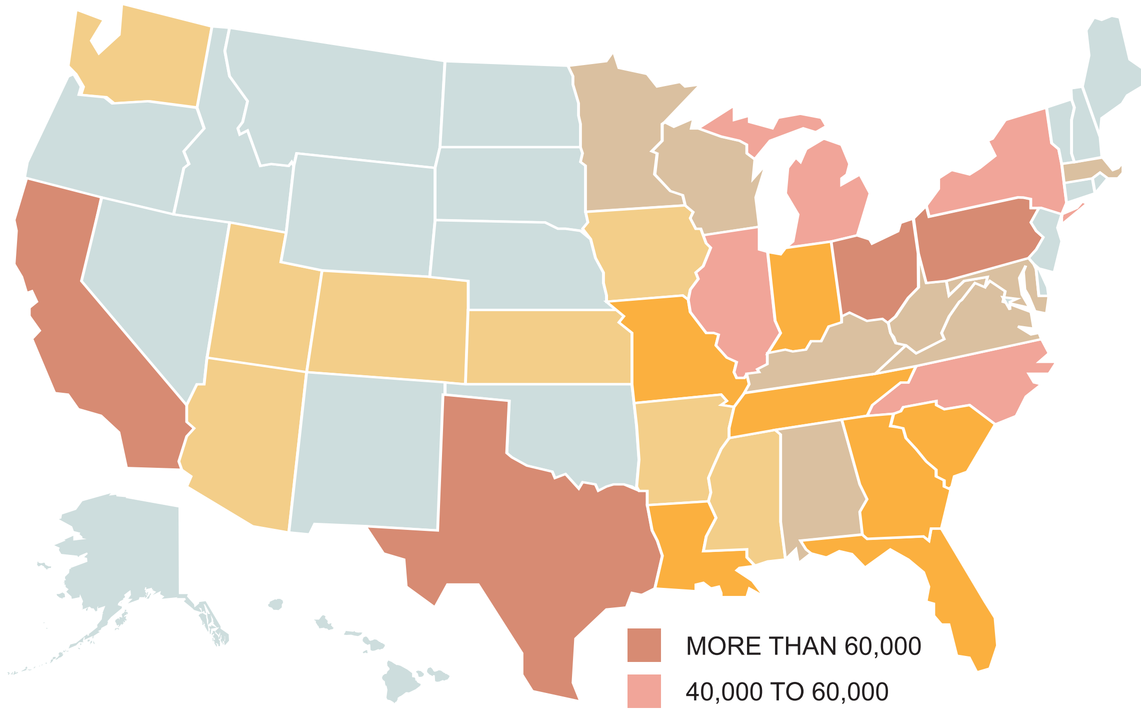


Figure D3-28. Concentration of Chemical Industry Jobs by State

and the United Kingdom ($41.2 billion). Japan exports $33.7 billion in chemicals, a somewhat smaller portion of its output. During the 1990s, world trade in chemicals grew two-and-a-half times that of global output during the past decade and has risen to $596 billion. Over 35% of this world trade is intra-company in nature.

The domestic chemical industries in developing nations generally make simple chemical products such as fertilizers and inorganic commodity chemicals. Some also produce minor volumes of specialty chemicals. Until two decades ago, these developing nations had only moderate domestic production. They were export markets for the chemical industries of the developed nations and provided little or no competition in other markets. During the 1980s, however, many developing nations embarked on ambitious programs to develop globally competitive chemical industries. This group includes several of the newly industrializing countries (NICs) of Asia such as Singapore, South Korea, Taiwan, and Thailand. Many of the larger economies of Latin America (Argentina, Brazil, Mexico, and Venezuela) have also made large investments in their chemical industries. Rapidly emerging as players in global petrochemical markets are the natural gas-rich nations in the Middle East. Although North America and Western Europe will likely remain centers of industry activity, China, other Asia-Pacific nations, Brazil, and Eastern/Central Europe will receive significant foreign direct investment and export interest in the future.

A major development beginning in the 1960s has been the globalization of the business of chemistry, with investments by companies of many countries in production facilities in foreign countries, and the development of world markets, with prices of chemicals determined by global supply and demand bounded by global cost structures. Competition

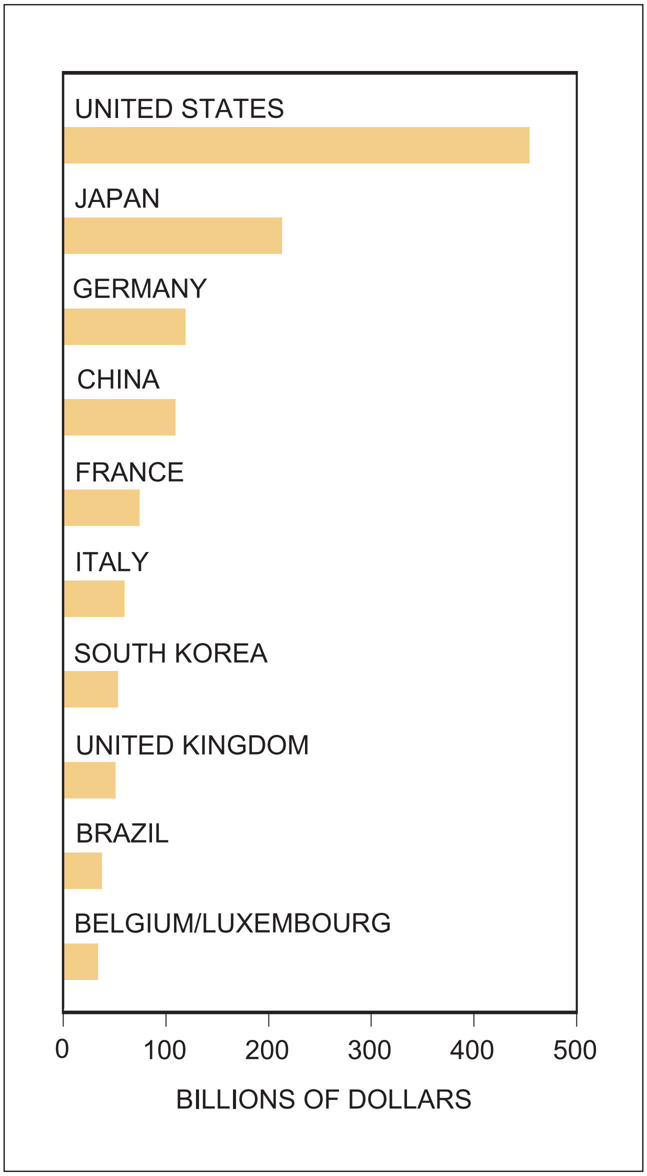


Figure D3-29. Output of Top Ten Chemical Producing Nations (2001)

between global producers has a major role in determining new investment direction. World economic growth, the reduction of tariffs, and other trade barriers that promoted world trade, as well as advances in telecommunications and air transportation, fostered this competition. The globalization of investments and markets has spread industry capital resources, technology, and managerial capabilities around the world and has resulted in the emergence of multinational chemical companies. Although a number of large companies had foreign subsidiaries for many years, international investment by American and Western European companies grew at a particularly rapid pace during the 1980s and in the 1990s. The 1990s saw the emergence of large companies originating from the developing nations. Figure D3-30 shows the relative economic contributions of chemical industry segments on a global basis.

C. The Business of Chemistry

Chemicals have a pervasive impact on the North American economy. Figure D3-31 lists several products for which chemicals are a key component, by showing the percentage of material inputs consumed in the manufacture of those consumer products. The chemical industry can be segmented in the following way:

- **Basic Chemicals** (commodity chemicals). These materials are the basic building blocks of the materials we consume through daily living. They use molecules contained in natural gas, oil, coal, and other minerals as raw materials. These chemicals include basic petrochemicals, key derivatives, polymers, and fertilizers. This is the largest segment in the business of chemistry.

- **Specialty Chemicals** (performance chemicals). These chemicals are more complicated and are designed with a specific purpose, i.e., adhesives, paints, electronics chemicals, flavors and fragrances, etc. These products are generally made by combining and reacting various basic chemicals.

- **Life Sciences.** These are very complex chemicals designed specifically to interact with life processes. These chemicals include pharmaceuticals, nutritional supplements, medical diagnostic chemicals, and crop protection chemicals.

- **Consumer Products.** These chemicals are relatively simple and have been a part of our lives for decades. These products include soaps, detergents, household cleaners, personal care products, cosmetics, and perfumes.

Importantly, natural gas is a raw material for several chemical processes. Figure D3-32 illustrates some of the major uses of natural gas, including a raw material for ammonia, methanol, hydrogen, and ethane-based ethylene.

Following are discussions of ethylene, methanol, and ammonia, the manufacture of which is significantly tied to natural gas.

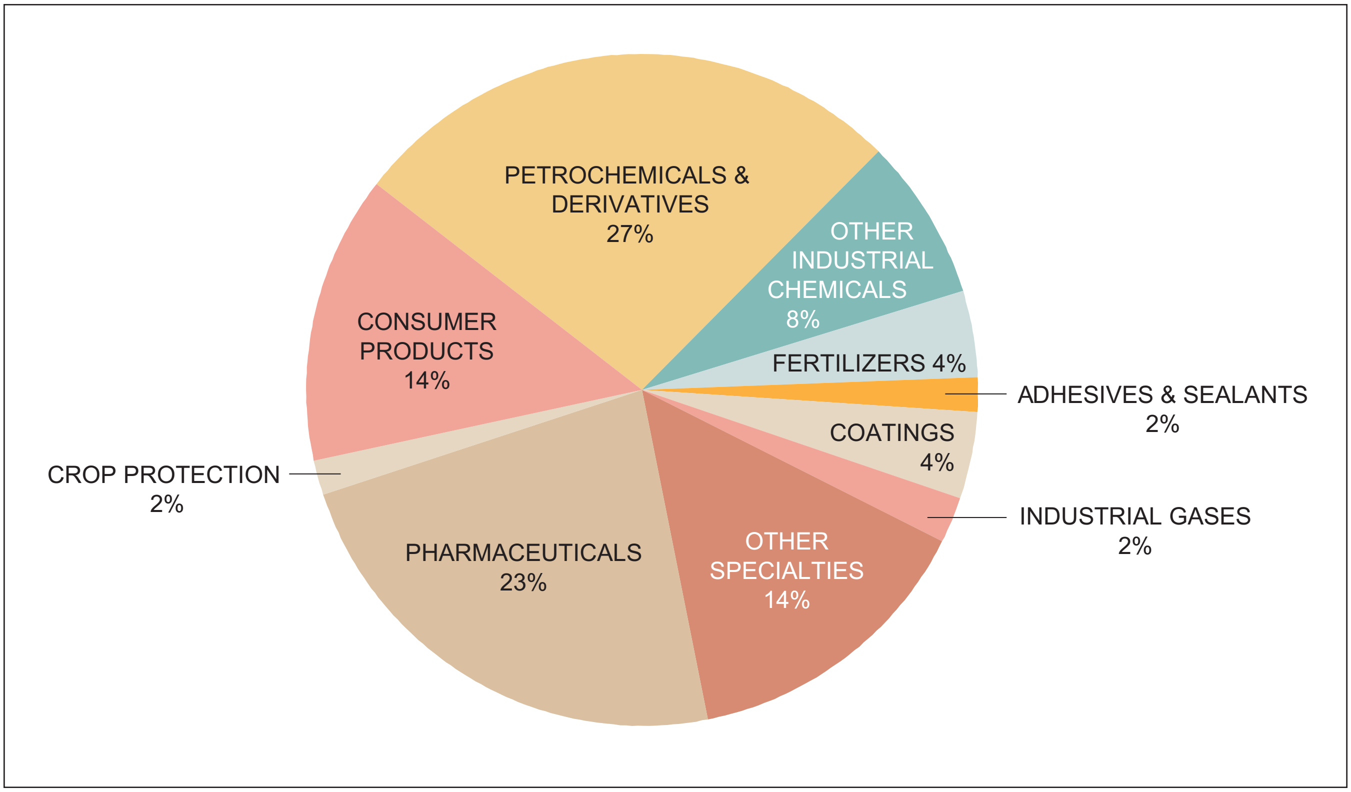


Figure D3-30. Global Business of Chemistry by Segment

1. Ethylene

Ethylene is an important component in chemical industry operations. In North America, ethylene is derived largely from ethane, a natural gas liquid; therefore, the ethylene market is an important aspect of the supply/demand picture for natural gas. The "value chain" for ethylene and its derivatives is represented schematically in Appendix I.

U.S. ethylene producers consume a variety of feeds in the manufacture of ethylene. These feeds range from crude oil-based liquids like naphtha and gas oil, to lighter hydrocarbons such as ethane, propane, and butane (collectively known as natural gas liquids, or NGLs, because they are condensed and recovered in the processing of natural gas).

Ethane is recovered from natural gas for sale to ethylene producers as a feedstock. The price of ethane will normally cover at least its alternative value as fuel (it can generally be left in the gas phase and sold as fuel) plus the cost of recovery. Consequently, ethane prices tend to be highly influenced by natural gas prices. In contrast, the other heavier NGLs must be largely removed from natural gas in order to meet pipeline specifications. The gas processor has fewer options other than removing these components from the raw natural gas. These other NGLs tend to compete with crude oil-based products in the fuels market, and their prices have historically correlated more closely with oil than natural gas.

The feed that an ethylene producer uses will depend upon the design and capability of its facilities and the current economics dictated by feed cost and co-product value. Outside of North America, ethylene is produced predominantly from naphtha. Only the Middle East is as dependent upon ethane cracking as North America, but in the Middle East, ethane is much less expensive due to the low value of natural gas.

Ethane, by far, is the most common ethylene feedstock in North America. Ethane accounts for about 50% of all U.S. ethylene produced. Most new ethylene plants built in North America since the 1980s have been ethane-based because these plants have been cheaper to build and operate than naphtha crackers, and because ethylene producers believed natural gas based feedstocks would remain competitively priced. Ethane crackers are cheaper because they exclude the additional investment required to handle the high volume

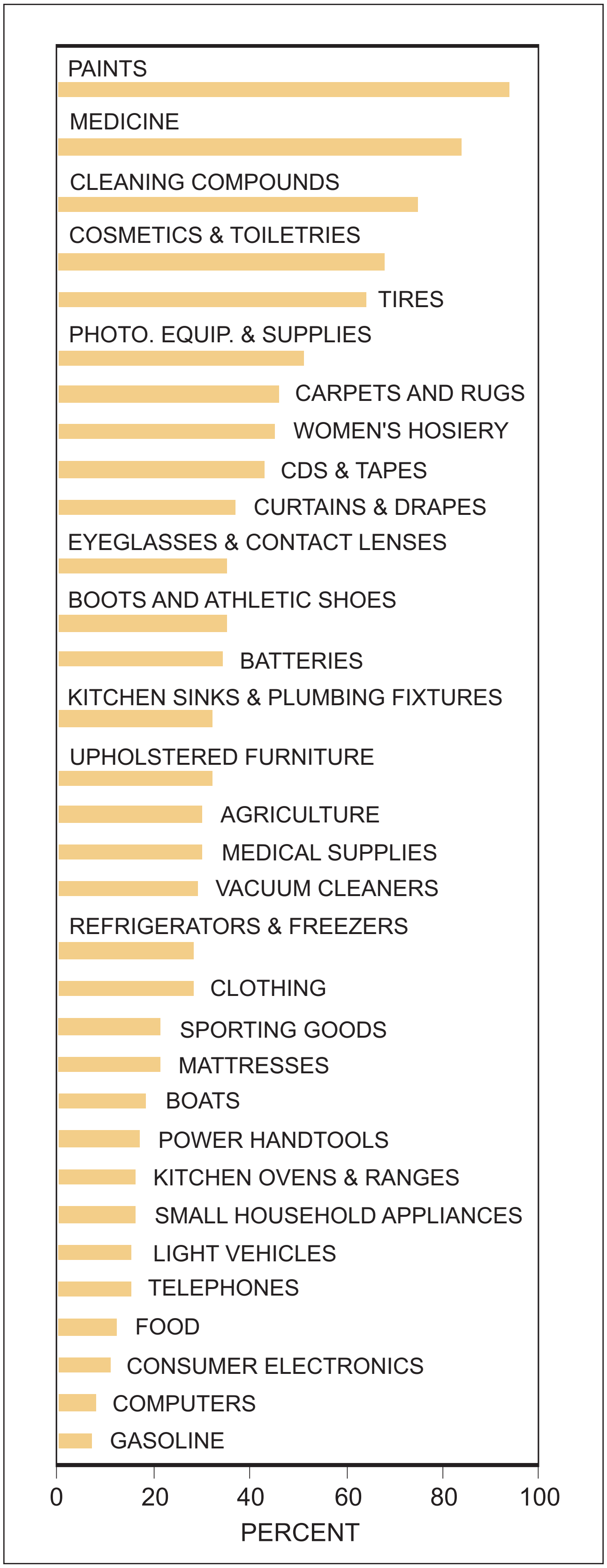


Figure D3-31. Products of Chemical Industry as a Percent of Material Inputs Consumed in the Manufacture of Consumer Products

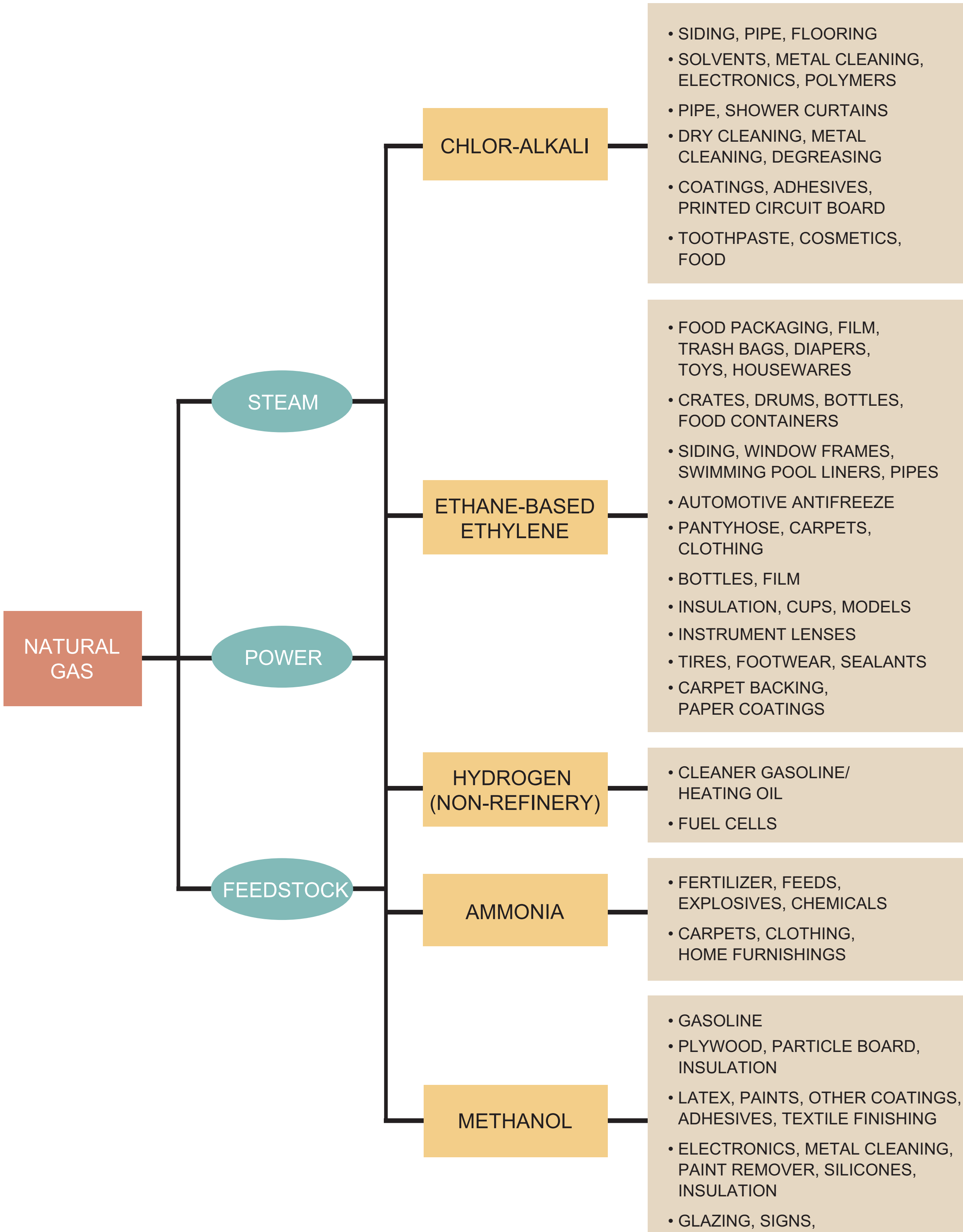
of co-products that come from cracking heavier liquid feeds like naphtha. While ethane crackers benefit from lower investment, they have little, if any, flexibility to process alternative feeds when these feeds may be more economic. Petrochemical producers indicated to the NPC Demand Task Group that retrofitting an existing ethane cracker to add feed flexibility would be prohibitively expensive.

The ratio of North American natural gas price to world oil price is a key indicator of the global competitiveness of the North American ethylene industry. As the gas to oil price ratio rises, the North American ethylene industry may become disadvantaged in two ways. First, energy costs in North America rise relative to other regions that derive their energy needs primarily from residual fuel oil. Because ethylene is a particularly energy-intensive process, the impact can be significant.

The second, and more important impact of a rising gas-to-oil price ratio is the effect on North American ethane feed costs. A higher gas-to-oil price ratio raises the cost of ethane-based ethylene relative to the cost of ethylene from other feeds. Since most of the rest of the world is based primarily on naphtha feeds, rising North American gas-to-oil price ratio makes North American ethane-based ethylene (and derivatives) less competitive in the world market.

When ethane feed becomes expensive, ethane-based ethylene producers with the capability to switch to a more economic feed will do so. Petrochemical producers suggested to the Demand Task Group that as much as half of the ethane currently consumed could be switched to naphtha or other feeds in response to a sustained higher gas to oil price ratio. Some of this switching would be immediate. The rest may require some time and minor investments to fully access flexible plant capacity. The ethane no longer purchased by ethylene producers would then be available to supplement natural gas supplies.

This situation would still leave about 25% of the U.S. ethylene capacity – the non-flexible ethane-based plants – with no feedstock alternative and vulnerable to high feed cost relative to competition. If the feedstock cost disadvantage were to grow large enough, the least efficient of these producers may be forced to cut back production or even shut down permanently. Initially, U.S. exports of polyethylene or other ethylene derivative products in such a situation would be backed out of the export market, unable to compete with lower



Sources: American Chemistry Council; Dow Chemical.

Figure D3-32. Simplified Diagram of Natural Gas Use in Selected Chemical Processes cost producers. Ultimately, the high cost U.S. producers would be vulnerable to imports of ethylene in the form of bulk polyethylene resin or, more likely, consumer products like polyethylene film and plastic bags. This would effectively suppress domestic ethylene and polyethylene demand growth.

How quickly new low cost overseas supplies of ethylene and polyethylene can grow to meet worldwide demand will be an important determinant of how long the higher cost U.S. producers are able to remain in business. With the recent higher natural gas prices, the ethane-based U.S. producers quickly became the high cost global ethylene supply.

2. Methanol

Methanol is a basic petrochemical containing four hydrogen atoms, one carbon atom, and one oxygen atom. It is chemically classified as an alcohol and is the simplest member of that class, which also contains ethanol (ethyl alcohol), isopropanol (isopropyl alcohol), and other alcohols. Thermodynamically, it is a partially oxidized methane molecule. Physically, it is a room-temperature stable liquid that, while flammable like gasoline, is also easily transported and stored.

Globally, methanol is a large-volume commodity chemical almost exclusively produced from natural gas. The production of methanol typically begins with a process known as steam methane reforming where natural gas and steam are reacted to produce a gaseous stream (referred to as synthetic gas, or "syngas") consisting of hydrogen gas and carbon monoxide, as well as smaller amounts of other components. The syngas is purified of co-produced carbon dioxide and then reacted with itself over a catalyst to generate methanol. Unreacted syngas is separated from the produced methanol and recycled back to the reactor. The separated methanol, which also contains some residual and co-produced water, is then purified by distillation. The process is shown schematically in Appendix I.

While steam methane reforming is a high-temperature process requiring fueled process heaters (i.e., furnace reactors), the syngas stream produces surplus hydrogen that can be burned in the furnaces to provide sufficient heat. In practice in the United States, the hydrogen is recovered and sold and the furnaces are fired with additional natural gas. The net result on methane consumption from this separation of hydrogen and use of additional natural gas in furnaces, however, is near zero since hydrogen produced from methanol plants typically displaces on-purpose hydrogen production at refineries and industrial gas plants.

The energy requirements of the separations and recycle processes are also largely balanced by the surplus heat from the exothermic reaction of hydrogen gas and carbon monoxide in the methanol reactor. As a result, the only real natural gas requirement from methanol production is as feedstock, but this requirement is very significant. Natural gas equivalent to approximately 0.11 million Btu (MMBtu) is required to make a gallon of methanol and this is generally over 95% of the variable cost of producing methanol. As a consequence, methanol production economics are impacted by natural gas prices, perhaps more significantly than any other industry.

Methanol is widely used throughout the world in the manufacture of a host of end-use products for consumers and business as shown in Appendix I. The largest use of methanol in the United States (35%) is in the production of formaldehyde, which is subsequently processed with other materials into end-use applications such as plywood, particle board, insulation, and furniture.

The second largest use of methanol (25%) is in the production of methyl tertiary butyl ether (MTBE), the oxygenated gasoline blendstock historically used to meet Clean Air Act requirements for gasoline. MTBE usage is diminishing in the United States due to regulatory issues. The impact of a total phase-out of MTBE to methanol demand would be significant.

The remaining uses of methanol are more varied, with acetic acid being the next largest use (8%). End-use applications are also varied: latex paints, coatings, and other adhesives, textile fibers, acrylic plastics, solvents, and silicones. Some of these applications are growing rapidly worldwide; however, the expected loss of demand due to an MTBE phase-out is expected to dominate the U.S. market over the next decade. Methanol is an established global commodity. In fact, prior to the development of the LNG industry, methanol was the only practical way to monetize stranded natural gas, due primarily to its low shipping cost and low infrastructure requirements for loading and unloading. Today, methanol moves in global arbitrage to generally equalize pricing on a freight-adjusted basis. Thus, the marginal producer in the world typically sets world prices during periods of global oversupply. When U.S. natural gas prices are high relative to the rest of the world and economies are weak, as has been the case much of the time since late 2000, the U.S. is the marginal producing area, U.S. production economics set world prices, and U.S. methanol industry profitability is diminished relative to other, lower-rent producers.

As a result of the relatively poor North American production economics at higher natural gas prices, the North American methanol production base has eroded over the past decade and may continue to erode in coming years. After 2004, U.S. methanol production capacity will be 2,600 thousand metric tons per year with another 800 thousand metric tons per year from Canada.[6] Natural gas consumption for methanol in 2002 was estimated by EEA to be approximately 178 BCF. Methanol production is typically the first tier of industrial demand that shuts down in response to higher prices. At sustained high natural gas prices, virtually all U.S. and Canadian capacity would be subject to possible shutdown. In the Reactive Path scenario, methanol demand for natural gas would decline to approximately 17 BCF/year by 2025, and to 21 BCF/year by 2025 in the Balanced Future scenario.

Methanol's emerging markets are as a hydrogen carrier for fuel cell vehicles, stationary fuel cell power plants, and portable fuel cell devices. Additionally, applications are being developed for use of methanol to remove nitrates from wastewater treatment plant effluent by accelerating bacterial degradation, and as a fuel for combustion turbines used in electric power generation. Neither of the two NPC scenarios assumed a material increase in North American methanol production – and thus, natural gas demand in North America – for these applications.

3. Ammonia

Like methanol, ammonia is a large-volume commodity chemical almost exclusively produced from natural gas. The production of ammonia begins with steam methane reforming to produce syngas, but uses a different chemical process than described above for methanol to create ammonia. Because natural gas is the only economically feasible raw material used in producing nitrogen fertilizers, it is by far the primary cost component. The primary nitrogen fertilizers consist of ammonia and its derivatives: ammonium nitrate, nitrogen solutions and urea. Because of leaching and volatility losses, nitrogen fertilizers must be applied every growing season. Corn, cotton, rice, and wheat are some of the large end-users of nitrogen fertilizers. Today, in the case of ammonia, natural gas accounts for 90% of the total cash cost of production. On average, it takes roughly 32-35 MMBtu of natural gas to produce one ton of ammonia. Thus, a $1.00 per MMBtu natural gas cost change translates to approximately $32-$35 per ton in ammonia margin. Given this heavy reliance on natural gas, the level of natural gas has a significant impact on ammonia manufacturers, as well as the domestic fertilizer industry, and by extension, the consumers of fertilizer.

The nitrogen production process involves a catalytic reaction between elemental nitrogen derived from the air with hydrogen derived from natural gas. The primary product from this reaction is anhydrous ammonia (NH_3). Anhydrous ammonia is used directly as a commercial fertilizer and contains the highest nitrogen content of any nitrogen fertilizer product (82% by weight), but requires specialized application equipment as it is a gas at atmospheric temperature and pressure. Direct application of ammonia is practiced primarily in developed countries that have the necessary infrastructure to support its use. In the United States, about 30% of total nitrogen fertilizer consumption is supplied from ammonia, compared to just 7% globally. Anhydrous ammonia is also the basic building block for producing virtually all other forms of nitrogen fertilizers such as urea, ammonium nitrate and nitrogen solutions, as well as diammonium phosphate and mono-ammonium phosphate.

Urea is synthesized from ammonia and carbon dioxide. Because of its carbon content, urea is the only primary nitrogen fertilizer that is classified as organic. Urea is by far the most popular form of solid nitrogen fertilizer globally, due to its high nitrogen content (46%) and solid state, which makes it easier to ship and apply than gaseous ammonia, and more efficient than nitrogen solutions. Given its convenience, urea represents more than 40% of global nitrogen fertilizer consumption. Although the bulk of urea production is consumed as a nitrogen fertilizer, it is also sold to non-fertilizer markets for use in products such as cattle feeds, urea-formaldehyde resins and melamine.

Ammonium nitrate is made by reacting ammonia with nitric acid, and has nitrogen content of 34%. The most popular end product forms are prills and granules, but liquid ammonium nitrate (combined with

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6 BP Chemicals.

liquid urea and sold as UAN Solutions) is gaining popularity in developing economies. Because it has lower volatility than ammonia, ammonium nitrate fertilizer is the preferred choice for pastures and no-till applications, where evaporative losses are a major concern. Ammonium nitrate solids represent approximately 9% of the world nitrogen fertilizer market, while nitrogen solutions represent roughly 5%. The low-density form of ammonium nitrate is used in the explosives industry.

In addition to these primary nitrogen fertilizers, plants can also obtain nitrogen from other products, such as calcium nitrates, ammonium sulfates, ammonium phosphates and blended products. In total, these other products comprise 15% of total global nitrogen fertilizer consumption and a lesser share of U.S. nitrogen fertilizer consumption.

Ammonia also serves as an intermediate product for several industrial applications. Globally, nearly 15% of ammonia production is used in a variety of industrial end markets, such as animal feeds, explosives and polymers. Within the U.S., with its highly developed chemical industry, a large share of merchant ammonia sales is made to industrial customers.

The higher level of U.S. natural gas prices of recent years has resulted in both temporary and permanent closure of nitrogen fertilizer manufacturing plants throughout North America. This situation threatens the U.S. industry and creates the potential to displace the thousands of workers who support it.

For instance, the U.S. nitrogen operating rate fell to below 70% of capacity by the end of December 2000; by the end of January 2001, operating rates dropped to an all-time low of only 46% due to the significant rise in U.S. gas prices during January 2001. To put this into perspective, the average U.S. operating rate during the 1990s was 92%.

Following this natural gas spike, gas prices began to moderate and by mid-2001 had fallen back to historical levels. In response, idled capacity in the U.S. quickly came back on-stream, and the industry operating rate climbed to just under 90% of capacity. The lower natural gas prices and higher operating rates were short-lived. By mid-year 2002, natural gas prices once again began to slowly escalate until February 26, 2003, when spot natural gas prices suddenly spiked to over $20 per MMBtu. Although natural gas prices again quickly moderated, they have remained well above historical averages.

By contrast, in many developing countries with surplus natural gas reserves, there is insufficient utility demand to consume all their available natural gas. This leads natural gas-rich countries such as Trinidad & Tobago, Venezuela, and Middle Eastern nations to promote construction of fertilizer plants as an attractive means for upgrading their low-value reserves into higher-value tradable commodities such as fertilizer.

This availability of low-cost natural gas in other countries has led to substantial capacity buildup in the nitrogen sector. Trinidad, for instance, is home to several ammonia facilities and has attracted foreign investment by offering natural gas price contracts that are indexed to fertilizer product prices. Unlike in the United States where natural gas feedstock costs are not correlated to product prices, this helps to limit margin volatility. Such contracts also reduce the upside profit potential, however, since the benefits of ammonia price increases are shared with the natural gas supplier.

Trade in nitrogen fertilizer accounts for only 10% of world ammonia production as there are many producers and most ammonia is consumed in the local market. But the trade volume is large. Russia, Trinidad, Ukraine, and Canada are the leading exporters and comprise more than three-quarters of the total ammonia trade and consume only a modest amount of their own production.

Fertilizer trade is in some ways more liberalized than trade in other agricultural commodities. Nevertheless, there remain many direct and indirect barriers to fertilizer trade that have the potential to distort trading patterns, inhibit growth in agriculture, and could be costly to consumers. Tariffs and duties can be direct barriers to trade, often favoring one supplier over another. For instance, the European Union (EU) has a wide variety of fertilizer tariffs. In contrast, the U.S. has no tariffs on imports of fertilizers from the EU; it eliminated all fertilizer tariffs in 1922.[7]

Continued higher natural gas prices as foreseen in the NPC outlooks, particularly the Reactive Path scenario, will likely lead to more U.S. plant closures and

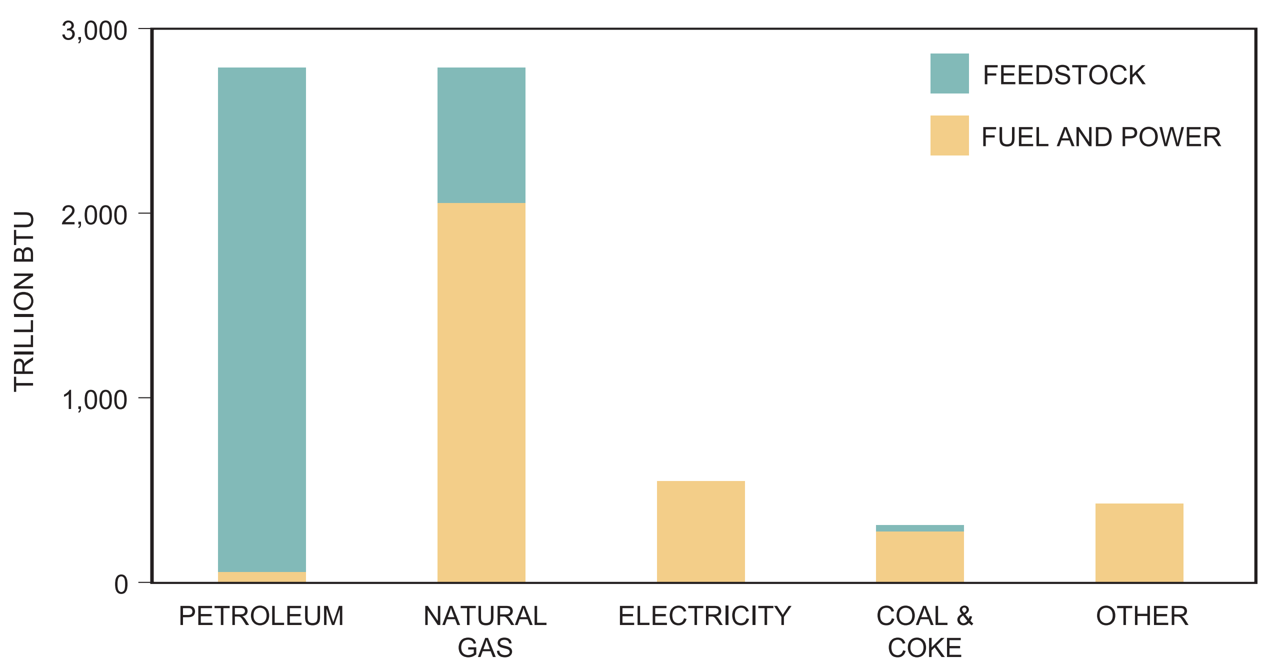
[7] Process Gas Consumers.

abandonment of marginally profitable infrastructure in rural communities. While higher volumes of imports will fill part of the potential loss in U.S. supply, it is also likely that some domestic production and distribution will remain financially viable to fully meet agricultural demand. Because the current distribution and storage system within the United States was constructed around a U.S. supply base, there is limited infrastructure to off-load, store, and transport larger and larger volumes of imports. The lack of infrastructure is particularly apparent for anhydrous ammonia, which requires refrigerated or pressurized tanks, pipelines, railcars, and barges. New investment and the associated lead-time may be needed if the existing infrastructure assets are left permanently stranded.

D. Fuel and Power

To perform the complex chemical reactions of the business of chemistry, the industry uses heat, pressure, and electricity to split hydrocarbons and minerals and then recombines the elements to make the products of chemistry. Thus, in addition to using natural gas as a raw material for the production of petrochemicals, about 2.5 TCF of natural gas is currently used as fuel to power boilers, generate process heat, or produce electricity. In many plants with large fuel and power requirements, cogeneration, or combined heat and power (CHP) has emerged as growing fuel and power technology. Figure D3-33 shows the relative shares of energy sources in the industry, and Figure D3-34 shows energy consumption in the chemical industry by end-use.

The chemical industry has been a leader in using cogeneration. Since most cogeneration facilities use clean burning natural gas and create two forms of energy (electric power and steam) from one amount of fuel, they are often twice as efficient as older coal-burning electric utilities. These efficiencies are boosted by the fact that the power generation is typically physically located close to the power consumption, thus avoiding transmission losses associated with consumption of power generated many miles away by large electric utilities. Use of CHP technologies by the chemical industry accounts for nearly a third of all CHP used in manufacturing. Through the use of CHP technology, the chemical industry has been able to greatly reduce its total fuel and power energy intensity. Appendix J contains an overview of cogeneration/CHP.



Sources: Bureau of the Census; Federal Reserve Board; Energy Information Administration; American Chemistry Council.

Figure D3-33. Composition of Energy Requirements

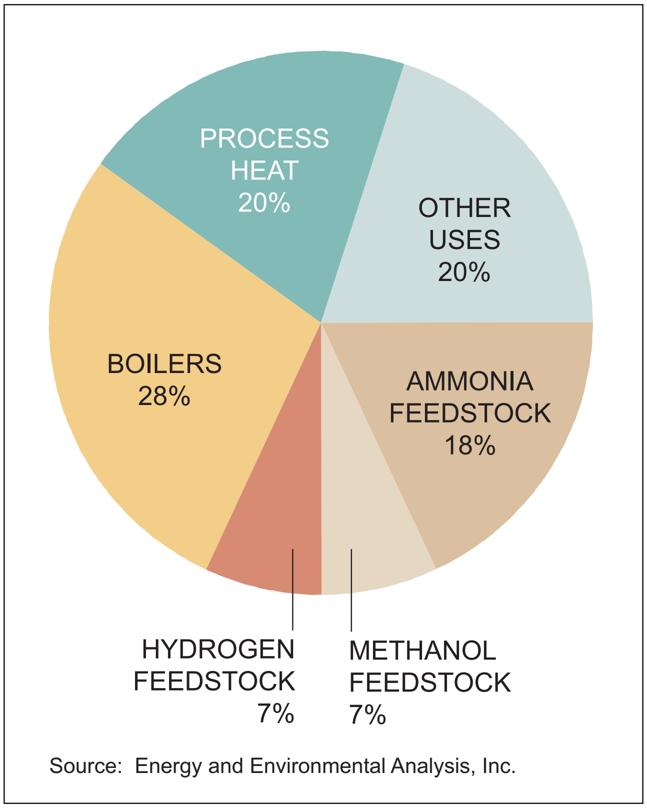


Figure D3-34. Chemical Industry Energy Consumption by End-Use

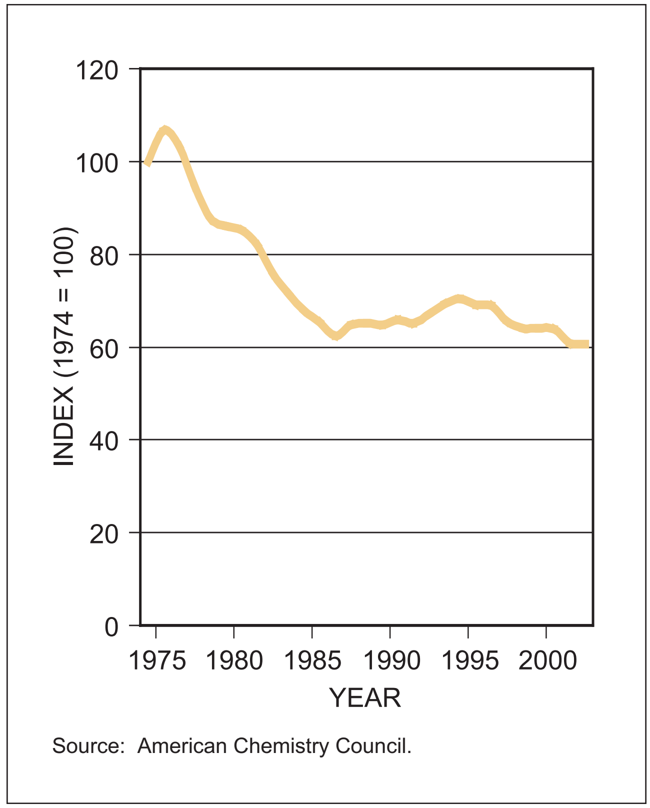


Figure D3-35. Energy Intensity for Fuel and Power in the U.S. Chemical Industry

E. Intensity of Natural Gas Use in the Chemical Industry

Substantial improvements in energy efficiency have taken place in the energy-intensive chemical industry. Since 1974, the industry has reduced its energy use for fuel and power consumption per unit of output by nearly 40%, as illustrated in Figure D3-35. One of the principal sources of efficiency gains has been implementation of cogeneration technologies. These applications create two forms of energy (electric power and steam) with the same amount of fuel, and are often twice as efficient as older utility generation facilities.

F. Feedstock

Natural gas and NGLs contain hydrocarbon molecules that are split apart during processing and are then recombined into useful chemistry products, including pharmaceuticals, fertilizers, paints, plastic soda bottles, compact disks, and polyester fleece blankets to name just a few. The industry used 660 billion cubic feet (BCF) of natural gas and 440 million barrels of NGLs as raw materials in 2002.

Liquid petroleum and natural gas contain hydrocarbon molecules that are split apart during processing and are then recombined into useful chemistry products. Although coal and biomass can be used as hydrocarbon feedstocks, liquid petroleum and natural gas account for 99% of hydrocarbon feedstocks for the industry. As displayed in Figure D3-36, NGLs are predominant, followed by naphtha and other heavy liquids. Besides methanol and ammonia, natural gas is directly used as a feedstock for carbon black. Coal represents a minor share but prior to the 1930s was the dominant source.

G. Chemical Industry Demand Outlook

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

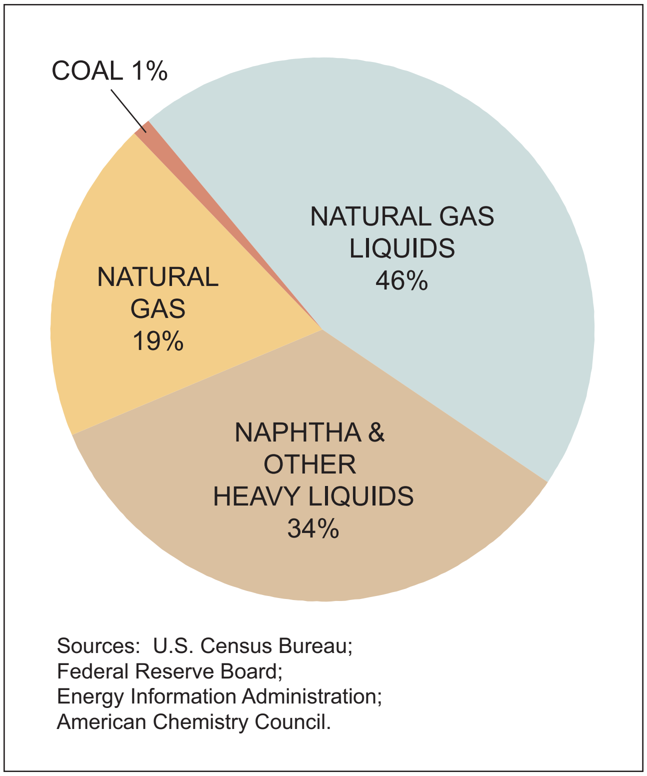


Figure D3-36. Share of Feedstock Consumption by Source

The average operating margin (a measure of profitability) for basic chemical companies was 6.8% in 1999, when the price of natural gas averaged $2.27 per MMBtu. In 2001, when the price of natural gas averaged $3.97 per MMBtu, operating margin dropped to 0.6%.[8] This decrease in operating margins led many chemical companies to evaluate whether to continue operations in the United States. During the winter 2000-2001 natural gas price spike, some chemical operations were idled: about 50% of the methanol capacity, 40% of the ammonia capacity, and 15% of the ethylene capacity shut down.

To develop outlooks for natural gas demand, in both the Reactive Path and Balanced Future scenarios, the Demand Task Group attempted to understand the chemical industry's response to the widely varying market conditions of the past 10 years. During the second half of 2000 and the first half of 2001, natural gas prices rose dramatically. Much of the growth in the North American chemical industry occurred in an environment in which natural gas prices were in the $2.50 per MMBtu range. Recent periods of sustained high gas prices have translated into higher energy and feedstock costs and have contributed to eroding margins in many segments of the chemical industry. Ammonia and methanol producers have been hit hardest with some players exiting the U.S. market and others going bankrupt. Also ethane-based ethylene production has been severely impacted with some plants being permanently closed during 2003.

Energy represents a significant share of U.S. chemical manufacturing costs. For some energy-intensive products, energy for both fuel and power needs and feedstocks account for up to 85% of total production costs. Because energy is a vital component of the industry's cost structure, higher energy prices can have a substantial impact on the chemical industry. Reflecting higher fuel costs, the industry spent $31.4 billion in 2001 on purchases of fuel, power, and feedstocks, up 5% from 2000 and 65% from 1999. As natural gas prices rose in December 2000 and January 2001, about 50% of U.S. methanol capacity, 40% of ammonia capacity, and 15% of the U.S. ethylene capacity, which depend on natural gas or natural gas derivatives as feedstocks, were idled.[9] With prices spiking again in 2003, much of this capacity remained idle during the first half of 2003.

In recent years, the chemical industry experienced a protracted inventory correction, the result of the high value of the dollar and higher natural gas prices, as well as a global recession. Production in the gas-intensive organic chemicals industry grew by only 0.6% annually from 1992 to 1998 and gas use grew by 1.3% during the same period. Gas use in boilers fell during the historical period but this was offset by increases in gas use for process heaters, feedstocks, and other processes including cogeneration. Gas use would have increased at only 0.4% per year without new cogeneration.

Both the Reactive Path and Balanced Future scenarios incorporate a recovery in overall industrial production, consistent with overall GDP growth of 3%. Figure D3-37 shows the NPC Reactive Path projection with a breakdown of gas demand for boilers, process heat, other processes, and feedstocks. Figure D3-38 shows a projection of gas use in the chemical industry for the Balanced Future scenario. All of the components are higher than in the Reactive Path scenario due to the lower gas prices. Gas use for feedstocks and other processes decline in the projection due to higher

[8] American Chemistry Council.

[9] American Chemistry Council.

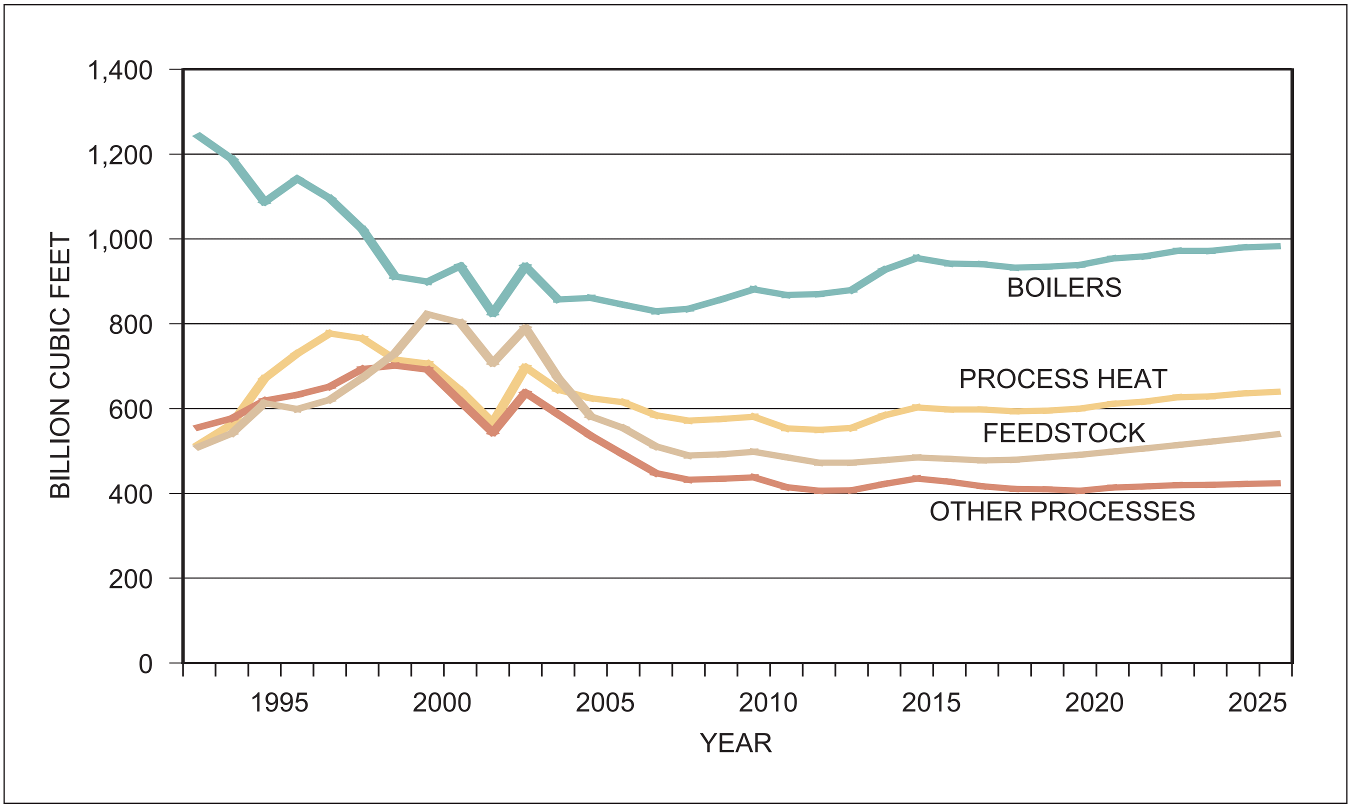


Figure D3-37. U.S. Chemical Industry Gas Demand in Reactive Path Scenario

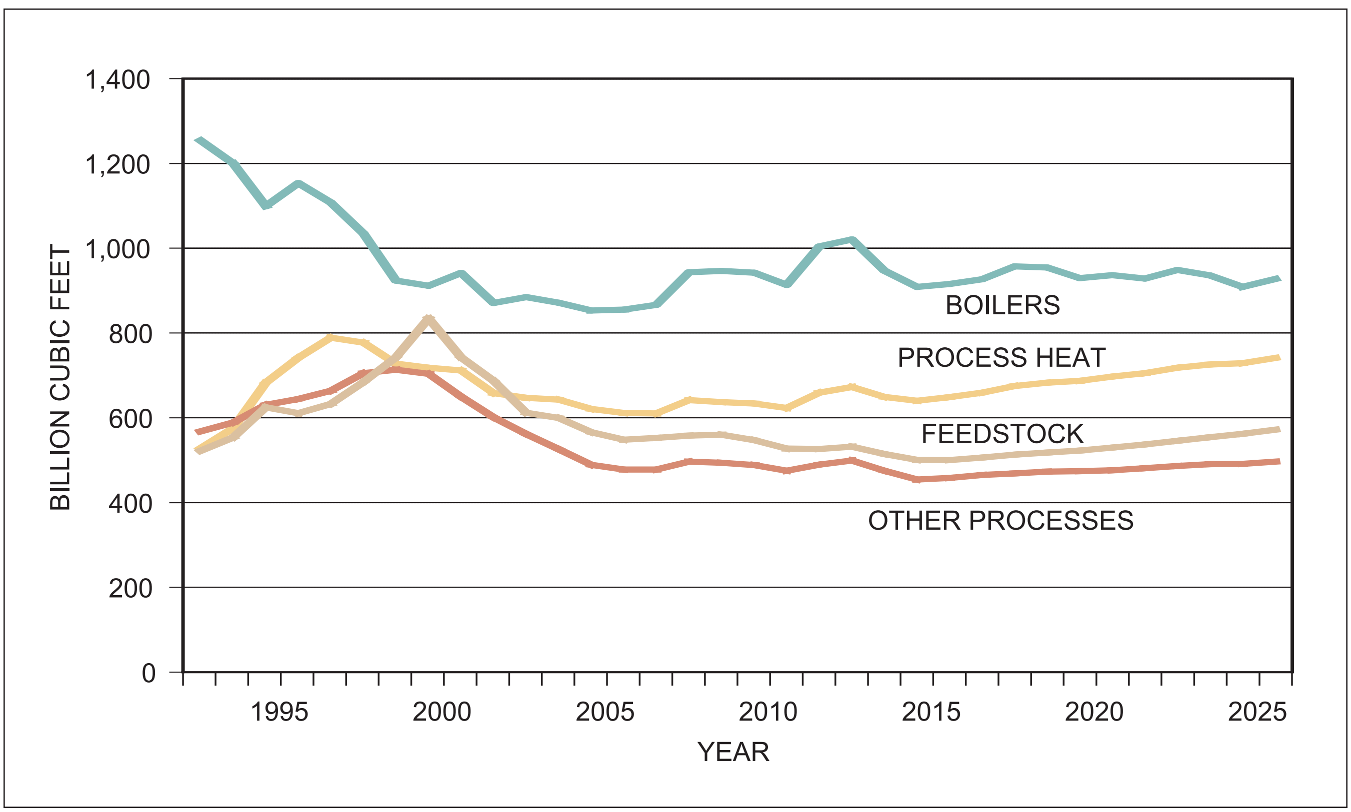


Figure D3-38. U.S. Chemical Industry Gas Demand in Balanced Future Scenario gas prices. The most affected industries are petrochemical and basic chemical sub-industries that use gas as a feedstock, e.g., ammonia production. The decline would be offset if there is even higher hydrogen production than currently anticipated for use in the refinery sector to manufacture low-sulfur transportation fuel. Gas use for boilers and process heat increases because of growth in other segments of the industry, including drugs, and soaps and detergent manufacture. New cogeneration is accounted for in the power sector but would contribute to increased gas consumption in the chemical industry.

III. Petroleum Refining

The petroleum refining industry is second to the chemical industry in natural gas demand among industrial consumers, using approximately 1.4 TCF in 2002. The refining industry plays a critical role in the North American economy by transforming crude oil into transportation fuels, lubricants, industrial fuels, and chemical plant feedstocks. The Demand Task Group found that this industry is highly capital intensive with a replacement value for U.S. capacity of approximately $300 billion. U.S. refineries process more than 16 MM bbl/day of crude oil to produce 350 MM gal/day of gasoline, 210 MM gal/day of distillate products, and 125 MM gal/day of other finished products. The U.S. refining industry employs roughly 100,000 people including company and contract workers.

The refining sector has been a dynamic and integral part of North American industry for over a century. The first refineries were primitive by today's standards, and modern refinery facilities often rival a small city in terms of complexity and the economic value of their output. Today's refineries make use of the latest technological innovations as they produce historic volumes of the fuels that are critical to the North American economy. The Demand Task Group also found that intense competition has resulted in low return on capital for the past 20 years. During this period, the refining industry has invested heavily to meet environmental regulations. The pending clean fuels regulations will likely require an additional $17 billion in capital investment. The heavy investment burden has led to the closure of over half of U.S. refineries since the mid-1970s, and no new refinery has been built since 1976.[10]

[10] Energy Information Administration, *Petroleum: An Energy Profile 1999,* DOE/EIA-0545(99), July 1999, p. 25.

However, the remaining refineries have kept pace with the growing demand for products through improved utilization and investment. Product imports have remained essentially constant at less than 1 MM bbl/day.

Following is a brief discussion of the industry's function and processes, with information about facilities, products, and some of the key challenges facing the industry. This discussion is focused on the U.S. petroleum refining industry. Subsequent studies by the National Petroleum Council and others should include Canada and Mexico refining capacity in a more robust manner. In particular, subsequent studies should consider the impact on natural gas demand in North American refining capacity resulting from the need to process bitumen from Alberta's oil sands. Both the Canadian Association of Petroleum Producers and the National Energy Board had studies and processes on the subject of refining capacity for this bitumen underway or nearing completion at the time of this study effort.

A. Background

Crude oil is not a homogenous substance. It varies widely in color, density (measured in terms of "API gravity" in the industry), viscosity, sulfur content, mineral content, and other characteristics. There are hundreds of crude oils available from a large variety of global sources. An oil refinery provides the link between crude oil and the finished product. A refinery is physically constructed from multiple process units designed to distill and convert crude oil into a more valuable slate of marketable products. Refinery process units are used to transform crude oil into products used in transportation, electric power generation, and home heating, as well as feedstocks for use in petrochemical processes. Figure D3-39 is a simplified flow diagram of a petroleum refinery. The first major process unit in a refinery is the atmospheric crude distillation unit (crude unit). The crude unit uses heat to separate the various hydrocarbon components of crude oil according to their boiling points. Downstream from the crude unit are other process units that increase the refinery's flexibility or complexity to further process the intermediate products and increase the yield and value of the products derived from the crude oil.

The complexity or sophistication of a refinery depends upon the physical properties of the crude oil

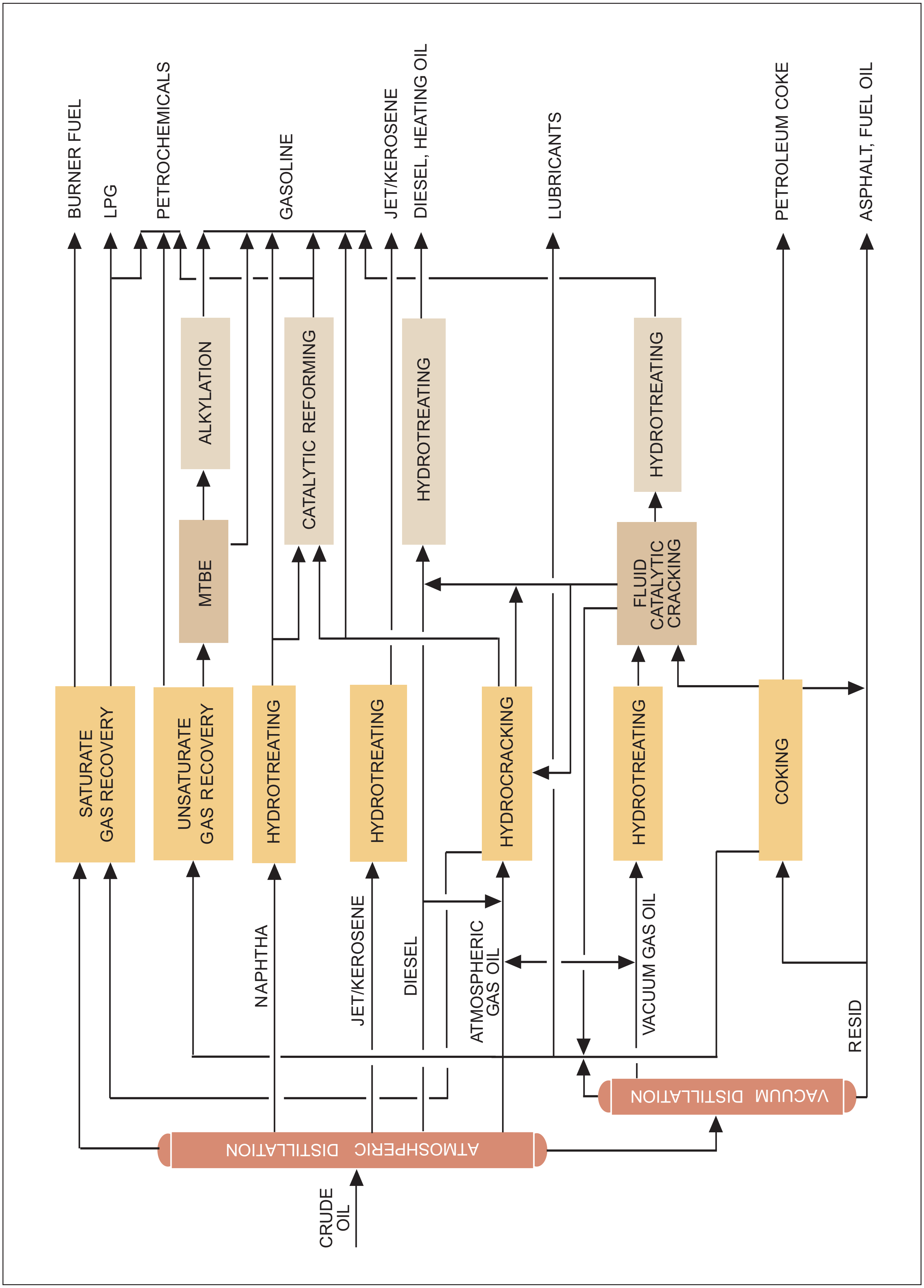


Figure D3-39. Simplified Flow Chart of a Complex Refinery to be processed and characteristics of the products to be produced. Complexity is defined as a measure of the relative construction costs of the refinery processes as they relate to the atmospheric crude distillation unit. The refinery's complexity indicates the amount of processing a barrel of crude oil receives during its flow through a refinery.

Downstream from the crude unit is typically the vacuum distillation unit; this unit further processes the heavy portions of the crude oil that will not distill or separate under atmospheric pressure. Other downstream units further separate the components of the crude oil through the use of catalysts, high temperatures, and pressure to produce low-sulfur, high-octane gasoline and other fuel products. Additional downstream units convert the heavier crude oil fractions into high-value products; combine or condense olefins (small hydrogen-deficient molecules) into more gasoline-blending stocks; rearrange hydrocarbon molecules to produce high-octane blending stocks and isomers; and finally remove sulfur and other contaminants from the product slate. The hydrocarbon streams produced are then blended into various gasoline blends, distillates (diesel, jet, home heating fuels), and other products.

Major types of processes in a refinery include:

- **Boiling.** *Distillation* uses heat to separate hydrocarbon components in crude oil; boils the crude oil and then cools and condenses the vapors. Distillation is the first processing step in a refinery. It separates the crude oil into unfinished gasoline, jet fuel, and diesel fuel fractions and a residual fraction that can be converted to the more valuable products with further processing.

- **Breaking.** *Cracking processes* use heat, pressure, and/or catalysts to convert "heavier" oil molecules to "lighter," more valuable products (such as gasoline). Examples: thermal cracking, catalytic cracking, and hydrocracking.

- **Bending**. Bending uses specific chemical reactions to rearrange and combine molecules to improve product quality (e.g., increase octane or combining small gaseous molecules into larger, liquid products) and remove contaminants (i.e., sulfur, nitrogen, and metals). Examples: alkylation, catalytic reforming, hydrotreating, isomerization, and polymerization.

- **Blending.** Blending puts the finished product together economically while meeting all fuel performance and regulatory specifications. For example, gasoline is a blend of components, such as butanes, reformate, alkylate, coker gasoline, hydrocrackate, isomerate, catalytic gasoline, naphtha, oxygenates, and additives.

The refining industry responds to changes in demand and economics by adjusting processes and blending procedures to vary the yield of finished products. There are many different petroleum products. Fuels, non-fuel products, and petrochemical feedstocks are petroleum product categories.

1. Fuels

- Gasoline
  - Motor gasoline
    - Types: reformulated gasoline (RFG), gasohol, conventional gasoline
    - Grades: regular, middle, and premium octane
  - Aviation gasoline

- Distillate Fuel Oil
  - Diesel: low sulfur highway and high sulfur off-highway
    - Off-highway examples: locomotives, ships, farm tractors, bulldozers, forklifts, underground mining equipment, backhoes, cranes
  - Home heating oil: space heating, electricity generation, crop drying, fuel for irrigation pumps on farms

- Jet Fuel
  - Kerosene-type: Commercial and Military Grades JP-5 and JP-8
  - Naphtha-type: Military Grade JP-4

- Kerosene
  - Uses: space heating, cooking stoves, water heaters, lamp oil

- Residual Fuel Oil
  - Use: fire boilers to provide steam for heating or electricity generation

- Liquefied Refinery Gases (LRG)
  - Propane, mixed butanes
  - Uses: space heating, cooking

- Still Gas or Refinery Gas
  – Use: a refinery fuel

2. Nonfuel Products

- Asphalt
- Lubricants
  – Uses: engine oil, gear oil, automatic transmission fluid, greases
- Petroleum Coke
  – Uses: carbon electrodes, electric switches
- Road Oil
  – Uses: dust suppressor, surface treatment on roads, roofing, waterproofing
- Solvents
- Wax
  – Uses: chewing gum, candles, crayons, sealing wax, canning wax, polishes
- Miscellaneous
  – Uses: cutting oil, petroleum jelly, fertilizers

3. Petrochemical Feedstocks

- Examples: benzene, toluene, xylene, ethane, ethylene, propane, propylene, naphtha, gas oil
- Uses: solvents, detergents, synthetic fibers, synthetic rubber, plastics, medicine, cosmetics

B. Industry Scope

The U.S. petroleum refining and distribution industry is a large and complex system:

- 149 refineries (owned by 57 companies) with aggregate atmospheric distillation crude capacity of 17 million barrels per day
- 200,000 miles of crude oil and refined petroleum product pipelines
- 38 Jones Act vessels (U.S. flag ships which move products between U.S. ports)
- 3,300 coastal, Great Lakes, and river tank barges
- 200,000 rail tank cars
- 1,400 petroleum product terminals
- 100,000 tank trucks
- 175,000 retail motor fuel outlets.

Refineries are located in most, but not all states, as shown in Figure D3-40.

As the number of operating refineries declined from more than 200 in 1990 to approximately 150 today, the nation's cushion of excess refining capacity has also disappeared. Annual average U.S. refinery capacity utilization increased from 78% in 1985 to 91% in 2002. The supply/demand balance in the gasoline market has tightened over the years, due to steadily increasing gasoline demand (reflecting growing population, larger cars, and more miles traveled) with relatively little growth in aggregate domestic refining capacity. No new refinery has been built in the last 25 years; refiners report that there are limited opportunities for expansion at existing refineries, and that these opportunities provide low returns on investment. The supply/demand balance will probably tighten in the diesel market in the future due to the Environmental Protection Agency's (EPA's) ultra low sulfur highway diesel standards (effective in 2006).

High average capacity utilization rates at U.S. refineries, growing petroleum product demand for transportation fuels, and the need to address several overlapping fuel regulatory specifications are a few of the current challenges. Maintaining adequate petroleum supplies will largely depend on maintaining sufficient growth in refining capacity and operating near maximum utilization. The U.S. refining industry is faced with recent and prolonged very low rates of return on capital, significant upcoming clean motor fuels investment requirements, and the need to increase production to meet rising domestic demand – all while providing dependable petroleum product supplies at accustomed prices.

Refinery process requirements differ with the quality of crude oil input; thus, a refinery's geographic location to a local source or to the world market influences its design. Many of today's crude oil feedstocks are heavier (reflected in lower API gravity numbers) and are more sour (higher sulfur content). As a result, refineries are under increasingly stringent environmental constraints and are becoming more complex to

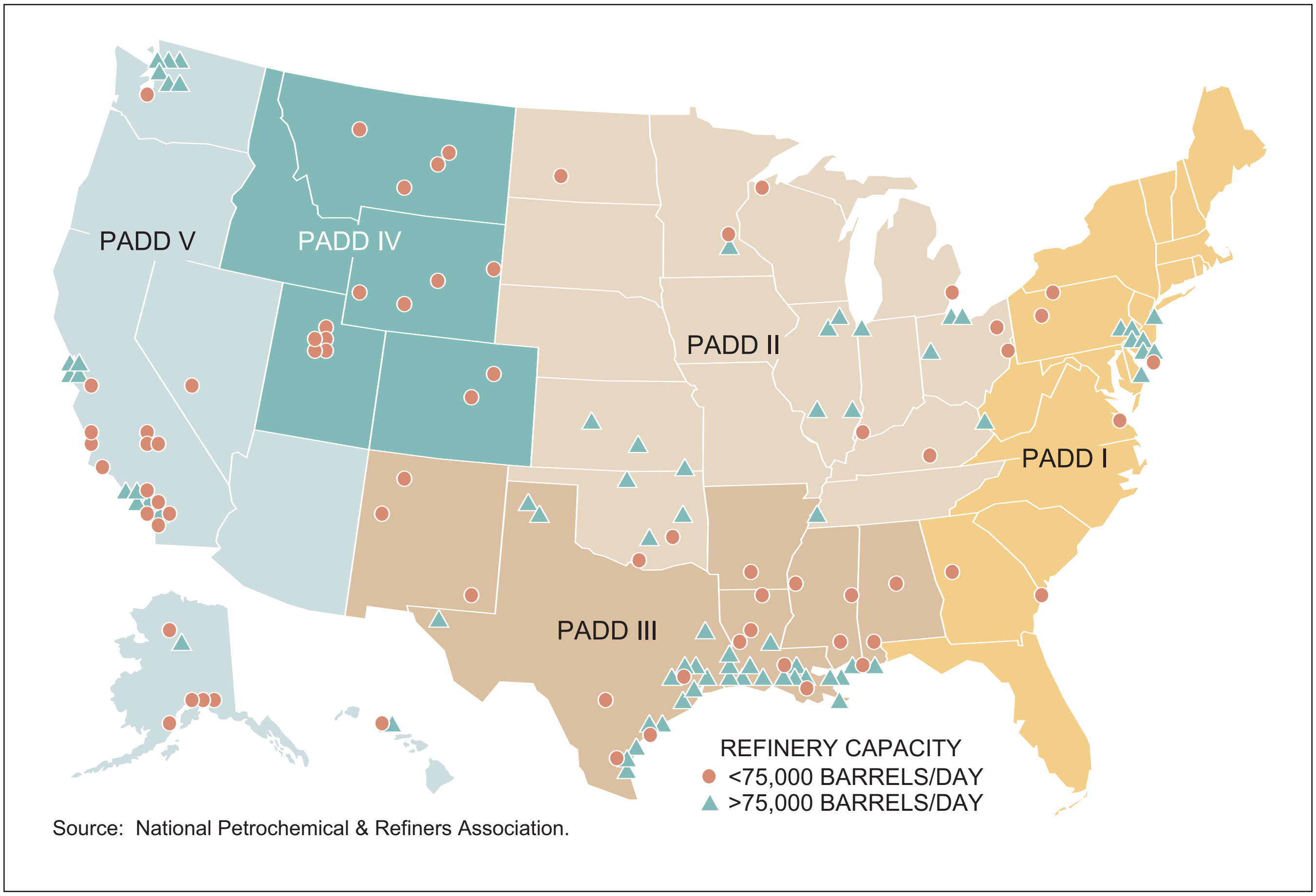


Figure D3-40. Location of U.S. Refineries

meet the demands of the more severe processing required. In fact, no two refineries are identical. Each refinery has developed over the years into its own unique configuration. The choice of refinery processes is based on the specific circumstances of each operation and is dependent on crude oil type, product demands, product quality requirements, and economic factors such as crude oil costs, product values, availability and cost of utilities, and availability of equipment and capital.[11]

C. Product Blends

Figure D3-41 shows an example of the mix of a "typical" refinery's output. However, modern refineries process various blends of many different crude oils, and different configurations of refining units are used to produce a given slate of products from available crude oils. A change in the availability of a certain type of crude oil can affect a refinery's ability to produce a particular product. The product slate at a given refinery is determined by a combination of demand, inputs and process units available, and the fact that some products are the result (co-products) of producing other products.[12]

Furthermore, other NPC reports emphasize the significance of this variability when referencing refinery configuration. The NPC found that most U.S. refineries have evolved at existing locations over a long period of time as opposed to having been designed and constructed as an integrated system. Therefore, each refinery is a unique combination of facilities producing a wide range of products. Refineries have intrinsic differences in the way they are configured. This results in a range of energy costs, maintenance requirements,

[11] National Petroleum Council, *U.S. Petroleum Refining, Assuring the Adequacy and Affordability of Cleaner Fuels,* June 2000, p. C-7.

[12] Energy Information Administration, *Petroleum: An Energy Profile 1999,* DOE/EIA-0545(99), July 1999, p. 27.

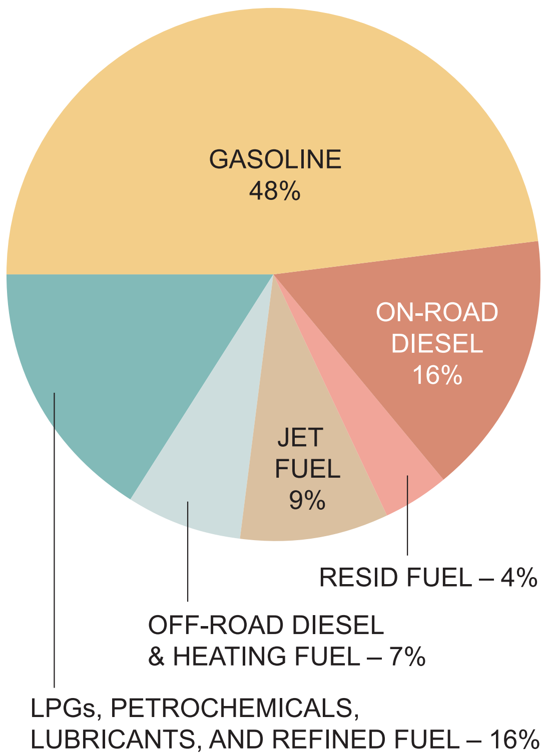


Figure D3-41. Typical Refinery Product Mix

technology utilization, product compositions, and many other factors that are refinery specific but are extremely important in considering a decision to make significant product quality investments.[13]

Gasoline is the largest volume petroleum product, accounting for nearly half of U.S. petroleum product production. Highway (or on-road) diesel represents 16% of the average production at a domestic refinery.

In 2002, domestic petroleum product demand was met as shown in Table D3-8.

D. Refinery Capacity and Product Demand

U.S. demand for petroleum products currently exceeds U.S. refining capacity, and is likely to increase each year for the foreseeable future. As Figure D3-42 shows, there is no extra supply "cushion" to deal with unforeseen supply problems. The U.S Energy Information Administration (EIA) summed up the situation on its website in early 2003: "With markets balanced so delicately, there is no room for sustained domestic infrastructure problems or reduced supplies from other countries."[14]

Figure D3-43 shows that although the number of refineries has continued to decline, aggregate capacity has been slowly increasing over the last five years from expansions at existing facilities. EIA concludes that the trend of domestic refinery shutdowns will continue. EIA further expects most future capacity additions will take place in the Caribbean and Middle East.

Historically, the refining industry has kept pace with increasing demand and quality requirements given adequate time and realistic expectations. Growing demand for transportation fuel and the need to comply with overlapping fuel regulatory specifications have created additional stress on supply capabilities. Figure D3-44 shows historical refining capacity and utilization.

As stated earlier, the supply/demand balance in the gasoline market has tightened over the years due to steadily increasing gasoline demand with relatively little growth in U.S. refining capacity. Future

[13] National Petroleum Council, *U.S. Petroleum Refining – Assuring the Adequacy and Affordability of Cleaner Fuels*, June 2000, p. 28.

[14] Energy Information Administration, *This Week in Petroleum*, EIA Website, February 20, 2003.

	Domestic Production	+	Imports	–	Exports
Gasoline	8.5		0.5		0.1
Distillate Fuel Oil	3.6		0.3		0.1
Jet Fuel	1.5		0.1		0.0
Other Finished Petroleum Products	3.2		0.5		0.6

Table D3-8. Petroleum Product Demand in 2002 (Million Barrels per Day)

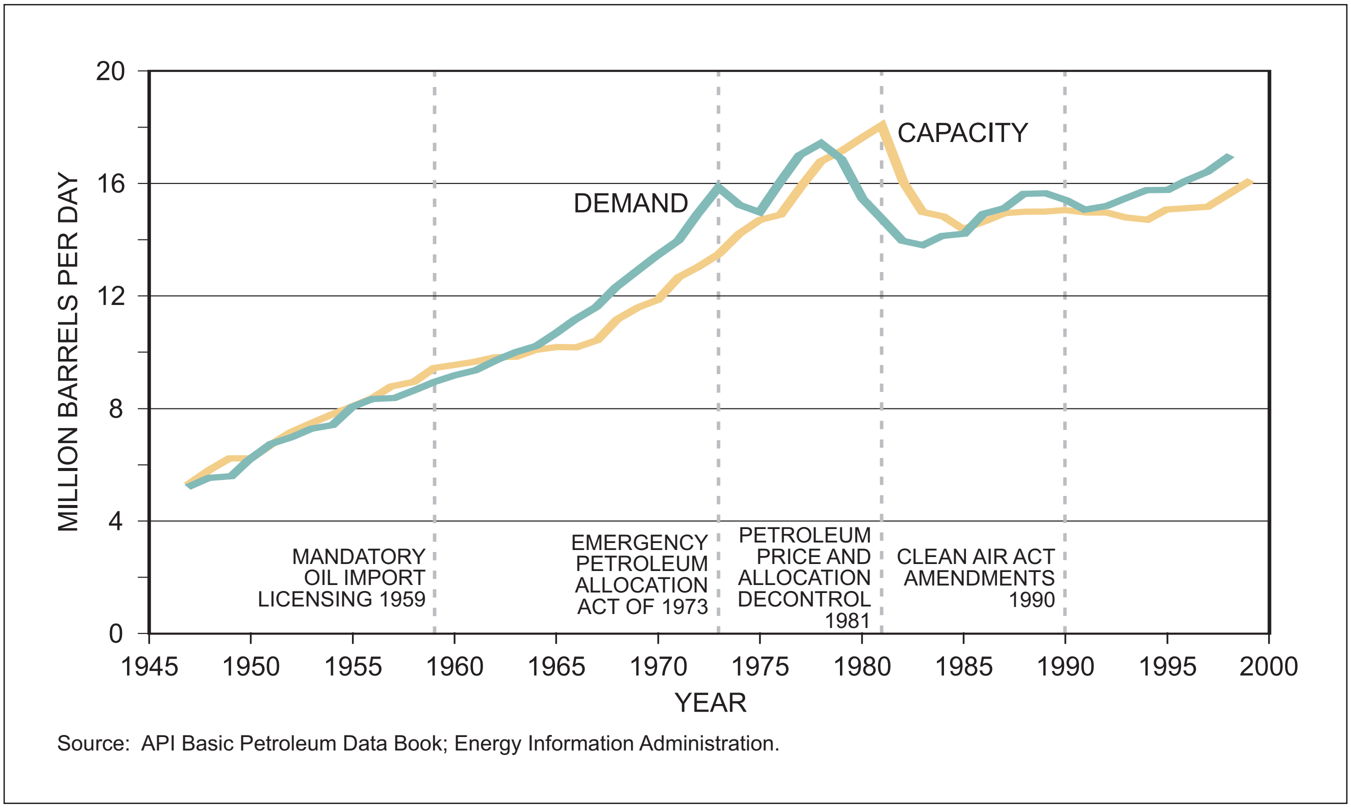


Figure D3-42. U.S. Operating Refinery Capacity and Finished Petroleum Product Demand

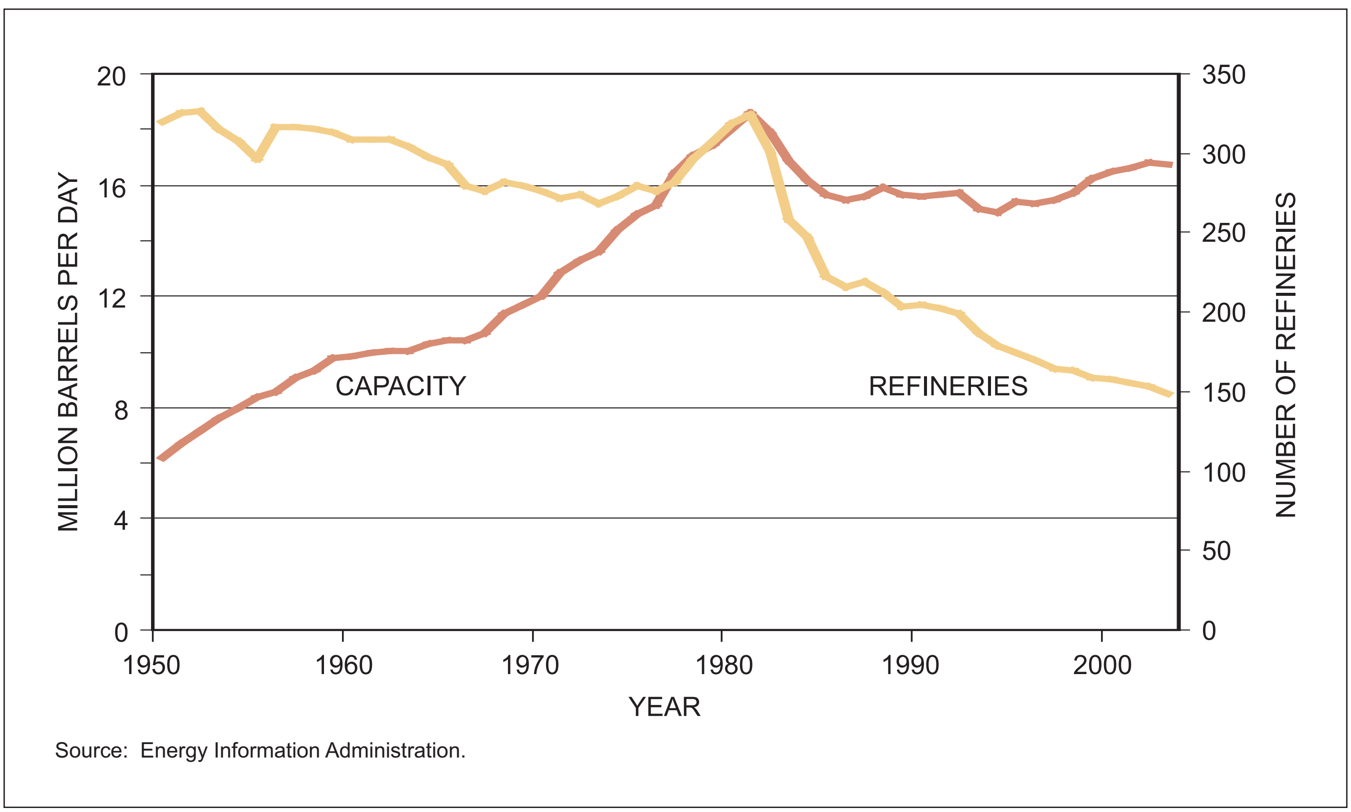


Figure D3-43. Number and Capacity of U.S. Refineries

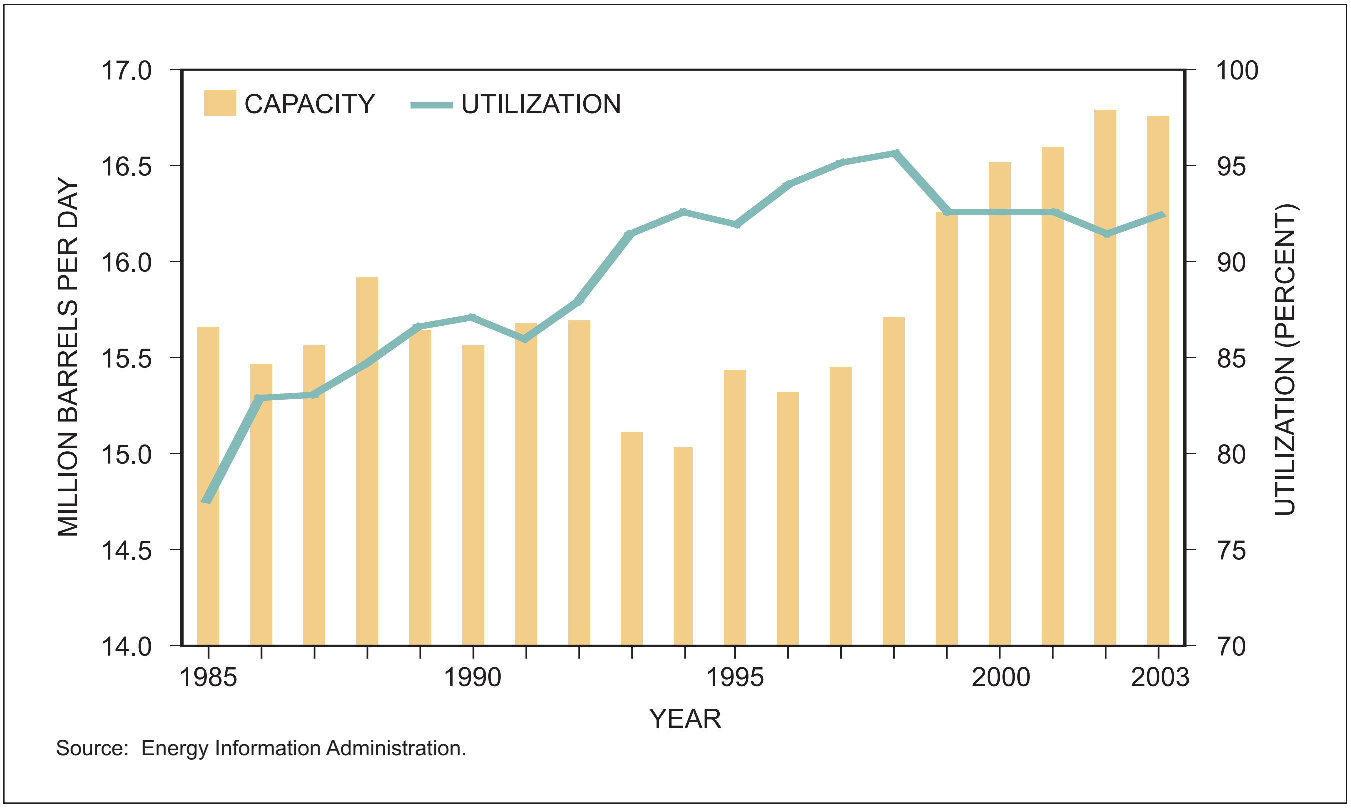


Figure D3-44. Refinery Capacity and Utilization

supply/demand balance will probably tighten in the diesel market due to EPA's ultra low sulfur highway diesel standards effective in 2006. The combination of the diesel and gasoline sulfur regulations is likely to increase concentration in the refining industry.

E. Environmental Pressures on Petroleum Refining

Stringent new petroleum product standards are addressed differently by individual companies. Some may choose not to invest. Others may invest in capacity additions as part of a coordinated and optimized improvement program. Oftentimes, during the initial implementation phase of new petroleum product standards, there can be short-term supply disruptions and accompanying price volatility. Domestic refining capacity expansions may not materialize if stringent new motor fuel composition standards and/or New Source Review compliance costs require unreasonable amounts of capital and/or discourage investment.

According to the National Petrochemical & Refiners Association, the potential refinery investment requirements of new regulations in United States is as follows:

- Tier 2 gasoline sulfur – $8 billion
- On- and off-road diesel sulfur – $9 billion
- MTBE phasedown/elimination – $2 billion
- Ethanol mandate.

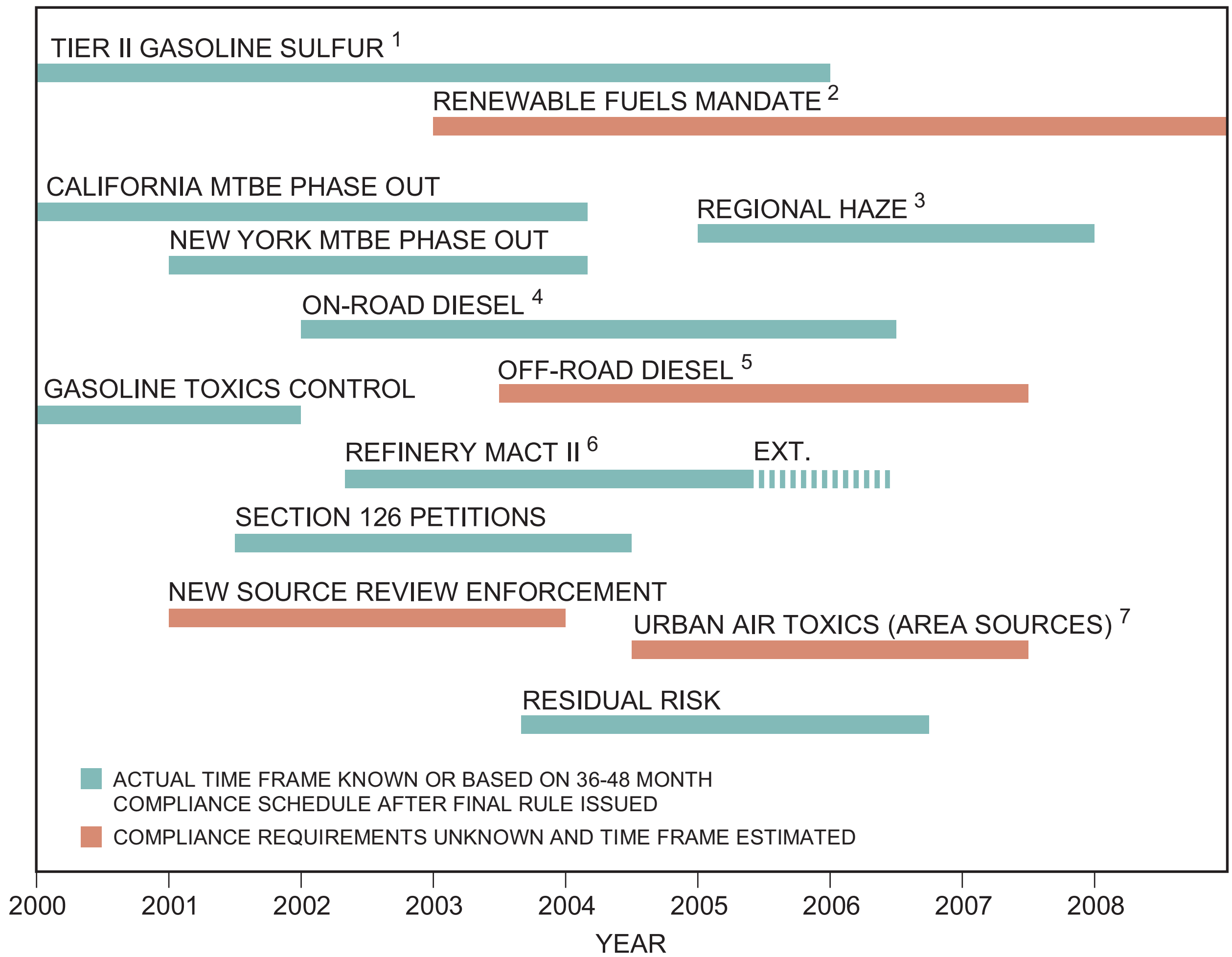
Therefore, potential costs for these programs add up to at least **$19 billion**.

Refinery configuration is constantly changing to meet new requirements. Refining capital requirements to meet EPA's new clean fuels rulemakings will be very high, as summarized above. Additional capital investments at U.S. refineries will be needed to assure adequate supplies of petroleum fuels. The National Petroleum Council estimated that $8 billion will be needed to meet EPA's low sulfur gasoline rule. An additional $7-8 billion will be needed to comply with the Agency's ultra low sulfur highway diesel rulemaking. EPA is initiating an off-road diesel sulfur reduction rulemaking. The Senate's version of the energy bill bans MTBE, which is significant because MTBE currently provides about 10% of RFG supplies in the Northeast, California, and the Houston and Dallas-

Fort Worth areas. Additional capital investment will be required to comply with possible future EPA rulemakings, such as Mobile Source Air Toxics (MSAT) Phase 2.

Figure D3-45 illustrates the many new regulatory requirements facing refiners. This chart shows a significant number of new environmental requirements – most of which fall within the same narrow time period for investment and implementation.

Government policy is a major determinant of whether adequate petroleum product supplies will be available at reasonable cost. The nation's energy delivery infrastructure is increasingly challenged by demand, with new construction and/or expansion complicated by several factors: regulatory impediments, a history of and projected continuation of limited economic returns in the industry, and siting challenges for industrial process facilities.



1. Longer compliance time for refineries in Alaska and Rocky Mountain states and small refineries covered by Small Business Regulatory Enforcement and Flexibility Act (SBREFA). Additional compliance time is available for these refineries if they produce ultra low sulfur highway diesel beginning in 2006.

2. Senate Energy bill (S. 517) proposes an ethanol mandate of 2.3 billion gallons in 2004 whichincreases to 5 billion gallons in 2012.

3. Regional Haze State Implementation Plans (SIPs) due 2005-2007. Earliest compliance date. Schedule may be impacted by National Ambient Air Quality Standard (NAAQS) litigation.

4. Longer compliance time for small refiners covered by SBREFA.

5. Estimated effective date based on proposed heavy duty vehicle standards.

6. Compliance date may be harmonized with Tier II schedule.

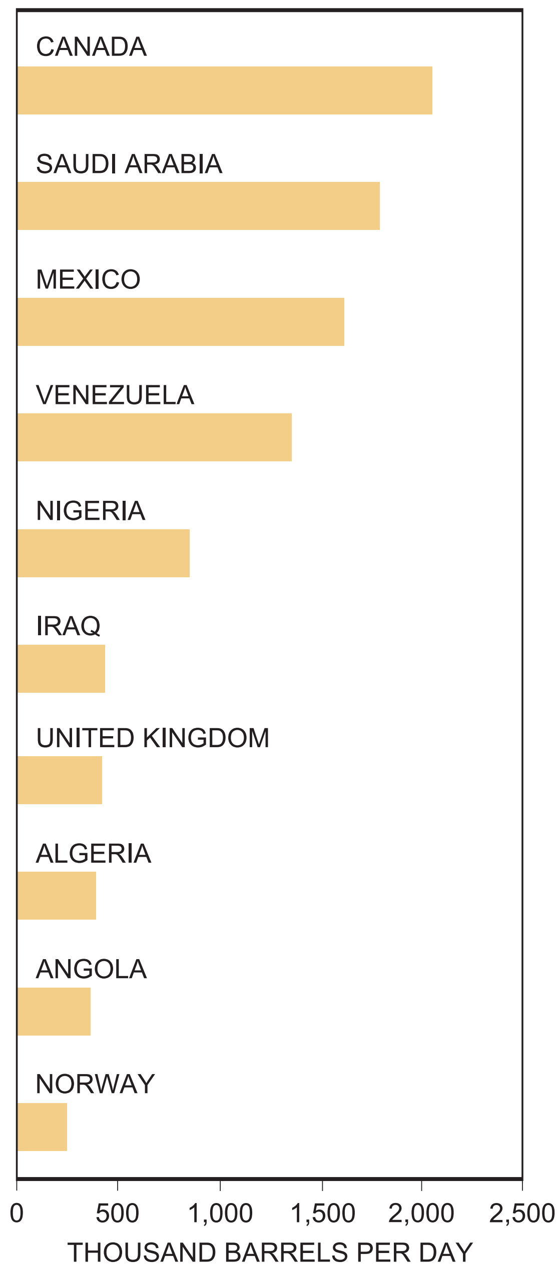
7. Urban Air Toxics Strategy includes potential controls of gasoline loading facilities at refineries. Estimated compliance schedule.

Source: National Petrochemical & Refiners Association, March 2002.

Figure D3-45. Cumulative Regulatory Impacts on Refineries, 2000-2008

F. Product Supply and Distribution

Although 95% of refined petroleum product demand is produced domestically, approximately 60% of the crude oil refined in the United States is imported from a diverse supply of nations and geographic regions. Figure D3-46 shows the major sources of crude oil imports to the United States.



Source: Canadian Association of Petroleum Producers.

Refining D3-46. Major Sources of Imported Crude Oil for United States in 2003

Local refinery production, net imports and net receipts (from one region to another) are possible sources of petroleum product fuel supply. The East Coast is dependent on supply from distant sources, Gulf Coast refineries and imports; East Coast refineries contribute only about 30% of local demand. The Midwest is dependent on supply from the East and Gulf Coasts. The Rocky Mountain area and the West Coast are generally self-sufficient. The refineries in the Gulf Coast meet local needs, contribute about half of the East Coast petroleum product demand, and are significant suppliers to Midwest consumers.

These region-to-region movements are significant because petroleum products are transported by pipelines and barges at slow rates (only a few miles an hour) and over long distances. Examples of long-distance pipelines moving petroleum products from the Gulf Coast to the East Coast are Colonial Pipeline (1,500 miles) and Plantation Pipe Line (1,100 miles). Explorer Pipeline (1,400 miles) and TEPPCO, LP (1,100 miles) are long-distance examples from the Gulf Coast to the Midwest. It can take 1.5 to 2 weeks for petroleum products to travel the entire length of these interstate pipeline systems.

The U.S. Census Bureau reported that the total value of shipments from petroleum refineries in 2001 was $200 billion (5% of total U.S. manufacturing) and represented total capital expenditures of $6.8 billion (also 5% of total U.S. manufacturing).

G. Gasoline Specifications

There are a number of federal and state gasoline specifications. The federal programs are reformulated gasoline (RFG) and summer Phase II RVP. There are also seasonal state regulations, including summer RVP and winter oxygenated gasoline. In addition, a few states have annual statewide gasoline programs, such as California RFG and oxygenated gasoline in Minnesota. Furthermore, there are some local requirements, e.g., year-round Arizona Cleaner-Burning Gasoline in Phoenix and winter Nevada Cleaner-Burning Gasoline in Las Vegas.

These product specification variations, generally referred to as “boutique fuels,” are in many cases attempts by local and regional policymakers to devise a fuel strategy for their area that balances environmental and economic considerations. Since gasoline is distributed by a complex system of pipelines, ships, barges, storage terminals, and delivery trucks, a pipeline outage or refining disruption can upset this delicate balance. The results, as have been documented many times, are tight supplies and price volatility.

Figure D3-47 illustrates the array of federal, state, and local gasoline specification requirements.

H. Cost to the Consumer

The refinery is the most complex, capital intensive, and perhaps vital component of the fuel production and distribution system – and nearly the least expensive to the driving public. Figure D3-48 is published monthly by the EIA, showing the distribution of costs for the four major components that comprise the price of gasoline to the consumer. It is noteworthy that government taxes account for the second largest cost (by over a factor of two) to the driving public.

I. NPC Modeling of Energy Consumption in Refining Processes

Petroleum refineries are energy intensive, consuming over 500 thousand Btu for every barrel of crude processed. Much of the energy required is derived from crude oil as it is converted into finished gasoline and diesel fuel. A breakdown of energy used in the refining process is shown in Figure D3-49.

Produced and consumed fuel consists of refinery fuel gas from refinery processing and fluid catalytic cracking (FCC) coke, which is deposited on the catalyst during the cracking of heavy oils and burned off in the regeneration process. Purchased utilities consist primarily of natural gas, electricity, and purchased steam.

Natural gas is used in three principal processes: as a supplement to the refinery fuel gas system; as a feed gas to hydrogen generation units; and as fuel for gas turbines used to generate power or drive large rotating equipment. Refineries also purchase steam from third parties, typically power cogeneration units. Utility companies or cogeneration facilities supply purchased electricity to refineries. The refinery fuel gas system is complex. Most process units in a refinery produce fuel gas, but also consume it in process heaters. By altering processing conditions, more fuel gas can be produced at the expense of liquid products like propane, butane and gasoline.

If natural gas prices exceed those of liquid products on a Btu basis, overall refinery economics can favor additional fuel gas production to reduce the need for natural gas. As energy efficiency improvements are made, less natural gas is required to supplement refinery fuel gas. Historically, refineries burned heavy fuel oil in some heaters and boilers reducing the need for natural gas; however, environmental initiatives have largely eliminated refinery oil burning due to sulfur and particulate emissions from stacks. Heavy fuel oil currently accounts for only about 1% of refinery produced and consumed energy. Many refineries can also vaporize propane or butane into the fuel gas system as an alternate to natural gas. This capability is limited, however, by infrastructure and the ability to avoid recondensation of the propane and butane in the fuel gas system. Propane and butane typically account for only about 1% of produced and consumed refinery energy needs in the United States.

The cogeneration of electric power and steam at refineries significantly improves overall efficiency. Natural gas, as opposed to refinery fuel, typically fires gas turbine generators due to reliability and warranty concerns. However, sustained high natural gas prices could provide incentive for refiners to switch gas turbines to distillate fuel. Higher natural gas prices relative to purchased power prices would discourage new cogeneration projects.

Hydrogen is used in the desulfurization process of gasoline and distillate. Natural gas is typically used as feed gas for hydrogen production. The hydrogen unit converts natural gas to hydrogen and CO_2, which is most often vented. Refinery fuel gas, propane, butane, or light naphtha could be substituted for natural gas feed to hydrogen plants with changes to equipment and/or catalyst. However, these alternate feed streams all have higher carbon to hydrogen ratios, resulting in greater CO_2 releases and greenhouse gas concerns relative to natural gas.

The NPC study group used the EEA model, comparing four available sources of data on energy consumption in the petroleum refining industry. These four data sources are:

1. EIA's 1998 Petroleum Supply Annual's (PSA) [Table: "Fuel Consumed at Refineries by PAD District, 1998"]. This report reflects data that were collected from the petroleum refining industry through EIA's biennial, annual and monthly surveys.

2. EIA's Manufacturing Energy Consumption Survey (MECS), 1998. This report reflects data that were

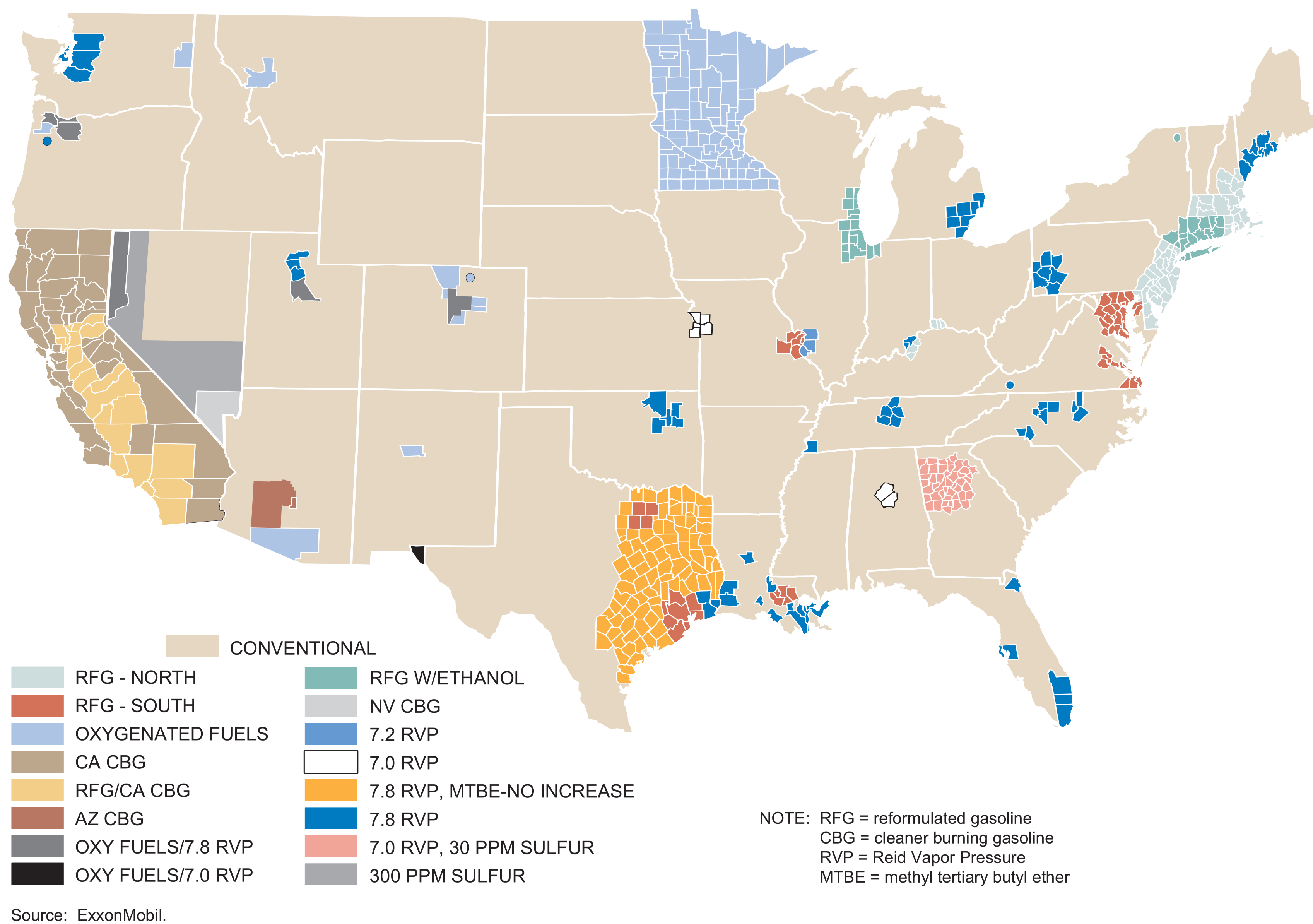


Figure D3-47. U.S. Gasoline Requirements in June 2004

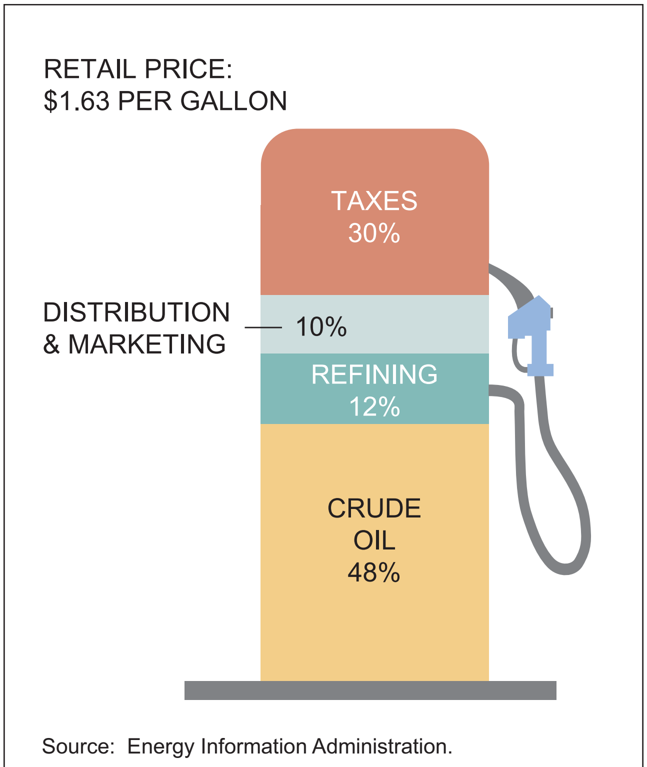


Figure D3-48. Components of Gasoline Prices in March 2004

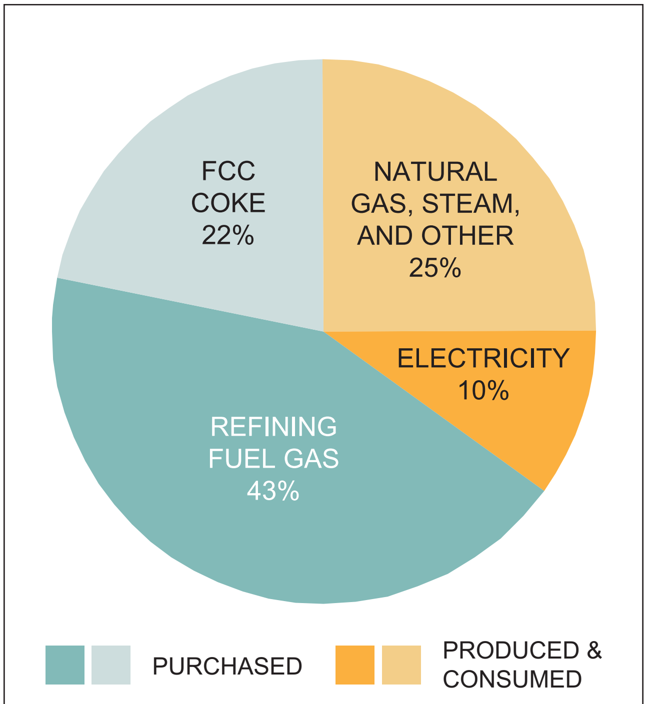


Figure D3-49. Breakdown of Energy Use in Petroleum Refining

collected by EIA from a statistical sample of manufacturing establishments (based on Census of Manufacturers mail file).

3. Industry/Solomon Data, 1998. The industry data were provided by ConocoPhillips to EEA. The data are based on Energetics, Inc. energy profiles of the refining industry, and the results are consistent with a proprietary survey of petroleum refiners done by Solomon.

4. EEA's 1998 Industrial Sector Baseyear Database.

These estimates of energy consumption in the petroleum refining industry were calculated from the "bottom-up." That is, given production data by various processes, the energy consumption is calculated based on unit electricity, direct fuels, and steam demand requirements. After calculating the electricity, direct fuels, and steam requirements in each of the processes, total steam demand and total electricity demand are then calculated by the EEA model by adding process, lighting, and HVAC requirements, and used to estimate boiler/cogeneration energy requirements for steam generation/cogeneration.

Boiler fuel consumption and cogeneration fuel consumption, as well as on-site electricity generation (from cogeneration) are estimated by the EEA model using a variety of data sources (e.g., EIA's MECS, EEA's boiler data, EEA's cogeneration data). Purchased electricity is calculated as the difference between total electricity demand and electricity generated on-site.

The bottom-up data are then benchmarked to top-down data from the EIA State Energy Data System (SEDS). EEA uses the SEDS data as the overall calibration standard for its industrial energy sector analysis because they are consistent with the national, total industrial energy data in EIA's Annual Energy Review data but provide disaggregation by fuel type and region. The bottom-up data from each industry and process are reconciled in the EEA model with the top-down SEDS data to produce a consistent national, industrial sector data set.

Byproduct fuels (still gas and petroleum coke) are also taken into account in the EEA calculations. Still gas is primarily used in the process heaters, while petroleum coke is used only in boilers. EEA estimates of still gas and petroleum coke consumption in the refining industry are based on the EIA SEDS. It is important to note that the reported petroleum coke values from SEDS are much higher than the estimate used for petroleum refining industry. A significant amount of petroleum coke is also consumed in other industries including aluminum and cement. Petroleum coke demand from these other industries is estimated and subtracted from the SEDS petroleum coke total to get the final petroleum coke consumption in the refining industry. In estimating fuel consumption in this industry, it is assumed that all of the still gas and available petroleum coke are consumed first, and that natural gas and other fuels supplement the remaining requirements.

It is also important to note that the EEA modeling framework includes "over-the-fence" cogeneration facilities, that is, it includes cogeneration facilities situated outside a petroleum refining plant that provide steam and/or electricity to a particular petroleum refining plant. The other data sources exclude such cogeneration facilities.

Table D3-9 compares the energy consumption estimates from the four data sources. For consistency, EEA's numbers have been adjusted to exclude the energy consumption from "over-the-fence" cogeneration facilities. Also the industry natural gas estimate includes natural gas consumption for hydrogen production.

The following may be observed from Table D3-9:

- EEA's total energy consumption level is between MECS' and PSA's energy consumption estimates. The industry estimate is substantially lower than the three (it is 26%, 31%, and 20% lower than EEA's, MECS' and PSA's, respectively).

- EEA's total fuel consumption level is between MECS' and PSA's fuel consumption estimates. The industry estimate is substantially lower than the three (it is 39%, 43%, and 33% lower than EEA's, MECS' and PSA's, respectively).

- EEA reports the largest natural gas consumption, being 31% and 46% more than those reported by MECS and PSA, respectively. On the other hand, the industry estimate is lower than MECS and PSA (33% and 25% lower, respectively).

- EEA and PSA report the same amount of still gas consumption (EEA uses the PSA/SEDS estimate when it developed the 1998 base year database). MECS' estimate for still gas consumption is very close to EEA's and PSA's. The industry estimate is significantly lower than the three estimates (38% lower than EEA's and PSA's and 36% lower than MECS').

- EEA's petroleum coke consumption is very close to the industry estimate, although both estimates are significantly lower than MECS' and PSA's estimates.

Energy Source	EEA*	MECS	PSA	Industry
Total Energy Consumption	**3,349**	**3,622**	**3,098**	**2,491**
Fuels	3,231	3,496	2,986	1,987
Natural Gas	1,315	1,006	901	673
Still Gas	1,431	1,399	1,431	890
Petroleum Coke	338	634	534	327
Subtotal (NG,SG,PC)	3,085	3,039	2,866	1,891
Coal	28	0	0	0
Other Fuels	118	457	121	96
Purchased Electricity	118	126	111	504

* EEA data exclude energy consumption of "over-the-fence" cogeneration facilities.

Note: EEA = Energy and Environmental Analysis, Inc.; MECS = EIA's Manufacturing Energy Consumption Survey; PSA = EIA's Petroleum Supply Annual.

Table D3-9. Comparison of 1998 Energy Consumption Estimates (Trillion Btu)

- Looking at the total of the three main fuels (natural gas, still gas, petroleum coke), the EEA and MECS estimates are very close. The PSA data show a lower total, although not substantially lower than the EEA and MECS. The industry total is much lower than the three other estimates.

- EEA is the only data source showing coal consumption, albeit relatively small.

- For other fuels (mostly oil and LPG), EEA, PSA, and the industry report very close estimates, while MECS shows almost four times as much.

- For electricity, EEA, PSA and MECS report very close estimates, while the industry shows over four times as much.

The table shows that the EEA, MECS and PSA estimates are fairly close for the total demand for total fuel and for the three main fuels: natural gas, still gas, and petroleum coke. EEA projects higher natural gas consumption than the other three data sources but this is explained by EEA's lower combined consumption levels of non-natural gas fuel (still gas, petroleum coke, other fuel). EEA used the SEDS data to benchmark the "other fuel" data. (Where the EIA sources differ, EEA uses the SEDS data as a benchmark because it is more consistent with the overall EIA totals.) Since the SEDS data for these fuels are lower than the consumption levels reported in MECS and PSA, the difference was made up by higher natural gas demand in the EEA calibration.

In summary, EEA's estimates are consistent with the estimates from MECS and PSA, despite the independent and different methodologies used by EEA, MECS, and PSA to develop their estimates. The industry data seem to be different in a variety of ways from the other three sources. We don't have sufficient information on the industry data to address those differences.

J. NPC Outlook for Natural Gas Consumption in Refining Processes

Natural gas usage at U.S. refineries is expected to continue to change. Increasing demand for petroleum products, efficiency gains, and clean fuels regulations are key factors impacting future natural gas demand from U.S. refineries. In general, efficiency gains in the industry will be offset by capacity expansions and increased processing severity to produce cleaner fuels from lower quality feedstocks. The price of natural gas also affects refinery demand because fuel-switching alternatives are readily available to most refiners.

Refineries will need to expand capacity by approximately 1.5% a year to keep pace with growing demand for petroleum products. This number is less than half the projected industrial growth rate and includes allowance for the improved efficiency of vehicles. While somewhat higher than growth rates in the immediate past, this growth rate is closer to actual growth rates over the last 25 years.

Even though more than half of all U.S. refineries have shut down since the late 1970s, the remaining refineries are producing more total products. Meanwhile, imports have been relatively constant over the past decade. Generally, smaller and less-efficient refineries have shut down, while larger refineries have invested in improvements to enhance production. This analysis assumes refinery capacity growth of 1% a year with product imports supplying any shortfall.

Energy efficiency improvements in refining will affect demand for natural gas. The integrated major oil companies have committed to the U.S. government to improve refinery energy efficiency by 10% from 2002 to 2012. However, additional processing severity and new processing units to meet clean fuels requirements will increase energy usage. Over the past 10 years, refinery efficiency improvements have averaged approximately 1.5% a year, but overall energy use per barrel of crude has dropped by only about 0.5% a year. This trend is expected to continue as environmental regulations continue to increase energy requirements per barrel of crude oil processed. In addition, there are diminishing returns on energy improvements as overall efficiency improves. In recent years, the most efficient refineries have reached a plateau while less-efficient refineries continue to improve. For this analysis, energy efficiency is expected to improve 1% a year from 2002 to 2012, 0.5% a year for 2013 to 2022, and 0.25% a year thereafter. Refinery flare losses are assumed to reduce by 50% compared to current levels, with a corresponding reduction in natural gas demand.

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

The net energy requirements for these new desulfurizers are modest, adding about 37 BCF a year, or 5% of today's refining natural gas demand. However, the hydrogen required for the desulfurization of gasoline and diesel fuel will require a net increase in natural gas demand, even after efforts are made to fully utilize available hydrogen. This analysis assumes that 20% of the additional hydrogen required is sourced from improved management of existing hydrogen systems.

Demand growth, efficiency gains, and regulatory impacts were projected based on the assumptions described above. If natural gas continues to be the most economic incremental fuel for refineries, NPRA projections show an increase in natural gas demand of approximately 0.9% per year for the period 2003 to 2030 – a 33% increase versus a 34% increase in light oil production. Overall energy use would drop from 536 thousand Btu/bbl to 495 thousand Btu/bbl during this period. The higher level of efficiency improvements assumed in 2003 to 2012 would be more than offset by increased hydrogen production for clean fuels. During 2013 to 2022, efficiency gains would keep pace with capacity growth and natural gas demand is relatively flat. From 2023 to 2030, natural gas demand would increase as efficiency gains would fall short of capacity growth.

If natural gas prices exceed those of alternative refinery fuels like propane, butane and gasoline, refiners will likely adjust operating conditions to increase fuel gas production and reduce natural gas consumption. It is estimated that refiners could reduce natural gas demand for fuel by approximately 45% through operational changes in the short-term.[15] Sustained higher prices for natural gas could provide incentive for refiners to invest in fuel-switching capabilities on large heaters, boilers, and gas turbines. Ultimately, natural gas for refinery fuel could be limited to the volume required for balancing swings in the refinery fuel gas system. This minimum volume is estimated at 20% of the natural gas currently used for refinery fuel. However, reducing natural gas demand to these levels would require capital investments over a several year period.

Higher natural gas prices could similarly affect natural gas feed to hydrogen plants. By modifying equipment and/or catalyst, refiners could switch hydrogen plants to fuel gas, propane, butane or naphtha. Assuming half of refinery hydrogen plants are switched to alternate fuels, overall natural gas demand for hydrogen production would be reduced by an equivalent amount. Combined with the reduction in natural gas for refinery fuel, overall natural gas projections could be reduced by 2/3 of the levels shown in the graph above – 1/3 through short-term operational changes, and an additional 1/3 over time as fuel-switching projects are implemented.

In summary, the National Petrochemical & Refiners Association (NPRA) expects natural gas demand at U.S. refineries is expected to increase by approximately 33% over current levels by 2030, assuming that natural gas remains the incremental fuel of choice. NPRA suggests that efficiency improvements will be more than offset by the need for additional refinery fuel to meet demand growth and clean fuels hydrogen needs. If higher natural gas prices fundamentally alter relative economics vs. the readily available alternatives, these demand projections could be reduced by up to 1/3 in the short term and by up to 2/3 in the long term as refiners optimize the tradeoffs between natural gas costs and product value. The NPC study group assumed that given the higher natural gas price levels foreseen in both base-case scenarios of this study, the refining sector will, in fact, respond to higher natural gas prices such that overall natural gas demand in refineries will remain essentially flat through 2025. Overall natural gas demand for merchant hydrogen, about 10% or 30-35 BFC per year of which would be used to supply refineries, is projected to double from 2002 to 2025 in both the Reactive Path and Balanced Future scenarios.

IV. Alberta Oil Sands

The use of natural gas has grown in the processing of the oil sands of Alberta, as a result of heavy investments in this resource in recent years. The outlook for future natural gas use in these applications is an important factor in understanding the North American natural gas supply/demand balance. In 2002, total natural gas used in oil sands extraction, processing and upgrading was over 630 MMCF/D.[16] Much of the following information was contributed by TransCanada Corporation and Encana Corporation.

Oil sands are deposits of bitumen, a heavy black viscous oil that must be treated to convert it into an

15 ConocoPhillips.

16 TransCanada.

upgraded crude oil for use by refineries to produce gasoline and diesel fuels. In the past, Alberta's bitumen deposits were referred to as tar sands. Bitumen will not typically flow unless heated or diluted with lighter hydrocarbons.

Alberta's oil sands contain the largest crude bitumen resource in the world, with approximately 315 billion barrels considered potentially recoverable under anticipated technology and economic conditions.[17] Of this potentially recoverable amount, the established reserves are 174 billion barrels. Through 2002, only 2% of the initial established crude bitumen reserve had been produced. Table D3-10 summarizes the crude bitumen and crude oil resources in Alberta. Figure D3-50 contrasts Canada's crude oil reserves to those of other oil-producing countries.

A. Oil Sands Areas

Alberta contains three major oil sands areas, as shown in Figure D3-51: Athabasca, Cold Lake, and Peace River. Different areas and deposits have distinct characteristics requiring different techniques to extract the bitumen:

- **Athabasca.** At 40,000 square kilometers, this is the largest and most accessible reserve, and also contains the most bitumen. Some of the oil sands near Fort McMurray are close to the surface and can be mined. However, less than 20% of the total area can be developed using mining techniques, and in situ techniques are needed to produce other deeper deposits. This area also includes deposits in the Wabasca region that are geologically associated with the Fort McMurray oil sands.

- **Cold Lake.** At 22,000 square kilometers, this area has Alberta's second largest reserve of bitumen held in deep deposits. Presently, some of these deposits are being recovered using in situ technology.

- **Peace River.** At 8,000 square kilometers, this is the smallest of Alberta's oil sands areas. As at Cold Lake, these deep deposits are being recovered with in situ methods.

[17] Alberta Energy and Utilities Board.

B. Natural Gas Use in Oil Sands Processing

The three major elements in the recovery and processing of bitumen from oil sands each consume natural gas. These are mining extraction, in situ extraction, and upgrading.

1. Extraction Methods: Mining and In Situ Extraction

Different areas and deposits have distinct characteristics and may require different techniques to extract the bitumen. In some cases, the oil sands are close enough to the surface to be mined. Everywhere else, the bitumen has to be recovered by underground, or in situ methods. Alberta produces approximately one million barrels per day of bitumen, with mined production making up 65% and in situ, or thermal, production making up the balance.

	Crude Bitumen		Crude Oil	
	Million Cubic Meters	Billion Barrels	Million Cubic Meters	Billion Barrels
Initial In-Place	259,250	1,631	9,852	62.0
Initial Established	28,330	178	2,603	16.4
Cumulative Production	610	3.8	2,343	14.7
Remaining Established	27,720	174	260	1.6
Annual Production	48.1	0.303	38	0.264
Ultimate Potential (Recoverable)	50,000	315	3,130	19.7

Table D3-10. Alberta Oil Sands Reserves and Production Summary, 2002

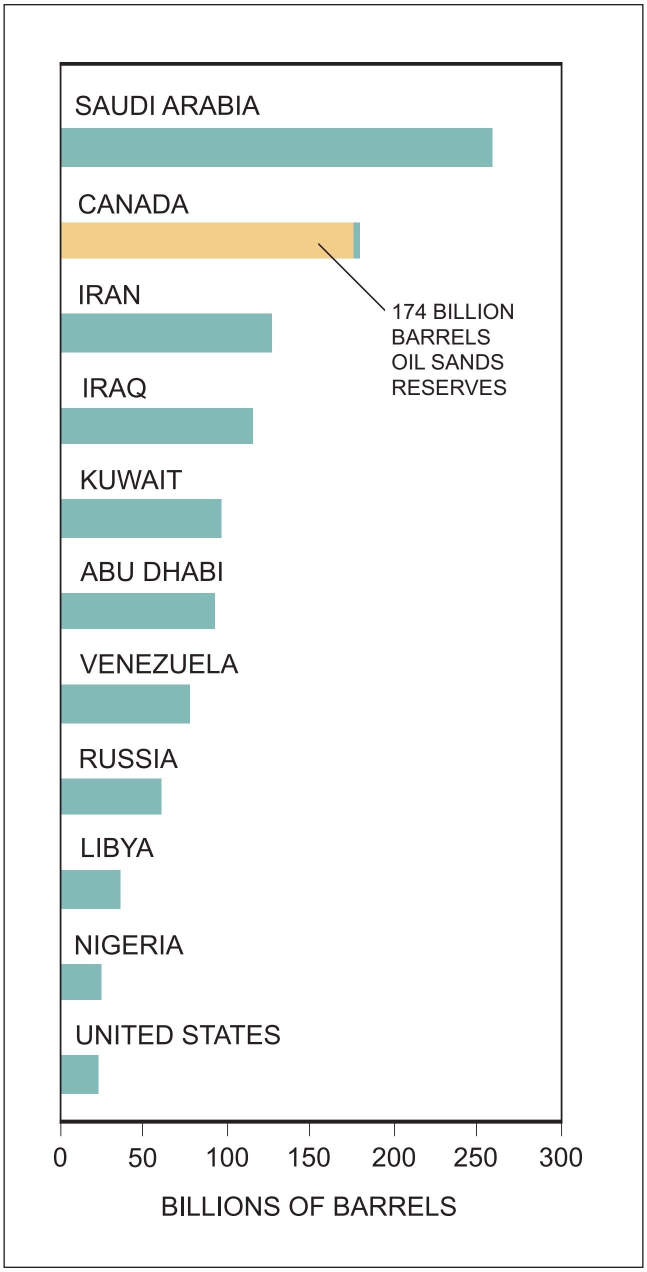


Figure D3-50. Crude Oil Reserves of Major Oil-Producing Countries

Figure D3-51. Major Oil Sands Areas of Alberta

In mining operations, about two tonnes of oil sands must be dug up, moved and processed to produce one barrel of oil. Most of the bitumen can be recovered from the sand; processed sand has to be returned to the pit and the site reclaimed.

In situ recovery is used for bitumen deposits buried too deeply – typically more than 75 meters – for mining to be practical. Most in situ bitumen and heavy oil production comes from deposits buried more than 400 meters below the earth's surface.

a. Surface Mining and Extraction

Figure D3-52 illustrates the major steps in the mining process, and Figure D3-53 depicts operating costs for mining and water-based extraction. At around $8 (Canadian) per barrel, the combination represents about 50% of costs from mine to synthetic crude. Capital costs for mining extraction add about $3-4 per barrel.

b. In Situ Production

Cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD) are the principal in situ recovery methods used for bitumen production from the oil sands. These involve injection of steam through vertical or horizontal wells, solvent injection and CO2 methods. Canada's largest in situ bitumen recovery project is at Cold Lake, where deposits are

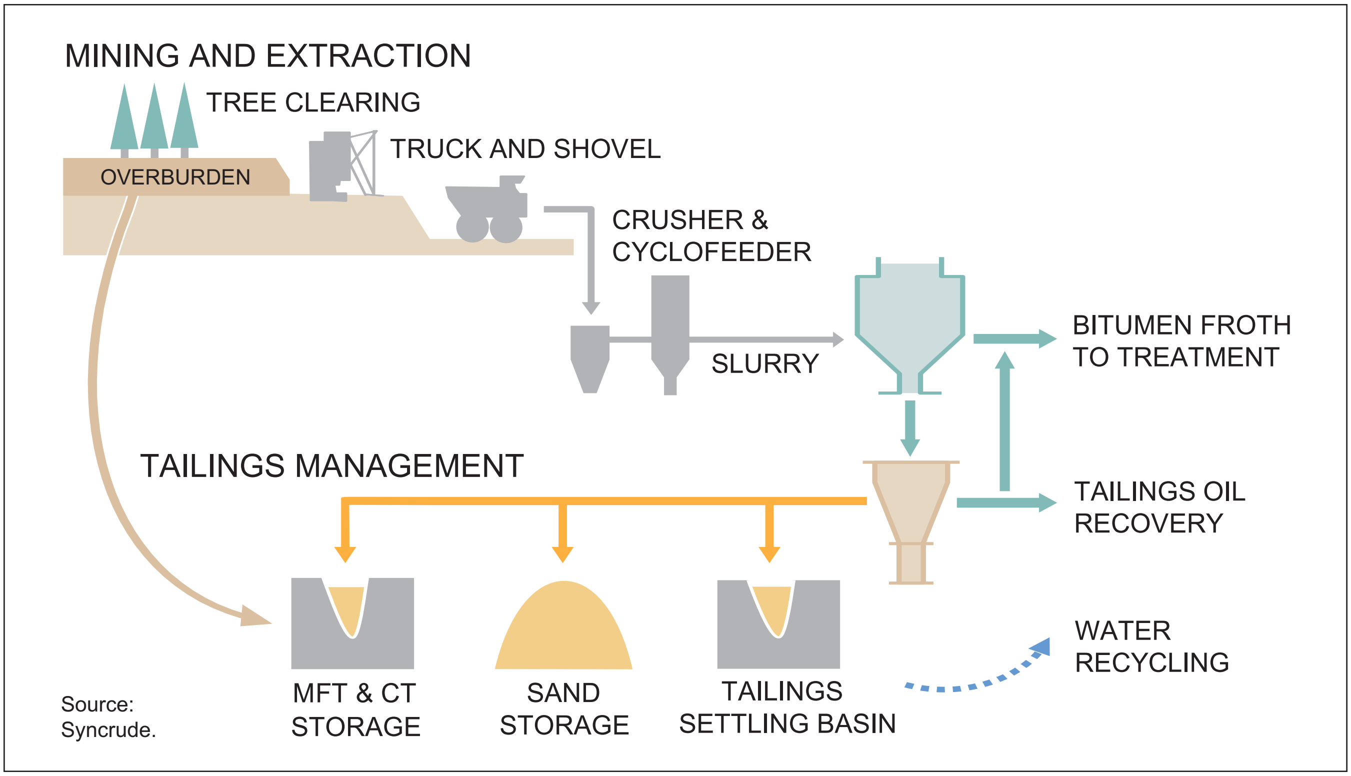


Figure D3-52. Major Steps in Oil Sands Mining

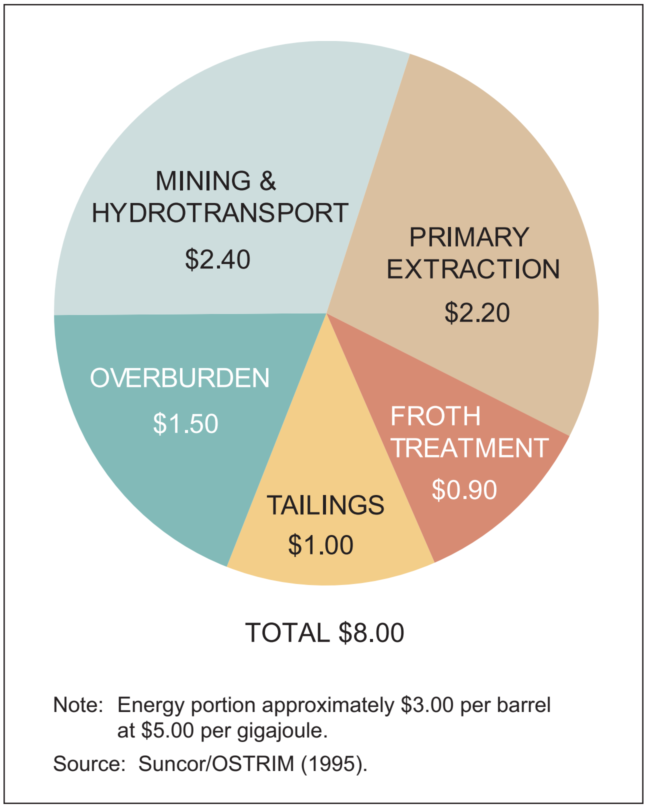


Figure D3-53. Major Operating Cost Elements (Estimated 2002 Canadian Dollars per Barrel)

heated by steam injection to bring bitumen to the surface, then diluted with condensate for shipping by pipelines.

Advanced horizontal drilling technology established the foundation for the SAGD process. In a SAGD operation, several horizontal well pairs are drilled from the same pad extending as long as 1,000 meters horizontally into the oil sands and about 5 meters apart vertically. The top well is used to inject steam to warm up a zone around and below the injector, reducing the viscosity and mobilizing an expanding zone of bitumen, which is then produced though the lower well. Figure D3-54 shows the SAGD concept.

The variable cost of recovery for in situ production was estimated for 2002 by the Alberta Energy Utilities Board at approximately $7.40 per barrel for high quality reservoirs, slightly lower than for surface mining operations. The elements of these costs are illustrated in Figure D3-55. However, sensitivity to energy prices is high compared with surface mining. Ultimate recovery for in situ processes typically ranges between 40% and 70%. Unlike mined bitumen, the product of the in situ process is generally low enough in base sediment and water to be handled conventionally in downstream

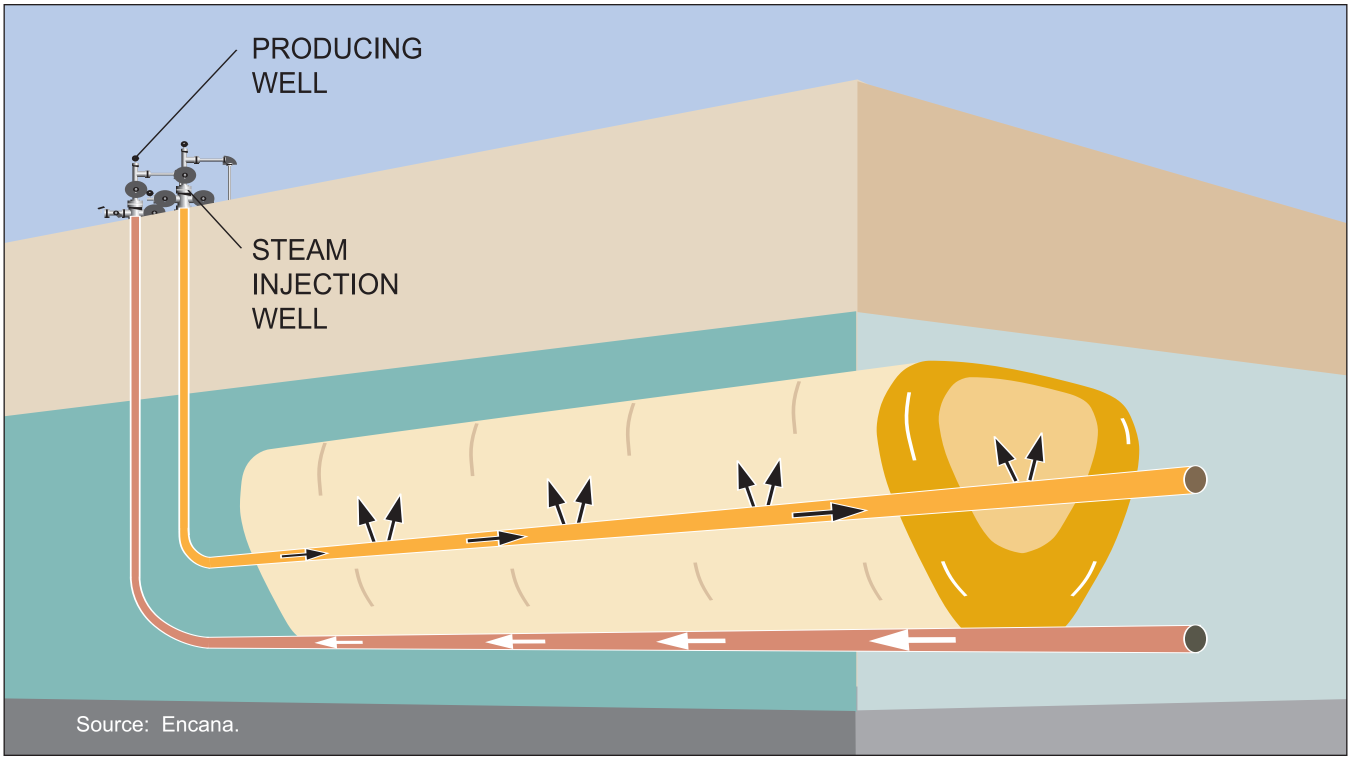


Figure D3-54. Diagram of Steam Assisted Gravity Drainage Process

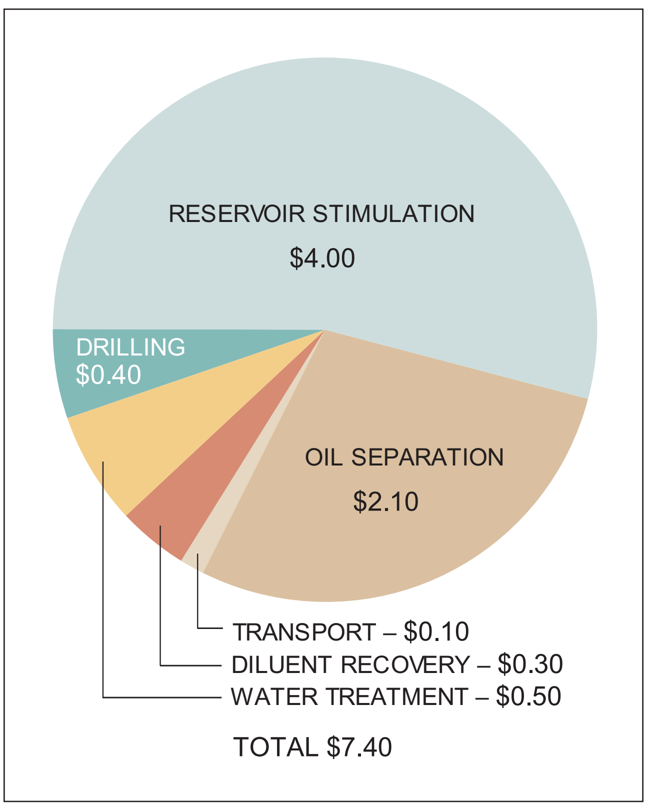


Figure D3-55. Major Operating Cost Elements for In Situ Processes (Estimated 2002 Canadian Dollars per Barrel)

refineries. Capital costs per barrel are approximately $3, with much of the capital for drilling spread over the life of the project.

2. Upgrading

Essentially all mined bitumen is upgraded to Synthetic Crude Oil (SCO) prior to refining, with the basic steps shown in Figure D3-56.

C. Crude Bitumen Production

In 2002, Alberta produced 193 million barrels from mining operations and 109 million barrels from in situ extraction, totaling 303 million barrels. Bitumen produced from mining was upgraded, yielding 161 million barrels of SCO. In situ production was marketed as non-upgraded crude bitumen. Figure D3-57 shows historical bitumen production, together with 2003 forecasts of the AEUB and Canadian Association of Petroleum Producers (CAPP), as well as publicly presented forecasts of FirstEnergy and TransCanada.

The NPC study group considered these forecasts and the many proposed projects for extraction and processing bitumen from the Alberta oil sands. Key

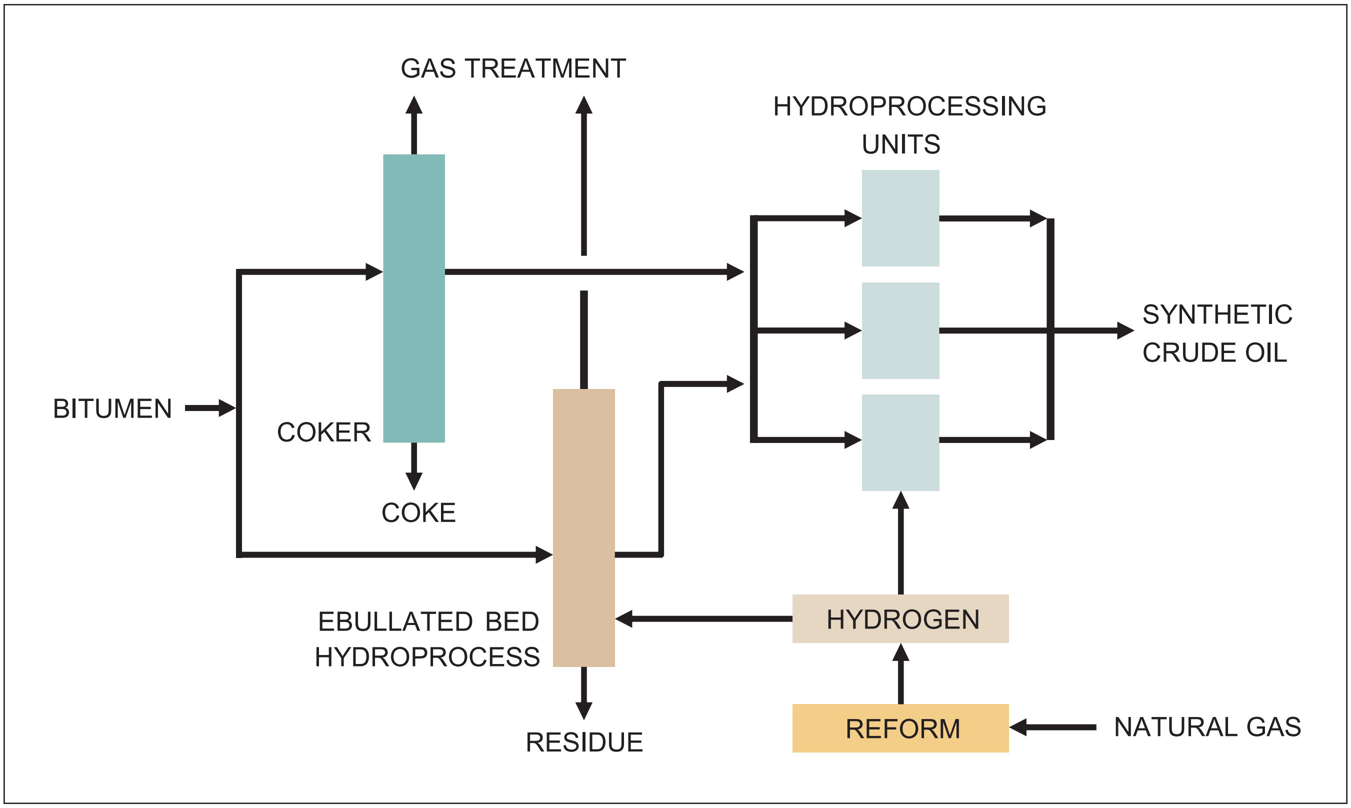


Figure D3-56. Diagram of Bitumen Upgrading Process

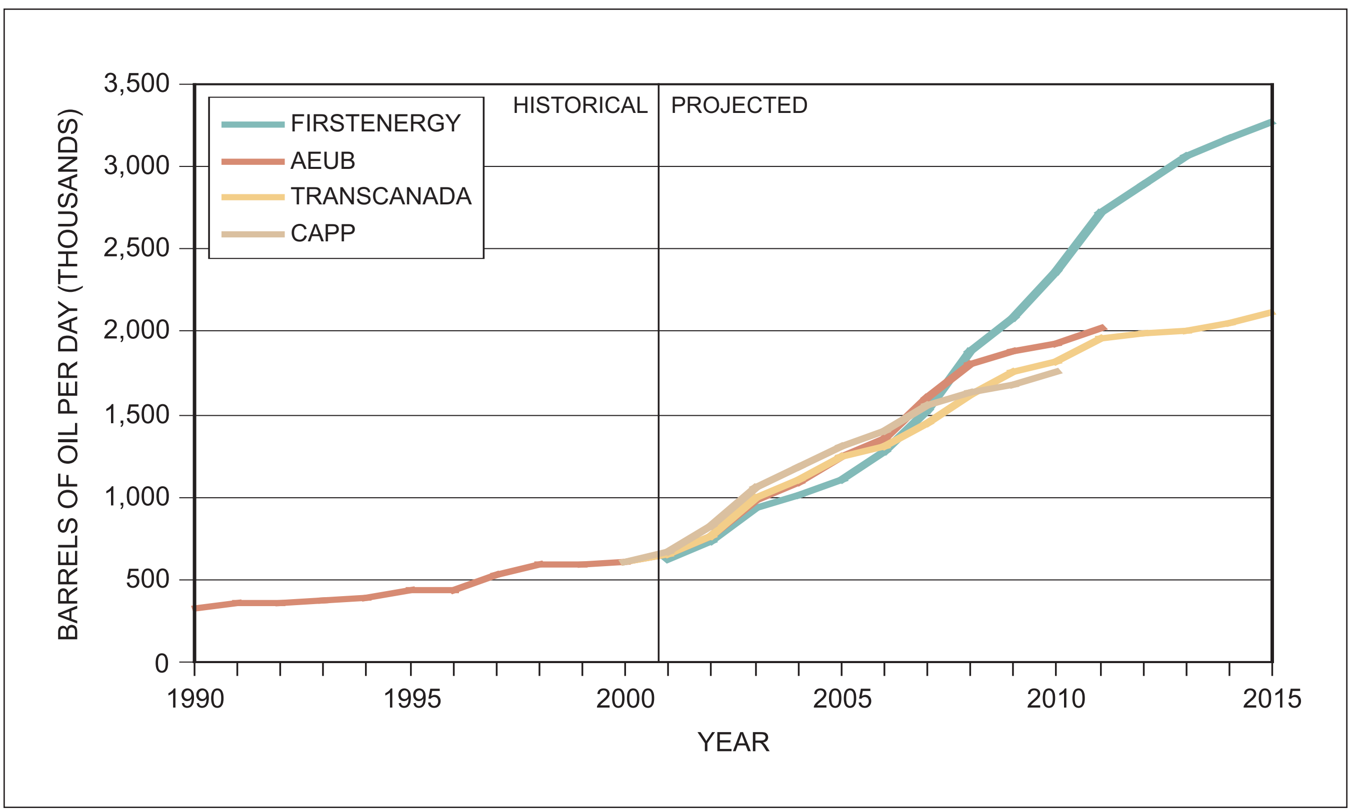


Figure D3-57. Alberta Bitumen Production and Various Forecasts insights drawn from market participants in Alberta included the following:

- Export market demand for bitumen will constrain potential production in the near-term and encourage upgrading in Western Canada.

- New bitumen upgrading capacity is likely for Western Canada.

- Price differentials for heavy crude will drive completion of many projects, but timing could be constrained by labor resources.

- Project development could be constrained by market demand for bitumen, as well as construction constraints.

- Higher natural gas prices will likely drive changes in process design and operation both for existing projects and for future, planned projects.

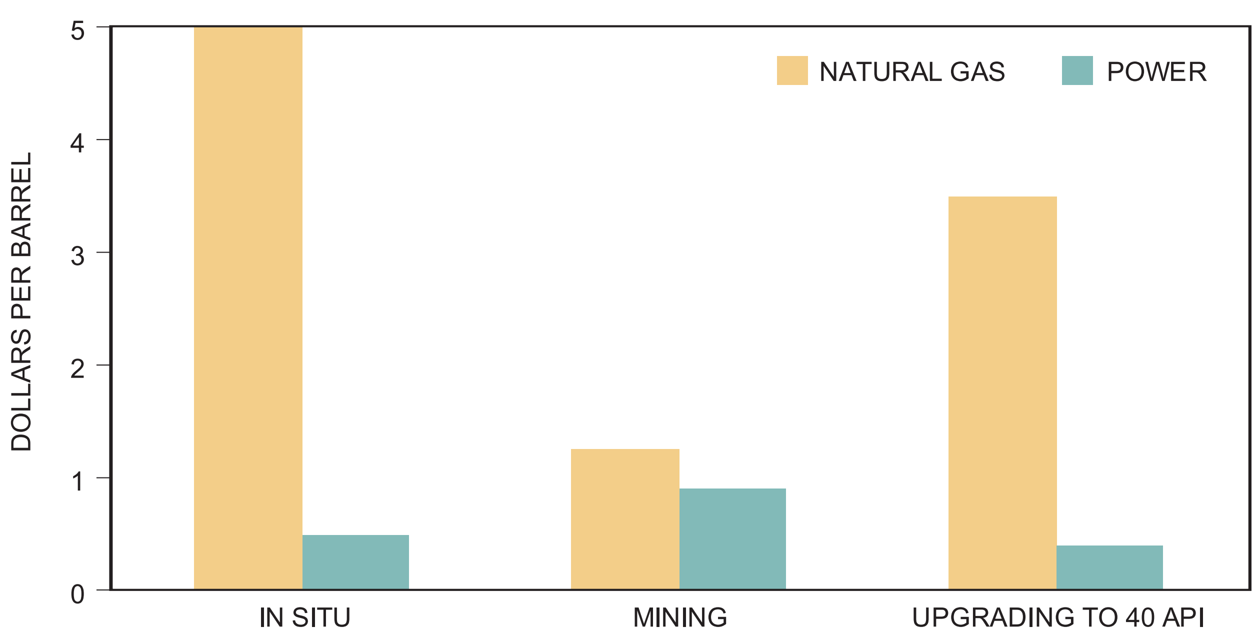
D. Energy Use and Costs

Different amounts of natural gas are used in the in situ, the mining, and the upgrading processes for oil sands. The historical dependence on abundant and relatively low-price natural gas, for fuel and the generation of hydrogen in oil sands production, has contributed to recent challenges on the part of oil sands production operations to better manage energy costs. Figure D3-58 provides an estimate of energy costs for each aspect of value in bitumen recovery and processing, including the added cost of hydrogen (via steam methane reforming of natural gas).

E. Future Natural Gas Demand in Oil Sands Processing

The NPC study group made projections of future natural gas demand for oil sands processing for use in EEA's model of industrial demand for Alberta. This modeling incorporated both growth in base industrial demand, including existing oil sands processing facilities, and specific assumptions for new oil sands processing. Table D3-11 shows the current ranges of gas intensity (gas used per barrel of oil) described by the Canadian Energy Research Institute (CERI) for the various elements of bitumen extraction and processing from the Alberta oil sands.

Figure D3-59 shows the historical natural gas usage for oil sands recovery and processing, together with the



Note: All figures estimate natural gas at $5/gigajoule and power at $0.60/kilowatt hour.
Source: Alberta Energy and Utilities Board.

Figure D3-58. Energy Components in Oil Sands Recovery and Processing

	Gas Intensity Range
SAGD In Situ	1.0 – 1.2 MCF/barrel
CSS In Situ	1.2 – 1.4 MCF/barrel
Mining and Extraction	0.25 – 0.30 MCF/barrel
Upgrading	0.15 – 0.45 MCF/barrel
Integrated	0.4 – 0.75 MCF/barrel

Table D3-11. Gas Intensity of Bitumen Extraction and Processing

assumed gas consumption used in both the Reactive Path and Balanced Future scenarios. In developing this outlook, the NPC study group assumed that gas demand would continue at current planned rates from existing projects and those for which capital outlays are currently underway. Beyond the gas demand from those projects, there is a significant level of uncertainty as to the many, individual investment and operational decisions that will be made by operators as they seek to optimize economic and environmental performance of their various extraction and processing activities in Alberta. The NPC study group believed that the emerging higher-price environment for natural gas would markedly influence the decisions of these operators. Therefore, the outlook for natural gas demand in the Reactive Path and Balanced Future scenarios assumes 25% of the potential natural gas demand will be realized from additional announced projects.

V. Primary Metals

The Primary Metals industries (NAICS 331) smelt and/or refine ferrous and nonferrous metals from ore, pig or scrap, using electrometallurgical and other process metallurgical techniques. The industry can be broken down into five sub-industries:

- Iron and steel mills and ferroalloy manufacturing
- Steel product manufacturing from purchased steel
- Alumina and aluminum production and processing
- Nonferrous metal (except aluminum) production and processing
- Foundries.

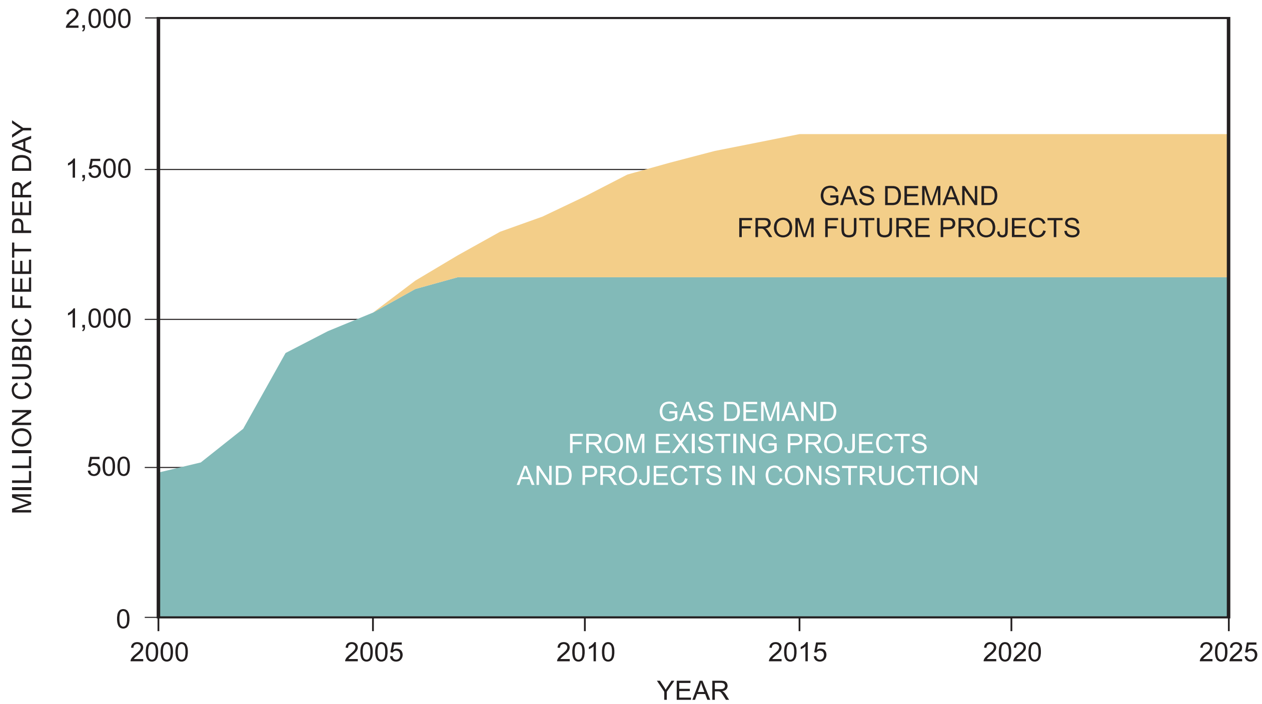


Figure D3-59. NPC Assumption of Natural Gas Usage for Oil Sands Recovery and Processing

These industries manufacture metal alloys and superalloys by introducing other chemical elements to pure metals. The products of smelting and refining, usually in ingot form, are used in rolling, drawing, and extruding operations to make sheet, strip, bar, rod, or wire, and in molten form to make castings and other basic metal products. The industry employed about 533,000 people and sold $138 billion of products in 2001.[18] Table D3-12 summarizes the characteristics of these segments.

Primary manufacturing of ferrous and nonferrous metals begins with ore or concentrate as the primary input. Companies manufacturing primary metals from ore and/or concentrate remain classified in the primary smelting, primary refining, or iron and steel mill industries regardless of the form of their output. Companies primarily engaged in secondary smelting and/or secondary refining recover ferrous and nonferrous metals from scrap and/or dross. The output of the secondary smelting and/or secondary refining industries is limited to shapes, such as ingot or billet, which will be further processed. Recovery of metals from scrap often occurs in establishments that are primarily engaged in activities, such as rolling, drawing, extruding, or similar processes.

[18] U.S. Census Bureau, Annual Survey of Manufacturers, "Statistics for Industry Groups and Industries: 2001."

A. Aluminum

The U.S. aluminum industry (SIC 333/5 or NAICS 3313) is the world's largest, producing about $41 billion in products and exports in 2002 and accounting for 10% of the world's primary aluminum production in 2002.[19] Aluminum products are used in transportation, construction, packaging, consumer durables, and electrical industries. As a lightweight, high-strength, recyclable, and structural material, aluminum will likely continue to play an increasingly important role in the U.S. economy as applications are extended into infrastructure, aerospace, and defense industries.

According to the U.S. Census Bureau, during 2001, the U.S. aluminum industry employed 76,000 people,[20] operating over 300 plants in 35 states and impacting communities throughout the country, either through physical plants and facilities, recycling, heavy industry, or the consumption of consumer goods.

Aluminum metal is classified as primary aluminum if it is produced from ore and as secondary aluminum if it is produced predominantly from recycled scrap. In 2002, exports of aluminum products accounted for

[19] Plunkert, "Aluminum," U.S. Geological Survey, 2002.

[20] U.S. Census Bureau, Annual Survey of Manufacturers, "Statistics for Industry Groups and Industries: 2001."

NAICS	Industry Name	Value of Shipments ($1,000)	Number of Employees	Cost of Purchased Electricity ($1,000)	Cost of Purchased Fuels ($1,000)	Total Cost of Electricity and Fuels ($1,000)
331	Primary Metals	138,245,466	532,819	4,600,001	4,108,279	8,708,280
3311	Iron and Steel Mills and Ferroalloy Mfg	44,896,062	130,296	1,842,656	2,345,134	4,187,790
3312	Steel Product Mfg from Purchased Steel	15,662,473	59,047	264,086	186,188	450,274
3313	Alumina and Aluminum Production and Processing	28,093,718	76,354	1,255,374	688,299	1,943,673
3314	Nonferrous (except aluminum) Production and Processing	21,617,836	67,779	450,394	354,693	805,087
3315	Foundries	27,975,357	199,343	787,492	533,966	1,321,458

Source: U.S. Census Bureau, Annual Survey of Manufacturers, 2001.

Table D3-12. Primary Metals Overview, Year 2001

14.9% of total shipments, while imports accounted for 40% of supply.[21] Aluminum is produced by processing mined bauxite, or aluminum oxide eventually through an electrochemical cell. Figure D3-60 is a basic flow diagram of the aluminum production process.

Global primary aluminum production has grown at 3.5% annually over the last five years[22] and demand for the product continues to rise as new applications are developed. The primary production of aluminum requires the availability of skilled labor, proximity to consumer markets, a highly developed infrastructure and, especially, low cost and reliable energy. Imported aluminum is the fastest growing source of U.S. supply and new primary aluminum facilities increasingly are being located outside of the United States, near sources of low-cost electricity. Aluminum remains one of the most energy-intensive materials to produce. Only paper, refining, steel, and petrochemical manufacturing consume more total energy in the United States than aluminum.

Aluminum production is the largest consumer of energy on a per-weight basis and is the largest electric energy consumer of all industries, spending approximately $1.9 billion annually on energy.[23] Figure D3-61 shows the energy expenditures of the aluminum manufacturing industry. The reduction of aluminum oxide (alumina) to aluminum represents about one-half of all energy consumption in the primary manufacturing of aluminum.[24] Electricity is nearly 92% of the energy used in primary aluminum production,[25] accounting

[21] Plunkert, "Aluminum," U.S. Geological Survey, 2002.

[22] Ibid.

[23] U.S. Census Bureau, Annual Survey of Manufacturers, "Statistics for Industry Groups and Industries: 2001."

[24] U.S. DOE Energy Information Administration, "Manufacturing Energy Consumption Survey for 1997," 2001.

[25] Ibid.

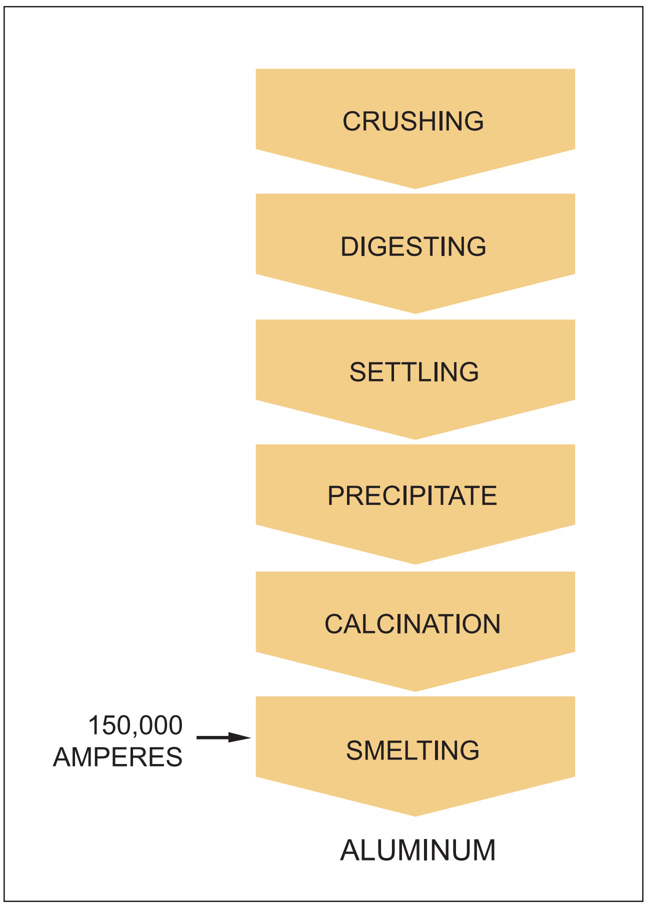


Figure D3-60. Flow Diagram of Aluminum Production Process

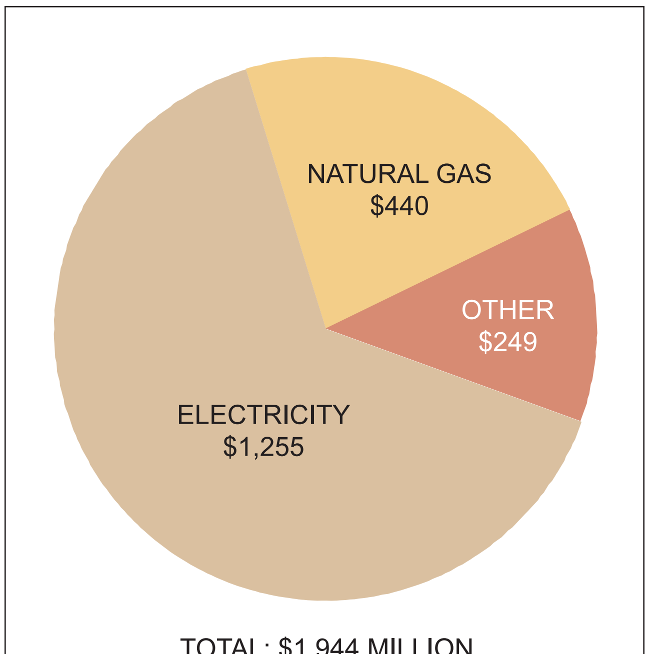


Figure D3-61. Energy Expenditures in 2001 (NAICS 3313 Alumina and Aluminum) (Millions of Dollars) for 28% of the cost of materials.[26] Recycled aluminum requires only about 6% of the energy needed for primary aluminum production. In 2002, more than 52% of the aluminum produced by U.S. industry came from recycled material; 40 years ago, recycled material was used to generate less than 18% of U.S.-produced aluminum.[27] Recycling is the largest contributor to the reduction of the energy intensity of aluminum produced in the United States.

Production variations of aluminum in the United States are more reflective of the costs to produce aluminum than of domestic demand. This factor makes energy efficiency and energy management prime industry objectives. The large electricity demands of the aluminum industry are relevant when assessing the environmental impact of production and the sensitivity of the industry to fluctuations in the electricity market. The U.S. primary aluminum industry has more than half of its capacity sited in regions where lower cost hydroelectric power is generated. Although the aluminum industry uses natural gas as energy input for various steps in the production process, the price fluctuations of natural gas have their largest impact in terms of the price of electricity. A key determinant of the industry's viability in the United States is access to low-cost, reliable energy and the development of energy-efficient production processes.

B. Iron and Steel

The United States is the largest steel producer in the world, producing 91.6 million tons of raw steel in 2002, nearly 10% of total world production.[28] The iron and steel industry (SIC 33 or NAICS 3311) provides about 1.1% of the total U.S. manufacturing shipments, employing more than 130,000 production workers in jobs paying 50% above the average for all U.S. manufacturing.[29] Steel is used in a diverse range of applications ranging from shipbuilding, national defense and construction, to food storage and transportation.

[26] U.S. Census Bureau, Annual Survey of Manufacturers, "Statistics for Industry Groups and Industries: 2001."

[27] Plunkert, "Aluminum," U.S. Geological Survey, 2002.

[28] Fenton, "Iron and Steel," U.S. Geological Survey, 2002.

[29] U.S. Census Bureau, Annual Survey of Manufacturers, "Statistics for Industry Groups and Industries: 2001."

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

Steel is primarily produced in the Great Lakes region; Ohio and Indiana currently are the largest producers in terms of value of shipments. Figure D3-62 shows the value of shipments for the top five producing states in the U.S.

Two processes are used for making steel in the United States. About 49.6% is made by integrated steel makers using the Basic Oxygen Furnace (BOF) process.[30] The BOF process is used to produce steel needed for packaging, car bodies, appliances, and steel

[30] Fenton, "Iron and Steel," U.S. Geological Survey, 2002.

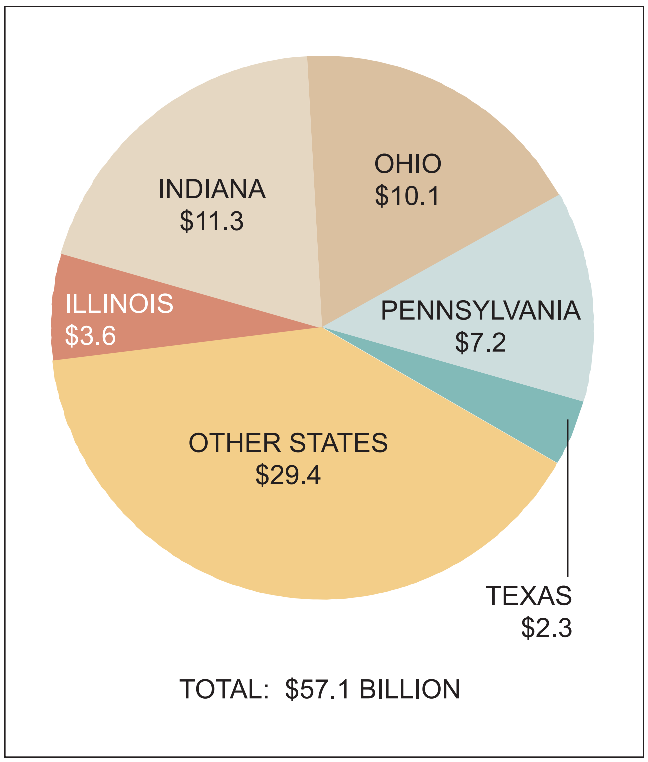


Figure D3-62. Value of Iron and Steel Shipments by State (NAICS 3311) (Billions of Dollars) framing; it uses about 70 to 80% of molten iron and 20 to 30% recycled scrap. The Electric Arc Furnace (EAF) process accounts for about 50.4% of raw steel production in the United States and is used to produce steel shapes such as railroad ties and bridge spans.[31] EAFs use electricity as the primary source of energy to melt charged materials, which typically consist of nearly 100% recycled steel or scrap. Figure D3-63 is a flow diagram of steel-making processes.[32]

The steel industry is highly energy-intensive. Energy costs account for 12 to 15% of the cost of manufacturing steel, on the order of $57 per ton.[33] The 2001 Annual Survey of Manufacturers reported that total steel industry energy expenditures were $4.2 billion.[34] Steel making requires energy both to supply heat and power for plant operations and as a raw material for the production of blast furnace coke. Its aggregated average energy consumption of about 18 MMBtu per ton of steel shipped represents approximately 2% of the energy consumed in the United States and over 10% of the energy use in the industrial sector.[35] [36]

Natural gas accounts for 27% of the steel's energy consumption, and electricity accounts an additional 10%. Coal, generally used to produce coke, accounts for 57% of the industry's energy procurement. Over the past 25 years, the iron and steel industry has invested nearly $8 billion in environmental control equipment. Through a combination of technological innovation and operating practice changes, the industry has reduced its process energy intensity by about 50% since 1975.[37] The industry's overall recycling rate is nearly 71%; over 63 million tons of scrap was recycled in 2002.[38] According to an EPA estimate, the energy savings associated with the use of recycled iron units, rather than processing iron ore, is equivalent to the annual electricity needed to power 18 million homes.

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

C. Gas Demand Projection for Primary Metals

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

Figure D3-64 shows the trends for the Reactive Path scenario in gas use for boilers, process heat, and other processes in primary metals. New cogeneration projects, classified as "other processes," contributed to increased gas use in the historical period. Gas use for process heat grew with production until 1996 when consumption began a long-term decline that continues throughout the forecast period. Gas use for boilers declined throughout the historical period, and is projected to decline through 2025 in both the Reactive Path and Balanced Future scenario. These declines in gas used by the steel industry reflect the shift from large, integrated mills to mini-mills, which are less energy-intensive and use electricity as the major source of energy. Significant improvements in energy efficiency and process changes continue to reduce the amount of gas used in the metals sectors.

Intense global competition also has made primary metals industries very aggressive about reducing costs such as for natural gas in heat treatment furnaces, where oxyfuel burners and electric thermal technologies can

[31] Ibid.

[32] American Iron and Steel Institute.

[33] U.S. DOE Energy Information Administration, "Iron and Steel Intensities," 2000.

[34] American Iron and Steel Institute.

[35] "Annual Energy Review 2002," U.S. DOE Energy Information Administration, 2003.

[36] U.S. DOE Energy Information Administration, "Iron and Steel Intensities," 2000.

[37] Ibid.

[38] Fenton, "Iron and Steel," U.S. Geological Survey, 2002.

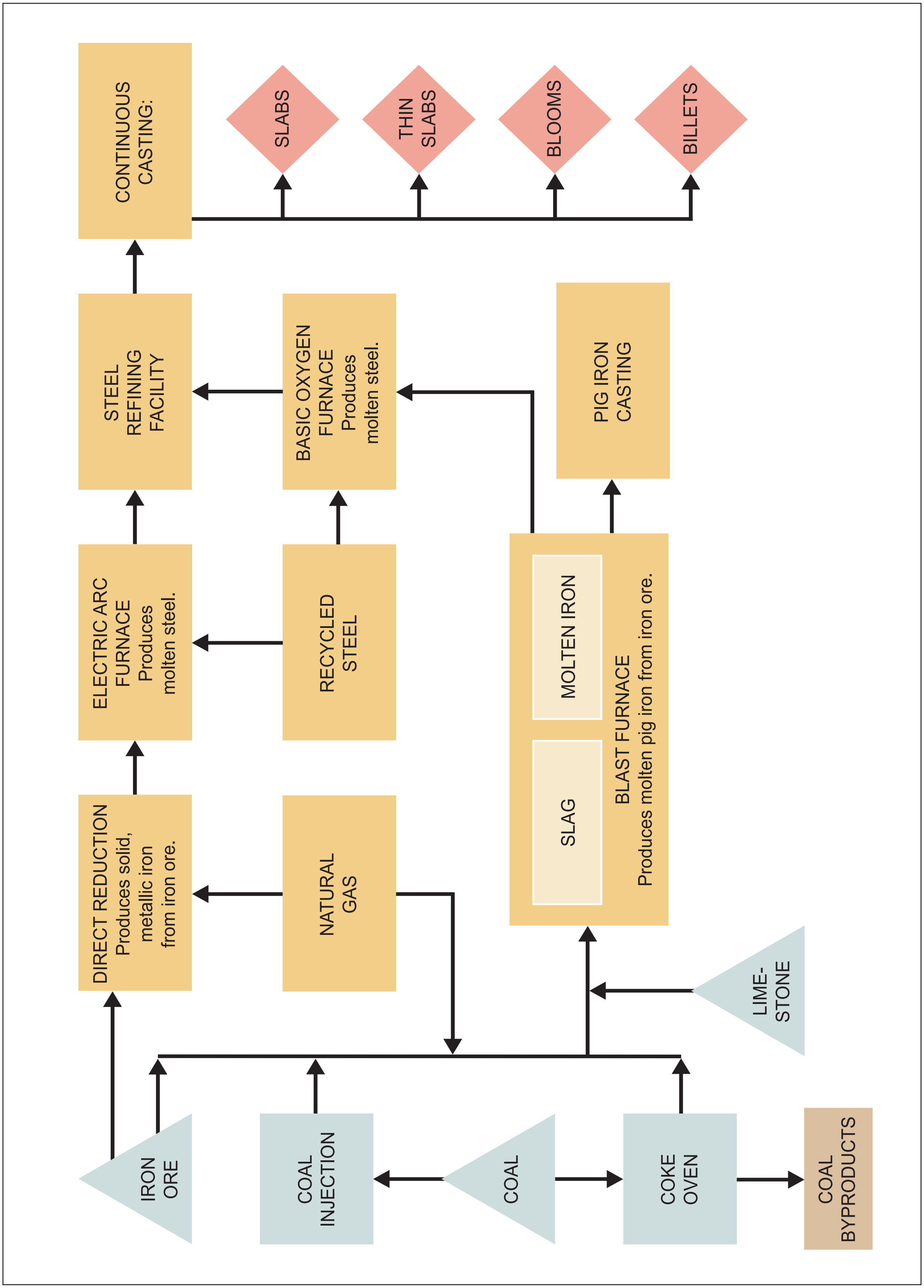


Figure D3-63. Diagram of Steel Making Process

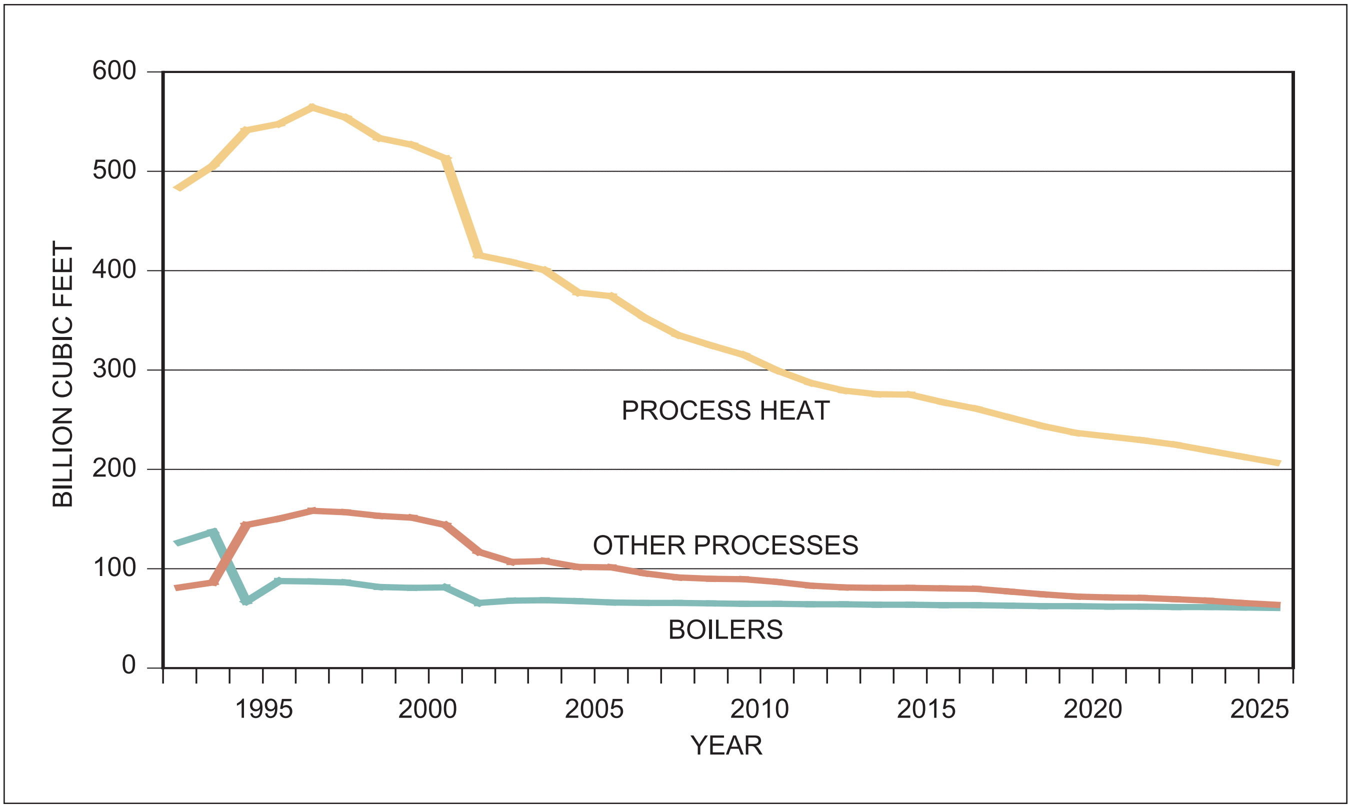


Figure D3-64. U.S. Primary Metals Gas Demand in Reactive Path Scenario

reduce or replace gas load. Global competition has had a strong negative effect on U.S. metals production, despite these advances by U.S. manufacturers.

In the period through 2025, as assessed by the Demand Task Group, gas consumption is projected in the Reactive Path scenario to decline 2.7% per year while production declines 0.2% per year. This outlook assumes trends toward more-efficient production technologies to continue, with most of the reductions in gas consumption coming from process heat applications.

Figure D3-65 shows the Balanced Future scenario for primary metals. The results are very similar to the Reactive Path scenario because the changes are due largely to industry trends rather than gas price issues.

VI. Paper

The U.S. paper industry produces pulp, paper, and paperboard products using fibers from timber or from recycled fibers. The industry produces a variety of pulp products (Kraft, mechanical, bleached, unbleached) to be used to manufacture different kinds of paper products (newsprint, printing and writing paper, tissue) and paperboard products (linerboard, corrugating material, and boxboards). About half of the industry's production is paper and the other half is paperboard. The paper industry is highly integrated, that is, pulp, paper, and paperboard production is usually performed within one mill. Table D3-13 summarizes the economic energy consumption characteristics of the paper industry.

The Converted Paper Product Manufacturing sub-industry accounts for the largest share of shipment value (54%) as well as the majority of the employees. The Paper Mills and Paperboard Mills sub-industries account for the largest share of energy expenditures. Altogether, these two industry subgroups account for 73%, 85%, and 80% of total electricity costs, fuel costs, and total energy costs, respectively.

Paper industry production has declined over the last 10 years (1993-2003), the greatest amount of which happened after 2000. The decline in production was driven by the decline in paper production, while paperboard production continued to grow after 2001, albeit very slowly.[39]

[39] Federal Reserve Board, *Industrial Production Index (time series)*, (various years).

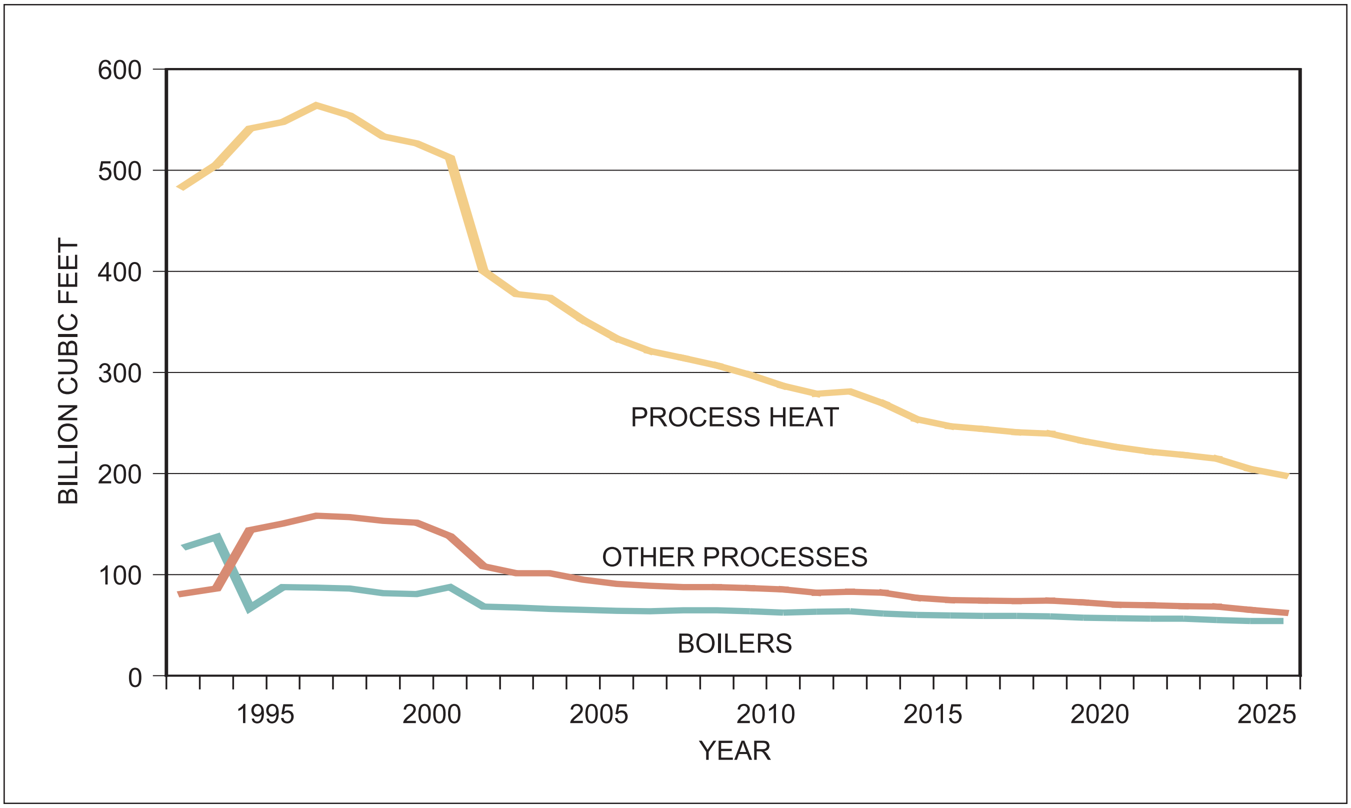


Figure D3-65. U.S. Primary Metals Gas Demand in Balanced Future Scenario

There are two main sources of fiber used to manufacture paper and paperboard products: wood pulp and recycled fiber. Wood pulp is the major source of fiber in the United States. The continued increase in the use of recycled paper has dampened the growth of wood pulp demand and production. Recent data show that U.S. recovery rate of recycled paper is close to 50%, which is much higher than the recovery rate over 10 years ago at 38%.[40]

[40] U.S. International Trade Commission, *Industry & Trade Summary, Wood Pulp and Waste Paper,* February 2002.

NAICS	Industry Name	Value of Shipments ($1,000)	Number of Employ-ees	Cost of Purchased Electricity ($1,000)	Cost of Purchased Fuels ($1,000)	Total Cost of Electricity and Fuels ($1,000)
322	Paper Manufacturing	155,846,001	530,245	3,181,003	4,133,060	7,314,063
3221	Pulp, Paper & Paperboard Mills	71,987,278	170,661	2,418,476	3,683,574	6,102,050
32211	Pulp Mills	3,238,832	7,218	81,083	166,641	247,724
32212	Paper Mills	46,852,538	114,670	1,441,777	2,025,320	3,467,097
32213	Paperboard Mills	21,895,908	48,773	895,616	1,491,613	2,387,229
3222	Converted Paper Product Mfg	83,858,722	359,584	762,527	449,486	1,212,013

Source: U.S. Census Bureau, Annual Survey of Manufacturers, 2001.

Table D3-13. Characteristics of the Paper Industry, Year 2001

The production of wood pulp, which basically involves the conversion of wood to pulp, is a highly steam- and electric-intensive operation. Wood pulp can be either produced mechanically or chemically. The mechanical pulping process has high yields but produces lower quality products. The chemical pulping process, which is dominated by the Kraft pulping process, has lower yields but produces high quality products. Mechanical pulps are commonly used for newsprint and some printing and writing paper. Chemical pulps are used for most of the printing and writing paper, tissue, and paperboard products.

Because wood is the primary raw material and cost factor of this industry, paper, pulp, and paperboard mills are usually located near their wood source. The preference towards the use of southern pine has resulted in the dominance of the South Atlantic region in wood pulp, paper, and paperboard production.[41]

Most of the paper industry's energy consumption (85%) is to generate steam for pulp making and paper and paperboard drying, pressing, forming, and bleaching. Black liquor, which is a byproduct of the chemical pulping process, and other wood wastes are the primary sources of boiler fuel. They account for two-thirds of total fuel consumption for steam production. Natural gas is the primary purchased fuel choice, followed by coal and fuel oil.[42]

The paper industry is a major user of cogeneration. Electricity generated on-site satisfies about 63% of the industry's electricity demand. The presence of byproduct fuels, and an optimal steam and electricity demand ratio, drove the industry to install cogeneration equipment, most of which are steam turbines.

In 1998, natural gas consumption in the industry was 622 BCF. Natural gas is primarily used for steam generation through boilers and cogeneration equipment. Eighty-seven percent of natural gas consumed in this industry is for this end-use.[43]

Although it enjoyed tremendous growth during the 1990s, U.S. paper production has declined since 1999. And, overall, the U.S. paper industry experienced a decline in production from 1993 to 2003.[44] For the future period assessed by the NPC study group, the paper industry is assumed to have no net growth, as measured by IP. In the projection, gas consumption in the paper industry is expected to decline due to the flat industrial output and increased fuel flexibility and switching.

VII. Non-Metallic Products (Stone, Clay, and Glass)

The Non-Metallic Product Industry (NAICS Code 327) has commonly been referred to as "stone, clay, and glass" and consists of five sub-industries:

- Lime and gypsum
- Clay product and refractory products
- Glass and glass products
- Cement and concrete
- Other nonmetallic mineral products.

These industries produce cut stone products, and clay products including bricks, glass, concrete, gypsum, and lime. They employ 508,000 people and generate about $100 billion in output per year to produce the cement, bricks, and glass products used in homes and infrastructure of the country as well as the containers for many food and consumer products; output is measured in terms of value of shipments. Unlike some sectors, these industries do not compete to a great extent with imports or export and production is often located within the same region as the target market. This is a consequence of their products being heavy, with a low price to weight ratio, thereby making transportation costs prohibitive for long-distance shipping. The highest concentration of energy use for stone, clay, and glass industries is in the East North Central and Middle Atlantic regions, where 36% of this segment's energy is consumed. After mined materials, energy is one of the most important inputs in production.

This industry group is relatively gas-intensive, and was chosen by the Demand Task Group and EEA to separately analyze for its energy consumption. Table D3-14

[41] Ibid.

[42] Energy and Environmental Analysis, Inc., *Industrial Baseyear Database.*

[43] Ibid.

[44] Federal Reserve Board, *Industrial Production Index (time series),* (various years).

provides an overview of the sector's economic activity and energy consumption in 2001.

In terms of shipments and employment, the largest segment of the Non-Metallic Product Industry is cement manufacturing. The cement industry accounts for 46% of total shipments (in dollars) and 44% of total employment. Glass manufacturing is the second largest segment of the industry.

Over the last 10 years (1993-2003), the stone, clay, and glass industries grew annually by 1.9%.[45] This is the fastest growth rate among the energy-intensive industries assessed by the Demand Task Group. This growth was supported by the growth of glass production (1.4% per year), and cement production (3.4% per year). The growth in residential and public works construction drove the growth in demand for these materials. In both the Reactive Path and Balanced Future scenarios, a growth rate of 2.8% per year was assumed, based in part on the outlook expressed by industry participants in various outreach discussions of the Demand Task Group.

Among the industries within this sector, the cement industry has the highest overall energy expenditures, due to the highest electricity cost and the second largest overall fuel cost (a part of which is natural gas costs). Glass manufacturing has the highest overall fuel cost and second highest electricity costs; glass manufacturing is second in total energy costs. The glass industry is also the larger user of natural gas.

Gas consumption in the stone, clay, and glass industries is mostly used in glass production (155 BCF), followed by brick (47 BCF), gypsum (42 BCF), and then cement (26 BCF). This is shown in Figure D3-66. Gas use in the industry is projected to grow at a moderate pace of 0.8% annually in both the Reactive Path and Balanced Future scenarios. The Demand Task Group assumed that slower growth of gas consumption is likely due to only a moderate growth in glass production, improved efficiencies, and fuel switching from gas to other fuels such as fuel oil, coal, and waste fuels.

A. Lime and Gypsum

Lime is a basic chemical usually used in the form of quicklime. The largest user of lime is the iron and steel industry, which accounts for 34% of total lime consumption in the U.S.[46] Other major markets for lime include environmental treatment applications (flue gas desulfurization, sludge treatment, and water treatment), construction, chemical manufacturing, and

[45] Federal Reserve Board, *Industrial Production Index (time series)*, (various years).

[46] U.S. Geological Survey, *Lime in the United States, 1950-2001*, November 2002.

NAICS	Industry Name	Value of Shipments ($1,000)	Number of Employees	Cost of Purchased Electricity ($1,000)	Cost of Purchased Fuels ($1,000)	Total Cost of Electricity and Fuels ($1,000)
327	Total Non Metallic Mineral Product Mfg	94,860,574	507,308	2,028,728	2,952,623	4,981,351
3271	Clay Product & Refractory Mfg	3,713,853	35,026	178,008	376,616	554,624
3272	Glass & Glass Product Mfg	22,914,238	122,504	574,680	848,883	1,423,563
3273	Cement & Concrete Product Mfg	43,851,552	222,337	773,614	828,217	1,601,831
3274	Lime & Gypsum Mfg	5,055,106	18,645	157,021	525,728	682,749
3279	Other Nonmetallic Mineral Product Mfg	14,254,028	74,211	300,081	347,154	647,235

Source: U.S. Census Bureau, Annual Survey of Manufacturers, 2001.

Table D3-14. Stone, Clay, and Glass Sector Overview, Year 2001

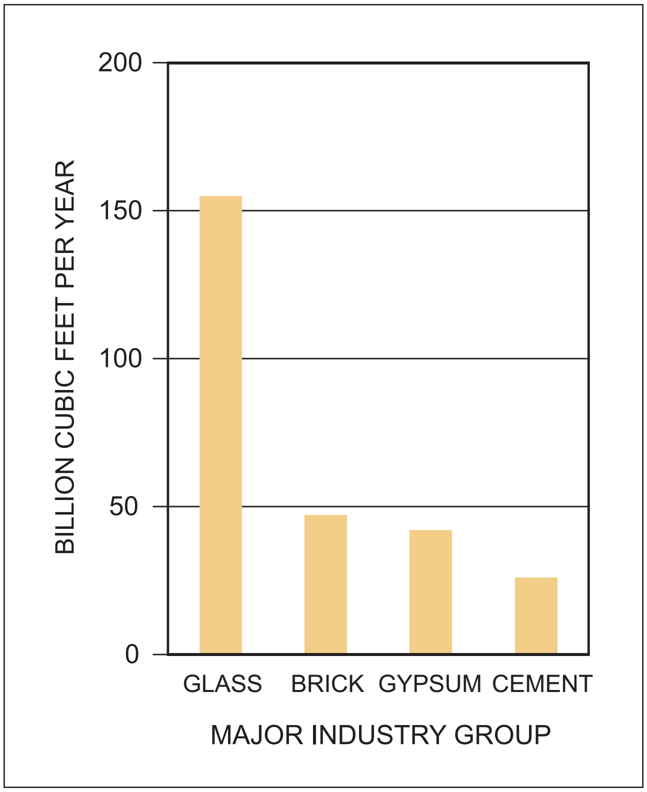


Figure D3-66. 2001 Natural Gas Consumption for Major Stone, Clay, and Glass Industries

other industries. Lime is produced by the calcination of limestone at very high temperatures. The most prevalent type of kiln used in the United States is the rotary kiln, although other types of kilns (such as vertical kilns, rotary hearths, and fluidized bed kilns) are also used. Like the cement industry, lime kilns are mostly fired with coal, due to its lower cost. Lime manufacturers requiring higher product quality use either natural gas or distillate fuel oil. The primary lime-producing states are Missouri, Alabama, Kentucky, Ohio, Texas, and Pennsylvania.

Gypsum is a white or gray naturally occurring mineral. It is processed into a variety of products for use as an additive in cement production, as a soil conditioner, or as raw material in manufacturing plasters and wallboard. To produce plasters and wallboard, gypsum is calcined at high temperatures. In the United States, the most common calciners are kettle calciners and flash calciners. Most gypsum calciners use natural gas or distillate oil as their primary fuel.[47]

[47] Energy and Environmental Analysis, Inc., *Industrial Process Heat Energy Analysis* (prepared for GTI, formerly GRI), September 1996.

B. Clay Product and Refractory Products

The clay product and refractory industry consists of brick and structural clay tile, ceramic wall and floor tile, other structural clay products, and refractory industries. Brick and structural clay manufacturing consumes the largest amount of energy within this industry group. In 2001, the brick and structural clay industry shipped $1.8 billion dollars worth of products and employed over 13,500 employees. The production of bricks and other structural clay products involves several steps including grinding, screening, and mixing of raw materials, followed by forming, drying, firing, and cooling. Firing and drying are the most energy-intensive steps. After forming, bricks and other similar products are dried at lower temperatures and are then fired using kilns. The most commonly used kiln is the tunnel kiln, which is most commonly fired with natural gas and coal. Fuel oil is usually employed as a backup fuel.

C. Other Nonmetallic Mineral Products

The other nonmetallic mineral product industry consists mainly of the stone product manufacturers, ground and treated mineral and earth producers, and mineral wool manufacturers. The mineral wool industry is the primary energy consumer within this industry group, accounting for over half of the energy consumption. Mineral wool is defined as any fibrous glassy product made from minerals. It is primarily used for insulation and as raw material for other construction materials such as ceiling tiles, wall boards, cement, and mortar. The most energy-intensive steps in the production of mineral wool are melting and curing. Melters are usually fired with coke, although natural gas and electricity melters are also used. The curing process is most commonly fired with natural gas.

D. Glass Industry

Glass is used in a variety of consumer and industrial products because of its low cost, structural value, transparency, and stability. The glass industry consists of the following sub-industries:

- Flat glass
- Other pressed and blown glass and glassware
- Glass containers
- Glass products made from purchased glass.

The first three sub-sectors comprise the actual production of glass from raw materials. Glass production is a highly energy-intensive process that is largely based on the use of natural gas. Table D3-15 summarizes the characteristics of the glass industry.

The flat glass industry manufactures glass windows, automobile windshields, and picture glass. This industry is the smallest segment of the glass industry, with shipments accounting for only 12% and employment accounting for only 9% of the entire glass industry. However, the flat glass industry experiences the second highest fuel expenditures among glass industries.

The pressed and blown glass industry manufactures table and ovenware, flat panel display glass, light bulbs, television tubes, and scientific and medical glassware. This industry has the second highest electricity costs. It also has the second highest total energy costs.

The container glass industry manufactures glass bottles, jars, and other packaging containers. It experiences the highest electricity, fuel, and total energy expenditures.

The "glass product from purchased glass" industry primarily assembles purchased intermediate glass products to manufactured products such as table tops, mirrors, art glass, aquariums, etc. This is the largest segment of the glass industry, accounting for 47% of total glass industry shipment value and over half of its employment. However, it is the smallest energy user because it is primarily an assembly industry, rather than a producer of glass. Its value of shipments is high because it produces finished products, which have a higher value than the intermediate products such as window glass or bottles produced in the other sub-industries. Energy expenditures in the glass industry account for about 7% of total manufacturing cost (sum of new capital, employment, raw materials, energy).

In 2002, the United States produced 248.5 million gross of glass containers.[48] Over half of the glass containers (53%) produced in the country are for beer, making it the largest market for glass containers. Food containers account for the second largest market share, at 20%. Other beverage containers account for the third largest market share, at 9%. The rest of the market consists of containers for liquor, ready-to-drink alcoholic drinks, wine, and household, industrial, and chemical products. Approximately 12% of the U.S. apparent consumption of container glass is imported.

In 2002, the glassware industry had total factory shipments of $4.6 billion.[49] The main markets for glassware are table and kitchenware, lighting and electronic glassware and other industrial and consumer glassware. U.S. imports of glassware are significant.

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[48] U.S. Census Bureau, *Current Industrial Reports* (various issues).

[49] Ibid.

NAICS	Industry Name	Value of Shipments ($1,000)	Number of Employees	Cost of Purchased Electricity ($1,000)	Cost of Purchased Fuels ($1,000)	Total Cost of Electricity and Fuels ($1,000)
3272	Glass & Glass Product Mfg	22,914,238	122,504	574,680	848,883	1,423,563
327211	Flat Glass Mfg	2,674,436	11,044	79,305	225,428	304,733
327212	Other Pressed & Blown & Glassware	5,169,452	33,379	164,232	224,068	388,300
327213	Glass Container	4,206,423	15,580	174,639	342,280	516,919
327215	Glass Product from Purchased Glass	10,863,926	62,501	156,505	57,107	213,612

Source: U.S. Census Bureau, Annual Survey of Manufacturers, 2001.

Table D3-15. Glass Industry Overview, Year 2001

For example, almost half of U.S. apparent consumption of table, kitchen, art and novelty glassware is imported. Also, 63% of lamp chimneys, bowls, shades, globes, and other similar glassware is imported.

In 2002, 6.3 billion square feet of flat glass were produced in the United States.[50] The construction industry accounts for more than half of the flat glass shipments. The car industry accounts for about 25% and other markets account for the rest. U.S. import reliance on flat glass is about 10%.

The process of making glass is generally consistent, regardless of the type of glass. Glass product manufacturing begins with batch preparation, when raw materials are blended. After batch preparation is glass melting and refining, which is the most energy-intensive step in glass making. It accounts for 60 to 70% of total energy consumption in glass manufacturing.[51] Melting requires different types of furnaces, depending on the product type and quality. Refining or fining occurs in the melting chamber to remove bubbles, homogenize the glass, and heat condition the glass for forming. The final steps are glass forming and post-forming, as shown in Figure D3-67.

Although the process of making glass is generally the same throughout the industry, the melters used are varied, depending on the production volume and type of product. There are two major categories of melters: discontinuous and continuous. Discontinuous furnaces are usually employed for small jobs (less than 5 tons per day). Continuous furnaces found in large operations dominate the industry.

Continuous furnaces can be fired with fossil fuels (mostly natural gas), electricity, or both. There are different types of continuous melters:

- *Unit melters* are used for relatively small continuous jobs of 20-150 tons per day. These are usually natural gas-fired.

- *Recuperative furnaces* are unit melters with recuperators to recover heat from exhaust gases. These are usually gas- or oil-fired, although some are equipped with electric boosters.

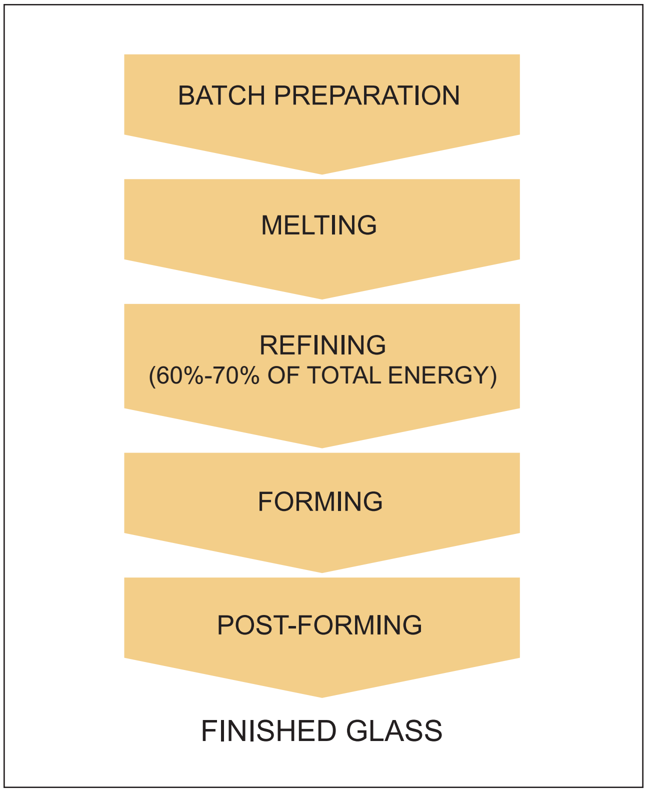

Figure D3-67. Major Steps in Glass Manufacturing

- *Regenerative furnaces* are the most common in the industry, accounting for about 42% of furnace population. These are much larger in capacities, reaching 1,000 tons per day. These are typically fired solely with natural gas, or employ gas with electric boost.

- *Electric melters* are typically used in pressed and blown glass production, but have also been used for other glass products.

Several developments have occurred over the last several decades to increase productivity, energy efficiency, and environmental performance of glass melters. These include electric boosting, oxy-fuel firing, preheating of batch, and oxygen-enriched air staging. Recent increases in gas price present a challenge for manufacturers with limited options to fuel switch because the obvious alternatives (propane and distillate oil) may have little long-run cost advantage.

Flat glass manufacturers use almost solely regenerative furnaces. Container glass manufacturers also use mostly regenerative furnaces, although some electric melters are also used. Unit melters and electric melters dominate pressed and blown glass production.

[50] Ibid.

[51] Energetics, *Energy and Environmental Profile of the U.S. Glass Industry* (prepared for U.S. DOE), April 2002.

Natural gas is the primary fuel used in glass melters. Regardless of the fuel, glass melters require very high reliability. If the supply is interrupted, the melted glass will solidify and the melter will have to be completely rebuilt. Fuel oil (distillate fuel oil) is used as a back-up fuel for gas. Electricity is used for batch preparation and electric melters.

From an environmental impact perspective, nitrogen oxide emissions have been the recent focus of environmental regulations affecting glass melter operations. To control NOx emissions, the industry has increased the use of oxy-fuel firing, which can reduce NOx emissions by about 70%.[52]

Recycling is also an important consideration in the glass industry. Recycling of glass containers is estimated at 35%.[53] Flat glass recycling is within a 10-40% range. The use of recycled glass reduces processing and raw material costs, lowers energy use and costs, and reduces landfill waste.

E. Cement Industry

Cement is a powder used as a binding agent in concrete and mortar. There are several different types of cement, and portland cement is the major product in this industry, accounting for about 95% of total cement produced in the U.S. Portland cement consists mainly of fused powder called clinker, and the production of clinker through fuel-fired kilns is one of the most energy-intensive processes in the entire industrial sector. It also has the largest energy cost share (share of total manufacturing cost) among all industries in the U.S. industrial sector. Energy expenditures in cement production account for about 25% of total cost (sum of new capital, employment, materials, and energy costs).

In 2003, U.S. production of portland and masonry cement reached 91 million metric tons.[54] Since 1999, annual production has increased by 2%. This is largely due to the continued growth in construction activities, which is the primary driver of cement demand.

In 2003, U.S. production of clinker, the main ingredient of cement, was 82 million metric tons.[55] This reflects an 8% increase in production from 1999. Clinker was produced at 109 plants, with a combined annual capacity of about 101 million tons. A majority of clinker production is situated in California, Texas, Pennsylvania, Michigan, Missouri, and Alabama. These states accounted for almost half of total U.S. clinker capacity and 40% of total U.S. clinker production.

Cement manufacturing capacity in the United States has been responsive to international competition since the early 1990s. While U.S. use of imported cement grew to 25% in 1999, net imports subsequently dropped to about 20% in 2003, with the main sources of U.S. cement imports being Canada, Thailand, China, Venezuela, and Greece. From 2003 to 2005, the cement industry plans to add another 23 million tons of capacity, or 27% of the capacity in 2003.[56]

As shown in Figure D3-68, about 75% of cement is sold to ready-mix concrete producers, 13% to concrete product manufacturers, 6% to contractors (mainly road paving), 3% to building materials dealers, and 3% to other customers.

Clinker production involves the high-temperature heating of a raw material mixture followed by rapid air cooling. The production of cement clinker can be categorized into two main categories: wet process or dry process. In the wet process, longer kilns are required to evaporate the water off the wet raw material mixture, thus requiring substantial amounts of fuel. In the dry process, the raw materials are kept dry so the evaporation section is eliminated. In addition, new versions of the dry process have been developed, such as those with preheaters and precalciners, further improving process energy efficiency. The use of the wet process has been declining over the last several years because of its relatively higher energy requirements. In 2002 (latest data), the wet process accounted for about 18% of total clinker production, which is substantially lower than its share in 1994, which was 27%. The dry process has been replacing the wet process during this period, and in 2002 it accounted for 78% of total clinker production. Four percent of clinker production in 2002

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[52] Ibid.

[53] Ibid.

[54] U.S. Geological Survey, *Mineral Commodity Summaries* (various years).

[55] Ibid.

[56] U.S. Geological Survey, *Minerals Yearbook* (various years).

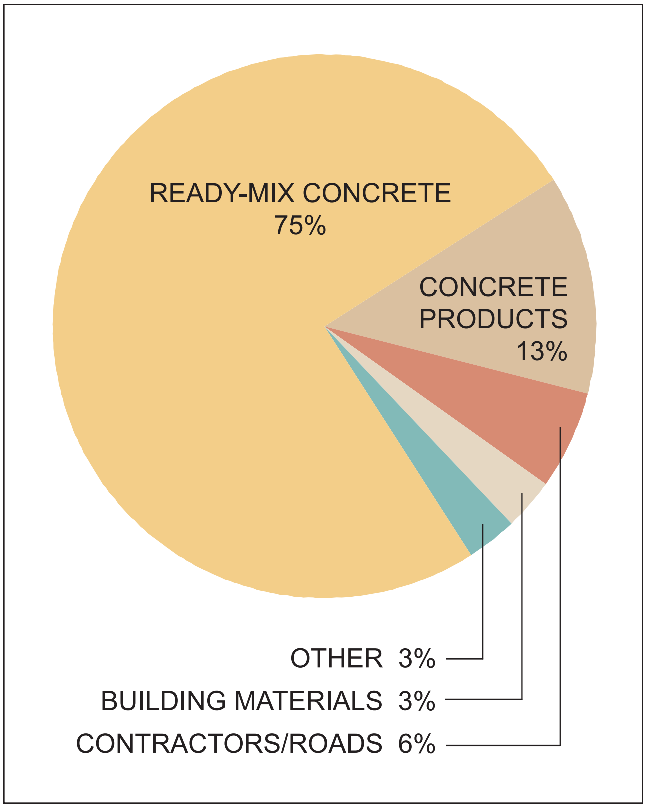

Figure D3-68. Uses of Concrete

was produced by plants with both wet and dry processes.[57]

There is a substantial amount of fuel flexibility in kilns because the fuel quality has little effect on the product. Coal, typically the most inexpensive fossil fuel on a $/MMBtu basis, dominates fuel use in kilns. In 2002, coal accounted for 65% of total fuel consumption. Coke and petroleum coke accounted for over 17%, waste fuels (tires, solid and liquid wastes) accounted for 12%, natural gas accounted for 5%, and fuel oil accounted for 1%.[58] Natural gas and fuel oil are used primarily for kiln warm-up. There has been a steady increase in waste fuel consumption in kilns since the early 1990s since these fuels are free or inexpensive, and the high temperature conditions of the kiln make for good incineration of wastes.

There has been some switching from coal to natural gas for kilns in recent years due to responses to environmental requirements in some regions, such as California. In 2000 and 2001, with the advent of higher natural gas prices, the consumption of natural gas in kilns declined to its lowest level since the early 1990s. Much of the natural gas use was switched to coal, reflected by the increased use of coal in kilns during that period.

The cement industry is one of the major sources of carbon dioxide (CO_2), criteria air pollutants (nitrogen oxides, sulfur dioxide, particulates, volatile organic compounds), and toxic chemicals. The emissions of CO_2, criteria pollutants and toxic materials are largely due to the increased use of waste fuels and petroleum coke. Despite the increased penetration of the more efficient dry process and the installation of more efficient kilns and processes, overall energy intensity (Btu used per ton of clinker produced) in the industry has been relatively level since the 1990s, and some studies show increasing energy intensity.[59] One of the reasons is the increased use of alternative fuels such as waste fuels and petroleum coke, which are not as efficient as coal, natural gas, and fuel oil.

F. Demand Outlook for Stone, Clay, and Glass

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

Production in the stone, clay, and glass industry is projected by the Demand Task Group to grow about 1.1% per year in the long-term, although incremental energy efficiency improvements will hold the growth in energy consumption to about 0.6% per year. The Demand Task Group assumed that natural gas consumption will grow at a slower rate than overall energy consumption, about 0.5% per year.

Figure D3-69 shows the projection of major natural gas uses in the Reactive Path scenario for stone, clay, and glass industries. Figure D3-70 provides a similar

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57 Ibid.

58 Ibid.

59 Jacott, Marisa, et al., *Energy Use in the Cement Industry in North America: Emissions, Waste Generation and Pollution Control, 1990-2001* (prepared for Commission for Environmental Cooperation), May 30, 2003.

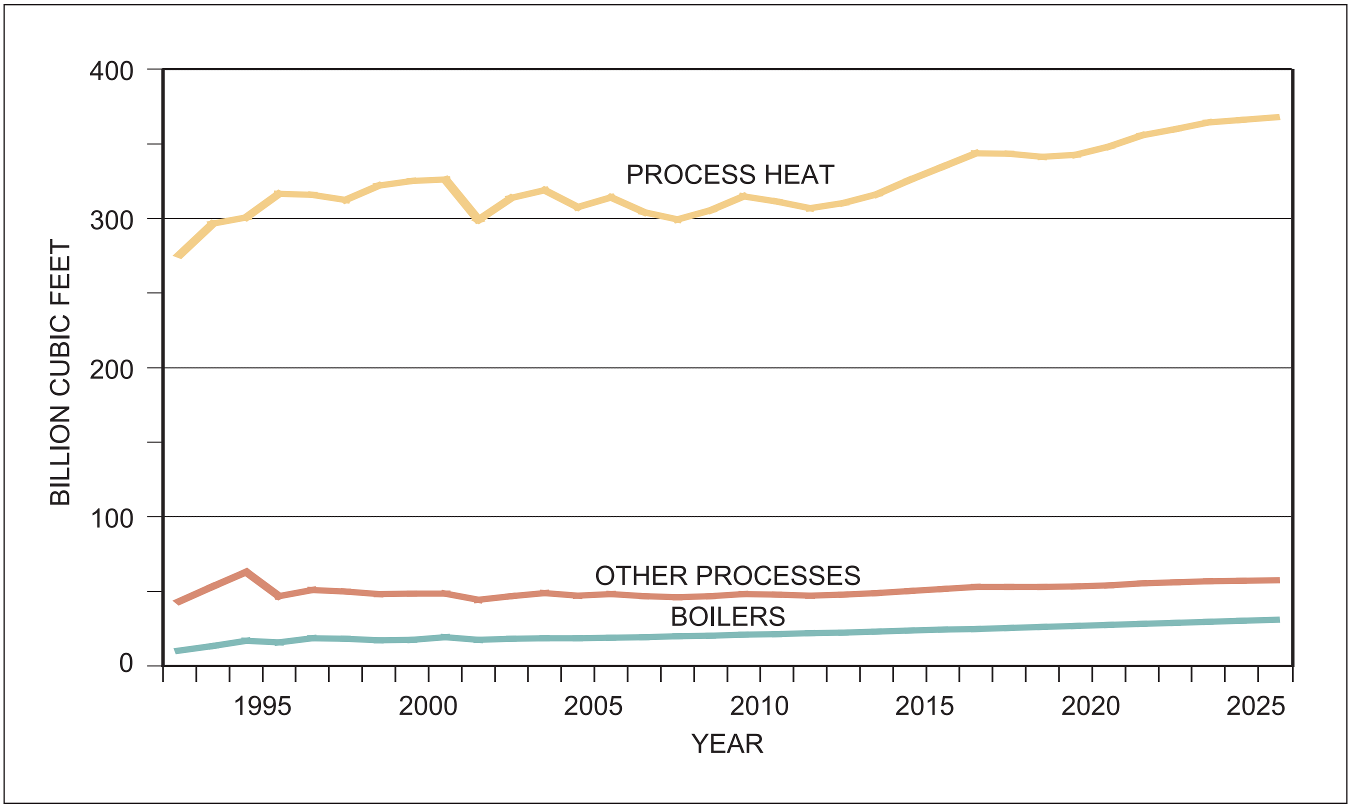

Figure D3-69. Stone, Clay, and Glass Gas Demand in Reactive Path Scenario

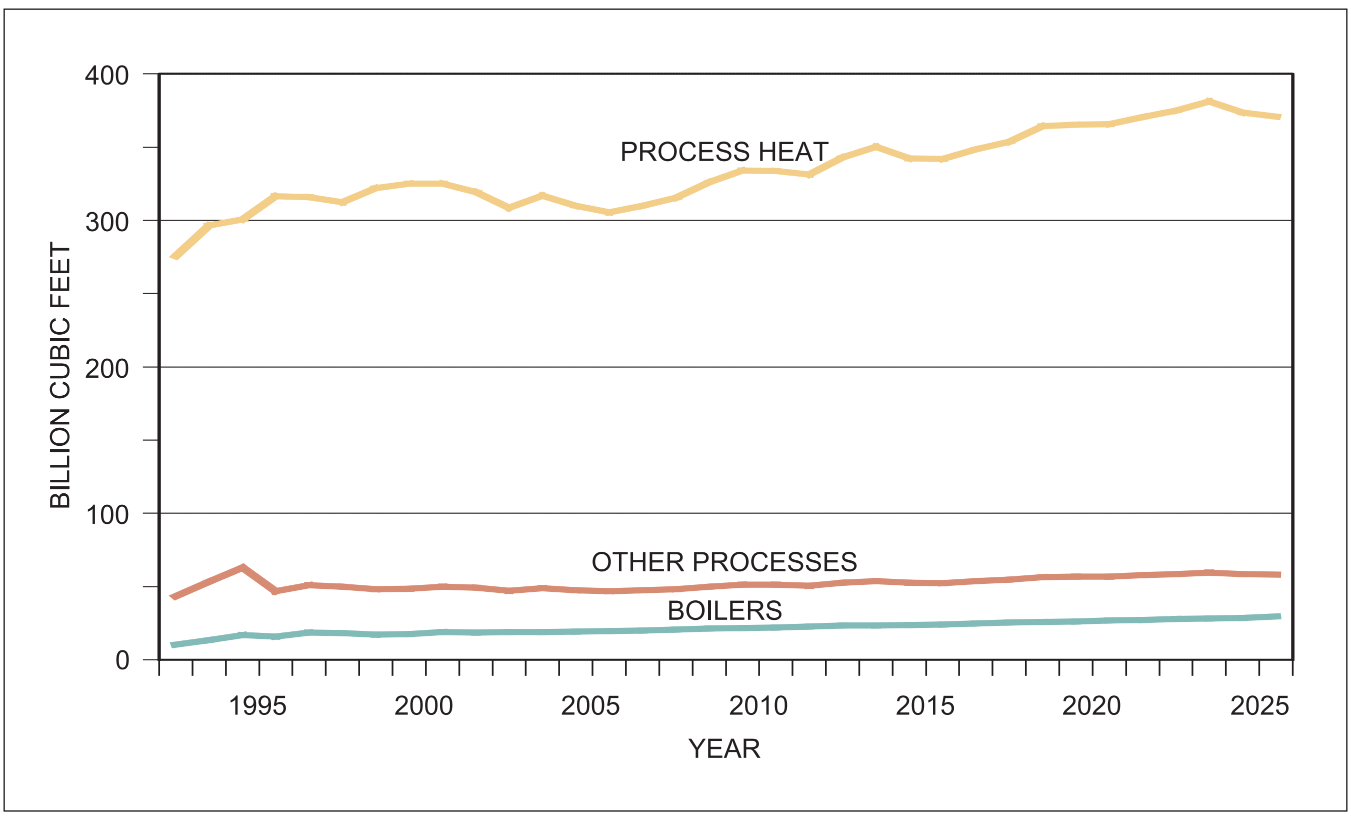

Figure D3-70. Stone, Clay, and Glass Gas Demand in Balanced Future Scenario projection for the Balanced Future scenario; lower gas prices in this scenario would likely increase the utilization of natural gas in process heat applications relative to the Reactive Path. The projections of the Balanced Future scenario incorporate the effects of increased fuel flexibility.

VIII. Food and Beverage

The food and beverage sector includes a wide variety of retail and industrial scale processors and preparers of food and food products. Table D3-16 summarizes the characteristics of these segments.

The table shows that the largest sub-industry is Meat Product Manufacturing (NAICS 3116), accounting for 24% of the Food and Beverage industry's total value of shipments. This industry is also the largest employer, with 30% of total employment in the Food and Beverage industry. It also has the largest electricity cost at $801 million in 2001.

The sub-industry with the largest energy expenditures is the Grain and Oilseed Milling industry. This industry accounted for 20% of total energy expenditures in the Food Manufacturing industry. Sixty percent of the sub-industry's energy cost is for fuels, making it the sub-industry with the largest fuels expenditures. Other sub-industries with large energy expenditures are Fruit and Vegetable Preserving and Meat Product Manufacturing.

The food processing industry in the state of California accounts for the largest share of food shipments in the country. In 2001, California accounted for 10% of total food industry shipments in the United States. Illinois and Texas account for the second and third largest representation of the industry, respectively.[60]

The food industry consumed 1.2 quadrillion Btu of energy in 1998. Fifty-four percent of this consumption was natural gas. Coal accounts for 19% of total energy consumption, while electricity accounts for another 19%. The rest of the fuels include fuel oil and biomass.[61]

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[60] U.S. Census Bureau, Annual Survey of Manufacturers, 2001.

[61] Energy and Environmental Analysis, Inc., *Industrial Baseyear Database.*

NAICS	Industry Name	Value of Shipments ($1,000)	Number of Employ-ees	Cost of Purchased Electricity ($1,000)	Cost of Purchased Fuels ($1,000)	Total Cost of Electricity and Fuels ($1,000)
311	Food Manufacturing	451,385,857	1,504,666	3,707,110	4,407,034	8,114,144
3111	Animal Food Mfg	26,724,933	49,549	244,521	184,054	428,575
3112	Grain and Oilseed Milling	46,176,372	55,434	644,915	969,507	1,614,422
3113	Sugar and Confectionery	25,515,879	84,755	198,258	285,261	483,519
3114	Fruit and Vegetable Preserving	52,262,484	176,783	568,590	949,370	1,517,960
3115	Dairy Product Mfg	65,512,415	132,151	456,200	357,675	813,875
3116	Meat Product Mfg	125,411,008	493,369	801,400	615,140	1,416,540
3117	Seafood Product Preparation	8,831,938	41,319	68,599	80,120	148,719
3118	Bakeries and Tortilla Mfg	49,132,718	323,326	404,997	329,498	734,495
3119	Other Food Mfg	51,818,110	147,979	319,630	276,409	596,039
3121	Beverage Mfg	65,687,655	150,807	410,548	322,909	733,457

Source: U.S. Census Bureau, Annual Survey of Manufacturers, 2001.

Table D3-16. Characteristics of the Food and Beverage Industry, Year 2001

Energy is a small portion of total production costs (includes new capital, labor, materials, and energy) with only 2% of total production cost. Raw materials account for the bulk of production cost at over 80%. Thus, food processing industries locate near raw materials supply.

The food industry uses substantial amounts of steam and hot water. As such, 53% of energy consumed in the food industry is used for steam generation using boilers and cogeneration. Because of its cleanliness, natural gas is the primary fuel for steam production. It accounts for 53% of fuel consumption for steam generation. Coal, which is mostly used in large operations such as grain mills, breweries, and sugar mills, is the second most commonly used fuel, accounting for 35% of total fuel use for steam.[62]

About 22% of total energy consumed is used for process heat applications such as baking, drying, and cooking. Again, because of its clean quality, natural gas dominates this end-use, accounting for 96% of total process heat energy use.[63]

Each of the food sub-industries is discussed below. Because the animal food manufacturing and seafood preparation industries have either low shipments value and/or low energy expenditures, they are not included in the discussion.[64] [65] [66]

A. Grain and Oilseed Milling

This industry consists of establishments that involve flour milling and malt manufacture, starch and vegetable fats and oil production, and breakfast cereal manufacturing.

The two industries with the largest energy consumption are wet corn milling and soybean processing. The wet corn milling industry consists of establishments that produce various corn products such as sweeteners, high fructose corn syrup, starch, oil, and gluten. This industry does not include producers of ethanol whose primary product is ethanol. Nevertheless it includes mills that produce mainly corn-based food products but also produce ethanol within the same mill. Iowa, Indiana, and Illinois are the principal producing states of these products. In 2001, this industry employed over 8,600 workers and shipped $7.6 billion worth of products.

Wet corn milling is a highly steam intensive industry. Two-thirds of the industry's energy consumption is for steam generation. Natural gas and coal are the primary boiler fuels. Some byproduct fuels are also burned in the boilers to cut down on fuel purchases.

The soybean processing industry consists of establishments that produce various soybean products such as soybean oil, flour, and soybean cake. Illinois, Iowa, Indiana, and Minnesota are the primary producing states of soybean products. In 2001, this industry shipped $11 billion worth of products and employed 6,600 workers.

Like wet corn milling, soybean processing also uses substantial amounts of steam. Soybean boilers are usually fired with natural gas.

B. Fruit and Vegetable Preserving

This industry includes establishments that produce frozen food and juice, and canned, pickled, and dried fruits and vegetables. California, Florida, and New York are the primary producing states for this industry.

The fruit and vegetable canning, pickling, and drying segment of this industry is the largest segment in terms of shipments and energy consumption. Energy expenditures in the fruit and vegetable canning, pickling, and drying industry account for 72% of total energy expenditures in the fruit and vegetable preserving industry.

The production of canned fruit and vegetables involves significant amounts of steam and hot water for pasteurization, sterilization, cooking, and blanching. About 80% of energy consumption in this industry is for steam and hot water production. Natural gas is the fuel of choice for boilers because of its cleanliness.

C. Meat Product Manufacturing

This industry includes establishments that are engaged in animal slaughtering, meat processing and

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[62] Ibid.

[63] Ibid.

[64] F. T. Sparrow and Associates, *Industrial Electrification: Technology & Economics,* June 1995.

[65] U.S. Census Bureau, Annual Survey of Manufacturers, 2001.

[66] U.S. Census Bureau, Census of Manufacturers, 1997.

packing, and meat rendering and refining. Nebraska, Kansas, Texas, and Iowa are the primary meat (non-poultry) producing states. Poultry processing is primarily in Arkansas, Georgia, and North Carolina.

The meat product manufacturing industry has the third largest energy expenditures within the food industry. It has also the largest electricity expenditure, accounting for 19% of total electricity costs in the food industry.

Like the grain mill, and fruit and vegetable preserving industries, the meat product industry consumes a lot of hot water and steam. It is estimated that about three-quarters of its energy consumption is for steam and hot water. Natural gas is the fuel of choice for boiler fuel.

D. Dairy Product Manufacturing

The dairy product manufacturing industry includes establishments that manufacture a variety of dairy products such as fluid milk, cheese, butter, whey, and ice cream. California and Texas dominate the production of fluid milk, while Wisconsin dominates butter and cheese production.

The dairy product manufacturing industry has the fourth largest energy expenditures. This industry is steam and hot water intensive, and prefers natural gas to fuel its boilers.

E. Bakeries and Tortilla Manufacturing

The bakeries and tortilla manufacturing industry includes establishments that are engaged in bread and bakery product manufacturing, cookie, cracker, and pasta manufacturing, and tortilla manufacturing.

The bread and bakery product manufacturing sub-industry, which is the largest component of the bakeries and tortilla manufacturing industry, consists of two major components: retail bakeries and commercial bakeries. Retail bakeries include establishments engaged in retailing bread and other bakery products not for immediate consumption, made on the premises from flour and not prepared dough. California has the largest number of retail bakeries with over 1,100 bakeries, followed by New York with almost 1,000 bakeries. Commercial bakeries include establishments primarily engaged in the manufacture of fresh and frozen bread and other bread-type rolls and fresh bakery products. California, Illinois, New York, and Tennessee are the primary states producing commercially baked goods.

Cookie, cracker, and pasta manufacturing is the second largest component of the bakeries and tortilla manufacturing industry. Illinois and Ohio are the primary states producing cookies, crackers and pasta.

Tortilla manufacturing is the smallest component of the bakeries and tortilla manufacturing industry. California and Texas dominate the production of tortillas in the United States.

The bakeries and tortilla manufacturing industry has the fifth largest energy expenditures in the food industry. Most of its energy consumption is for direct heating or baking. Natural gas is the fuel of choice for baking due to its cleanliness.

F. Beverage Manufacturing

The U.S. beverage industry includes manufacturers of soft drinks, bottled water, and ice, and breweries, wineries, and distilleries. The largest component of this industry is the soft drinks industry, accounting for 55% of total shipments of the beverage industry. The second largest segment of the industry is breweries, which represents 26% of total beverage industry shipments. California, Texas, and Pennsylvania are the top state producers of soft drinks. California, Texas, and Wisconsin are the top state producers of brewery products. California overwhelming dominates winery production, accounting for 90% of shipments from U.S. wineries.

The production of malt beverages is the most energy-intensive component of the beverage manufacturing industry. It uses processes that are highly steam and hot water intensive. Coal and natural gas are the primary boiler fuels.

G. Other Food Manufacturing

This industry includes establishments engaged in the production of snack foods, coffee, tea, flavoring syrup, and seasonings and dressings. The largest component of this industry is snack food production.

The snack food industry consists of producers of roasted nuts and peanut butter, and potato chips, corn chips and pretzels. California is the primary state producing roasted nuts while Georgia is the primary state producing peanut butter.

The major processes involved in this industry are frying, baking, and roasting. These are all direct (non-steam) heat applications. Natural gas is the fuel of choice in this industry.

H. Sugar and Confectionery Product Manufacturing

This industry consists of sugar manufacturing, and chocolate and confectionery manufacturing from cacao beans, confectionery manufacturing from purchased chocolate, and non-chocolate confectionery manufacturing. Although the largest in terms of value of shipments is confectionery manufacturing from purchased chocolate, the sub-industry with the largest energy expenditures and consumption is sugar manufacturing. The sugar manufacturing component accounts for 56% of total energy expenditures of the sugar and confectionery product industry.

The sugar manufacturing sub-industry consists of sugarcane mills, cane sugar refiners, and beet sugar producers. Sugarcane mills are primarily engaged in processing sugar canes to produce raw cane sugar. Louisiana and Hawaii have the primary representation of sugarcane mills. Louisiana and Hawaii also have the largest representation of cane sugar refiners. Cane sugar refiners take the raw cane sugar and convert them to refined sugar. Beet sugar producers are engaged in the production of sugar from beets, and are mainly located in Florida, Louisiana, and Texas.

Sugar manufacturing is an energy-intensive process. In particular, it consumes substantial amounts of steam. It generates byproduct fuels, which are burned in its boilers and are supplemented with coal, fuel oil, and natural gas.

IX. Other Industries

The primary focus for the industrial sector analysis is the six key industries (chemicals; petroleum refining; primary metals; paper; stone, clay, and glass; and food and beverage), which accounted for 80% of the industrial natural gas consumption. The NPC study group also considered natural gas demand for “Other Manufacturing” and “Non-Manufacturing.” These “Other Industries” include 19 other industries that comprise the remainder of the industrial sector (SIC categories 1-39), including (by SIC):

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

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

Tobacco and leather products are declining in the United States and are not large energy or gas consumers. The electronics industry is growing quickly but is not gas intensive. A few of the other industries do have some significant gas consumption. The SIC industries 1 through 15 are non-manufacturing and include agricultural, construction, and mining. The total gas consumption of these sectors in 2001 was about 600 BCF. Of this, about 480 BCF was in the mining industry and much of this was for gas-fired cogeneration related to steam generation for enhanced oil recovery in central California. The remainder of the gas was used for other on-site generation, space heating, and process heating.

SIC industries 20 through 39 are "manufacturing." The manufacturing SICs other than the six major gas-consuming sectors consumed about 900 BCF. This consumption can be divided into three primary groupings, listed below with the approximate 2001 natural gas consumption:

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

The rubber and miscellaneous plastics category has been a fast-growing sector, pushed by increased demand for plastic in consumer goods and electronic items. Gas is used for steam generation and process heat. However, it is not a gas-intensive sector and gas use has lagged the production growth. The metal durables category includes appliances, automobiles, and electronic equipment. As such, it was by far the fastest growing sector of the economy during the 1990s, growing by 15% per year. This sector is not a gas-intensive sector and it saw major decreases in energy intensity during the 1990s. The metal durables sector consumed only 1.8 thousand Btu of energy per dollar of output in 2000 compared to 40 thousand to over 100 thousand Btu per dollar of output in the energy intensive industries. In recent years, the growth in this sector has dropped substantially due to the technology downturn. The uses of gas in this segment include space heating, process heating, and some cogeneration.

Industrial production in the "Other Industries" grew by 5.2% per year during the 1990s. The NPC projection assumes a lower rate of 2.6% per year based on more recent industry performance. Natural gas consumption grows by only 0.1% per year in this sector in the two base-case scenarios, due to the low and decreasing gas intensity. The outlooks resulting from this modeling for the Reactive Path scenario are shown in Figure D3-71, and in Figure D3-72 for the Balanced Future scenario.

X. Summary

The U.S. industrial sector arguably leads the world in production. Its chemical, petroleum refining, steel, and aluminum industries are the world's largest. Another industrial process focused on by the Demand Task Group was the extraction and processing of bitumen from Alberta's oil sands; this resource rivals that of Saudi Arabia's crude oil.

The industrial sector of the North American economy currently consumes more natural gas than any other, and uses natural gas as both an energy source and a raw material. Like other segments of the economy, industrial consumers have embraced the economic and environmental benefits of natural gas and invested accordingly in recent years. Rising natural gas prices in recent years have negatively affected many North American industrial consumers. Some industrial facilities were shut down or temporarily idled during recent, prolonged price rises. Some of the most gas-intensive industries – such as ammonia and methanol producers, and foundries operating at the margin – shut down plants because imports were more competitive. Since natural gas-based power generation capacity is on the margin in many areas of North America, higher natural gas prices have also fostered higher electricity prices. Therefore, some aluminum smelters and electrochemical units such as chloralkali facilities shut down in response to both gas prices and electricity prices. To meet the demand of their own markets, these North American industries relied on overseas operations, or allowed their customers to switch to overseas suppliers.

Considering both historical and recent behavior of industrial consumers, the Demand Task Group developed an outlook for future natural gas demand by this sector by focusing on the most gas-intensive industries, and determining the likely price-responsiveness of these industries. The following five key findings of the NPC study are particularly relevant to the current situation and future outlook for industrial natural gas consumers:

- There has been a fundamental shift in the natural gas supply/demand balance that has resulted in

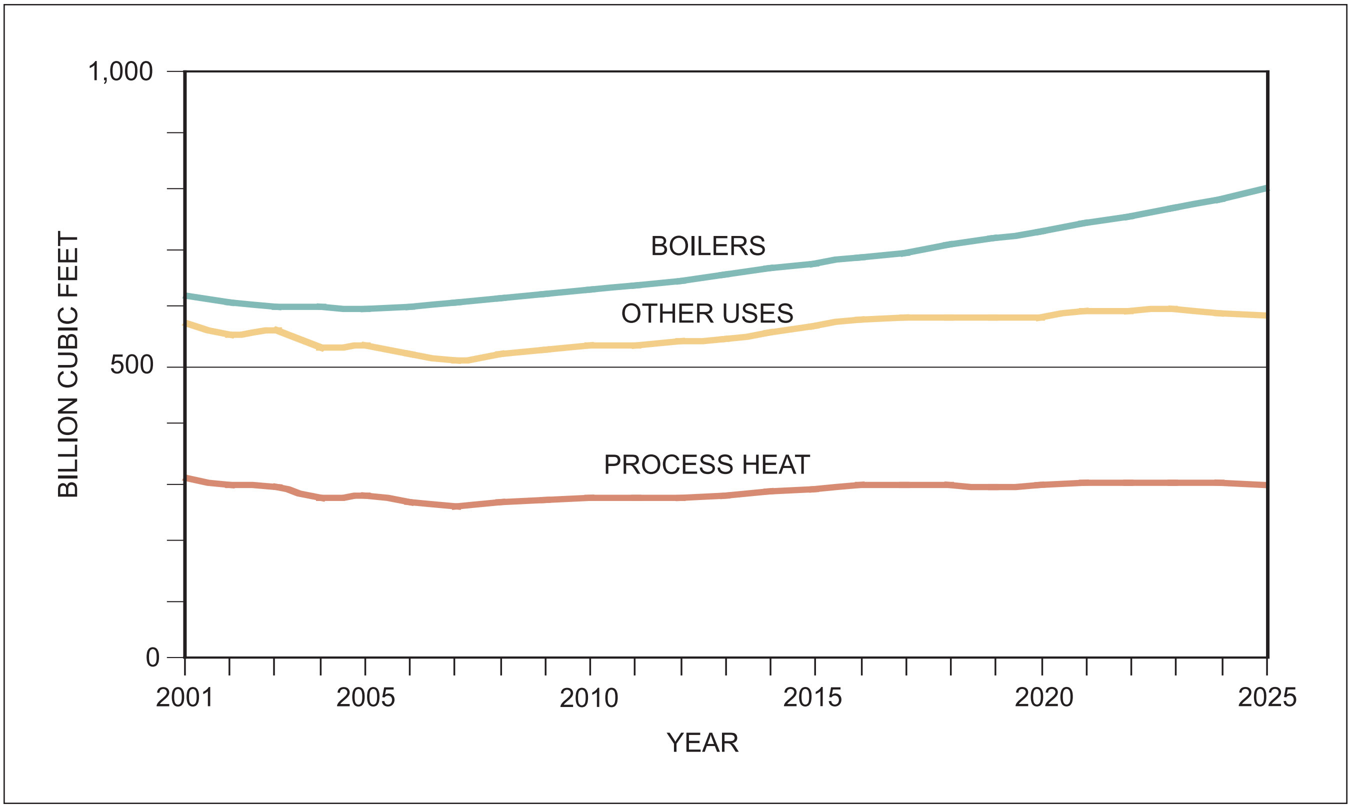


Figure D3-71. Demand Projection for "Other Manufacturing" and "Non-Manufacturing" in Reactive Path Scenario

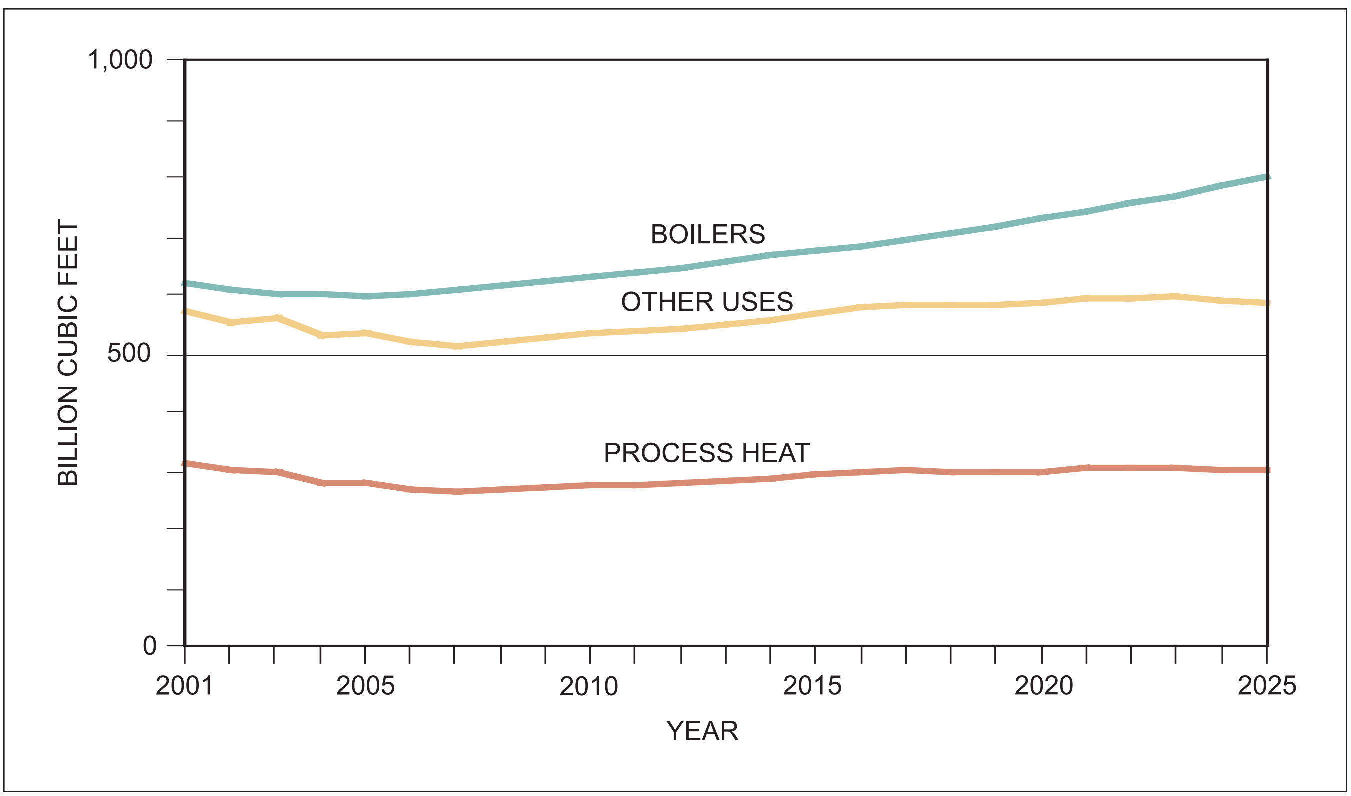


Figure D3-72. Demand Projection for "Other Manufacturing"and "Non-Manufacturing" in Balanced Future Scenario higher prices and volatility in recent years. This situation is expected to continue, but can be moderated.

- 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.

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

While both the Reactive Path and Balanced Future scenarios assumed the North American economy would grow at historical rates, the projections of each of these scenarios showed a "no-growth" picture for overall industrial natural gas demand. In the case of the most gas-intensive chemical manufacturers – ammonia and methanol – and primary metals manufacturers, significant reductions in natural gas demand are foreseen. As suggested in the findings, the higher-price environment for natural gas illustrated by this study, particularly that which is characteristic of the Reactive Path scenario, will likely negatively impact the competitiveness of the most gas-intensive industries described in this chapter. This will likely cause some of these industries, and the associated jobs, to relocate outside North America.

Importantly, the Demand Task Group incorporated into its outlooks assumptions for continued efficiency gains in industrial process energy and boiler operations, reflecting continued innovation in response to a higher-price environment. Further, while the Reactive Path scenario reflects a continuation in the historically low amount of fuel flexibility for industrial consumers, the Balanced Future scenario illustrates how additional flexibility could contribute to a lower-price environment.

CHAPTER 4

RESIDENTIAL AND COMMERCIAL CONSUMERS

Natural gas is used by over 60 million U.S. households and supplies over 40% of commercial energy requirements. The residential and commercial sectors accounted for over one-third of U.S. natural gas consumption in 2002. Since 1997, total residential and commercial natural gas use has remained relatively constant. Figures D4-1 and D4-2 illustrate the growth in number of residential and commercial customers, respectively, and show natural gas demand in these sectors since 1990.

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

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

The primary residential sector uses of natural gas are space heating, water heating, cooking, and clothes drying (see Table D4-1). Other uses include natural gas fireplaces, barbeques, swimming pool heaters, and outdoor lighting. The primary commercial sector natural gas uses are space heating, space cooling, and water heating.

I. Analytical Approach

The residential and commercial demand projections were modeled using a combination of an econometric projection module and an engineering/economic stock-adjustment validation module in the EEA modeling framework. A "base projection" of demand in each of the two sectors was calculated using an econometric equation for each demand region. The econometric equation projects "real-time" monthly demands[1] that are passed to the optimization routine that calculates gas flows and prices.

The consumption volumes were summed to annual totals and passed to the validation module. Based upon user inputs and historical data, the validation module performs a decomposition analysis that is used to calculate the number of customers, the use per customer and trends implicit within the in the econometric equations. To the extent that the user wishes to consider alternative scenarios regarding appliance efficiency, new customer hookup, or conversion behavior, the validation module can be used to calculate the effects. The revised demand levels are translated into "add factors" (which can be either positive or negative

1 The demands are real-time in the sense that they represent the gas consumed in each month. Many commonly referenced data series, such as EIA data published by the Department of Energy, reflect the volume of gas that is billed each month rather than the amount of gas consumed. As a result, approximately half of the gas reported as consumed by EIA in any month was actually consumed in the prior month.

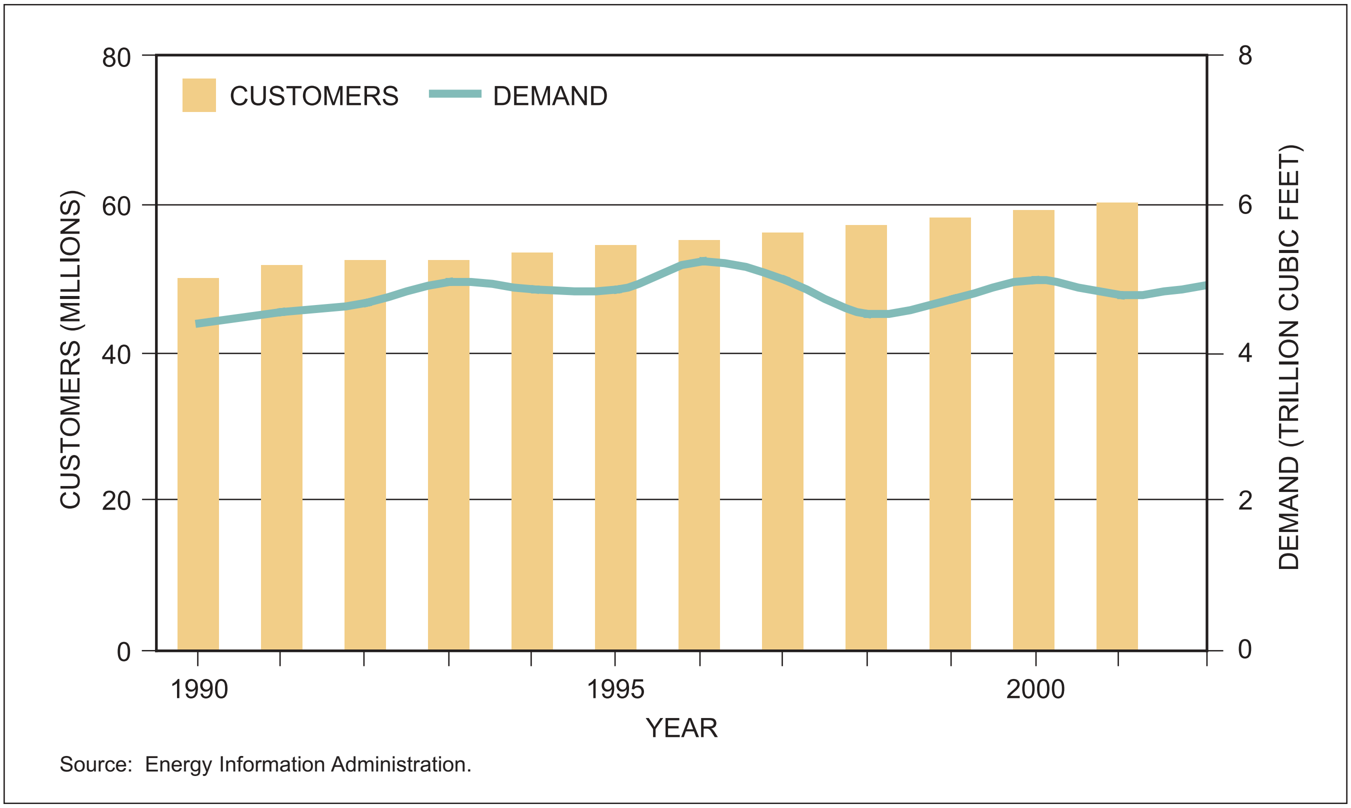


Figure D4-1. U.S. Residential Customers and U.S. Residential Demand

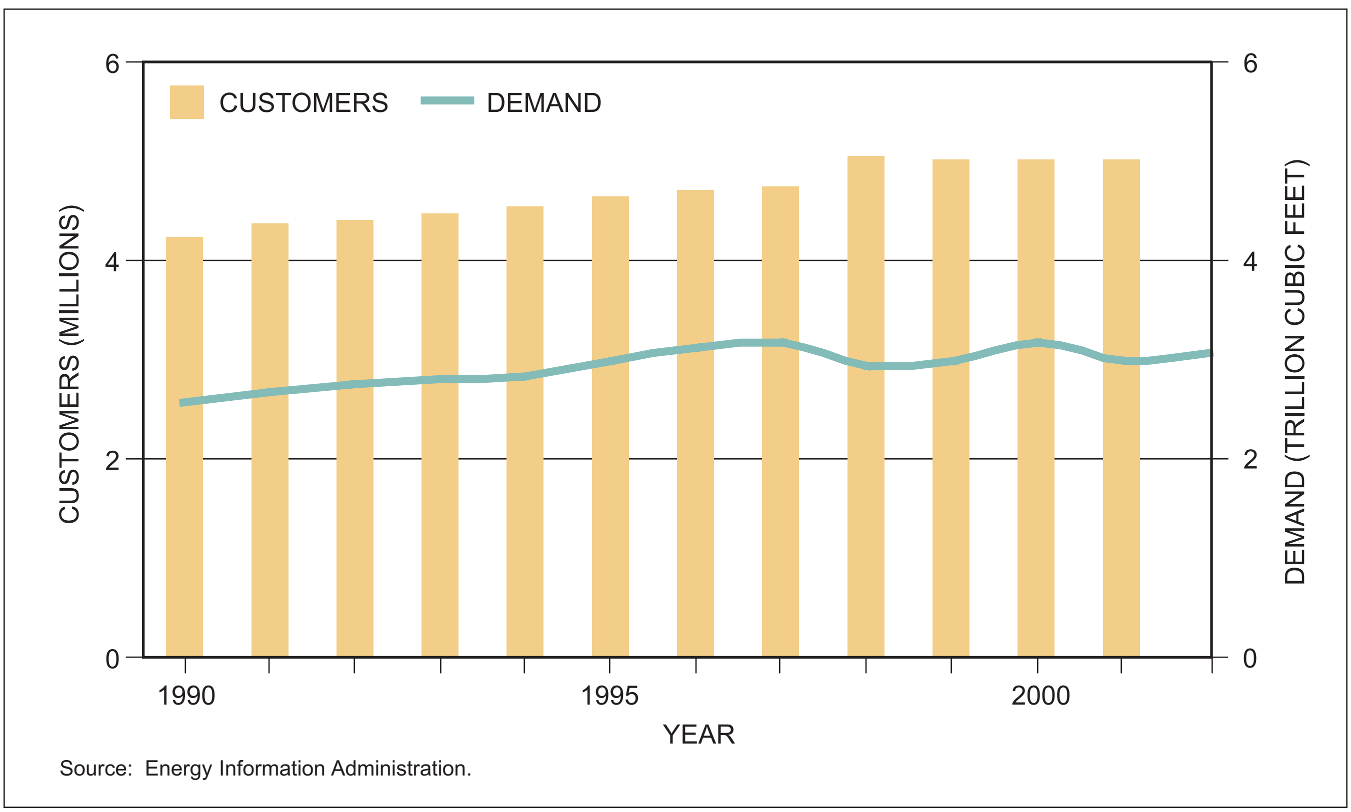


Figure D4-2. U.S. Commercial Customers and U.S. Commercial Demand

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

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

Table D4-1. U.S. Residential Market 2001 Annual Natural Gas Consumption per Appliance

values) that are used to revise the demand projections that are passed to the optimization routine and reflected in the model's price and flow solution. This aspect of the EEA model framework allowed the Demand Task Group to model different assumptions for the Reactive Path scenario, the Balanced Future scenario, and various sensitivity analyses; these are discussed in greater detail in Chapter 6.

A. Econometric Equations

"Base projections" of demand in the residential and commercial sectors are calculated in the EEA model framework using the equation for each demand region shown in the box below. The residential and commercial demand equations were fit using data from 1984 through 1998 for regions in the United States and from 1988 through 1998 for Canada. Implicitly, an econometric projection implies that fundamental trends and relationships that existed during the historical period used for the regressions are valid through the projection period. As a result, the projection implicitly assumes that population demographics such as the move from the "rust belt" to the "sun belt" continue. Similarly, the projection assumes that regional economic activity in the projection period maintains the same relationship to national growth as existed during the historical period. The Demand Task Group assessed this and agreed

Gas Demand = $(a + b_1 * (1 + b_2*\text{HDD}) * \text{HDD}) * (1 + \text{Time}*b_3)$ * GDP effect * Price effect

Where:

a, b_1, b_2, and b_3 are the fit coefficients

HDD = Monthly Heating Degree-Days

Time = Time counter representing growth over time

GDP effect = Impact of GDP on demand = (Moving Average GDP/Reference GDP) $^{\text{GDP Elasticity}}$

Price effect = Impact of gas prices on demand = ((Moving Average Citygate Price + Distribution Margin)/ (Reference Citygate Price + Distribution Margin)) $^{\text{Price Elasticity}}$

Moving Average GDP = 48-month moving average of GDP growth rate

Reference GDP = 2.5 percent growth per year

Moving Average Citygate Price = 48-month moving average regional gas prices

Reference Citygate Price = 48-month average (Jan-95 to Dec-98) regional gas prices

Distribution Margin = Average national distribution margin for each sector

GDP Elasticity = 0.4 for residential, 0.6 for commercial

Price Elasticity = -0.1 for residential, -0.2 for commercial

The coefficients a, b_1, b_2, and b_3 are fit econometrically for each of 26 demand regions. Residential r^2 values are all above 0.89 with most regions above 0.93. Commercial r^2 values are all above 0.83 with most regions with these implicit assumptions. The Demand Task Group also concurred with EEA's recommendation to override this implicit relationship in the California demand region. During the 1980s and early 1990s, the performance of the California economy was substantially below the national average. For the Reactive Path and Balanced Future scenarios, as well as all sensitivity analyses, the regional GDP coefficient was raised in California to reflect economic growth that is only slightly below the national level.

For the residential sector, the historical data show relatively stable gas market share in new single family and multifamily homes from 1991 through the end of the period. Before that, market share of new homes grew from the low levels of the early 1980s. Competition with heat pumps in southern states favored gas on a lifecycle cost basis, but not on a first cost basis, which has a disproportionate impact on equipment decisions of builders. The historical fit period also incorporated a substantial number of conversions from oil to gas. These conversions were concentrated in the Northeast and Mid-Atlantic regions. Conversions accounted for 40,000 to 80,000 additional gas heated households per year during 1980s. That number declined to an estimated average of less than 30,000 households during the 1990s.

For the commercial sector, the historical data reflect modest growth in gas demand in the face of strong competition from electric applications. Gas use in the commercial sector has been dominated by space-heating requirements. However, these space-heating requirements have grown at a very slow level. Water-heating, drying, and cogeneration applications have grown at faster rates, albeit from much smaller base levels.

B. Residential Demand Validation Module

The residential validation module is constructed in a spreadsheet. The module can be calibrated to reflect a specific Gas Market Data and Forecasting System (GMDFS) case and the econometric results of the scenario. Alternatively, the program can be executed independently to examine the impact of alternative assumptions regarding technology, demographics, and household behavior on residential gas demand.

The module is constructed to examine residential demand from a "bottom up" approach at a simple level using:

- Total number of households
- The number of households served by gas (gas market share times total)
- Gas use per 1,000 household/household per heating degree-day
- Heating degree-days.

A time series of historical data is used to determine the base for gas households by region. Annual growth rates are used to calculate growth in the total number of households and the number of gas households.

> Gas consumption in each region and in each year = [Gas Households] X [Gas use per 1,000 households per heating degree-day] X [heating degree-days]

Base year levels of gas use per 1,000 households per heating degree-day are calculated in the historical series. Initially, a forecast calculation can be made assuming that these historical trends continue. The initial projection is then compared to the results of the projection made by the econometric relationships. Given the relatively higher gas prices that were projected in the modeling of the Reactive Path and Balanced Future scenarios, the econometric forecasts generally project substantially larger declines in gas use per 1,000 households per heating degree-day than were experienced in the 1996 through 2000 period. In other words, the NPC scenarios imply a significant amount of price-induced demand response in the residential sector compared to the 1990s when gas prices averaged below $3 per MMBtu.

C. Commercial Demand Validation Module

The commercial validation module is also constructed in a spreadsheet. The module can be calibrated to reflect a specific GMDFS case and the econometric results of the scenario. Alternatively, the program can be executed independently to examine the impact of different assumptions regarding technology, demographics, and household behavior on residential gas demand.

The module builds up commercial consumption estimates from the sum of five segments of the commercial market:

- Space heating
- Water heating
- Space cooling

- Cogeneration (including distributed generation)
- Other miscellaneous applications.

As with the residential module, the commercial module generally uses an activity variable and gas intensity variable to examine future consumption. For space heating, space cooling, and water heating, the module uses commercial square footage that is served by gas as the activity variable. For cogeneration and distributed generation, the model uses installed capacity.[2]

The data for the historical period is taken from the GRI 2001 Baseline Projection including the sector decomposition by end use and the square footage data. In the space heating, water heating, and space cooling categories, the projection is made reducing or increasing the intensity variable by applying efficiency improvements or reductions. The projected consumption is calculated by multiplying intensity by square footage by applicable weather data.

In the cogeneration and distributed generation categories, the module uses the capacity data, utilization data, and the heat rate. Efficiency trends are applied to the heat rates to reflect technology improvement.

As noted above, the residential and commercial validation modules provide a user with the ability to quantify trends that are implicit in the econometric relationships used in the GMDFS. The major limitation is that the price response is not endogenous to these modules. Importantly, when used in conjunction with the GMDFS econometric results, the models provide more detail and flexibility than either approach used separately.

II. Residential Consumers

In 1997, the average household consumed 91.2 MMBtu and spent $603 on natural gas. In 2001, average household consumption fell to 79.3 MMBtu but annual expenditures for natural gas rose to $750. This reflects a 13% decrease in consumption and a 24% increase in expenditures. During this period the average price increased 43% from $6.62 in 1997 to $9.45 per MMBtu in 2001.[3]

In 2002 there were approximately 119 million housing units in the United States. Total natural gas consumption by households equaled almost 5 TCF or 22% of total U.S. gas consumption. Slightly more than 62% of U.S. housing units used natural gas in 2001 (see Figure D4-3). Although newer houses are larger, average gas use per household is declining because of better insulation and more energy efficient equipment.

As a space heating fuel, natural gas competes with electricity, fuel oil, and propane. Over the decades, natural gas has become the dominant space heating fuel in the United States (see Figure D4-4).

The use of fuels for space heating differs regionally, as shown in Table D4-2. Electricity is the major competing heating source in all regions except the Mid-Atlantic and New England. Electricity is a strong competitor in the South Atlantic and East South Central regions where electric heat pumps provide space heating for 28% and 22% of households, respectively. The major alternative to natural gas space heating in the Mid-Atlantic and New England is fuel oil. In 2001, fuel oil was the main heating fuel in 25% of households in the Mid-Atlantic and 50% in New England.

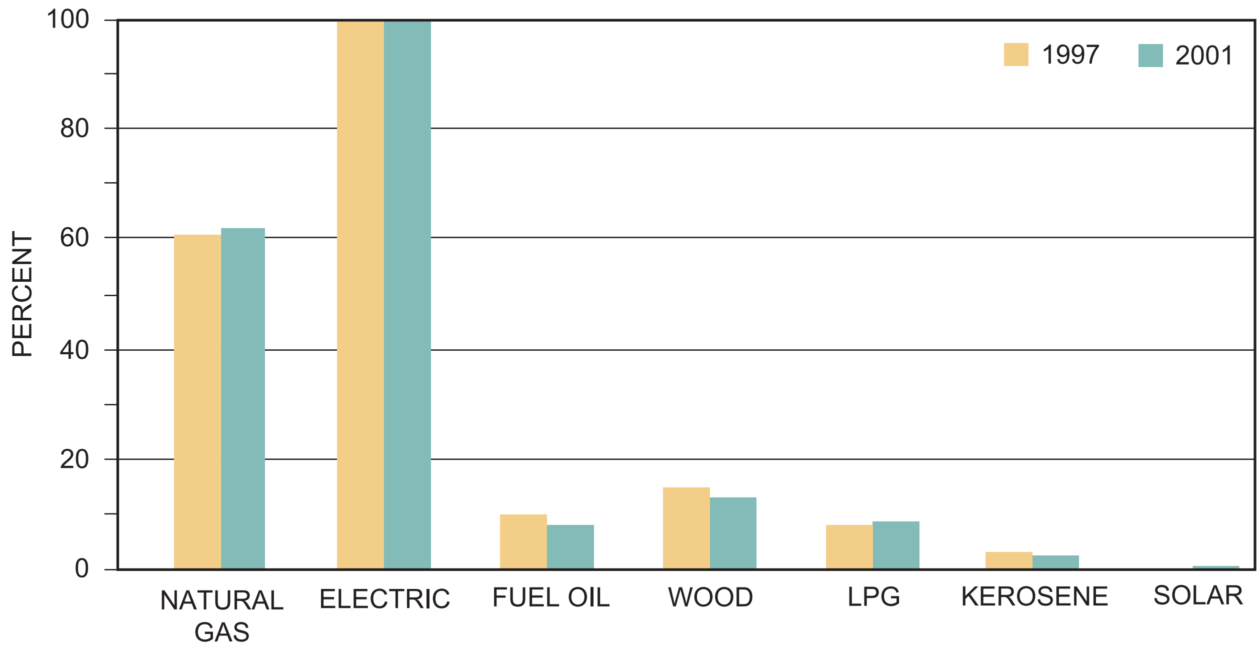
New residential construction is heavily weighted toward natural gas heating. In recent years, approximately 70% of newly completed single-family homes installed gas heat.[4] In addition, the percentage of natural gas heating in new multi-family construction increased slightly. By comparison, 27% of new housing units installed electric heat, predominantly in the Southern states. Fuel oil is losing its market share as a heating fuel nationwide. Table D4-3 provides summary information on the application of natural gas and competing fuels in new housing in 2001.

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

2 The other miscellaneous category is a simple trend calculation.

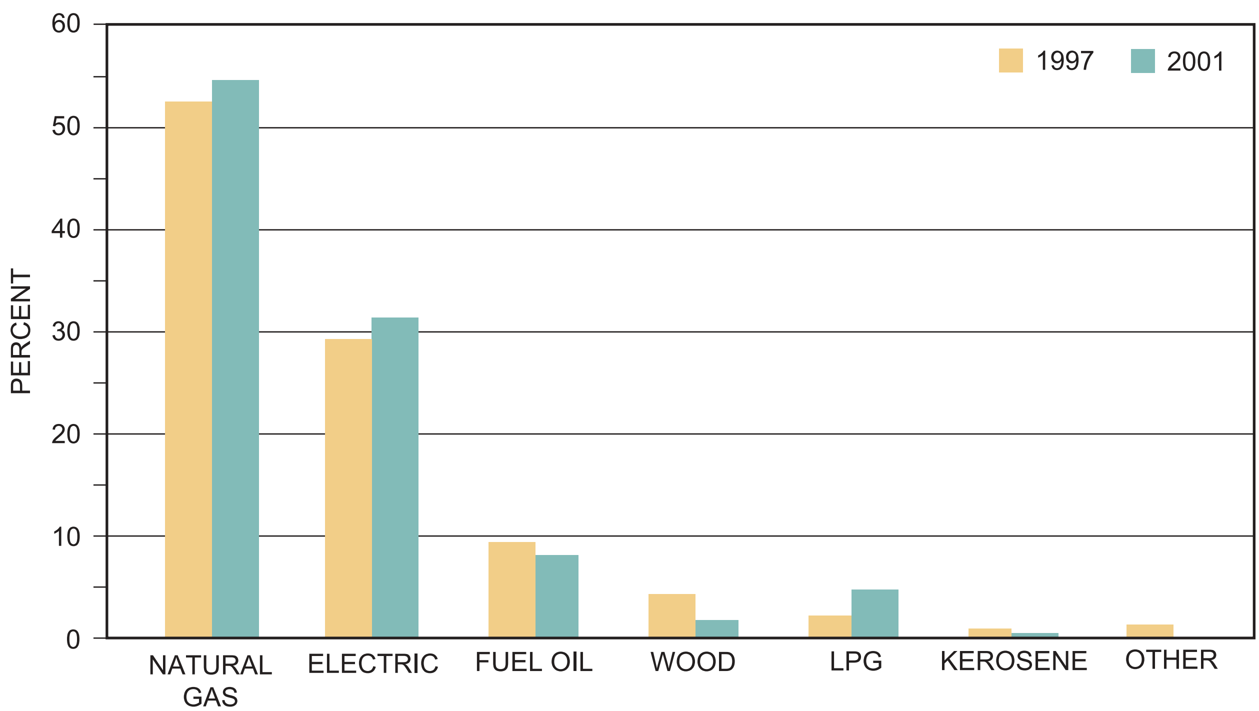
3 American Gas Association, *2002 Gas Facts: A Statistical Record of the Gas Industry, 2001 Data,* 2003, pg. 59.

4 Ibid., pg. 72.



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

Figure D4-3. Fuel Used in U.S. Housing Units



Source: Energy Information Administration, Residential Energy Consumption Surveys, 1997 and 2001.

Figure D4-4. U.S. Primary Household Heating Fuel

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

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

Table D4-2. Percentage of U.S. Households with Natural Gas as the Main Heating Fuel

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

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

Natural gas consumption and expenditures are positively correlated with household income: the higher the household income, the more a household consumes and spends on energy. This higher use and related expenditures reflects in the typically larger homes owned by higher-income families, requiring more heating. However, the cost of fuel is, on average, a higher proportion of household income for low-income families. The average residential energy costs in 2001 (including heating, cooling and all other energy uses in the home) for U.S. households in 2001 was $1,537 per household, or 7.0% of income. Low-income households spent an average of $1,311 on energy, representing 14.0% of household income; for households qualifying for Low Income Home Energy Assistance Program (LIHEAP) funding – two-thirds of which have incomes less than $8,000 per year – the percentage of income represented by energy expenditures was 17.2%.[5]

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

5 The LIHEAP Home Energy Notebook for FY 2001.

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

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

Table D4-3. U.S. Private Housing Completions in 2001 by Heating Fuel

III. Commercial Consumers

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

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

The average growth rate for commercial gas consumption was -0.5% between 1997 and 2002. As shown in Figure D4-5, some of this variation was due to weather – a cold year (1997) followed by a warm year (1998). The number of commercial natural gas customers increased approximately 6% between 1997 and 2001, from 4.6 million to 4.9 million.

Figure D4-6 illustrates the growth in the number of commercial natural gas customers. The commercial market fluctuates, and the upward trend in the number of customers does not necessarily reflect the amount of floor space served by natural gas. New commercial buildings are constructed and older buildings are converted to commercial uses. At the same time, older commercial buildings may be razed or converted to noncommercial uses. Commercial floor space may also fluctuate concurrently. Commercial floor space may be converted to non-commercial uses, which will impact commercial demand. Minimal growth in commercial demand is due in part to efficiency in building design and natural gas appliances and equipment.

Most of the natural gas consumed by the commercial sector is used for space heating and water heating, and there has been a strong trend for customers to choose gas for these applications where gas is

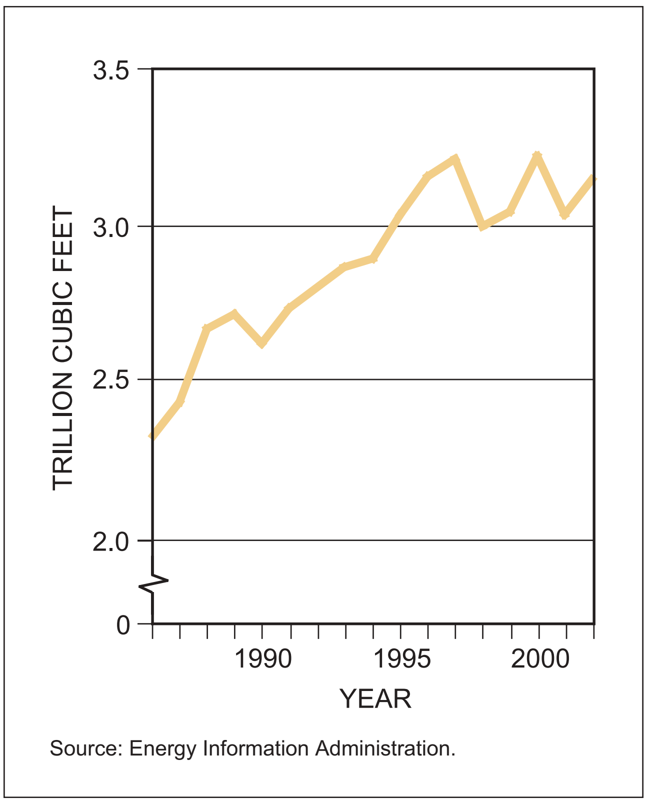


Figure D4-5. Natural Gas Delivered to U.S. Commercial Consumers

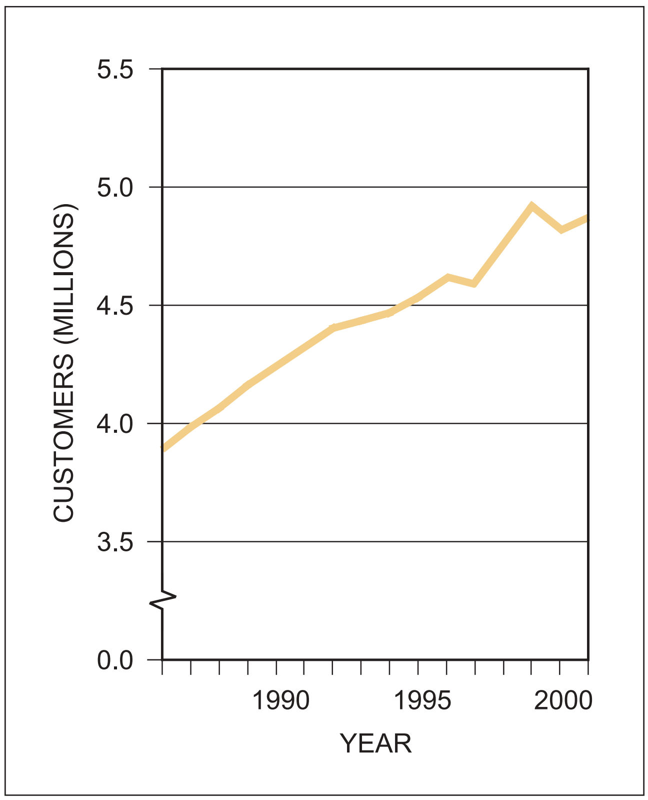


Figure D4-6. Number of U.S. Commercial Natural Gas Customers available. Other uses such as cooling, cooking, drying, desiccant dehumidification, and cogeneration applications comprise a smaller share of natural gas applications. While space and water heating usage have become increasingly efficient, alternate uses of natural gas have continued to make up a larger share of total commercial gas use.

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

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

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

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

IV. Natural Gas Vehicles

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

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

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

V. Regional Considerations in Residential and Commercial Demand

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

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

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

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

Current natural gas consumption is also an outcome of historical accessibility to natural gas in urban and rural locations. Sub-regional profiles of households with natural gas service may differ from the regional profile. Households with gas service are predominantly in the more urban areas, while the percentage of households with gas service in rural areas is much lower. Figures D4-7 and D4-8 illustrate this trend.

VI. Efficiency in Residential and Commercial Consumption

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

The U.S. Environmental Protection Agency introduced ENERGY STAR in 1992 as a voluntary labeling program designed to identify and promote energy-efficient products. The ENERGY STAR label is now on major appliances, office equipment, lighting, home electronics, and more. The EPA has also extended the label to cover new homes, and commercial and industrial buildings. The ENERGY STAR program delivers technical information and tools that consumers need in order to choose energy-efficient solutions and best management practices. Energy efficiency can result in the delivery of the same (or more) services for less energy. Energy efficiency helps the economy by saving consumers and businesses millions of dollars in energy costs. Energy-efficient solutions can reduce the energy bill for many homeowners and businesses by 20% to 30%.

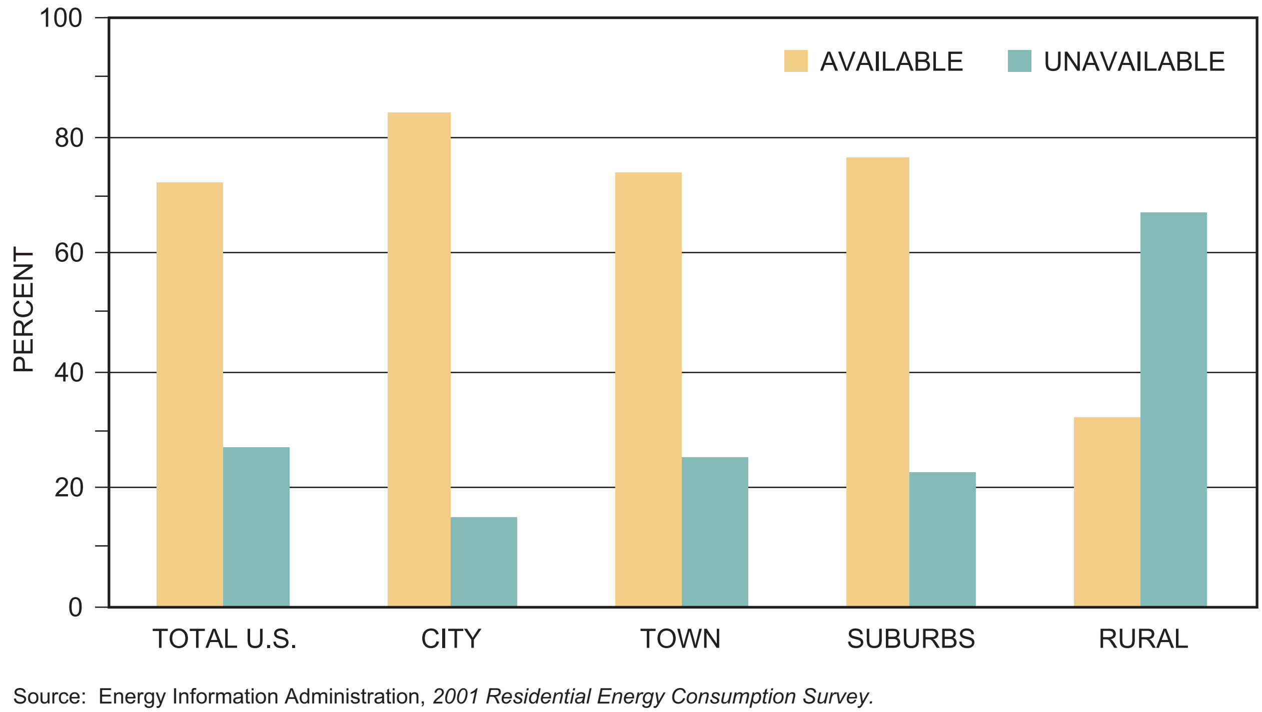


Figure D4-7. Percentage of U.S. Housing Units with Natural Gas Available in Neighborhood in 2001

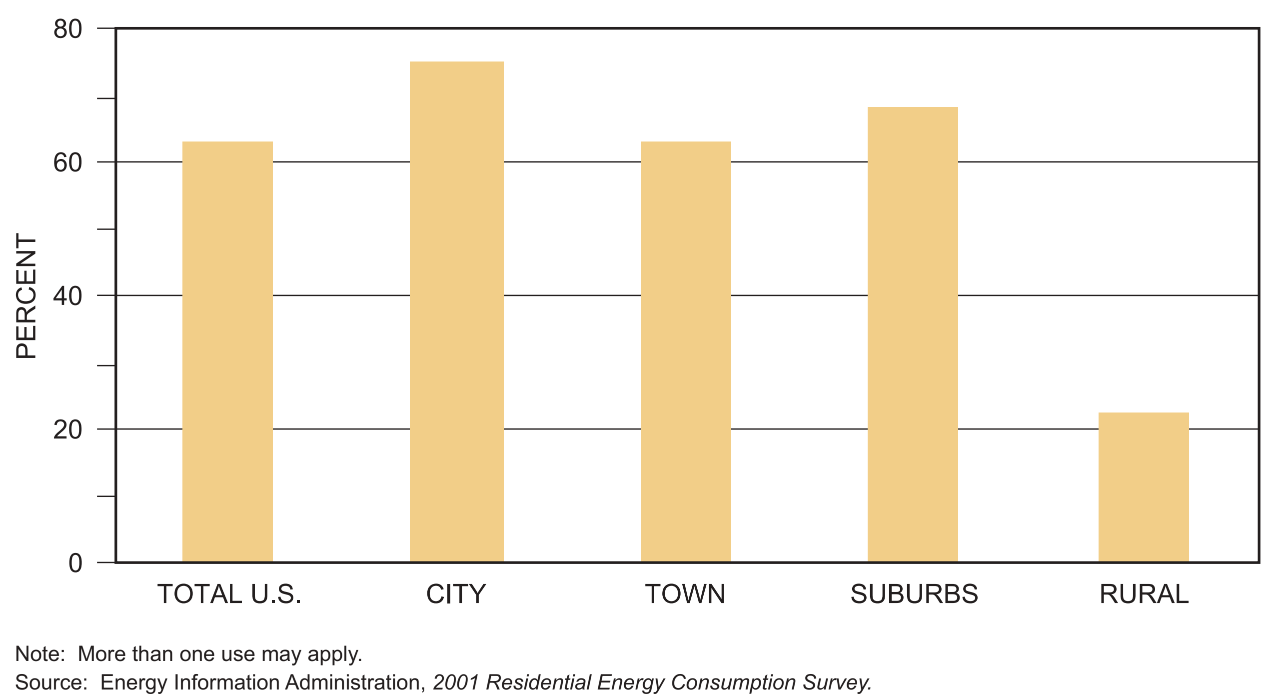


Figure D4-8. Natural Gas Used in U.S. by Type of Location in 2001

In the residential sector, newer housing stock is, on average, 18% larger than the existing housing. However, energy use per square foot is lower for new construction.[6] This trend will likely continue, with newer houses being tighter as a result of more stringent building codes, better insulation, tighter window treatment, and tighter building design. Ongoing structural efficiencies will continue to reduce the demand for natural gas per customer.

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

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

VII. Summary of Residential and Commercial Demand

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

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

Residential demand in the Balanced Future scenario is lower than in the Reactive Path scenario primarily due to increased efficiency in space and water heating per household. Figure D4-9 depicts projections for total U.S. residential natural gas demand in the two scenarios. Table D4-4 compares the difference in demand and the average annual growth rate of the scenarios. Additionally, this table shows the effects of different economic growth rates modeled in sensitivity analyses, comparing higher and lower

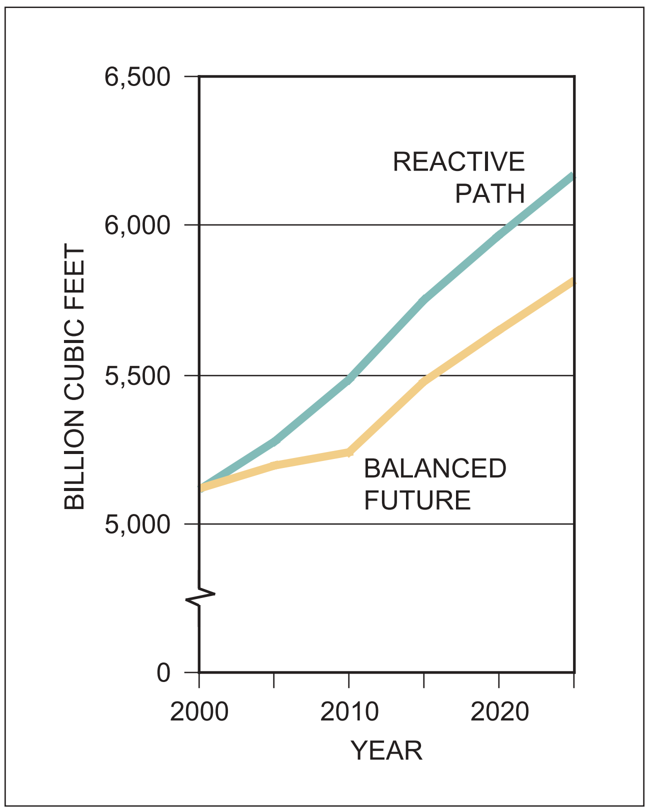


Figure D4-9. Total U.S. Residential Natural Gas Demand

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

	Consumption: 2000 (BCF)	Consumption: 2030 (BCF)	Annual Percent Change: 2000-2025
Reactive Path	5,116	6,167	0.75
Balanced Future	5,116	5,817	0.51
High Economic Growth	5,116	6,252	0.81
Low Economic Growth	5,116	6,091	0.70

Table D4-4. U.S. Residential Natural Gas Consumption

GDP growth to the Reactive Path scenario. Figure D4-10 illustrates the effects of energy efficiency modeled in the Reactive Path and Balanced Future scenarios.

Unlike the residential sector, the commercial sector experiences higher demand growth in the Balanced Future scenario than in the Reactive Path scenario. The conservation assumptions reflected fewer opportunities for additional conservation than in the residential sector, and the lower prices in the Balanced Future scenario were modeled as stimulating additional commercial gas consumption. Figure D4-11 depicts projections for total U.S. commercial natural gas demand in the two scenarios. The figure indicates that gas consumption in the Balanced Future scenario rises above that of the Reactive Path scenario, especially after 2020. Table D4-5 compares

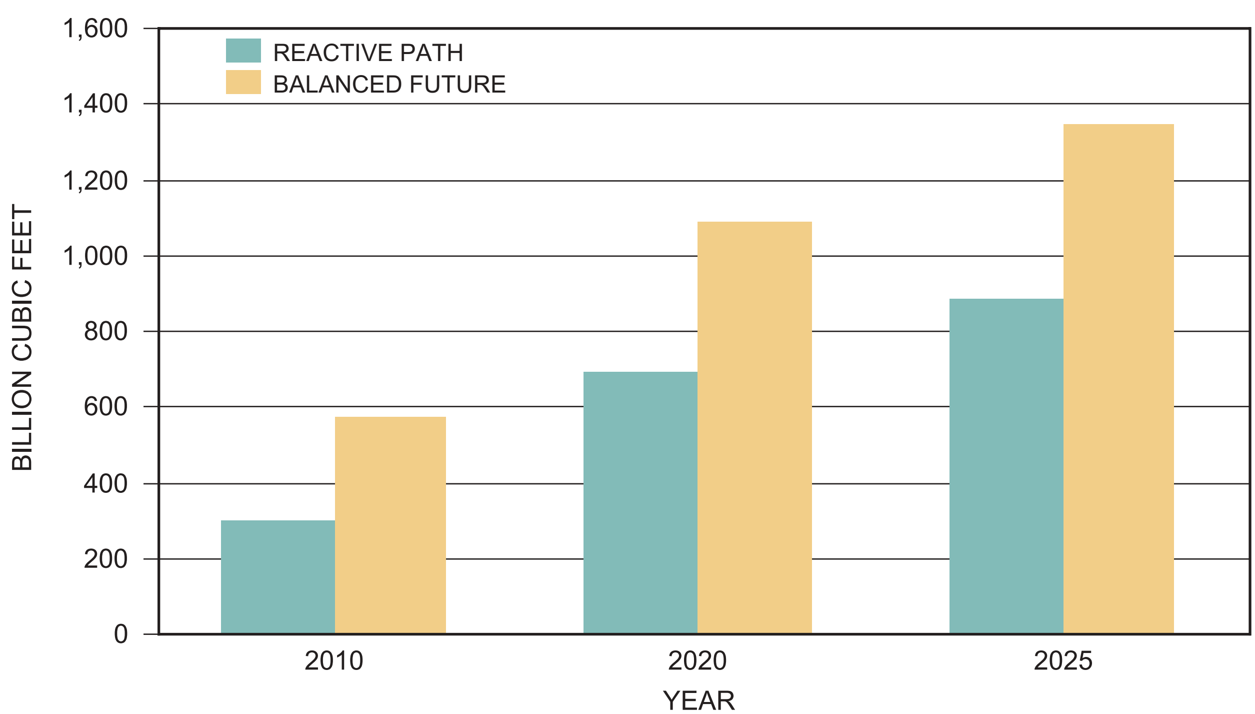


Figure D4-10. Cumulative Energy Efficiency Effects in U.S. Residential and Commercial Sectors

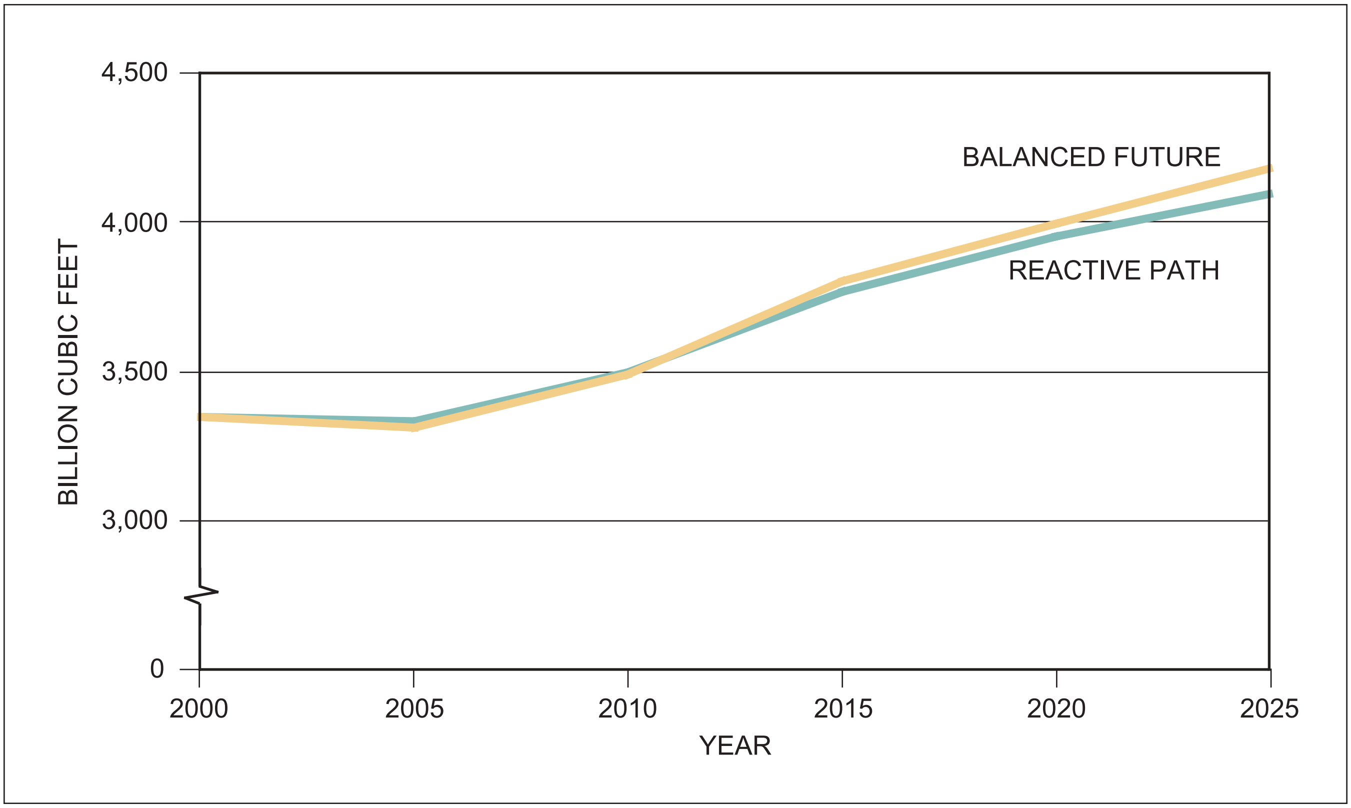


Figure D4-11. Total U.S. Commercial Natural Gas Demand

the difference in commercial demand and the average annual growth rate of the Reactive Path and Balanced Future scenarios, as well as sensitivity analyses assessing higher and lower economic growth.

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

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

	Consumption: 2000 (BCF)	Consumption: 2030 (BCF)	Annual Percent Change: 2000-2025
Reactive Path	3,346	4,093	0.81
Balanced Future	3,346	4,180	0.89
High Economic Growth	3,346	4,153	0.87
Low Economic Growth	3,346	4,043	0.76

Table D4-5. U.S. Commercial Natural Gas Consumption and become more energy efficient. In addition, high natural gas prices will likely provide a catalyst for residential and commercial consumers to consume less natural gas by reducing the amount of energy services they consume. The most immediate means to reduce energy consumption is to adjust thermostat settings and use more energy-efficient natural gas equipment. Table D4-6 illustrates demand reduction results from an aggressive response scenario that includes improved efficiency, lower gas market shares, and permanent thermostat turn-back of 2°F – down in winter, up in summer.

Figure D4-12 illustrates the projections for regional growth in residential and commercial natural gas demand for the Reactive Path scenario. The largest impact projected was in the South Atlantic, East South Central, and West South Central regions. The Mid-Atlantic, New England, and the East North Central regions exhibited the smallest percentage change in consumption.

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

Table D4-6. U.S. Residential and Commercial Sensitivity – Decrease in Gas Consumption in 2025 (Relative to 2002)

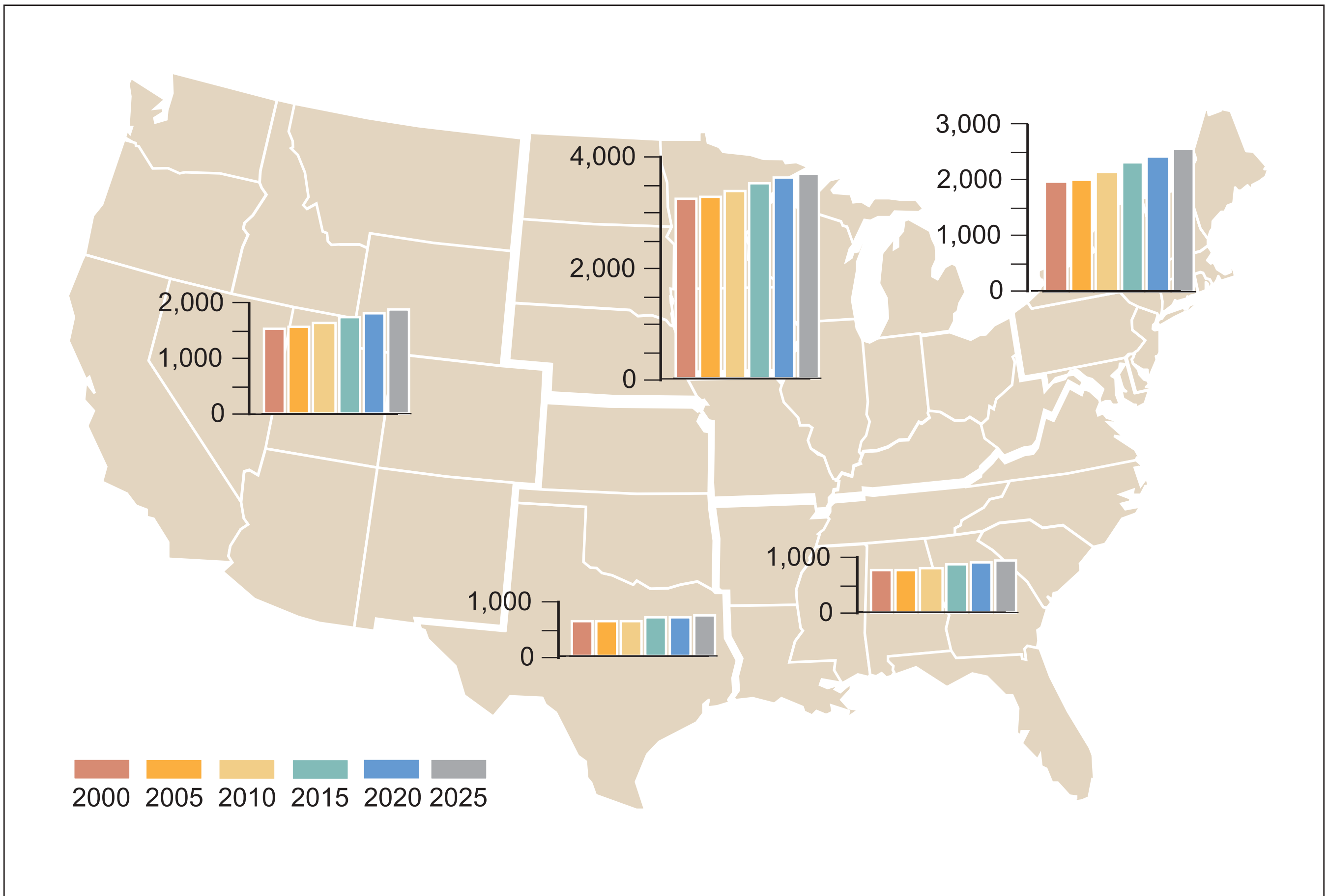


Figure D4-12. U.S. Residential and Commercial Natural Gas Demand in Reactive Path Scenario (Billion Cubic Feet per Year)

CHAPTER 5

ELECTRIC POWER

Electricity usage is pervasive throughout our society, touching all aspects of life in the United States. The wealth of a nation and its electric usage are closely linked as shown in Figure D5-1. Increased electrification raises productivity and improves the basic quality of life. In the United States, electricity is coupled to its economic growth and is projected to remain correlated to the economy throughout the study period. Growth in electric power demand in the United States and Canada is directly dependent upon growth in their respective Gross Domestic Products (GDP), while shorter-term fluctuations in demand are driven by other factors.

I. Analytical Approach and Electric Power Demand

A. Study Approach

The NPC study evaluated electric power supply (capacity) and demand regionally using a model that solves for monthly electricity demand, power generation

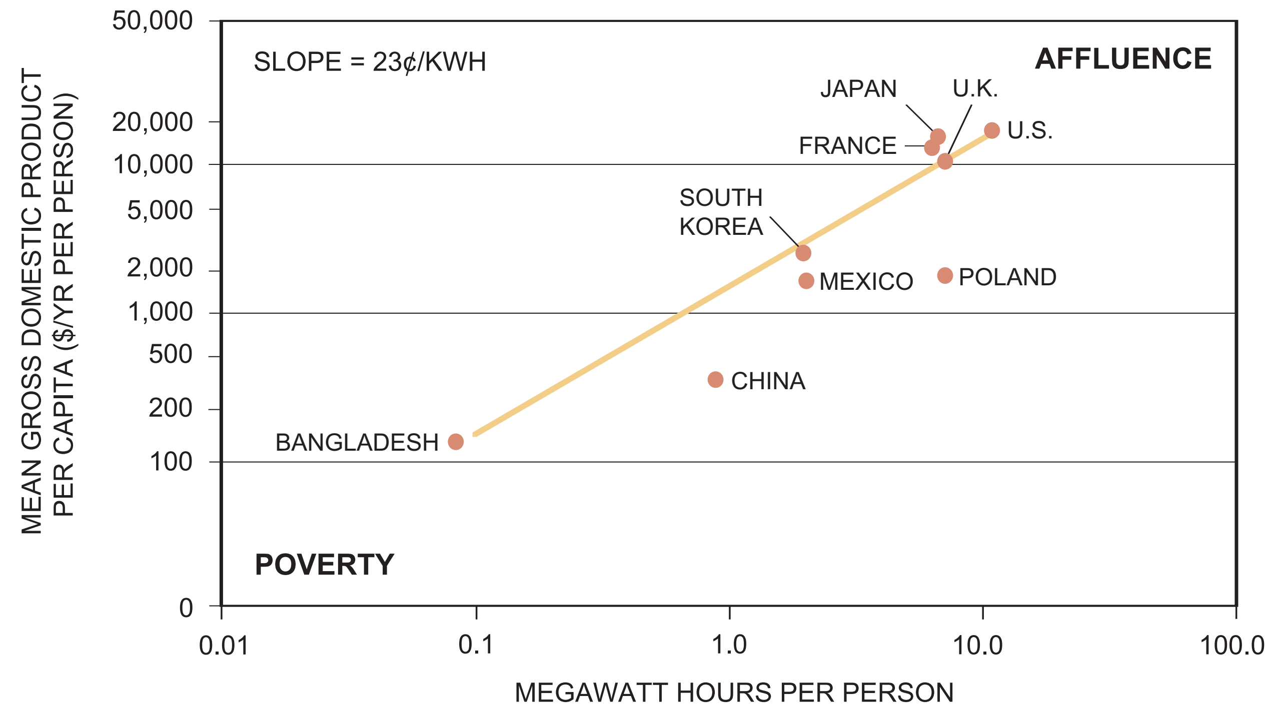


Figure D5-1. 2002 Mean Power Consumption by type of fuel, generating capacity additions, and fuel use. New capacity builds were determined in a separate model using logic parameters provided by study participants. Wide ranges of potential generation technologies were considered whenever the model logic called for new builds. The study participants imposed some constraints on coal and residual oil-fueled new builds, but the general approach was to allow economically rational choices to be made in both the Reactive Path and Balanced Future scenarios. Canada was modeled and analyzed, but with much less detail and rigor than the U.S. lower-48. The portions of Mexico that are interconnected at border regions were treated as interconnected net power transfers.

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

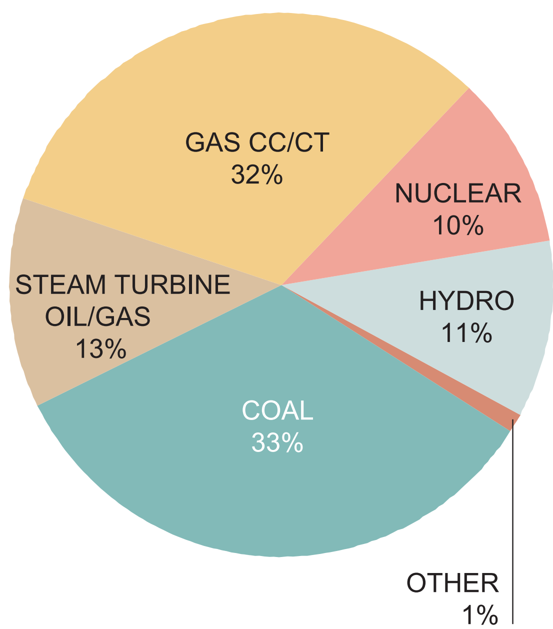
The study approach was to model current laws and regulations in environmental emissions, siting, and ongoing operations. The power model used for the study does not allow discrete generation unit evaluation of environmental emissions, but each case, sensitivity and scenario output was evaluated to ascertain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

The demand for electric power fluctuates during the day with a peak normally occurring in the middle of the day or late afternoon depending upon the season. Demand also fluctuates seasonally since weather and the applications electricity is used for depend upon the time of day, day of the week, and seasonal climate. Therefore the two biggest drivers that influence electric demand are the economy and weather. Electric demand must be met with supplies generated in North America, since no existing technology allows the production of electricity and shipment over distance via any mechanism other than conducting wires.

Electric power generation available to meet demand in the United States is fueled by coal, nuclear, natural gas, hydropower, oil, and a variety of renewable resources. Fossil fuels, headed up by coal, provide 70% of the average annual generation of power. The share provided by natural gas has been increasing, and much of the growth in power demand over the next five years will be served by natural gas since it represents the majority of capacity that is not fully utilized, particularly during peak demands. Figure D5-2 shows the projected capacity mix by fuel type in 2005.

B. Interconnected Power Transmission Grid

There are over 200,000 circuit miles of high voltage transmission lines creating a highly interconnected grid in North America with the United States, Canada, and some of the border regions of Mexico being interconnected in three synchronous regions. This means that within each region, the electric power grid is operating at the same frequency throughout each control area that has been set up to control operations and reliability. In the past, control areas were predominately the broad geographic areas of electric utilities that owned and operated generation and transmission. This included investor owned utilities and large quasi-governmental operations like Tennessee Valley Authority and Bonneville Power Authority. There also exist tight power pools like ERCOT, NEPOOL, NYISO, and PJM. These pools began under the auspices of providing mechanisms to ensure reliability and have



Note: CC/CT = combined cycle/combustion turbine.

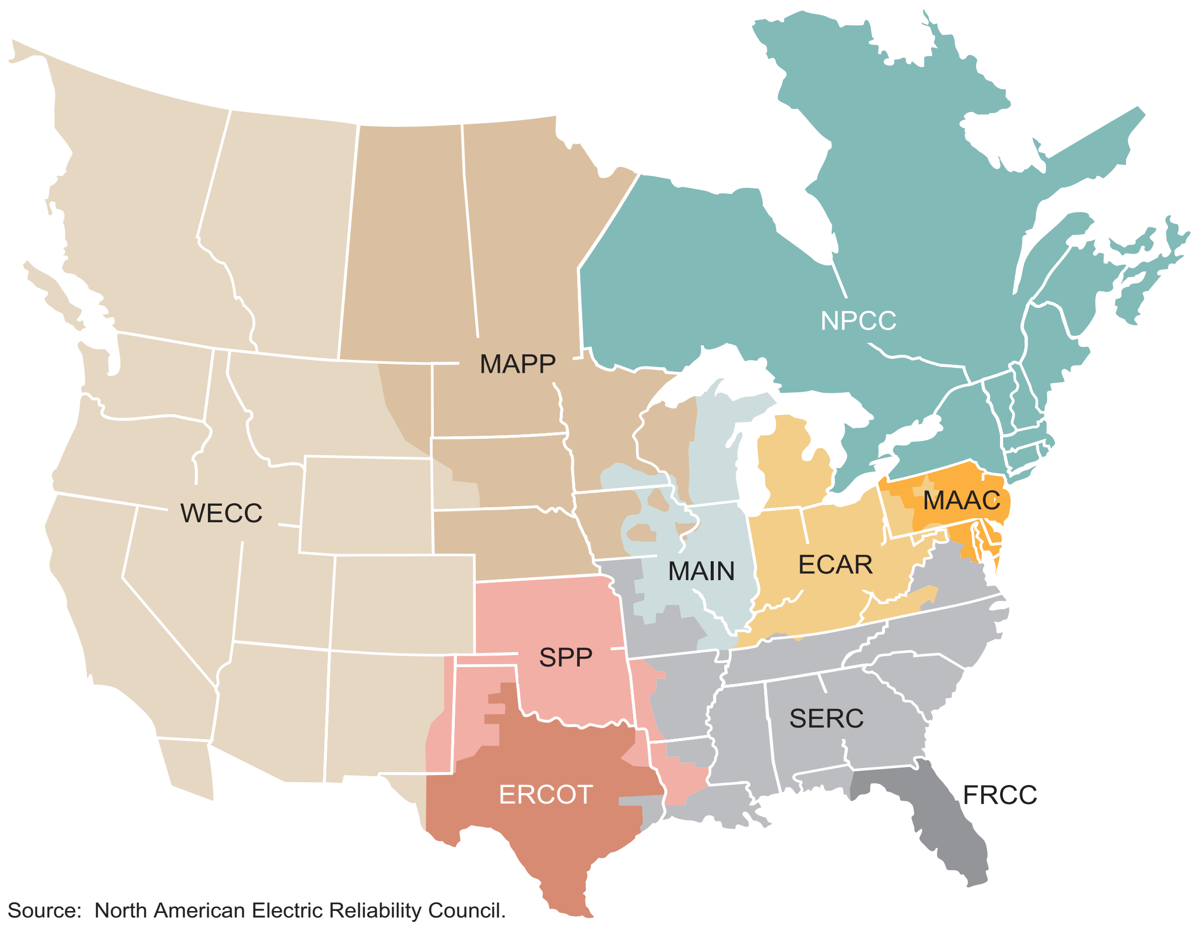
Figure D5-2. Projected Lower-48 Electric Generating Capacity – Year 2005, Reactive Path Scenario evolved into defined market centers with central dispatch of connected power plants and a variety of rules governing commercial transactions and power flows. The reliability of the grid became of paramount importance to the industry and government following the Northeast blackout of 1965. To minimize the risk of this event reoccurring, an industry cooperative was formed and is known as the North American Electric Reliability Council (NERC). Figure D5-3 shows the regional councils making up NERC.

The function of NERC is to establish procedures and processes to provide guidance in making the grid reliable. Currently the NERC participation and suggested guidelines are voluntary. However, a blackout in late 2003 in parts of the eastern United States and Canada has many stakeholders in the electric industry suggesting the reliability guidelines should become mandatory upon the owners and operators of transmission grids and power generation facilities.

Practically speaking there is no electric power storage; therefore demand must be constantly balanced by generation. The most direct measure of the grid's balance is the frequency at which electricity is oscillating. The grid operates by having each control area ensure that its frequency stays within certain tolerances around the desired 60 Hz (cycles per second) level. To compensate for unexpected spikes in demand or sudden outages of generation, the grid requires a portion of the generation resources to be held in "spinning" reserve, ready to deliver power on very short notice.

C. Electric Demand Profiles

Electric demand fluctuates daily as a function of weather, day of the week, and time of day. The time of day driver reflects the normal usage patterns of industrial, residential, and commercial customers where the lowest usage is in the hours past midnight. Typically weekend demand is lower than weekday demand with



Source: North American Electric Reliability Council.

Figure D5-3. NERC Regions

reductions in load from the commercial office space and industry. Power demand also has seasonal characteristics with summer and winter periods having higher demands than the spring and fall, which are normally called "shoulder months." Electric demand is also closely coupled to economic activity in the United States economy.

Satisfying the daily load shape is an important consideration that drives natural gas demand. An electrical system's peak demand can exceed its nighttime low demand period by more than 100%. An example of a large power pool's generation shape is shown in Figure D5-4. The total load of this power pool would equal the generation plus/minus imports from the interconnected grid. Since most power generation technologies cannot cycle completely off overnight, the system needs to balance its projected next day load against the physical constraints of minimum loads on its baseload generation. This balancing act includes reliability requirements, the variable economic considerations of each unit that is on-line, its shutdown and startup costs, plus its ability to ramp up and down to meet short-term load fluctuations. Transmission constraints and the ability to sell or purchase power from the grid also play a role in determining how a system dispatches its units and plans for the next day and upcoming week projected demands and market conditions. A brief description of different generation technologies role in meeting hourly/daily demand is provided below. A more comprehensive treatment of generation is found in the Electric Power Generation Fleet section of this chapter.

In a typical region the installed nuclear plants operate at maximum achievable output every hour possible. Their variable costs are the lowest of any non-hydro or renewable technology generation so maximum output is the desired economic outcome. The typical nuclear unit has a 25-50 day outage every 18 months for refueling and maintenance.

Coal fueled generating units are normally considered baseload or intermediate load units. Baseload units are typically larger, newer, and more emission controlled than units that are classified and operated as intermediate load units. In regions where installed capacity of coal and nuclear based generation exceeds 50% of the total generation, even the baseload coal units must reduce their output during the night to accommodate the need to have other units running and available to meet the next day's peak demand.

Hydroelectric power units consist of either small, run of the river units or dam storage. Dam storage can either be a once through flow of water past turbines, or it can be pumped storage. Dam storage can either operate as a baseload source of power, peaking power, or a combination of both. Pumped storage takes advantage of lower cost off-peak power to pump water from a lower level basin of water into the higher level basin. The water is then released during peak periods of demand.

Combined cycle plants run on either natural gas or distillate fuel oil. Some older technologies run on residual oil in other parts of the world. Most combined cycles are gas only fuel. Some plants are capable of running only the gas turbine portion as a simple cycle unit and thus operate as a peaking unit. However, the optimum heat rates and efficiency are gained when the units are operated in the combined cycle mode. In the combined cycle mode, the units take a few hours to start up and become synchronous with the grid.

Simple cycle turbines can run on either natural gas or distillate oil. Depending upon the type of turbine they can "quick start" in 10 minutes or less. The newer, larger, more efficient turbines normally take 30 minutes or more to bring on-line.

Renewable technologies vary by type. Wind is only available when the wind is above the threshold velocity. Biomass tends to be baseloaded, but can have seasonal aspects depending upon the source of the biomass. The other technologies have their own characteristics as they fit into the supply stack of generation available to meet load.

Each regional market has a supply stack whether it is an organized power pool like PJM[1] or if it is just the interconnected control areas with an active wholesale market. A supply stack is the available generation that could be used to meet power demand. The typical way to represent a supply stack is shown in Figure D5-5. The units are "stacked" by variable costs: including fuel, variable O&M, emissions, and any other appropriate charge. The shape and composition of the supply stack varies due to outages and the

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1 PJM is a regional transmission organization that coordinates the movement of electricity in all or parts of Delaware, Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia, and the District of Columbia.

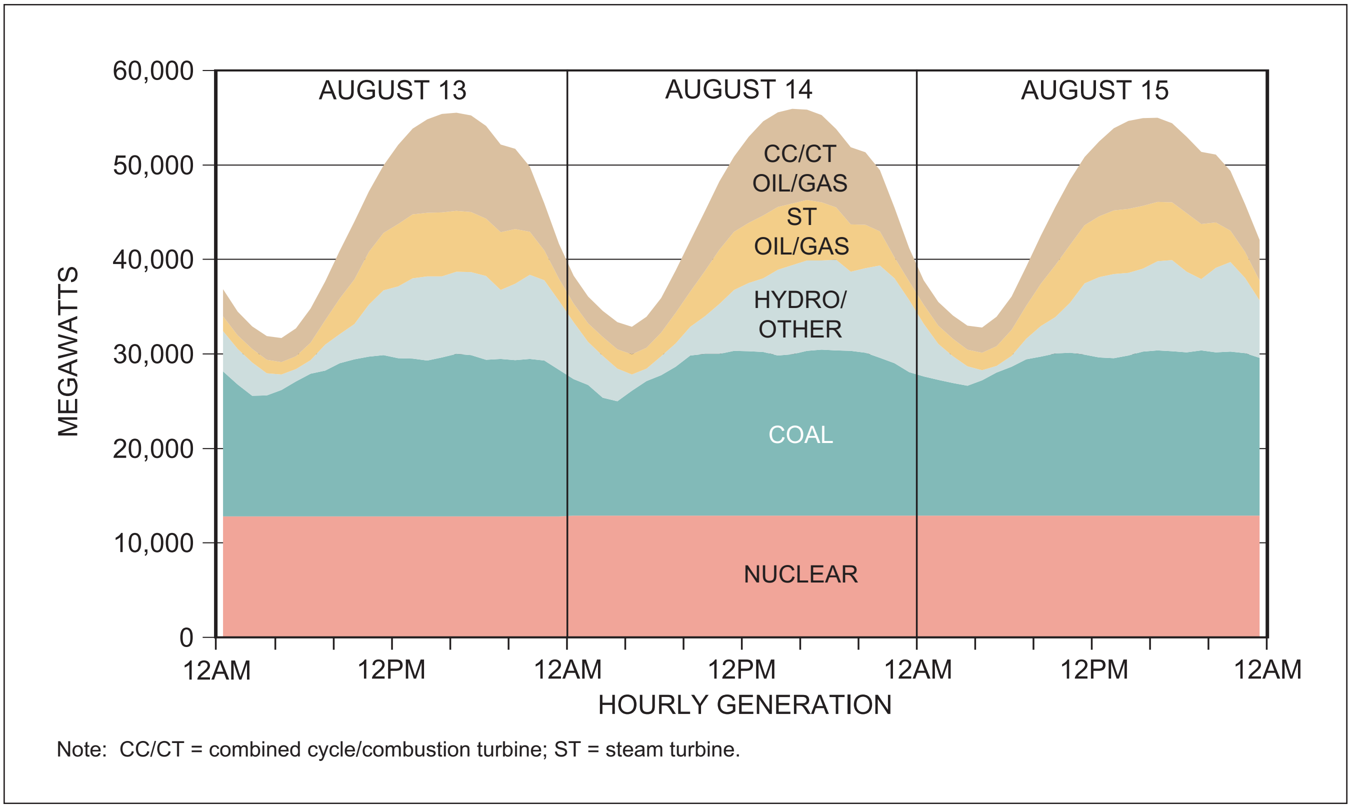


Figure D5-4. PJM Hourly Generation by Fuel Type, August 13-15, 2002

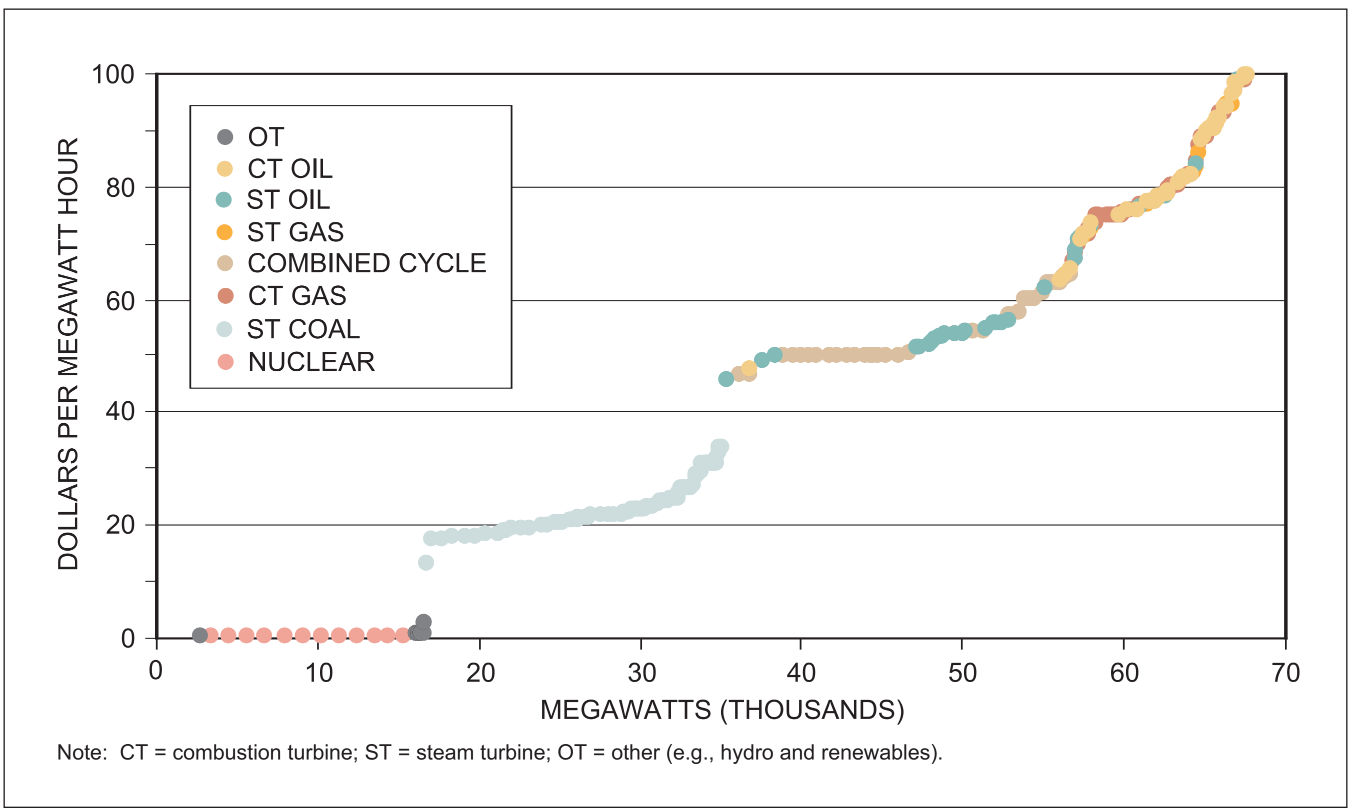


Figure D5-5. Supply Stack for Large Power Pool effective generating capacity of individual units. Outages are both planned for maintenance and unplanned, or forced outages, which occur whenever some type of mechanical failure occurs that does not allow the unit to continue to operate in a safe and environmentally controlled manner. Fossil units have different effective capacities in the winter and summer due to the thermodynamic properties of the steam cycle. Capacity ratings are lower in hotter weather than in the winter. Combustion turbines also experience a difference in capacity rating with higher ratings in colder weather due to the density of air used in the combustion process.

Figure D5-5 shows the relative competitiveness of the different units in this power pool, but the actual dispatch of units to meet load is more complex than starting at the bottom of the stack and dispatching just enough generation to meet projected load. The need to meet the projected peak demand is balanced against physical constraints of minimum loads on the generating units that run overnight. Large coal units with SOx and NOx emission controls running may have overnight minimums greater than 50% of their rated capacity. Smaller coal units have a wide range of minimum capability ranging from 33% to as much as 60%. NERC and the organized power pools also have requirements for spinning reserve, which is an amount of generation readily available to meet sudden losses of other units, or higher loads. Gas-fired combined cycle units also have overnight minimum load constraints, but typically have more flexibility than coal units.

Natural gas is increasingly the fuel that supplies generation on the margin of dispatch in most areas. In power pools like ERCOT (Electric Reliability Council of Texas), natural gas is the marginal fuel over 95% of the time. In areas with mostly coal generation, natural gas is increasingly meeting short-term peaks loads and slowly increasing its share of overall generation. Figure D5-6 projects the percentage of hours that natural gas or oil generation is on the margin by broad region in 2004. This is a substantial change from the late 1990s and is likely to persist or expand even more over the next 5 years as recent gas-fired generation additions to the generating capacity meet electric power demand growth.

The higher utilization of gas-fired generation will ultimately lead to more natural gas consumption. However, in the near term, increased efficiency of combined cycle plants in lieu of older steam plants are offsetting the effects of higher utilization. These older steam plants have heat rates ranging from 11,000 to over 14,000 Btu/KWH. The newer technology combined cycle plants consistently achieve heat rates less than 7,000 Btu/KWH.

D. Electric Demand Growth

Everyone agrees that annual electric energy use grows as a function of GDP growth in the United States. The precise nature of the function is subject to vigorous debate in academia, industry, and by the Demand Task Group's Power Generation Subgroup. Figure D5-7 depicts the level of GDP and annual electric energy demand for the period 1982-2002. The electric power demand is not weather normalized in this chart, but still shows the strong correlation that exists. The overall rate of growth in electric energy demand has been modeled in the Reactive Path scenario to vary from a starting factor of 0.72 times the forecasted growth in GDP in 2003 and decreasing linearly to a level of 0.62 times the forecasted growth in GDP by 2025. The growth rates were applied regionally by the modeling effort. The regional breakout is shown in Table D5-1.

Peak demand for electricity is growing slightly faster than electric energy. This is a result of greater saturation of electric cooling and heating equipment and usage patterns in the residential and commercial consuming segments. Industrial users and some commercial establishments have used technology to manage peak demands when the economics and utility rate structures create an economic advantage to controlling peak demands. Increased usage of time-of-day rates and associated technology to manage equipment would further limit peak demand growth rates.

Most usages of electric power are considered relatively price inelastic with higher prices only modestly reducing consumption. This "truism" is even more strictly applied to residential demand. The experiences in the western United States during very high power and natural gas prices at the end of 2000 suggests that high energy prices do make a difference in consumer behavior if the high prices are communicated in a manner that creates awareness and if economically felt by the consumer. Both of these requirements were met during the high price event in 2000. Media publicity was very high, governmental officials made numerous appeals for conservation, and actual shortages reinforced the reality of the

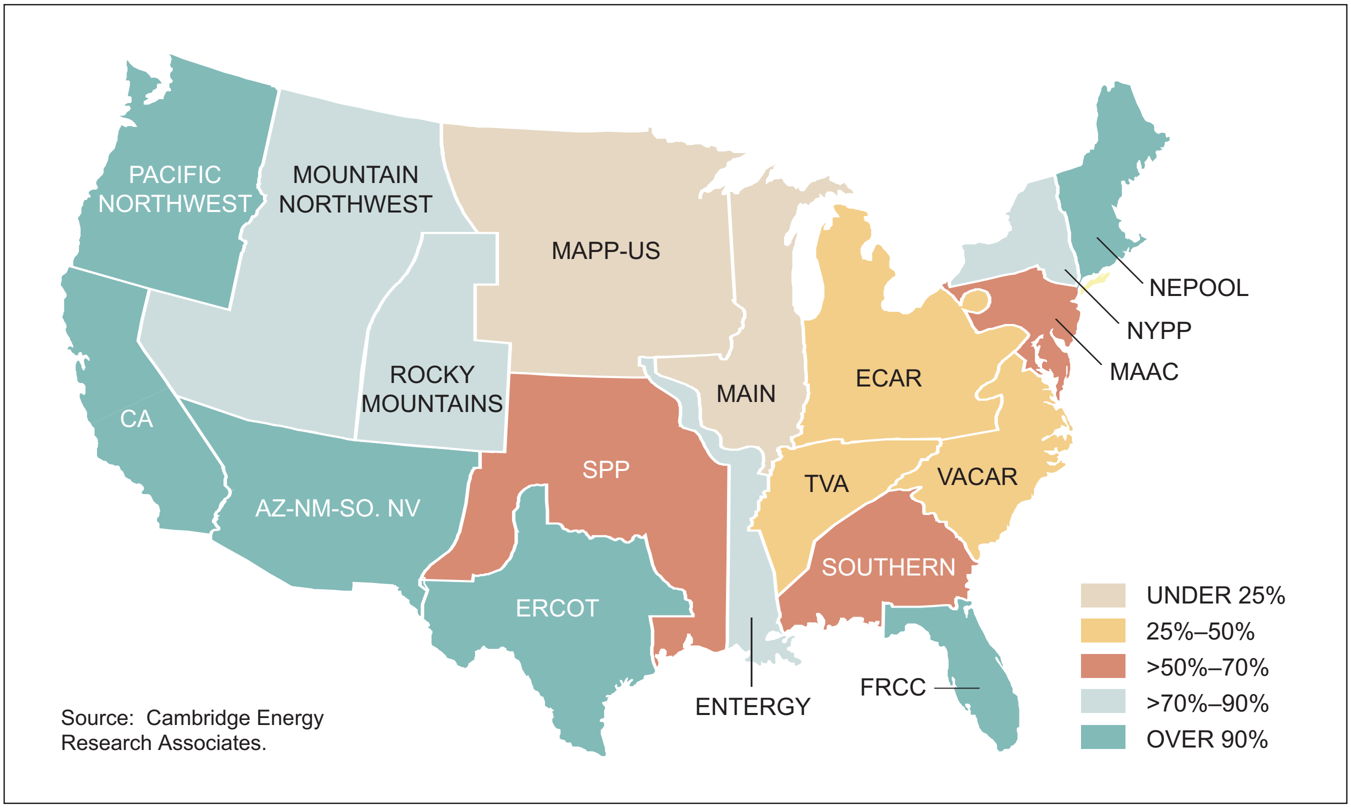


Figure D5-6. Percentage of Hours on Margin

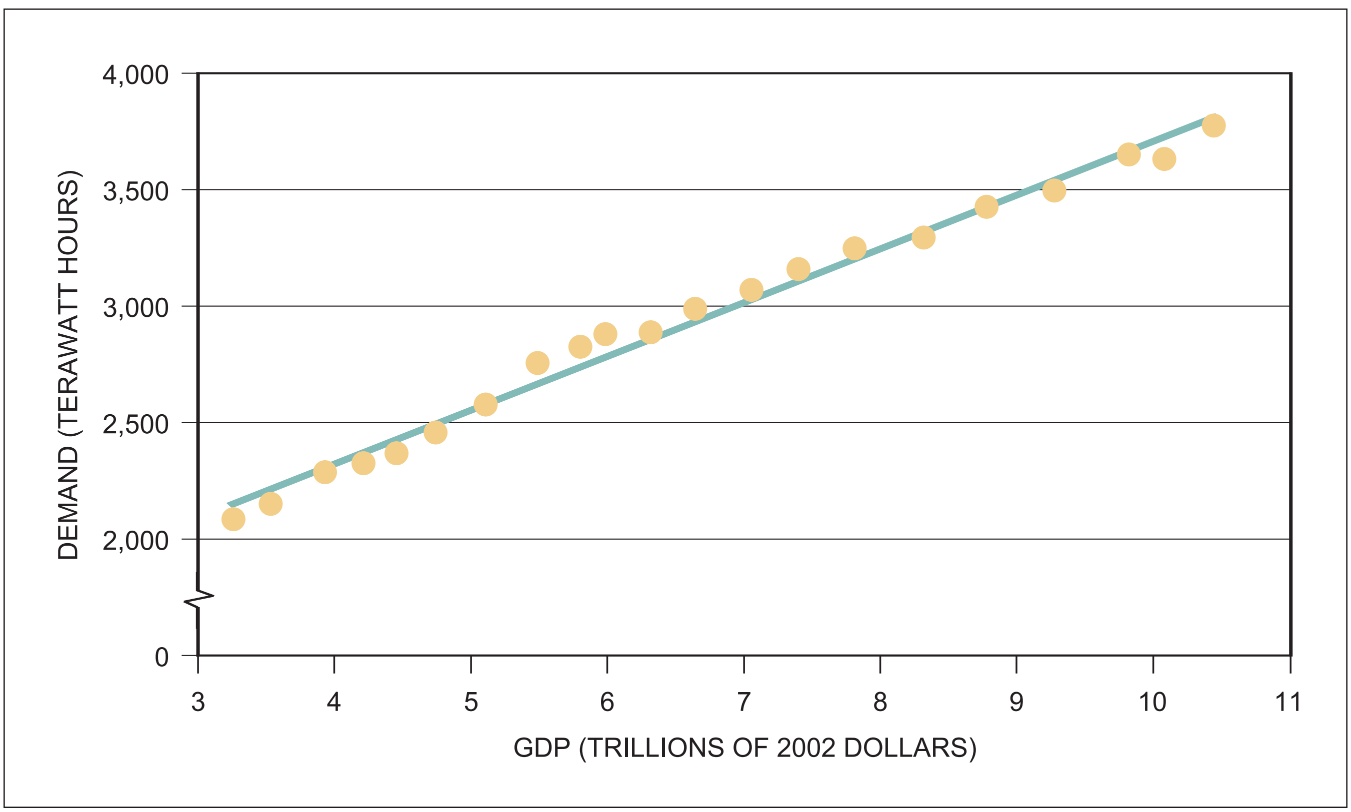


Figure D5-7. Electric Power Demand vs. GDP, 1982-2002

Region*	% Average Annual Electric Energy Growth	% Average Annual Household Growth
New England	1.9	0.7
New York	1.7	0.8
MAAC	1.7	0.8
SERC	2.3	1.2
Florida	2.4	1.4
ECAR	1.5	0.8
MAIN	1.9	0.6
MAPP	1.9	0.6
SPP	1.9	1.2
ERCOT	2.1	1.2
CA/NV	2.4	1.0
Pacific NW	2.4	1.0
Rockies	2.3	1.5

*Regions are based on North American Electric Reliability Council (NERC) regions.

Table D5-1. Regional Growth Rate of Electric Energy and Households

energy situation facing the consumers. While electricity received more of the publicity, the cause and effect between gas prices and electricity became evident to most market participants and consumers did reduce electric demand. Numerous aluminum smelters stopped operations in the Pacific Northwest, other industries were affected, and residential and commercial customers exhibited conservation.

With the exception of a few notable real time pricing programs, retail electric rates generally do not send such clear price signals to customers. Average costs of generation and power purchases, prior period adjustments and numerous other factors cause retail power prices to lag wholesale prices and the marginal cost of generating power. The factors make a clear-cut analysis of price elasticity more difficult. This is true even in the industrial segment of consumption where GDP and energy intensity also drive power demand. Figure D5-8 shows that electricity sales to industrials, as measured by the monthly Federal Reserve Board survey, have fallen and stagnated since the high point in the year 2000. The economic downturn was primarily responsible for reduced power demand, but high-energy prices played a role in moderating demand. It has been speculated that the impact of high natural gas prices on the operations of energy-intensive industrials resulted in a bigger impact on their power demand than the outright power prices that they experienced. There is inadequate data available to confirm that speculation, but the outreach meetings of the power team and industrial teams provided substantial anecdotal data.

Peak demand is primarily a function of weather. As air conditioning has become more prevalent over the last 40 years, the system has become summer peaking. The highest demands are typically experienced in the hot summer afternoons of July or August during the days of Monday through Thursday. The weekends, beginning Friday afternoon, have lower loads.

Due to the greater saturation and more significance of air conditioning in the hotter regions, the increased electricity use in response to higher temperatures is greater in the South. Figure D5-9 shows the change in peak demand in percentage terms per 1 degree Fahrenheit change in summer afternoon temperatures. For example, a 1-degree increase in temperature across a day in Atlanta will increase peak demand by 1.2%. Therefore, weather that is 5 degrees above normal (with 100 degrees rather than 95 on an August afternoon) will increase peak demand by 6% and will consume 6% of a 13-17% reserve margin.

The peak demand is also a function of "heat build ups." That is, if it has been hot for a few days, the load will be higher due to some combination of a build up in walls and buildings and the consumers' diminished tolerance for hot weather. In PJM at 2 pm on a Wednesday afternoon, for example, a 1-degree change in that single hour's temperature will increase electricity demand about 500 megawatts (MW) (compared to a day differing only by that one hour's temperature). If the temperature has been 1 degree hotter in each of the last 24 hours, the 2 pm temperature will be about 1,000 MW higher (compared to a day in which the temperature has been lower by 1 degree in each of the previous 24 hours). (These relationships were developed in 2001 based on hourly data from 1995-2000 before the recent geographical expansions in PJM. Since the housing and appliance stock changes slowly, these relationships change very slowly over years.)

Sometimes these calculations of "weather normal" or "average weather" peak demands are developed without accounting for the variation by day of the week or holidays, resulting in overestimates of the

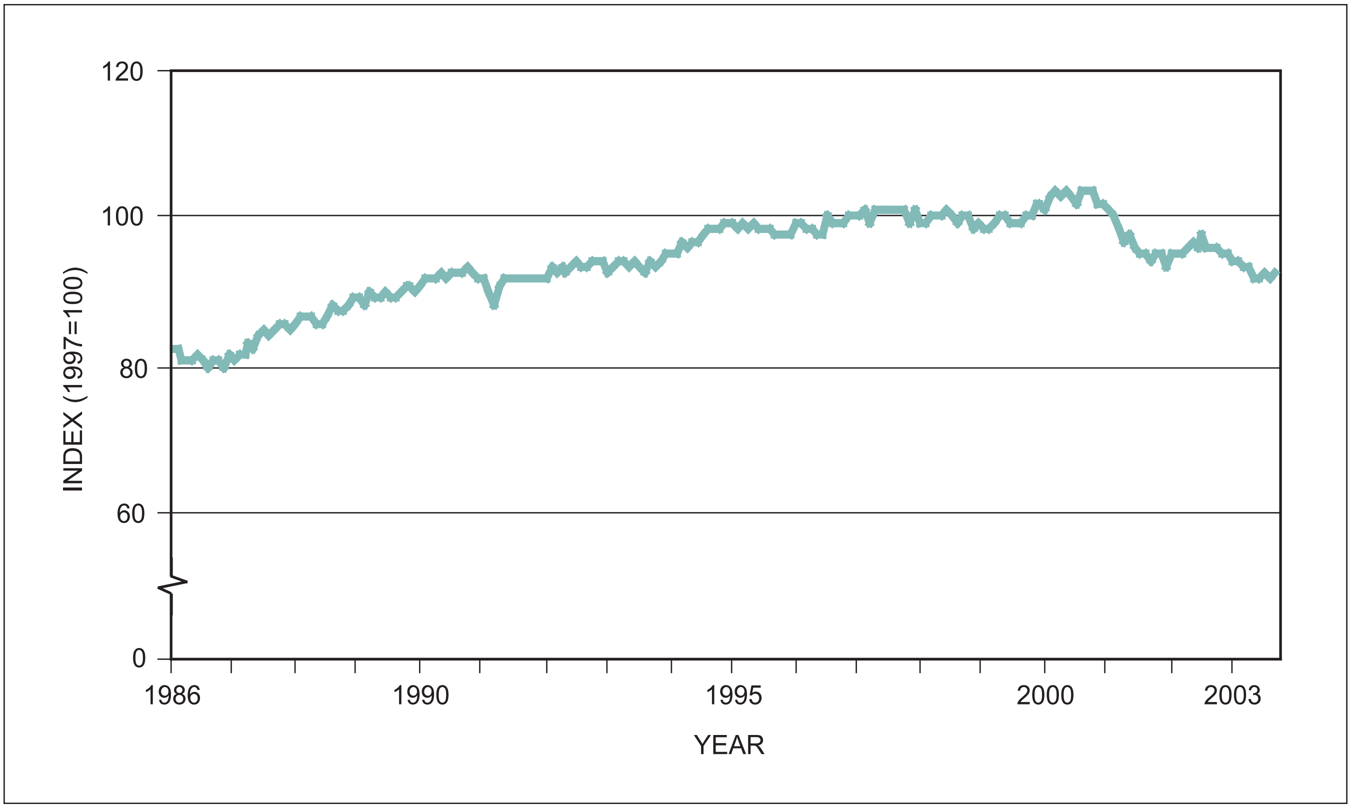


Figure D5-8. Federal Reserve Board Electric Use by Industrials

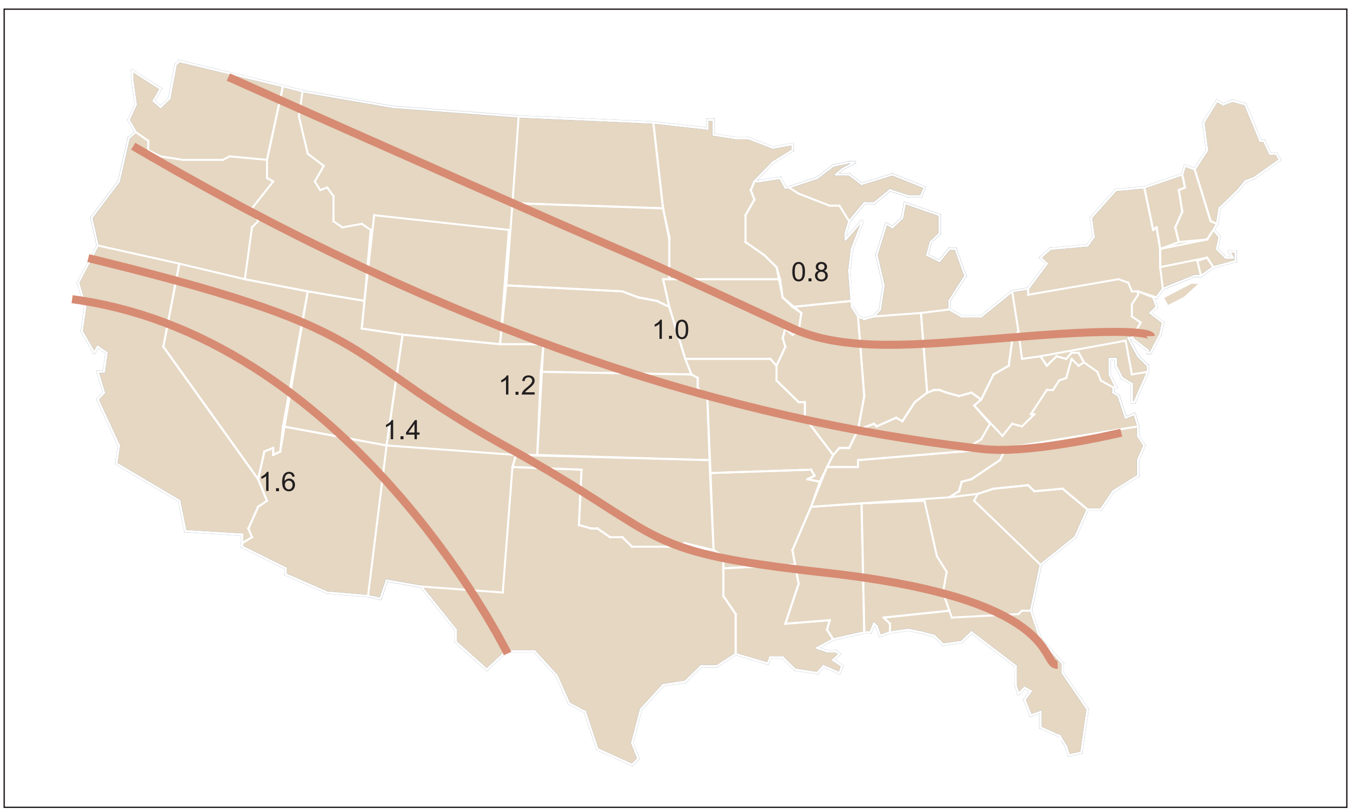


Figure D5-9. Change in Load with Temperature standard error and underestimates of the peak demand. As an example of the factors that matter in the PJM analysis, the demand at 2 pm on a July afternoon would be 900 MW lower on Friday compared to Tuesday through Thursday, a few thousand MW lower if the day is July 4, and more than 7,000 MW on a Sunday.

Figure D5-10 shows the single hour effects of a 1-degree Fahrenheit increase in temperature in PJM for each of the 24 hours in a day by month. For example, in the winter, a 1-degree increase in temperature will lower the load by up to 200 MW and in the summer it will increase the load by up to 600 MW.

The temperature has an important effect on gas use, and in the West the effect of another aspect of weather is even greater. During drought years, the hydro available can be as low as 50% of normal in California and the Desert Southwest – dropping from 50 TWH to 25 TWH. The vast majority of the shortfall in energy must be generated with gas. Because the droughts last for months, the additional gas use can deplete storage and significantly drive up prices.

II. Regulatory Issues Impacting Generation and Demand

A. Renewable Portfolio Standards

A Renewable Portfolio Standard (RPS) is currently a state implemented policy that requires retail suppliers of electricity (otherwise referred to as load serving entities, or LSEs) to meet a portion of their energy supply needs with eligible forms of renewable energy. RPS policies are generally designed to maintain and/or increase the amount of generation capacity contributed by renewable energy to electricity supply. An RPS normally establishes numeric targets for renewable energy supply, thus providing a market for qualifying technologies to meet those targets. LSEs can meet their requirements with renewable energy facilities that they own, or construct new, or through bilateral purchases of renewable energy from other suppliers. In some states, LSEs can use tradable renewable certificates, or TRCs, to meet their RPS obligations. Where TRCs are used, one is created for each megawatt hour (MWH) of renewable energy generated, and it can be traded separately from the underlying electricity generation.

Currently 13 states have RPS while several other states have goals for renewable energy or are considering some type of RPS action. Figure D5-11 shows the current states that have implemented RPS. The most aggressive programs are in the southwestern United States, with California setting the highest standard at 20% by 2017 and Nevada targeting 15% by 2013. In the Reactive Path scenario, these states were modeled to exceed the targeted amounts of renewable generation capacity and contained the bulk of new renewable capacity. In the Balanced Future scenario, renewable capacity was dispersed geographically, with the western and southern states generally meeting state mandated targets while capacity in the Midwest and Northeast were not modeled to meet the timetables currently required.

The model used wind power as a proxy for all renewable power sources as a simplifying assumption, *not* as an endorsement of that resource versus other viable technologies. This has some minor issues surrounding capacity factors since biomass, geothermal, and certain other technologies have substantially different capacity factors/availability than does wind power. However, given renewable capacity trends this simplifying assumption was deemed to provide reasonable quantities of annual electric energy to the balance of supply and demand.

B. New Source Review

The Environmental Protection Agency's (EPA) New Source Review (NSR) regulations have had and continue to have the potential to substantially affect investments in existing power plant capacity, particularly coal-fired generation. Uncertainty over the rules interpretation, threshold events and conditions that require its application all combined to restrict cost effective improvements and maintenance that in some cases would have led to reduced emissions and in most cases would have improved energy efficiency. NSR is a Clean Air Act requirement that State Implementation Plans must include a permit review applying to the construction and operation of new and modified stationary sources in nonattainment areas. This requirement was instituted to satisfy national ambient air quality standards. If maintenance, or a plant modification triggered NSR, the generating unit was required to meet Best Available Control Technology (BACT) and Emission Offsets in some cases.

EPA issued a new rule that became final on October 27, 2003 that clarified several of the areas that have discouraged industry investment in existing facilities. These clarifications would have the effect of providing

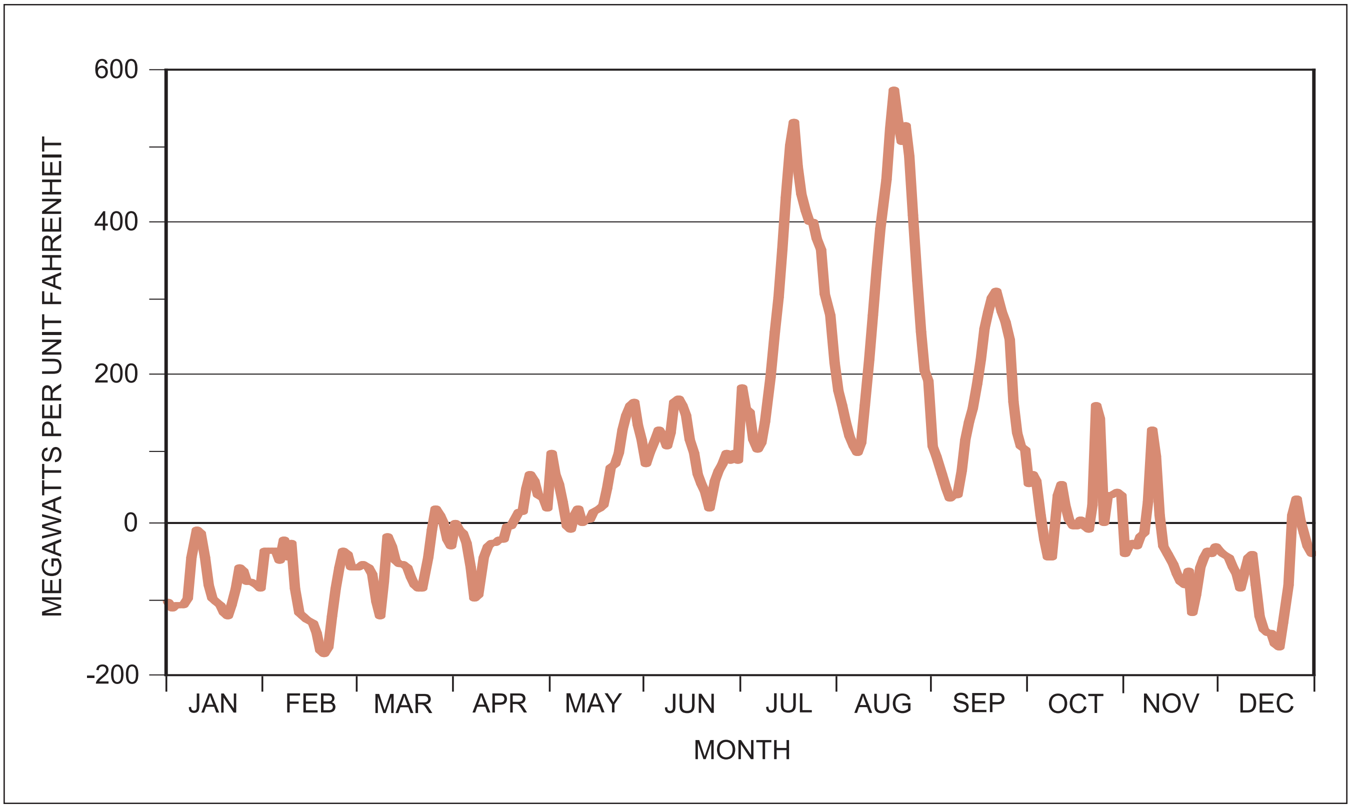


Figure D5-10. Single Hour Effects of a 1-Degree Fahrenheit Increase in Temperature in PJM

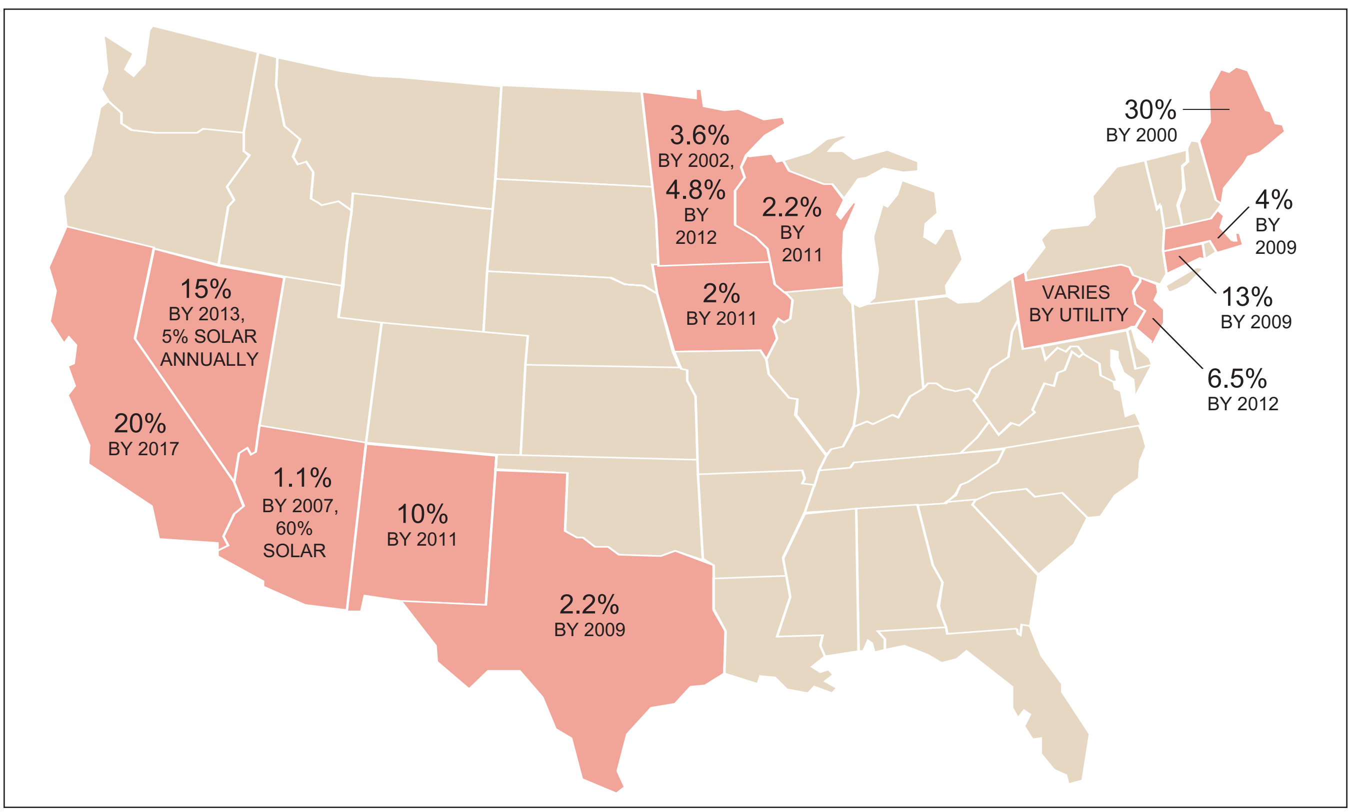


Figure D5-11. States with Renewable Portfolio Standards a higher degree of certainty in maintenance and replacement of equipment decision making. Under this rule, an equipment replacement activity automatically will be excluded from NSR requirements if:

- It involves replacement of any existing component(s) of a process unit with an identical or functionally equivalent component(s);
- The fixed capital cost of the replaced component, plus the costs of any repair and maintenance activities that are part of the replacement activity (such as labor, contract services, major equipment rental, etc.), does not exceed 20% of the replacement value of the entire process unit;
- The replacement(s) does not change the basic design parameters of the process unit; and
- The replacement(s) does not cause the unit to exceed any emissions limits.

The rule allows sources to use the following approaches to determine the replacement value of a new process unit:

- Replacement cost;
- Invested cost, adjusted for inflation;

The insurance value of the equipment, where the insurance value covers complete replacement of the process unit; or

- Another accounting procedure, based on Generally Accepted Accounting Principles.

In addition, the final rule also:

- Defines a "process unit;"
- Specifically delineates the boundary of a process unit for certain specified industries;
- Defines a "functionally equivalent" component; and
- efines how an owner or operator establishes basic design parameters for electric utility steam generating units and for other types of process units.

Almost immediately, the Attorney's General of 12 states (CT, MA, MD, ME, NH, NJ, NM, NY, PA, RI, VT, and WI) and several Northeastern cities sued the EPA to block implementation of the final rule. This ongoing litigation is likely to continue the climate of uncertainty and reduce any incentive to improve the efficiency of existing facilities.

C. Appliance Efficiency Standards

U.S. consumers spend more than $100 billion for the energy to power appliances each year. They also spend approximately $20 billion to buy new appliances each year. Any increases in efficiency create potentially significant reductions in the rate of electric power growth. These embedded efficiencies are one of the key drivers to the assumption documented above for decreasing the energy intensity as a function of GDP growth. The assumptions of increased efficiencies was decided upon by the power team in recognition that existing law calls for efficiency standards to continue and a general acceptance in the consumer marketplace for the increased cost of more efficient appliances. The subject of mandatory efficiency standards has historically created conflict between two schools of thought. Some advocates insist market forces alone should decide the relative efficiencies of new appliances while other advocates believe government mandates are needed to overcome market failures. They cite third-party decision makers for initial appliance installation (builders/developers) and inadequate consumer education. The NPC power team does not take an advocacy position for or against these standards, we have merely recognized they exist and will likely continue to expand in their areas of influence.

Efficiency standards started in response to the energy crisis of the 1970s. In 1975, The Energy Policy Conservation Act (EPCA) directed the U.S. Department of Energy (DOE) to develop voluntary appliance efficiency targets. The National Energy Conservation Policy Act of 1978 (NECPA) directed DOE to set Minimum Energy Performance Standards (MEPS) in replacement of the EPCA voluntary targets, and gave federal MEPS preemption over state standards.

The National Appliance Energy Conservation Act of 1987 and amendments of 1988 (NAECA) established MEPS for the twelve categories of appliances covered under EPCA and NECPA, and instructed DOE to set MEPS for one additional product if technically feasible and economically justified. It also required DOE to review and update the MEPS to keep pace with technological improvements, and strengthened the preemption of federal MEPS over state standards. The

Energy Policy Act of 1992 directed DOE to develop voluntary national testing and information programs for widely used types of office equipment. It established MEPS for nine categories of energy- and water-using commercial sector products, electric motors, lighting products, plumbing products, and office equipment. It instructed DOE to set MEPS on three additional products if technically feasible and economically justified.

NECPA also required the Federal Trade Commission (FTC) to mandate labels for appliances that indicate their energy consumption. The FTC issued guidelines for the comparative label in a rule promulgated in November 1979. This required manufacturers of the major home appliance types to place energy labels on their appliances starting in 1980. Finally, there are two voluntary endorsement labeling programs in the United States. The Energy Policy Act of 1992 directed DOE to support a voluntary office equipment program (Energy Star). Energy Star is a joint effort with DOE and the U.S. Environmental Protection Agency (EPA); the lead agency depends on the product. Appliances labeled under this program include office equipment, household appliances and electronics, air conditioners and fans, furnaces and boilers, residential lighting products, and windows and roof products. In addition, a non-profit organization called Green Seal has implemented a voluntary ecolabel since 1992 – the Green Seal of Approval – which endorses energy efficient products. Appliances labeled under this program include lamps, clothes washers and dryers, dishwashers, freezers, ranges/ovens, refrigerators, refrigerators-freezers, residential air conditioners, and heat pumps.

Built into the national legislation for establishing appliance standards are provisions to periodically revise and update them. As technology continues to advance, and economic conditions change, existing standards become obsolete and potential avenues for new savings are created. DOE recently proposed new standards for eight appliance products: water heaters, fluorescent ballasts, room air conditioners, pool/spa heaters, mobile home furnaces, non-ducted heating equipment, ranges and ovens, and televisions.

Under the North American Energy Working Group, Canada and Mexico are coordinating the efficiency standards of appliances in their countries. The Working Group has compared standards and labels in the three countries, and has reached the following conclusions. Out of 46 energy-using products for which at least one of the three countries has energy efficiency regulations, three products – refrigerators/freezers, split system central air conditioners, and room air conditioners – have similar or identical MEPS in the three countries. These same three products, as well as three-phase motors, have similar or identical test procedures. There are ten products with different MEPS and test procedures, but which have the near-term potential to develop harmonized test procedures, MEPS, and/or labels. These are listed in Table D5-2.

The United States does not have a clear-cut national building energy standard, although standards exist for federal buildings and federally assisted housing, and most states have adopted some form of building codes for residential, commercial, or both. The energy code to measure against for most residential voluntary rating systems is the International Energy Conservation Code (IECC), which superceded the Model Energy Code (MEC) in 1998. The IECC basically ensures that a planned building has minimum requirements for thermal resistance in the building shell and windows; minimum air leakage; and minimum equipment efficiencies.

Different versions of the MEC/IECC have been adopted by states, creating a complicated patchwork of residential and commercial codes across the country. The federal Energy Policy Act of 1992 requires states to review and adopt the MEC, or justify to the Secretary of Energy its reasons for not adopting it. Figure D5-12 shows the status of states adoption of building

Minimum Energy Performance Standards (MEPS)	Testing Procedures/Labels
Clothes Washers	Clothes Washers/Dryers
Dishwashers	Dishwashers
Fluorescent Lamp Ballasts	Fluorescent Lamp Ballasts
Fluorescent Lamps	Fluorescent Lamps
Incandescent Lamps	Incandescent Lamps
Motors	Water Heaters
Small Motors	Transformers
Single packaged CAC & HP	

Table D5-2. Potential Uniform North American Appliance Testing Standards

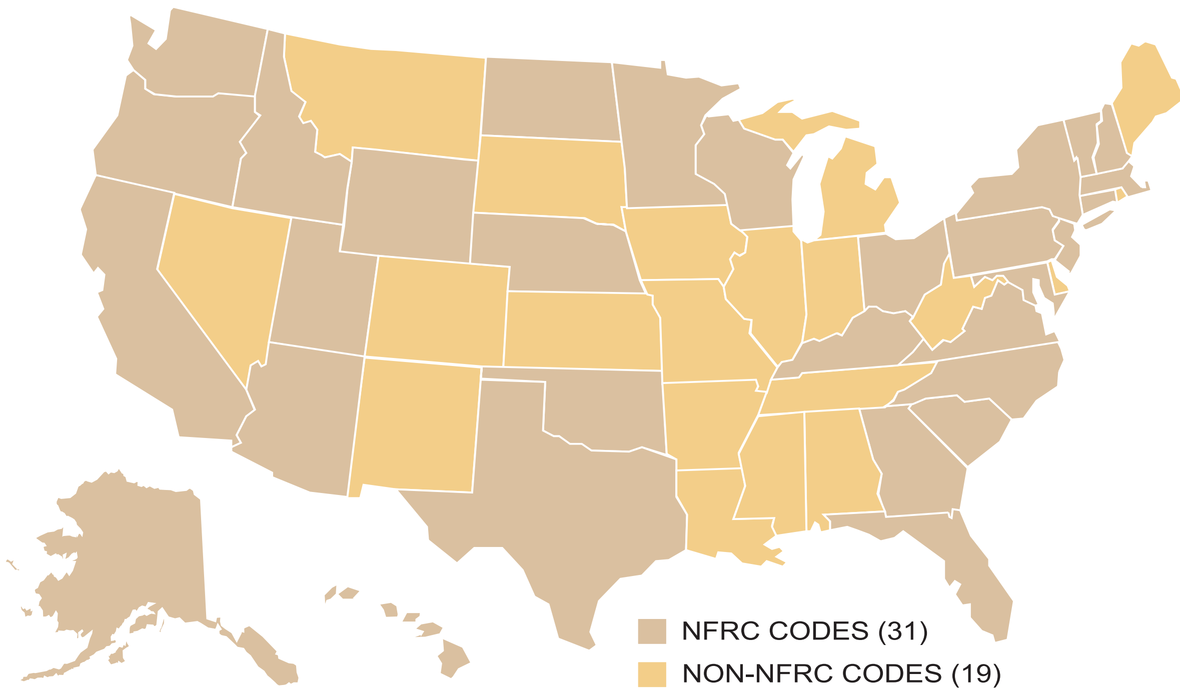


Figure D5-12. Status of State Adoption of NFRC Building Codes in 2002

standards. The NPC power team does not take an advocacy position for or against these standards, we have merely recognized they exist and will likely continue to expand in their areas of influence.

III. Environmental Issues

When you say environmental, most people automatically think only of air quality issues that face the electric power industry. Air quality regulations and uncertainty are the biggest environmental issue facing the power industry that will ultimately affect natural gas demand, however, the power industry also faces substantial challenges in water quality, solid waste disposal, and the spent nuclear waste disposal issue. Each of these issues has some potential impact on natural gas consumption, as a result of generation capacity choices the industry will make. They are smaller impacts and more difficult to quantify than the air quality regulations in the discussion below.

A. Current Legal Framework

Although the 1990 Clean Air Act Amendments are federal law covering the entire country, the states do much of the work to carry out the Act. For example, a state air pollution agency holds a hearing on a permit application by a power or chemical plant and enforces violations of air pollution limits. Under this law, EPA sets limits on how much of a pollutant can be in the air anywhere in the United States. This ensures that all Americans have the same basic health and environmental protections. The law allows individual states to have stronger pollution controls, but states are not allowed to have weaker pollution controls than those set for the whole country.

The law allows states to take the lead in carrying out the Clean Air Act, because pollution control problems often require special understanding of local industries, geography, housing patterns, etc. States have to develop state implementation plans (SIPs) that explain how each state will do its job under the Clean Air Act. A state implementation plan is a collection of the regulations a state will use to clean up polluted areas. The states must involve the public and other stakeholders, through hearings and opportunities to comment, in the development of each state implementation plan. EPA must approve each SIP, and if a SIP isn't acceptable, EPA can take over enforcing the Clean Air Act in that state.

A few common air emissions are found all over the United States. EPA calls these emissions criteria air pollutants because the agency is supposed to regulate them by first developing health-based criteria (science-based guidelines) as the basis for setting permissible levels. One set of limits (primary standard) is supposed to protects health; another set of limits (secondary standard) is intended to prevent environmental and property damage. A geographic area that meets or does better than the primary standard is called an attainment area; areas that don't meet the primary standard are called nonattainment areas. Although EPA has been regulating criteria air pollutants since the 1970 Clean Air Act was passed, many urban areas are classified as nonattainment for at least one criteria air pollutant. Table D5-3 lists some of the EPA's Criteria Air Pollutants.

EPA refers to chemicals that cause serious health and environmental hazards as hazardous air pollutants (HAPs) or air toxics. When cars and trucks burn gasoline, air toxics come out of the tailpipes. (These air toxics are combustion products – chemicals that are produced when a substance is burned.) Air toxics are released from small stationary sources, such as dry cleaners and auto paint shops. Large stationary sources, such as chemical factories and incinerators, also release hazardous air pollutants. The 1990 Clean Air Act deals more strictly with large sources than small ones, but EPA must regulate small sources of hazardous air pollutants as well.

To reduce air toxics pollution, EPA must first identify the toxic pollutants whose release should be reduced. The 1970 Clean Air Act gave EPA authority to list air toxics for regulation and then to regulate the chemicals. The agency listed and regulated seven chemicals through 1990. The 1990 Act includes a list of 189 hazardous air pollutants selected by Congress on the basis of potential health and/or environmental hazard; EPA must regulate these listed air toxics. The 1990 Act allows EPA to add new chemicals to the list as necessary.

To regulate hazardous air pollutants, EPA must identify categories of sources that release the 189 chemicals listed by Congress in the 1990 Clean Air Act. Categories could be gasoline service stations, electrical repair shops, coal-burning power plants, chemical plants, etc. The air toxics producers are to be identified as major (large) or area (small) sources.

Once the categories of sources are listed, EPA will issue regulations. In some cases, EPA may have to specify exactly how to reduce pollutant releases, but wherever possible companies will have flexibility to choose how they meet requirements. Sources are to use Maximum Achievable Control Technology (MACT) to reduce pollutant releases; this is the highest level of pollution control.

EPA must issue regulations for major sources first, and must then issue regulations to reduce pollution from small sources, setting priorities for which small

Name/Descriptor	Source(s)
Ozone (Precursor to smog)	Chemical reaction of VOC and NOx
Volatile Organic Compounds* (smog)	Burning fuel (gasoline, oil, coal, etc.) solvents, paint, glues, chemical plants
Nitrogen Dioxide (smog)	Burning fuels: cars, trucks, power plants, homes
Carbon Monoxide	Burning fuels
Particulate Matter (dust, smoke, soot)	Burning of wood, coal, industrial plants, agriculture, unpaved roads
Sulfur Dioxide	Burning of coal, oil; industrial processes (paper, metals)
Lead	Phased out leaded gasoline, paint in older structures, smelters, making lead batteries

* VOCs are technically not listed as criteria pollutants but are included here due to the ongoing efforts to reduce urban smog.

Table D5-3. EPA Designated Criteria Air Pollutants sources to tackle first, based on health and environmental hazards, production volume, etc.

B. Emission Compliance Strategies

The EPA programs for compliance that provides an overall emission cap with allowance trading allows the greatest flexibility and usually obtains the lowest cost, overall optimum industry solution by allowing the multitude of compliance strategies to compete. The SO_2 and NOx markets are good examples of this approach. The compliance strategies typically involve an evaluation of building emission controls at one or more units, fuel switching, unit retirement and replacement with lower emitting units/fuels compared to buying emission allowances from the market from another participant who can create the emission reduction for a lower cost than another market participant can. Phase I of the 1990 Clean Air Act Amendments designated 261 coal units that were required to comply with the new emission levels. An additional 174 units opted into the program under the rules established by the EPA. Table D5-4 shows the compliance strategies adopted by the designated 261 by the year 1995, as surveyed by the EPA.

The reduction in tons allowed to be emitted in Phase II of the program has led to additional fuel switching and scrubber building. Greater reductions proposed under various legislative and regulatory proceedings would accelerate the need to build scrubbers on most coal-fired capacity or to switch to lower sulfur fuels, primarily natural gas.

Table D5-5 provides the typical sulfur emission levels of various fuel and technologies.

C. NOx SIP Call

The expansion of NOx limits from the Northeastern states that made up the Ozone Transport Region (known as the OTC for Ozone Transport Compact) to most of the states that make up the eastern interconnected grid beginning with the 2004 ozone season creates additional potential demand for natural gas. Depending upon the cost of NOx emission allowances, the uncontrolled coal units can cost more to run than gas-fired combined cycle units. NOx emission prices have exceeded $5,000 per ton. A non-SCR coal unit might have an emission rate of 0.42 lb. NOx per MMBtu while a controlled gas-fired combined cycle would have a rate approaching 0.02 lb. NOx per MMBtu. This would translate into $1.00 per MMBtu in this example, or $0.20 per MMBtu per $1,000 of NOx allowance price "penalty" on coal versus gas.

D. Multi-Pollutant Initiatives

During the writing and editing process for the task group reports, the EPA issued two proposals for air quality improvements. EPA proposed further reductions in SO_2 and NOx emissions plus options for controlling mercury emissions from coal-fired power plants. Together, the Interstate Air Quality (IAQ) proposal and the Utility Mercury Reductions proposal call for the largest single investment in any clean air program in history. The IAQ proposal calls for utilities to utilize a cap and trade program based on EPA's highly successful Acid Rain Program to achieve emissions reductions in the most cost effective way.

The IAQ proposal would reduce power plant emissions in a total of 29 eastern states and the District of Columbia in two phases. Sulfur dioxide emissions

Compliance Method	Number of Generators	% of Phase I Capacity	% SO_2 Reduction
Fuel Switch/Blend	136	53	59
Buy Allowances	83	27	9
Scrubbers	27	16	28
Retirement	7	2	2
Other	8	2	2
Total	261	100	100

Table D5-4. Phase I Compliance Strategies by 1995

Fuel or Technology	Emission Rate* (lb. SO_2/MMBtu)	% Removal
High Sulfur Bituminous	2 - 6	N/A
Low Sulfur Bituminous	0.84	N/A
Powder River Coal	0.5	N/A
Natural Gas	0.01	N/A
Low Sulfur Distillate	0.05 - 0.1	N/A
Low Sulfur Resid (0.7%)	0.8	N/A
Scrubber (Spray Dryer)	0.29	70%-90%
Scrubber (Wet)	0.35	85%-98%

*Based on 2003 emission rates published by EPA.

Table D5-5. Emission Rates for Fuels and Technologies

would drop by 3.6 million tons in 2010 (a cut of approximately 40% from current levels) and by another 2 million tons per year when the rules are fully implemented (a total cut of approximately 70% from today's levels). NOx emissions would be cut by 1.5 million tons in 2010 and 1.8 million tons annually in 2015 (a reduction of approximately 65% from today's levels). Emissions will be permanently capped and cannot increase.

The consequences of these two air quality initiatives on gas demand are not clear and easily quantified. The mercury reduction effort would be closer to the Balanced Future scenario, while the IAQ proposal would impact existing coal and potential new coal in a mode closer to Reactive Path but more restrictive on emissions resulting in potentially more gas demand from 2010 to 2018 while the market adjusts to the new, lower limits. Therefore, no real adjustments need to be made in the modeling or analytic approaches to gas for power demand. The fate of these two initiatives is not clear. It is certain that both proposed rules will be challenged in court, and therefore are subject to being overturned partially or completely. The situation that would lead to the highest electric power demands on natural gas would be for the mercury proposed rule to be overturned and replaced with a MACT requirement at the plant/unit level while leaving the IAQ proposed rule unchanged when it becomes final.

E. Carbon Emission Limits

Limitations on carbon emissions continue to be a major environmental issue for power generation. Numerous policy proposals continue to surface at the federal, state, provincial, and local levels of government that call for a limit on carbon emissions and/or a reduction to some prior level of emissions. Some electric utilities have committed to voluntary limits or reductions in emissions in association with programs allowing for carbon credits to be obtained and traded. Since coal is the most carbon intensive fossil fuel, any legislative or regulatory limits on carbon emissions will impact coal more heavily than natural gas. The Demand Task Group ran a pseudo carbon control case where the full burden of meeting an assumed level of emissions fell solely on the power industry, rather than being spread across industrial demand and transportation segments of the economy. The assumed level of emissions was the year 2000 emissions being met by the year 2015. This case caused coal-fired generation capacity to decline by 31 gigawatts (GW) between 2010 and 2025 and required 117 GW of nuclear capacity to be built in order to meet projected power demand. The case did not decrease GDP growth as an assumption to the overall economic climate likely to be caused by a carbon reduction scenario.

IV. Electric Power Generation Fleet

A. New Generating Capacity

A significant quantity of new generating capacity has recently been completed or is still under construction. New Plant data and announcements of activity suggest that the by the end of 2005 the United States will have added 220,000 MW of new generation. Approximately 200,000 MW of this generation is gas fired, and the vast majority of this capacity does not have any backup fuel. Figure D5-13 shows new power plant construction by fuel type from 1966-2005. The total amount of construction and reliance on a single fuel are both unprecedented.

This new plant construction has resulted in most parts of the country having ample to surplus generating capacity. Only limited pockets, like New York City have ongoing generation capacity requirements. Figure D5-14 shows the projected capacity margins for 2004 and 2010 by NERC region. The 2010 values are twofold; first with no new capacity additions post 2005 projects under construction, and second, with new capacity as projected by NERC in their most recent 10 year assessment.

The lack of capacity requirements over the next few years combined with uncertainty for wholesale markets, retail markets, environmental regulations, fuel prices (particularly natural gas), and regulatory treatment of capital expenditures for new generation and environmental compliance creates an investment climate that does not encourage major power plant construction. This is particularly true for long lead time projects like coal and nuclear baseload capacity. Consequently, natural gas is projected to remain the generating capacity of choice by many industry observers. The consistent reasons for choosing gas-fired technologies are ease of siting, shorter lead times for total project, and superior emissions capability.

B. New Build Economics

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

"Busbar" refers to the transmission equipment just at the edge of the power plant's site. The costs "behind the busbar" include all fuel costs, construction costs, financing costs, taxes, operations and maintenance expenses, and all the other costs of owning and operating a power plant. These cost inputs were developed in

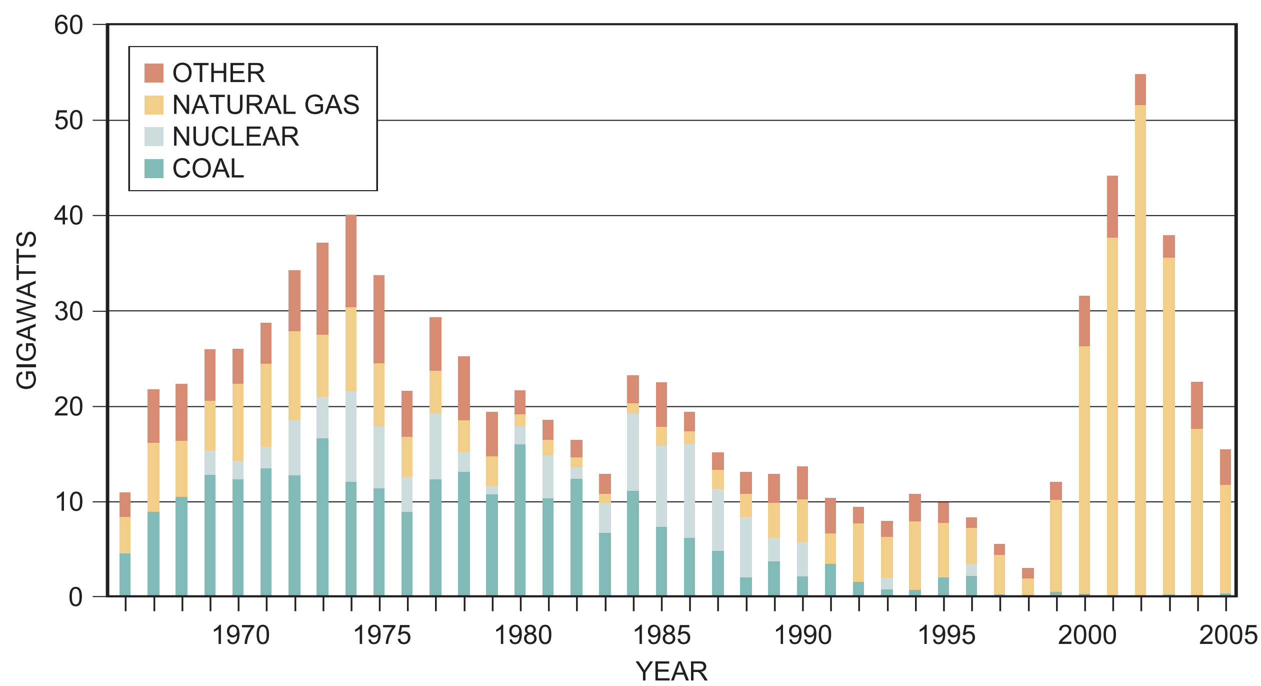


Figure D5-13. Comparison of Annual Installed New Generation Capacity

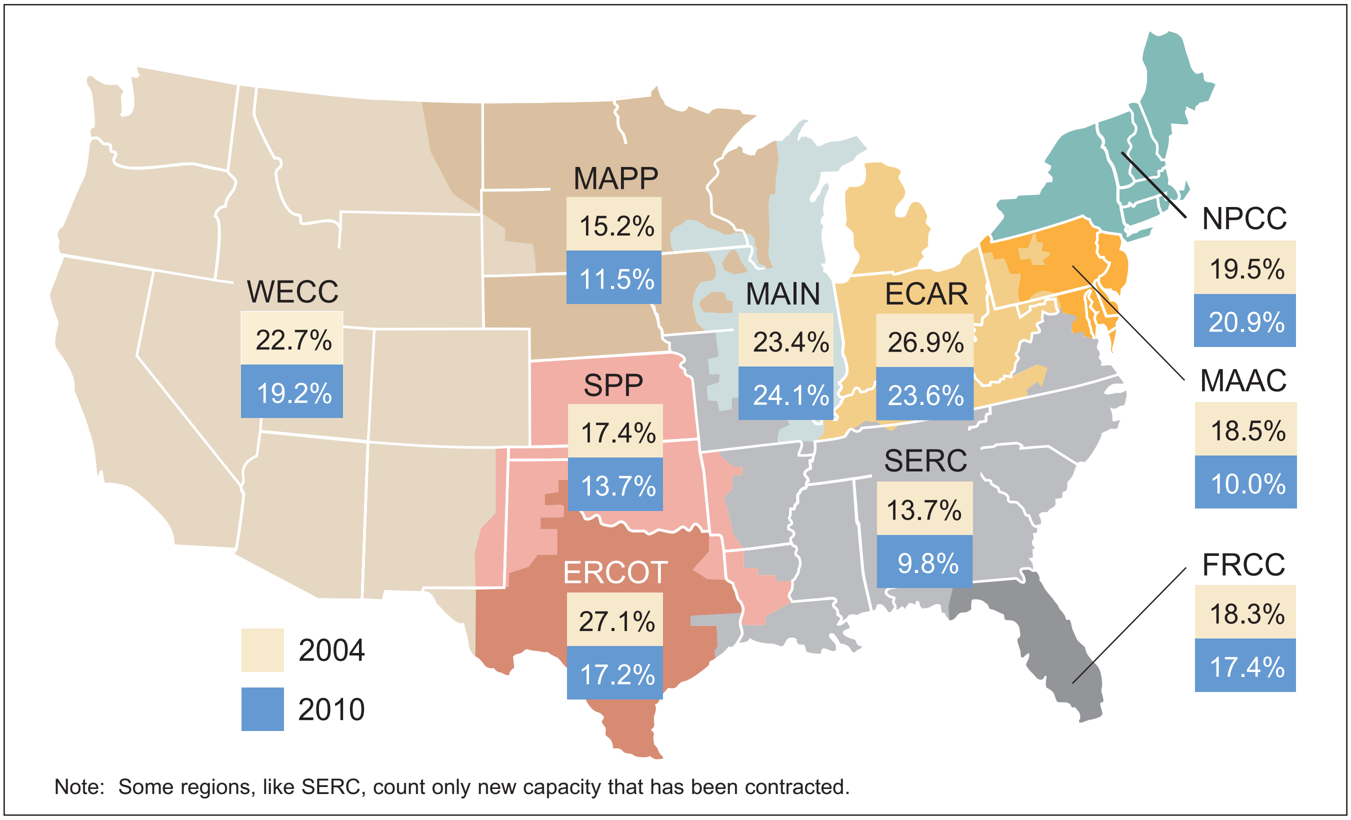


Figure D5-14. NERC Region Capacity Margins

"real" or "constant dollar" terms and converted to "nominal" dollars using escalation rates for the various costs.

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

Table D5-6 shows the technologies considered and a selection of the input criteria. A more detailed list is included in Appendix K.

C. Plant Siting Issues

Power plant developers must weave the economic choices described above into a complex siting process where fuel choice and economics are part of the compromise necessary to achieve permits and societal acceptance of new generating capacity. Siting any significant sized electrical generation facility or power transmission line is a difficult undertaking in most locations throughout North America. States have primary authority to site power facilities except for nuclear plants where the Nuclear Regulatory Commission has a significant role. The siting process invariably include the following considerations:

- A showing of need
- Environmental permits (air, water, solid waste, etc.)
- Building permits
- Land use
- Noise
- Cultural resources
- Public involvement.

Technology Description	Lead Time (Years)	Capital Cost (2002$/KW)	2010 Heat Rate (Btu/KWH)	SO_2 Emission Rate (#/MMBtu)	NOx Emission Rate (#/MMBtu)	Max. Cap. (%)
Conventional Pulverized Coal w/ Scrubber	7	1,200	9,300	0.4 [5# coal]	0.28	85
Integrated Coal Gasification Combined Cycle Greenfield	6	1,400	9,000	0.1	0.1-0.15	90
Integrated Coal Gasification Combined Cycle Brownfield	5	1,400	9,000	0.1	0.1-0.15	90
Super Critical Pulverized Coal w/ All Environmental	7	1,250	8,600	0.4 [5# coal]	0.06	85
Gas Combined Cycle	3	600	7,000	Nil	0.02-0.04	92
Low Sulfur Diesel Combined Cycle	3.5	600	7,200	Nil	0.02-0.04	90
Distillate Combined Cycle	4	670	7,400	0.05-0.1	0.02-0.04	88
E-Class Residual Oil Combined Cycle w/ Environmental	4	800	8,100	0.1	0.06	70
Gas Combustion Turbine	1.5	350	10,000	0.05-0.1	0.02-0.04	15*
Low Sulfur Diesel Combustion Turbine	2.5	400	10,600	Nil	0.02-0.04	15*
Advanced Nuclear	10	1,500	10,500	N/A	N/A	92
Renewable – Wind	3	1,100	N/A	N/A	N/A	30

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

Table D5-6. Generation Technologies Model Input Parameters

Most siting processes have specified timetables that require action by agencies that are involved. The state of Florida's siting process is shown in Figure D5-15.

Table D5-7 shows basic criteria and exemptions by state. A website link is also provided in the table allowing the user to examine the rules, regulations, and processes in greater detail and on an updated basis. These processes have evolved over the past twenty years and have contributed to the apparent advantage that natural gas-fired generation has enjoyed in siting new facilities over the past five years. The smaller footprint and lower stack heights of gas only facilities help minimize public opposition to building or expanding generation sites.

Siting new transmission facilities are even more difficult than power plants. This is a significant factor in specific decisions to build generation rather than transmission. The other main obstacles to new transmission facilities are market and/or cost recovery uncertainty, and the disconnect between state siting authority and federal rate making authority. The resultant combination of public and environmental opposition to major new transmission lines and business risk of making a return on investment will continue to hamper efforts to improve the carrying capacity of the transmission system. Notwithstanding these difficulties, the transmission grid has been slowly expanding. Table D5-8 shows the gradual growth in

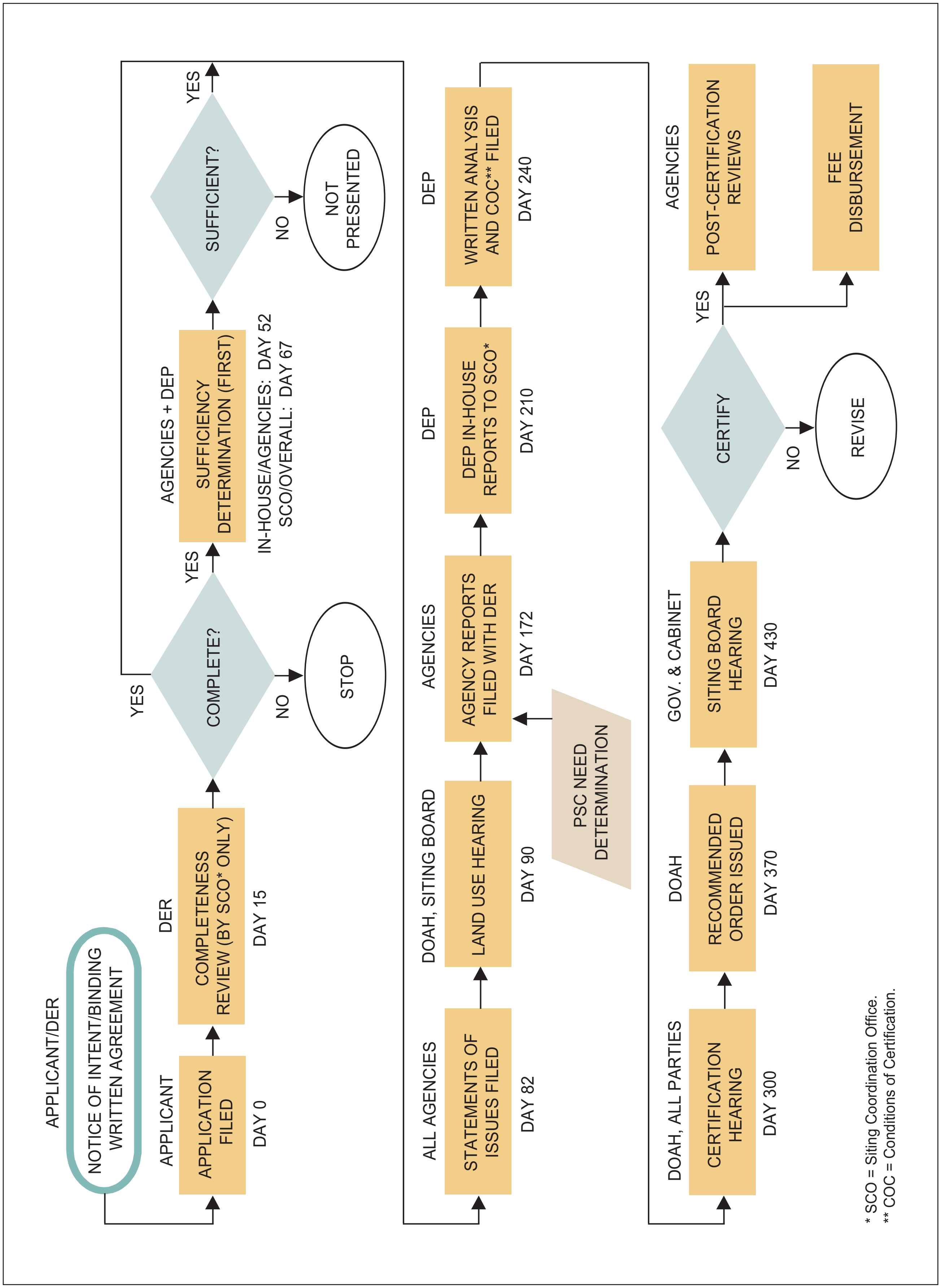


Figure D5-15. Power Plant Siting Process – Florida

State	Size Criteria	Exemptions
Alabama	No	Need Public Service Commission Approval
Alaska	No	Need Regulatory Commission Approval
Arizona	100 MW or Greater	N/A
Arkansas	No	
California	50 MW or Greater	
Colorado	No	Need Public Utility Commission Approval
Connecticut	Renewable Sources greater than 1 MW, Cogeneration Sources greater than 25 MW	Need Siting Council Approval
Delaware	No	No
Florida	75 MW or greater	
Georgia	No	
Hawaii		
Idaho	No	
Illinois	No	
Indiana	No	
Iowa	25 MW or greater	
Kansas	No	
Kentucky	10 MW or greater	
Louisiana	DG applications greater than 10 MW	
Maine	No	
Maryland	70 MW or greater	Need Commission approval for anything other than wholesale
Massachusetts	100 MW or greater	
Michigan	No	Need Commission approval to sell excess to retail customers
Minnesota	50 MW or greater	
Mississippi	No	Must inform PSC of intent to construct
Missouri	No	
Montana	No	
Nebraska	No	Need Commission approval to sell excess to retail customers
Nevada		
New Hampshire	30 MW or greater	
New Jersey	No	
New Mexico	300 MW or greater	
New York	80 MW	
North Carolina	Must Inform Utilities Commission of intent to construct	
North Dakota	50 MW or greater	
Ohio	50 MW or greater	
Oklahoma	No	
Oregon	25 MW or more for thermal power; 35 MW or more for geothermal, solar or wind energy	
Pennsylvania	No	
Rhode Island	40 MW or greater	
South Carolina	75 MW or greater	
South Dakota	100 MW or greater	
Tennessee	50 MW or greater	
Texas	Must register with the Public Utility Commission	
Utah	No	
Vermont	No	
Virginia	No	
Washington	350 MW or greater	
West Virginia	All proposed facilities	
Wisconsin	100 MW or greater	
Wyoming	No	

Source: Energy and Environmental Analysis, Inc.
Web Link: http://www.eea-inc.com/rrdb/DGRegProject/Siting.html

Table D5-7. Basic Size Criteria and Exemptions by State

NERC Region*	1993	1998	2002	% Change/Year
ECAR	15,929	15,976	16,422	0.31%
ERCOT	6,950	7,032	7,301	0.51%
FRCC	6,176	6,580	6,769	0.96%
MAAC	6,821	7,031	7,031	0.31%
MAIN	5,518	5,592	6,178	1.20%
MAPP	19,923	19,973	21,012	0.55%
NPCC	33,341	35,188	35131	0.54%
SERC	22,412	28,068	28880	2.89%
SPP	12,213	7,211	7639	-3.75%
WECC	64,857	67,580	68,992	0.64%
Total	**194,140**	**200,231**	**205,355**	**0.58%**

* Entities in SPP switched reporting to SERC between 1993 and 1998.

Table D5-8. North American High Voltage Transmission Circuit Miles of 230 Kilovolts or Higher

reported circuit miles for high voltage lines as reported to NERC. This growth is substantially lower than load growth and generating capacity growth.

Generation capacity and transmission capacity are not directly substitutable for one another. This is a function of the interconnected nature of the transmission grid and its inherent flow characteristics versus the dispatch requirements that dictate plant operation. A balance between major new transmission facilities and a portfolio of new plants (baseload, intermediate, and peaking operation) would provide the lowest cost, most reliable system. The difficulty lies in developing market mechanisms that mesh with state and federal regulatory responsibilities in a coherent, predictable manner thus allowing optimal investment, operating and transactional decisions to be made by market participants.

Table D5-9 summarizes the changes in generating capacity over the study period for each of the two scenarios. Retirements have to be netted against new builds to see the change in capacity. The Balanced Future scenario ends with more total coal capacity, since coal is not retired due to mercury assumptions.

D. Gas-Fired Generation

Natural gas-fired generating capacity has increased more rapidly than anyone would have anticipated in 1998/99. The 1999 NPC report on natural gas projected 115 GW of new gas-fired capacity would be added by 2015, and included a table (D-7) showing announced projects totaling 102 GW by 2004. Both of these estimates were criticized as overly optimistic by some industry analyst, however, the actual industry far exceeded this level of new build activity. By the summer of 2005, approximately 200 GW of gas capacity will have been added to the United States generating fleet. Figure D5-16 shows the regional breakdown of the new capacity, its composition between combined cycle and combustion turbine technology.

Generation Type	Reactive Path	Balanced Future
New Coal	132	133
New Natural Gas	148	128
Nuclear Upgrades	1.9	9.7
New Renewables	73	155
Oil/Gas Retirements	(9)	0
Coal Retirements	(20)	0

Table D5-9. Changes in Generation Capacity (Gigawatts)

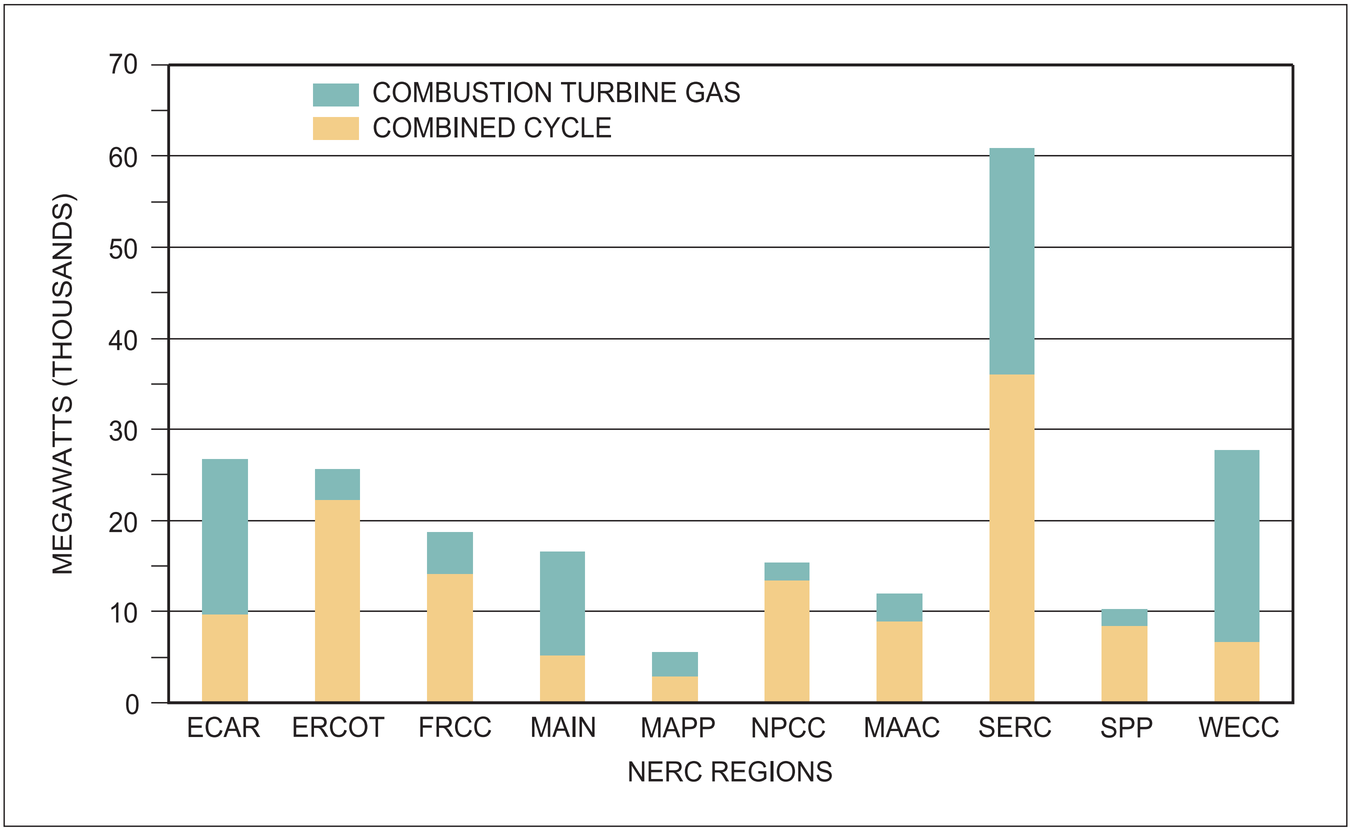


Figure D5-16. Gas-Fired Generation – New Capacity 1998-2005

This capacity was built by a variety of market participants: utilities, "energy merchants," and the traditional power developers were the most prominent. The newly emerging energy merchants were an important driver to the financing of these plants by taking commodity positions that hedged the gas price to power price "spark spread." Many of the new plants relied upon this hedge position to achieve high levels of non-recourse debt for financing the projects. The demise of the energy merchants, with several bankruptcies and declines in market values has led to a situation where the project lenders may have to assume ownership of the underlying asset. Consequently there have been several announced delays and cancellations of projects already under construction, and also the mothballing of plants that have achieved commercial status, but which do not dispatch enough to cover their ongoing costs. Part of the rationale for building so much capacity was the new capacity would cause retirement of old, gas steam capacity and small, old coal plants with high environmental remediation costs. To some extent the gas steam plants have been "mothballed" in places like Texas and New England, but little coal has been forced to retire due to the large price differentials between coal and natural gas that allows the environmental compliance to be economically satisfied.

The dynamics described above have led to a muddled near-term outlook on gas demand. Claims that little of the new capacity will run due to high gas costs are wrong, and claims that massive amounts of gas will be consumed by the new units are wrong. The most likely outlook for electric power gas demand is that it will grow over the next 2-5 years with the following caveats:

- Depends upon the weather;
- Depends upon regional economic growth;
- In regions where new gas displaces older gas-fired steam technology, it will decline as measured on a normalized weather and economic basis;
- In heavy coal generation regions, combined cycle units will be dispatched during heavy coal maintenance periods and during prolonged high demand periods, otherwise combustion turbines will meet peak demands;

- In regions where efficiency gains are not expected it will grow commensurate with economic drivers; and
- Depends on the oil switching economics and availability of oil capability.

1. Natural Gas Infrastructure Capability and Flexibility

New England and California are the only two regions where there has been a consistent focus on the natural gas transmission, storage, and distribution system's ability to satisfy customers growing natural gas demand, with particular emphasis on new gas-fired generation. In New England, a variety of groups have been involved in assessing the interdependency between electric power and natural gas. These groups have commissioned studies and have maintained close involvement between industry, customer, and regulatory stakeholders. The most recent effort has been FERC's Docket No. PL04-01-000 New England Natural Gas Infrastructure. In California, the California Energy Commission has been the primary driver of evaluations and studies of the gas industries ability to meet projected demands in California and the western regions. The remainder of the country has had episodic initiatives to understand the growing interdependency of the natural gas and power industries. These have been led by industry trade associations and more recently by the National Laboratories under the jurisdiction of the Department of Energy. The general assessments have been that market solutions should satisfy the needs for new capacity and flexibility of services. These assessments may be incorrect if power generators do not contract firm storage, and capacity. Very low load factors make firm capacity uneconomic for combustion turbine peakers and combined cycle plants are not projected to run at high enough capacity factors for several more years to ensure a return on guaranteeing fuel reliability. Figure D5-17 shows the relative cost of firm capacity depending upon the capacity factor that the unit dispatches.

This example uses a 165 MW combustion turbine with a 10.3 MMBtu/MWH heat rate requiring a firm contract of 40,000 MMBtu/day capacity. This assumes compliance with the pipeline's ratable hourly take tariff requirements and a range of annual capacity factors from 5% to 100%. At capacity factors less than 30% the incremental cost per MMBtu of natural gas used exceeds $1. Most combustion turbines currently operate at capacity factors less than 10% and are likely to continue to operate at those low levels because they are designed to operate during peak power demand periods.

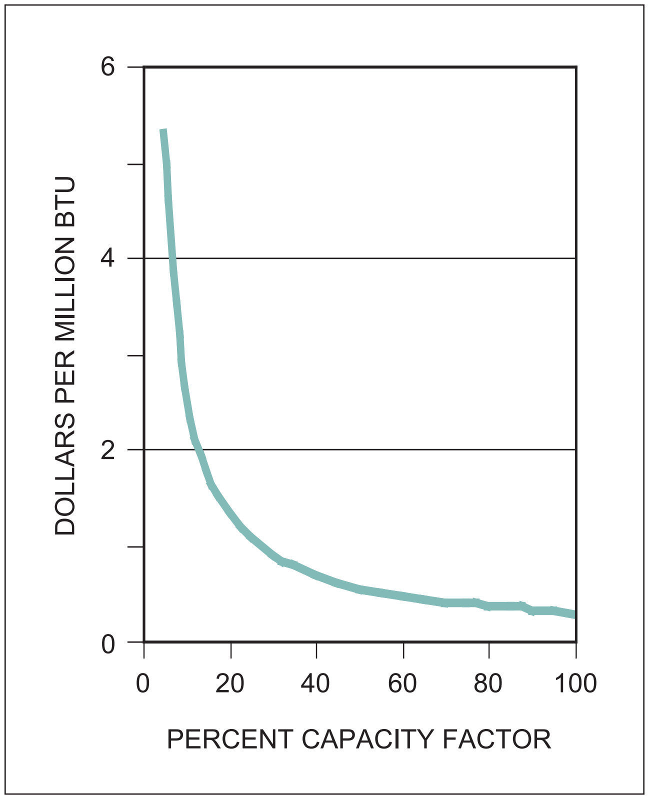


Figure D5-17. Unit Cost of Firm Transportation Demand Charges

2. Alternate Fuel Capacity

There exist apparent discrepancies between the stated generation capacity that can switch between natural gas and alternate fuels and the load conditions required to activate switching combined with actual ability or willingness to switch fuels. EIA data suggests that approximately 160 GW (summer rating) of generating capacity (circa 2002) have dual fuel capability. A simple calculation using a 10,000 Btu/KWH heat rate and a one day capacity factor of 60% suggests the maximum switching that would economically occur is 23 billion cubic feet per day (BCF/D) equivalent. Even during recent natural gas price spikes that far exceeded distillate and residual oil prices, the market data never suggested switching beyond approximately 6 BCF/D, including the ability of oil only units to substitute for natural gas and act as an additional proxy for fuel switching. Figure D5-18 shows the annual historical trend of oil based generation decreasing relative to natural gas based generation.

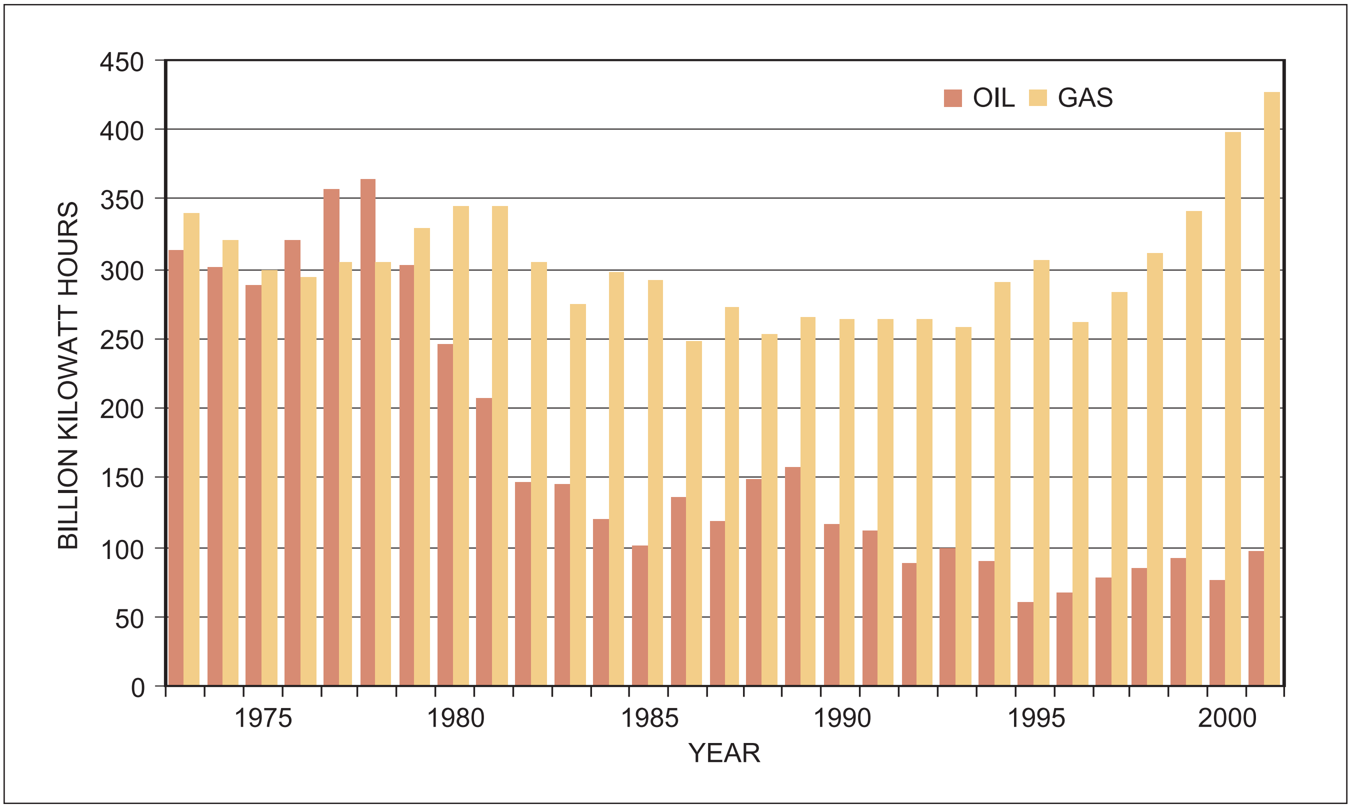


Figure D5-18. U.S. Electricity Generated, by Oil and Gas

The outright ability of the pre-1998 gas-fired generation fleet to switch fuels has been diminishing over the past few years as older, less efficient steam units have begun to retire. Utilities in ERCOT have announced more than 4,000 MW of mothballing or retirements over the past two years. We assumed 9 GW of retirements in old gas/oil steam capacity between 2002 and 2010 for the Reactive Path scenario, while the Balanced Future scenario assumed that capacity remained available.

Fuel switching capability in newer units appears to be quite limited. It is estimated that only 10% of the new capacity installed from 1998-2003 has any ability to switch to an alternate fuel. Additionally, all of this new switching capability is distillate type fuels (No. 2 oil and kerosene), which inherently have a higher price threshold than the residual fuel that historically dominated fuel-switching economics. While official data on the most recent year of installed generation is not available, anecdotal information suggests that the recent trend of limited alternate fuel capability has continued with only 10-15% of the newest capacity having any alternate fuel capability.

Two primary drivers led to limitations on new generation having alternate fuel capability. These were switching economics and permitting/siting impediments. Many power developers analysis of gas price and reliability resulted in little incentive to add the capital and O&M expenses associated with equipping new, low-NOx emitting turbines (including the front end of combined cycle units) with the ability to burn No. 2 oil. For those developers who desired to add this flexibility to switch fuels it added to the complexity of the environmental permitting, and increased local opposition to siting plants due to the larger footprint of the plant, potential truck traffic and typically taller exhaust gas stacks.

The decreasing ability of power generation to switch fuels for economic and reliability purposes places greater strains on gas supply, pipeline and gas storage infrastructure, and organized power pools in meeting the growth of power generation, particularly peak demand periods.

E. Oil-Fired Generation

Oil only generation capacity in the United States declined from 49 GW of in 1990 to a low of 35.6 GW in 1999 before rebounding to approximately 40 GW of capacity. Most of the oil only capacity of any substantial size units exists along the east coast and Florida. Many small diesel units exist throughout the country at major plants for black start reliability purposes. These units are not routinely run to supply the grid.

The amount of oil consumed for power generation has declined as discussed in the fuel switching section above, however a portion of oil consumption in power has been a constant fixture due to the lack of gas pipeline infrastructure into Florida. Consequently Florida routinely consumes oil as part of its inherent fuel mixture. Figure D5-19 shows oil consumption in Florida for power generation. The introduction of new pipeline capacity into Florida in 2003 and 2004 and proposals for LNG imports from the Bahamas may further decrease the oil consumption in the future.

Florida also serves a classic example of how oil only capacity mimics the market impact of an oil/gas switching unit. When oil is cheaper than natural gas in Florida, the oil only units move lower on the dispatch order than gas units and effectively displace natural gas consumption. The concentration of oil units on the east coast and Florida was driven by the ability to deliver the cheaper residual fuel blends via barge or ocean vessel which is substantially cheaper than trucking oil which is the primary method of delivering distillate base fuels to newer units or those not close to adequate waterways.

1. Residual Oil

Residual oil is also known by its numeric designation No. 6 oil and is a viscous, high Btu product derived from the simple distillation process of refining crude oil. Traditionally residual oil has been marketed to industrial and power plant steam boilers and as an ocean going shipping fuel (bunker fuel). This "residual" or leftover oil typically had sulfur contents ranging from 0.3% to >3% and also has some concentration of heavier metals such as nickel. Due to its high viscosity, residual oil needs to have its temperature maintained by outside heat during the winter in most northern climates, which adds to its difficulty and expense of handling as a fuel resource. Table D5-10 shows some typical properties of residual oil based upon their sulfur content.

Based upon the crude oil price assumption underlying the analysis, it was economic to build residual

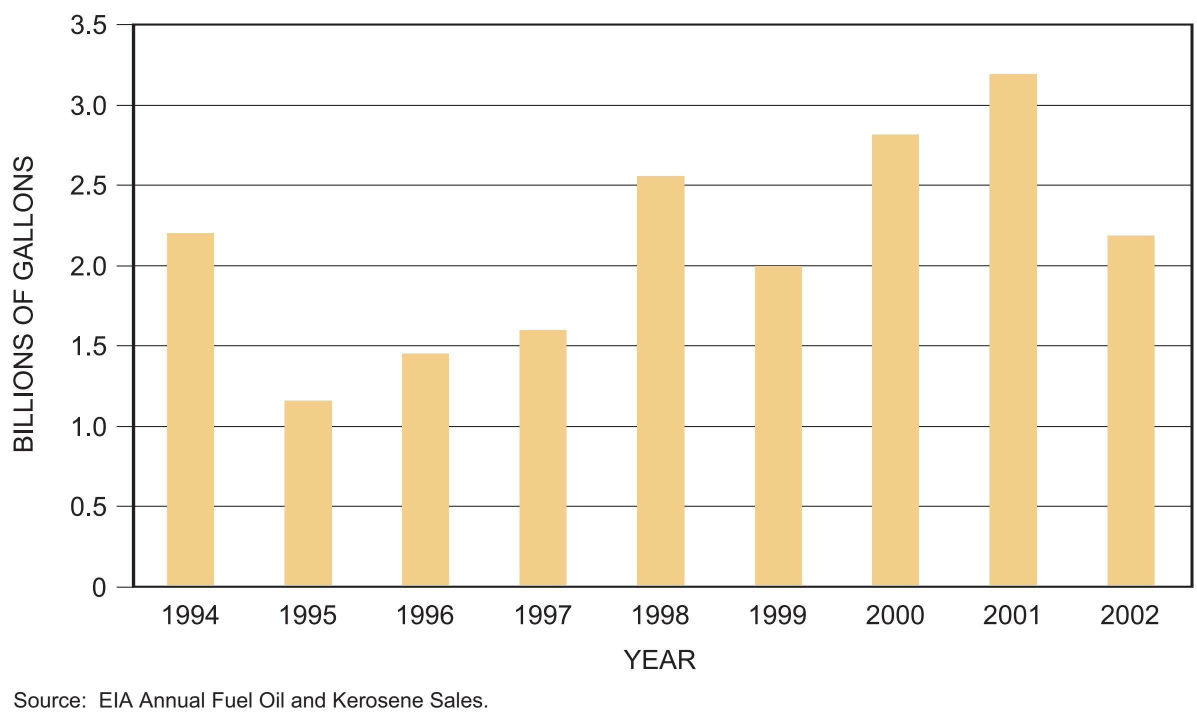


Figure D5-19. Florida Oil Consumption for Power Generation

Property	High Sulfur	Intermediate Sulfur	Low Sulfur
Sulfur, % by weight	2.2	0.96	0.50
Carbon, % by weight	86.25	87.11	87.94
Hydrogen, % by weight	11.03	10.23	11.85
Nitrogen, % by weight	0.41	0.26	0.16
API gravity	17.3	21.5	24.7
Ash, %	0.08	0.04	0.02
Vanadium (ppm)	350	155	70
Nickel (ppm)	41	20	10

Table D5-10. Typical Properties of Residual Oil

oil-fired combined cycles utilizing older turbine technologies. The new capacity was limited to geographic areas in the Southeast and Gulf Coast areas of the United States adjacent to primary waterways able to accommodate barge shipments of residual oil. The total amount of resid fired capacity built was 21 GW in the Reactive Path scenario and 42 GW in the Balanced Future scenario.

2. Distillate Oil Characteristics

Distillate oil is commonly thought of as diesel or heating oil comparable to the fuel used in residential space heating application. It is also referred to as No. 2 oil. This oil, plus kerosene (comparable to jet fuel) are used in power generation, particularly for combustion turbines. In most applications, distillate oil is considered a backup fuel rather than a viable fuel for economic switching. This is primarily driven by the distillate oil infrastructure. The amount of on-site tankage is normally less than 48 hours of full load requirement and refueling the tanks is normally accomplished by trucking the fuel. Trucks used to transport distillate range between 8,000 gallons and 12,000 gallons per truck with 10,000 gallons being a typical arrangement. No. 2 oil has a typical heat content of 138,000 Btu per gallon. For a 500 MW combustion turbine peaker plant with a 10,300 Btu/KWH heat rate the hourly fuel usage is 37,300 gallons. On-site fuel storage varies by plant and is dictated by plant acreage, siting (permit) considerations, and economics. A typical installation where distillate oil is used as a backup would have a 1 million gallon tank for this amount of generating capacity. This implies a storage capability of 27 hours of usage and a truck delivery every 15 minutes to balance fuel oil demand with supply. Truck traffic and tank visibility have been at the forefront of public concerns over allowing oil capability to be added to gas-fired facilities.

We assumed the gas-fired capacity installed after 2005 could be dispatched 10% of the time on distillate in the Reactive Path scenario, and 15% of the time in the Balanced Future scenario. This mimicked the results that adding a comparable amount of dual switching capacity would have produced.

F. Coal Generation Capacity

Summer rated capacity of coal was estimated at 312 GW effective in 2003. Total coal capacity grew slightly in both scenarios until 2008. At that point, the Reactive Path assumed approximately 20 GW of older, single unit coal plants retired over a two year period in response to mercury regulations before new coal builds began adding to the fleet. Both scenarios built approximately 132 GW of capacity. Using the EEA screening tool and our embedded assumptions for costs and performance, the super critical pulverized coal unit was selected each time. The nominal size was 1 GW per plant and they included costs to be fully compliant with current emission regulations. Geographic and annual construction limitations were assumed for new coal construction that impacted the total amount constructed. No new coal was allowed in the non-attainment areas of the east coast. No new coal in the states abutting the Pacific Ocean, and Florida had a 4 GW limit. Annual coal construction was limited to 14 GW in the areas that were permitted to build.

Coal fleet utilization was a critical variable in meeting the projected power demands. Economic value was assumed to create conditions allowing high degrees of availability leading to coal utilizations of 81% in the Reactive Path and 79% in the Balanced Future. The difference between the scenarios reflected the retirement of older coal units in the Reactive Path that were assumed to have lower availabilities than new coal units. If the fleet were unable to achieve high availability factors the resulting decrease in utilization would be made up with gas capacity running at higher utilization rates. The combined gas and oil fired fleet experienced capacity factors between 14% and 25% depending upon the year and the modeled case. Figure D5-20 shows the utilization rates of coal and the combined gas/dual fuel fleet of units.

1. Coal Fleet Age

The nation's coal fleet is aging, with an average age of 38 years. However, a better measure is weight the average by MW since the newer coal units have tended to be larger. Weighting for the unit's size gives a younger fleet age of 31 years. Given the absence of substantial coal capacity construction activity, the average age of the fleet will grow quickly until new capacity comes on-line after 2010. By any measure, the fleet will be at an age when capital investment requirements call into question the viability of the asset over the capital recovery period. Given the relatively high natural gas prices in the scenarios, it was assumed that the existing fleet would be maintained, other than the retirements due to mercury in the Reactive Path scenario described elsewhere.

2. Environmental Issues for Coal Consumption

Coal fired electric generators continue to face numerous financial and operating challenges associated with coal combustion. Proposals for new, sweeping changes to existing rules and anticipated regulations continue to create uncertainty beyond the inherent uncertainty of known regulatory initiatives that do not have final rules issued. Table D5-11 lists the major federal environmental regulations affecting the power industry and their planned implementation date. The cumulative costs to comply with these known regulations are estimated to exceed $30 billion in capital investment by the power industry.

3. Clean Coal Technology

North America's abundant coal resources have made the development of clean coal combustion

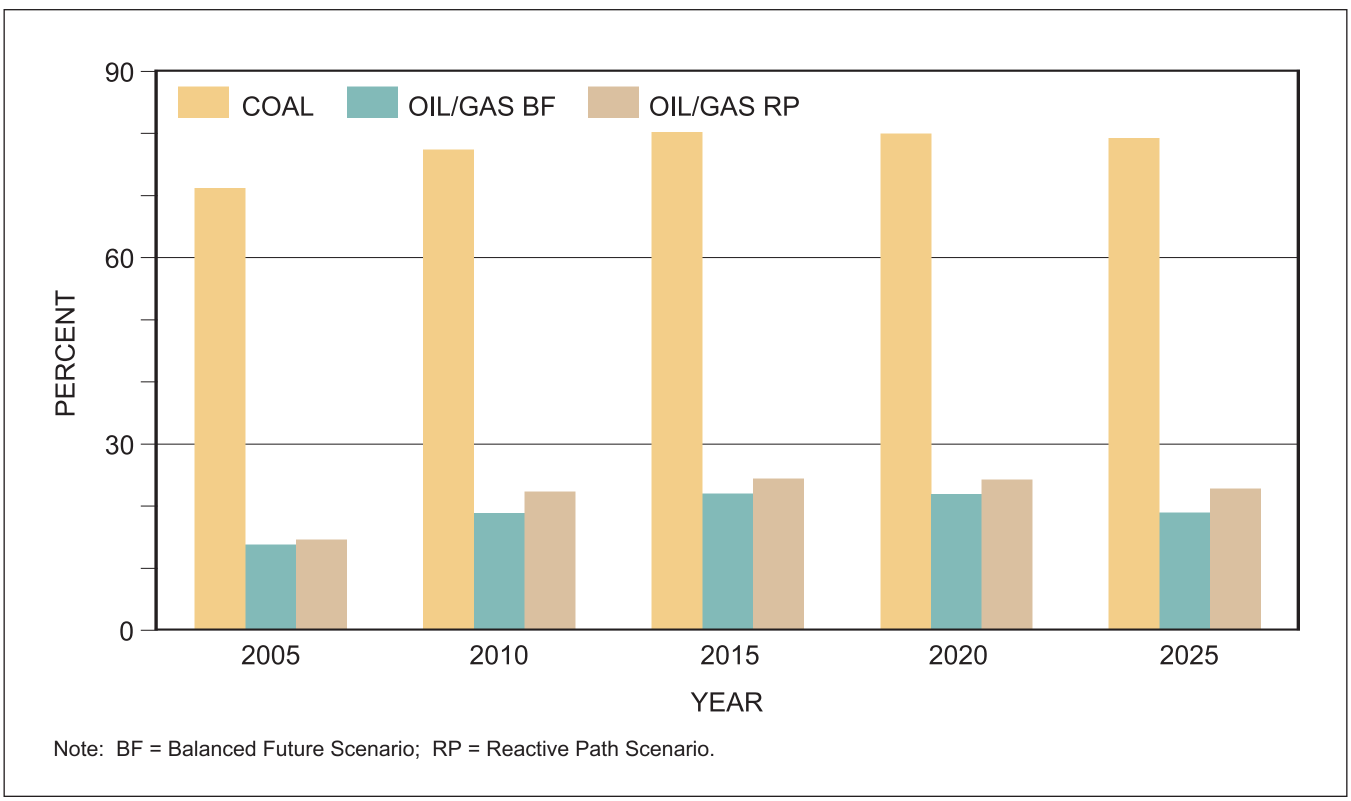


Figure D5-20. Capacity Factor by Generation Type

Regulation	Issuance Date	Implementation Date
New Source Review (NSR) Enforcement	Ongoing	
New Source Review (NSR) Rule – Routine Maintenance		2004
NOx (Section 126) State Petitions		2004
NOx State Implementation Plan (SIP) Call		2004
Clean Water Act 316(b)		2004
Mercury controls (MACT, Maximum Achievable Control Technology)	2003	2008
Ozone (8 hour)		2010
Fine particulate standards		2010
Regional Haze (BART, Best Available Retrofit Technology)		2012

Table D5-11. Environmental Regulations Affecting Power Industry

technology a high priority. DOE and others have made substantial investments in different clean coal initiatives. There have been 8 projects announced as part of a 10 year, $2 billion program that was announced in 2002. One technology that already has commercial application is the Integrated Gasification Combined Cycle (IGCC). Gasifiers are used around the world to convert oil, petroleum coke, coal and any carbon based fuel into a usable gas. Most of these are used in the chemical business but at least four plants are integrated into power production as part of a combined cycle application. This technology is receiving significant attention with higher natural gas prices and the significant number of combined cycles that have been added to the generation fleet combining to suggest candidates for repowering with an upfront gasifier. IGCC has an advantage for reducing emissions, particularly mercury, and possibly to reduce the projected cost of sequestering carbon dioxide.

4. Coal Supply and Pricing

The price of coal was assumed to be $1.46 per MMBtu on a volume weighted national average. It was assumed to decrease 1% annually on a real dollar basis, so in nominal dollars it was increasing. This level of coal price was predicated on the underlying crude price assumption, the anticipated pressure on coal generation pricing associated with environmental compliance, continued improvements in technology, and the continuation of trends for increases in the use of western sub-bituminous coal.

Coal usage and production has doubled in the United States since 1970, growing from 520 million tons to 1,100 million tons. Over 90% of the coal mined is supplied to the power industry. The estimated recoverable reserves are sufficient to meet expected demand for the next 250 years, with the United States being the largest reserve holder of coal. However, only 18.2 billion tons of recoverable reserves are connected to open, active mines. These reserves will support projected usage for approximately 15 years, thus providing adequate time for new, deeper, more expensive reserves to be brought into production.

Opening new mines will faces its own environmental obstacles, particularly surface mining in the eastern United States. According to the Office of Surface Mining's 2002 Annual Report there were six significant legal decisions rendered that impact coal producers. The most significant was the Hayden decision that made mountain top mining's technique of placing overburden in adjacent valleys a violation of the Clean Water Act, and therefore not permissible. This ruling was appealed but it demonstrated the potential impediments to opening new mines as existing mines deplete their reserves.

G. Nuclear Generation

More than 100 nuclear plants, totaling 96.5 GW of capacity, supply more than 20% of the United States' electric generation. Nuclear plants are dispersed throughout the country, as shown in Figure D5-21, with Illinois having the most capacity of any state.

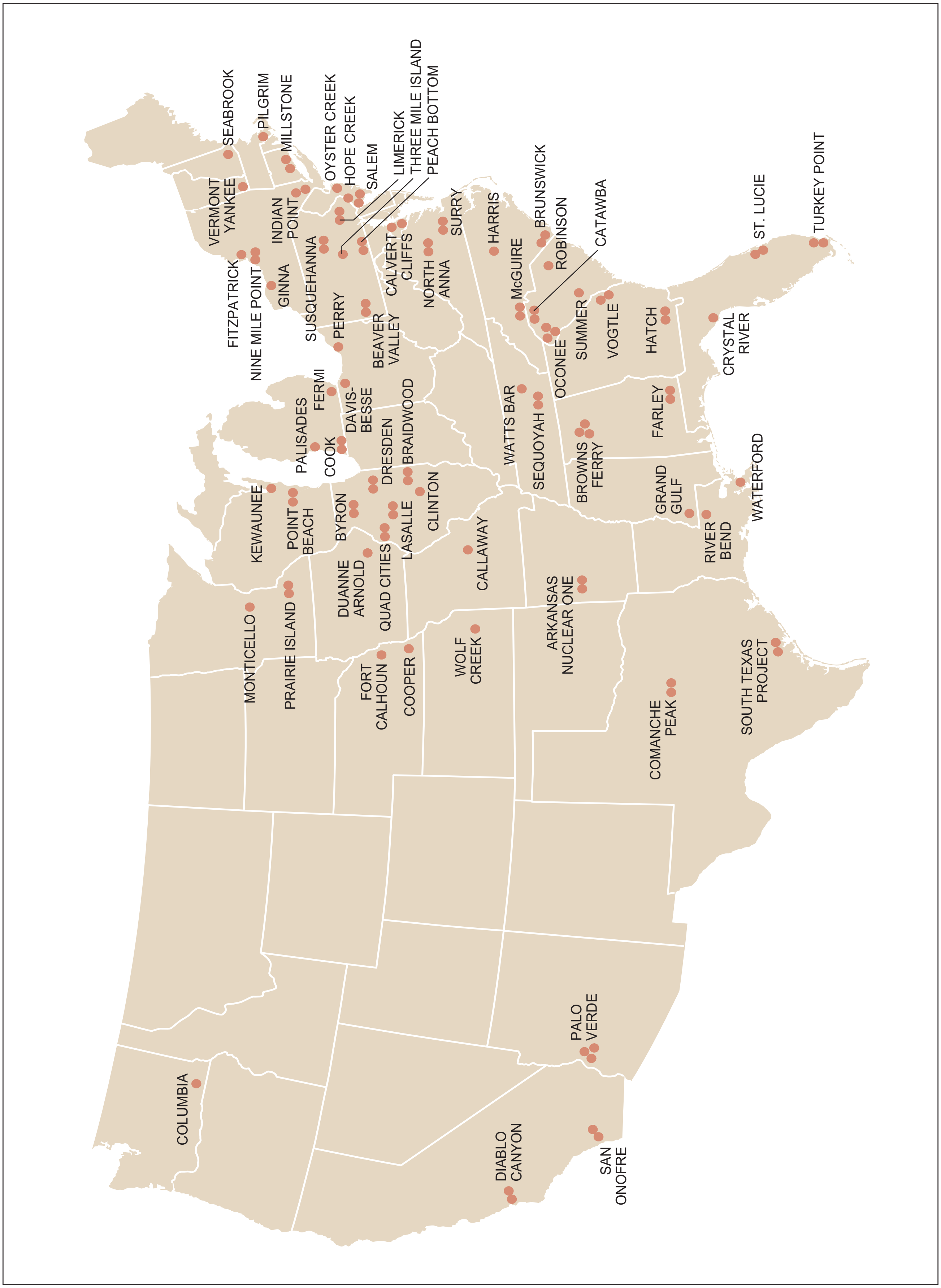


Figure D5-21. Nuclear Plant Locations in the United States

Nuclear based generation was dictated by two primary assumptions: (1) each plant would be successfully relicensed one time, and (2) the high availability and utilization rates achieved over the past few years is sustainable during the forecast period for both scenarios. Currently 25 reactors have received a 20-year license extension, 17 reactors have filed for extension, and 26 more are expected to file within the next 2 years. The high utilization rates are a relatively recent achievement, but the economic incentives and operating expertise gained over the past two decades support making this aggressive assumption. These critical assumptions tie directly back to natural gas demand. Any plant not relicensed, or whenever plants do not operate at high capacity factors gas-fired generation will provide the replacement energy, particularly in the areas where gas is on the margin a high percentage of the time.

Both scenarios saw nuclear capacity increased from existing plants by incorporating minor modifications to the plant consistent with the experiences of the 1990s, and as proposed in a number of projects with the Nuclear Regulatory Commission (NRC). In the Reactive Path nuclear capacity is assumed to increase by 6% through these projects while other regulatory actions decrease capacity, resulting in a net increase of 2% (2 GW). The Balanced Future scenario projects a net increase of 10% (9.7 GW) over the scenario life.

New nuclear capacity was not prohibited in the modeling effort that determined new generating capacity. Nuclear was estimated as a longer lead time, more expensive capacity option than any of the other choices. Only in our simplistic Carbon Case sensitivity did nuclear capacity get added to the generating fleet.

H. Hydroelectric Generation

Generation from hydroelectric was input to the models on a completely exogenous basis, using historical averages of quantities generated. This eliminated the oscillations of high water years and low water years in different portions of the country. The total generation modeled was 303 TWH each year. This quantity was distributed across the year and geographically based upon the multi-year average experience.

Approximately half of the hydropower generation was modeled in the western United States. Washington, Oregon, and California routinely lead the nation in hydropower with Tennessee and New York normally rounding out the top five hydropower producing states. There is approximately 104 GW of hydropower capacity. The United States government owns 38 GW of capacity at 165 locations, while the remainder is privately owned and spread over more than 2,000 sites. There are more than 75,000 dams in the United States and only 3% are used for any type of hydroelectric power production. There is an estimated 20 GW of upgrades that could occur without the construction of any new dams, and existing sites have had some success in upgrading their technology thus increasing generation output. However, the licensed projects must go through a renewal process periodically. We assumed any upgrades in output are offset by losses of capacity that might occur in the relicensing process. Between 1986 and 2001, 246 hydroelectric projects went through relicensing with the average annual generation loss of 4.23%. Over the next two decades more than 32 GW of non-federal capacity must undergo relicensing. A listing by state is included in Table D5-12.

The operation of dams for impounding water has become ever more complex. In many cases, the dam operator must balance the estimates of water available to flow into the impoundment against the varied needs of power production, flood control, fish migration/spawning, irrigation, recreation, and various environmental restrictions. The amount of water released and its timing directly controls the elevation of the reservoir. In the west, snow melt combined with the rainy season imposes a requirement to draw down reservoir elevation to make room for the anticipated water. Snow pack can be estimated with a reasonable degree of accuracy, but the forecast of rain amounts is subject to normal errors associated with weather forecasts, and are heavily dependent upon historical statistics. The fluctuation in elevation can exceed 80 feet over the course of the year for certain reservoirs as shown in Figure D5-22 for Lake Roosevelt on the Columbia River in Washington State. Lake Roosevelt is contained by Grand Coulee dam, the largest hydro single hydro resource in the United States with 6,800 MW of capacity.

Another source of hydroelectric power is pumped storage. This form of hydroelectric is essentially an electric storage device to assist in meeting peak demand. Water is pumped from a lower elevation reservoir to an upper reservoir during off-peak hours and allowed to flow through the turbines during peak

State	Number of Projects	Total Non-Federal Hydro Capacity (Megawatts)	Capacity Requiring Relicensing Thru 2018	Percent of Total Capacity Needing Relicensing
Alabama	9	1,918	1,647	86%
Alaska	6	290	32	11%
Arizona	2	10	10	100%
Arkansas	1	897	65	7%
California	45	9,824	5,099	52%
Colorado	8	396	336	85%
Connecticut	3	139	117	84%
Florida	0	11	0	0%
Georgia	6	1,441	65	5%
Idaho	13	2,766	1,563	57%
Illinois	1	54	4	7%
Indiana	1	89	81	91%
Iowa	1	4	3	71%
Kentucky	1	347	80	23%
Louisiana	1	278	86	31%
Maine	25	709	219	31%
Maryland	1	512	512	100%
Massachusetts	6	1,718	1,003	58%
Michigan	13	1,955	37	2%
Minnesota	4	221	68	31%
Missouri	2	603	584	97%
Montana	4	641	22	3%
Nebraska	1	180	48	27%
Nevada	0	204	0	0%
New Hampshire	5	479	80	17%
New Jersey	1	2,380	365	15%
New Mexico	0	49	0	0%
New York	25	5,797	3,975	69%
North Carolina	13	1,626	1,500	92%
Ohio		168	0	0%
Oklahoma	2	497	360	72%
Oregon	12	1,214	1,092	90%
Pennsylvania	6	2,046	1,527	75%
Rhode Island	0	5	0	0%
South Carolina	9	2,828	1,120	40%
Tennessee	1	327	327	100%
Texas	0	33	0	0%
Utah	7	72	9	13%
Vermont	10	360	193	54%
Virginia	3	2,905	719	25%
Washington	18	9,662	7,197	75%
West Virginia	6	438	157	36%
Wisconsin	24	485	191	39%
Wyoming	0	7	0	0%
Total	**296**	**56,583**	**30,493**	**54%**

Table D5-12. Summary of Hydroelectric Capacity Subject to Relicensing

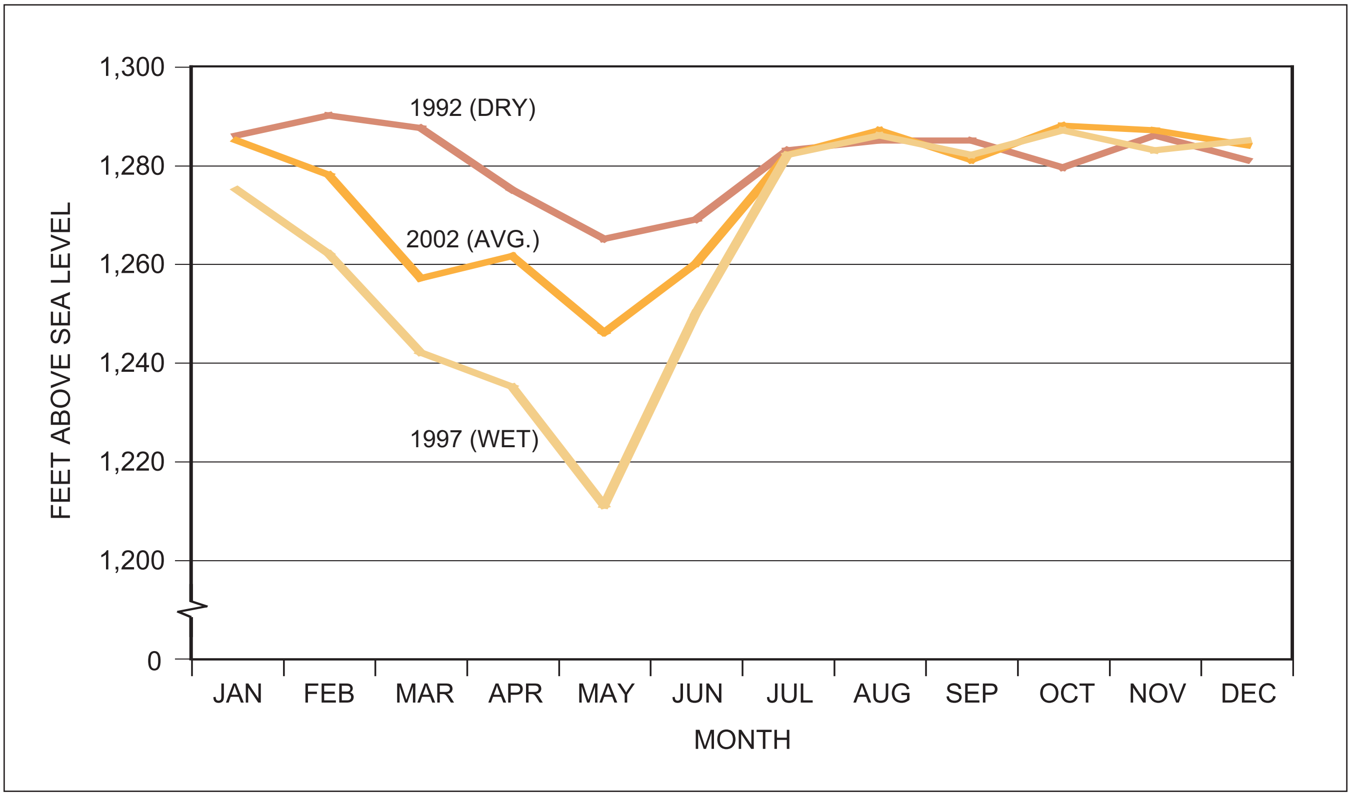


Figure D5-22. Lake Roosevelt Water Elevations

demand hours. 140 units contribute 19 GW of hydroelectric capacity to the mix of available generation resources. These resources are spread out across the country, with higher concentrations on the East and West coasts.

Canada is normally the largest hydroelectric power producer, with the United States in second place during normal water years. Canada has 68 GW of hydroelectric capacity located in only 233 plants greater than 10 MW each. The remaining 0.9 GW of capacity comes from very small facilities. In 2003 Canada exported 40,000 GWH of energy to the United States. Two-thirds of Canada's electric energy is produced from hydroelectric sources and Canada has the theoretical potential to add another 118 GW of capacity. Several projects are underway or anticipated in the near future totaling several thousands of megawatts. The introduction of megaprojects in Quebec could change the electric supply/demand in the eastern United States and have direct downward demand pressure on natural gas.

I. Renewable Generation

Capacity modeled for renewable generation was determined by evaluating the current and likely technologies, costs, and mandated Renewable Portfolio Standards (RPS) that have been adopted by several states. Capacity was input into the model and wind power was used as a proxy for all renewable capacity. This is not an endorsement of wind over other technologies; rather it was a simplifying assumption. 73 GW of capacity was assumed to be built in the Reactive Path scenario, mostly located in the California/Nevada model node. Table D5-13 is a table excerpted from the Energy Information Administration (EIA) providing a comparison of combustion turbine life cycle costs and renewable technologies for California/Southern Nevada.

The Balanced Future scenario projects 155 GW of capacity to be added with much broader geographic dispersion. In both these scenarios more than 70% of the new capacity is added in the last 10 years of the forecast period. Consequently, the level of uncertainty is larger than more traditional generating resources over the type of technology, the societal incentives like tax credits and RPS, and any emerging siting opposition. The study team developed the capacity additions to reflect our best view of the blending between incentives and the ability of renewable capacity to compete economically over time.

Technology	Capacity	Overnight Capital Costs (1995$/KW)	Total O&M (1995 Cents/ KWH)*	Capacity Factor (%)	Levelized Costs (1995 Cents/ KWH)†
Gas Combustion Turbine	160	329	1.08	85	6.03
Gas Combined Cycle	250	480	2.06	85	5.93
Biomass	100	2,630	1.13	80	8.43
Geothermal	50	1,765	1.08	80	3.76
Solar Thermal	100	3,064	1.25	42	10.78
Solar Photovoltaics	5	4,283	0.4	28	19.60
Wind	50	778	9.4	31	4.02

* Does not include fuel costs.

† Includes fuel costs, externalities, and credits.

Source: Energy Information Administration.

Table D5-13. Costs for Combustion Turbines and Renewables – California and Southern Nevada

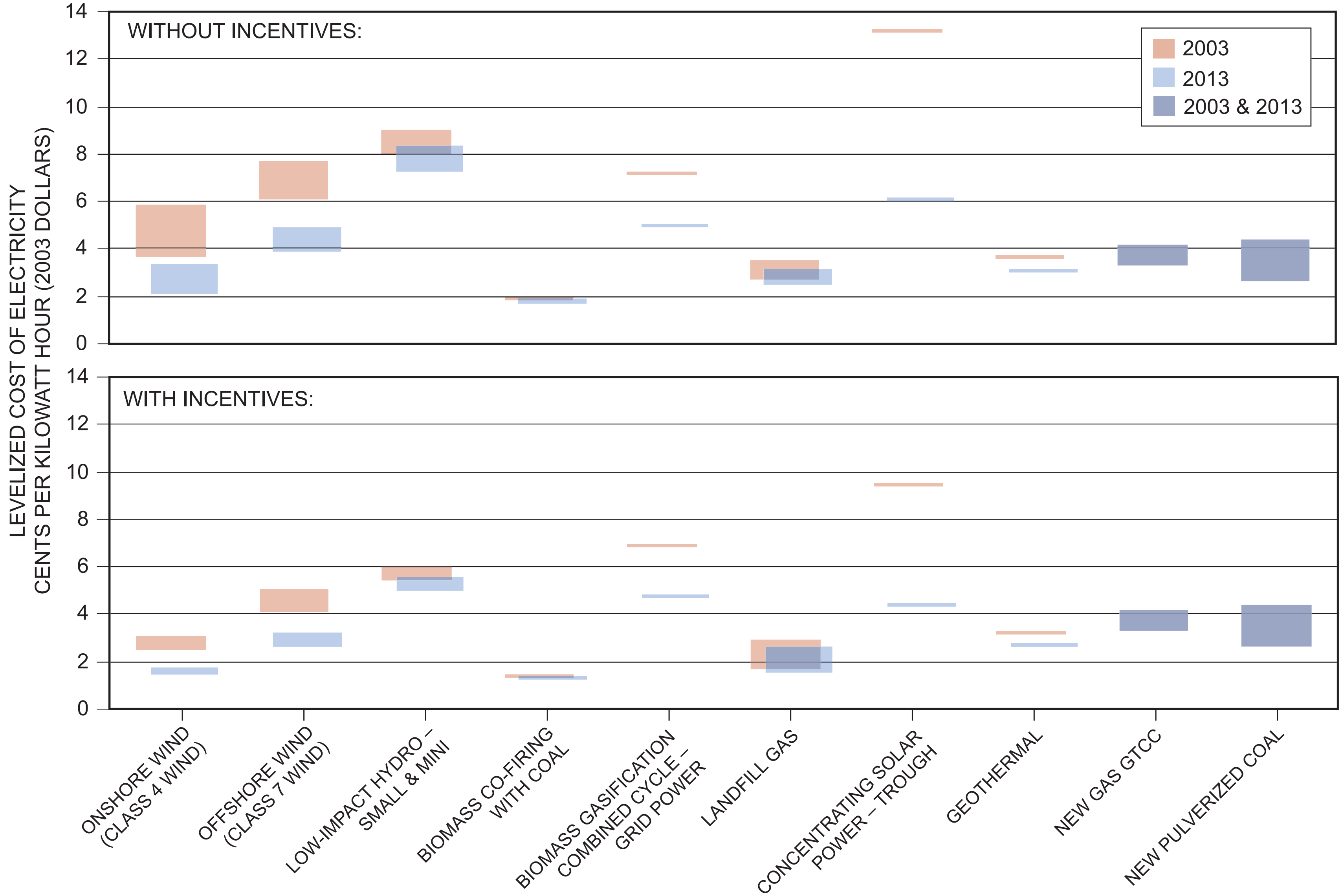
Figure D5-23 shows the relative competitiveness of the various technologies currently and in 2013. It also shows the impact on costs for policies that continue incentives.

Market based incentives are an important part of the assumptions underlying the renewable capacity. The ability to identify and monetize the value of increasing renewable generation is captured in the concept of a Renewable Energy Credit (or Certificate) known under the acronym REC. These RECs can be traded and banked like other power outputs like emission allowances such as NOx and SOx. The principle behind the REC is for generators to earn them by producing power from certified renewable facilities and for electric retailers to be required to surrender RECs to the governing agency as part of their service to retail demand. Currently Texas has the most liquid, active market in the United States and its REC price has fluctuated between $6 and $14 per MWH over the past two years. RECs in other areas have sustained higher prices due to the composition of the generation capacity producing them and the supply/demand for the RECs. Texas is currently amply supplied compared to the required surrender amounts for the next few years. However, if no more renewable capacity is built in Texas the surplus supply will eventually become a deficit. These types of market-based implementations of mandates typically allow lower overall costs to be realized for the consumer.

One implication of using wind as the proxy for all renewables is the impact upon gas combustion turbine capacity. The energy amount produced from the renewable resource was projected to have a capacity factor less than 20%, which leads to the need for additional installed capacity to manage peaks when the wind energy is not available. While this is an accurate reflection of industry experience with wind capacity and the capacity planning process, it does not reflect the capabilities of other renewable capacity types like solar, biomass, etc. Consequently the model shows more gas combustion capacity than would have been the case using other generation capacity resources.

J. Distributed Generation

No specific distributed generation was modeled in any of the scenarios or sensitivities. This approach was used to simplify the analysis surrounding technology and fuel choices, and is not an implication that distributed generation will not play a role in meeting power requirements in the future. A full treatment of distributed generation would have required a more detailed modeling of the power transmission and distribution networks and was beyond the scope of the NPC analysis. Natural gas supplied fuel cells are one of the



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

Figure D5-23. Life Cycle Cost of Electricity – Renewable Energy Options, With and Without Incentives promising technologies that could impact the use of natural gas for power generation. Setting aside capital and maintenance costs, a gas sourced fuel cell would utilize less natural gas to produce power than existing gas based technology primarily due to higher conversion efficiency and elimination of losses in transmission and distribution of the power. Figure D5-24 shows the current estimated costs of power generated by distributed generation technologies. Advances in technology and more widespread usage are projected to make the fuel cell costs decline relative to other technologies.

V. Canada

The EEA model produces a combined forecast for Canada's industrial and power generation gas demand. The model's forecast for combined Canadian industrial/power gas demand is based on Canadian GDP growth.

The study forecasted relatively robust demand growth for the combined sectors. Since Canada is integrated into the synchronous regions of NERC for capacity, demand, and power flows the historical patterns of power imports/exports are captured in the underlying data.

Canada currently has approximately 110 GW of generating capacity, as shown in Figure D5-25. Hydropower is the largest capacity source followed by steam units (coal, oil, and natural gas). This capacity is projected to grow to 150 GW by 2025. The composition of this capacity will still feature hydroelectric capacity as the primary source of power. Natural gas and renewable technologies will vie for the bulk of new capacity builds over the period. In the near term most new capacity planned is natural gas based.

Canada has significant potential impact on gas demand in the power sector. Potential increases in their demand for natural gas would be driven by policy decisions to shut down other generation resources. Canada's nuclear fleet has experienced significant down times for safety and public policy reasons. Uncertainty continues around the long-term viability of a portion of the Canadian nuclear capacity. As described in the hydroelectric portion of the report, large-scale hydroelectric projects by Canada, primarily in Quebec and British Columbia could reduce gas demand by displacing it with hydroelectric generation. The probability of gas demand increase is considered greater than the likelihood of gas demand decrease by these factors.

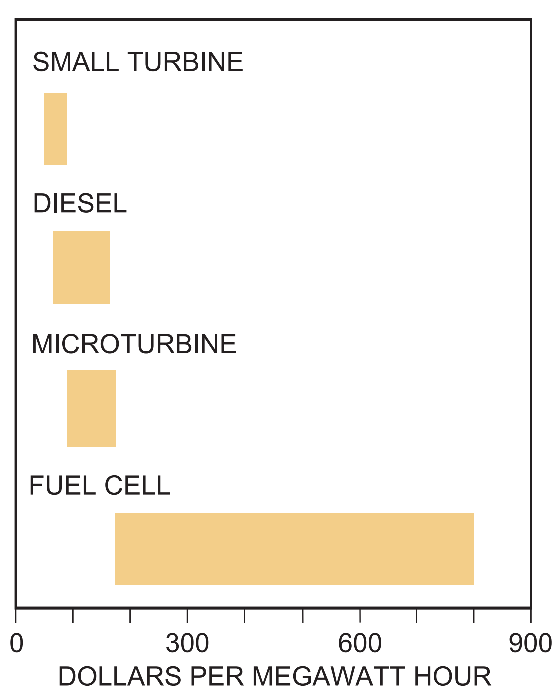


Figure D5-24. Electricity Cost Ranges for Distributed Generation Technologies

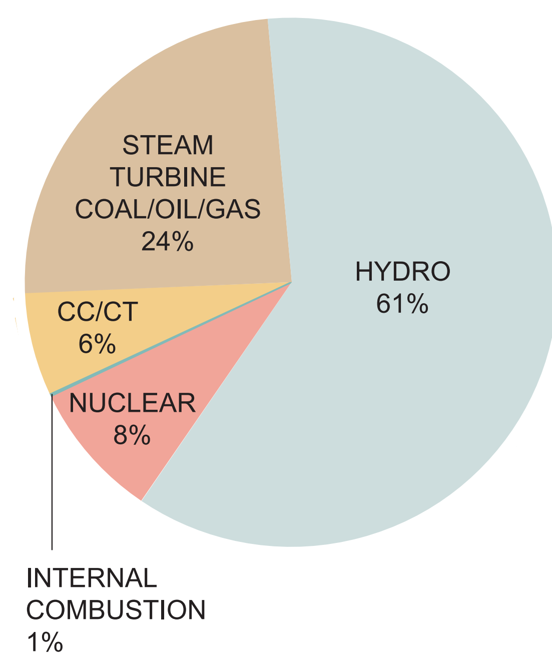


Figure D5-25. Canadian Generating Capacity

Ontario's current government has made a commitment to shut down all coal-based generation within the province by the end of 2007. The recent additions of 1,250 MW of gas-fired generation within the province combined with the reactivation of the Bruce and Pickering nuclear units has provided adequate reserve margins for the next few years. However, only gas can be built quickly enough to satisfy the entire potential shut down of coal-based generation. Approximately 6,000 MW of capacity has been proposed to the Independent Market Operator of Ontario and 5,000 MW is gas fired.

VI. Mexico

Only limited portions of Mexico's border region is synchronous with the United States electric grid. The demand for these regions was incorporated into the base United States demand and grown in concert with the interconnected region. The net exports to Mexico have averaged less than 1.3 million MWH over the past 5 years. The planned development of direct current (DC) ties to Mexico's main electric grid could facilitate even greater cross border energy commerce.

CHAPTER 6

UNCERTAINTIES
AND SENSITIVITY ANALYSES

The Demand Task Group considered many factors that drive natural gas demand. Based on those factors, the study participants created consistent input data sets to use the forecasting models for both the "base" scenarios (Reactive Path and Balanced Future) and to evaluate alternative assumptions to test how the natural gas market might evolve under different conditions. Those alternative assumptions addressed the general economic environment, weather, end-use efficiency improvements, government policies affecting demand, and other factors.

A number of sensitivity cases were modeled to test the effects of these alternative assumptions on the outlook for natural gas supply and demand. In most of these cases, the intent was to test the effect of changing a single variable on the natural gas market outlook; e.g., raising the U.S. GDP growth rate. However, two of the sensitivity cases examined the impact of a much broader range of changes in the market environment: the Fuel Flexibility case combines changes to a number of different demand-side factors that lessen the requirement for natural gas; and the Carbon Reduction case considers the possible effects from constraints on carbon emission in the electric power sector. As part of the overall sensitivity analyses, twelve separate cases were modeled to examine the potential effects of weather variations on the outlook for natural gas supply, demand, and infrastructure.

In terms of assessing future natural gas demand, this collection of case analyses serves many purposes, including:

- Examining the effects of various government policies on demand
- Measuring the impacts of increasing end-use efficiencies on electricity demand and natural gas markets
- Exploring the critical linkages between economic activity and the demand for electricity and natural gas
- Quantifying the effects of "fuel flexibility" policies on consumer costs, price volatility, and other outcomes
- Illustrating the uncertainty inherent in some factors, such as oil prices or trends in electricity sales.

Table D6-1 summarizes the assumptions made in each of the demand sensitivity cases. Some of these same assumptions were used in other cases. For example, the demand-side assumptions for Fuel Flexibility were also used in the Balanced Future scenario, which also added different assumptions for gas supply development.

Figure D6-1 is a schematic presenting a summary of the results of each of the demand-side sensitivities (excluding the weather cases), relative to the Reactive Path scenario. It shows the Henry Hub price differences (Y-axis) and the combined U.S./Canadian gas supply/demand differences (X-axis) averaged over the period 2011 to 2025. This time period was chosen for this discussion of broad effects, but similar comparisons are possible for multiple timeframes from the data sets available with this report in digital form. The black circle at the center represents the Reactive Path scenario and, by definition, is at zero on both axes. Sensitivities above and to the right of the center point represent increases in gas demand and prices, while

	Economic Environment	Residential/ Commercial Efficiency	Income Elasticity of Electricity Sales	Industrial & Power Gen. Fuel Switching	Fossil Generation	Nuclear Capacity	Renewable Capacity and Generation	Other Items
Low Electricity Sales-to-GDP Elasticity			More Elasticity/ Lower Growth in Electricity Sales					
High Electricity Sales-to-GDP Elasticity			Less Elasticity/ Higher Growth in Electricity Sales				More Growth in Capacity	
Low Economic Growth	Lower GDP & Industrial Production Growth							
High Economic Growth	Higher GDP & Industrial Production Growth							
Low Industrial Production Growth	Lower Industrial Production Growth							
High Industrial Production Growth	Higher Industrial Production Growth							
Fuel Flexibility		Greater Efficiency	More Elasticity/ Lower Growth in Electricity Sales	Greater Flexibility	More Favorable to Coal and Oil	Increased Uprates of Existing Units	More Growth in Capacity	
$28/bbl WTI Price								Oil Price is $28/bbl for WTI
Carbon Reduction	Slightly Lower GDP & Industrial Production Growth		More Elasticity/ Lower Growth in Electricity Sales		High Retirement Rates for Old Steam Units, No New Conventional Coal Plants	New Nuclear Units after 2012	More Growth in Capacity	Power Industry Carbon Emissions Constrained approx. to 2000 Levels

Table D6-1. Summary of Non-Weather Demand Sensitivity Case Assumptions

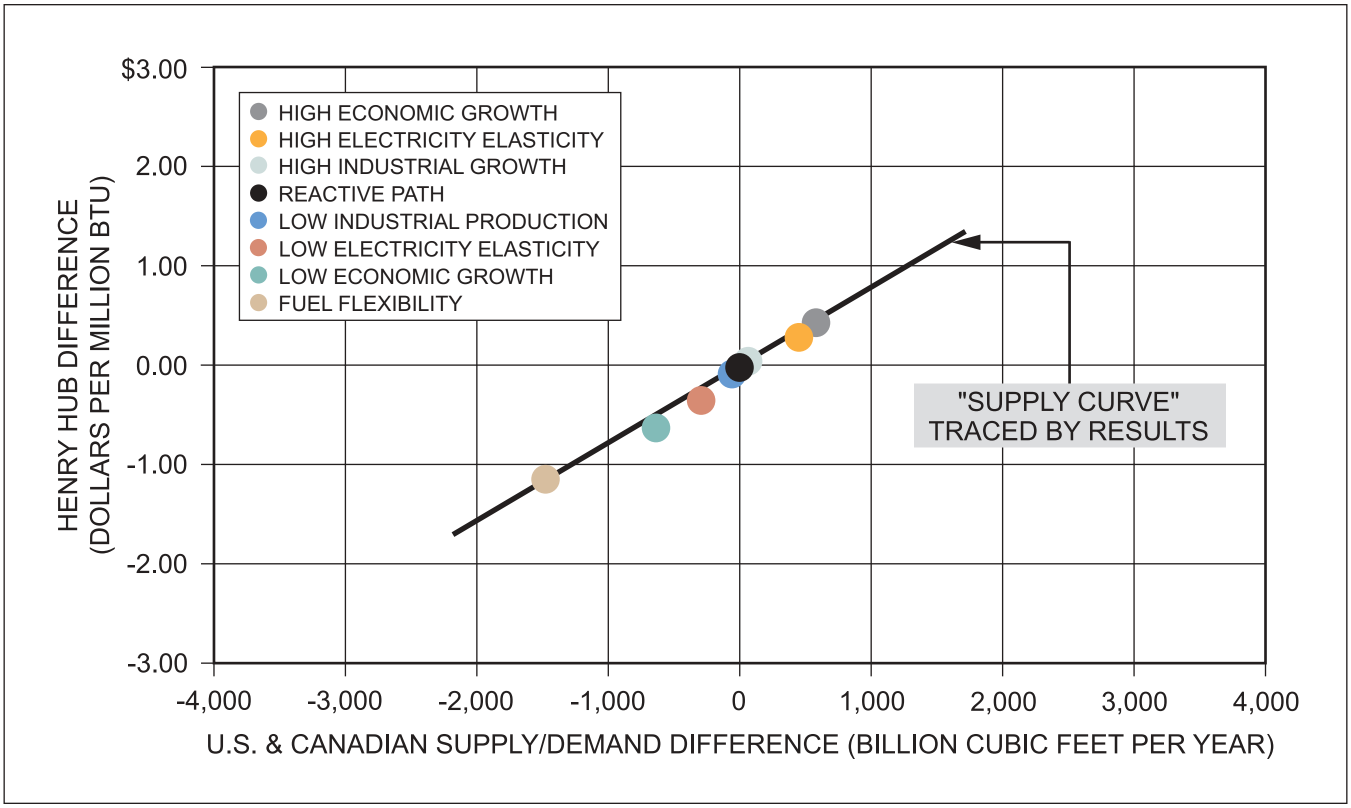


Figure D6-1. Selected Demand Sensitivities – United States and Canada (2011-2025 Averages)

those beneath and to the left of center point represent decreases in gas demand and prices.

I. Major Factors Considered in the Demand Sensitivities

This section provides a brief explanation of, and commentary on, the sensitivity analyses considered by the Demand Task Group as most relevant to natural gas demand.

A. GDP Growth and the Growth of Electricity Demand

The pace of economic growth, as measured by the annual rate of change in the gross domestic product (GDP), has historically affected the rate of growth in gas demand. For both the "base scenarios" (Reactive Path and Balanced Future), U.S. GDP growth was assumed to average 3.0% per year from 2005 to 2025, which is essentially the average GDP growth experienced in each of the three decades preceding this study. For Canada, the assumed GDP growth rate was 2.6% per year, based on similar logic.

As modeled in the study, an emerging significant effect of GDP growth on gas demand is in the growth of electricity sales.[1] Growth in electricity sales has historically been highly correlated to GDP growth. The ratio of growth rate of electricity sales to the growth rate of the GDP is referred to as the elasticity of electricity sales to GDP. Based on recent historical data, the current elasticity is about 72%. So, if U.S. GDP is projected to increase at 3.0% per year, then electricity sales would be projected to increase at 2.2% per year.

However, the elasticity of electricity sales has not been constant; it has in fact generally decreased over the past three decades. There are a number of drivers behind this trend, such as market saturation and growth in the efficiency of energy use. Whether or not this downward trend in elasticity continues could have a profound impact on future demand for electricity. The assumption for the Reactive Path scenario was that the elasticity would continue on a downward trend, declining to 62% by 2025.

[1] For the purpose of the study, electricity sales were defined as on-grid deliveries of electricity to retail customers, and do not include electricity consumed at the source of generation or direct sales.

Residential and commercial gas demand trends are also affected by economic growth. Higher GDP growth can result in greater growth in disposable income and the construction of larger homes that consume more gas. Likewise, the growth of the service sector can increase gas consumption at commercial establishments. The effect of economic growth on residential and commercial gas demand were modeled as a relationship between the growth in U.S. GDP and the growth rate of gas demand in these sectors. In the High Economic Growth sensitivity case, growth in residential and commercial demand was accelerated. Likewise, in the Low Economic Growth sensitivity case, growth in residential and commercial demand was slowed.

B. Industrial Production and Energy Intensity

Growth in industrial gas demand is a function of the growth in industrial production and the change in energy intensity over time. Growth in industrial production is measured as a change in the value of goods produced over time. For the NPC study, the industrial sector was divided into ten major industrial categories: Food and Beverage; Paper; Petroleum Refining; Chemicals; Stone, Clay, and Glass; Iron and Steel; Primary Aluminum; Other Primary Metals; Other Manufacturing; and Non-Manufacturing. For each industry, there was an assumed rate of growth in output that was represented by a monthly production index.

Energy intensity is a measure of the amount of energy consumed per unit of output. Energy intensity can change over time, for example due to increased efficiency in existing manufacturing methods or the introduction of new products or processes. As with industrial production, energy intensity was represented as an annual index with a base of 1.00 in 2001 for each of the ten industry groups. The value of the indices decreases over time, representing the decrease in the use of natural gas per unit of output.

C. Fuel Switching

Within both the industrial and electric power sectors, there are many consumers of natural gas with the ability to use an alternate fuel, commonly oil, to provide fuel for process energy, to generate electricity, or to use as a feedstock in the production of a chemical product. In some cases, because of either the nature of the end product or the processes involved, it is not practical to use a fuel or feedstock other than natural gas. However, in most cases the fuel and/or feedstock is an economic choice. Therefore, the amount of fuel switching that actually occurs is a function of the number of facilities with the infrastructure necessary to switch from gas to oil (e.g., storage tanks), and the relative price of natural gas versus oil products.

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

The ease, operational risk, and economics of fuel switching within the electric power sector vary depending upon the technology. Steam units, combined cycle units, and combustion turbines have very different considerations for the decision to switch fuels. Many older steam units can switch "on the fly" through a simple communication with the plant operators for changes to the fuel burn mix. The process requires adjustments to the oil-gas intake flows and replacements of various boiler fuel guns. Also, these fuel-switching decisions can typically be implemented under a wide range of plant output levels, and have very limited risk of unit output runback or tripping when being executed. Conversely, combined cycle units and combustion turbines have far greater sensitivity to the procedures for switching fuels. They often must be at specific megawatt output levels or in some cases must be shut down completely to avoid unit runback or tripping off-line from the transmission grid.

Power sector switching economics do not depend solely on the competing delivered cost of fuels. Distinct aspects of the determination or decision include considerations for differences in fixed and variable maintenance costs, increased emission costs, unit megawatt derates, and fuel infrastructure capability/costs are. Regulated utilities also consider the fuel recovery and operational and maintenance cost recovery risks as part of the decision to switch.

The net effect of these costs, operational constraints, and environmental issues has led to a significant decline in oil usage for power generation and an increase in the price differential needed to encourage fuel switching.

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

Adding to capability to switch to oil at times when gas prices are high could seem to be a logical choice for most industrial and power gas consumers; however, in practice relatively few facilities have this capability. During the 1990s, natural gas prices were relatively low, so there was little financial incentive to invest in the capability to switch to oil.

Another factor affecting fuel switching in the 1990s was environmental regulations. The Clean Air Act Amendments of 1990 were primarily focused on reducing sulfur dioxide (SO2) and nitrogen oxide (NOx) emissions from electric power plants and, to a lesser extent, from industrial and transportation sources. To comply with the mandates of both the first (1995-1999) and second (2000+) phase of the Act, generators and industry turned increasingly to natural gas, either by switching existing facilities from other fuels to gas or investments in new, gas-only equipment. While this strategy has been effective in reducing emissions, it has limited the ability to switch to other fuels when the natural gas market becomes stressed.

In addition to the federal environmental regulatory obstacles, an oil-burning facility may also face opposition at the local level from communities that surround the proposed site. Objections to the visual appearance of oil storage tanks or the perception of oil as a "dirty" fuel may create community opposition to the use of oil at the facility for even a limited number of days per year. Since the support of the local community is often needed to obtain the permits to construct a facility, developers of industrial and power facilities may choose to avoid potential local conflicts (and the time delays and costs they entail) by opting to build a "gas-only" facility.

The impact of fuel switching on industrial and power sector gas demand was examined in the sensitivity cases by varying the switching capability within each sector. To model fuel-switching behavior of industrial consumers, boiler-switching relationships were developed for each region of the United States and Canada. In the Fuel Flexibility case, the percentage of industrial boilers that would be able to fuel switch was increased from a low in 2003 of 2% to 8%, depending on the region, to a high of 28% in all regions by 2025. Since the switchable boilers cannot operate 100% on oil due to operational constraints, the maximum oil percentage for the switching curves was varied to account for the differences in boiler capabilities by region. Tables of the boiler switching assumptions used in the Reactive Path scenario and Fuel Flexibility case are shown in Tables D6-2 and D6-3, respectively.

In the electric power sector, prospective changes in fuel-switching capability were represented by changes at existing gas-based power plants and in the construction of new power plants to include oil backup capability or to build plants that burn oil exclusively, subject to some geographic restrictions. The Reactive Path scenario assumed that a number of limits on the addition of either oil-only or dual-fuel units will continue to be experienced. The NPC assumed that no new oil-capable capacity would be allowed in the northeastern or west coast states, and that the amount of switching capability for the United States as a whole would be limited to 25% of the gas and oil capacity total. Additionally, the construction of residual oil-only units was limited to regions where it was felt that there would be sufficient existing infrastructure to accommodate the additional oil consumption. Due to a number of constraints, such as permit conditions and the availability of oil, there are also limitations to the amount of switching possible at dual-fuel units. Therefore, the total capability to switch from gas to oil is the sum of all the oil-only capacity plus a fraction of the dual-fuel capacity, based on the maximum number of hours per year the dual-fuel units can operate on oil.

	New England	Mid-Atlantic	South Atlantic	East North Central	West North Central	East South Central	West South Central	Mountain 1	Mountain 2	Pacific 1	Pacific 2
2001	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2002	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2003	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2004	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2005	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2006	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2007	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2008	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2009	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2010	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2011	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2012	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2013	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2014	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2015	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2016	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2017	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2018	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2019	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2020	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2021	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2022	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2023	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2024	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2025	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%

Table D6-2. Fraction of Industrial Boiler Capacity That Can Fuel Switch – Reactive Path Scenario

	New England	Mid-Atlantic	South Atlantic	East North Central	West North Central	East South Central	West South Central	Mountain 1	Mountain 2	Pacific 1	Pacific 2
2001	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2002	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2003	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2004	4.0%	4.0%	8.0%	8.0%	8.0%	4.0%	2.0%	8.0%	8.0%	8.0%	2.0%
2005	5.1%	5.1%	9.0%	9.0%	9.0%	5.1%	3.2%	9.0%	9.0%	9.0%	3.2%
2006	6.3%	6.3%	9.9%	9.9%	9.9%	6.3%	4.5%	9.9%	9.9%	9.9%	4.5%
2007	7.4%	7.4%	10.9%	10.9%	10.9%	7.4%	5.7%	10.9%	10.9%	10.9%	5.7%
2008	8.6%	8.6%	11.8%	11.8%	11.8%	8.6%	7.0%	11.8%	11.8%	11.8%	7.0%
2009	9.7%	9.7%	12.8%	12.8%	12.8%	9.7%	8.2%	12.8%	12.8%	12.8%	8.2%
2010	10.9%	10.9%	13.7%	13.7%	13.7%	10.9%	9.4%	13.7%	13.7%	13.7%	9.4%
2011	12.0%	12.0%	14.7%	14.7%	14.7%	12.0%	10.7%	14.7%	14.7%	14.7%	10.7%
2012	13.1%	13.1%	15.6%	15.6%	15.6%	13.1%	11.9%	15.6%	15.6%	15.6%	11.9%
2013	14.3%	14.3%	16.6%	16.6%	16.6%	14.3%	13.1%	16.6%	16.6%	16.6%	13.1%
2014	15.4%	15.4%	17.5%	17.5%	17.5%	15.4%	14.4%	17.5%	17.5%	17.5%	14.4%
2015	16.6%	16.6%	18.5%	18.5%	18.5%	16.6%	15.6%	18.5%	18.5%	18.5%	15.6%
2016	17.7%	17.7%	19.4%	19.4%	19.4%	17.7%	16.9%	19.4%	19.4%	19.4%	16.9%
2017	18.9%	18.9%	20.4%	20.4%	20.4%	18.9%	18.1%	20.4%	20.4%	20.4%	18.1%
2018	20.0%	20.0%	21.3%	21.3%	21.3%	20.0%	19.3%	21.3%	21.3%	21.3%	19.3%
2019	21.1%	21.1%	22.3%	22.3%	22.3%	21.1%	20.6%	22.3%	22.3%	22.3%	20.6%
2020	22.3%	22.3%	23.2%	23.2%	23.2%	22.3%	21.8%	23.2%	23.2%	23.2%	21.8%
2021	23.4%	23.4%	24.2%	24.2%	24.2%	23.4%	23.1%	24.2%	24.2%	24.2%	23.1%
2022	24.6%	24.6%	25.1%	25.1%	25.1%	24.6%	24.3%	25.1%	25.1%	25.1%	24.3%
2023	25.7%	25.7%	26.1%	26.1%	26.1%	25.7%	25.5%	26.1%	26.1%	26.1%	25.5%
2024	26.9%	26.9%	27.1%	27.1%	27.1%	26.9%	26.8%	27.1%	27.1%	27.1%	26.8%
2025	28.0%	28.0%	28.0%	28.0%	28.0%	28.0%	28.0%	28.0%	28.0%	28.0%	28.0%

Table D6-3. Fraction of Industrial Boiler Capacity That Can Fuel Switch – Fuel Flexibility Case

The Fuel Flexibility sensitivity case assumes that actions are taken by power generators to increase the amount of fuel switching beyond that contemplated in the Reactive Path scenario by retrofitting 25% of existing combined-cycle and combustion turbine facilities for backup fuel; this retrofitting was modeled as taking place between 2004 and 2025, such that the growth in retrofits was linear over time.

D. Composition of the Power Generation Fleet

In addition to examining fuel-switching capability in the electric power sector, the sensitivity cases also examined the impact of changes in overall composition of the U.S. generation fleet. After a period of relative inactivity from the late 1980s to the mid-1990s, the U.S. power sector has experienced explosive change over the past several years. From 1998 through 2005, over 200,000 megawatts of gas-fired generation will have been added to the U.S. generation fleet, representing a 31% increase of total generation capacity and a 290% increase in the gas-fired only generating capacity. These new additions to the fleet are a combination of combustion turbines, used mainly for peaking power, and combustion turbines combined with a steam generator, commonly referred to as a combined-cycle plant.

The majority of the gas-fired plants built before 1998 were steam turbines. These older plants are less efficient and more costly to operate than the new combined-cycle or combustion turbines. As a result, many are being mothballed or retired, since the newer gas-fired plants can satisfy the current requirements for peak and intermediate power at a lower cost. However, a higher percentage of the older steam plants have the ability to switch to oil, while the newer plants have a very limited switching capability. Therefore, while the retirement of older oil/gas steam plants increases the overall efficiency of the generation fleet, it also decreases fuel flexibility by decreasing the percentage of gas-fired plants that can switch to oil. In the Reactive Path scenario, it was assumed that 21.5 gigawatts (GW) of oil/gas steam capacity would be retired by 2025. In contrast, the Fuel Flexibility case had no retirements of oil/gas steam capacity.

If done purely on the basis of achieving the lowest overall operating cost, power developers would build plants with the lowest life-cycle cost to meet a given generating need. This is the basic assumption behind the decision logic used to determine new power capacity construction in each of the scenarios and sensitivity cases, subject to the aforementioned constraints. (The power generation capacity planning logic used in the study is discussed in greater detail in Chapter 5.) The cost and operating assumptions used for each technology type are shown in Table D6-4.

Given the current capital costs of technologies and fuel cost, this usually makes a coal-fired plant the most economically attractive option to provide base-load power. However, many other factors play in the decision process. For example, uncertainty over future restrictions on carbon emissions can discouraged developers from building new coal plants, since it creates uncertainty about the ability to operate the plants on a profitable basis in the future.

A more immediate concern for those planning a new coal-fired plant is obtaining approval from all the federal, state, and local government agencies involved in the process. As with adding oil-burning generation capability, communities surrounding the site of a proposed coal-fired plant often oppose the plans due to environmental and aesthetic concerns. While local opposition will not always prevent a coal plant from being built, it can lengthen the time it takes to get the plant built, and thereby raise the cost.

Another concern for operators of the existing coal fleet is the upcoming regulation of mercury emissions. It is likely that operators will chose to retire some older, small coal plants, due to the cost of adding mercury control technology. It was assumed for the Reactive Path scenario that the response to the pending mercury legislation would be the retirement of any coal-fired unit that is: (1) 40 years old or older, (2) smaller than 200 megawatts, and (3) not co-located with another larger unit or otherwise strategically required. This amounts to 21 GW of coal capacity retired by 2010 in the Reactive Path scenario. In contrast, there were no near-term retirements of coal plants in the Fuel Flexibility case or the Balanced Future scenario.

Despite some recent setbacks, the Demand Task Group considered the future for the existing fleet of nuclear plants to be good. Overall output has been steadily increasing, many plants have received extensions to their operating licenses, and some plants have undergone minor refurbishing to increase their rated capacities. For the Reactive Path scenario, it was assumed that all currently operating nuclear plants will

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

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

Table D6-4. Cost and Operating Assumptions for Generating Technologies

receive license extensions and that refurbishing of existing plants would expand the capacity of the existing nuclear fleet by 1.9 GW. However, the outlook for any new nuclear plants is very uncertain. Capital costs are high and lead times are long, and the issue of long-term waste disposal was found by the Demand Task Group to be a significant impediment to investment in new nuclear capacity. While new nuclear plants were allowed to "compete" in all of the modeled sensitivities and scenarios, the only case in which modeling results called for nuclear power plant construction was the Carbon Reduction case.

Renewable energy (from wind, solar, geothermal, and biomass) was found by the Demand Task Group to hold a great deal of promise for contributing to the supply of electricity, and thereby decreasing the need for natural gas. To model renewable power capacity and utilization, wind power was used as a proxy for all renewable power sources. This was done as a simplifying assumption, not as an endorsement of that resource versus other viable technologies.

To date, the cost of electricity from renewable plants such as wind farms is still high relative compare to fossil-fuel plants, although the Demand Task Group found that costs are likely to improve significantly over time. Much of the near-term growth in renewable capacity construction is due to renewable portfolio standards implemented in 13 states, which mandate that a certain percentage of a state's total generation come from renewable energy sources.

In the Reactive Path scenario, the Demand Task Group assumed that 73 GW of new renewable capacity additions will be made in the U.S. by 2025, while in the Fuel Flexibility case 155 GW of renewable capacity additions were assumed. While the forecast growth of renewables is substantial in both cases, the share of total generation in the Reactive Path scenario and the Fuel Flexibility case is relatively modest at 1.8% and

3.6%, respectively. The basis for these assumptions is described in Chapter 5.

E. Residential and Commercial Efficiency

Gas demand in the residential and commercial sectors is projected to increase over time as the number of homes using gas increases and the amount of gas consumed for commercial space heating and other uses increases over time. At the same time gas consumption is growing, the end-use efficiency is also projected to increase due to the installation of newer, more efficient gas appliances and commercial equipment. This increase in efficiency offsets some of the growth in residential and commercial gas demand. Policies that increase the efficiency of new equipment and/or speed up the replacement of old equipment can change the trend in efficiency over time.

The Reactive Path scenario assumes base levels of improvement in the efficiency of gas use in the residential and commercial sectors. In the residential sector, the weather-normal consumption of gas per household is expected to decrease at an average rate of about 0.5% per year over the forecast. Within the commercial sector, space heating accounts for well over one half of all gas consumption. Gas use per square foot for commercial space heating is also expected to decrease at a rate of 0.5% per year. In the Fuel Flexibility case, these rates of improvement for the residential and commercial sectors were increased to 0.8% and 0.7%, respectively.

F. Weather

Weather is the single greatest factor driving gas demand in the short term. The base assumption for all the cases was normal weather based on NOAA's 30-year averages for the period 1970 to 1999. The sensitivity analysis included a total of twelve alternate weather cases (six for Reactive Path scenario and six for the Balanced Future scenario) that focused on particular forecast years, substituting either a colder or warmer weather pattern.

II. Description of the Demand Sensitivity Cases

A. Economic Growth Sensitivities

Two sensitivity cases were run to examine the impact of economic growth on the gas market outlook. The first was a high economic growth case, which increased the growth rates of U.S. and Canadian GDP and U.S. industrial production by 10% over the values in the Reactive Path scenario. The second was a low economic growth case, which decreased those values by 10%.

GDP and industrial production are represented in the model by indices, where the value for the base year (1987 for U.S. and Canadian GDP, and 2000 for U.S. industrial production) are set to 1.00. Industrial production is represented by separate indices for ten major industrial categories. These index values can be translated into absolute values for each year of the forecast by multiplying the base year value by the index. The absolute values represented by the GDP and industrial production assumptions are shown in Figures D6-2, D6-3, and D6-4.

The primary impact of shifts in the U.S. GDP growth rate is in the growth rate of electricity sales (Figure D6-5). Increasing the U.S. GDP annual growth rate from 3.0% to 3.3% increased the average growth rate of electricity sales from 2.1% to 2.3%. In the High Economic Growth sensitivity, annual electricity sales were 5,565 gigawatt hours (GWh) per year, 246 GWh greater than the Reactive Path scenario.

To meet the additional demand for electricity, generating capacity was increased by 11 GW, with 10 GW of new coal capacity and 1 GW of new oil/gas capacity. Because of transmission and distribution losses, the increase in generation is slightly higher than the increase in electricity sales. Fossil generation increased by 266 GWh in 2025 (Figure D6-6). Of the total increase in generation, 50% (133 GWh) was met by increased gas-fired generation, 34% (91 GWh) was met by coal, and 16% (42 GWh) was met by oil. Gas generation makes up a greater share of the increase than coal, even though it is has a higher marginal cost than coal generation. This is because the coal plants are already operating at their maximum capacity utilization, and overall it is less expensive to increase gas-fired generation than to build additional coal plants. The increase in gas-fired generation yields a corresponding increase in natural gas consumption (Figure D6-7). By 2025, gas demand in the power sector is 8,910 billion cubic feet (BCF), a 731 BCF increase over the Reactive Path scenario.

The increase in GDP growth also yields some modest increases in residential and commercial gas demand. In total, 2025 gas demand in these two sectors

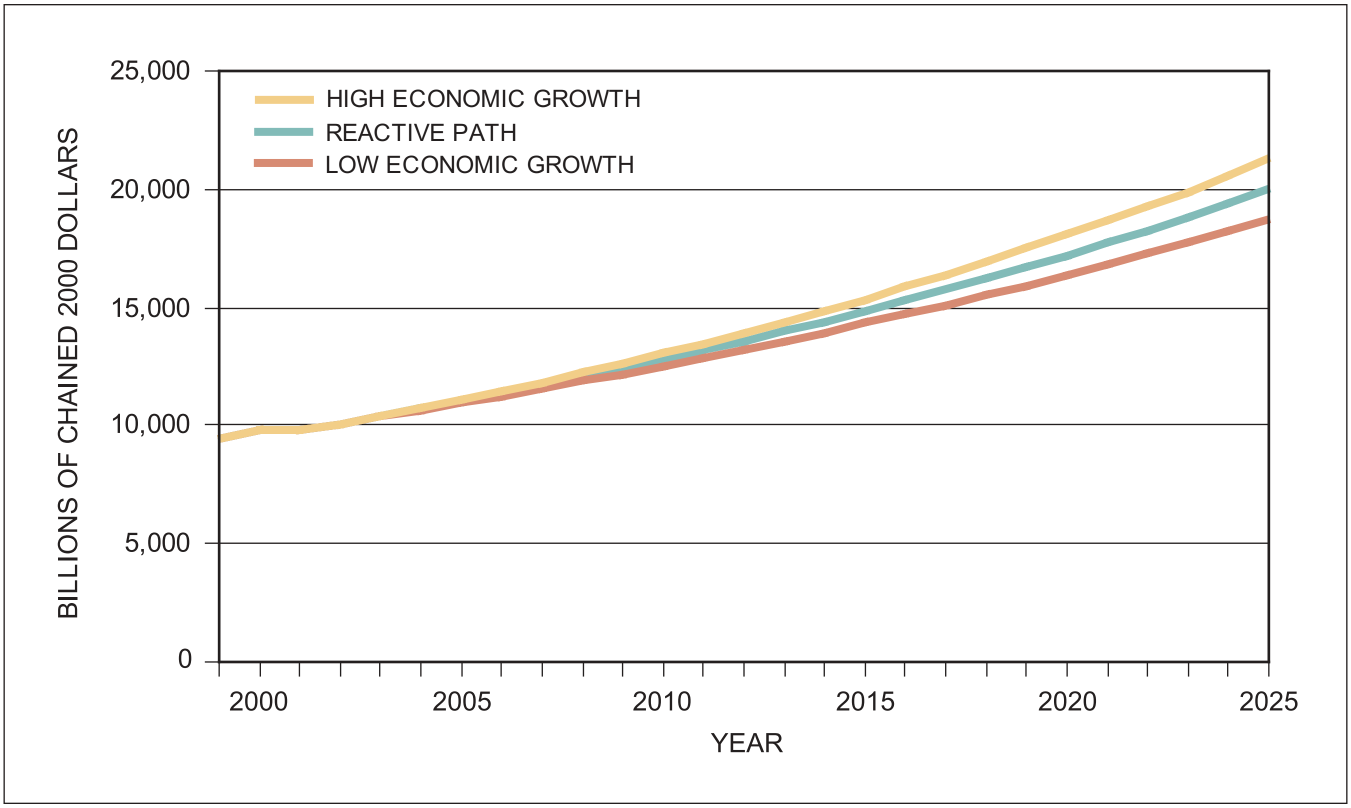


Figure D6-2. Comparison of U.S. GDP Growth Assumptions in Economic Growth Sensitivities

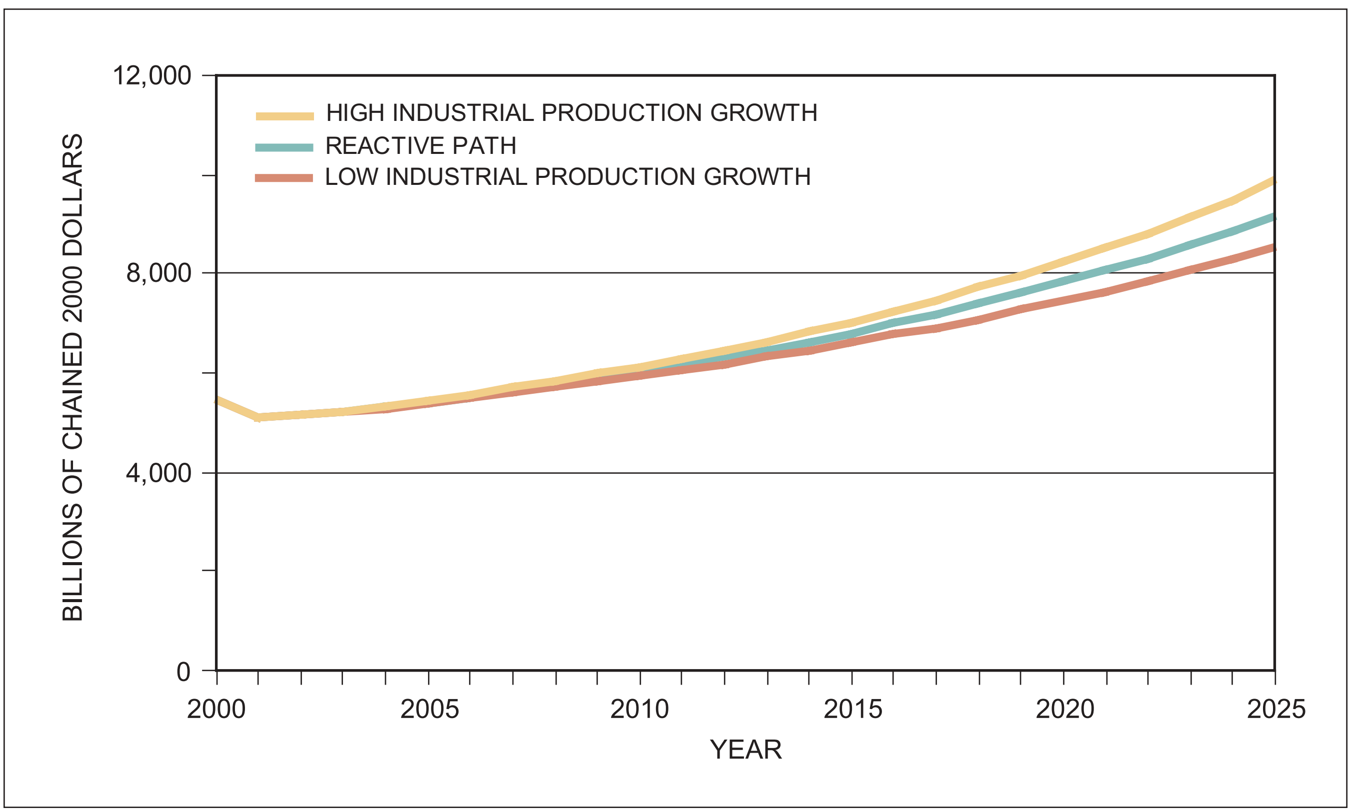


Figure D6-3. Comparison of U.S. Industrial Production Growth Assumptions in Economic Growth Sensitivities

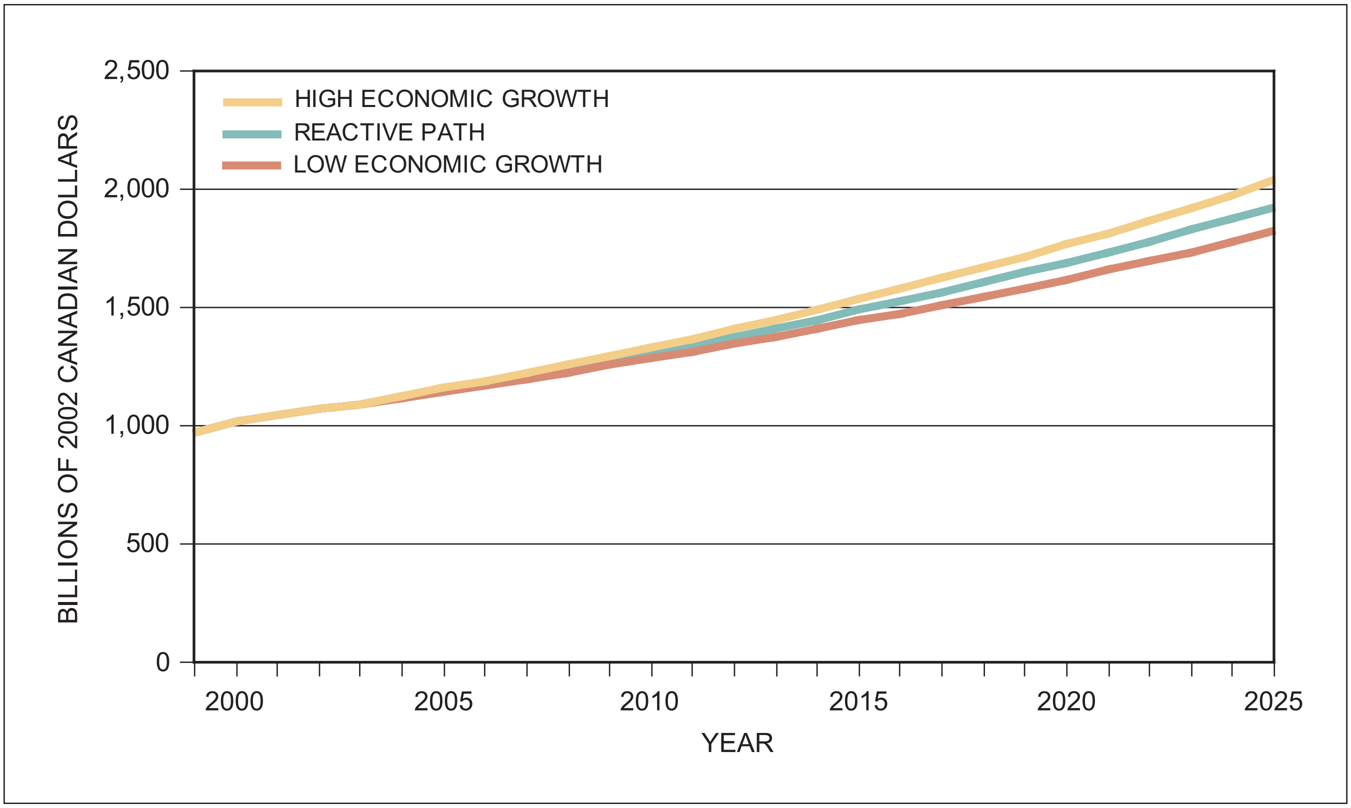


Figure D6-4. Comparison of Canadian GDP Growth Assumptions in Economic Growth Sensitivities

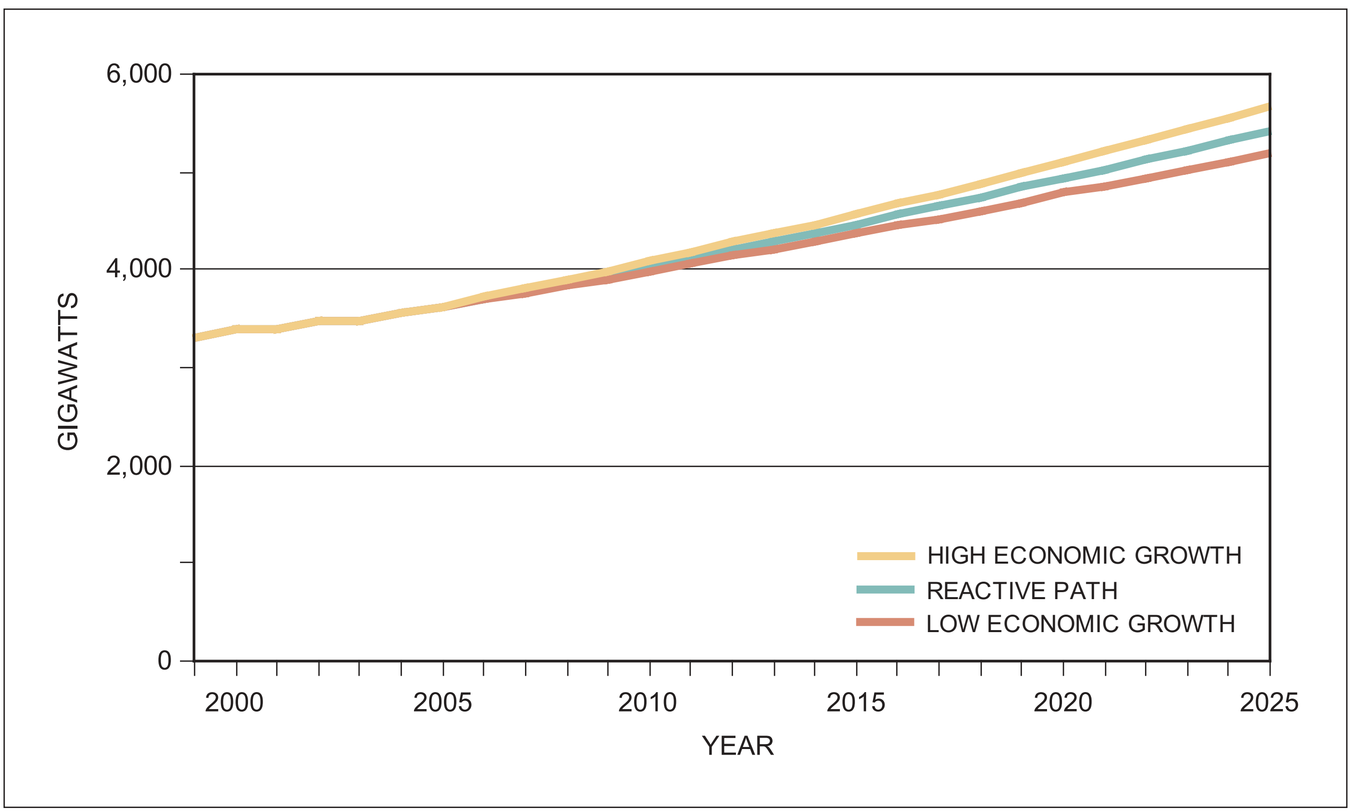


Figure D6-5. Comparison of Electricity Sales Growth Rates in Economic Growth Sensitivities

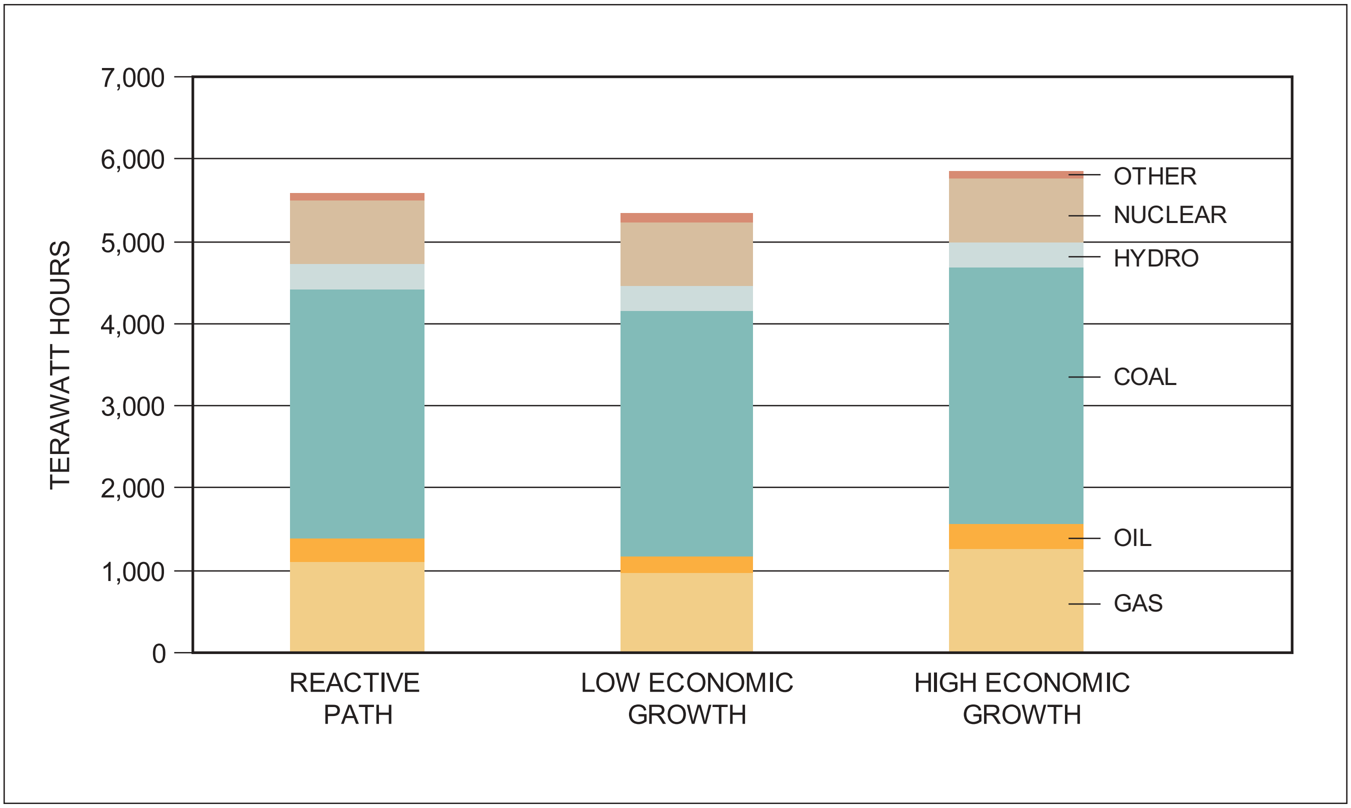


Figure D6-6. Comparison of 2025 Generation Mix in Economic Growth Sensitivities

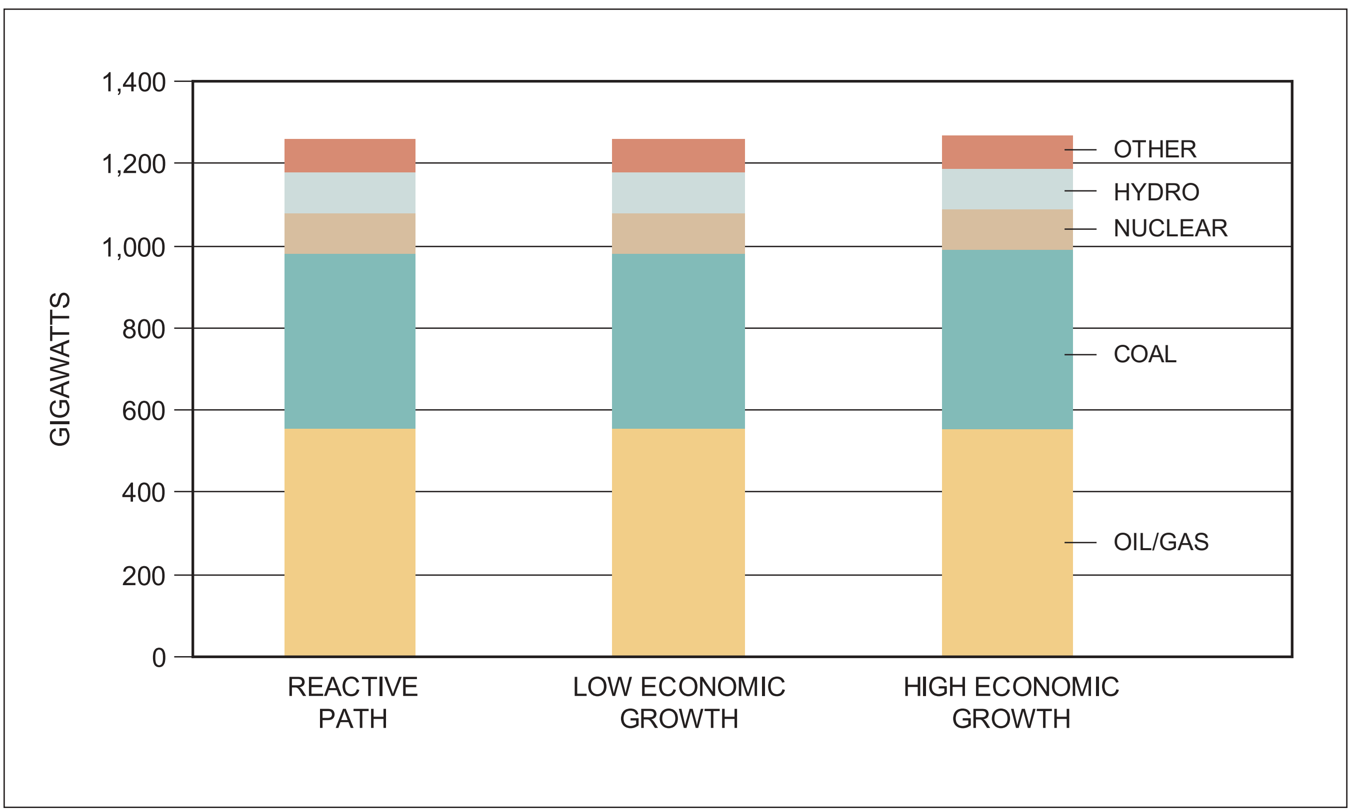


Figure D6-7. Comparison of 2025 Capacity Mix in Economic Growth Sensitivities is increased by about 1.5%, or 145 BCF over the Reactive Path scenario.

In the industrial sector, two different factors are working in opposition. The increase in industrial production growth tends to increase gas demand. However, industrial gas demand is highly sensitive to changes in natural gas prices. The substantial increase in power sector gas demand has driven up prices (Figure D6-8). Over the period 2011 to 2025, the Henry Hub gas price averages $0.47 higher than the Reactive Path scenario. The effects of higher prices overwhelm the increase in production growth, and industrial gas demand actual decreases by 308 BCF in 2025 (Figures D6-9 and D6-10). For all sectors in total, U.S. gas demand in 2025 increases to 28,212 BCF, and increase of 591 BCF over the Reactive Path scenario.

In some ways, the Low Economic Growth case is the mirror image of the High Economic Growth case. Electricity sales in 2025 are down by 236 GWh, very similar the level of increase in the High case. Likewise, the decreases in residential and commercial gas demand are very similar to the absolute value of the demand increases in the High case.

However, there are some important difference in the power and industrial sectors. While the Low case's decrease in total generation is similar to the magnitude of increase in the High case, a much higher share of the displaced generation is gas-fired. Since gas-fired generation is on the margin, it is disproportionately affected by the change in electricity sales. In the Low case, gas-fired generation drops 149 GWh in 2025, or 59% of the total decrease in generation (Figure D6-11). Power sector gas demand is also decreased by a greater amount, dropping by 950 BCF (Figure D6-12).

As with the High case, production growth and prices effects are pulling industrial demand in different directions. In the Low case, decreased gas demand for power generation and (to a lesser extent) for residential and commercial use lowers the average gas price by $0.59 compared to the Reactive Path scenario. The price drop results in a net increase in industrial gas demand to 7,334 BCF in 2025, a 231 BCF increase over the Reactive Path scenario. The increase in industrial gas demand is smaller than the absolute value of the decrease in the High case in part because slower economic growth has yielded lower industrial activity and less ability to consume natural gas. The demand increase is also smaller because the industrial demand

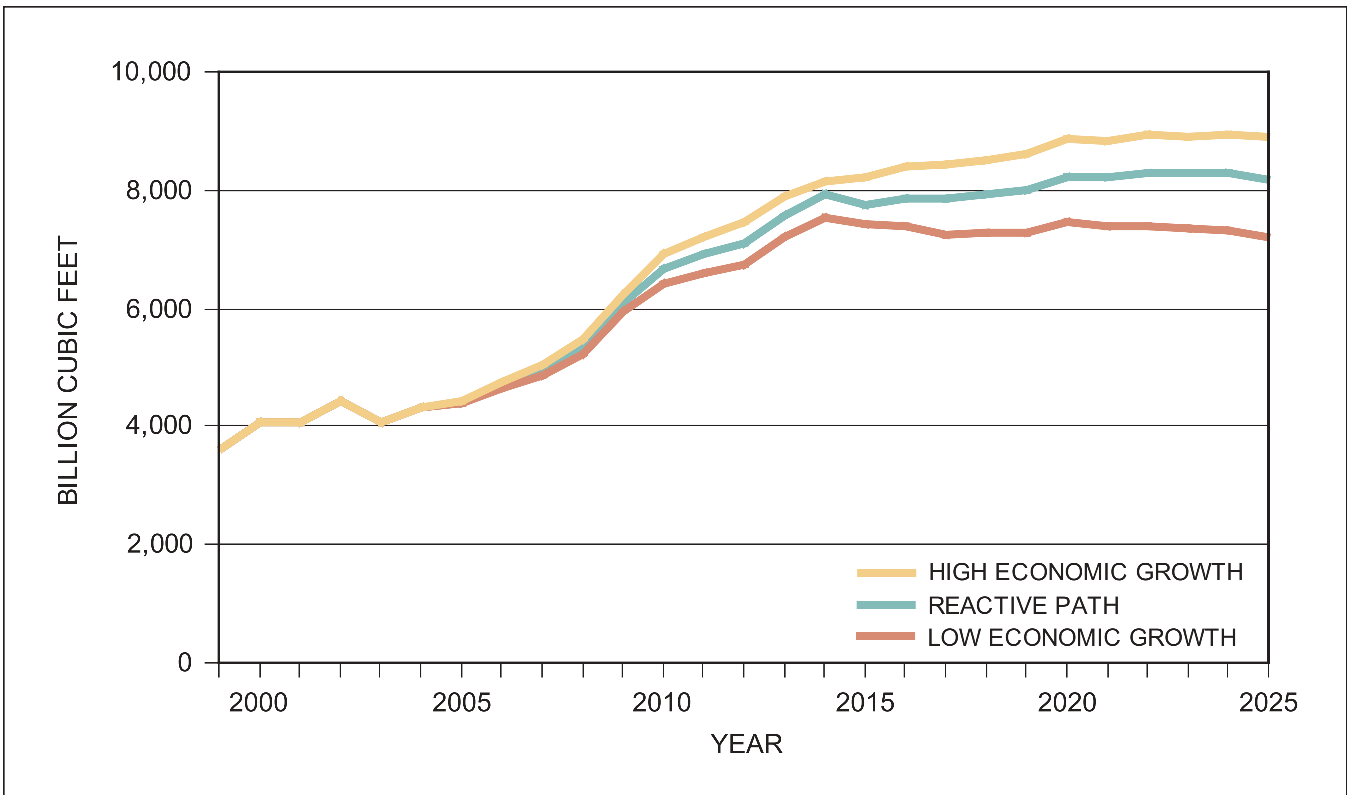


Figure D6-8. Comparison of U.S. Power Generation Gas Demand in Economic Growth Sensitivities

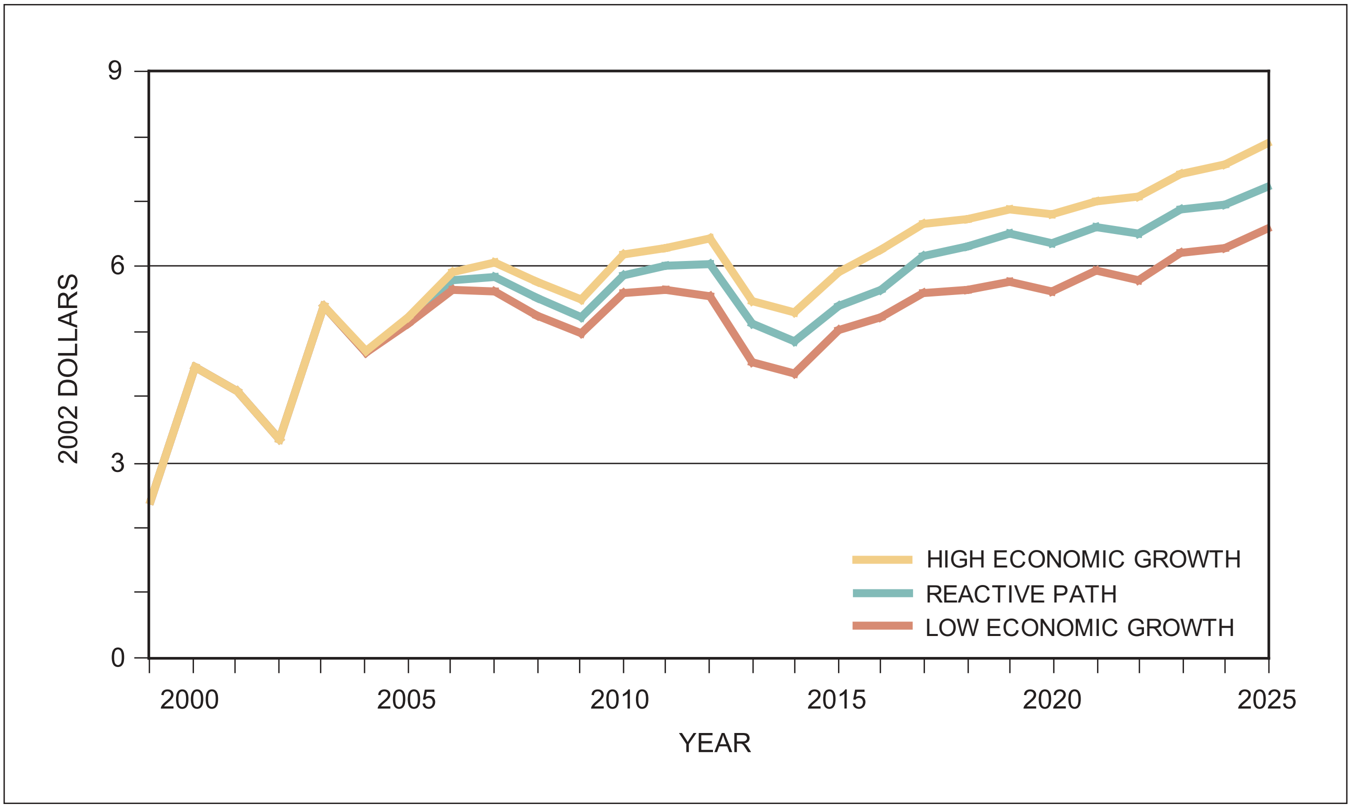


Figure D6-9. Comparison of Henry Hub Gas Prices in Economic Growth Sensitivities

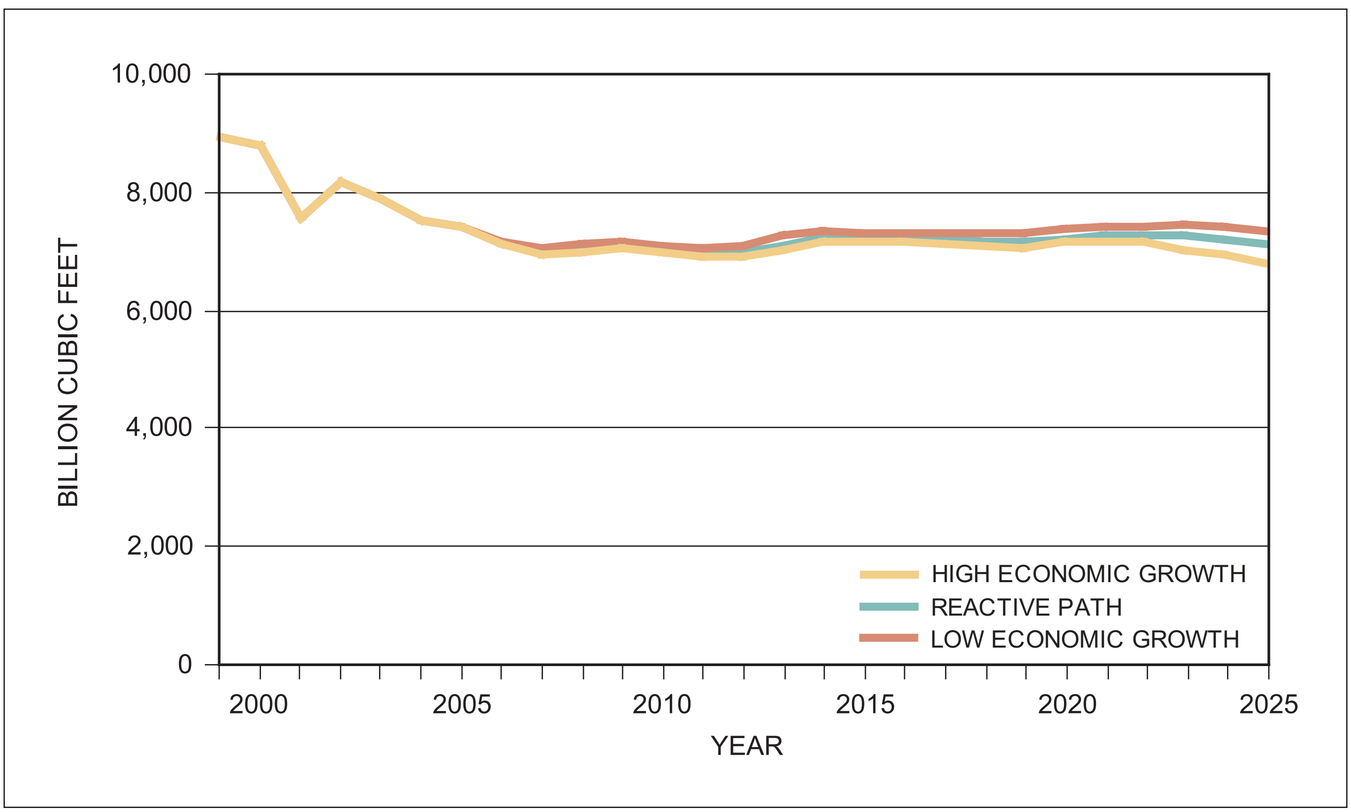


Figure D6-10. Comparison of U.S. Industrial Gas Demand in Economic Growth Sensitivities

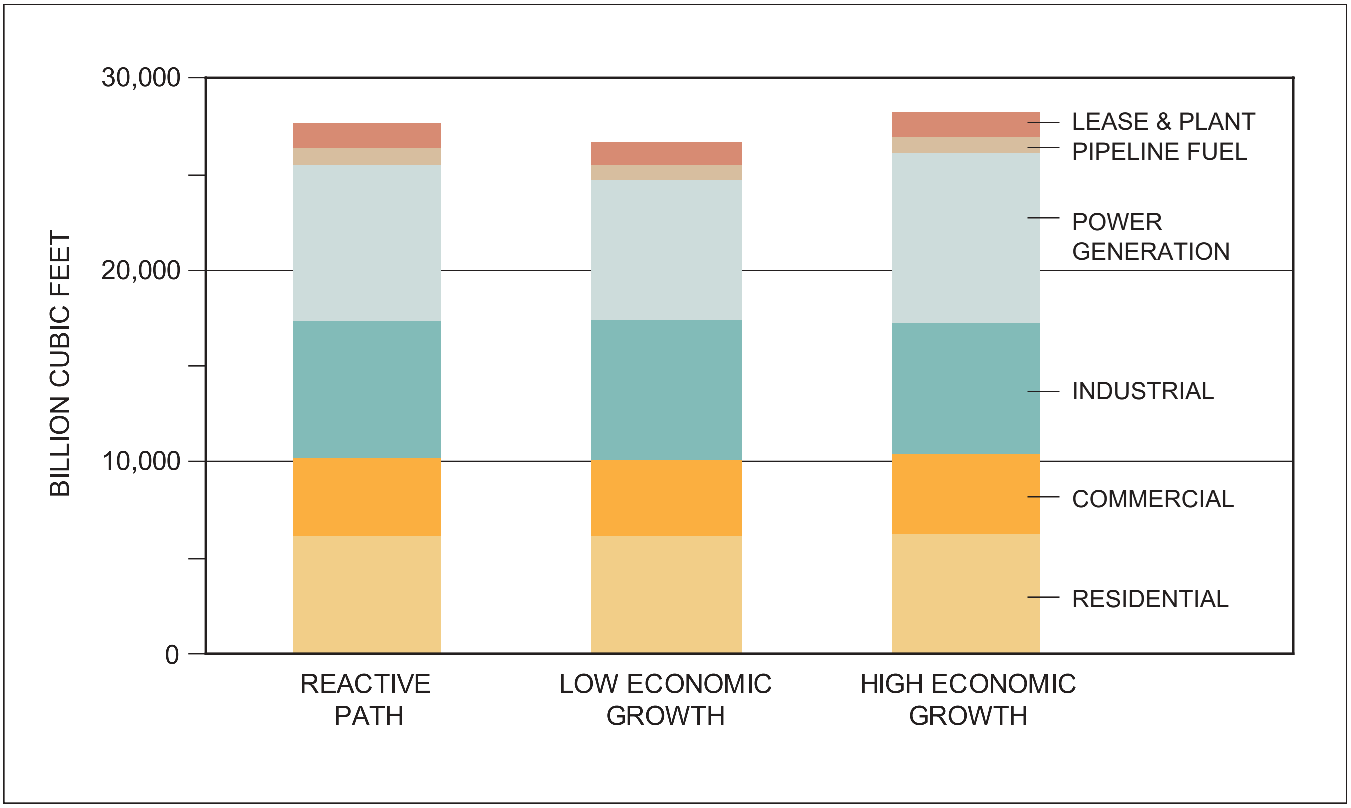


Figure D6-11. Comparison of 2025 U.S. Gas Demand in Economic Growth Sensitivities

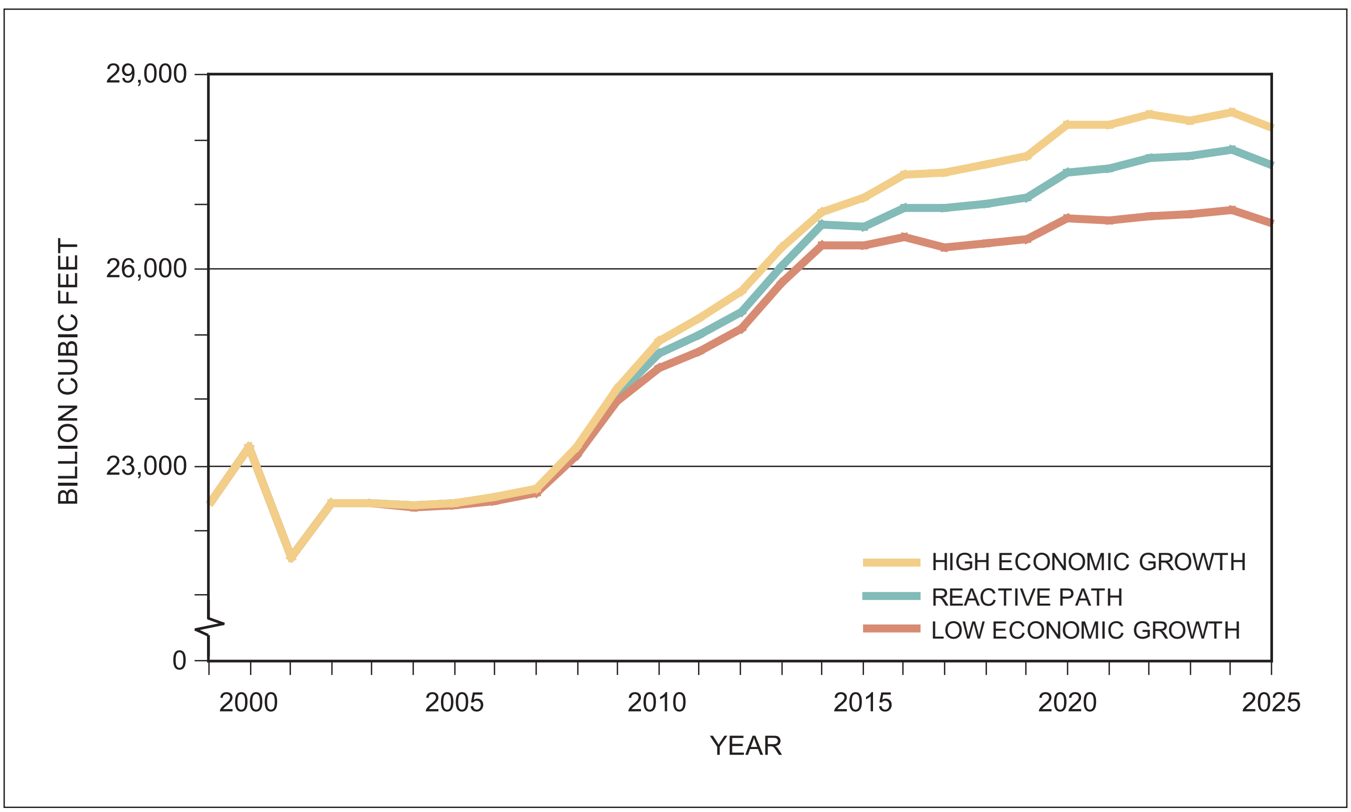


Figure D6-12. Comparison of U.S. Gas Demand in Economic Growth Sensitivities tends to be less price-elastic in response to downward price trends than it is to upward price trends. The net effect of the Low Economic Growth sensitivity on total U.S. gas demand is a decrease of 894 BCF by 2025.

To further assess and "test" the GDP and industrial production assumptions, modeling process, and results, the E&D Subgroup enlisted Global Insight to use a detailed macroeconomic model. Appendix D contains the report from Global Insight. While the prices in the Global Insight report reflect interim NPC modeling results, this report aided the NPC study group in understanding the broad impacts of higher prices.

B. Industrial Production Growth Sensitivities

The industrial production (IP) growth sensitivity cases assessed the potential effects of high and low IP growth on the gas supply/demand balance (shown in Figure D6-3), assuming the U.S. and Canadian GDP growth rates of the Reactive Path and Balanced Future scenarios.

Production growth tracks were developed for ten distinct industrial categories based on two-digit SIC codes. By far the fastest growing industrial category is Other Manufacturing, which includes SIC codes 36 (electrical equipment, which includes computers) and 37 (transportation equipment, including automobile manufacturing). In aggregate, industrial output increases at an annual rate of 3.0% in the Reactive Path scenario (Figure D6-13). In the sensitivity cases, the growth for each of the ten industries were changed proportionately to yield a growth rate that was either 10% higher or lower than the value in the Reactive Path scenario. The High Industrial Production Growth case has an aggregate growth rate of 3.3%, while the Low Industrial Production Growth case has a growth rate of 2.7%. Figure D6-14 compares the price effects for the high and low economic growth sensitivity cases. Figure D6-15 shows overall natural gas demand in 2025 for these two cases, and contrasts it to the Reactive Path scenario; Figure D6-16 and D6-17 illustrate industrial natural gas demand and total natural gas demand, respectively, through time for these two cases, in contrast to the Reactive Path.

Since GDP growth was not modified, electricity sales were the same as the Reactive Path scenario in both industrial growth sensitivities. Residential and commercial demands are also very similar to the results in the Reactive Path scenario, although price elasticity

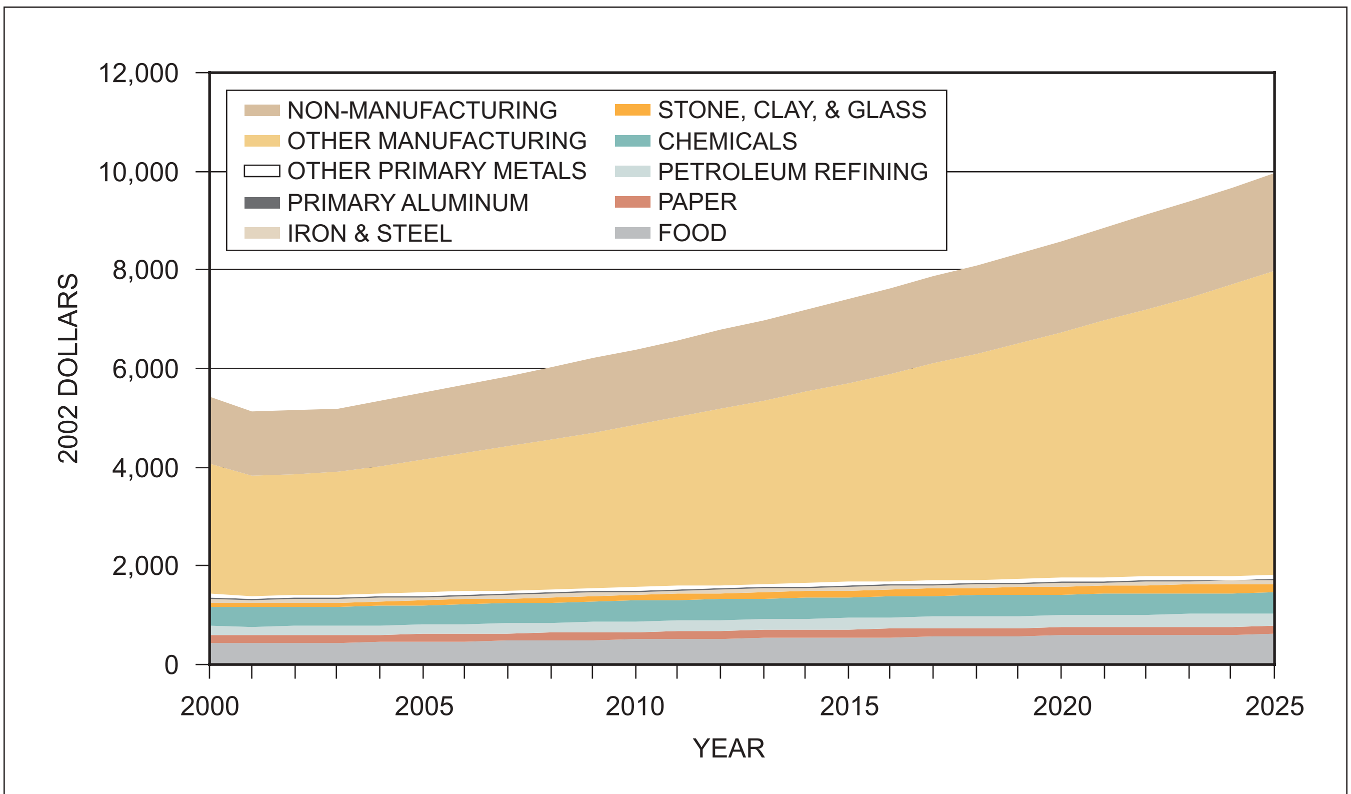


Figure D6-13. Value of Industrial Output by Industry for Reactive Path Scenario

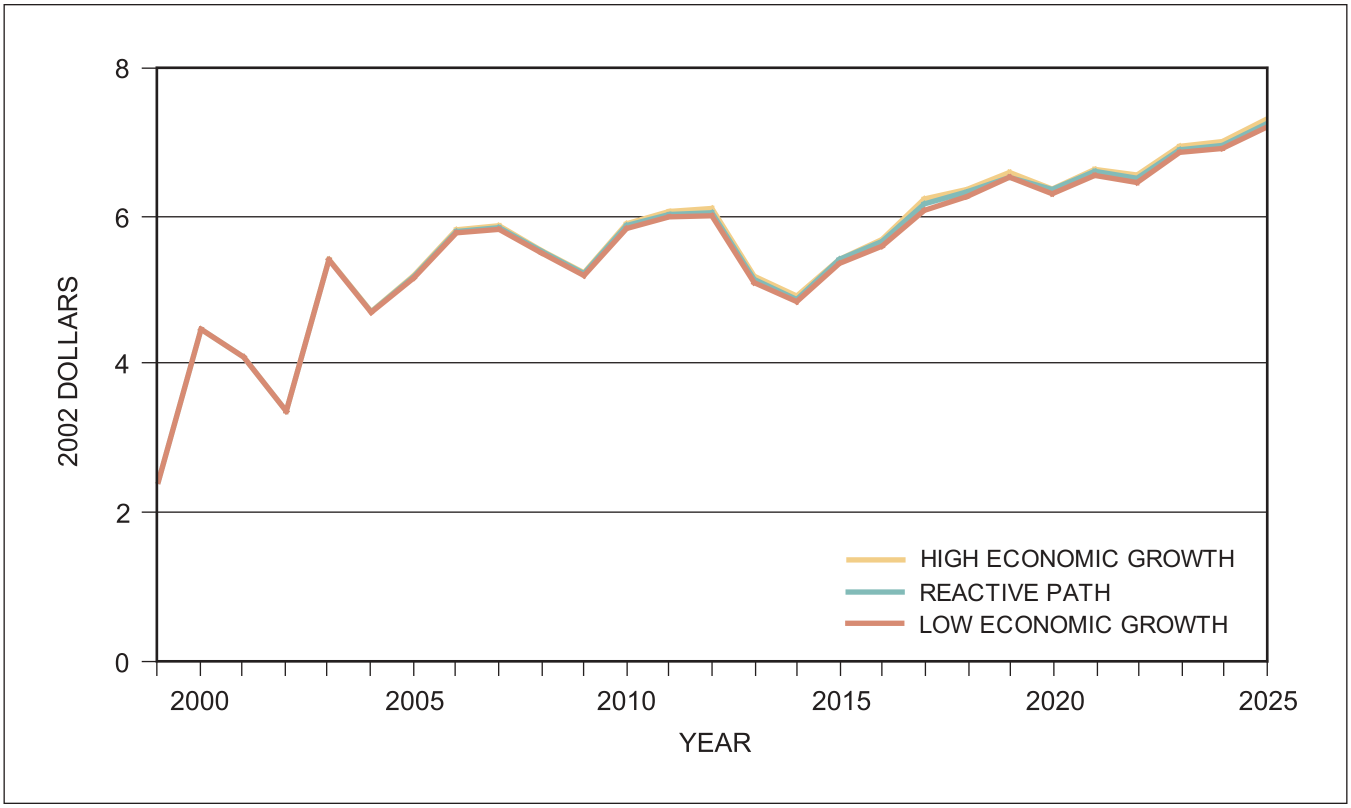


Figure D6-14. Comparison of Henry Hub Gas Prices for Industrial Production Growth Sensitivity Cases

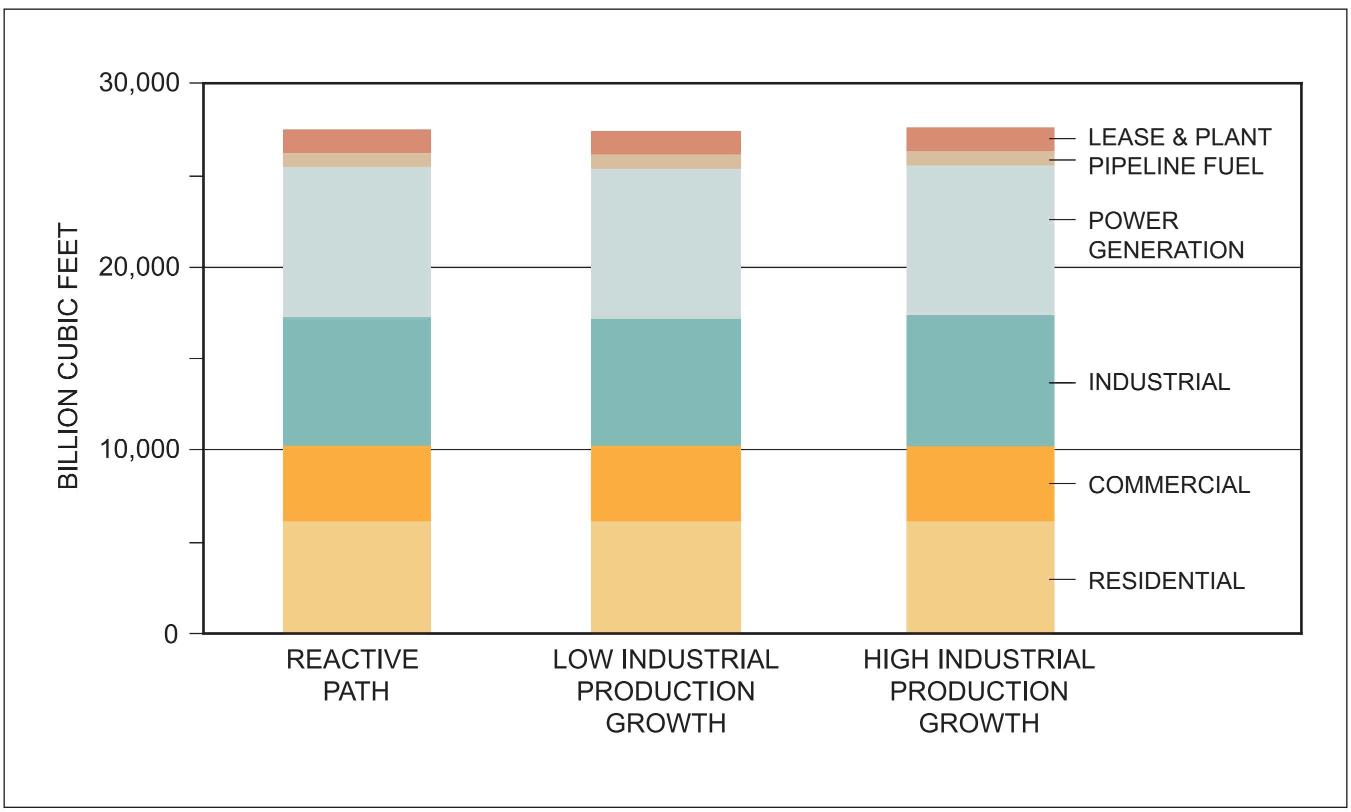


Figure D6-15. Comparison of 2025 U.S. Gas Demand in Industrial Production Growth Sensitivity Cases

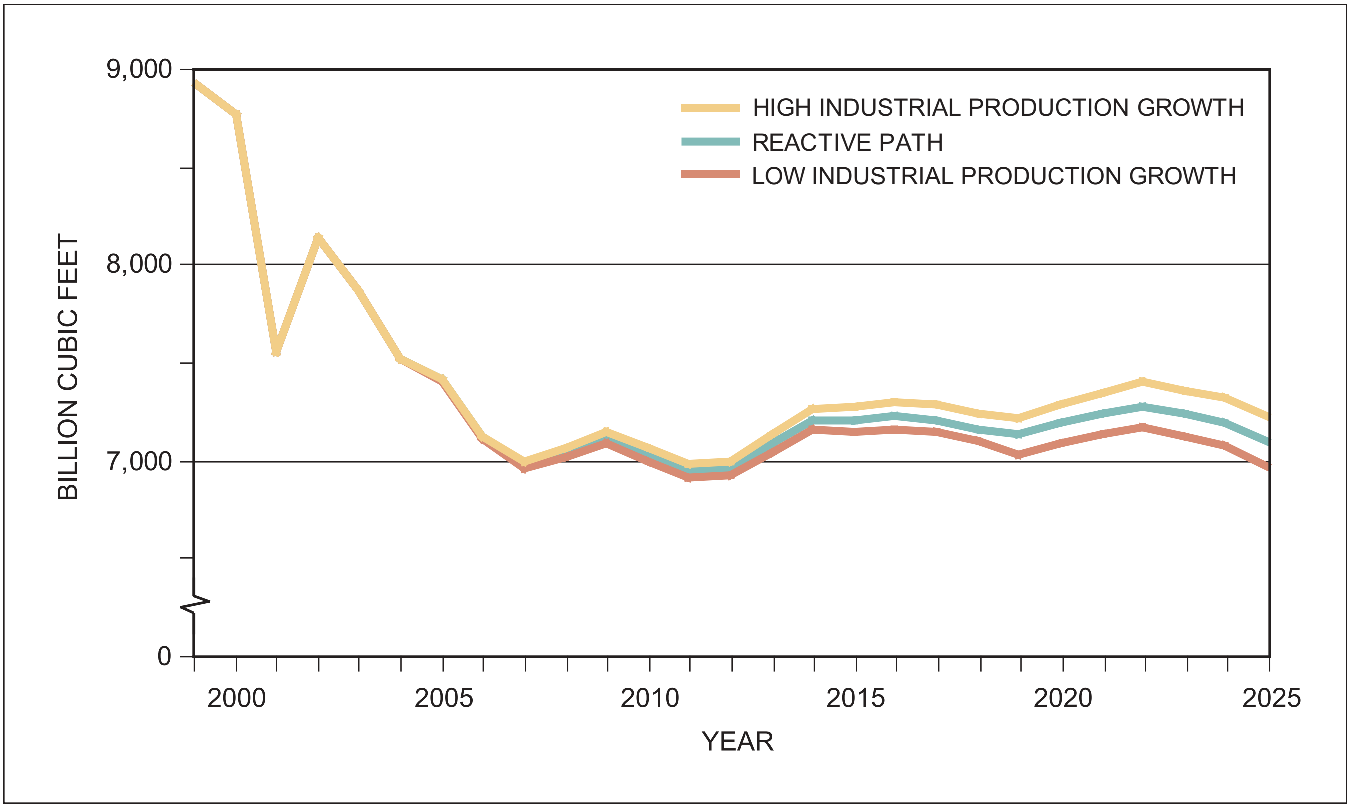


Figure D6-16. Comparison of U.S. Industrial Gas Demand in Industrial Production Growth Sensitivity Cases

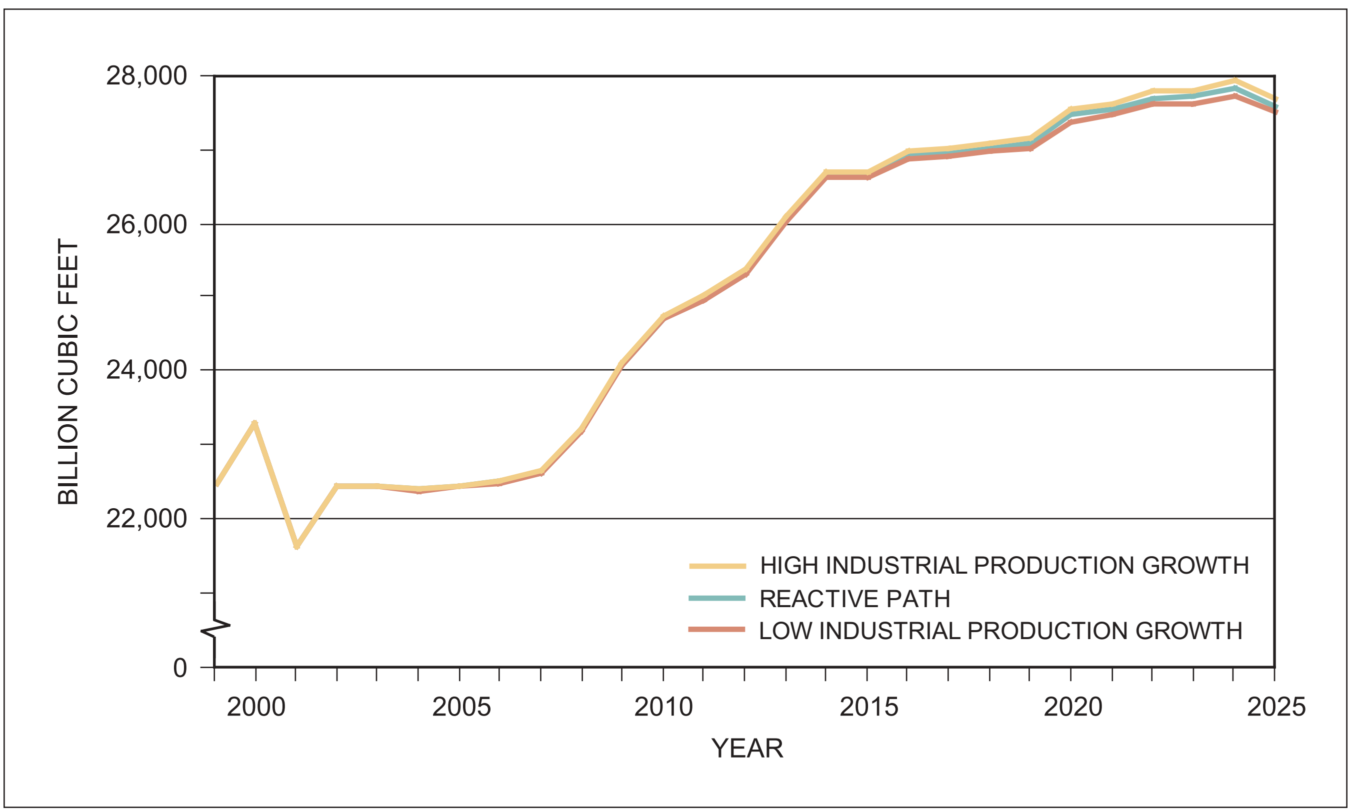


Figure D6-17. Comparison of Total U.S. Gas Demand in Industrial Production Growth Sensitivity Cases responses create small differences between the sensitivity cases and the Reactive Path scenario.

The primary impact of these sensitivities is on industrial gas demand. As with the economic sensitivities, price elasticity in the industrial sector creates some negative feedback on the gas demand response. This price feedback tends to move demand in opposite direction of the growth rate change. However, the price changes are relatively small in both industrial growth cases. In the Low case, the average price is down by only $0.05, while in the High case the average price is up by only $0.04.

As a result, the demand response to price is much smaller than the effect of the growth rate change, so industrial gas demand moves in the same direct as the change in the growth rate. In the High case, industrial demand in 2025 is up by 133 BCF over the Reactive Path scenario; in the Low case, industrial demand is down by 126 BCF. In total, U.S. gas demand in 2025 is up by 88 BCF in the High case, and down by 93 BCF in the Low case.

C. Electricity Sales Sensitivities

The electricity sales sensitivity cases examined the relationship between GDP growth and the growth in electricity sales. The assumption used in the Reactive Path scenario was that the elasticity of electricity sales to GDP would continue decline as it has in the past, although at a progressively slower rate, declining from 72% in 2003 to 62% by 2025.

While this assumption was felt to be the most plausible of all considered, the Electric Power Subgroup found that there were for other possible trends in GDP elasticity. Greater uses of electric appliances by households and increased use of electricity in manufacturing may cause the elasticity to level off. Alternately, increases in efficiency and/or decreases in energy-intensive manufacturing in the United States may be the downward trend in elasticity continues at a pace similar to the historical trend. To explore these alternate trends, two sensitivity cases were run. In the High Electricity Sales-to-GDP Growth Elasticity case (referred to herein as "High Elasticity"), the elasticity was held constant at 72%, suggesting an environment in which economic growth spurred additional power demand but this growth was not muted by efficiency gains. In the Low Electricity Sales-to-GDP Growth Elasticity case (referred to herein as "Low Elasticity") the relationship declined more quickly to 52% in 2025 (Figure D6-18), potentially providing insight into the effects of efficiency improvements and demand-response measures in power markets. GDP growth rates were held constant at 3.0% in both cases.

While the elasticities were changed by equal amounts in the high and low cases (plus or minus 10 percentage points), the resulting change in electricity sales was not symmetrical (Figure D6-19). By 2025, electricity sales increased by 580 GWh in the High case, while in the Low case they decreased by only 248 GWh compared to the Reactive Path scenario.

In the High Elasticity case, higher levels of electricity sales increased the need for capacity. Compared to the Reactive Path scenario, the High Elasticity case builds an additional 68 GW of capacity by 2025 – 46 GW of coal, 16 GW of renewables, and 6 GW of oil/gas capacity. The increased in electricity sales yielded a 626 GWh increase in total generation by 2025. Of the total increase, 51% came from coal, which was up by 321 GWh over the Reactive Path scenario (Figure D6-20). Gas generation was up 210 GWh, contributing 33% of the increase, while oil generation and renewables made up the remainder.

In the High Elasticity case, power sector gas consumption in 2025 was 1,243 BCF above the Reactive Path scenario, an increase of over 15%. This increase in gas demand pushed projected gas price higher. In response, gas demand moved downward in the industrial sector (Figure D6-21). By 2025, industrial gas demand is down by 514 BCF compared to the Reactive Path scenario. In total, the High Elasticity case caused a net increase in 2025 gas demand of 645 BCF over the Reactive Path scenario.

By contrast, the changes in electricity sales were more modest in the Low Elasticity case. Since the change in elasticity was ramped in over time, most of the effect of the decrease is not seen until relatively late in the forecast. By 2025, total generation in the Low Elasticity case is 268 GWh lower than the Reactive Path scenario. However, almost 60% of that decrease came from a decline in generation from natural gas (Figure D6-22). Likewise, gas demand in the power sector is predicted to be down by 1,043 BCF in this case.

The drop in power sector gas demand leads to a decline in gas prices (Figure D6-23), which in turn increases industrial demand. By 2025, industrial gas demand is 368 BCF greater than the Reactive Path scenario. In total, the Low Elasticity case has a net decrease in gas demand of 594 BCF (Figure D6-24).

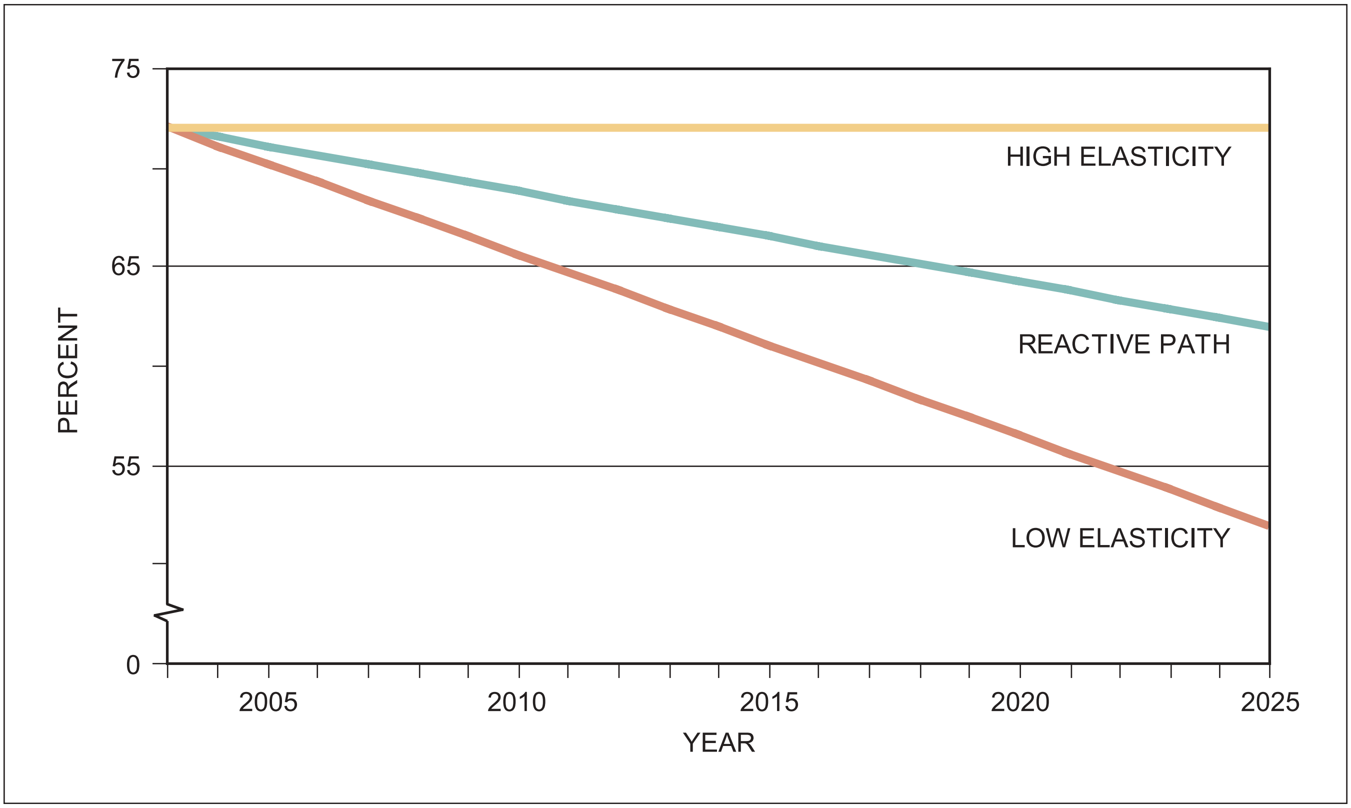


Figure D6-18. Comparison of Elasticity Values in the Electricity Sales Sensitivity Cases

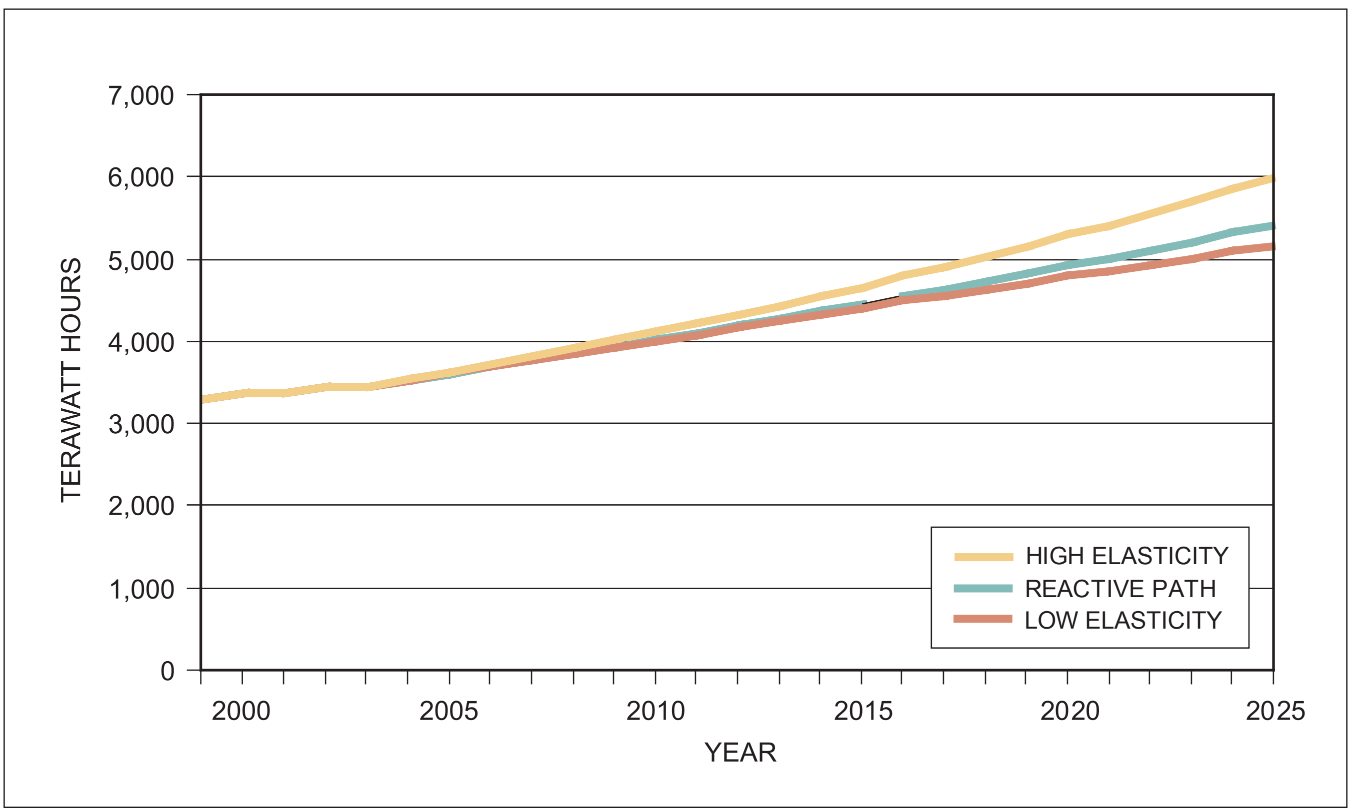


Figure D6-19. Comparison of Electricity Sales in the Electricity Sales Sensitivity Cases

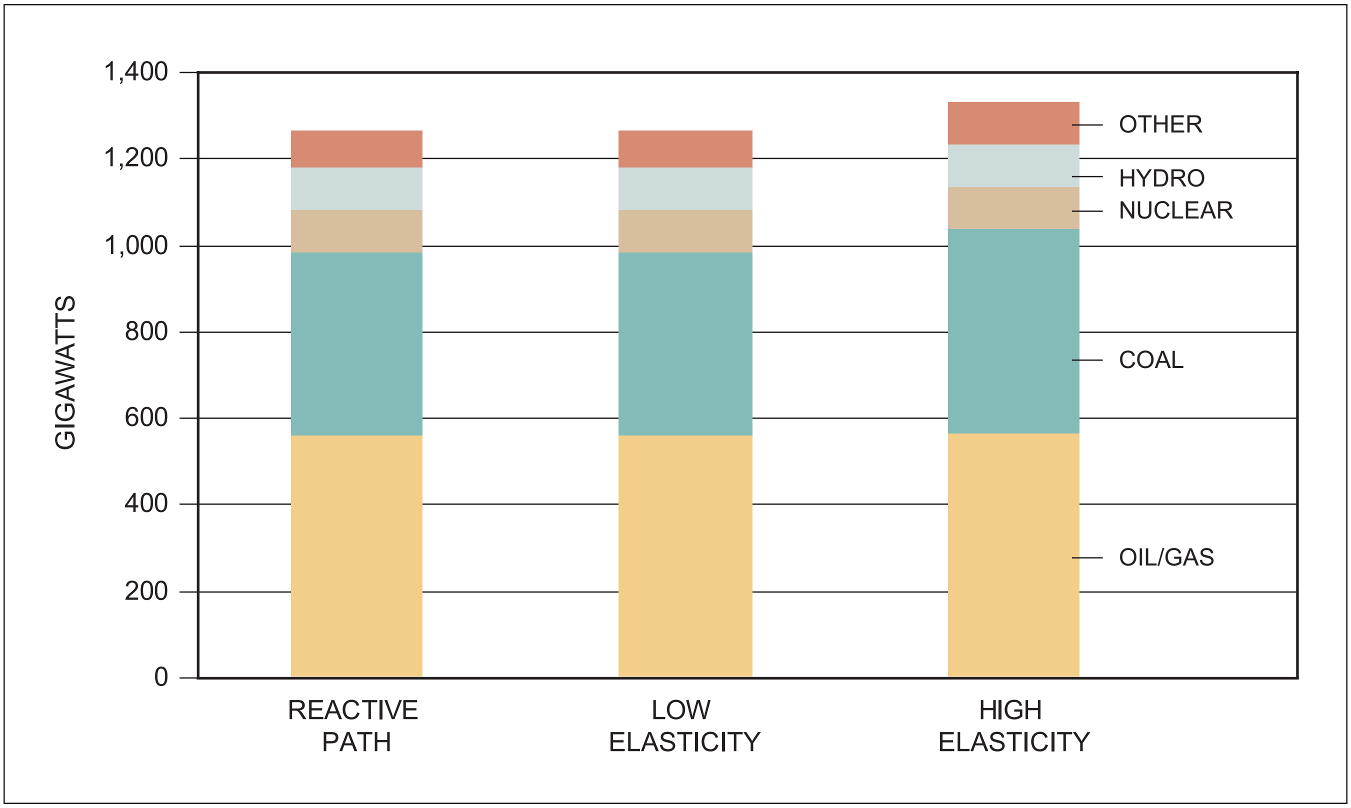


Figure D6-20. Comparison of 2025 Capacity in the Electricity Sales Sensitivity Cases

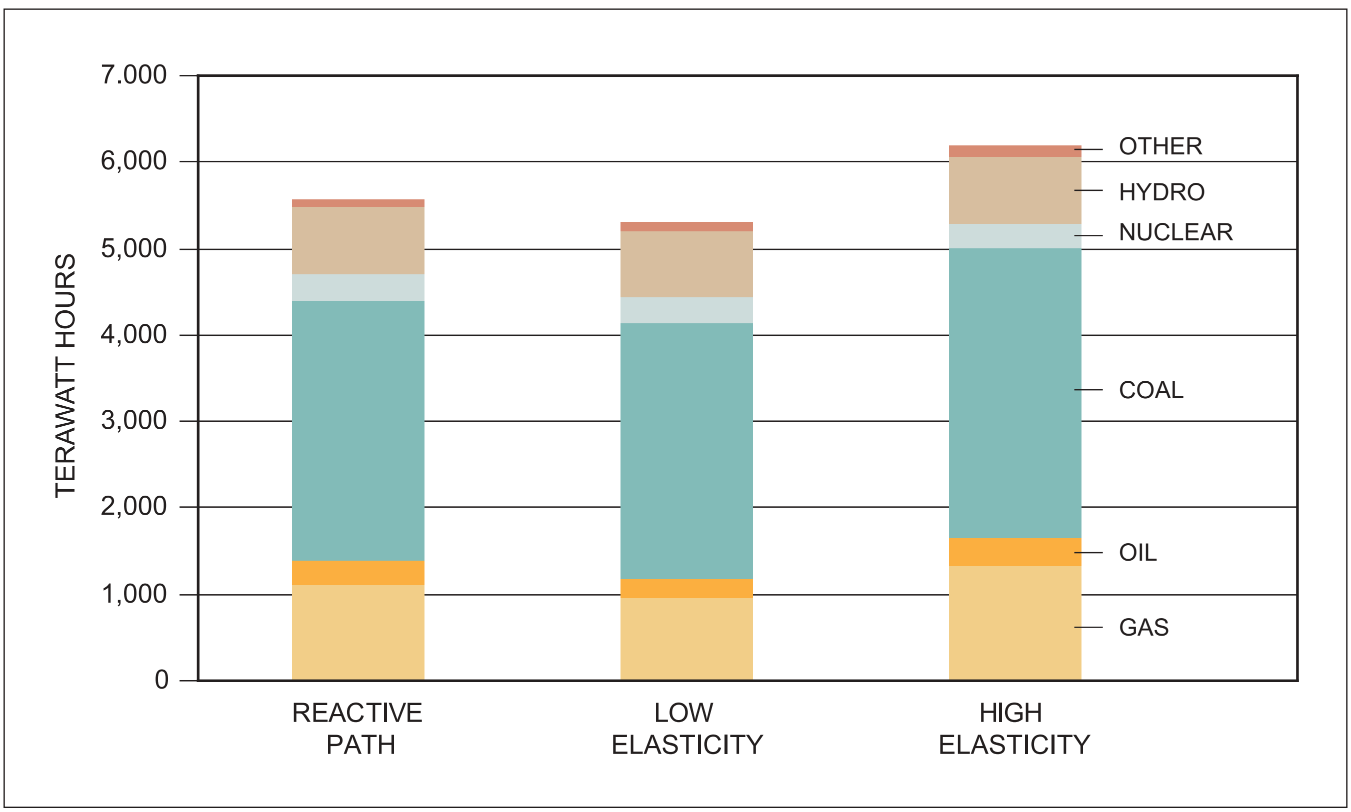


Figure D6-21. Comparison of 2025 Generation in the Electricity Sales Sensitivity Cases

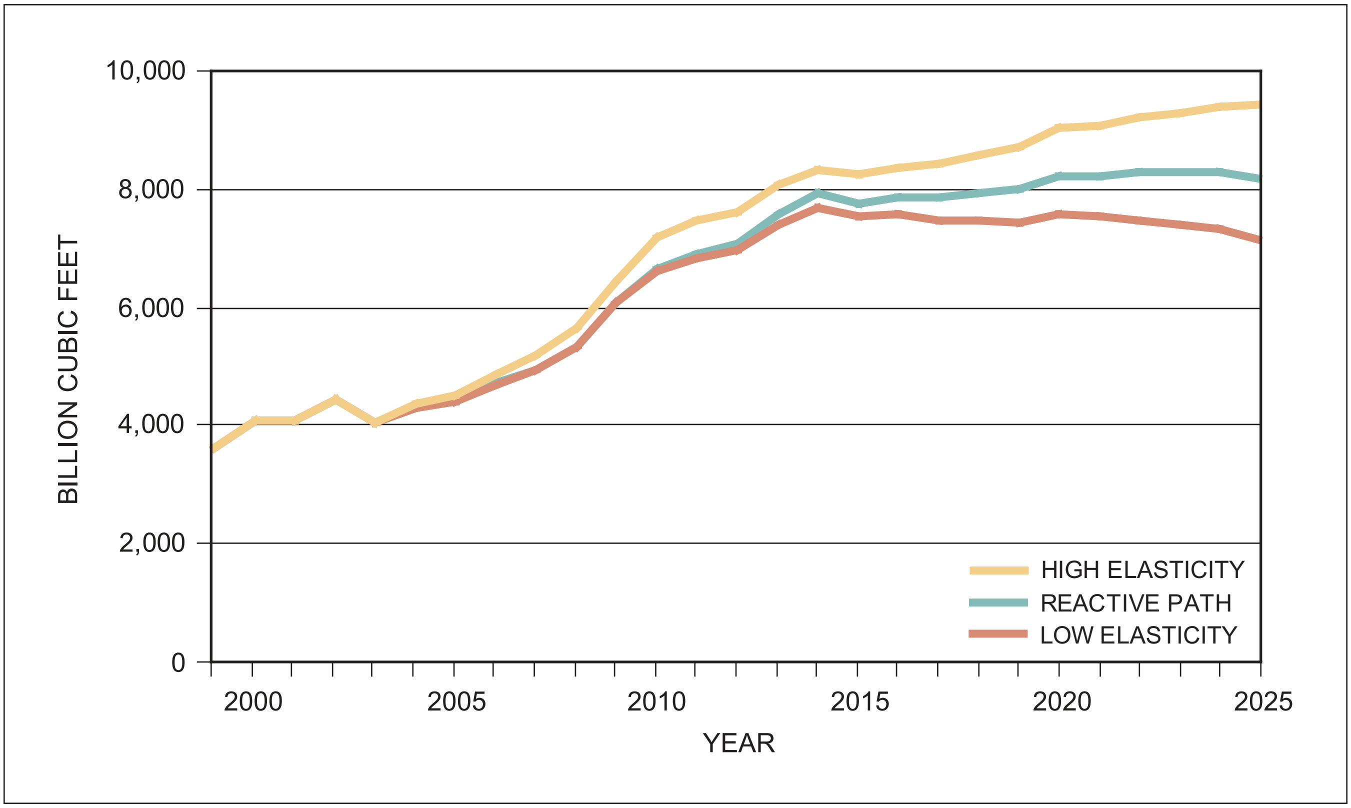


Figure D6-22. Comparison of U.S. Power Sector Gas Demand in the Electricity Sales Sensitivity Cases

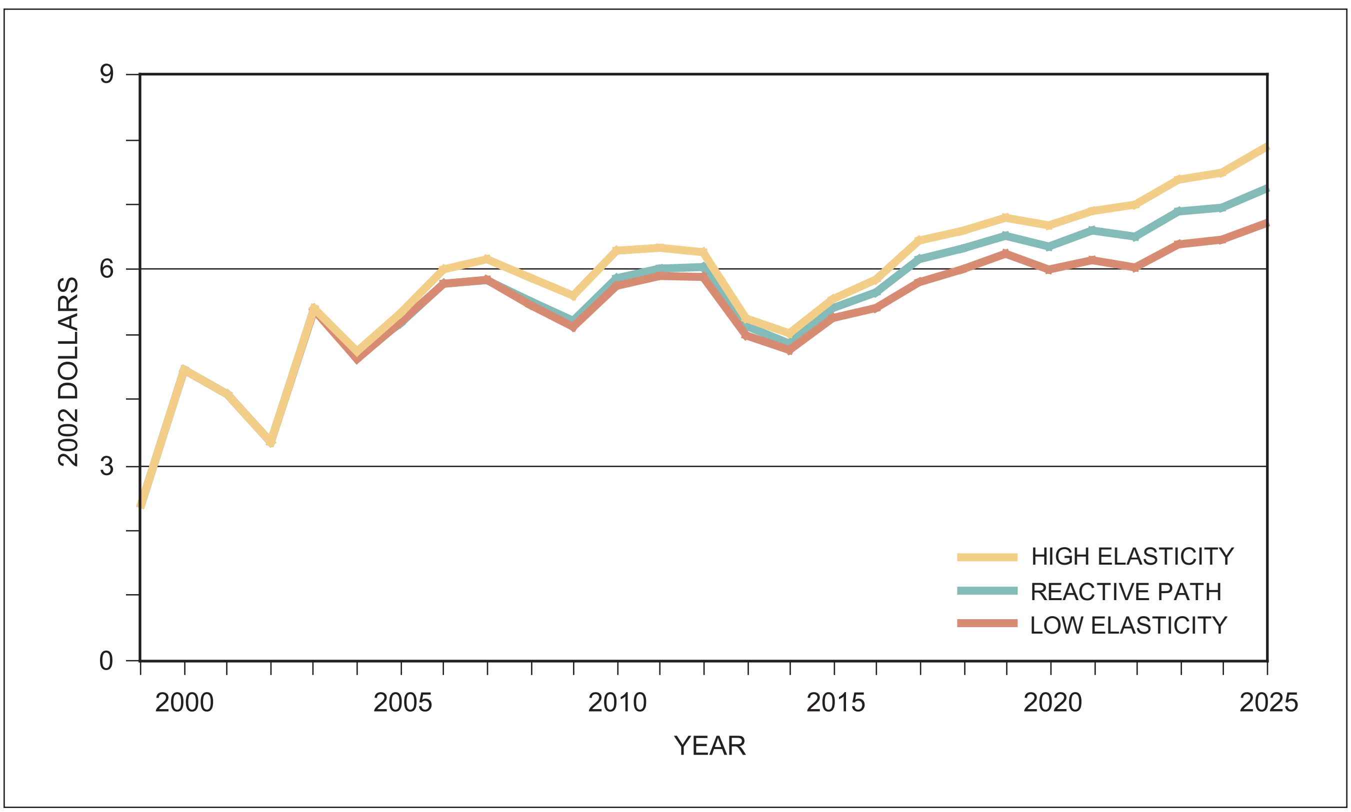


Figure D6-23. Comparison of Henry Hub Gas Prices in the Electricity Sales Sensitivity Cases

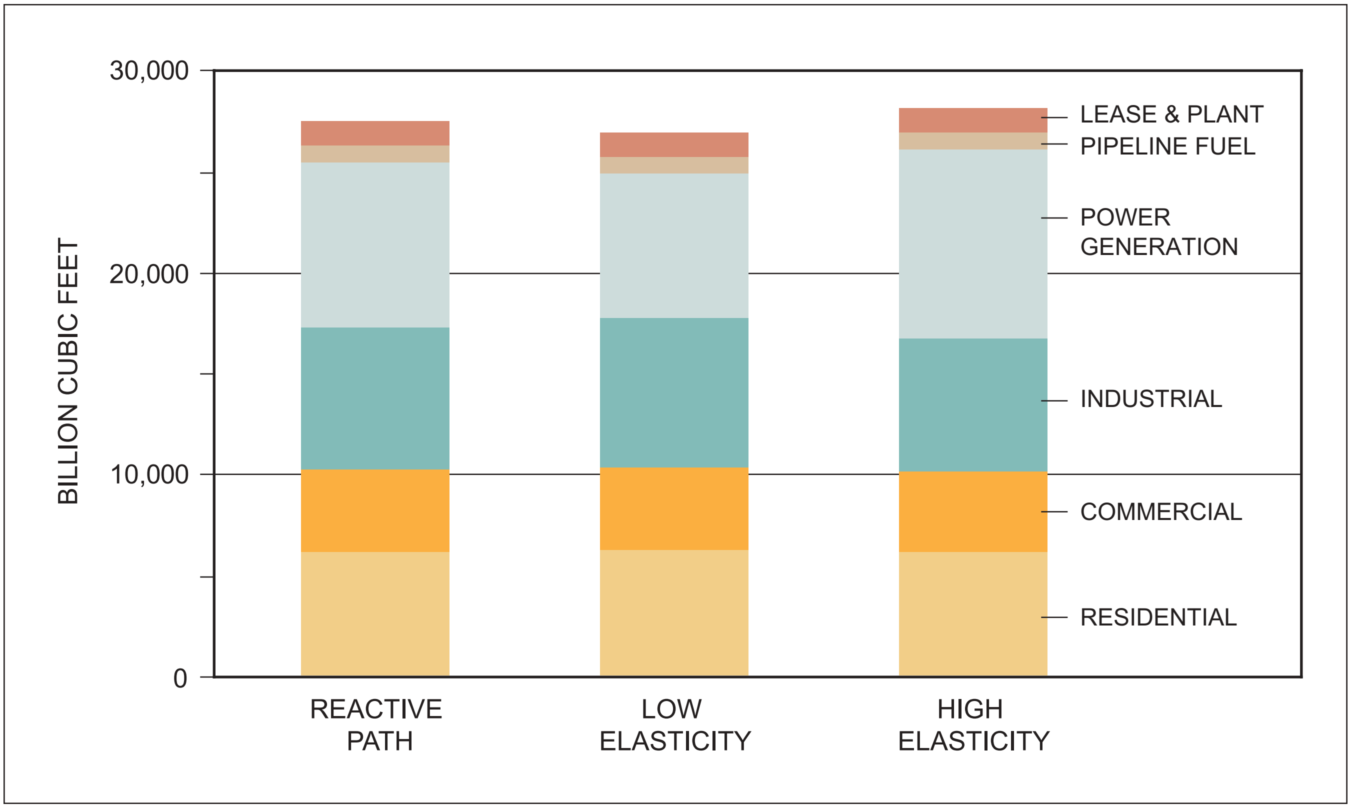


Figure D6-24. Comparison of 2025 Gas Demand in the Electricity Sales Sensitivity Cases

D. $28 WTI Oil Price Sensitivity

The reference assumption for forecast oil prices was a West Texas Intermediate (WTI) crude oil price of $20.00 per barrel in 2002 dollars. Because U.S. refineries use many different grades of oil, the refiner's acquisition cost of crude (RACC) is actually lower than the WTI price. The RACC price was assumed to be 90% of the WTI price, or $18.00 per barrel. The prices for refined oil products were assumed to be fixed ratios of the RACC price; residual fuel oil was assumed to be 84% of the RACC price, while distillate fuel was 140% of RACC.

To examine the impact of oil prices on the forecast, a sensitivity case was run using higher oil prices. This alternate case used a WTI price of $28.00 per barrel, equivalent to a RACC price of $25.20. The ratios for residual and distillate fuel oils were not changed.

The primary effect of higher oil prices on the forecast is in the fuel switching behavior in the industrial and power sectors. Fuel switching is a function of the ratio of the gas price to the oil price, so an increase in the price of oil discourages oil use and encourages gas use. In the industrial sector, fuel switching primarily occurs at boilers which can switch between natural gas and residual fuel oil. In the power sector, switching can occur at either older steam turbine plants or new combined cycle and combustion turbine plants. Older steam plants use residual oil as an alternate fuel, while combined cycle and combustion turbine plants use distillate fuel oil. While many of the older steam plants have oil backup, very few of the new plants were built with the capability to switch to oil.

Oil contributes a relatively small share to total U.S. power generation needs, so the increase in oil prices had no impact on the capacity additions forecast. The effects of higher oil prices on power sector gas and oil consumption can be seen in Figures D6-25 and D6-26. Higher oil prices increase the consumption of gas in 2025 by over 5%, while oil consumption is down by over 9%. This increase in gas demand drives up the price of gas.

The power sector is relatively constrained in its response to higher gas prices. Gas-fired plants are the marginal source of generation, which implies that all other sources are already being used at their

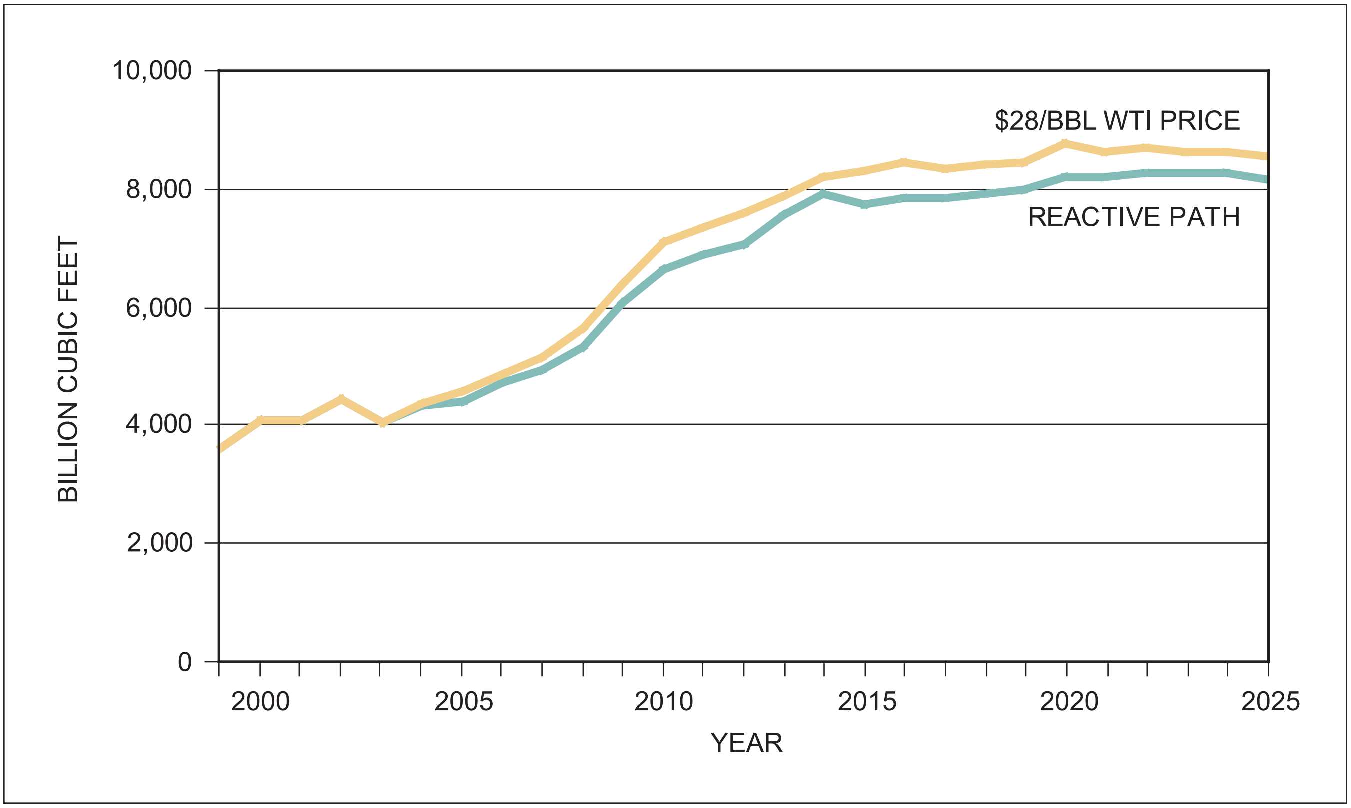


Figure D6-25. U.S. Power Generation Gas Demand in $28 WTI Sensitivity Case

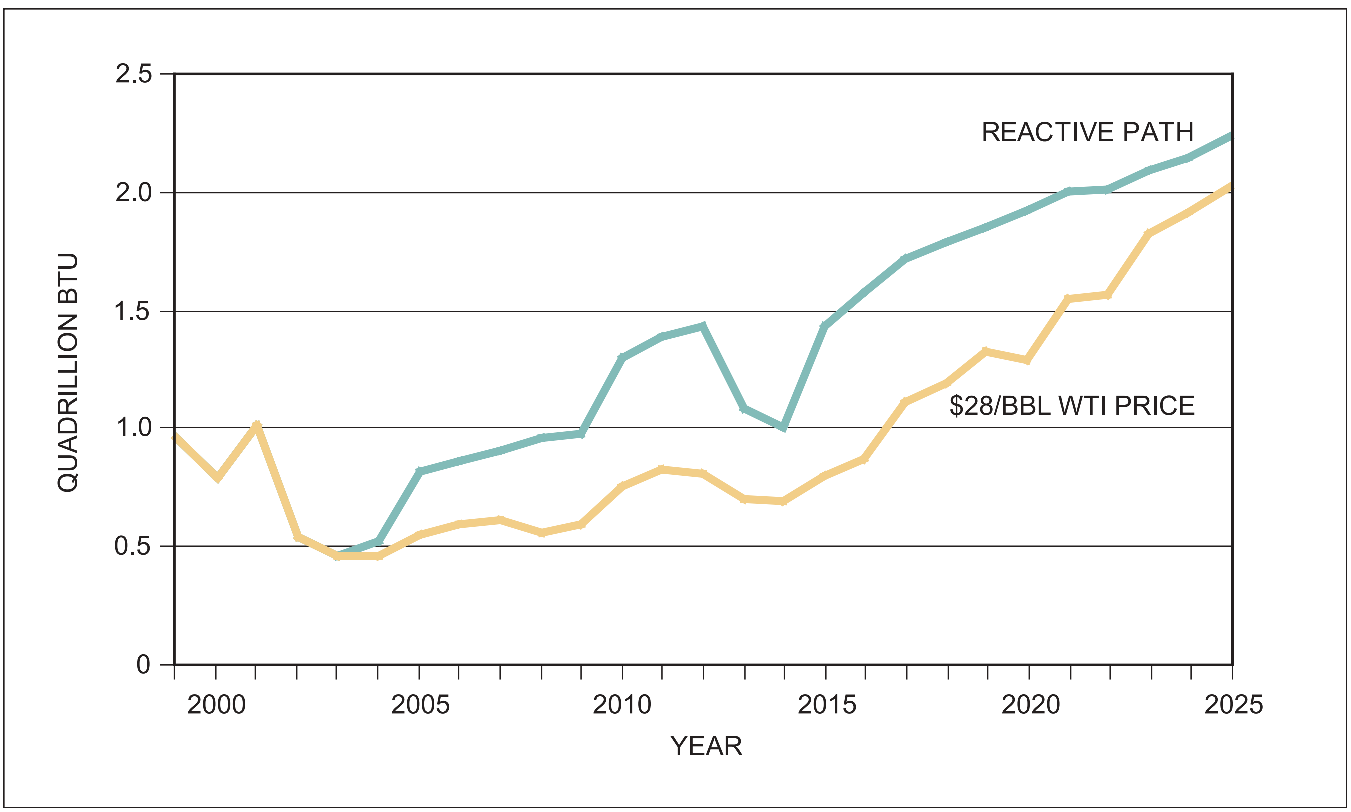


Figure D6-26. U.S. Power Generation Oil Demand in $28 WTI Sensitivity Case maximum capacity utilization. Also, all U.S. electricity demand must be met by U.S. power generators, with some limited imports from Canada. In contrast, industries can move overseas in response to higher gas prices and export there products back to the United States. This is particularly true for products where the cost of natural gas represents a high percentage of the cost of production. So, while switching to oil in the industrial sector is reduced in the high oil price sensitivity case, the primary impact is a reduction in the level of industrial gas demand due to higher gas prices (Figure D6-27). The net impact on total U.S. gas demand in 2025 is an increase of 202 BCF (Figure D6-28).

E. Fuel Flexibility Case

The purpose of the Fuel Flexibility case was to examine the impact of a broad range of changes by providing energy consumers with greater flexibility in making fuel choices. Unlike other demand sensitivity cases, the Fuel Flexibility case changed multiple input assumptions, and as such is an alternate scenario for the North American gas market. The demand assumptions used in the Fuel Flexibility case were also used in the Balanced Future scenario, which added different assumptions for gas supply. The changes to the Fuel Flexibility case fall into five categories: electricity sales elasticity, residential and commercial efficiency, fuel switching, fossil-fuel generating capacity, and nuclear generating capacity. The changes represent a different policy path which would result in lowering the growth in gas demand.

To represent greater emphasis on efficiency in electricity consumption, the elasticity of electricity sales was lowered from 62% to 60% (Figure D6-29). This relatively minor change in the elasticity assumption results in a 1% decrease in electricity sales by 2025. Since gas-fired generation is the marginal source of electricity supply, even small decreases in the demand for electricity can have significant impacts on power generation gas demand.

Likewise, the rates at which residential and commercial energy efficiency would improve were both increased. In the residential sector, the rate of efficiency improvement (measured as weather-normal gas consumption per household) was increase from 0.5 to 0.7% per year. In the commercial sector, the rate of efficiency improvement for space heating (measured as weather-normal gas consumption per million

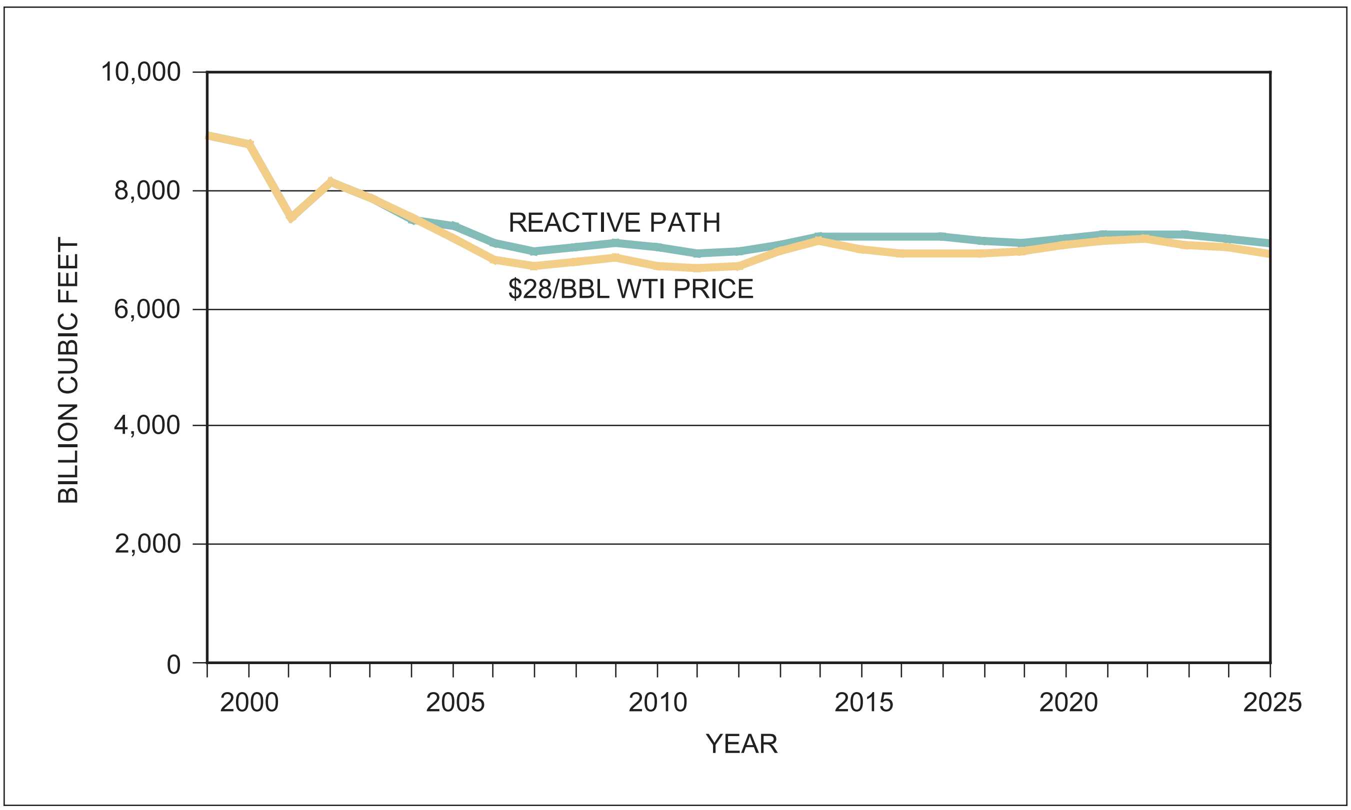


Figure D6-27. U.S. Industrial Gas Demand in $28 WTI Sensitivity Case

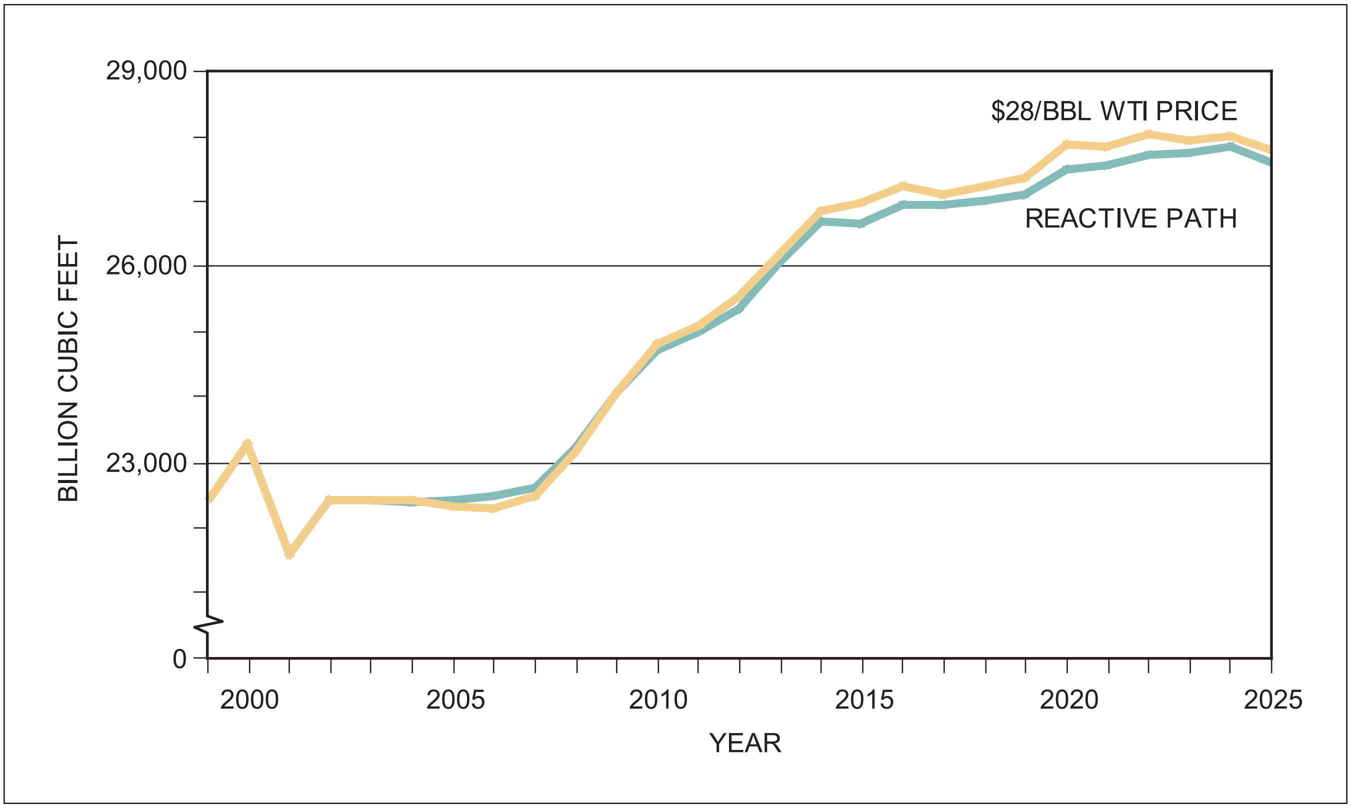


Figure D6-28. U.S. Total Gas Demand in $28 WTI Sensitivity Case

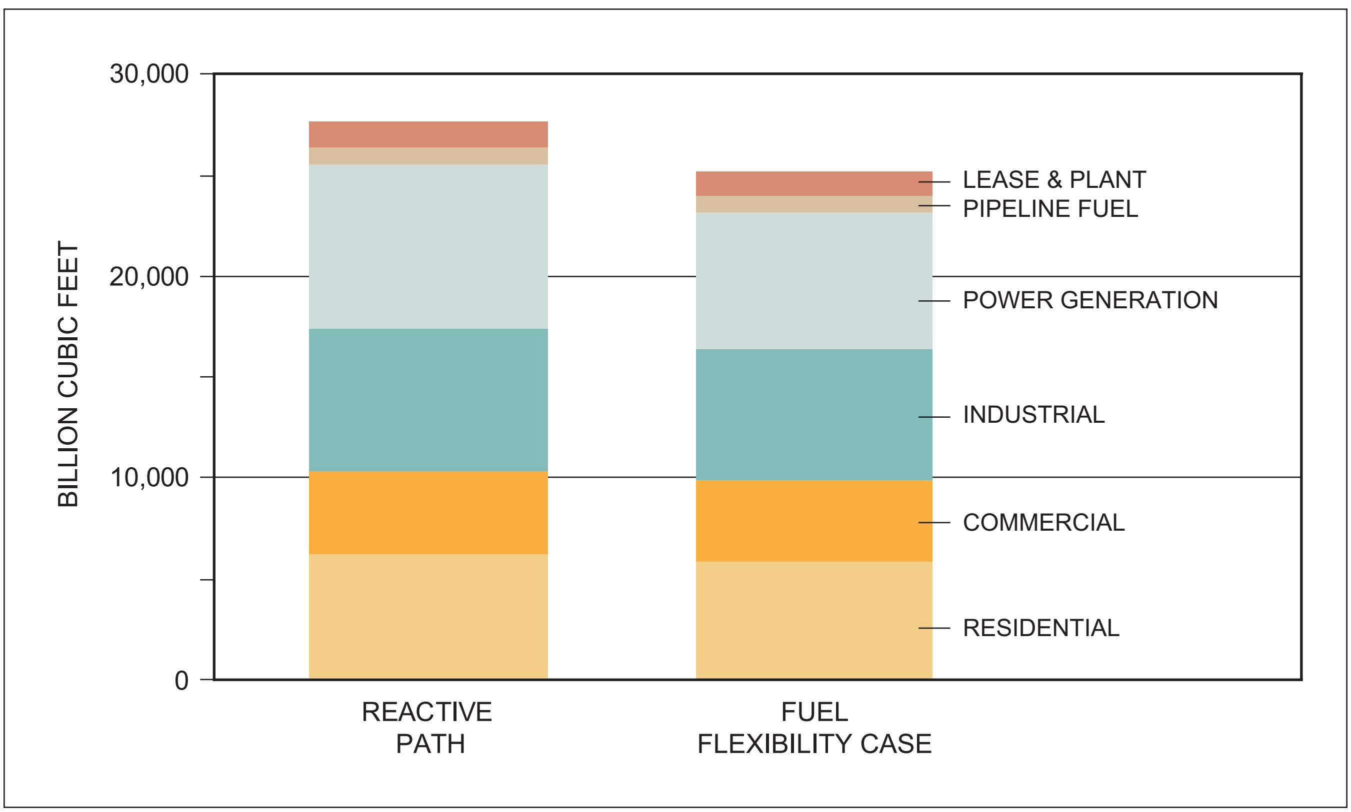


Figure D6-29. 2025 U.S. Gas Demand in the Fuel Flexibility Case square-feet) was increased from 0.5 to 0.8% per year. These improvements represent higher standard for gas appliance efficiency and a higher rate of replacement of the existing stock of appliances with new equipment.

Fuel-switching assumptions were modified in both the industrial and power sectors. In the industrial sector, the percentage of industrial boilers that would be able to fuel switch was increased from a low in 2003 of 2% to 8%, depending on the region, to a high of 28% in all regions by 2025 (Table D6-3). Since the switchable boilers cannot operate 100% on oil due to operational constraints, the maximum oil percentage for the switching curves was varied to account for the differences in boiler capabilities by region. In the power sector, the amount of switchable capacity was increase by assuming that 25% of existing combined-cycle and combustion turbine facilities would be retrofitted to burn oil as a backup fuel.

In addition to the changes in fuel-switching assumptions, several changes were made to the generating capacity forecast. While the Reactive Path scenario retired 21.5 GW of oil/gas steam capacity, the Fuel Flexibility case retired none. Leaving these older units in place provides both greater fuel-switching capability and more switching at lower gas prices, since the steam units switch to lower cost residual fuel oil. The Fuel Flexibility case also eliminated the 21.1 GW of coal plant retirements forecast in the Reactive Path scenario, assuming that there is greater flexibility in the implementation of limits on mercury emissions. The Fuel Flexibility case also assumed a more favorable environment for permitting and siting new coal- and oil-fired power plants. While the Fuel Flexibility case built no new nuclear plants, it assumes larger capacity upgrades at the existing units. While the Reactive Path scenario increased the capacity of the existing nuclear fleet by 2%, the Fuel Flexibility case increased it by 10%.

The combined effect of these changes on total U.S. gas demand is dramatic: by 2025, demand is down by over 2,500 BCF per year (Figure D6-30). As a consequence of the lower demand, prices are also significantly lower. Over the forecast years 2011 to 2025, gas prices averaged over $1.00 less that in the Reactive Path scenario (Figure D6-31). Total gas demand peaks much sooner in the Fuel Flexibility case, and actually trends downward in the final five years of the forecast. Figures D6-32 and D6-33 show

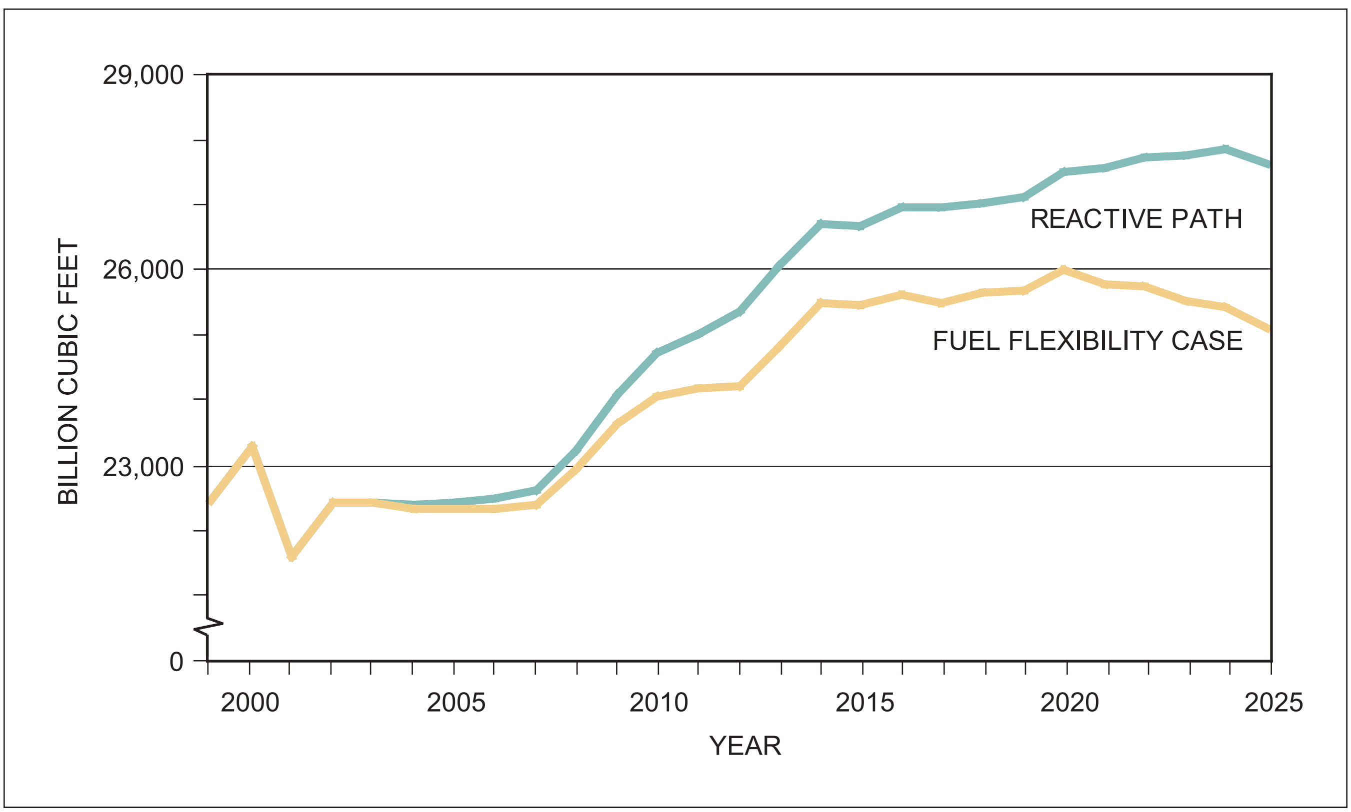


Figure D6-30. U.S. Gas Demand in the Fuel Flexibility Case

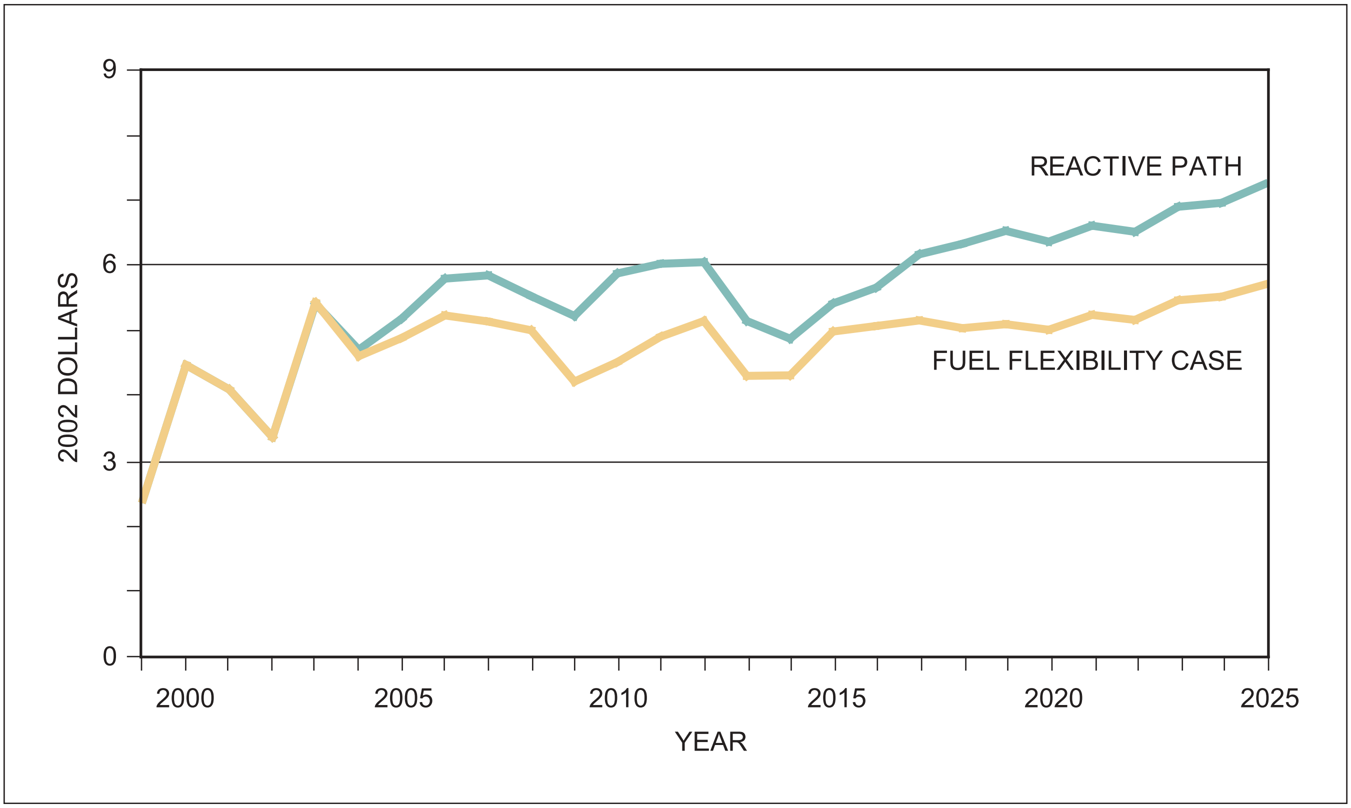


Figure D6-31. Henry Hub Gas Prices in the Fuel Flexibility Case

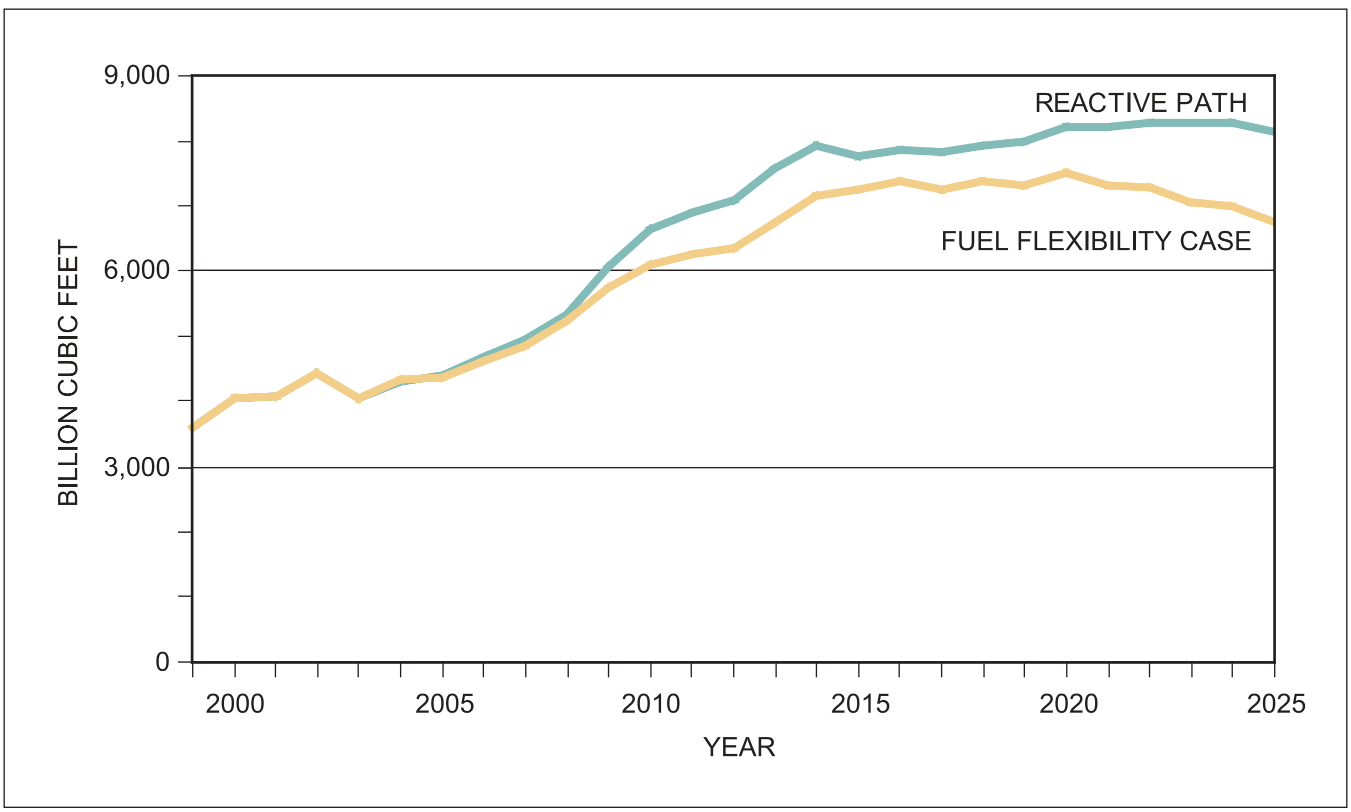


Figure D6-32. U.S. Power Generation Gas Demand in the Fuel Flexibility Case

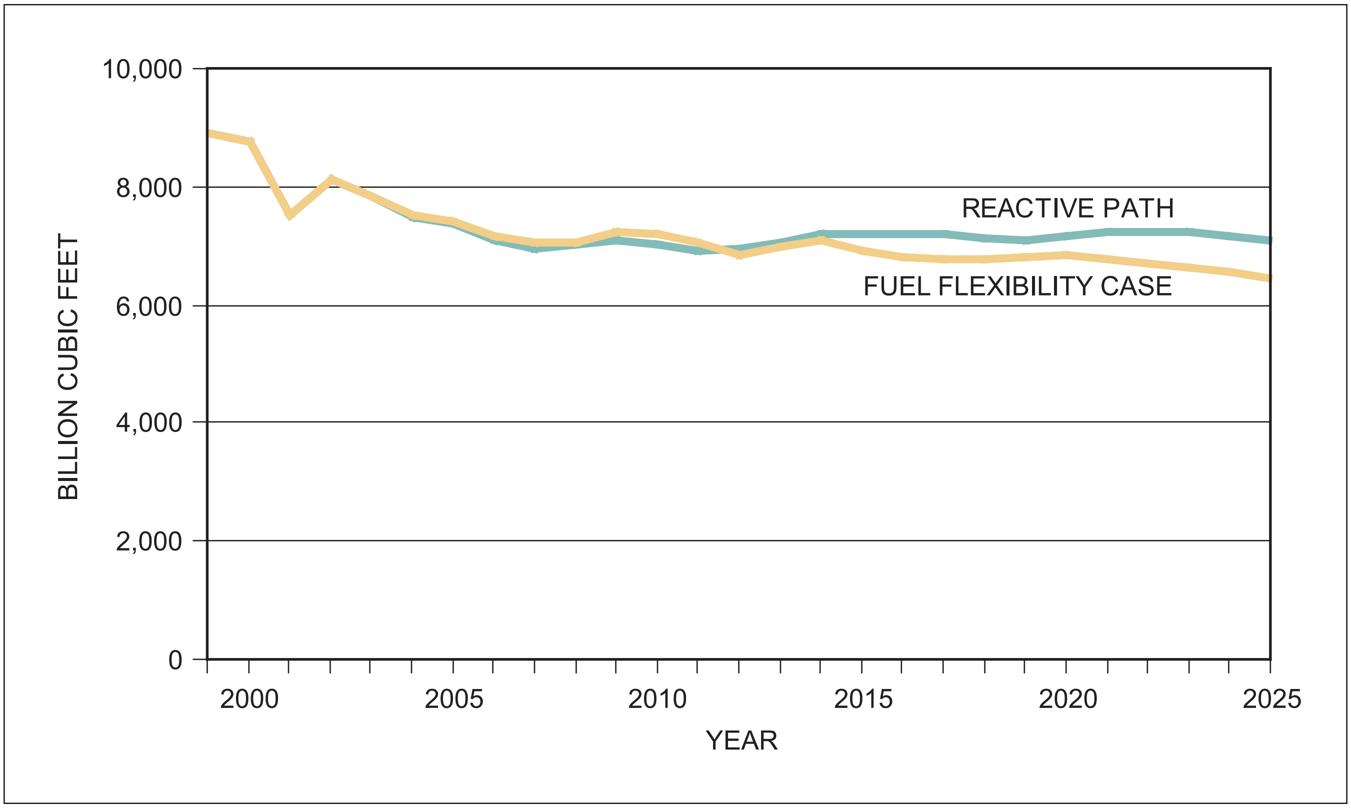


Figure D6-33. U.S. Industrial Gas Demand in the Fuel Flexibility Case

natural gas demand in the power generation and industrial sectors, respectively, for the Fuel Flexibility case.

F. Carbon Reduction Case

The Carbon Reduction sensitivity tested the impacts on natural gas demand and the resulting market prices of limitations on CO_2 emissions. Natural gas has lower CO_2 emissions than other carbon-based fuels. Therefore, natural gas combustion technologies are likely to be a substantial aspect of the market's response to limitations on CO_2 emissions in industrial processes and power generation.

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

Both GDP and industrial production growth rates were lowered slightly from their Reactive Path levels to reflect the likely negative impact on economic growth from carbon emissions restrictions. The GDP growth rate was lower to 2.95%, and all the industrial production growth trends were lowered proportionately to the GDP growth change. Additionally, the electricity sales elasticity was lowered to the same level used in the Fuel Flexibility case to reflect the greater energy efficiency that would be encouraged by higher electricity prices. Overall, electricity sales are reduced by about 2% in 2025 compared to the Reactive Path scenario.

The constraint used to simulate a regulatory limit on carbon emissions was to limit emissions from the power sector to within 3% of the 2000 level after 2010 (Figure D6-34). The main means of achieving this goal was to remove coal plants from service. In contrast to the Reactive Path scenario, which removes 21.1 GW of coal capacity through 2010, the Carbon Reduction case

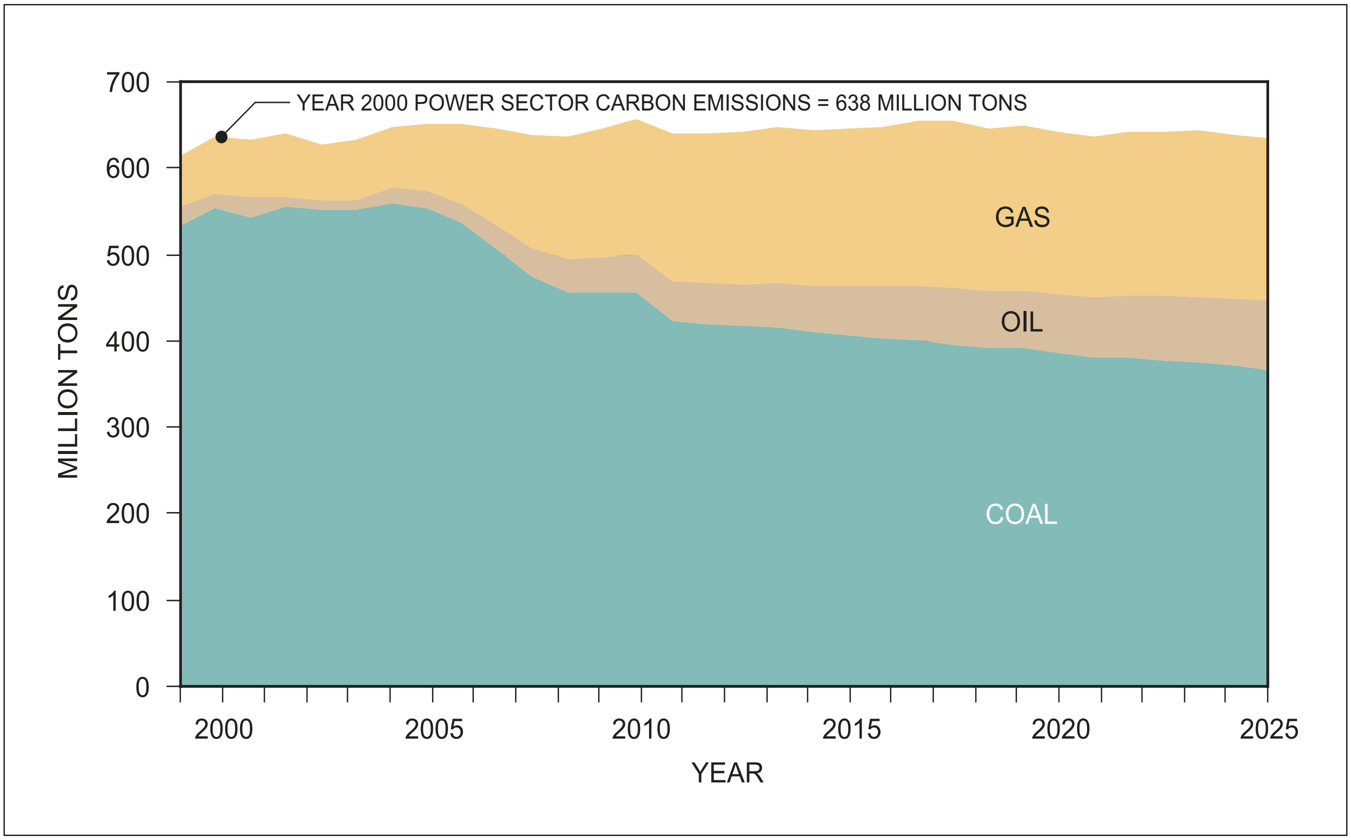


Figure D6-34. Projected Carbon Emissions in the Carbon Reduction Case

removes 84 GW of coal by 2010 in anticipation of the carbon limit (Figures D6-35 and D6-36). In the near-term, the coal capacity removed from service was replaced with gas-fired capacity. Through 2010, gas capacity additions are up by 85 GW over the Reactive Path scenario. After 2010, the addition of 117 GW of new nuclear capacity and 24 GW of additional renewable capacity lessens the need for any further gas capacity additions.

The effect of the carbon emissions constraint on power generation gas demand is dramatic. By 2025, power sector demand is up over 2,300 BCF compared to the Reactive Path scenario (Figure D6-37). However, reduced growth in industrial production coupled with the negative response to higher gas prices has reduced industrial sector gas demand by over 1,000 BCF. Residential and commercial demands are also reduced due to the increase in gas prices, which average over $1.70 higher than the Reactive Path scenario. Figures D6-38 and D6-39 show natural gas demand in the power generation and industrial sectors, respectively, for the Carbon Reduction case.

G. Weather Sensitivities

Weather is the single biggest factor driving short-term gas demand, and weather effects have considerable potential for causing price volatility. To examine the effects of weather on the forecast, two sets of six sensitivity cases were run using alternate sets of weather assumptions derived from actual historical weather information. Six cases were run using the Reactive Path scenario assumptions, and six were run using the Balanced Future assumptions. Of each set of six weather cases, three cases used a warmer-than-normal weather assumption for the target year, while the other three used colder-than-normal weather (Table D6-5).

Weather assumptions were input into the model as monthly heating and cooling degree-days for each month of the forecast. All the non-weather related case used the NOAA 30-year normal monthly values for the forecast period. To construct the weather sensitivity cases, a series of historical weather data was substituted for normal data in the forecast period. The target time periods examined in the weather sensitivities were the

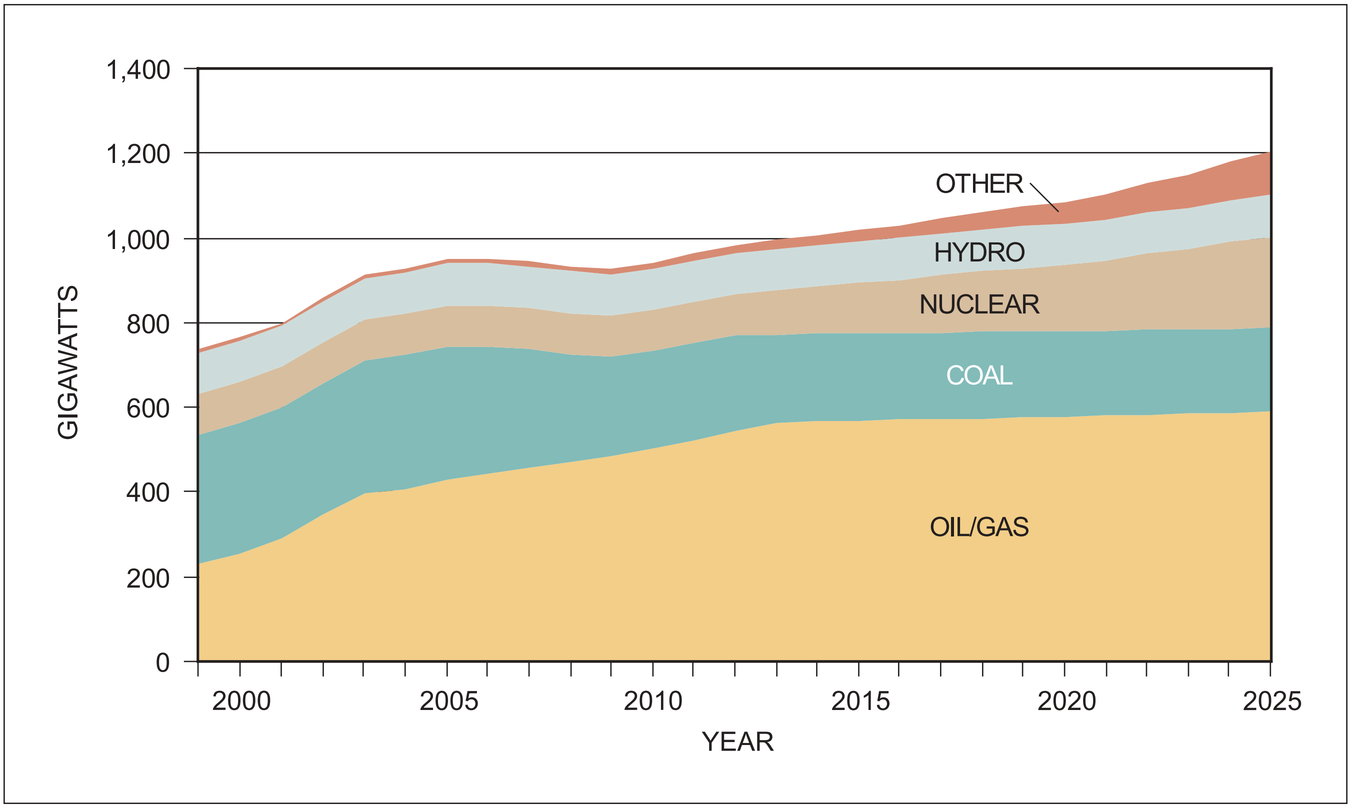


Figure D6-35. Generating Capacity in the Carbon Reduction Case

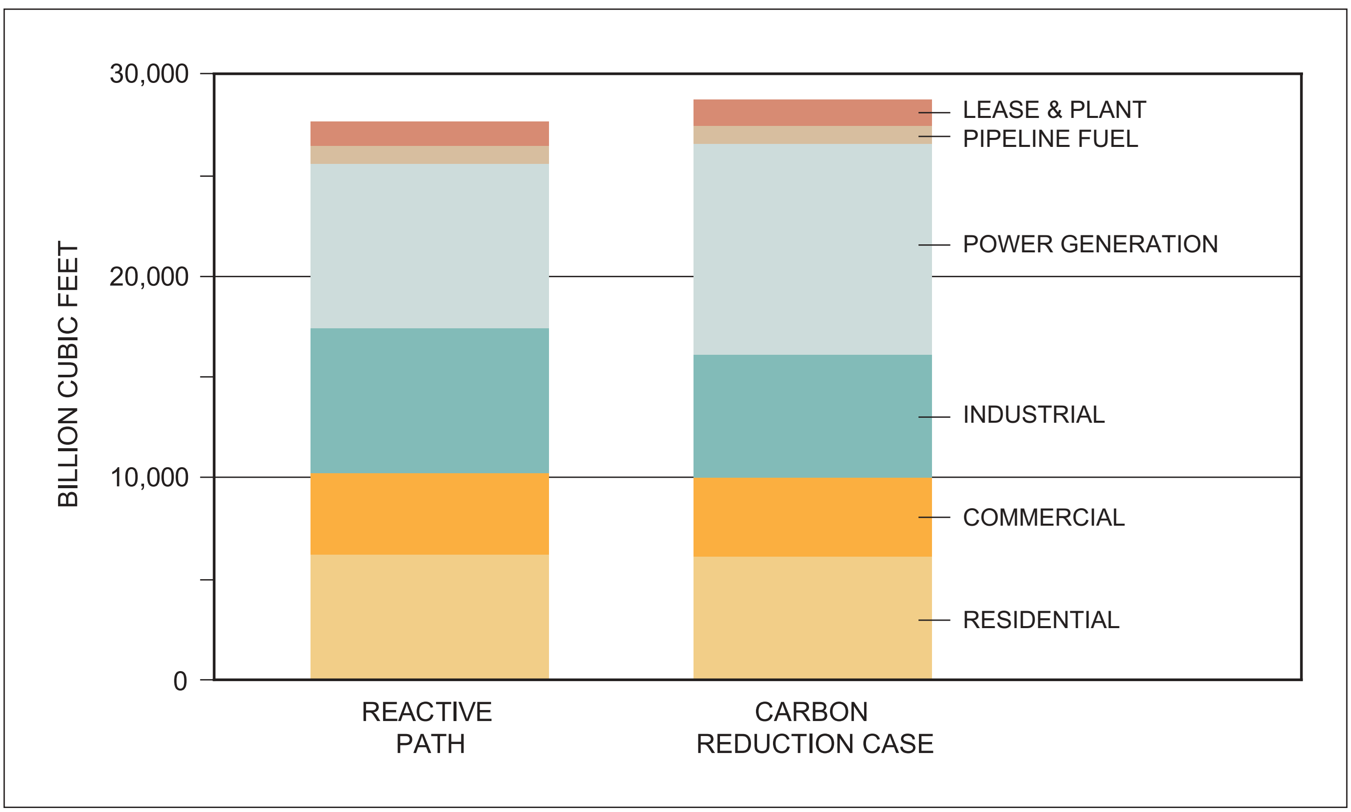


Figure D6-36. 2025 U.S. Gas Demand in the Carbon Reduction Case

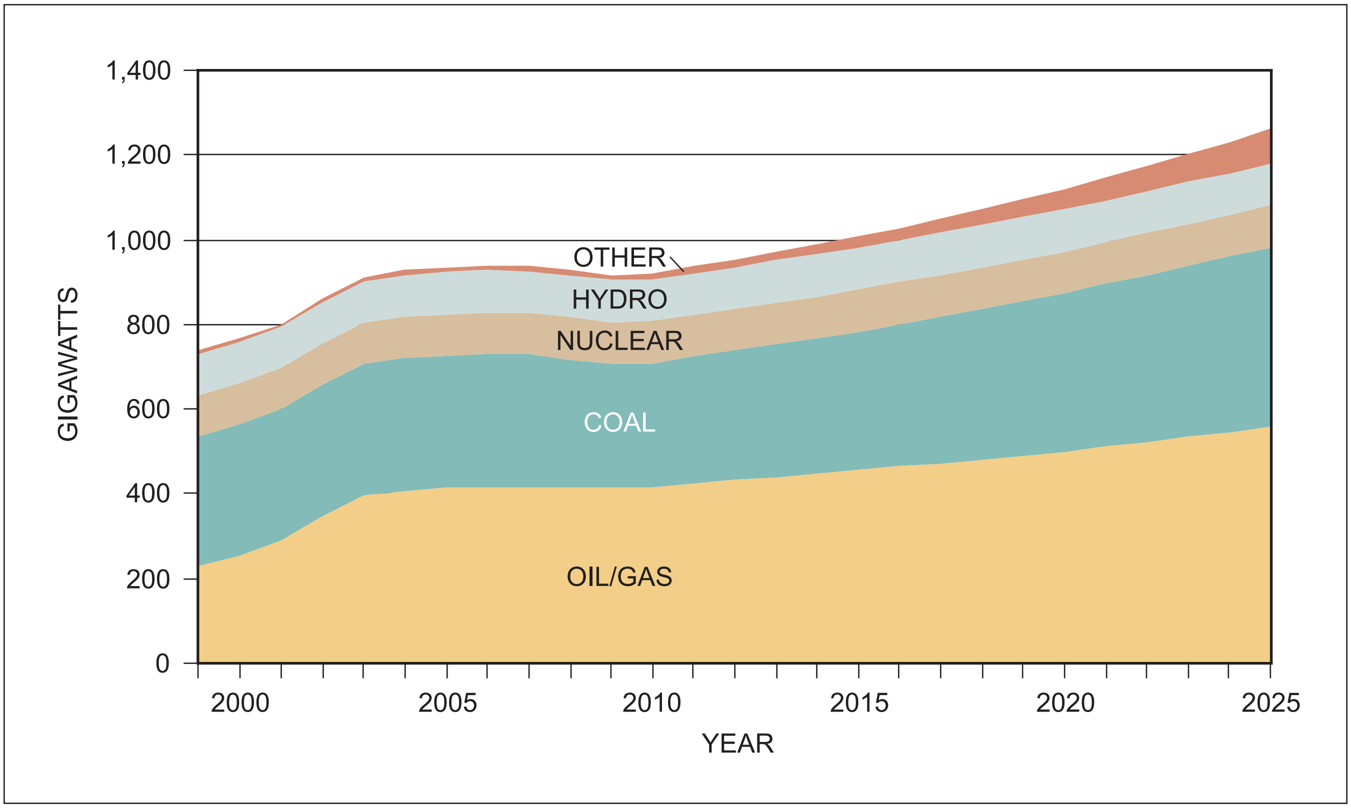


Figure D6-37. Generating Capacity in the Reactive Path Scenario

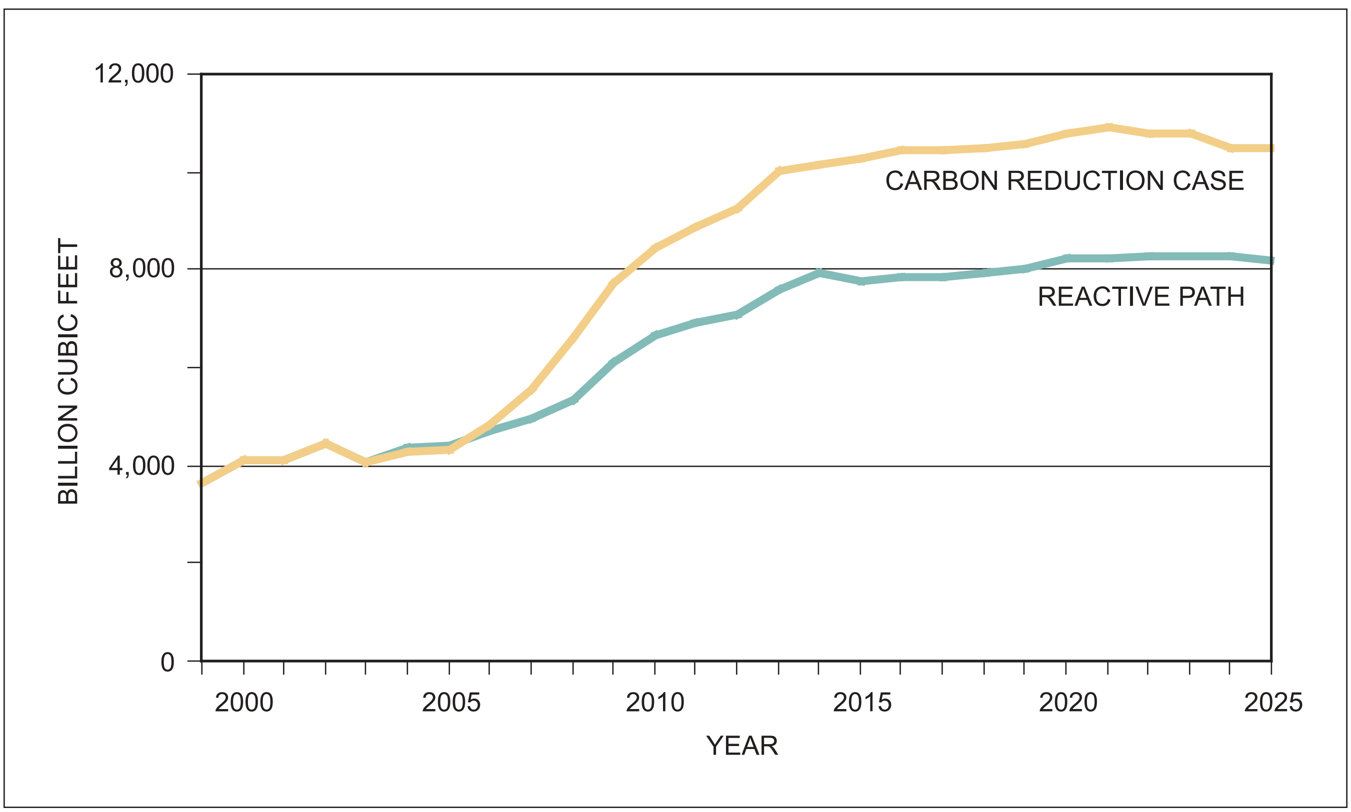


Figure D6-38. U.S. Power Generation Gas Demand in the Carbon Reduction Case

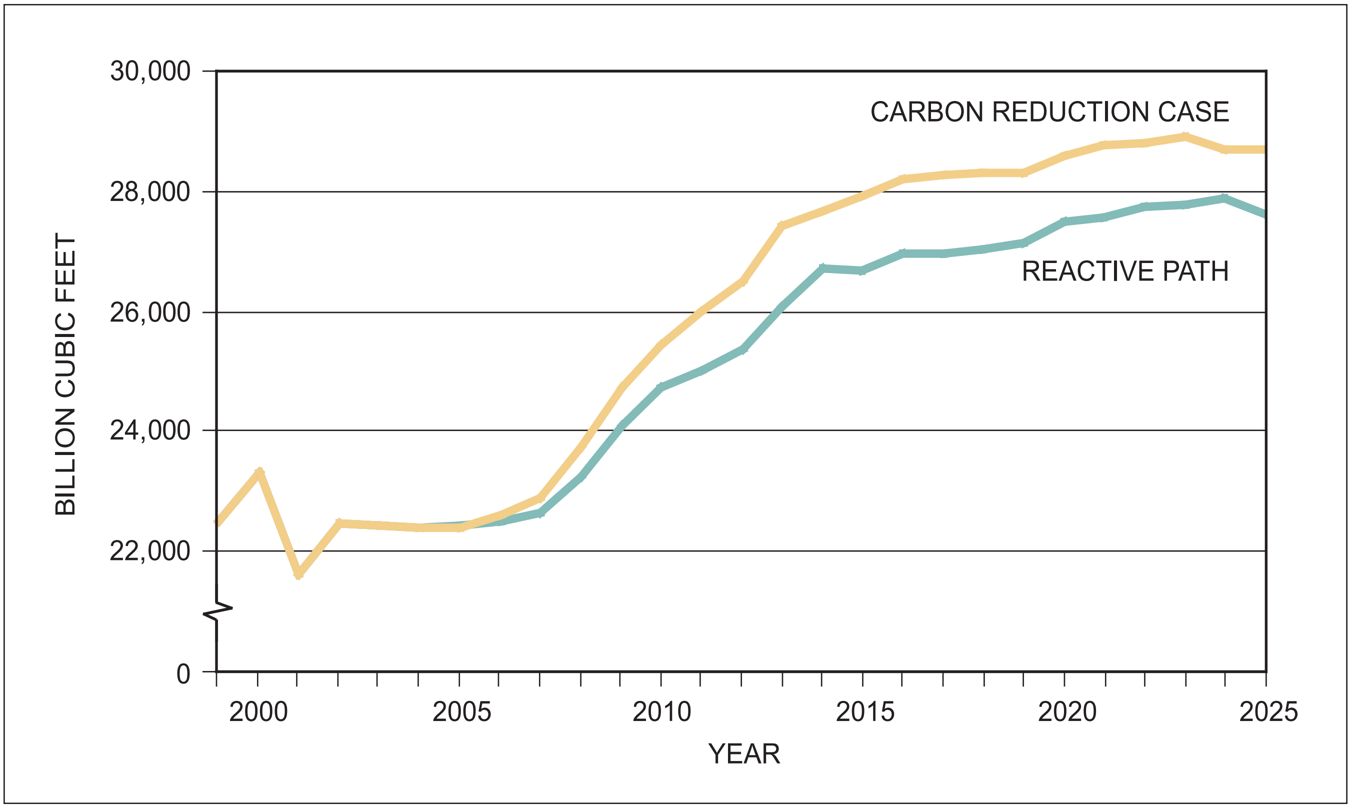


Figure D6-39. U.S. Industrial Gas Demand in the Carbon Reduction Case

Reactive Path	Balanced Future
Cold 2005	Cold 2005
Cold 2014	Cold 2014
Cold 2025	Cold 2025
Warm 2005	Warm 2005
Warm 2014	Warm 2014
Warm 2025	Warm 2025

Table D6-5. List of Weather Sensitivities

winters of 2004-2005, 2013-2014, and 2024-2025. To represent a colder-than-normal winter, the weather data from the winter of 1977-1978 (the coldest winter in the last 70 years) was used. To represent a warm winter, the weather data from the winter of 1953-1954 (the warmest winter in the last 70 years) was used. Historical weather data for the surrounding years was then inserted to complete the data series for forecast weather (Figure D6-40).

Figures D6-41 and D6-42 show the resulting Henry Hub gas prices for the Reactive Path and Balanced Future weather cases, respectively. The lines represent the base forecast for each case, while the bars indicate the high and low prices for each of the cold and warm weather cases. The weather sensitivities for both scenarios had the greatest prices spreads in the winter of 2005. Generally, the Reactive Path scenario, which has higher base prices, showed greater variability in the weather price spreads. On average, the Reactive Path cases had a high-to-low price spread of just over $2.00, while the price spread for the Balanced Future cases was less than $1.70.

III. Summary

The Demand Task Group used alternate base scenarios, combined with selected sensitivity analyses to assess many key factors that drive demand. These base scenarios and related sensitivity analyses can be used by policy makers and analysts to draw insights into the likely outcomes from various decisions and/or physical factors influenced by, or affecting the natural gas supply/demand balance and related infrastructure.

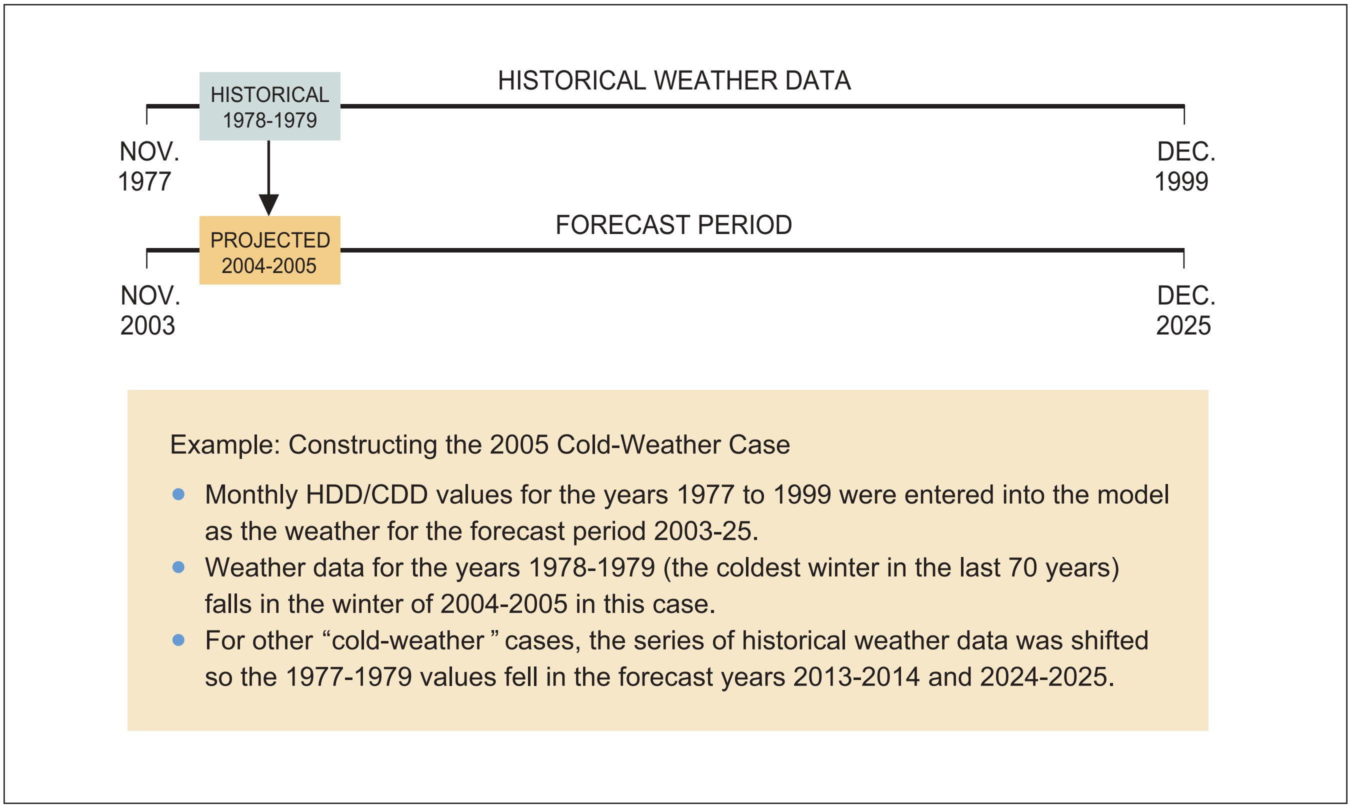


Figure D6-40. Construction of Weather Sensitivity Input Data

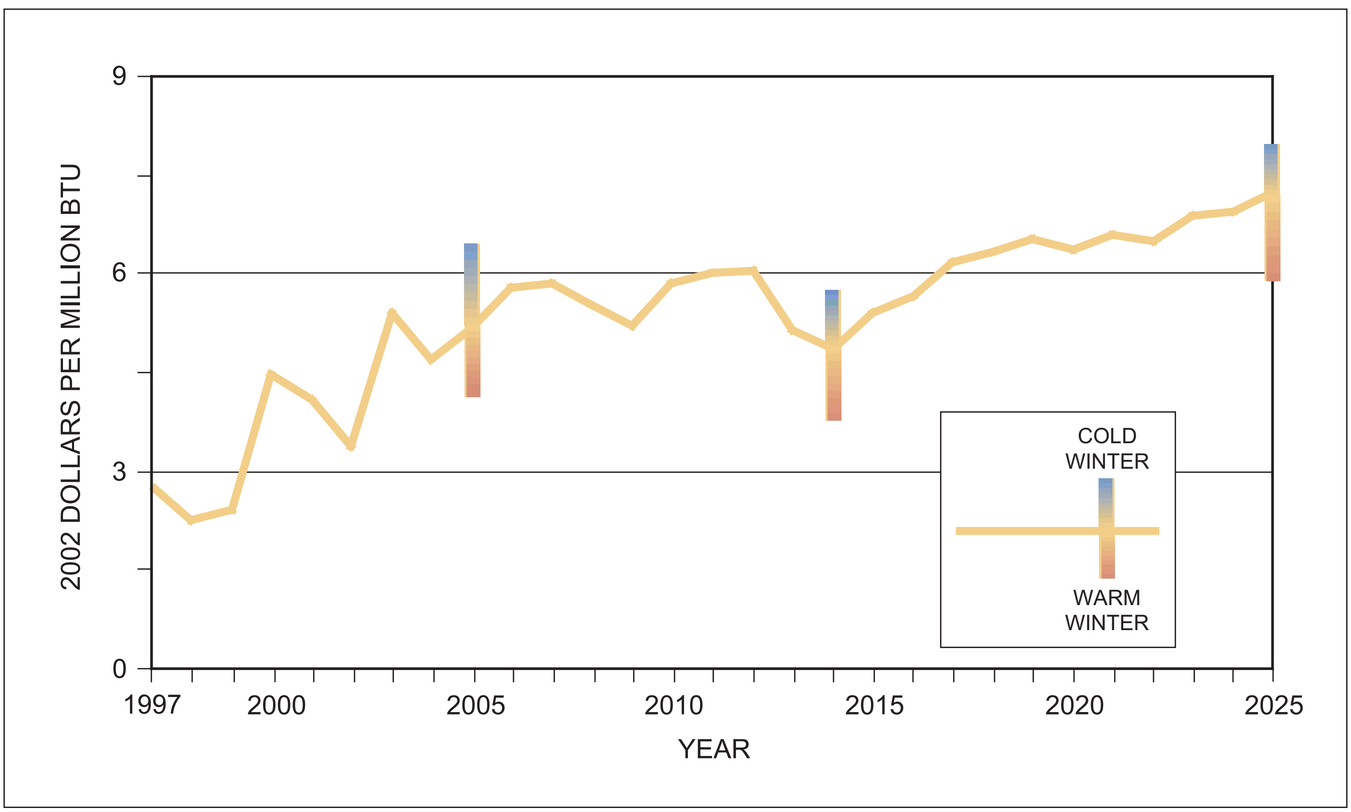


Figure D6-41. Henry Hub Gas Prices in the Reactive Path Weather Sensitivity Cases

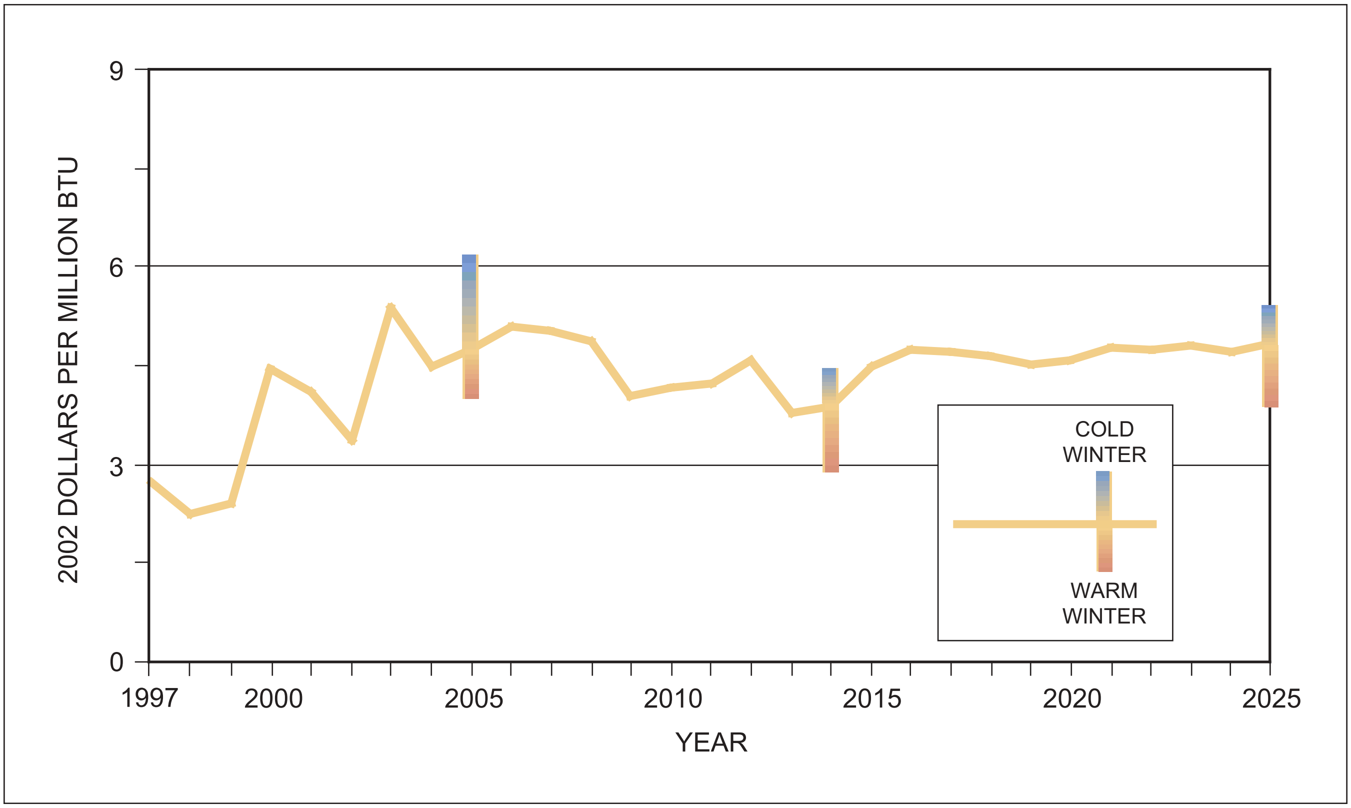


Figure D6-42. Henry Hub Gas Prices in the Balanced Future Weather Sensitivity Cases

APPENDICES

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,

Secretary Abraham

DESCRIPTION OF THE NATIONAL PETROLEUM COUNCIL

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council (NPC) on June 18, 1946. In October 1977, the Department of Energy was established and the Council was transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by the Secretary, relating to oil and natural gas or the oil and gas industries. Matters that the Secretary of Energy would like to have considered by the Council are submitted in the form of a letter outlining the nature and scope of the study. The Council reserves the right to decide whether it will consider any matter referred to it.

Examples of studies undertaken by the NPC at the request of the Secretary of Energy include:

- *Factors Affecting U.S. Oil & Gas Outlook (1987)*
- *Integrating R&D Efforts (1988)*
- *Petroleum Storage & Transportation (1989)*
- *Industry Assistance to Government – Methods for Providing Petroleum Industry Expertise During Emergencies (1991)*
- *Short-Term Petroleum Outlook – An Examination of Issues and Projections (1991)*
- *Petroleum Refining in the 1990s – Meeting the Challenges of the Clean Air Act (1991)*
- *The Potential for Natural Gas in the United States (1992)*
- *U.S. Petroleum Refining – Meeting Requirements for Cleaner Fuels and Refineries (1993)*
- *The Oil Pollution Act of 1990: Issues and Solutions (1994)*
- *Marginal Wells (1994)*
- *Research, Development, and Demonstration Needs of the Oil and Gas Industry (1995)*
- *Future Issues – A View of U.S. Oil & Natural Gas to 2020 (1995)*
- *Issues for Interagency Consideration – A Supplement to the NPC's Report: Future Issues – A View of U.S. Oil & Natural Gas to 2020 (1996)*
- *U.S. Petroleum Product Supply – Inventory Dynamics (1998)*
- *Meeting the Challenges of the Nation's Growing Natural Gas Demand (1999)*
- *U.S. Petroleum Refining – Assuring the Adequacy and Affordability of Cleaner Fuels (2000)*
- *Securing Oil and Natural Gas Infrastructures in the New Economy (2001).*

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of the oil and gas industries and related interests. The NPC is headed by a Chair and a Vice Chair, who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

NATIONAL PETROLEUM COUNCIL

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The National Petroleum Council wishes to acknowledge the numerous other individuals and organizations 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.

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APPENDIX C

SUMMARY OF EFFICIENCY EFFECTS

	Total Consumption Reactive Path	Efficiency Gain in Reactive Path	Total Consumption Balanced Future	Efficiency Gain in Balanced Future	Ratio Efficiency Balanced Future/ Reactive Path
Residential	5,478	301	5,238	573	1.90
Commercial	3,496	115	3,488	251	2.18
Industrial	7,031	361	7,411	390	1.00
Power Generation					
Electricity Consumption	6,670	476	6,151	544	1.14
Heat Rate Improvement		40		35	0.88
Pipe Fuel	806	-	782	-	-
Lease and Plant	1,248	-	1,252	-	-
Total	**24,729**	**1,293**	**24,322**	**1,793**	**1.39**

<u>Calculated Conservation in billion cubic feet, based on effects from:</u>

Residential	Increased efficiency for Space and Water Heating per household
Commercial	Increased efficiency for Space and Water Heating, and Space Cooling per Square Foot
Industrial	Lower gas intensity per unit of output (same for both cases) Note: Increasing oil switchability in Balanced Future scenario and price differences affect consumption mix between industrial sectors causing slight difference in conservation numbers between cases.
Power Generation	
Electricity Consumption	Reduction in Electricity Income Elasticity, assuming a 66% share for gas at the margin. Electricity growth factor (times GDP growth) starting at 0.72 in 2003, reducing to 0.62 in 2025 for the Reactive Path scenario; 0.72 in 2003, reducing to 0.55 in 2025 for the Balanced Future scenario
Heat Rate Improvement	Marginal heat rate for new units decreases from 7,800 to 7,100 Btu/KWH from 2003 to 2005

Table C-1. U.S. Annual Gas Consumption – 2010

	Total Consumption Reactive Path	Efficiency Gain in Reactive Path	Total Consumption Balanced Future	Efficiency Gain in Balanced Future	Ratio Efficiency Balanced Future/ Reactive Path
Residential	5,478	301	5,238	573	1.90
Commercial	3,955	260	3,996	393	1.51
Industrial	7,192	592	7,394	618	1.00
Power Generation					
Electricity Consumption	8,228	1,764	7,874	2,048	1.16
Heat Rate Improvement		150		131	0.88
Pipe Fuel	882	-	848	-	-
Lease and Plant	1,277	-	1,285	-	-
Total	**27,499**	**3,460**	**27,041**	**4,280**	**1.24**

Calculated Conservation in billion cubic feet, based on effects from:

Residential	Increased efficiency for Space and Water Heating per household
Commercial	Increased efficiency for Space and Water Heating, and Space Cooling per Square Foot
Industrial	Lower gas intensity per unit of output (same for both cases) Note: Increasing oil switchability in Balanced Future and price differences affect consumption mix between industrial sectors causing slight difference in conservation numbers between cases.
Power Generation	
Electricity Consumption	Reduction in Electricity Income Elasticity, assuming a 66% share for gas at the margin. Electricity growth factor (times GDP growth) starting at 0.72 in 2003, reducing to 0.62 in 2025 for the Reactive Path scenario; 0.72 in 2003, reducing to 0.55 in 2025 for the Balanced Future scenario
Heat Rate Improvement	Marginal heat rate for new units decreases from 7,800 to 7,100 Btu/KWH from 2003 to 2005

Table C-2. U.S. Annual Gas Consumption – 2020

	Total Consumption Reactive Path	Efficiency Gain in Reactive Path	Total Consumption Balanced Future	Efficiency Gain in Balanced Future	Ratio Efficiency Balanced Future/ Reactive Path
Residential	6,167	885	5,817	1,346	1.52
Commercial	4,093	363	4,180	514	1.42
Industrial	7,104	666	7,377	678	1.00
Power Generation					
Electricity Consumption	8,179	2,800	7,241	3,200	1.14
Heat Rate Improvement		200		175	0.88
Pipe Fuel	827	-	771	-	-
Lease and Plant	1,251	-	1,238	-	-
Total	**27,621**	**4,914**	**26,624**	**5,913**	**1.20**

Calculated Conservation in billion cubic feet, based on effects from:

Residential	Increased efficiency for Space and Water Heating per household
Commercial	Increased efficiency for Space and Water Heating, and Space Cooling per Square Foot
Industrial	Lower gas intensity per unit of output (same for both cases) Note: Increasing oil switchability in Balanced Future and price differences affect consumption mix between industrial sectors causing slight difference in conservation numbers between cases.
Power Generation	
Electricity Consumption	Reduction in Electricity Income Elasticity, assuming a 66% share for gas at the margin. Electricity growth factor (times GDP growth) starting at 0.72 in 2003, reducing to 0.62 in 2025 for the Reactive Path scenario; 0.72 in 2003, reducing to 0.55 in 2025 for the Balanced Future scenario
Heat Rate Improvement	Marginal heat rate for new units decreases from 7,800 to 7,100 Btu/KWH from 2003 to 2005

Table C-3. U.S. Annual Gas Consumption – 2025

APPENDIX D

THE IMPACT OF HIGHER GAS PRICES ON THE U.S. ECONOMY

Spot natural gas prices are at historic highs. They have been driven up by several coincident factors – some fundamental and some episodic. The fundamental factors include: (1) supplies have been tightening over the last few years both in the United States and Canada, (2) demand by the power sector has been increasing as new gas-fired capacity has come on-line over the last few years, due in part to environmental regulations, and (3) the rise in world oil prices has placed an additional call on natural gas supplies. The episodic factors include the cold weather that plagued most of the nation for the 2002-2003 winter heating season, and the sharp rise in world oil prices during this same period.

Prices are projected to stay high. Low storage levels in combination with increasing demand for natural gas to meet new environmental regulations (both national and state) are expected to maintain upward pressure on prices. Pressure that is unlikely to be offset by increased production and imports. As a result, industry and consumers are facing commensurate increases in their costs of energy. Energy intensive industries are under significant pressure as the weak economy reduces their ability to pass the total increase in energy costs on to their customers and ultimately to final consumers. This squeeze on industry is projected to slow the economic recovery, placing further pressure on energy intensive industries.

Energy Outlook

Global Insight's base case has domestic gas prices returning to levels that would retain the United States' current productive capacity for most energy intensive industries. However, there is a significant risk that the price of natural gas could remain high, as the outlook for domestic gas resource development is uncertain. (Global Insight's long-run outlook for WTI is approximately $24 per barrel in 2002 dollars.)

The National Petroleum Council provided Global Insight with its outlook for the price of natural gas at Henry Hub, the domestic production of natural gas. In addition, the National Petroleum Council provided guidance on the imports of natural gas and the expected timing of sales of natural gas from the Alaskan North Slope to lower-48 states. (For this analysis, the outlook for the price of WTI was assumed to be $20 per barrel in 2002 dollars.)

Table D-1 highlights the difference between the NPC outlook and the Global Insight outlook. Over the long-term, Global Insight's analysis shows that approximately 20 TCF/year of supply is available from the U.S. lower-48 if prices are sustained between $3.50 and $4.00 per MCF in 2002 dollars. The NPC analysis shows that a much higher price is necessary to induce lower-48 production at that level.

The Impact on the U.S. Economy

Natural gas currently represents nearly 25% of U.S. energy consumption, playing a significant role in meeting energy requirements in all sectors of the economy. Sustained higher natural gas prices would result in changes in production patterns and processes. As with the oil price shocks in the 1970s

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The material in this appendix was prepared for the National Petroleum Council by Global Insight Inc., in May 2003.

	2004	2005	2010	2015	2020	2025
NPC Outlook						
Henry Hub (2002$/MMBtu)	5.18	5.15	3.71	4.89	4.98	6.39
Domestic Natural Gas Production* (TCF/year)	19.23	19.26	20.12	19.95	21.62	21.46
Alaskan North Slope Gas (TCF/year)				1.43	1.48	1.50
Net Imports of Natural Gas (TCF/year)	3.65	3.63	5.46	5.69	6.14	6.49
Total Consumption of Natural Gas (TCF/year)	22.4	22.6	25.4	27.0	29.1	29.3
Global Insight Outlook						
Henry Hub (2002$/MMBtu)	3.31	3.31	3.37	3.50	3.61	
Domestic Natural Gas Production* (TCF/year)	19.00	19.10	19.20	19.80	20.20	
Alaskan North Slope Gas (TCF/year)				1.46	1.46	
Net Imports of Natural Gas (TCF/year)	4.31	4.86	5.65	6.21	6.73	

* Excludes Alaskan North Slope production.

Table D-1. Energy Outlook

and early 1980s, inflation would increase, economic activity would be reduced, and unemployment would rise. Since natural gas is used in the production of all goods and services, all other prices would rise as well, depending on the energy content of that product.

Higher prices impose a burden on the U.S. economy – workers and producers must adjust to an environment with radically different relative prices. For businesses, the rising price of natural gas (relative to other inputs) hurts their profitability, discourages their use of natural gas, and encourages the use of more energy-efficient capital equipment and some additional labor to produce their products. Businesses respond by shifting towards other fuels and their total use of energy relative to their labor and capital. However, their net effect is an increase in costs, which reduces U.S. wealth and competitiveness.

Consumers face an increase in the cost of natural gas and electricity, encouraging them to reduce their expenditures on energy. Some workers lose their jobs through a weaker economic environment, while other workers lose well-paying manufacturing jobs, and find only lower wage service jobs. All workers face a slowing in their real wage growth. Further, real disposable income falls due to reduced employment and lower wages.

In addition, the economy is worse off as the increase in natural gas prices pushes up inflation and interest rates. Higher interest rates reduce housing starts, vehicle sales, and business investment. With a lower level of productive capital stock, fewer people are employed and real gross domestic product (GDP) – the total output of goods and services – is smaller.

One key reason for the lower level of real GDP is reduced global competitiveness. Because the imposition of the natural gas is not borne equally by all countries, U.S. exports are relatively more expensive on the world market. As a consequence, exports are lowered while imports are increased. Real net exports – the difference between total exports and total imports of goods and services – are lower in an era of rising natural gas prices. Table D-2 is a summary of U.S. economic impacts.

Real GDP. The level of real gross domestic product is 2.4% lower than the base case in 2010. By about 2020, the economy has adjusted to the pattern of rising energy prices and is able to compensate somewhat for the mini-shocks of continuously rising natural gas prices. Consequently, the percentage reduction in GDP falls to 1.7%.

Inflation. Inflation increases, due to the higher natural gas prices. Initially, inflation is substantially higher

	2003	2004	2005	2010	2015	2020	2025
Economic Activity							
Real GDP	-0.5%	-1.0%	-1.1%	-0.6%	-0.2%	-0.3%	-0.4%
Industrial Production	-0.8%	-1.7%	-1.8%	-1.8%	-1.8%	-2.2%	-2.6%
Components of GDP							
Consumption Expenditures	-0.4%	-0.9%	-1.2%	-0.9%	-0.5%	-0.5%	-0.8%
Non-Residential Fixed Investment	-0.7%	-1.8%	-2.0%	0.2%	0.7%	0.7%	0.5%
Residential Investment	-1.3%	-3.0%	-3.3%	-1.0%	0.1%	0.1%	0.0%
Government							
Net Exports	-0.6%	-3.6%	-4.0%	-0.8%	1.1%	1.1%	-1.0%
Exports	0.0%	0.0%	0.0%	-0.1%	-0.1%	-0.1%	-0.1%
Imports	-0.2%	-1.1%	-1.2%	-0.2%	0.2%	0.2%	-0.3%
Employment & Wages							
Employment, Establishment	-0.2%	-0.7%	-0.9%	-0.4%	-0.1%	-0.2%	-0.3%
Manufacturing	-0.3%	-1.3%	-1.4%	-0.6%	-0.5%	-0.8%	-0.9%
Non-Manufacturing	-0.2%	-0.6%	-0.8%	-0.3%	-0.1%	-0.2%	-0.2%
Employment, Establishment (diff. in mil.)	-0.32	-0.94	-1.21	-0.53	-0.15	-0.38	-0.51
Manufacturing	-0.05	-0.20	-0.22	-0.10	-0.08	-0.13	-0.16
Non-Manufacturing	-0.27	-0.74	-0.99	-0.43	-0.07	-0.25	-0.35
Employment Cost Index—Private Sector	0.1%	0.3%	0.4%	0.6%	0.5%	0.4%	-0.3%
Real After-tax Hourly Compensation, Private Sector	-0.4%	-0.5%	-0.6%	-0.8%	-0.8%	-0.7%	-0.9%
Real Disposable Income	-0.6%	-1.2%	-1.3%	-0.9%	-0.6%	-0.7%	-0.9%
Inflation							
GDP Price Deflator	0.4%	0.8%	1.0%	1.2%	1.0%	0.9%	0.4%
CPI - Urban	0.5%	0.9%	1.1%	1.4%	1.2%	1.1%	0.6%
CPI - Core	0.1%	0.3%	0.5%	0.9%	0.7%	0.6%	0.2%
PPI	2.3%	2.8%	3.0%	3.4%	3.2%	3.3%	3.0%
Interest Rates (difference in basis points)							
Federal Funds Rate	0.02	-0.08	-0.22	-0.21	-0.23	-0.32	-0.50

Table D-2. Summary of Economic Impacts (Percent Difference from Baseline)

– almost by a percentage point from 2000 through 2010. After 2010, the impact on inflation moderates, ultimately returning the inflation rate to baseline levels before 2020. This is true for producer price inflation, consumer price inflation, and the widest measure of inflation, the GDP chain price index.

Employment. At the peak year, employment losses would exceed 1.0 million jobs. The higher unemployment levels would lead potential workers to bid down the real wage, allowing the labor-to-output ratio to rise and the unemployed to be absorbed back into the workforce. While this restores employment to Base Case levels, labor productivity is reduced. Labor is less productive because it is coupled with lower levels of energy and capital in the production process.

Consumption. Consumers, reacting to lower real disposable income due to lower real wages and fewer jobs, cut spending. Consumer spending is down by 0.9% in 2010, recovering somewhat to be down only 0.5% by 2020.

Non-Residential Fixed Investment. Rising natural gas prices induce businesses to shift their investments towards more energy-efficient equipment and structures.

Government. Real government spending on purchases of goods and services remains very similar to the baseline projection. Because economic activity is lower and interest rates are higher in the simulation, the deficit is worse in the NPC Case.

International Trade. The trade deficit worsens as U.S. competitiveness is hurt by the higher domestic natural gas prices.

The Impact on the U.S. Industry

The impact on U.S. industry is shown in Table D-3. Significant losses in output are projected for industries that are gas-intensive. Even in industry that is not natural gas intensive there is a measurable impact. As natural gas prices rise, all industry attempts to reduce use of this fuel. For gas-intensive industry, it is projected that there would be some movement of production to other countries with lower gas costs. The loss of output from these two effects would cause a ripple through the rest of the economy. Supply industry and services would be negatively impacted as their sales decline.

Supporting Data

The following three tables provide further detail on the data inputs and outputs of this analysis. Table D-4 details the two price forecasts compared by Global Insights. Table D-5 reflects the percentage decline in industrial output, by industry, calculated by Global Insights for the interim price forecast considered by the NPC study group. Table D-6 details the macroeconomic impacts calculated by Global insights for these comparative data sets.

	Industry	2003	2004	2005	2010	2015	2020	2025
1.	Agricultural Chemicals	10.71	11.40	16.32	8.09	25.33	33.17	28.97
2.	Leather, Tanning and Finishing and Cut Stock	10.38	10.93	14.81	9.05	60.58	0.00	0.00
3.	Chemical Fertilizer	8.62	9.80	14.09	6.38	21.32	27.70	23.55
4.	Other Metal Mining	7.99	9.39	13.03	5.36	17.54	22.21	18.43
5.	Chemical Products	6.81	8.00	11.51	4.83	16.55	20.64	16.59
6.	Blast Furnaces and Steel Mills Products	5.73	6.98	9.37	4.15	11.68	14.79	12.46
7.	Copper	5.46	6.59	8.92	3.86	11.20	14.04	11.61
8.	Tires and Tubes	5.27	6.27	7.99	3.67	10.07	12.96	11.19
9.	Motor Vehicles and Parts	5.87	6.83	6.78	4.10	3.73	3.65	3.23
10.	Rubber and Plastic Footwear, Hose, Belting	4.01	4.89	6.30	2.95	7.38	9.27	7.74
11.	Other Wood Products	3.01	4.54	6.03	2.51	6.47	8.70	7.36
12.	Nonferrous Metal Products	3.62	4.39	5.87	2.50	6.63	7.93	6.20
13.	Pulp, Paper, and Paperboard Mill Products	3.19	4.05	5.75	2.47	7.34	9.22	7.52
14.	Broadwoven Fabrics and Other Textiles	3.19	4.09	5.34	2.56	6.66	9.07	8.06
15.	Other Stone, Clay, and Glass Products	2.39	3.57	4.70	2.07	4.63	6.05	5.04
16.	Other Nonmetal Mining	2.38	3.47	4.68	2.04	5.02	6.61	5.51
17.	Miscellaneous Fabricated Metal Products	2.89	3.61	4.39	1.99	4.00	4.65	3.65
18.	Cotton	2.29	2.99	3.97	1.83	4.67	6.25	5.48
19.	Paints and Related Products	2.15	3.20	3.81	1.76	2.82	3.51	2.91
20.	Other Transportation	3.17	3.83	3.76	2.52	1.86	1.86	1.74
21.	Kitchen Articles and Pottery	0.50	2.70	3.65	2.28	1.76	1.93	1.76
22.	Gas	1.46	2.41	3.63	3.96	5.60	6.45	5.70
23.	Household Radio and Video Equipment	0.97	2.97	3.59	1.76	0.99	1.12	1.09
24.	Knitting Mill Products	2.03	2.72	3.28	1.56	3.61	5.41	5.24
25.	Miscellaneous Plastic Products, n.e.c.	1.77	2.41	3.17	1.42	2.92	3.46	2.69
26.	Wood Buildings, Mobile Homes	1.21	2.79	3.15	1.12	0.30	0.61	0.47
27.	Building Materials and Wire Products	1.49	2.47	3.07	1.37	2.06	2.59	2.09
28.	Railroads	1.70	2.32	2.93	1.37	2.83	3.46	2.85
29.	Residential Contract Construction	1.13	2.63	2.89	0.93	0.01	0.22	0.11
30.	Furniture, except Household	1.40	2.57	2.81	1.28	0.70	1.29	1.22
31.	Iron and Steel Foundry Products	1.80	2.30	2.76	1.50	2.51	2.78	2.01
32.	Other Leather Products	7.40	3.15	2.70	0.00	0.00	0.00	0.08
33.	Coal Mining	1.36	1.92	2.57	1.25	2.77	3.45	2.84
34.	Refrigeration, Heating and Service Industry Mach	1.46	2.32	2.55	1.11	0.68	0.80	0.59
35.	Asphalt Paving and Roofing Materials	0.89	1.99	2.48	1.02	0.77	1.11	0.94
36.	Metal Cans and Shipping Containers	1.26	1.77	2.47	1.39	2.97	3.72	3.15
37.	Wood Containers, Pallets and Skids	1.29	1.95	2.45	1.05	1.76	2.14	1.72
38.	Paperboard Containers and Boxes	1.27	1.83	2.40	1.15	2.06	2.47	1.99
39.	Carpets and Rugs	0.86	2.09	2.39	0.93	0.34	0.63	0.77
40.	Nonresidential Contract Construction	0.60	1.63	2.31	1.11	0.72	0.98	0.89

Table D-3. NPC High Natural Gas Price Scenario (Percent Decline from Baseline)

Industry	2003	2004	2005	2010	2015	2020	2025
41. Household Furniture	0.54	1.88	2.27	1.00	0.38	0.63	0.82
42. Motor Freight and Warehousing	1.14	1.73	2.16	1.02	1.68	2.11	1.79
43. Household Appliances	0.55	1.78	2.15	0.95	0.38	0.63	0.77
44. Miscellaneous Converted Paper Products	0.93	1.52	2.07	0.98	1.76	2.21	1.86
45. Electric (Public and Private)	0.96	1.52	2.01	1.03	1.83	2.31	1.95
46. Industrial Machinery, n.e.c.	1.36	1.66	1.86	0.97	1.12	1.06	0.64
47. Sanitary Services	0.92	1.34	1.82	0.97	1.88	2.30	1.91
48. Electric Lighting and Wiring Equipment	0.78	1.38	1.80	1.38	1.41	1.47	0.99
49. Radio and Television Broadcasting	0.85	1.45	1.78	0.77	1.00	1.25	1.03
50. Wholesale Trade	0.88	1.48	1.76	0.68	0.72	0.89	0.71
51. Apparel Manufacturing	1.45	1.85	1.76	1.36	1.31	1.85	1.81
52. Pipelines, Except Natural Gas	0.88	1.47	1.76	1.02	1.47	1.73	1.46
53. Internal Combustion Engines	1.54	1.62	1.72	1.72	1.86	1.61	1.01
54. Petroleum Refining, exc Paving and Roofing	0.88	1.48	1.72	0.84	1.27	1.53	1.26
55. Metalworking Machinery	0.95	1.44	1.68	1.46	2.41	2.75	1.99
56. Fats and Oils	0.76	1.17	1.68	0.98	1.97	2.51	2.19
57. Other Durable Goods	0.52	1.28	1.62	0.73	0.59	0.84	0.77
58. Railroad Equipment	1.26	1.72	1.60	1.02	1.99	2.11	1.38
59. Retail Trade	0.70	1.38	1.58	0.94	0.50	0.62	0.73
60. Farm and Garden Machinery	0.76	1.38	1.56	1.00	0.60	0.69	0.23
61. Cutlery and Handtools	0.51	1.15	1.55	1.40	1.44	1.57	1.34
62. Engineering & Mangement Services	0.55	1.13	1.48	0.42	0.60	0.83	0.64
63. Miscellaneous Electrical Equip & Supplies	1.10	1.33	1.46	0.83	0.71	0.58	0.23
64. General Industrial Machinery	0.95	1.10	1.43	1.71	2.83	2.91	1.93
65. Forestry, Fishery Services	0.48	1.03	1.38	0.76	0.93	1.20	1.05
66. Auto Repair and Rental	0.56	1.10	1.38	0.60	0.49	0.62	0.56
67. Newspapers, Periodicals and Books	0.52	1.09	1.36	0.65	0.58	0.78	0.73
68. Glass Containers	0.54	0.97	1.36	0.98	1.26	1.52	1.39
69. Other Publishing and Printing	0.47	1.04	1.35	0.57	0.62	0.84	0.73
70. Drugs, Soaps, Toiletries	0.37	0.83	1.33	1.01	1.25	1.50	1.38
71. Other Communications	0.53	1.18	1.31	0.40	0.00	0.07	0.18
72. Business Services	0.46	1.02	1.30	0.52	0.54	0.73	0.62
73. Electrical Transmission and Distribution Eq.	0.47	1.06	1.29	1.04	1.27	1.28	0.48
74. Federal Enterprises	0.34	1.00	1.24	0.59	0.23	0.35	0.42
75. Electrical Industrial Apparatus	0.64	0.86	1.16	0.75	1.27	1.22	0.50
76. Postal Service	0.33	0.89	1.13	0.44	0.31	0.48	0.48
77. Transportation Services	0.48	0.89	1.13	0.36	0.52	0.70	0.57
78. Water	0.39	0.85	1.10	0.41	0.50	0.66	0.62
79. Special Industry Machinery	0.40	0.85	1.08	1.26	2.38	2.76	1.82
80. Other Contract Construction	0.23	0.72	1.08	0.61	0.38	0.48	0.43
81. Local and Interurban Passenger	0.26	0.81	1.06	0.44	0.13	0.20	0.21

Table D-3. NPC High Natural Gas Price Scenario (Percent Decline from Baseline) – Continued

Industry	2003	2004	2005	2010	2015	2020	2025
82. Meats, Animals, Livestock	0.34	0.77	1.04	0.72	0.66	0.80	0.79
83. Miscellaneous Personal Goods	0.06	0.74	1.03	0.59	0.36	0.62	0.52
84. State and Local Enterprises	0.28	0.72	1.02	0.67	0.80	0.98	0.88
85. Ophthalmic Goods	0.19	0.93	1.02	0.14	0.00	0.00	0.00
86. Personal and Repair Services	0.03	0.72	1.00	0.09	0.00	0.21	0.25
87. Meat Products	0.33	0.73	0.99	0.74	0.62	0.72	0.73
88. Construction, Mining, and Material Handling Eq.	0.45	0.73	0.95	0.71	0.75	0.66	0.17
89. Legal	0.06	0.72	0.95	0.15	0.00	0.08	0.13
90. Oil-Bearing Crops	0.33	0.60	0.91	0.54	0.95	1.22	1.09
91. Dairy and Poultry	0.28	0.68	0.90	0.69	0.45	0.51	0.56
92. All Other Foods	0.28	0.67	0.90	0.72	0.50	0.55	0.60
93. Beverages	0.28	0.67	0.89	0.76	0.45	0.47	0.54
94. Feed Grains	0.26	0.63	0.86	0.61	0.50	0.60	0.61
95. Dairy Products	0.25	0.65	0.85	0.66	0.35	0.38	0.45
96. Hotels and Lodging	0.22	0.63	0.85	0.43	0.33	0.40	0.32
97. Agriculture, N.E.C.	0.26	0.61	0.84	0.75	0.56	0.62	0.61
98. Tobacco Products	0.06	0.52	0.83	0.75	0.37	0.49	0.65
99. Complete Aircraft	0.47	0.94	0.75	0.00	0.00	0.00	0.00
100. Aircraft Parts	0.29	0.57	0.72	0.00	0.12	0.25	0.16
101. Air	0.18	0.54	0.71	0.02	0.00	0.10	0.02
102. Finance	0.00	0.49	0.70	0.00	0.00	0.00	0.00
103. Insurance	0.00	0.45	0.67	0.11	0.00	0.00	0.00
104. Real Estate	0.20	0.50	0.67	0.52	0.40	0.38	0.28
105. Turbines and Turbine Generator Sets	0.26	0.50	0.66	0.31	0.47	0.41	0.09
106. Food Grains	0.13	0.40	0.58	0.42	0.31	0.37	0.38
107. Forestry and Fishing	0.13	0.40	0.58	0.42	0.31	0.37	0.38
108. Health	0.14	0.29	0.58	0.73	0.31	0.30	0.32
109. Amusements	0.00	0.33	0.52	0.00	0.00	0.00	0.00
110. Photographic Goods	0.07	0.29	0.44	0.00	0.00	0.00	0.00
111. Shipbuilding and Tanks	0.23	0.39	0.39	0.05	0.11	0.12	0.01
112. Membership and Social Services	0.00	0.19	0.36	0.00	0.00	0.00	0.00
113. Measuring and Controlling Devices	0.18	0.27	0.34	0.00	0.00	0.00	0.00
114. Medical Instruments and Supplies	0.08	0.16	0.27	0.00	0.00	0.00	0.00
115. Search and Navigation Equipment	0.07	0.18	0.20	0.00	0.00	0.00	0.00
116. General Government	0.00	0.14	0.18	0.00	0.00	0.00	0.00
117. Communication Equipment	0.01	0.06	0.10	0.00	0.00	0.00	0.00
118. Ordnance and Accessories	0.02	0.08	0.10	0.00	0.00	0.00	0.00
119. Computer and Office Machines	0.00	0.00	0.00	0.00	0.00	0.00	0.00
120. Electronic Components and Accessories	0.00	0.00	0.00	0.30	0.32	0.05	0.00
121. Educational	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table D-3. NPC High Natural Gas Price Scenario (Percent Decline from Baseline) – Continued

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
National Petroleum Council																		
Crude Oil (2002$/bbl)		20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Henry Hub (2002$/MMBtu)	5.72	5.18	5.15	5.21	5.21	4.28	3.71	3.71	4.18	3.87	3.60	3.94	4.89	5.59	5.95	5.44	5.04	4.98
Henry Hub (nominal$/MMBtu)	5.83	5.39	5.46	5.66	5.81	4.89	4.35	4.46	5.17	4.89	4.68	5.25	6.69	7.85	8.61	8.10	7.74	7.90
Average Acquisition Cost of Natural Gas	582.1	538.0	544.6	563.1	576.4	485.4	431.9	442.3	512.7	485.6	464.5	521.2	663.6	777.8	851.6	800.5	764.2	779.5
Global Insight Winter 2002-2003 Long Term Forecast																		
Henry Hub (2002$/MMBtu)		3.31	3.31	3.28	3.29	3.30	3.32	3.37	3.35	3.41	3.45	3.49	3.50	3.52	3.53	3.56	3.57	3.61
Henry Hub (current$)		3.44	3.51	3.56	3.66	3.77	3.89	4.05	4.13	4.32	4.49	4.65	4.78	4.94	5.11	5.30	5.49	5.73
Average Acquisition Cost of Natural Gas	346.8	342.8	322.0	327.1	337.2	345.7	356.9	368.8	379.2	395.9	414.1	431.2	448.0	464.0	481.5	495.6	509.6	528.1
Deflator for GDP	1.15	1.17	1.20	1.22	1.25	1.29	1.32	1.36	1.39	1.43	1.46	1.50	1.54	1.58	1.63	1.68	1.73	1.79
Deflator for GDP (2002 = 1)	1.02	1.04	1.06	1.09	1.11	1.14	1.17	1.20	1.23	1.27	1.30	1.33	1.37	1.41	1.45	1.49	1.54	1.59
Percent Difference*																		
Average Acquisition Cost of Natural Gas	68	57	69	72	71	40	21	20	35	23	12	21	48	68	77	62	50	48

* Difference between the NPC Strawman and the price forecast used in the Long Term Macroeconomic Trend Baseline prepared by Global Insight, Inc.

Table D-4. Price Inputs Used by Global Insight in Comparing Interim NPC Modeling to Global Insight Base Case

Industry Description	SIC	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Manufacturing																								
Food Products	**20**	0.31	0.71	0.95	1.03	1.03	0.92	0.81	0.73	0.72	0.59	0.49	0.46	0.57	0.67	0.77	0.70	0.64	0.65	0.65	0.67	0.67	0.69	0.72
Tobacco Products	**21**	0.06	0.52	0.83	0.98	1.04	0.96	0.85	0.75	0.64	0.56	0.48	0.40	0.37	0.36	0.37	0.41	0.45	0.49	0.53	0.57	0.62	0.68	0.74
Textile Mill Products	**22**	2.50	3.42	4.34	4.71	4.58	3.32	2.17	2.02	3.30	2.15	1.50	2.00	4.60	6.82	8.53	7.12	6.11	6.18	5.76	5.84	5.41	5.46	5.51
Apparel Products	**23**	1.45	1.85	1.76	1.61	1.51	1.45	1.42	1.36	1.31	1.16	1.00	1.04	1.31	1.63	1.90	1.84	1.79	1.85	1.88	1.91	1.87	1.76	1.66
Lumber & Wood Products	**24**	2.83	4.34	5.72	6.33	6.09	4.28	2.64	2.37	4.05	2.55	1.72	2.40	5.93	8.91	11.24	9.32	7.92	7.99	7.36	7.41	6.75	6.76	6.77
Furniture and Fixtures	**25**	0.84	2.12	2.45	2.29	2.03	1.63	1.30	1.08	0.87	0.64	0.49	0.41	0.46	0.56	0.68	0.73	0.73	0.77	0.80	0.84	0.87	0.91	0.95
Paper & Allied Products	**26**	2.01	2.71	3.77	4.26	4.21	2.94	1.79	1.68	3.03	1.91	1.30	1.78	4.26	6.28	7.77	6.33	5.30	5.28	4.81	4.79	4.32	4.27	4.22
Printing & Publishing	**27**	0.49	1.07	1.35	1.37	1.28	0.98	0.71	0.61	0.68	0.44	0.28	0.29	0.60	0.88	1.10	0.93	0.80	0.81	0.76	0.77	0.73	0.74	0.75
Chemical Products	**28**	4.70	5.60	8.05	9.44	9.49	6.48	3.71	3.61	7.39	4.65	3.19	4.59	11.23	16.61	20.52	16.64	13.90	13.83	12.54	12.48	11.19	11.03	10.87
Petroleum Refining	**29**	0.88	1.50	1.74	1.83	1.69	1.25	0.87	0.84	1.08	0.74	0.54	0.63	1.25	1.78	2.18	1.80	1.52	1.52	1.39	1.38	1.25	1.24	1.23
Rubber & Plastics Prod.	**30**	2.54	3.26	4.22	4.57	4.41	3.14	2.01	1.90	3.16	2.10	1.51	1.97	4.31	6.23	7.61	6.23	5.24	5.20	4.72	4.67	4.19	4.09	3.99
Leather & Products	**31**	0.27	0.50	0.68	0.55	0.46	0.37	0.26	0.22	0.22	0.12	0.06	0.05	0.11	0.17	0.20	0.14	0.08	0.04	0.00	0.00	0.00	0.00	0.00
Stone, Clay, & Glass	**32**	2.21	3.33	4.40	4.81	4.62	3.34	2.17	1.99	3.13	2.07	1.48	1.91	4.28	6.28	7.80	6.48	5.52	5.54	5.09	5.10	4.63	4.59	4.55
Primary Metal Industries	**33**	4.37	5.31	7.09	7.88	7.69	5.31	3.21	3.10	5.72	3.73	2.67	3.63	8.34	12.18	14.91	12.14	10.21	10.20	9.30	9.25	8.32	8.18	8.04
Fabricated Metal Industries	**34**	1.93	2.66	3.31	3.47	3.28	2.41	1.67	1.56	2.27	1.60	1.22	1.48	2.91	4.11	4.99	4.14	3.53	3.51	3.21	3.17	2.85	2.76	2.68
Industrial Machinery	**35**	0.33	0.58	0.80	0.64	0.49	0.26	0.09	0.11	0.27	0.15	0.10	0.16	0.44	0.64	0.76	0.63	0.51	0.44	0.29	0.15	0.00	0.00	0.00
Electrical Machinery	**31**	0.27	0.50	0.68	0.55	0.46	0.37	0.26	0.22	0.22	0.12	0.06	0.05	0.11	0.17	0.20	0.14	0.08	0.04	0.00	0.00	0.00	0.00	0.00
Transportation Equipment	**37**	4.42	5.24	5.10	4.43	3.80	3.24	2.98	2.91	2.81	2.63	2.53	2.52	2.62	2.80	2.86	2.79	2.67	2.56	2.49	2.38	2.27	2.15	2.04
Instruments & Related Prod.	**38**	0.10	0.24	0.32	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Miscellaneous Durable Prod.	**39**	0.30	1.01	1.32	1.31	1.24	0.99	0.77	0.66	0.63	0.44	0.32	0.30	0.47	0.65	0.81	0.77	0.72	0.73	0.70	0.69	0.65	0.63	0.62
Non-Manufacturing																								
Agriculture	**AGR**	0.46	0.89	1.20	1.32	1.31	1.09	0.87	0.80	0.93	0.70	0.55	0.58	0.96	1.30	1.57	1.34	1.18	1.19	1.13	1.15	1.08	1.10	1.11
Construction	**C**	0.78	1.93	2.41	2.45	2.17	1.70	1.27	1.00	0.85	0.59	0.41	0.34	0.45	0.60	0.77	0.73	0.68	0.69	0.66	0.66	0.61	0.60	0.59
Finance, Insurance, RE	**FIR**	0.06	0.49	0.68	0.71	0.65	0.50	0.36	0.29	0.26	0.12	0.01	0.00	0.09	0.19	0.28	0.20	0.13	0.13	0.11	0.12	0.10	0.11	0.13
Mining	**MIN**	2.15	3.00	3.74	4.16	3.95	2.52	1.23	1.31	2.70	1.50	0.86	1.44	4.27	6.61	8.32	6.68	5.51	5.55	5.02	5.03	4.47	4.42	4.37
Services	**SVO**	0.22	0.83	1.09	1.07	0.93	0.62	0.38	0.26	0.28	0.06	0.00	0.00	0.16	0.40	0.59	0.45	0.34	0.35	0.32	0.34	0.31	0.33	0.36
Retail Trade	**TR**	0.70	1.38	1.58	1.55	1.44	1.24	1.07	0.94	0.81	0.66	0.55	0.48	0.50	0.54	0.60	0.61	0.60	0.62	0.64	0.67	0.70	0.75	0.81
Transportation & Utilities	**TRTPU**	0.78	1.37	1.74	1.81	1.72	1.32	0.98	0.87	1.06	0.72	0.51	0.57	1.10	1.55	1.88	1.56	1.32	1.32	1.22	1.22	1.13	1.13	1.13
Wholesale Trade	**TW**	0.88	1.48	1.76	1.70	1.51	1.12	0.79	0.68	0.77	0.51	0.35	0.37	0.72	1.02	1.25	1.05	0.90	0.89	0.81	0.80	0.72	0.71	0.69

Table D-5. Percentage Decline of Industrial Output by Industry Relative to Global Insight Baseline

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
GDP in Billions of 2002$																									
Real GDP																									
National Petroleum Council	9215	9436	9667	10065	10451	10781	11115	11433	11765	12135	12534	12974	13453	13915	14292	14693	15103	15525	15953	16376	16767	17181	17608	18057	18536
Global Insight Baseline	9215	9436	9714	10163	10565	10897	11223	11527	11846	12207	12594	13024	13494	13950	14324	14728	15142	15568	15999	16424	16819	17236	17666	18118	18602
(% Difference)	0.0	0.0	-0.5	-1.0	-1.1	-1.1	-1.0	-0.8	-0.7	-0.6	-0.5	-0.4	-0.3	-0.2	-0.2	-0.2	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.4
Durables																									
National Petroleum Council	932	1000	1006	1060	1097	1141	1189	1232	1280	1327	1385	1452	1540	1629	1699	1771	1838	1905	1989	2075	2157	2235	2315	2397	2478
Global Insight Baseline	932	1000	1017	1085	1125	1168	1212	1251	1296	1341	1397	1462	1548	1636	1706	1778	1847	1915	1999	2085	2168	2247	2329	2413	2495
(% Difference)	0.0	0.0	-1.1	-2.3	-2.4	-2.3	-1.9	-1.5	-1.2	-1.1	-0.8	-0.7	-0.5	-0.4	-0.4	-0.4	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.6	-0.6	-0.7
Non Durables																									
National Petroleum Council	1870	1928	1977	2060	2141	2209	2270	2333	2400	2476	2564	2668	2780	2893	2985	3074	3161	3251	3344	3440	3534	3632	3736	3847	3968
Global Insight Baseline	1870	1928	1982	2074	2161	2231	2294	2355	2421	2496	2581	2684	2795	2906	2997	3086	3174	3265	3359	3457	3553	3652	3758	3872	3996
(% Difference)	0.0	0.0	-0.3	-0.7	-0.9	-1.0	-1.0	-1.0	-0.9	-0.8	-0.7	-0.6	-0.5	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.5	-0.5	-0.5	-0.6	-0.7	-0.7
Investment																									
National Petroleum Council	1575	1583	1639	1769	1870	1939	2025	2109	2221	2353	2498	2641	2802	2946	3031	3140	3252	3371	3493	3630	3758	3912	4073	4235	4406
Global Insight Baseline	1575	1583	1663	1817	1917	1978	2053	2125	2228	2355	2495	2632	2789	2931	3016	3125	3241	3361	3483	3620	3747	3900	4060	4220	4391
(% Difference)	0.0	0.0	-0.3	-0.8	-1.0	-1.1	-1.1	-1.1	-1.0	-0.9	-0.8	-0.7	-0.6	-0.6	-0.5	-0.5	-0.5	-0.5	-0.6	-0.6	-0.6	-0.6	-0.7	-0.7	-0.8
Non Residential Investment																									
National Petroleum Council	1255	1183	1216	1331	1453	1538	1616	1697	1800	1922	2056	2198	2358	2520	2636	2744	2866	2995	3126	3274	3418	3580	3754	3935	4125
Global Insight Baseline	1255	1183	1224	1355	1483	1563	1633	1705	1800	1919	2049	2188	2344	2503	2619	2727	2852	2982	3112	3260	3403	3564	3737	3917	4106
(% Difference)	0.0	0.0	-0.7	-1.8	-2.0	-1.6	-1.0	-0.4	0.0	0.2	0.3	0.5	0.6	0.7	0.7	0.6	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
Net Exports																									
National Petroleum Council	-416	-482	-501	-519	-521	-517	-512	-507	-520	-543	-578	-624	-682	-740	-780	-809	-819	-829	-860	-916	-958	-1011	-1079	-1150	-1218
Global Insight Baseline	-416	-482	-504	-538	-543	-536	-528	-517	-527	-547	-578	-621	-677	-733	-771	-801	-811	-822	-853	-910	-954	-1010	-1081	-1157	-1230
(% Difference)	0.0	0.0	-0.6	-3.6	-4.0	-3.7	-3.1	-2.1	-1.5	-0.8	-0.1	0.4	0.8	1.0	1.1	1.0	0.9	0.8	0.8	0.6	0.4	0.2	-0.2	-0.6	-1.0
CPI Index																									
National Petroleum Council	1.771	1.799	1.848	1.886	1.927	1.971	2.021	2.076	2.134	2.194	2.255	2.317	2.380	2.446	2.512	2.582	2.657	2.739	2.825	2.916	3.010	3.106	3.205	3.306	3.411
Global Insight Baseline	1.771	1.799	1.838	1.869	1.907	1.947	1.994	2.047	2.104	2.163	2.225	2.287	2.350	2.416	2.482	2.551	2.626	2.708	2.794	2.885	2.979	3.076	3.177	3.281	3.389
(% Difference)	0.0	0.0	0.5	0.9	1.1	1.3	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.2	1.2	1.2	1.2	1.2	1.1	1.1	1.0	0.9	0.9	0.8	0.6
Employment (Millions)																									
National Petroleum Council	131.93	130.78	130.92	133.31	136.09	138.22	140.21	141.77	143.02	144.40	145.90	147.37	149.06	150.85	152.36	153.82	155.28	156.73	158.07	159.54	160.79	161.81	162.68	163.79	164.64
Global Insight Baseline	131.93	130.78	131.24	134.26	137.30	139.41	141.27	142.61	143.68	144.93	146.30	147.66	149.27	151.01	152.51	154.00	155.52	157.04	158.42	159.92	161.19	162.24	163.14	164.28	165.15
(% Difference)	0.0	0.0	-0.2	-0.7	-0.9	-0.9	-0.7	-0.6	-0.5	-0.4	-0.3	-0.2	-0.1	-0.1	-0.1	-0.1	-0.2	-0.2	-0.2	-0.2	-0.3	-0.3	-0.3	-0.3	-0.3
Unemployment Rate (%)																									
National Petroleum Council	4.79	5.78	6.24	5.69	5.47	5.50	5.42	5.11	4.95	4.86	4.75	4.64	4.53	4.46	4.62	4.67	4.65	4.63	4.60	4.59	4.60	4.60	4.61	4.60	4.63
Global Insight Baseline	4.79	5.78	6.10	5.29	4.97	5.01	4.98	4.75	4.67	4.61	4.55	4.48	4.40	4.35	4.50	4.54	4.50	4.46	4.43	4.41	4.40	4.40	4.40	4.38	4.41
(% Difference)	0.0	0.0	2.4	7.6	10.1	9.8	8.8	7.5	6.2	5.3	4.3	3.6	3.1	2.7	2.5	2.7	3.2	3.7	4.0	4.2	4.4	4.6	4.8	5.0	5.2

Table D-6. Macroeconomic Impacts Expressed as Percentage Change from Baseline

APPENDIX E

BACKGROUND ON CHEMICAL INDUSTRY PROCESS ENERGY FLOWS

Physical Configuration

Process heating is estimated to consume over 1 quadrillion Btu per year in the chemical industry.

The components of process heating systems are typically made up of four elements:

- Heating devices that generate and supply heat
- Heat transfer devices to move heat from the source to the product
- Heat containment devices, such as furnaces, heaters, ovens, and kilns
- Heat recovery devices.

In most applications, heat is supplied by one or more of four heating methods: fuel fired heating, steam heating, hot oil/air/water heating, and electric heating. The heat is transmitted either directly from the heat source or indirectly through the furnace walls, or through other means such as jets and recirculating fans. The most basic types of process energy are boiler-based steam, as shown in Figure E-1, and a process heater, shown schematically in Figure E-2. Note that an additional source of process energy is steam or hot air from a cogeneration facility, which is discussed separately in Appendix I.

Alternatives/Fuel Switching

As process heaters come in a variety of configurations, there are sometimes alternatives for heating. For example, steam may be used for heating a process fluid instead of using a fuel-fired heater. However, specific process requirements typically dictate a specific type of process heating device. A partial list of heating devices is listed in the Technology/Conservation/Efficiency section below.

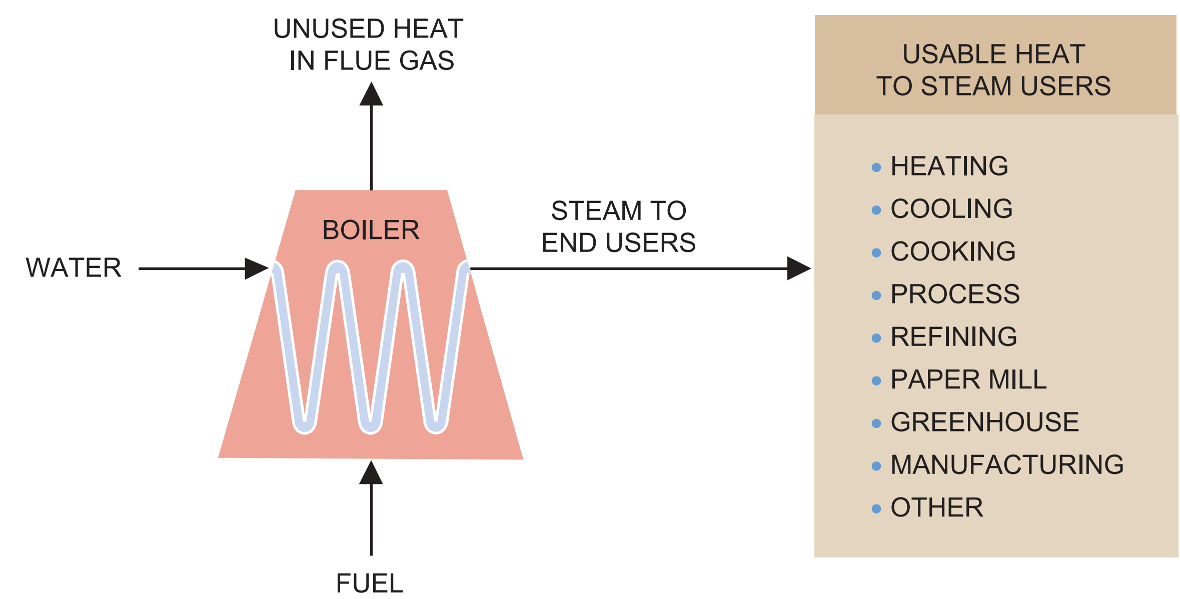
Fuel fired process heaters in some cases have more flexibility on fuel selection than other technologies, such as gas turbines. The burners and combustion sections may have enough space to accommodate different types of burners. However, different fuels create different radiation effects and flame patterns that may not be acceptable for an existing system. Environmental permitting frequently dictates the fuel choice for fired equipment.

The predominant fuel used in the chemical industry is natural gas or internally produced gaseous fuel, indicating there is likely not a lot of fuel switching taking place in either cogeneration or process heating operations. A factor in the 1998 to 2000 time frame was lower natural gas prices that may have driven the choice of fuel to natural gas even though other types of fuel could be consumed.

Technology/Conservation/Efficiency

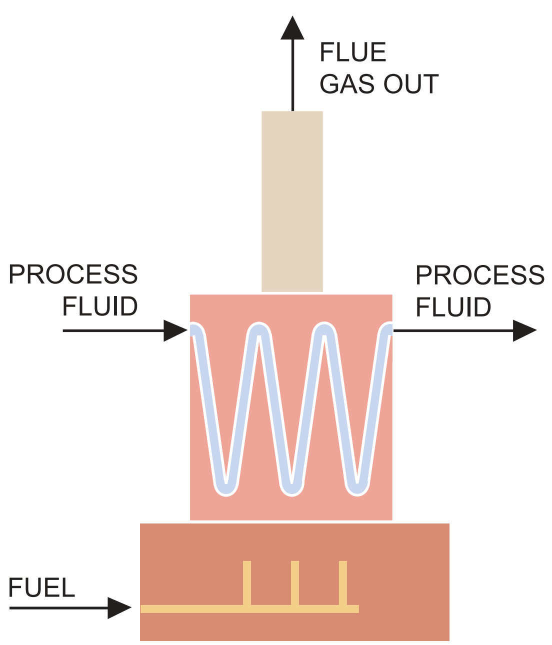
There are a wide variety of technologies employed in process heating. Some high temperature process heaters include:

- Pyrolysis furnaces for thermal cracking to produce ethylene and propylene
- Steam hydrocarbon reformers for natural gas reforming to produce ammonia



Source: U.S. Department of Energy, Industrial Technology Program, "Process Heating."

Figure E-1. Boiler-Based Steam



Source: U.S. Department of Energy, Industrial Technology Program, "Process Heating."

Figure E-2. Process Heater

- Steam hydrocarbon reforming for synthetic gas to produce methanol, hydrogen, and ammonia.

Some medium temperature processes include:

- Reboilers for reformate extraction to produce benzene
- Steam superheaters for ethylbenzene dehydrogenation to produce styrene
- Cracking furnace for ethylene dichloride cracking to produce vinyl chloride monomer.

According the U.S. Department of Energy, the overall thermal efficiency of process equipment varies from 15% to 80%.[1] "Lower efficiency levels for process heating opens the door for significant energy savings. The greatest potential is in the higher temperature range processes, as the margin for improvement is large and the returns are greatest. With the use of advanced technologies and operating practices, process heating energy consumption could be reduced by an additional 5%-25% within the next decade."

[1] U.S. Department of Energy, Process Heating Supplement to "Energy Matters."

APPENDIX F

INDUSTRIAL BOILER FUEL-SWITCHING RELATIONSHIPS IN NPC MODELS

The industrial model incorporates a short-term fuel-switching algorithm between natural gas and residual fuel oil use in boilers. The basic modeling approach estimates the market share of natural gas over the total switchable market, given the relative price between natural gas and residual fuel oil. The total switchable market incorporates only the boilers that are capable of switching between natural gas and residual fuel oil. Boilers that are dual-fuel fired but are not capable of switching due to various factors such as zone restrictions and environmental regulations are not included in the total switchable market. The relationship between the natural gas share and the relative price are represented in a "switching curve." A curve is developed for each of the regions represented in the model. These curves were developed by EEA using the results of a study undertaken for the Gas Technology Institute (GTI, formerly Gas Research Institute).[1]

The total switchable market is an exogenous variable in the model. For the NPC study, the share of the total boiler market that is switchable varied by region, and was assumed to be the following:

- New England: 4%
- Middle Atlantic: 4%
- South Atlantic: 8%
- East North Central: 8%
- West North Central: 8%
- East South Central: 4%
- West South Central: 2%
- Mountain 1: 8%
- Mountain 2: 8%
- Pacific 1: 8%
- Pacific 2: 2%

These share values were estimated based on information on dual-fuel capacity developed by EEA, considering input provided to the NPC study group and EEA in outreach meetings with industrial consumers. These values considered environmental regulations that might affect an industry's fuel flexibility.

The switching curves developed through the GTI fuel-switching study mentioned above take into consideration various other critical factors, including technical constraints, fuel supply and distribution constraints, historical fuel price data, and historical behavior of industries regarding fuel switching. Figures F-1 to F-10 show the fuel-switching curves used in the model by region.

[1] The results of the study are documented in the GRI report *Fuel Switching Issues in the Industrial Sector*, December 1993.

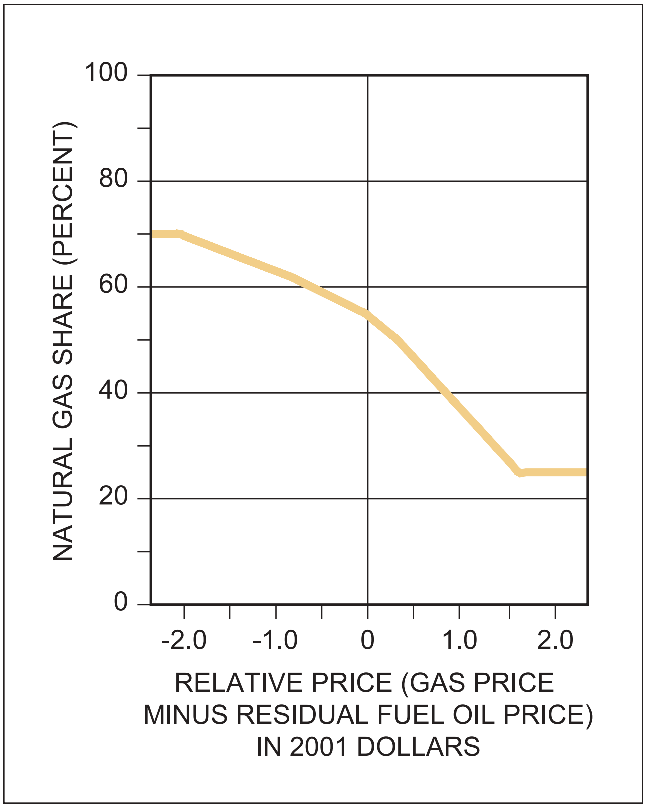


Figure F-1. New England Fuel-Switching Curve

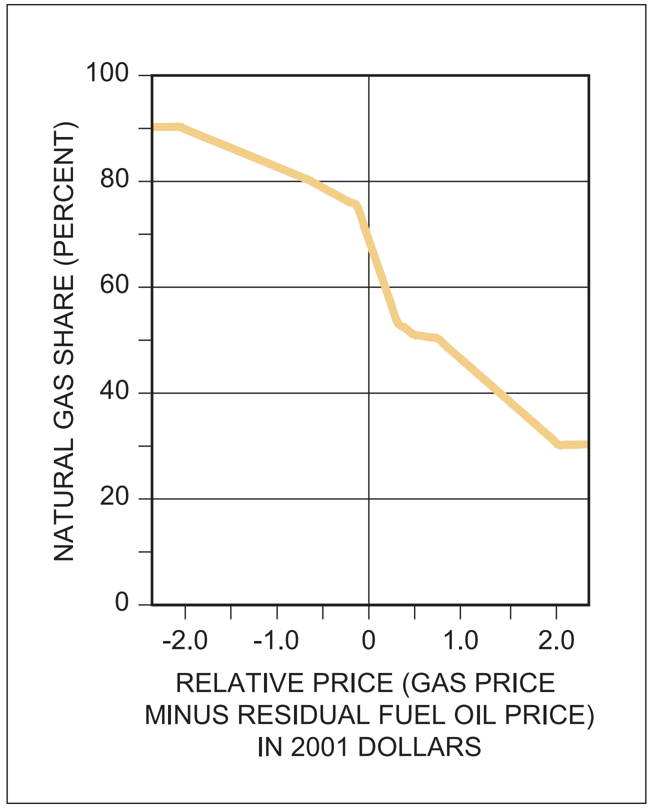


Figure F-2. Middle Atlantic Fuel-Switching Curve

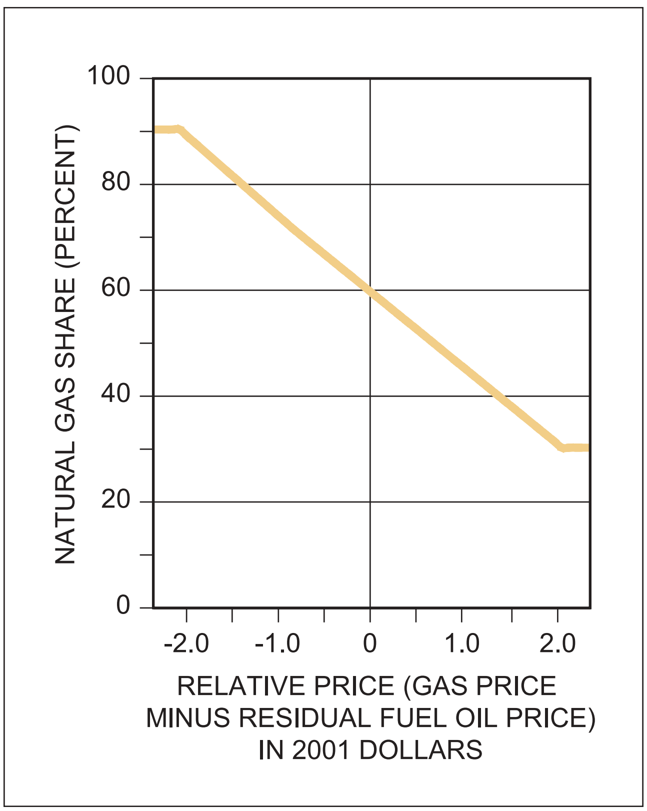


Figure F-3. South Atlantic Fuel-Switching Curve

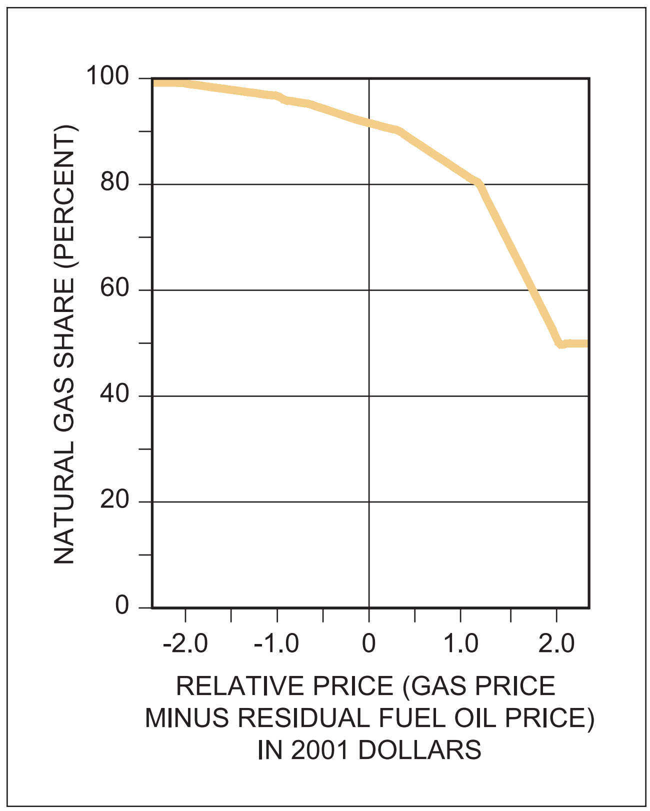


Figure F-4. East North Central Fuel-Switching Curve

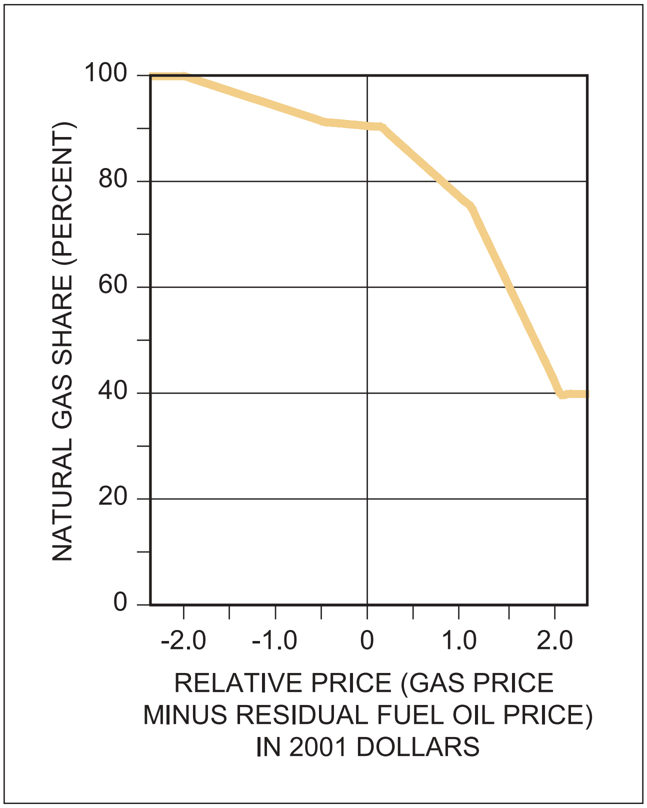


Figure F-5. West North Central Fuel-Switching Curve

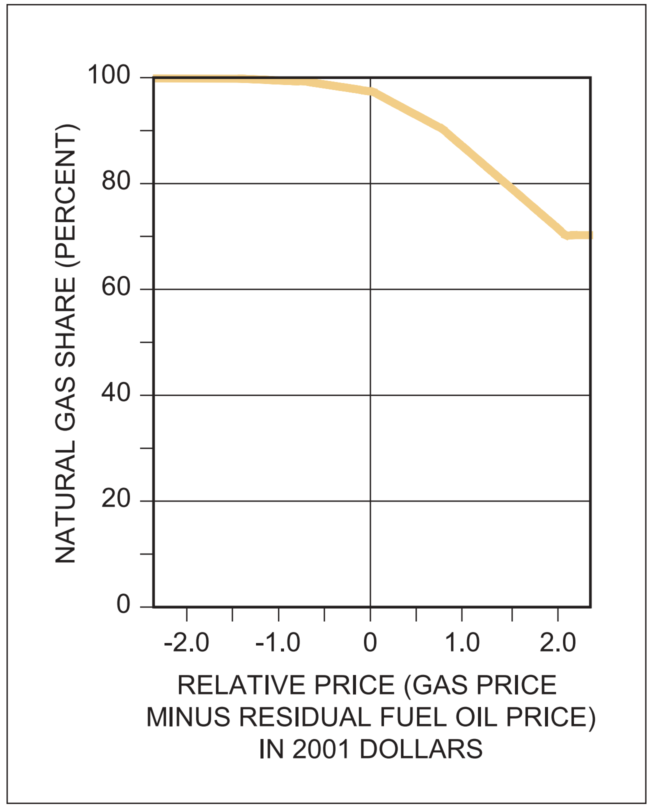


Figure F-6. East South Central Fuel-Switching Curve

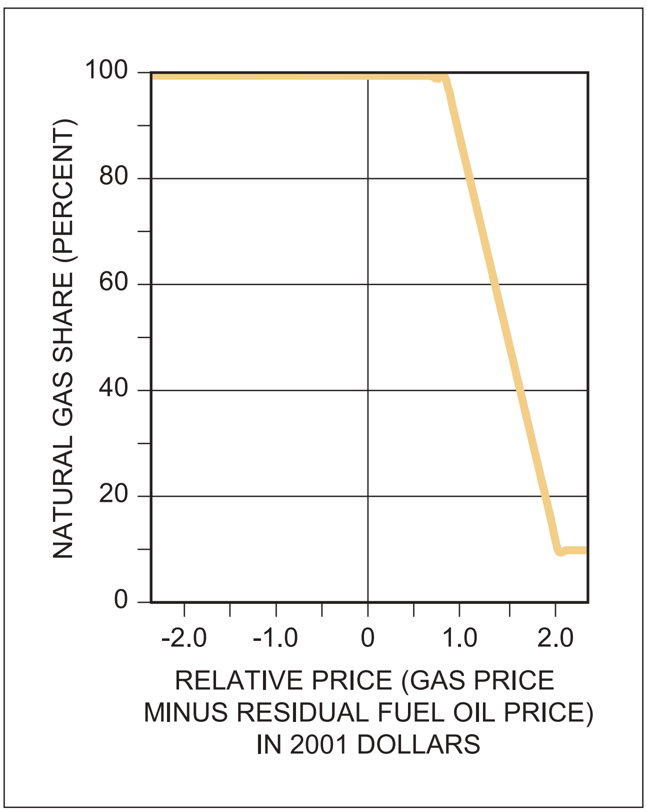


Figure F-7. West South Central Fuel-Switching Curve

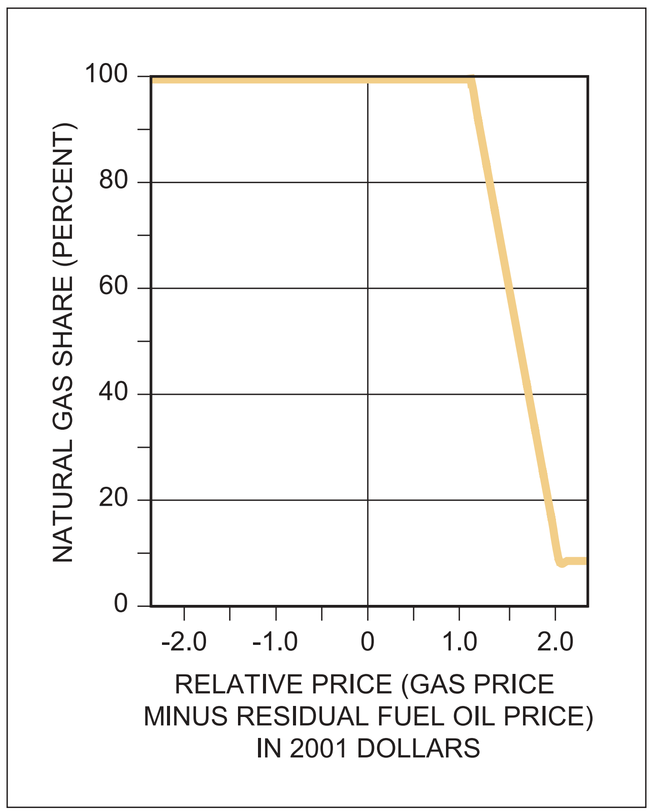


Figure F-8. Mountain 1 and 2 Fuel-Switching Curve

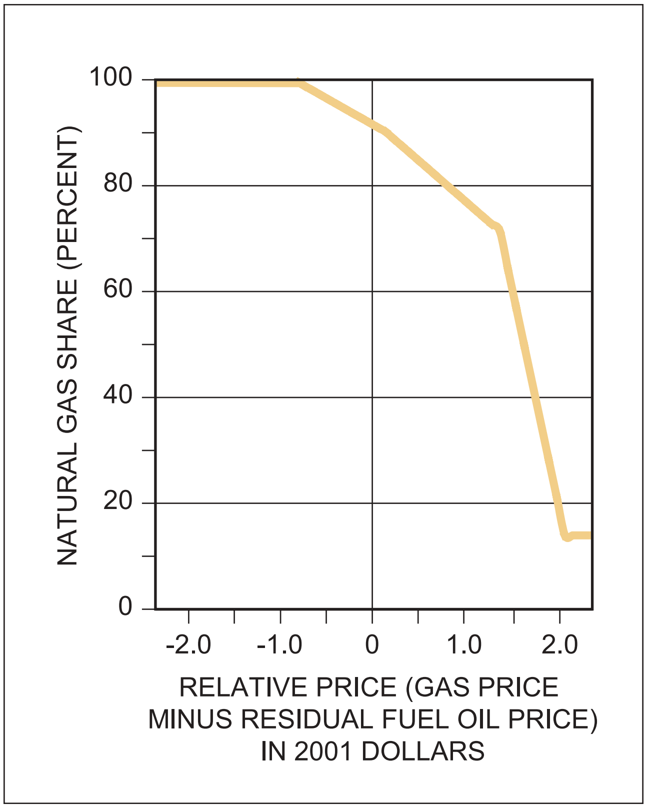


Figure F-9. Pacific 1 Fuel-Switching Curve

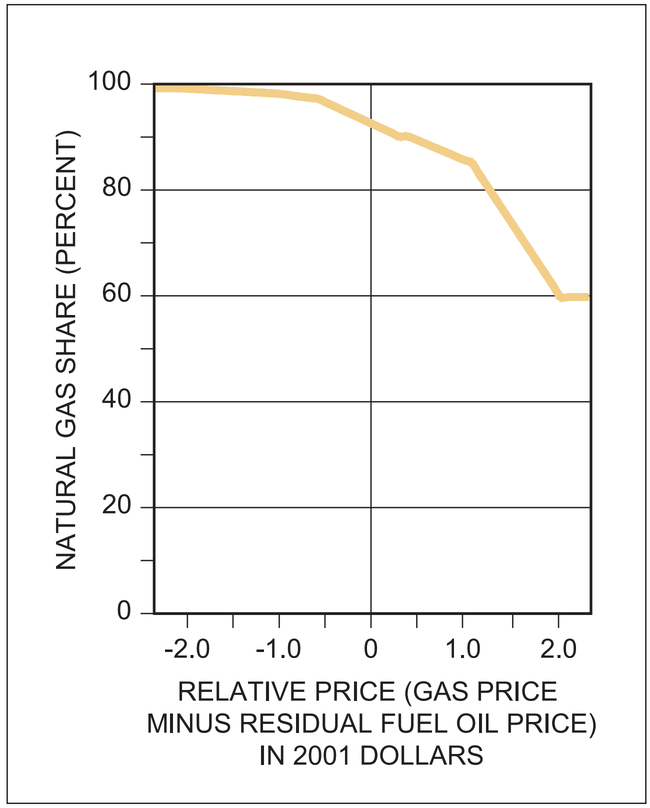


Figure F-10. Pacific 2 Fuel-Switching Curve

APPENDIX G

SUMMARY OF EEA ISTUM-2 INDUSTRIAL DEMAND MODEL

Modeling of industrial demand by the NPC study group addressed process heat end-use, which includes all uses of energy that involves direct heating (instead of indirect heating like steam); and "other use", which includes all the other uses, including non-boiler cogeneration, on-site electricity generation, and space heating. The NPC study group decided to approach both end-use categories by using EEA's large and detailed industrial model called the Industrial Sector Technology Use Model (ISTUM-2), described herein. ISTUM-2 projects industrial energy consumption by 2-digit SIC, and is more detailed for some industries, by energy service categories, technology, fuel, and region. EEA has used ISTUM-2 for a variety of projects including the Gas Technology Institute's (formerly, Gas Research Institute (GRI) baseline projections.

The following description of the Industrial Sector Technology Use Model (ISTUM-2) framework provides the details on how the model is structured, its inputs, its outputs, and the level of industrial sector detail and fuel consumption.

Structure of the ISTUM-2 Model

Definition of Important Terms

A useful starting point in understanding the analytical framework is to review how the model characterizes the industrial sector in relation to energy demands. Figure G-1 outlines the schematic framework and defines key terms.

Major process step refers to the various integrated processes in an industry, e.g., pulping, bleaching, or papermaking in the paper industry. **Subprocess** is a second level of distinction required for complex industries. Examples of subprocesses in Figure G-1 include pelletizing and sintering, the two major beneficiation techniques included in agglomoration process step in the steel industry.

The **energy services** required in these major process/subprocess steps are specified with examples in Figure G-1. There are two classes of energy services: generic and process-specific. **Generic energy services** refers to those energy services that are common to most industries, such as steam generation, mechanical drive, and space heating. **Process-specific energy services** refers to energy services specific to a particular product's process/subprocess step, e.g., distillation and steel reheating. Distillation is the major energy-using activity in petroleum refining and reheating is the major energy-using activity in secondary rolling, a subprocess in which basic steel forms from the primary rolling step are processed into a variety of shapes and forms. **Process technologies** are the basic items of equipment in which the processing activity takes place. Examples include coke ovens, glass melters, and thermal crackers.

The energy process technology is the basic unit of analysis in the model. It transforms input energy in a primary form (e.g., natural gas) or an intermediate form (e.g., steam, byproduct gas) into useful energy services. For example, suppose that it requires 5 MMBtu of useful heat to melt raw material to produce 1 ton of a specific product. The 5 MMBtu/ton is the energy service demand actually required to perform this process step. If that process has an efficiency of one-third, then it requires 15 MMBtu/ton of input energy carriers to provide the required energy service.

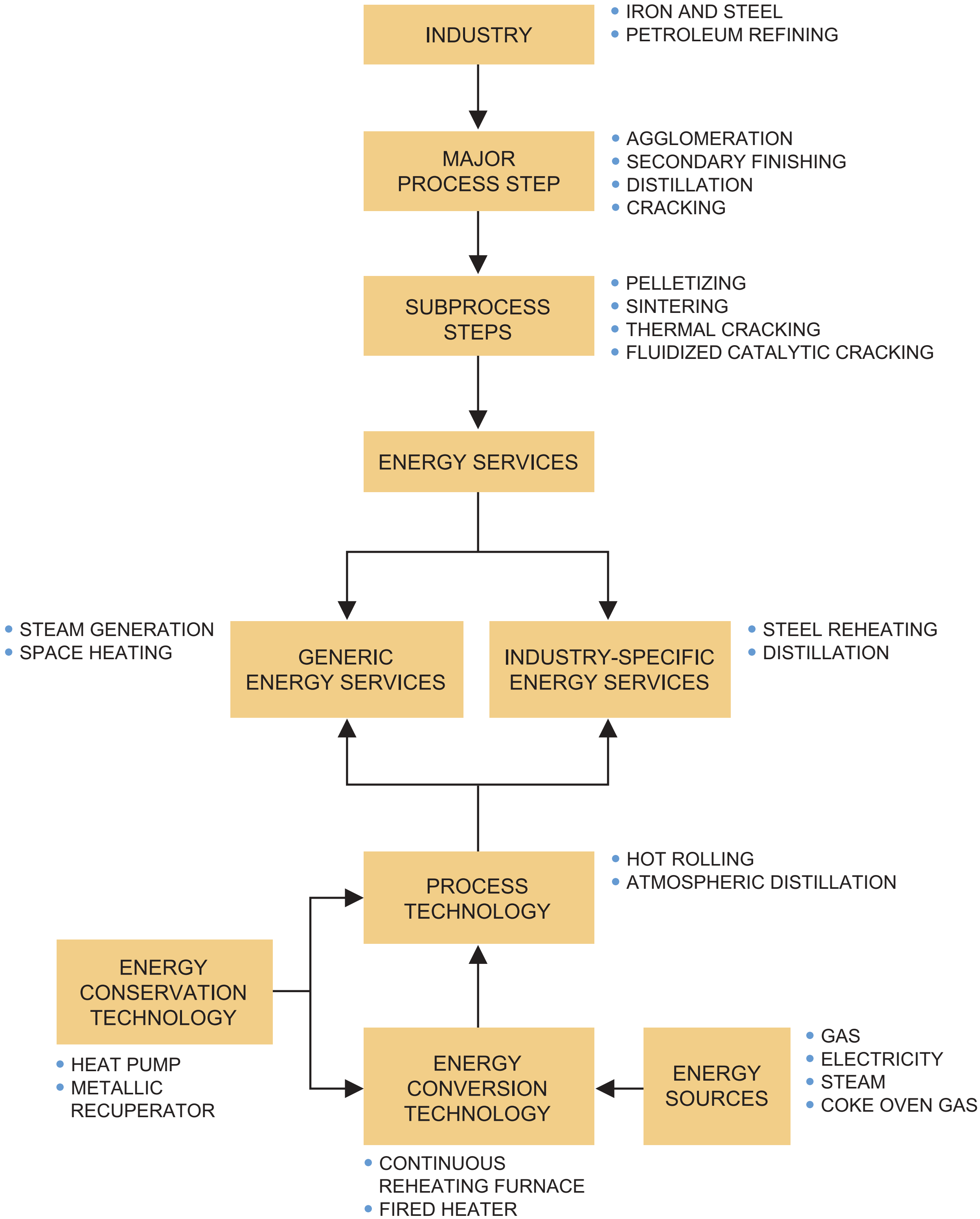


Figure G-1. Schematic Framework of Industrial Energy Use

Alternative technology configurations may all satisfy the required energy service demand per ton of product, but may use different amounts of energy input because of variations in efficiency.

Another term to be defined is **energy carrier**. This is the energy form used by a process technology to generate energy services required in a particular process. The energy carrier may be a primary fuel form, such as fuel oil or natural gas, or a processed energy form, such as electricity, which may be internally generated by the industrial plant or purchased at the battery limits of the plant. Other energy carriers may require fuel supply equipment on the plant site.

To summarize, Figure G-1 delineates the basic chain used in characterizing industrial energy use. The first step is to identify major process steps, then subprocess distinctions, if appropriate. The energy services required to perform the process then are identified. The next step is to categorize energy technologies or the equipment items, which provide the energy services. The process technologies may be complementary technologies or competitive technologies. The last step is to identify energy carriers that provide useful energy delivered to the process technology.

Several other concepts are worth defining and clarifying. **Energy conservation technologies** are typically add-on equipment options that can be applied to process or carrier technologies to reduce the levels of energy carrier demands. One class of conservation technologies is waste heat recovery devices, add-on devices that do not alter the basic energy process technologies.

Energy management is another broad class of options to improve energy productivity. Energy management options include housekeeping activities, improved operating practices for industrial equipment, and computer control systems to improve synchronization of process flows between integrated process steps or to reduce peak electricity demands in order to decrease purchased electricity costs. Energy management options generally are management intensive and tend to affect operating practices and cost rather than requiring the significant capital expenditures typical in conservation technologies.

Process modifications and fundamental equipment changes also are used to improve energy productivity. Process modifications can include radical innovations in the production process. Two examples of major process changes include the introduction of direct reduction of iron ore vs. blast furnaces and continuous vs. ingot casting in steel. These major process changes alter the ratio of energy service Btu's per product processed because they change the basic nature of the production process.

Equipment changes refer to basic changes in energy process technology, which result in increased energy efficiency. In this case, the energy process technology may be performing the same original function, e.g., generating steam, but at an improved efficiency. Such changes might include new burner designs, modifications in furnace designs, new materials or refractory developments. Both process and equipment modifications tend to be capital-intensive and typically are associated with the construction of new facilities and installation of energy process equipment.

Size Dimensions in the ISTUM-2 Model

The basic structure of the model is designed to simulate industrial energy decisions on an appropriate level of detail. Since the level of detail in the model is extensive, this section attempts only to summarize the size dimensions.

Two basic elements of structure are industry group and energy service class. ISTUM-2 separately delineates and tracks energy decisions for 27 separate industry groups listed in Table G-1. The model also distinguishes 52 different types of energy services, as shown in Table G-2. Of these energy service sectors:

- Some are generic, which are required in all industrial sectors (e.g., space heating);
- Others are specific to one or two industries (e.g., paper drying); and
- Others are generic classes of services such as direct, clean heating, which are typically aggregations of types of services used in many industries but not covered elsewhere by more specific energy service categories.

Each industry subsector, along with appropriate energy service requirements, is further tracked separately for 10 regions of the country, listed in Table G-3. The regionalization is intended to provide a pattern of regional energy demand by industry in the future and to reflect regional variations in the existing structure of energy use and energy prices.

Non-Manufacturing Industries
Agriculture-Crops (SIC 01)
Agriculture-Livestock, etc (SIC 02, 07, 08, 09)
Mining-Energy (SIC 12, 13)
Mining-Non-Energy (SIC 10, 14)
Construction (SIC 15)
Manufacturing Industries
Food and Kindred Products (SIC 20)
Tobacco Products (SIC 21)
Textile Mill Products (SIC 22)
Apparel and Other Textile Products (SIC 23)
Lumber and Wood Products (SIC 24)
Furniture and Fixtures (SIC 25)
Paper and Allied Products (SIC 26)
Printing and Publishing (SIC 27)
Chemicals and Allied Products (SIC 28)
Petroleum and Coal Products (SIC 29)
Rubber and Miscellaneous Plastic Products (SIC 30)
Leather and Leather Products (SIC 31)
Stone, Clay, and Glass Products (SIC 32)
Iron and Steel (SIC 331)
Aluminum (SIC 3334, 3341, 3353, 3354, 3355)
Other Primary Metals (other SIC 33)
Fabricated Metal Products (SIC 34)
Industrial Machinery and Equipment (SIC 35)
Electronic and Other Electric Equipment (SIC 36)
Transportation Equipment (SIC 37)
Instruments and Related Products (SIC 38)
Miscellaneous Manufacturing (SIC 39)

Table G-1. List of Industry Groups Represented in ISTUM-2

Within these industry groups, energy service sectors, and regional classes, the model considers providing energy services through:

- Over 400 energy process technology forms (e.g., glass reverberatory furnace)
- Eight intermediate (e.g., low temperature steam) energy carrier forms, six byproduct energy forms, and 23 primary forms of energy carriers purchased across the plant boundaries.
- Over 60 energy conservation technology options
- Fourteen boiler and 17 cogenerator system configurations.

Within a given industry, region, and energy service sector, the applicable process, carrier, and conservation options are competed for market shares in smaller "cells" or decision units where costs vary according to an estimated distribution. In short, the model breaks down the sector into thousands of decision cells of alternative technology configurations to provide energy services at varying costs.

Model Capability

The ISTUM-2 model's capability includes:

- Forecasts of the quantity of industrial energy service demands. The total level of energy services required to support future industrial production levels is estimated by service category.
- Projection of regional fuel demands. The level and mix of primary energy forms (e.g., natural gas, coal, oil) that will be used to provide required energy services are estimated on a regional basis.
- Estimates of market penetration of options to improve energy productivity. This output includes quantitative assessments of the market potential and projected penetration of a variety of options that will improve energy productivity, including waste heat recovery, improved housekeeping practices, and new production process equipment.
- Evaluation of the impact of government policy. The model can be used to assess the impacts of factors such as higher fuel prices and government policy on energy productivity in the industrial sector.

Generic Services

- Boiler generated steam
- Cogenerated steam
- On-site electricity generation (non-cogen)
- Off-highway transportation
- Machine drive
- Lighting
- HVAC

Paper Industry

- Pulping
- Bleaching
- Paper making
- Chemical recovery
- Pulp drying
- Lime calcining

Petroleum Refining Industry

- Distillation
- Cracking
- Alkylation
- Hydrogen production
- Hydrotreating
- Reforming
- Other petroleum products

Iron and Steel Industry

- Agglomeration
- Iron making
- Coking
- Steel making
- Primary finishing
- Secondary finishing
- Heat treating

Aluminum Industry

- Aluminum melting
- Aluminum electrolysis
- Aluminum heating

Chemical Industry

- Organic chemicals
- Inorganic chemicals
- Plastics and resins
- Chemical fertilizers
- Chemical feedstocks

Stone, Clay, and Glass Industry

- Brick firing
- Cement making
- Glass melting

Food Industry

- Food drying
- Food concentration

Others

- Refrigeration
- Direct steam
- Dirty heating
- Direct clean heating
- Dirty drying
- Direct clean drying
- Lime calcining (other than paper)
- Concentration
- Paint drying
- Textile drying
- Metal melting
- Forging
- Heat treating (other than steel)
- Feedstocks

Table G-2. List of Energy Service Categories Represented in ISTUM-2

New England (MA, ME, NH, VT, RI, CT)
Middle Atlantic (PA, NJ, NY)
South Atlantic (DE, DC, GA, FL, MD, SC, NC, VA, WV)
East North Central (IL, IN, MI, OH, WI)
West North Central (IA, KS, MN, MO, NE, ND, SD)
East South Central (AL, KY, MS, TN)
West South Central (AR, LA, TX, OK)
Mountain (CO, ID, MT, NV, UT, WY, AZ, NM)
Pacific 1 (AK, OR, WA)
Pacific 2 (CA, HI)

Table G-3. List of U.S. Regions Represented in ISTUM-2

Overview of ISTUM-2 Model Logic

The ISTUM-2 is an energy demand model of the industrial sector. Consequently, exogenous inputs to the model include industry production growth rates and trajectories of purchased prices of various energy forms. Figure G-2 provides a schematic of the overall model logic.

Industry Process Flow Module

As shown in Figure G-2 (starting at the top left corner), projected growth in industrial output is introduced into the flow model of the particular industry together with projections of product mix changes and raw material constraints. Detailed industry process flow models are used for four large energy-consuming industries: pulp and paper, petroleum refining, iron and steel, and chemicals. The structure of these models is designed to simulate each industry's operating decisions on the macro process level when faced with significant changes in product mix, raw material price or availability, or the introduction of new and clearly superior processes.

The approach adopted in the ISTUM-2 flow model is based on two key premises:

- In the long run, industry decision-makers allocate product flows to applicable processes such that total production costs are minimized within such constraints as existing process capacity, product/process compatibility, and accepted industry practices.
- Shifts in process allocations do not happen abruptly at any point in time, but rather gradually as more information becomes available and various decision-makers, who may be seeing different circumstances, start implementing changes that result in industry-wide impacts.

The flow model decision rules follow an optimization path that adjusts process allocations on a total cost minimization basis similar to what a mathematical optimization approach, e.g., a linear programming model (L/P) would recommend. However, unlike an L/P model, changes in allocations and process environments are carried out gradually in finite steps while checking if industry goals have been achieved to avoid making unnecessary changes.

The outputs of the flow models are projections of the amount of material that is likely to be transformed in each of the major processes in the industry. This flow rate, or process load, is termed 'process service demand' in this analysis and is measured in physical units (e.g., tons per year, barrels per day, etc.) at the level of a major process (such as pulping in paper, ironmaking in steel, and cracking in petroleum refining).

Market Applicability

This step matches energy-related technologies to the applicable process activity, such as pulping. This matching is performed on the basis of "technical applicability." Potential market applicability is defined for three broad levels of energy technology: process, energy carrier, and conservation add-on.

Process technology (equipment that transforms primary energy forms such as coal or intermediate energy forms such as byproduct gas into useful energy services) market applicability defines which processes can perform the required energy services. For example, three types of furnaces (reverberatory, unit, and electric) can perform glass melting services, but within certain limits or maximum market fractions. Unit glass melters can be used only to produce certain glass products, while reverberatory furnaces can produce any type of product and, thus, would have a maximum market fraction of 1.0. Generally, maximum market fractions less than 1.0 occur because of product limits or because the energy service sector is an aggregate mix of services and some process technologies can perform

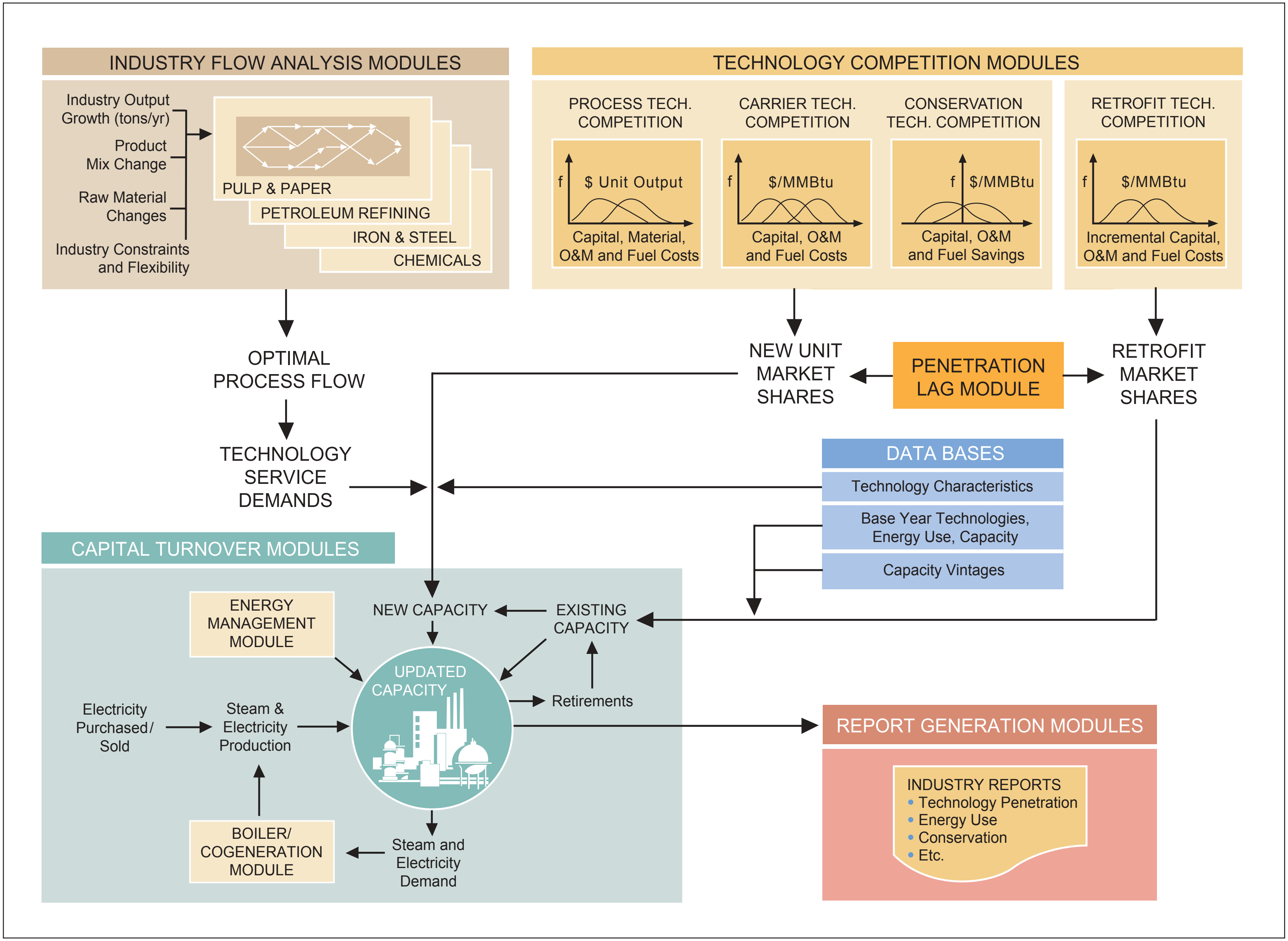


Figure G-2. Overview of the Industrial Sector Technology Use Model only a certain subset of these services. For process technologies, the maximum market fraction represents a means of reflecting more detailed constraints without having to further disaggregate the energy service categories.

Energy carriers (primary energy forms such as natural gas or processed energy forms such as electricity) are also matched to process technologies. Generally, the match-up depends on the technical characteristics of the process technology, whether it uses electricity, steam, fossil fuels, or byproduct gases. Certain energy carriers may not be used in specific processes. Add-on conservation technologies also are matched against applicable markets. For example, high temperature recuperators are only applicable to process technologies where flue gas temperatures are sufficiently high, such as gas-fired steel reheat furnaces.

This phase – matching market applicability – defines where process, carrier, and conservation technologies can potentially be applicable to energy service categories solely on a technical basis. Maximum market shares less than 1.0 are used in this "matching matrix" where applicability is limited to less than the total market.

Technology Competition – Nominal Market Share

At this point in the model logic, various energy technologies have been matched to energy service categories (e.g., all the process, carrier, and conservation technology options which relate to energy services associated with the paper pulping processes). The next step is to 'compete' these options to see which configuration of technologies provides the necessary energy services at a minimum cost per unit of product to be processed.

This step converts inputs on energy efficiencies (useful energy output/energy inputs), required energy service Btu/unit of product for process technologies, energy carrier costs (e.g., price of natural gas, cost of steam), and non-energy operating costs into the total costs of providing energy services per unit of product.

For example, in the petroleum refining industry the process flow model will indicate a certain amount of required service demand for thermal cracking as a major process. At least three types of process technologies can provide that service, namely delayed coking, fluid coking, and vis-breaking. In the technology competition module, applicable process technologies are competed to estimate the market share of each technology for the thermal cracking energy service demand. Depending on the type of coker, there are also a number of carrier technologies available to transform fuels into suitable forms of energy (i.e., sensible heat at a certain temperature, with desired flame characteristics, etc.). In the case of coking process technologies, the available carrier technologies are fired heaters burning such fuels as natural gas, residual fuel oil, still gas, or distillate fuel oil. For each coking technology, the competition between carrier technologies is performed to determine the optimal mix of fuels.

The third level of competition (the first two being process and carrier technologies) is in conservation technologies that apply to either or both process and carrier technologies in order to improve their energy or material efficiency. Conservation technologies are generally add-on type units that can be added to a new or existing unit whenever they are economically justifiable (e.g., their savings in fuel or material outweigh their total costs by a desired margin). Again, in the example of coking processes, there are several add-on options that improve efficiency, such as alloy heat exchanges, heat wheels, waste heat boilers, and CO boilers.

It is important to add that the competition framework integrates options from the lower levels into decisions at the next level up for carrier and process technology competitions. In other words, the economic competition occurs sequentially starting with conservation technologies (matched to all potential carriers and process options), then moves to the carrier level, and finally ends at the process technology level. This means that the choice between two fired heaters in coking will depend not only on their own costs and fuel efficiency, but also on those factors after the addition of applicable conservation units to each heater.

This multiple step competition is a critical element of the model logic. For example, for a forging furnace, it is first determined whether a heat recovery device would achieve sufficient fuel savings to justify installation on a gas-fired forging furnace. If a high temperature recuperator is economical, then the gas-fired furnace with heat recovery competes against an electric induction forging furnace. Without heat recovery, the gas-fired addition of the heat recovery device may narrow the energy efficiency differences enough so that the fuel cost advantage of natural gas will allow the gas forging furnace to gain a share of the forging market.

The process of economic competition is performed separately for both new markets (economic growth plus normal replacement of retired facilities) and for existing facilities. In effect, the process solves for the technology market shares (process, carrier, conservation technology configurations) per unit of product separately for new and existing facilities. In existing facilities, various equipment configurations already were providing energy services in the preceding model solution year. However, these facilities can be altered by retrofitting equipment such as:

- Addition of heat recovery equipment
- Fuel switching (e.g., gas to oil)
- Certain types of process change.

Generally, retrofit technology options are more limited than technologies potentially available in new installations.

The basic decision criterion in the model is minimization of directly attributable costs. As applied to energy-using technologies, this translates into a minimization of the life cycle costs for technologies providing similar services and output. The decision rule is a local rather than global concept in that technology choice decisions are based on costs of competing options for the specific service to be met, without regard for other investment priorities within the industry using the service. Global priorities, based on such effects as capital constraints, risk aversion, and competition for corporate resources, are determined in a subsequent behavioral analysis step.

Another key assumption underlying the market competition analysis is that the costs of alternative technologies cannot be represented adequately as a single point estimate, even at the level of disaggregation of ISTUM-2. Site-specific factors often will significantly affect costs, so that when all such cases are aggregated, a distribution of costs will take shape. These distributions are developed explicitly within ISTUM-2. With technology cost distributions possibly overlapping, the decision rule for determining the market share for each technology evaluated in ISTUM-2 is defined more accurately by its probability of being the least life cycle cost option. Thus, changes in the life cycle costs for technologies relative to each other will lead to changes in market share but not to "winner takes all" decisions.

Each production process in each submarket will experience a distribution of capital, operating, and fuel costs. These factors vary for reasons such as:

- Fuel quality premiums (e.g., related to the sulfur content in coal and residual fuel oil)
- Transportation costs (relative distances from supply sources)
- Installation costs can vary by a factor of three among facilities due to differences in labor costs or to fairly random differences in equipment design or space limitations.

Varying costs are portrayed in ISTUM-2 for each production process, energy carrier, and conservation technology configuration competing for a market share of any energy service category.

Penetration Lag Module

The technology competition described above results in technology market shares per unit of production by energy service sector for new and existing facilities. In ISTUM-2 terminology, these are referred to as nominal or economic market shares. The competition that produces these nominal market shares makes the following critical assumptions:

- All technology options are considered proven (although the dates of commercial availability will differ).
- The reliability of untested technologies is equivalent to proven technologies.
- Costs of untried technologies are known.
- Capital is assumed to be available in sufficient quantities to fund the investments associated with installing the technology at a fixed discount rate.

Nominal market shares for new technologies should be interpreted as the optimal economic potential (in the long run), but not what will actually occur in the marketplace. In actual experience, the market penetration of technologies will not occur as fast because of behavioral/uncertainty lags and capital constraints. Industrial users invariably introduce new technologies slowly into the production process, even where the apparent economics are highly favorable. The reasons for this type of lag include:

- The desire to demonstrate the technology is reliable and performs as expected, in a technical sense
- The need to affirm that costs estimates are accurate
- The desire to gain operating experience with the technology before encouraging widespread use.

The magnitude of this behavioral lag in new technology penetration will vary depending on such factors as:

- Industrial firms' perception of the applicability of experimental or pilot plant results in other facilities and the degree of information dissemination
- The apparent cost effectiveness of the new technology in comparison to conventional technologies
- The risk to the reliability of the production process caused by introducing new, untried equipment
- The capital costs of the new equipment and the financial constraints of the industry.

In addition to the above factors underlying behavioral lags, capital scarcity could also constrain the pace of investments due to overall capital availability for an industry, but especially for discretionary investments in new, unproven technologies. It has been argued that capital scarcity has been a major reason for the slow pace of installation of heat recovery equipment, even where such equipment is already economically proven.

The ISTUM-2 model incorporates a behavior lag model that adjusts the nominal market shares for these factors to produce "actual" market shares. This two-step competition process includes the following market share concepts:

- *Nominal Market Share.* Factors considered are expected technology and cost performance, potential market applicability, and economic market penetration.
- *Actual Market Share.* Nominal shares are adjusted to account for behavior lag related to introducing unproven technologies, and lags related to capital constraints.

Capital Turnover Module

Data on existing technologies, energy use patterns, and technology capacity define the existing capacity in the model's base year, 1994. New process capacity then is computed for 1995 and beyond as the difference between the projected year's total required capacity and the previous year's capacity minus retirements. New capacity is defined in finer detail by applying technology market shares to its total service demands combined with technology characteristics (e.g., fuel requirements, efficiency, costs, etc.). Retirements are a function of age distributions or vintages in the base year capacity, the industry's growth rate, and the average physical life of new units.

Energy Management

Before reporting total primary fuel and electricity demands for the industrial sector, fuel savings due to "energy management" activities are taken into account. The energy management module represents housekeeping type activities that are labor and management intensive versus capital intensive conservation measures (e.g., add-on conservation technologies). Such activities include training of labor on energy savings techniques, insulating steam pipes, better temperature monitoring in combustors, periodic inspection of valves and replacement of leaky ones, etc. Since the economics of such a diverse set of activities is hard to quantify and rank, savings due to energy management are estimated using regression analysis of actual savings over the past few years. These regression equations, one for each industry or industry group, are used to project energy management savings in the future as a function of time.

Recent Updates of ISTUM-2

The current version of ISTUM-2 has a base year of 1998. The cost and performance data of boilers, cogeneration equipment, and other distributed generation technologies were updated by EEA during the period in which the NPC study was conducted to better reflect current and future state of these technologies.

APPENDIX H

STATE CHEMICAL STATISTICS

Rank	State	Value of Shipments (million $) 2000	Chem. GSP* (million $) 2000	Chem. % of Total GSP (%) 2000	Chem. Employ-ment (thou.) 2001	Ave. Wages and Salaries ($) 2000	Chem. Estabs. (no.) 1997	Chem. Exports** (million $) 2001
1	Texas	71,639	13,943	1.9%	82.7	62,882	1,115	8,014
2	Louisiana	31,279	6,032	4.4%	28.4	64,572	264	947
3	New York	26,528	9,322	1.2%	57.5	69,705	634	5,520
4	New Jersey	25,972	23,417	6.4%	93.9	99,275	793	7,215
5	California	24,360	14,419	1.1%	82.6	71,427	1544	4,566
6	North Carolina	24,157	11,407	4.0%	47.8	56,077	426	2,390
7	Pennsylvania	23,478	16,101	4.0%	72.8	75,210	616	5,175
8	Illinois	22,360	8,643	1.8%	59.9	62,934	745	4,603
9	Ohio	21,899	9,966	2.7%	64.3	61,593	715	2,924
10	Indiana	18,237	8,752	4.6%	32.0	79,993	310	2,403
11	Michigan	11,535	9,764	3.0%	41.0	74,868	436	3,813
12	Georgia	11,265	3,469	1.2%	22.3	49,537	481	1,376
13	South Carolina	10,956	2,806	2.5%	23.8	46,406	254	868
14	Tennessee	10,589	4,262	2.4%	27.6	50,452	288	1,511
15	Virginia	10,524	3,554	1.4%	19.8	53,698	185	647
16	Missouri	9,840	5,114	2.9%	23.3	68,551	366	1,844
17	Florida	7,469	3,044	0.6%	21.0	48,282	576	1,959
18	Alabama	7,390	1,645	1.4%	11.4	54,157	207	169
19	Massachusetts	7,299	3,007	1.1%	17.9	85,349	358	1,794
20	Kentucky	7,070	2,950	2.5%	15.0	54,549	173	548
21	West Virginia	6,395	2,899	6.9%	13.5	62,669	73	779

State Chemical Statistics (Ranked by Value of 2000 Shipments)

Rank	State	Value of Shipments (million $) 2000	Chem. GSP* (million $) 2000	Chem. % of Total GSP (%) 2000	Chem. Employ-ment (thou.) 2001	Ave. Wages and Salaries ($) 2000	Chem. Estabs. (no.) 1997	Chem. Exports** (million $) 2001
22	Iowa	6,222	2,156	2.4%	7.2	46,054	125	274
23	Connecticut	6,007	3,628	2.3%	22.3	90,785	166	1,674
24	Wisconsin	5,983	2,603	1.5%	15.1	51,957	307	660
25	Maryland	5,274	2,672	1.4%	14.3	60,468	170	52
26	Delaware	5,181	2,210	6.1%	20.6	80,609	51	3,385
27	Mississippi	3,826	1,177	1.7%	7.5	44,685	114	650
28	Minnesota	3,566	1,401	0.8%	11.1	57,630	239	671
29	Arkansas	2,889	653	1.0%	6.1	42,433	118	119
30	Kansas	2,771	1276	1.5%	7.3	49,623	128	336
31	Colorado	2,541	887	0.5%	5.1	50,755	176	148
32	Arizona	2,319	1059	0.7%	6.9	44,473	174	338
33	Nebraska	2,030	817	1.5%	3.9	42,475	67	166
34	Oklahoma	2,005	1093	1.2%	3.6	43,120	126	281
35	Oregon	1,895	440	0.4%	3.7	46,447	161	310
36	Idaho	1,713	528	1.4%	2.4	45,771	45	115
37	Washington	1,585	1527	0.7%	6.0	115,489	230	918
38	Utah	1,467	614	0.9%	8.0	36,813	120	231
39	Wyoming	1,029	752	3.9%	2.0	57,813	23	38
40	Rhode Island	847	139	0.4%	2.2	41,975	68	63
41	Nevada	421	125	0.2%	1.4	44,941	69	101
42	New Hampshire	404	189	0.4%	1.4	50,752	55	84
43	Maine	379	181	0.5%	1.6	46,074	50	52
44	New Mexico	314	101	0.2%	0.9	33,893	41	46
45	Alaska	n/a	66	0.2%	0.3	78,972	6	4 6
46	District of Columbia	n/a	101	0.2%	0.2	n/a	0	100
47	Hawaii	n/a	77	0.2%	0.5	39,272	17	8
48	Montana	n/a	53	0.2%	0.6	40,030	49	36
49	North Dakota	n/a	11	0.1%	0.0	30,506	13	23
50	South Dakota	n/a	20	0.1%	0.3	30,635	24	14
51	Vermont	n/a	63	0.3%	0.8	37,078	18	105
	Total U.S.	**451,580**	**193,135**	**2.0%**	**1,021.9**	**67,409**	**13,382**	**71,572**

* Gross State Product.

** Exports by state are on an SIC basis, and do not include exports from unidentified states, thus they do not match the national total $80.2 billion.

Sources: Bureau of the Census, Bureau of Economic Analysis, Bureau of Labor Statistics.

State Chemical Statistics (Ranked by Value of 2000 Shipments) – Continued

APPENDIX I

FLOW DIAGRAMS
FOR SELECTED CHEMICAL PROCESSES

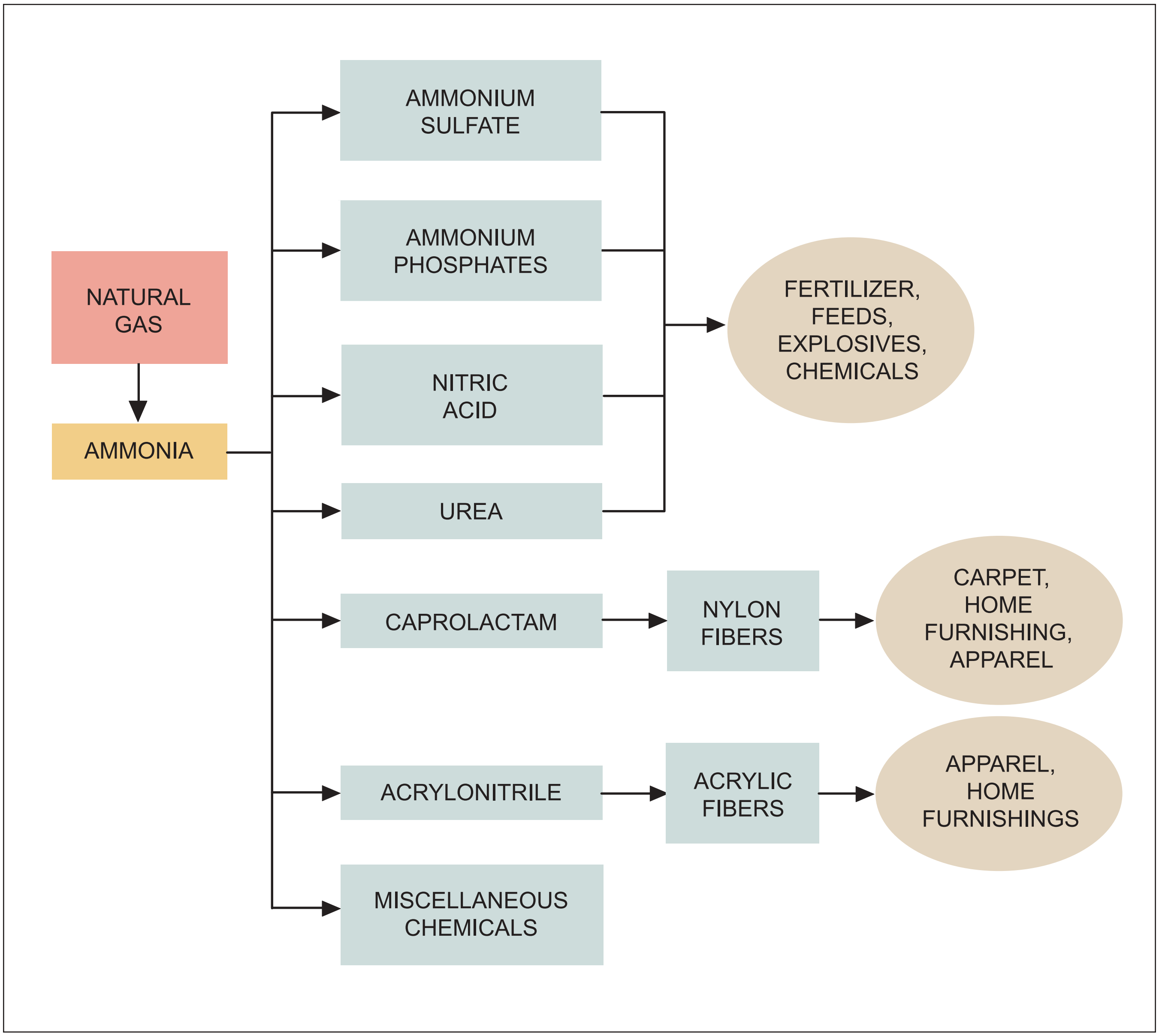


Figure I-1. Ammonia Value Chain

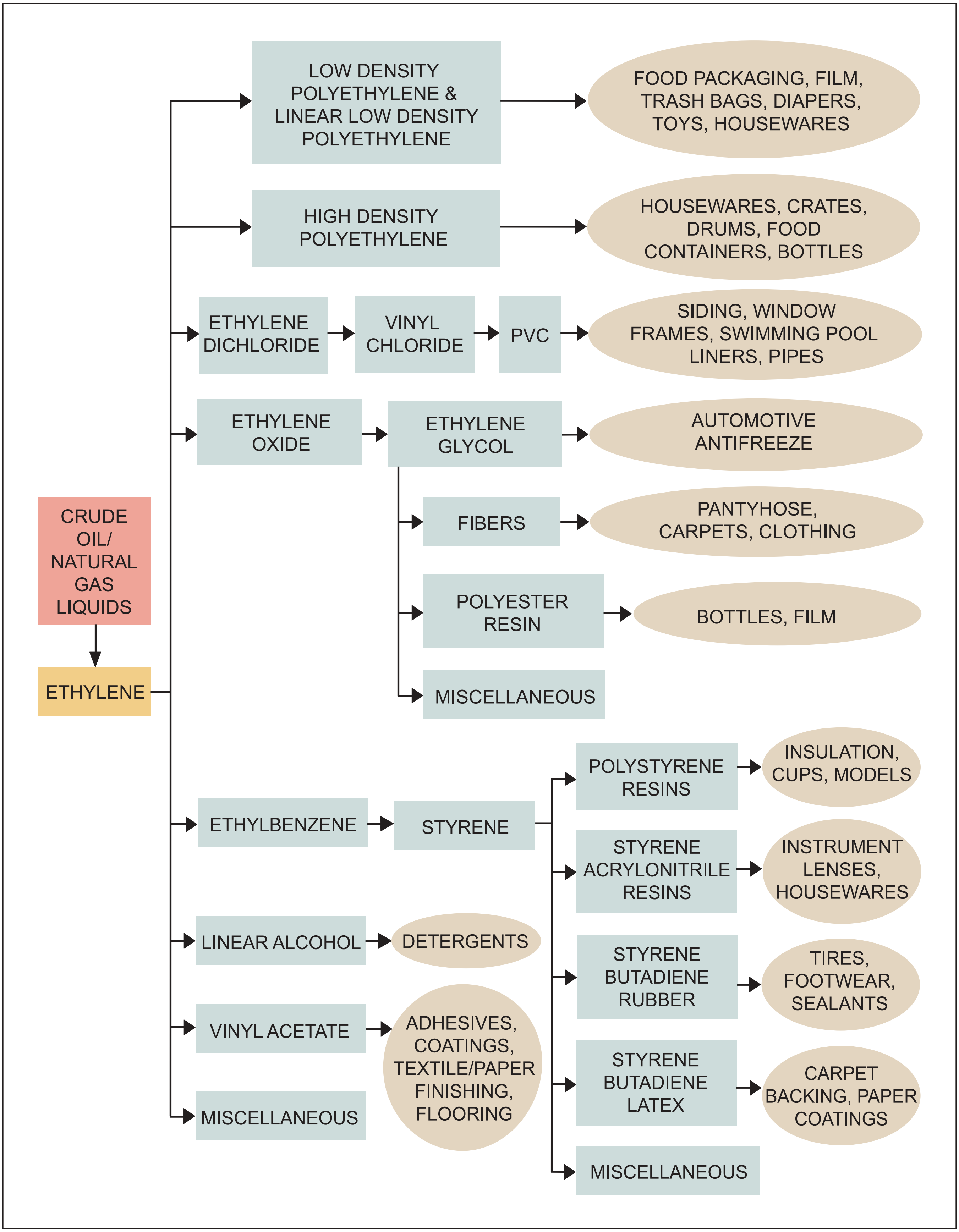


Figure I-2. Ethylene Value Chain

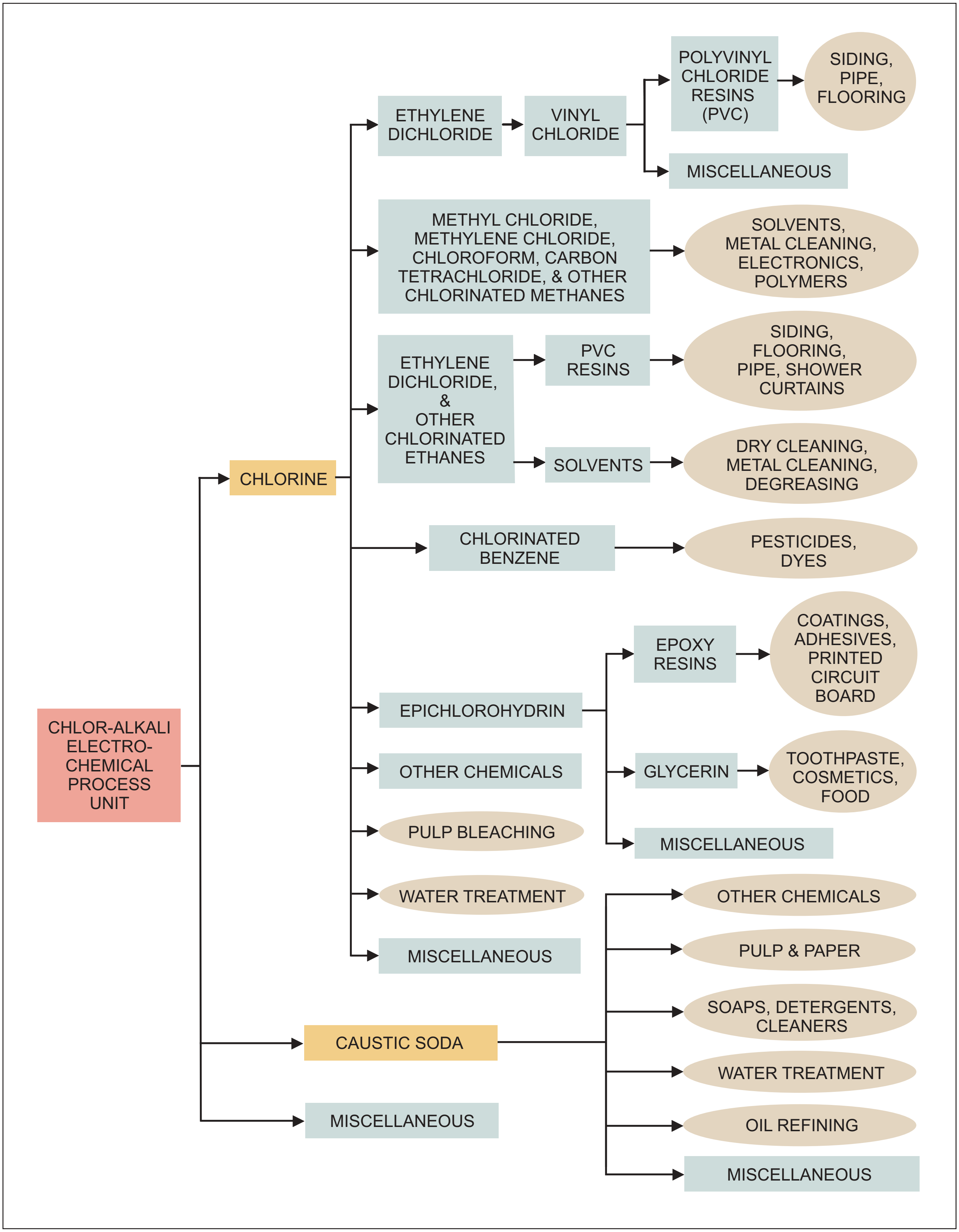


Figure I-3. Chlor-Alkali Value Chain

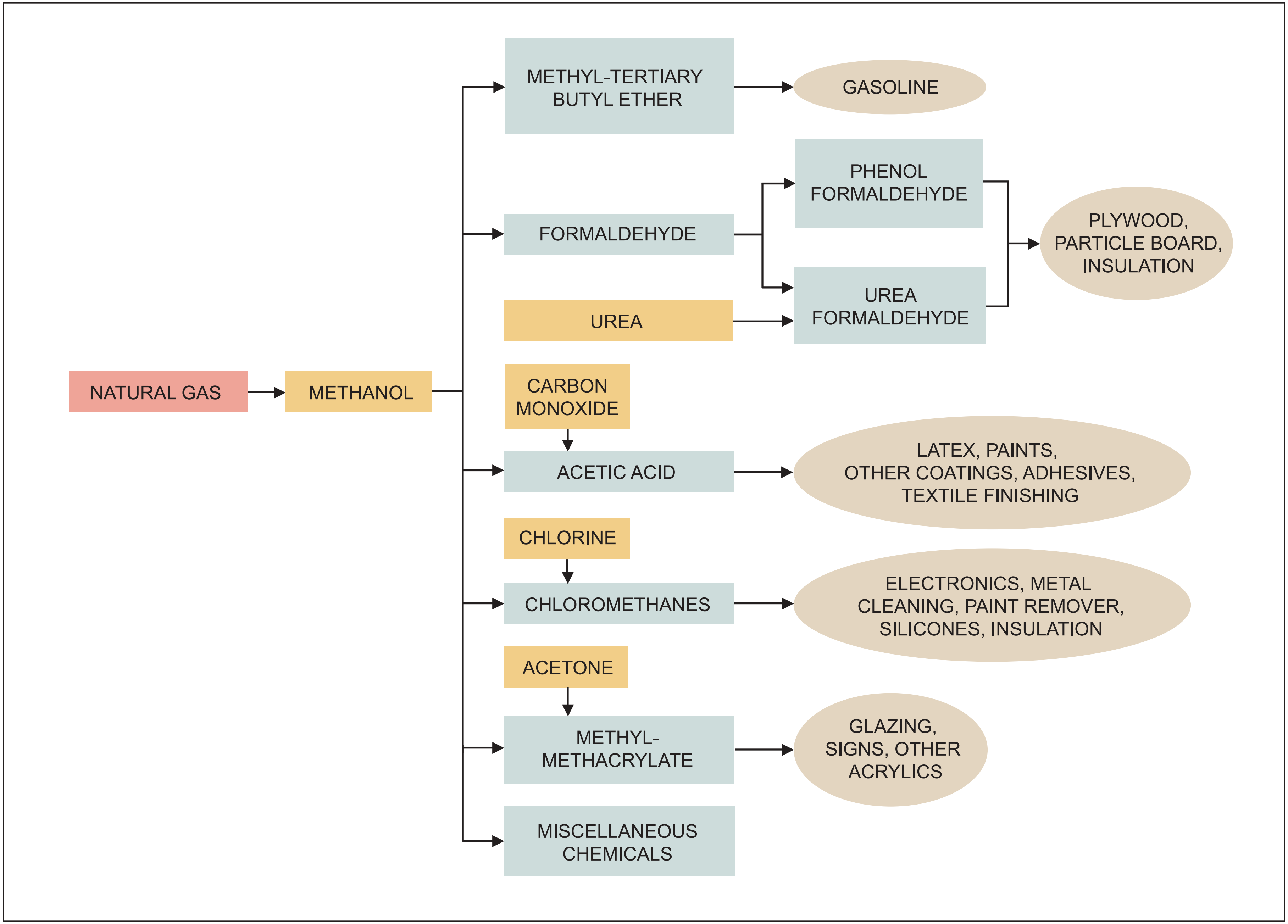


Figure I-4. Methanol Value Chain

APPENDIX J

SUMMARY OF COGENERATION PROCESS AND APPLICATIONS

Physical Configuration

Cogeneration systems (also known as combined heat and power systems, or CHP) produce electricity or mechanical power and capture recoverable heat that is otherwise discarded from conventional power generation to produce thermal energy. This energy is used to provide cooling or heating for industrial facilities, district energy systems, and commercial buildings.

By recycling this waste heat, CHP systems achieve typical effective electric efficiencies of 50% to 70% – a dramatic improvement over the average 33% efficiency of conventional fossil-fueled power plants.

Most new cogeneration plants typically consist of a combination of gas turbines, steam turbines, and heat recovery boilers using natural gas as fuel. Cogeneration can also be done with fired boilers and steam turbines using any fuel. A brief discussion follows on gas turbine-based cogeneration, as illustrated schematically in Figure J-1.

- The process begins when natural gas is burned in the gas turbine.
- The gas turbine drives an electrical generator to produce electricity, and also produces high-temperature air.
- High-temperature air is converted to high-pressure steam in a heat recovery boiler.
- High-pressure steam drives a steam turbine that produces more power. In addition, a significant portion of this steam is extracted from the steam turbine at lower pressures to supply other process energy requirements.
- Cogeneration can also be used for the creation of direct mechanical energy (to drive a compressor for example).

Cogeneration systems can also be configured with a fired steam boiler and steam turbine. Steam may go to process directly from the boiler, though it is more efficient to extract steam off the steam turbine at lower pressures and send it to process. Figure J-2 illustrates cogeneration with a steam boiler, and Figure J-3 shows how cogeneration can occur in a combined-cycle configuration.

Alternatives/Fuel Switching

Cogeneration systems with fired boilers can use a wide variety of fuels, including solids, liquids and gases. Cogeneration systems with gas turbines typically burn natural gas, although gas turbines can also be configured to burn liquid fuels as well. Sometimes byproduct fuel gases are combined with the natural gas. Dual-fuel liquid and gas capability is also available. The majority of both fired-boiler and gas turbine cogeneration systems in the United States for the process industries, however, burn natural gas. The additional costs of liquid fuel burning equipment and maintenance coupled with environmental permitting restrictions, have limited the use of liquid and solid fuel burning in cogeneration applications. On-site purchases of energy by the chemical industry, as reported by the American Chemistry Council, includes a relatively small percentage of liquid or solid fuels purchased for all energy use. As a result of investment

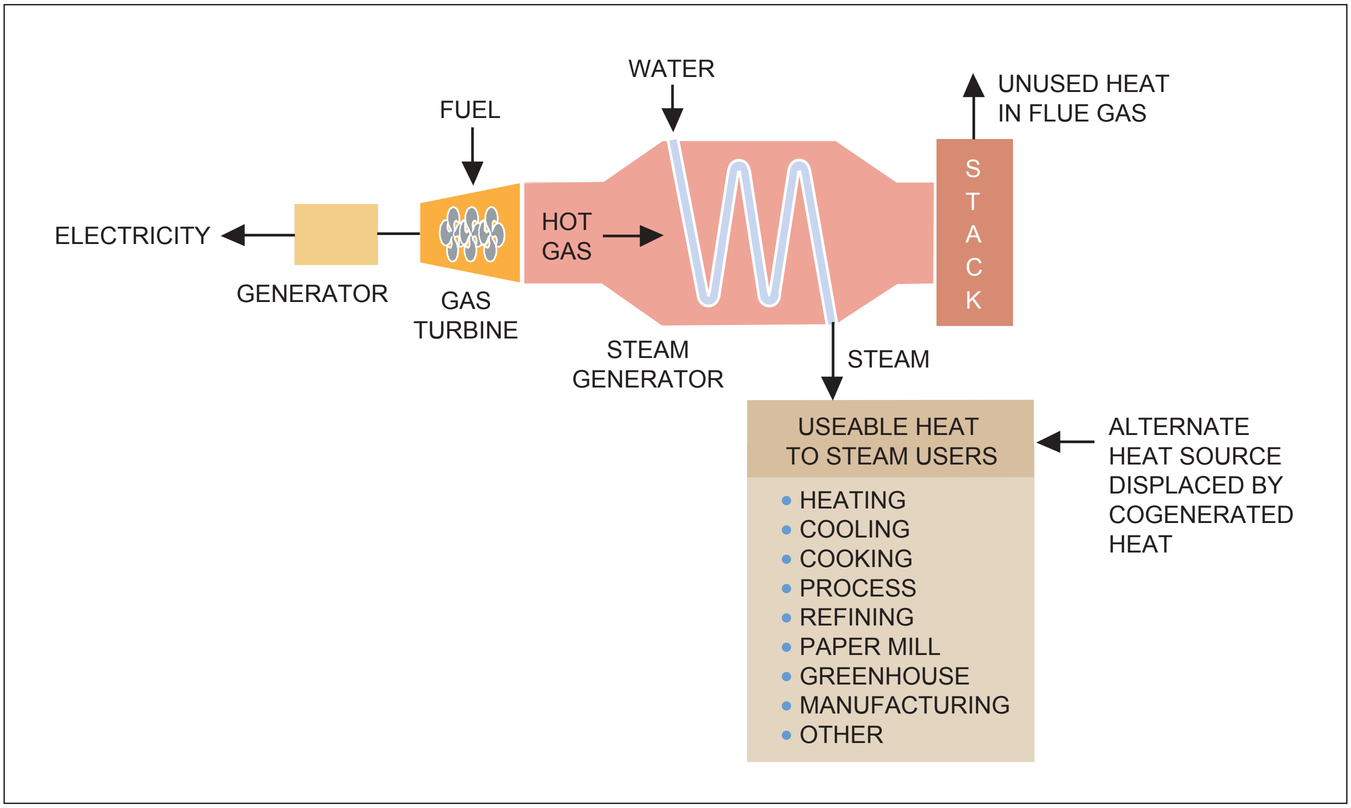


Figure J-1. Combustion Turbine-Based Cogeneration

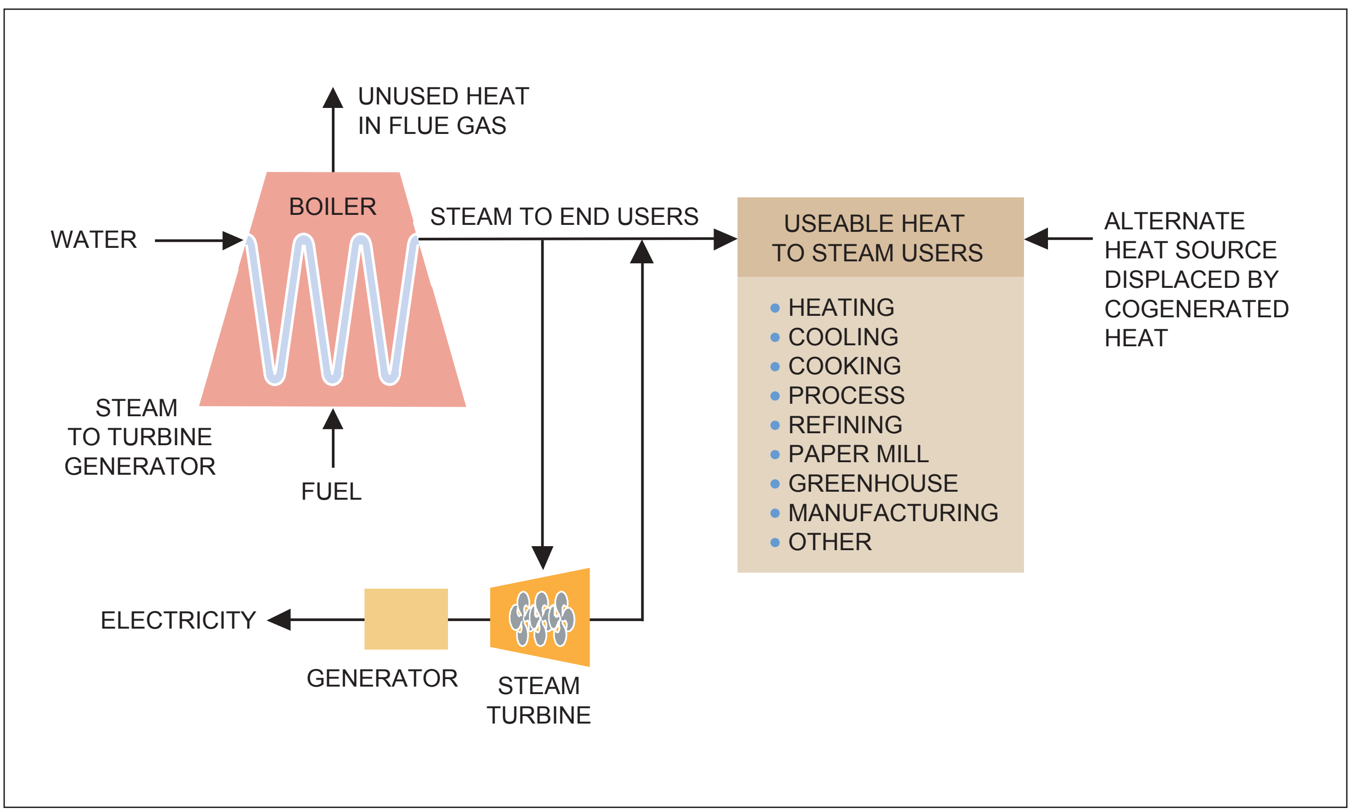


Figure J-2. Steam Turbine-Based Cogeneration

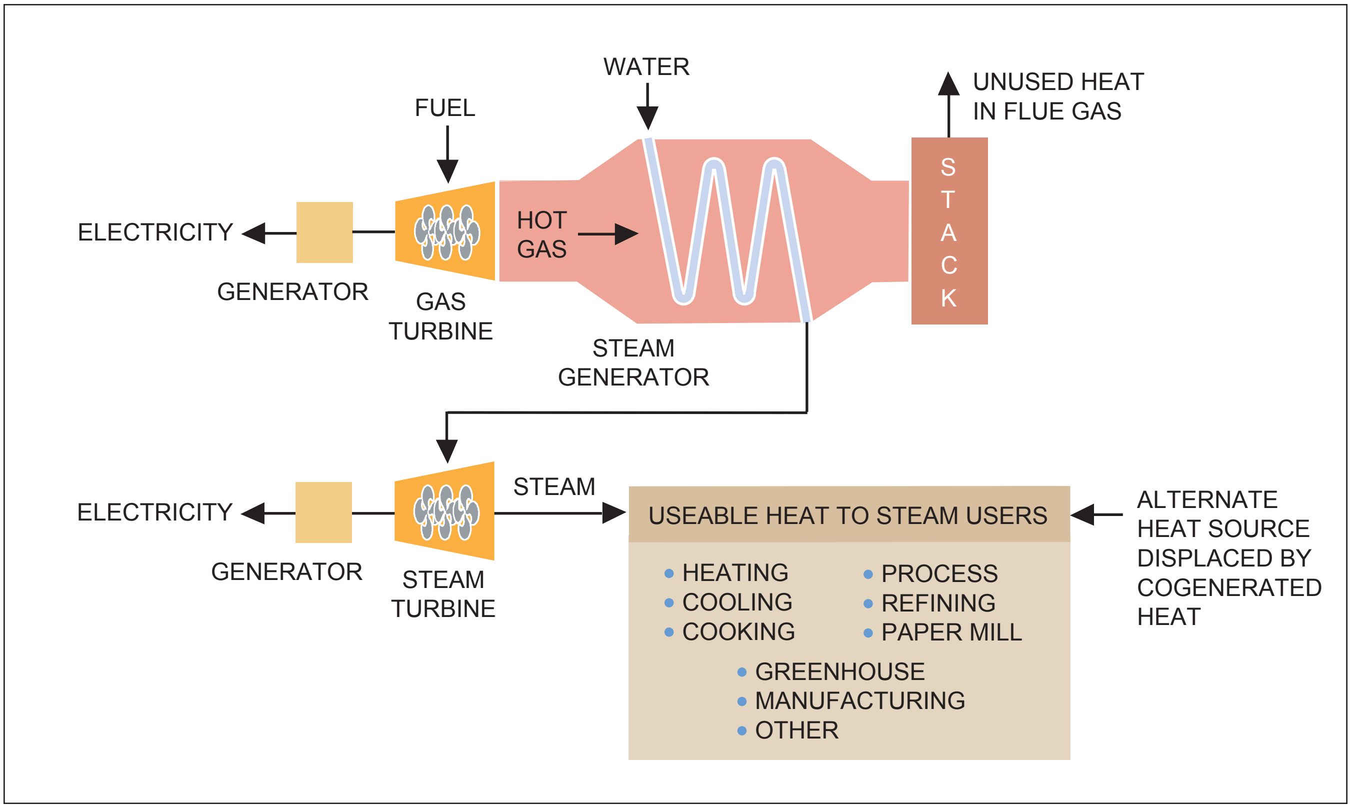


Figure J-3. Combined Cycle-Based Cogeneration

decisions leading to little fuel switching, coupled with the additional costs and permit restrictions, there is very little fuel switching available in the chemical industry today.

Data from the Energy Information Administration, 1998 Manufacturers Energy Consumption Survey (MECS) provides some additional information on cogeneration and fuel use in the chemical industry (Energy Information Administration "Energy Use in Manufacturing," 1998 data tables), as follows:

- For NAIC Code 325, which includes the general category of Chemicals manufacturing, there were 8, 962 establishments in this category. Of this number, 494 had some form of cogeneration in use at the facility.
- Of those chemical facilities that had on-site generation, cogeneration accounted for 43,496 Million kWh of generation or approximately 95% of all on site generation.
- Total demand for electricity from Chemical Facilities was 215,008 Million kWh, so cogeneration represented about 20% of total electrical demand served.

Technology/Conservation/Efficiency

Over the last 20 years there has been a significant improvement in combined cycle gas turbine power plant efficiencies. Heat rates under 7,000 Btu/kWh (HHV) are possible with the largest gas turbine trains, compared to over 8,000 Btu/kWh a decade or so ago. Extracting steam from the steam turbine for process, as shown in Figure J-3, uses improves the cycle energy efficiency even more. Without major changes in blade material technology, incremental improvements in energy efficiency for gas turbines will be smaller than what we have experienced recently.

Steam turbine efficiencies have seen some moderate improvements recently due to improved turbine blade design and metallurgy, although the gains have been less than the gas turbines.

Although the technology may be maturing for the moment, there are still numerous opportunities for cogeneration to be implemented by industrial consumers to improve energy efficiency. The American Council for an Energy Efficient Economy, in a May

1999 report, stated that industrial cogeneration was likely to not develop much more unless barriers were removed. These barriers generally involve permitting and other regulatory hurdles and interactions with transmission companies when cogenerators attempt to connect to the transmission grid.

APPENDIX K

POWER TECHNOLOGIES
AND MODEL INPUT CRITERIA

This appendix is broken into two areas. First, Table K-1 is a blank table that was used to solicit expert opinion on a number of technology, efficiency, and environmental issues that were incorporated into the modeling effort. No attempt is made within this appendix to summarize the range of results of this Delphic process; the results are incorporated into the assumptions that have been fully detailed within the body of the report. Second, Table K-2 shows a comprehensive list of generating technologies that were included in the generation new build logic, along with their cost and efficiency over time.

	Likely to Emerge		Earliest	Large Gas Effect		% Gas	
TECHNOLOGY	Yes	No	Date	Yes	No	Change	Comments
DSM/Lighting/Heat Pumps							
Xmsn/Superconductivity							
Fuel Cells							
Hydrogen Economy							
Env. Technology							
Water Desalination							
Resid-fired CC improvements							
ENVIRONMENTAL/MARKET POLICIES							
ENVIRONMENTAL							
New Builds							
Conventional Coal w/Scrubber/NOx Control							
IGCC Coal							
Coal Other							
Advanced Nuclear							
Oil Combined Cycle							
Oil/Gas Switchable CC							
Distillate							
Resid							
Tax Credits for Wind							
New Hydro							
Major Projects							
Lowhead Dams							
Solar							
Environmental Policies							
Clear Skies							
NOx							
SOx							
Hg							
New Source Review							
Fine Particulates							
Regional Haze BART							
Carbon Scenarios							
Full Kyoto							
2000 Stabilization with Cap and Trade							
2005 Stabilization with Cap and Trade							
State Carbon Controls							
Local Carbon Controls							
Market Issues and Policies							
Implementation of SMD							
Rollback of wholesale deregulation							
Rollback of retail deregulation							

Table K-1. Technology/Environmental/Market Considerations

	Conventional Pulverized Coal w/ Scrubber	Coal IGCC Greenfield /1	Coal IGCC Brownfield /1	Super Critical Pulverized Coal w/Scrubber and SCR	Gas Combined Cycle	Low Sulfur Diesel Combined Cycle	Distillate Combined Cycle	E-Class Residual Oil Combined Cycle w/ Scrubber and SCR	Gas Combustion Turbine	Low Sulfur Diesel Combustion Turbine	Advanced Nuclear	Renewable (Wind) /6	Residual Oil Combined Cycle
Lead Time (Years)													
Development (years)	3.5	3	2	3.5	1	1.5	2	2	0.5	1.25	5		1
Construction (years)	3.5	3	3	3.5	2	2	2	2	1	1.25	5		2
Total Lead Time (years) /2	7	6	5	7	3	3.5	4	4	1.5	2.5	10	3	3
Construction Period Carrying Cost (equity and debt) added to installed book value % of overnight	28.2%	20.9%	19.6%	28.2%	11.9%	11.9%	12.8%	12.8%	4.8%	5.9%	89.2%	11.9%	
Contingency Factor (%) /3											20%	10%	7%
Total Installed Costs with financing during construction and contingencies where applicable ($2002/KWH)	1,200	1,400	1,400	1,250	600	600	670	800	350	400	1,500	1,100	642
Variable O&M ($2002/KWH)	0.0020	0.0025	0.0025	0.0020	0.0015	0.0025	0.0029	0.0031	0.0070	0.0079	0.0010	0.0000	0.0045
Fixed O&M ($2002/KWH)	20.00	55.00	55.00	20.00	16.00	18.00	20.70	33.28	8.00	10.00	55.00	30.00	21.00
Derated Heat Rate of Unit Built in 2002 (Btu/KWH) HHV/4	9,500	9,500	9,500	8,800	7,200	7,600	7,800	8,200	11,000	11,660	10,500	0	7,920
Derated Heat Rate of Unit Built in 2010 (Btu/KWH) HHV/4	9,300	9,000	9,000	8,600	6,800	7,200	7,400	8,100	10,000	10,600	10,500	0	7,480
Derated Heat Rate of Unit Built in 2020 (Btu/KWH) HHV/4	9,300	8,600	8,600	8,600	6,500	7,200	7,400	8,100	10,000	10,600	10,500	0	7,150
Derated Heat Rate of Unit Built in 2030 (Btu/KWH) HHV/4	9,300	8,600	8,600	8,400	6,500	7,200	7,400	8,100	10,000	10,600	10,500	0	7,150
Maximum Capacity Utilization (Annual Average %) /5	85%	90%	90%	85%	92%	90%	88%	70%	15%	15%	92%	30%	75%
Useful Life (Max = 40)	35	30	30	35	30	30	30	30	30	30	35	30	30
Economic Life	25	20	20	25	20	20	20	20	20	20	30	20	20
Debt in Capital Structure	55%	55%	55%	55%	55%	55%	55%	55%	45%	45%	50%	55%	55%
Debt Cost	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	10%	8%	8%
Equity in Capital Structure	45%	45%	45%	45%	45%	45%	45%	45%	55%	55%	50%	45%	45%
Equity Cost	16%	16%	16%	16%	14%	14%	14%	14%	14%	14%	15%	14%	14%
Capital Recovery Factor (Economic Carrying Cost, to be increased by Capacity Value Escalation if used in nominal models)	12.7%	12.9%	12.9%	12.7%	11.7%	11.7%	11.7%	11.7%	12.8%	12.8%	13.7%	11.7%	11.7%

1. For IGCC, Capital Costs excludes the costs of an Air Separation Unit (ASU), heat rate includes the ASU power requirememts. ASU capital recovery and operating costs are includes in IGCC operating costs.
2. Number of years from the time the plant is ordered until it is on-line.
3. The contingency factor accounts for construction cost variances, plus a risk factor for technologies that are not currently commercial in the U.S. (i.e, advanced nuclear and coal gasification).
4. Forecast heat rate for vintage 2010, 2020, and 2030 units.
5. Estimate annual capacity utilization for a new unit, based on economic and technical operating limits for each unit type.
6. Wind turbines have the most favorable cost and performance characteristics of all currently available non-hydro renewable technologies.

Table K-2. Capacity Planning Assumptions

ACRONYMS AND ABBREVIATIONS

AEO	EIA's Annual Energy Outlook
AEUB	Alberta Energy and Utilities Board
AFUE	annual fuel utilization efficiency
AGA	American Gas Association
ANGTA	Alaska Natural Gas Transportation Act of 1976
ANGTS	Alaska Natural Gas Transportation System
ANWR	Arctic National Wildlife Refuge
API	American Petroleum Institute
BACT	Best Available Control Technology
BCF	billion cubic feet
BCF/D	billion cubic feet per day
BLM	U.S. Bureau of Land Management
Btu	British thermal unit
CAPP	Canadian Association of Petroleum Producers
CC/CT	combined cycle/combustion turbine
CCGT	combined-cycle gas turbines
CEQ	Council on Environmental Quality
CERI	Canadian Energy Research Institute
CFE	Comision Federal de Electricidad (Mexico's Federal Electricity Commission
CFTC	Commodity Futures Trading Commission
CGPC	Canadian Gas Potential Committee
CHP	combined heat and power
CO2	carbon dioxide
COAs	conditions of approval
CRE	Comision Reguladora de Energia (Mexico's Energy Regulatory Commission)
CSS	cyclic steam stimulation
CZM	Coastal Zone Management
D&C	drilling and completion
DG	distributed generation
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
E&P	exploration and production
EEA	Energy and Environmental Analysis, Inc.
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency

EPCA	Energy Policy Conservation Act of 1975
ERCOT	Electric Reliability Council of Texas
EUR	estimated ultimate recovery
FCC	fluid catalytic cracking
FERC	Federal Energy Regulatory Commission
FPC	Federal Power Commission (forerunner of FERC)
FTC	Federal Trade Commission
GDP	gross domestic product
GIIP	gas initially in place
GIP	gas in place
GMDFS	EEA's Gas Market Data and Forecasting System
GOM	Gulf of Mexico
GRI	Gas Research Institute
GSR	EEA's Gas Supply Review
GW	gigawatts
GWH	gigawatt hours
HCI	hydrocarbon indicator
HSM	EEA's Hydrocarbon Supply Model
HVAC	heating-ventilation-air conditioning systems
IECC	International Energy Conservation Code (superceded Model Energy Code in 1998)
IHS	IHS Energy Group
INGAA	Interstate Natural Gas Association of America
IP	industrial production
IP	initial production rate
ISTUM-2	Industrial Sector Technology Use Model
JAS	API's Joint Association Survey
KW	kilowatts
KWH	kilowatt hours
LDC	local distribution company
LIHEAP	Low Income Home Energy Assistance Program
LNG	liquefied natural gas
LSE	load serving entity
MACT	Maximum Achievable Control Technology
MCF	thousand cubic feet
MECS	EIA's Manufacturing Energy Consumption Survey
MEPS	Minimum Energy Performance Standards
MM	million
MMBtu	million British thermal units
MMCF	million cubic feet
MMCF/D	million cubic feet per day
MMS	Minerals Management Service
MOU	memorandum of understanding
MSC	Multiple Services Contract
MTA	million tons per annum
MTBE	methyl tertiary butyl ether
MW	megawatts
MWH	megawatt hours
NAECA	National Appliance Energy Conservation Act of 1987 and amendments of 1988
NAICS	North American Industry Classification System
NEB	National Energy Board of Canada

NECPA	National Energy Conservation Policy Act of 1978
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NGL	natural gas liquid
NGPA	National Gas Policy Act of 1978
NGV	natural gas vehicle
NOx	nitrogen oxides
NOAA	National Oceanic and Atmospheric Administration
NPC	National Petroleum Council
NPRA	National Petrochemical & Refiners Association
NPRA	National Petroleum Reserve, Alaska
NSR	EPA's New Source Review
NYMEX	New York Mercantile Exchange
OCS	Outer Continental Shelf
O&M	operation and maintenance
Pemex	Petroleos Mexicanos
PIFUA	Powerplant and Industrial Fuel Use Act of 1978
POLR	provider of last resort
PSA	EIA's Petroleum Supply Annual
PSAC	Petroleum Services Association of Canada
psi	pounds per square inch
PUC	public utility commission
PURPA	Public Utility Regulatory Policies Act of 1978
quads	quadrillion Btu
RACC	refiner acquisition cost of crude oil
R&D	research and development
REC	Renewable Energy Credit (or Certificate)
RFG	reformulated gasoline
ROE	return on equity
R/P	reserves to production (ratio)
RTOs	Regional Transmission Organizations
RPS	Renewable Portfolio Standards
SAGD	steam-assisted gravity drainage
SEDS	EIA's State Energy Data System
SENER	Secretaria de Energia (Mexico's Energy Ministry)
SIC	Standard Industrial Classification
SIP	state implementation plan
SOLR	supplier of last resort
SOx	sulfur oxides
SO_2	sulfur dioxide
TAPS	Trans-Alaska Pipeline System
TCF	trillion cubic feet
TRC	tradable renewable certificates
TW	terawatts
TWH	terawatt hours
USGS	United States Geological Service
WCSB	Western Canada Sedimentary Basin
WTI	West Texas Intermediate crude oil

GLOSSARY

Access
The legal right to drill and develop oil and natural gas resources, build associated production facilities, and 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. Development of these reservoirs can require different technologies than 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.

Terawatts

One trillion watts.

Watt

The common U.S. measure of electrical power.