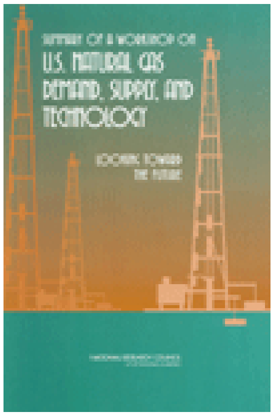

Summary of a Workshop on U.S. Natural Gas Demand, Supply, and Technology: Looking Toward the Future

Committee on U.S. Natural Gas Demand and Supply Projections: A Workshop

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SUMMARY OF A WORKSHOP ON U.S. NATURAL GAS DEMAND, SUPPLY, AND TECHNOLOGY

LOOKING TOWARD THE FUTURE

Committee on U.S. Natural Gas Demand and Supply Projections:
A Workshop

Committee on Earth Resources

Board on Earth Sciences and Resources

Division on Earth and Life Studies

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Acknowledgments

This workshop summary has been reviewed by individuals chosen for their diverse perspectives and technical expertise in accordance with procedures approved by the National Research Council's (NRC) Report Review Committee. The purpose of this independent review is to provide candid and critical comments that will assist the authors and the NRC in making their published summary as sound as possible and to ensure that the summary meets institutional standards for objectivity, evidence, and responsiveness to the study charge. The content of the review comments and the draft manuscript remain confidential to protect the integrity of the deliberative process. We wish to thank the following individuals for their participation in the review of this summary:

Tom Bates, Lime Rock Partners
James T. Jensen, Jensen Associates
Richard Nehring, NRG Associates
Greg Stringham, Canadian Association of Petroleum Producers
Robert J. Weimer, Colorado School of Mines (*emeritus*)

Although the individuals listed above provided many constructive comments and suggestions, they did not see the final summary before its release. The review of this summary was overseen by David L. Bodde, Henry W. Block School of Business, University of Missouri. Appointed by the NRC, he was responsible for making certain that an independent examination of this summary was carried out in accordance with institutional procedures and that all review comments were carefully considered. Responsibility for the final content of the summary rests entirely with the authoring committee and the NRC.

Preface

Committee members John Curtis, James Emme, Vello Kuuskraa, and Dianne Nielson and National Research Council staff members Tammy Dickinson, Monica Lipscomb, and Karen Imhof were fundamental in developing the workshop agenda, identifying speakers, running the workshop, and writing this report. It was a great team effort. My thanks to each of them.

For 150 years, U.S. energy consumption trends have led global energy consumption trends. Those trends indicate that the future of energy is most likely a hydrogen and solar future utilizing technology that today may not even exist. As we transition toward the future, a mix of known energy sources—coal, oil, natural gas, nuclear, hydro, and other renewables—will be required over the next 100 years to meet global energy demands. Certainly there is a global supply of coal for the next century that can be burned for electricity and gasified for transportation fuel if policy so directs. Similarly, there is a global supply of cleaner and more efficient natural gas for the next 100 years, which in addition to being burned as a direct energy source could provide feedstock for hydrogen if policy so supports.

Recognizing that fossil fuels supply 85 percent of the world's energy needs today, that the world has been steadily progressing away from solid and liquid forms of fossil energy toward natural gas, nuclear, and renewable energy, and that all fossil fuels are only an energy bridge to the next century, it is important to determine the best mix of fossil energy sources for the economy, health, and well-being of our planet during the present century. In that context, energy and the environment should be conjunctive terms, and reasonable compromises—guided by good science and good application of technology—should be made to transition sensibly toward the 22nd century.

Scott W. Tinker, *Chair*

Contents

Summary

Nobel laureate and workshop keynote speaker Richard Smalley believes that energy leads the list of humanity's most important issues, which include water, food, the environment, poverty, terrorism and war, disease, education, democracy, and population (Richard Smalley, Rice University, personal communication, 2003). And although there is a very predictable and long-term decarbonization of the world's energy sources—from coal, to oil, to natural gas, and eventually to hydrogen—the United States today, and for the foreseeable future, will remain dependent on fossil fuels to satisfy on the order of 85 percent of its energy demand (EIA, 2001a). Because natural gas represents a growing proportion of the global fossil energy mix, accurately projecting natural gas supply and demand is critical. In this context, according to some workshop participants, key efforts in achieving the most efficient use of natural gas resources are (1) creating the proper mix of access and incentives to encourage efficient and environmentally sound exploration and production activities, (2) designing a strategic private-public partnership to foster the innovative research and technology development that are fundamental to meet long-term U.S. energy demand, and (3) encouraging the infrastructure development to create a global natural gas transportation network that will be required for increased use of natural gas.

The National Research Council, under the auspices of the Committee on Earth Resources of the Board on Earth Sciences and Resources, was requested by the U.S. Department of Energy, the Minerals Management Service, and the U.S. Geological Survey (USGS) to host a workshop to address projections for the supply of and demand for natural gas over the next 10 to 20 years and methods of increasing reserves and production. The workshop, held on April 21, 2003, in Washington, D.C., addressed three questions: (1) What projections have been made by government agencies for the U.S. supply of and demand for natural gas over the next 10 to 20 years? (2) Where are the current natural gas reserves and resources? (3) By what means and by how much can future reserves, resources, and production be increased? The workshop included participants from academia, industry, federal and state government agencies, and non-profit organizations.

This workshop summary is not a comprehensive report on natural gas but rather a synopsis of the presentations and discussions at the workshop. There are many important and timely topics related to natural gas supply and demand that were not discussed at the workshop. These include but are not limited to (1) factors that influence private-sector investment in natural gas, (2) natural gas transportation infrastructure and pipeline capacity, (3) natural gas storage, (4) significant environmental benefits of natural gas over other fossil fuel energy sources, (5) the impact of U.S. policy on perturbing the global trends of decarbonization of energy sources, (6) the impact on the U.S. and global economies of a transition to a natural gas economy, (7) carbon sequestration, (8) the national security effects of a U.S. transition to natural gas, and (9) a review of the EIA models. This summary does not contain any conclusions and recommendations.

By design the workshop focused on natural gas demand and factors that cause uncertainty in demand, North American supply estimates and variability in those estimates, natural gas resource and reserves, and ways to meet future U.S. natural gas demand—especially through technology and liquefied natural gas (LNG) transportation. Several additional issues were brought forward during the workshop, including (1) the impact of tax incentives and royalties on the natural gas supply, (2) the growing need for research and technology as the natural gas resource base becomes increasingly unconventional, (3) the significant decrease in private-sector research and development funding, (4) the need for new federal-private research and technology models, and (5) the significant decline in the number of graduate students enrolled in geosciences and petroleum engineering who will be available to replace retiring workers over the next decade as the oil and gas industry faces the loss of well over half its technical workforce.

In terms of U.S. natural gas consumption, some workshop participants projected an overall increase in the next 5 years, owing largely to an anticipated rebound in industrial production and continued growth in new natural gas-fired electric power plants. They also discussed the longer-term outlook for natural gas, which will depend on its affordability by the industrial sector, its competitive position for new power facilities, the energy conservation and efficiency response to higher gas prices, price volatility, and the creation of a global transportation and storage network. In addition, proposed and pending energy policies, such as the Bush Administration's Clear Skies Initiative, and international pressures for addressing carbon emissions and global climate change will further influence the demand for and price of natural gas. Consumption of natural gas is projected by the Energy Information Administration (EIA, 2003a) to grow from 22.4 trillion cubic feet (Tcf) in 2002 to 27.1 Tcf in 2010 and to 34.9 Tcf in 2025. This rate equates to an average annual increase in natural gas consumption of 2 percent per year and is faster than the expected growth in overall primary energy consumption. The bulk of the increase is from electricity generation as the share of natural gas in this market, assuming natural gas is available at moderate prices, is expected to increase from 17 percent in 2001 to 29 percent in 2025 (EIA, 2003a).

Committee members and participants noted that workshop assessments of the future supply of natural gas in North America sent somewhat mixed signals. Some workshop participants believe (1) that the United States will continue to require increasing amounts of imported natural gas to meet projected demand; (2) that Canada will increase its domestic consumption, with little excess export capacity beyond that of the present day; and (3) that Mexico will most likely remain a net importer of natural gas. LNG imports—and perhaps natural gas hydrates in the longer term—will most likely be required to augment the North American natural gas supply. Participants also thought the accuracy of the supply assessment is limited by (1) perception and understanding of the origin and occurrence of the resource, (2) the quality and distribution of available data with which to conduct the estimates, and (3) the methods used in the assessment. Owing to these variables, a range of assessment values as opposed to a single number could be expected.

Total assessed gas resources for the United States have been increasing over the past 20 years owing to (1) an improved understanding of the phenomenon of reserve appreciation or reserve growth whereby gas (and oil) fields ultimately produce three to nine times the amounts initially estimated by standard engineering techniques; (2) an understanding of the potential for new "plays"*; and (3) an evaluation of the role of current and advanced technologies in gas exploration and production (Thomas Ahlbrandt, USGS, personal communication, 2003). A total of 1,289 Tcf of

*A play is a group of prospects and any related fields having common oil or gas sources, migration relationships, reservoir formations, seals, and trap types. The prospects thus share any common elements of geological risks (White, 1992).

technically recoverable resources has been reported for the United States by the Energy Information Administration, using predominantly USGS and Minerals Management Service data, with proven reserves accounting for 14 percent of the remaining U.S. resource (Mary Hutzler, EIA, personal communication, 2003). Unconventional natural gas—comprising tight (low-permeability) sands and carbonates, fractured shale gas, and coalbed gas—accounts for 34 percent of remaining U.S. resources (Mary Hutzler, EIA, personal communication, 2003). Controversy exists, however, as to the size and geological nature of the tight sands gas resource in the U.S. Rocky Mountains region, where the bulk of the assessed unconventional gas is thought to reside (Ben Law, Pangea Hydrocarbon Exploration, personal communication, 2003; Keith Shanley, Stone Energy, personal communication, 2003). The remaining potential global supply of natural gas is more than 13,000 Tcf according to USGS (2000) assessments. Undiscovered natural gas is concentrated in the former Soviet Union, the Middle East, and North Africa. Known reserves account for 35 percent of the remaining potential supply.

Workshop discussion focused on ways to meet projected demands and to counter natural gas price increases and volatility in the United States, including the need for an educated and trained workforce; access to off-limits lands; increased natural gas storage capacity; a global transportation infrastructure, especially for offshore production and imports; more efficient and competitive fiscal and regulatory regimes; and rapid technological improvements—with emphasis on the development of unconventional reservoirs and conventional deepwater and frontier resources. Rapid technological improvements—which in the past two decades have served to create unconventional gas reserves such as tight gas, shale gas, and coalbed gas—have historically relied on large private-sector investment. In terms of future unconventional natural gas resources, workshop participants also discussed the need for investment in research and development, including a greater proportion of federal investment than in the past.

Until pipeline and LNG transportation projects are put in place and natural gas storage solutions are found, the interplay between factors such as wellhead price, weather, imports, domestic gas rig activity, deliverability of new wells, and availability and cost of external supplies (i.e., pipelines) will continue to result in price and storage volume volatility. New sources of natural gas from Canada via pipelines and globally via LNG appear to be competitive in a sustained \$3.25 per thousand cubic feet (Mcf) or greater price environment.

The workshop was designed to address projections for the supply of and demand for natural gas over the next 10 to 20 years and methods of increasing reserves and production. As noted at the workshop, it seems relevant to recognize that in order to meet global demand all sources of energy will be critical over the next 50 to 100 years as the world transitions out of a fossil fuel energy-dominated economy, including continued (1) production and consumption of coal with positive impacts from advances in "clean coal" technology, (2) renewable and nuclear energy production and associated research, (3) oil consumption and enhanced oil recovery research, and (4) natural gas consumption and associated research and technology development across the upstream-to-downstream natural gas spectrum. According to some workshop participants, because long-term global trends are toward a natural gas economy and away from coal and oil, the issue of meeting natural gas technology needs in the face of decreased private and federal spending on oil and gas research and technology, decreased geoscience and engineering enrollments in graduate schools, and an aging energy company workforce provides a framework for future U.S. policy directions.

1

Introduction

Energy leads the list of humanity's top 10 problems of the next 50 years. Recognized as an important component of the standard of living, energy is required in order to meet other important challenges: water, food, environment, poverty, terrorism and war, disease, education, democracy, and population (Richard Smalley, Rice University, personal communication, 2003).

Fossil fuels account for 84 percent of global and U.S. energy consumption (EIA, 2001a). According to EIA (2001b), the past 20 years have seen a steady and predictable decrease in the percentage of global energy consumption satisfied by oil (from 46 percent to 40 percent) and coal (from 26 percent to 22 percent), and an associated increase in the percentage of global energy consumption satisfied by a combination of natural gas, nuclear, and other renewables (from 28 percent to 38 percent) (see Figure 1.1). During the same period, total global energy consumption increased by nearly 35 percent (from 282 quadrillion British thermal units [Btu] [quads] to 379 quads), and U.S. total energy consumption increased 23 percent (from 78 to 97 quads); (EIA, 2001b). In contrast to global consumption, which shows a trend away from coal and oil to more efficient, abundant, and environmentally sound natural gas, nuclear, and renewables, the U.S. energy consumption mix has remained unchanged for two decades and is at a point today where it is nearly identical to the global energy mix (coal, 22 percent; oil, 39 percent; natural gas, 23 percent [EIA, 2000a]).

Accurately projecting natural gas supply and demand is important for the United States. Historically, world energy consumption has re-

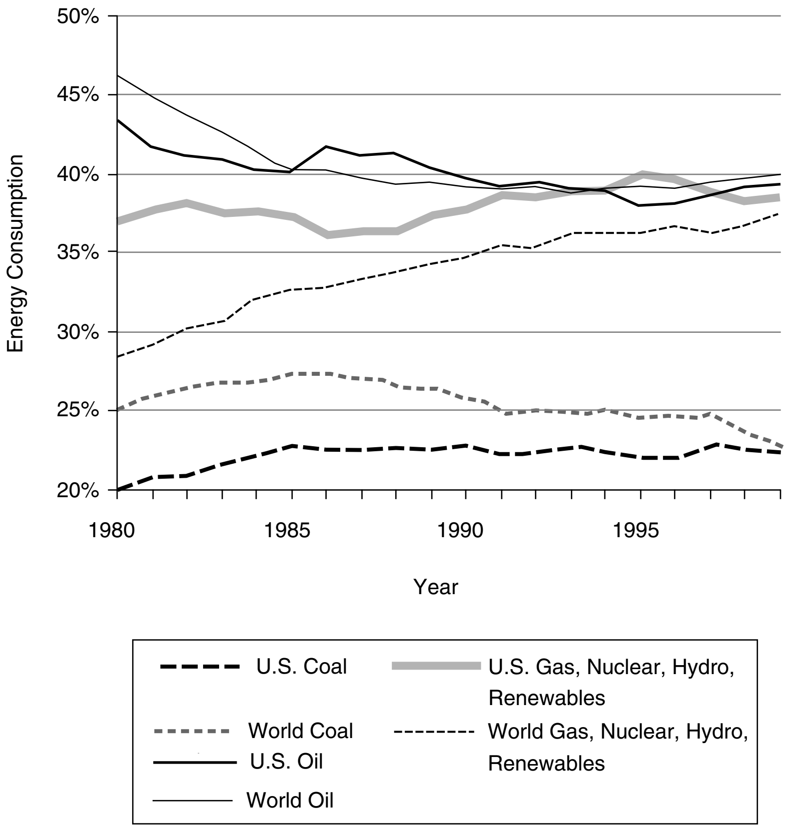

FIGURE 1.1 U.S. and world energy consumption by fuel type. SOURCE: Scott Tinker, University of Texas at Austin, personal communication, 2003. Data are from EIA (2000a, 2001b).

flected a series of carbon-based resource periods, with the predominance of coal and oil in the 20th century evolving to a projected dominance of natural gas in the 21st century (see Figure 1.2). Most workshop participants believe that the longer-term global trend to natural gas is real, although actual U.S. energy consumption data for the mid-1970s to the present show a flattening in coal, oil, and natural gas compared to the curves fit in these 1994 projections. The progression in technology to a methane economy (Fisher, 2002) will result in a cleaner-burning, lower-carbon-emitting (see Figure 1.3), more efficient energy source. However, this will increase demand and put pressure on existing reserves and exploration and production technology.

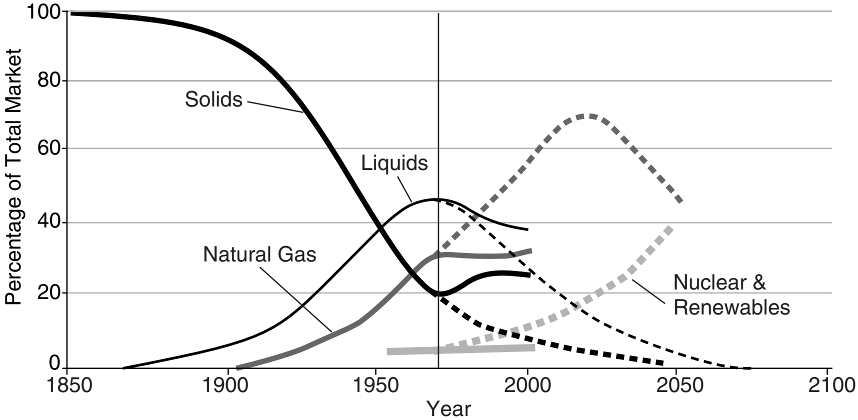

FIGURE 1.2 World primary energy substitution showing evolving resource periods. Dashed lines represent forecast concept of Marchetti and Nakicenovic (1974). Solid lines represent smoothed curves fit to actual data from EIA (2001b). SOURCE: Scott Tinker, University of Texas at Austin, personal communication, 2003. Data are from Marchetti and Nakicenovic (1974).

With a growing population, increased demand for electricity, and improved cost and efficiency of advanced gas combined-cycle generation, the consumption of natural gas by electric generators is expected to more than double over the next two decades (EIA, 2003a). Electricity generation fueled by natural gas and coal is projected to increase through 2020 to meet growing demands for electricity and to offset the projected retirement of existing nuclear units (Ausubel, 1996). The demand for electricity generation is expected to triple between 1999 and 2020. As a result, the overall demand for natural gas in the United States is projected to grow by an average 1.8 percent per year from 22.7 trillion cubic feet (Tcf) in 2001 to 34.9 Tcf in 2025. While these consumption levels are expected to materialize only if prices do not rise appreciably, concerns have been raised about the ability of the industry to supply the necessary gas at moderate prices.

Annually, U.S. natural gas consumption has exceeded domestic production since the mid-1980s, and by 2025 the differential is anticipated to be 8 Tcf, roughly 23 percent of total demand (Mary Hutzler, EIA, personal communication, 2003). According to the EIA (2001b), in order to meet projected demands and to counter price increases and volatility for natural gas, the United States will need technological advances, increased exploration and developmental drilling, increased capacity for natural gas imports, and conservation. Projections through 2025 consistently predict sufficient supply to meet U.S. demand, but delivering on a reserve estimate

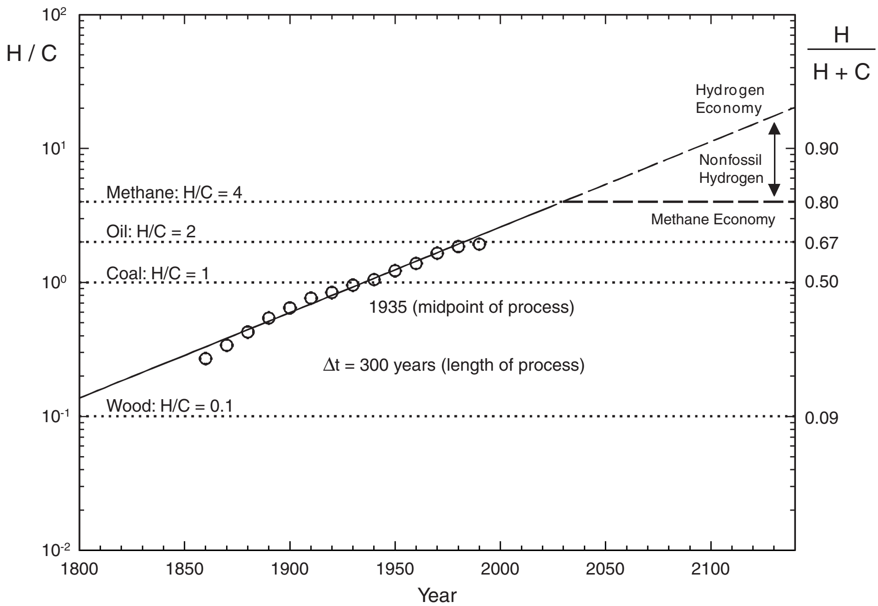

FIGURE 1.3 Decarbonization of primary energy. World primary energy sources have collectively declined in carbon intensity since coal began to compete with wood and hay about 200 years ago. The evolution is seen in the ratio of hydrogen to carbon in the world fuel mix, graphed on a logarithmic scale, analyzed as a logistic growth process, and plotted in the linear transform of the logistic (S) curve. Progression of the ratio above natural gas (methane) requires production of large amounts of hydrogen fuel with nonfossil energy. SOURCE: Ausubel (1996). Illustration by Aaron Cox, *American Scientist*. Reprinted by permission of *American Scientist*, magazine of Sigma Xi, The Scientific Research Society.

is dependent on more than future markets. Key assumptions include technology to improve exploration and production success, an educated and trained workforce, access, and infrastructure, especially for offshore production and imports (Mary Hutzler, EIA, personal communication, 2003).

The committee and workshop participants discussed how current trends appear to challenge these assumptions. While liquefied natural gas (LNG) transport and conversion facilities are common internationally, domestic facilities essential for offshore imports are limited (Colleen Sen, Gas Technology Institute, personal communication, 2003). Furthermore, pipelines for both imports and interstate transport are yet to be built. Although industry research facilities formed the core of oil and gas technology development in the past, private-sector research and development funding plummeted in the 1990s. Within the U.S. Department of Energy,

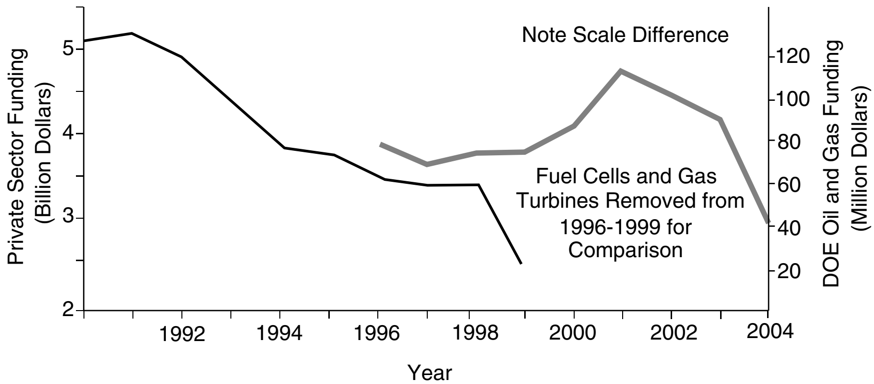

FIGURE 1.4 U.S. natural gas production from unconventional sources, including coalbed methane, shale gas, and tight gas—and results from new exploration concepts and new technology. Significantly decreased private and federal funding for oil and natural gas research could negatively impact the future supply of natural gas, particularly unconventionals. SOURCE: Scott Tinker, University of Texas at Austin, personal communication, 2003. Private-sector data are from Ross and Trewhella (2001).

the $40 million proposed for oil and gas research marks a sharp decline in federal funding (see Figure 1.4). University enrollments for geoscience graduates and petroleum engineers—the future educated workforce—have declined by more than 50 percent since 1985, with steeper declines for engineers (see Figure 1.5). Some workshop participants expressed concern about meeting the demand for natural gas and other fossil fuels given decreasing graduate student enrollments. Committee members and workshop participants discussed ways to meet increasing demand for natural gas and technological requirements at a time when oil and gas research and development funding, university science and petroleum engineering enrollments, and industry employment are all declining.

STUDY AND REPORT

The National Research Council, under the auspices of the Committee on Earth Resources of the Board on Earth Sciences and Resources, was requested by the U.S. Department of Energy, the Minerals Management Service, and the U.S. Geological Survey to host a workshop to address projections for the supply of and demand for natural gas over the next 10 to 20 years and methods of increasing reserves and production. The workshop and resulting summary, without conclusions and recommendations, were specifically focused on addressing the following questions:

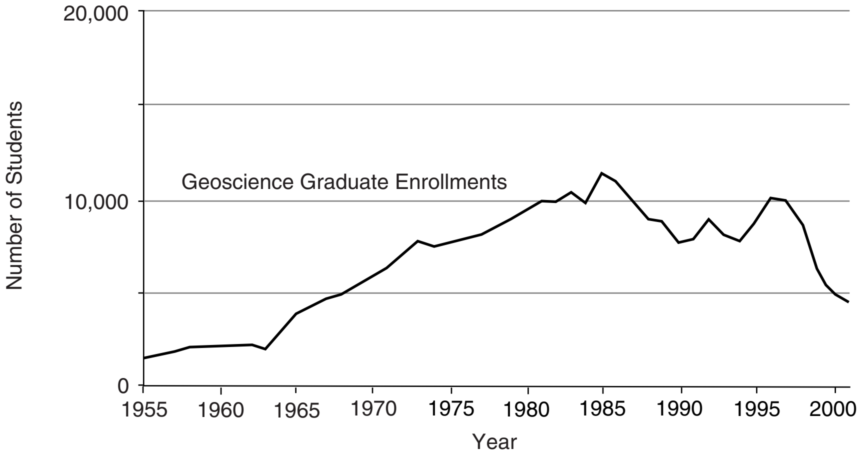

FIGURE 1.5 University geoscience enrollments for the period 1955 to 2000. Petroleum engineering enrollments show similar trends. SOURCE: AGI (2001).

1. What projections have been made by government agencies for the U.S. supply of and demand for natural gas over the next 10 to 20 years?
   - What methods were used?
   - On what assumptions are the projections based?
   - What external factors could impact the projections?
2. Where are the current natural gas reserves and resources?
   - How much is technically available?
   - How much is economically available?
   - How much is in conventional versus nonconventional supplies?
   - How much is offshore?
   - How much is in Canada and Mexico?
3. By what means and by how much can future reserves, resources, and production be increased?
   - Technology
   - Imports (from Canada and Mexico)
   - Tax incentives/royalties
   - Access
   - Demand

To address this charge the National Research Council established the Committee on U.S. Natural Gas Demand and Supply. The committee consists of five experts from academia, state government, and industry with expertise in reservoir characterization, resource assessment, gas recovery technologies, oil and gas exploration and development, energy economics and modeling, environmental health, and safety. Brief biographies of the committee members appear in Appendix A. The committee held a workshop on April 21, 2003, in Washington, D.C. The workshop included participants from academia, industry, federal and state government agencies, and nonprofit organizations. An agenda for the workshop is given in Appendix B.

This workshop summary is not a comprehensive report on natural gas but rather a synopsis of the presentations and discussions at the workshop. There are many important and timely topics related to natural gas supply and demand that were not discussed at the workshop. These include but are not limited to (1) factors that influence private-sector investment in natural gas; (2) natural gas transportation infrastructure and pipeline capacity; (3) natural gas storage; (4) significant environmental benefits of natural gas over other fossil fuel energy sources; (5) the impact of U.S. policy on perturbing the global trends of decarbonization of energy sources; (6) the impact on U.S. and global economies of a transition to a natural gas economy; (7) carbon sequestration; (8) the national security effects of a U.S. transition to natural gas, and (9) a review of the EIA models.

By design the workshop focused on natural gas demand and factors that cause uncertainty in demand, North American supply estimates and variability in those estimates, natural gas resource and reserves, and ways to meet future U.S. natural gas demand—especially through technology and LNG transportation. Several additional issues were brought forward during the workshop, including (1) the impact of tax incentives and royalties on the natural gas supply, (2) the growing need for research and technology as the natural gas resource base becomes increasingly unconventional, (3) the significant decrease in private-sector research and development funding, (4) the need for new federal-private research and technology models, and (5) the significant decline in the number of graduate students enrolled in geosciences and petroleum engineering who will be available to replace retiring workers over the next decade as the oil and gas industry faces the loss of well over half its technical workforce.

This summary does not contain any conclusions or recommendations. It is intended for multiple audiences, including the federal sponsors, other federal agencies, policymakers, consultants, scientists, and engineers. Chapter 2 examines the outlook for U.S. natural gas demand. Chapter 3 examines the North American natural gas supply. Chapter 4 considers options for meeting the U.S. natural gas demand, and Chapter 5 provides a workshop summary and highlights overarching issues discussed during the workshop.

2

U.S. Natural Gas Demand

Natural gas is considered by many as the transition fuel, or bridge, to a continually lower carbon-fueled and eventually hydrogen-fueled, economy. How well this clean, versatile energy source will meet this role will depend greatly on how long natural gas remains reliable and affordable. After years of stability, natural gas prices have recently become volatile and have been trending upward. Recent natural gas wellhead prices (monthly average for 2000 through 2002) have ranged from about $2 per thousand cubic feet (Mcf) to over $8/Mcf, in a roller coaster fashion (see Figure 2.1). At the start of 2003, wellhead prices for natural gas again resumed their roller coaster climb, reaching an estimated $6.70/Mcf (average for March 2003) before once again heading down (EIA, 2003b). These increasing and volatile gas prices are raising concerns about the electric power market's high reliance on natural gas. They are also beginning to price industrial demand out of the market and are impairing investments in gas supply. Price instability is one reason natural gas companies are reluctant to make long-term contracts similar to those made by coal companies.

Price volatility and supply reliability are of particular concern to the electric power sector. Future availability and prices for domestic electricity are linked to the outlook for gas supply, as essentially all new near-term power capacity and the great bulk of new long-term power capacity are projected to be gas fired. Because of higher prices and price volatility, projections of natural gas use for electric power generation have already been reduced in the most recent EIA (2003a) Annual Energy Outlook. The recently volatile and high natural gas prices have weakened the competi-

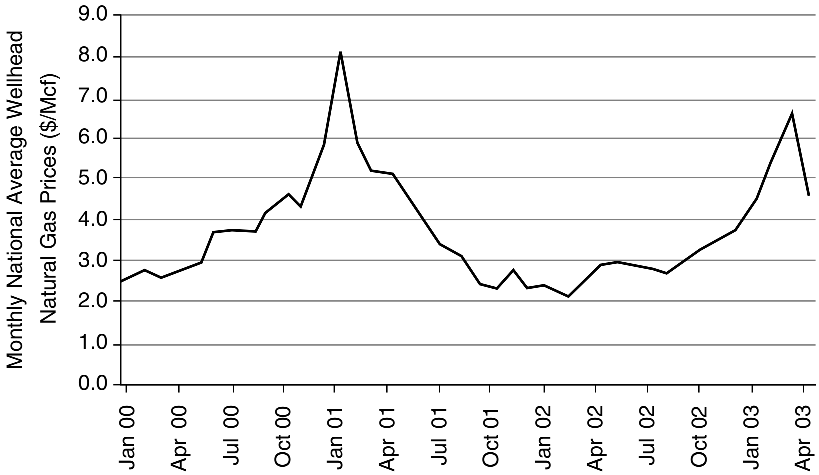

FIGURE 2.1 Monthly wellhead prices for natural gas for the period January 2000 to March 2003. SOURCE: EIA (2003d).

tive position of domestic industries utilizing natural gas, such as ammonia and methanol (particularly if feedstock ethane and propane are left in the gas stream). High prices for natural gas have also led the industrial sector to significantly reduce (and some sectors to curtail) its use of natural gas in the past 5 years, particularly during the first half of 2003. Because of price volatility, the natural gas production industry (awaiting assurance that the recent price rise is more than just a temporary phenomenon) has been slow to respond to the market's price signals.

The U.S. natural gas drilling rig count averaged only 746 rigs during the first quarter of 2003, up 11 percent compared to the first quarter of 2002, even though wellhead gas prices averaged $5.54/Mcf during this time, about two and one half times higher than the first quarter of 2002 (EIA, 2003c). Following a period of sustained higher wellhead natural gas prices, averaging $5/Mcf during the second quarter of 2003, and expectations that prices will remain strong into 2004, development of natural gas is increasing, with over 900 rigs drilling for natural gas in the United States in June 2003. A portion of the price volatility has been due to a lack of timely and comprehensive information on actual and expected gas demand, in a market where small volumes of surplus or shortage in the demand and supply balance can lead to significant short-term price volatility (Matt Simmons, Simmons and Company International, personal communication, 2003).

Projected consumption of natural gas is expected to remain flat for the next 2 years, with an anticipated rebound in industrial production and continued growth in new natural gas-fired electric power countering energy conservation and loss of gas demand in the petrochemical sector (EIA, 2003a). However, the longer-term outlook for natural gas consumption is less certain and will depend greatly on its affordability by the industrial sector, its competitive position for new power facilities, and the energy conservation and efficiency response to higher recent gas prices. In addition, proposed energy policies, such as the Bush Administration's Clear Skies Initiative, conservation, and international pressures to address carbon emissions and global climate change will further influence the demand and price for natural gas in coming years. This chapter examines the outlook for natural gas demand and the forces that will shape the role it may play in our domestic energy future.

PROJECTING NATURAL GAS DEMAND

Fundamental to any projections of natural gas demand are expectations for economic growth, assumptions for overall energy consumption, and economic competition among the fuels.

Growth of the U.S. Economy

The output of the U.S. economy—its gross domestic product (GDP)—is projected to increase by an average of 3 percent per year between 2001 and 2025 (EIA, 2003a). While this projected growth rate is less than what was achieved in the second half of the 1990s, it is comparable with long-term (years 2001 to 2025) economic growth expectations by other forecasters. For example, Global Insights, Inc. (GII, formerly Data Resources, Inc.–Wharton Energy Forecasting Associates) forecasts long-term GDP growth of 3.1 percent per year (EIA, 2003a). Shorter-term (years 2001 to 2012) economic growth expectations are 3.2 percent by the Office of Management and Budget and 3.1 percent by the Congressional Budget Office, both in line with near-term economic growth assumptions in the 2003 Annual Energy Outlook.

Primary Energy Demand

Primary energy use is projected to grow by an annual average rate of 1.5 percent between 2001 and 2025 (EIA, 2003a). As such, total domestic energy consumption would increase from 97 quads in 2001 to 139 quads in 2025. The slower growth in energy use compared to GDP growth reflects an expected decline in energy intensity due to efficiency improvements in end-use energy applications, higher efficiencies in electric power

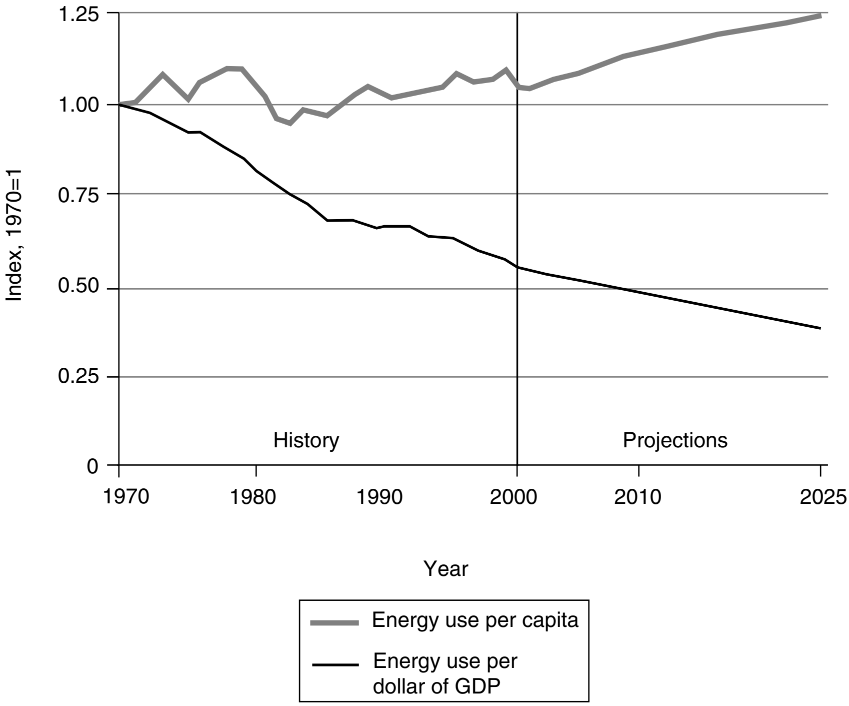

FIGURE 2.2 Energy use in the United States per capita and per dollar GDP from 1970 to 2025 (index, 1970 = 1). SOURCE: EIA (2003a, p. 5).

production, and shifts in the economy toward less energy-intensive industries (see Figure 2.2). The 2003 Annual Energy Outlook projections (EIA, 2003a) for annual growth in primary energy consumption of 1.5 percent are somewhat higher than the 1.3 percent annual growth projected by GII (from 2001 to 2020).

Competition among Fuels

Assuming natural gas prices moderate and become less volatile, natural gas consumption is projected to increase faster than consumption of competing fuels—coal, nuclear, petroleum, and renewables (EIA, 2003a). Consumption of natural gas is projected to grow from 22.4 Tcf (61 Bcf/day) in 2002, to 27.1 Tcf (74 Bcf/day) in 2010, to 34.9 Tcf (96 Bcf/day) in 2025 (see Figure 2.3) (EIA, 2003a). This equates to an average annual increase in natural gas consumption of 2 percent per year and is faster than the expected growth in overall primary energy consumption. The bulk of

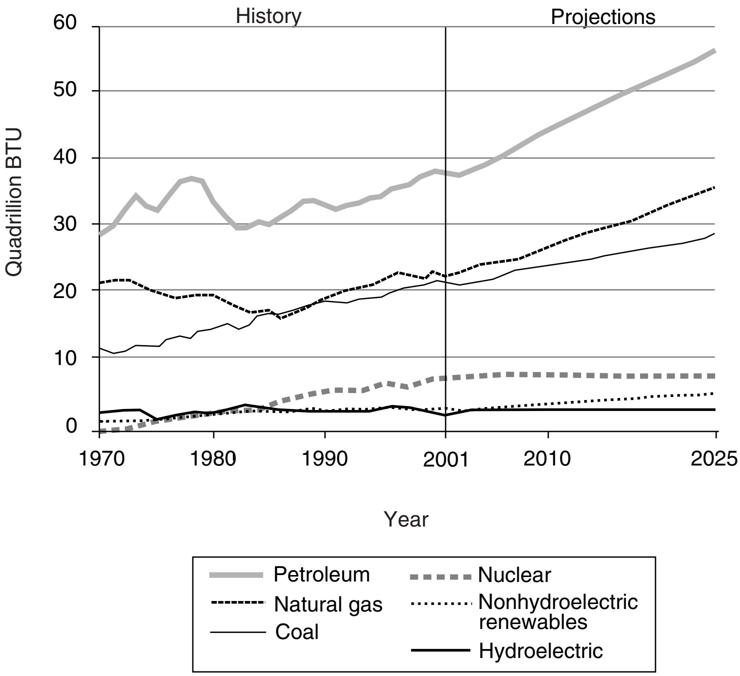

FIGURE 2.3 U.S. energy consumption by fuel for 1970 to 2025. SOURCE: EIA (2003a).

the increase is from electricity generation as the share of natural gas in this market, assuming natural gas is available at moderate prices, is expected to increase from 17 percent in 2001 to 29 percent in 2025 (see Figure 2.4) (EIA, 2003a). In the past four years (1999 to 2002), the industry added 144 gigawatts (GW) of electricity generation capacity, of which 138 GW has been natural gas-fired. Assuming natural gas prices remain moderate, as forecast by the 2003 Annual Energy Outlook, 80 percent of the new electricity generation capacity of the 428 GW projected to be needed by 2025 would be fueled by natural gas, if available and competitively priced.

OUTLOOK FOR U.S. NATURAL GAS DEMAND

Historical Perspective

The overall consumption of natural gas increased moderately but steadily during the 1990s from 19.2 Tcf (53 Bcf/day) in 1990 to 22.4 Tcf (61 Bcf/day) in 1999, an annual average increase of 1.5 percent per year (see

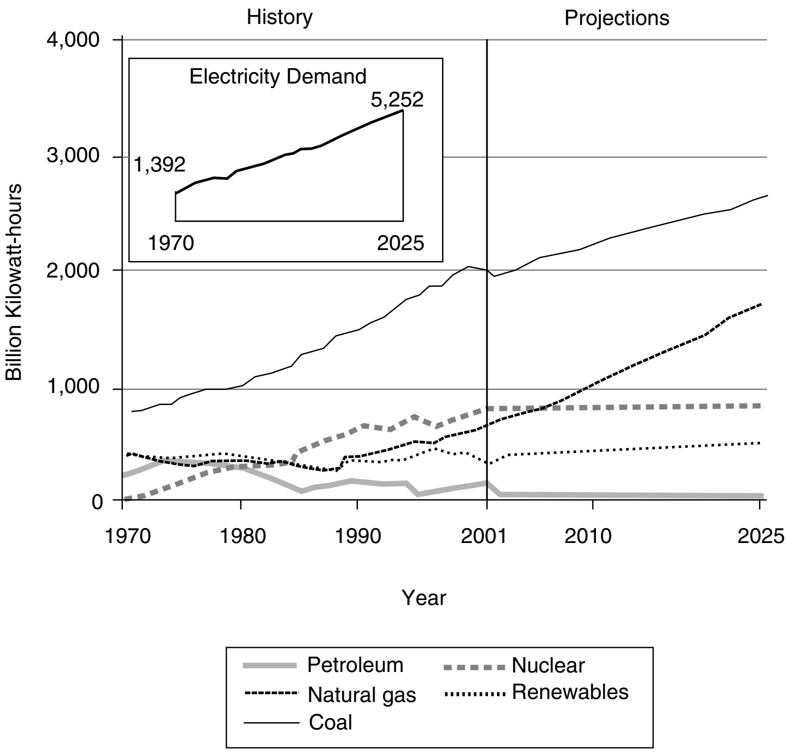

FIGURE 2.4 U.S. electricity generation by fuel for 1970 to 2025. SOURCE: EIA (2003a).

Figure 2.5) (EIA, 2003c). Much of the growth was due to increased use of natural gas for electric power, including industrial use of combined heat and power. During this time, natural gas prices at the wellhead were relatively low and stable, averaging less than $2.00/Mcf and ranging from $1.55 to $2.32/Mcf (in nominal dollars).

Ten years of stability in natural gas prices and predictability in demand came to a halt in late 2000. Low rainfall in the northwest led to a decline in hydroelectric power production. Electricity generation from hydroelectricity was 266 billion kilowatt-hours (kwh) in 2000, down from 309 billion and 414 billion kwh, respectively, in the previous 2 years (EIA, 2003a). The year 2000 also saw a cold winter, following two mild winters. Heating degree-days in year 2000 were 4,460 compared to 4,169 and 3,951 in the previous 2 years (EIA, 2003c). Driven by increased electricity and heating demand, consumption of natural gas jumped by 1.1 Tcf (3 Bcf/day) to 23.5 Tcf (64 Bcf) in 2000 (EIA, 2003a). With the increase in demand

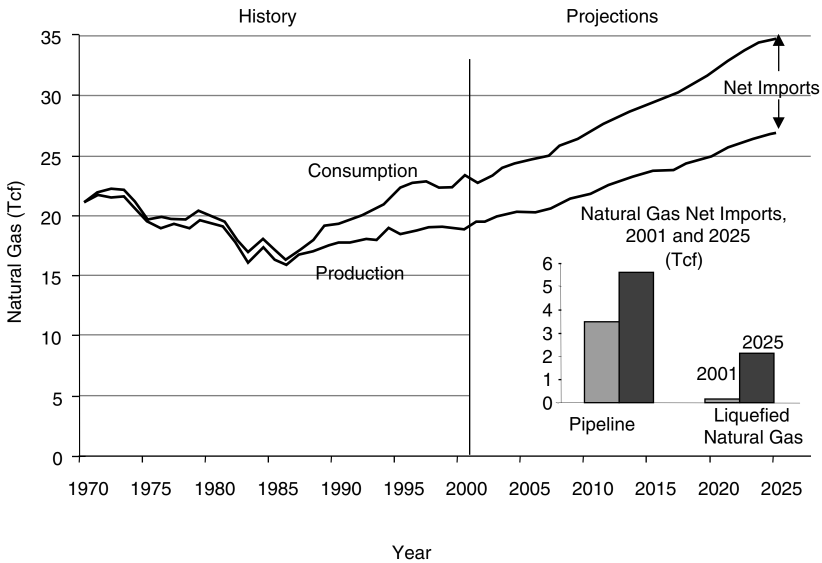

FIGURE 2.5 Natural gas production, consumption, and imports for 1970 to 2025.
SOURCE: EIA (2003a).

came major increases in natural gas wellhead prices that averaged $5.77/Mcf in December 2000 and $8.06/Mcf in January 2001 (EIA, 2003e). Overall, wellhead prices for natural gas averaged $3.70/Mcf in 2000 and $4.02/Mcf in 2001, up considerably from $2.19/Mcf in 1999, the last year of stable natural gas prices (EIA, 2003c). The higher natural gas prices induced conservation as well as the beginning of demand destruction in selective industrial sectors, reducing natural gas demand and causing a temporary decline in gas prices. In 2002, natural gas prices (at the wellhead) averaged $2.96/Mcf as gas consumption stabilized at 22.4 Tcf (61 Bcf/day) (EIA, 2003c).

Recent Situation

Preliminary data indicate that natural gas consumption may remain relatively flat for 2003 and 2004. Meanwhile, natural gas prices (at the wellhead) are expected to average $5/Mcf in 2003, declining to about $4.30/Mcf in 2004 (EIA, 2003c). With working natural gas in storage at the end of the winter heating season at 680 Bcf, the lowest end of March gas storage level since 1976 (the first year recorded by the EIA), it is not surprising that gas prices are expected to remain strong through 2004 (EIA, 2003c). With higher domestic gas production and lower demand during the second quarter of 2003, approximately 1,100 Bcf of natural gas has been added to storage. While the recent rate of injection into storage has been impressive, the volume of working gas in storage is still about 15 percent below the 5-year average, providing the basis for continued high near-term gas prices and its associated loss (and possible destruction) of industrial demand.

Longer-Term Expectations

In the longer term, consumption of natural gas has been projected by the EIA (2003a) and other forecasting organizations to once again grow and to grow steadily, reaching 27.1 Tcf (74 Bcf/day) in 2010, 32.1 Tcf (88 Bcf/day) in 2020, and 34.9 Tcf (96 Bcf/day) in 2025. The majority of this consumption increase is projected to be from the use of natural gas for electric power generation and from the restoration of domestic industrial demand (see Figure 2.6). Over 60 percent of the 11.7 Tcf (32 Bcf/day) of projected growth in annual natural gas consumption, between 2002 and 2025, would be from these two sectors (see Table 2.1).

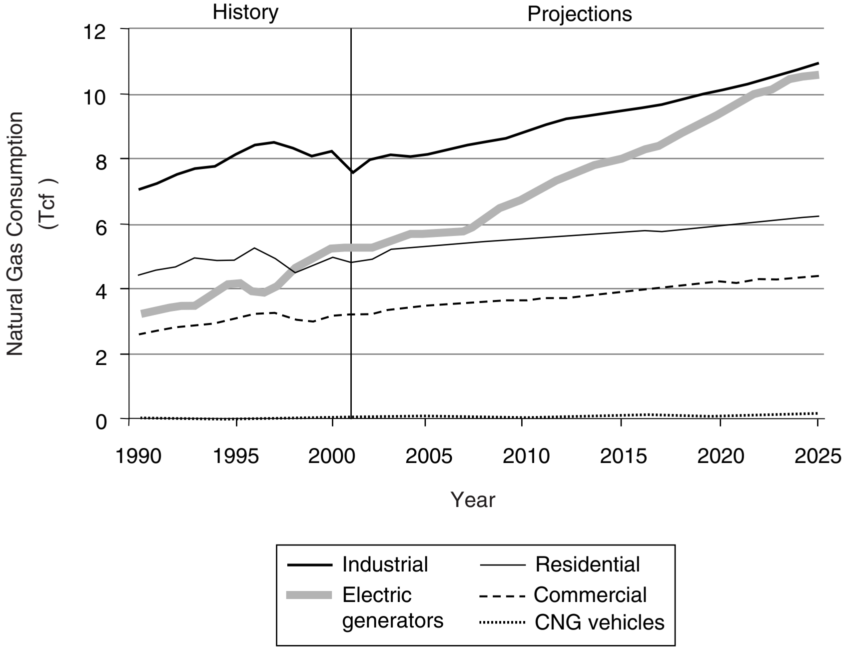

FIGURE 2.6 Natural gas end-use consumption by sector for 1990 to 2025. SOURCE: EIA (2003a).

TABLE 2.1 Projected U.S. Natural Gas Consumption in Tcf for 2002 to 2025

Sector	2002	2010	2020	2025
Residential	4.9	5.5	6.0	6.2
Commercial	3.2	3.7	4.2	4.4
Industrial	7.1	8.9	10.1	10.9
Electric generation	5.5	6.8	9.4	10.6
Other	1.7	2.2	2.4	2.8
TOTAL	22.4	27.1	32.1	34.9

SOURCE: EIA (2003a).

The most critical assumption underlying EIA's projected growth in natural gas consumption (EIA, 2003a) is that natural gas prices will decline from current high levels and remain relatively moderate, between $3 and $4/Mcf (in real-year 2001 dollars) (see Figure 2.7). Another key as-

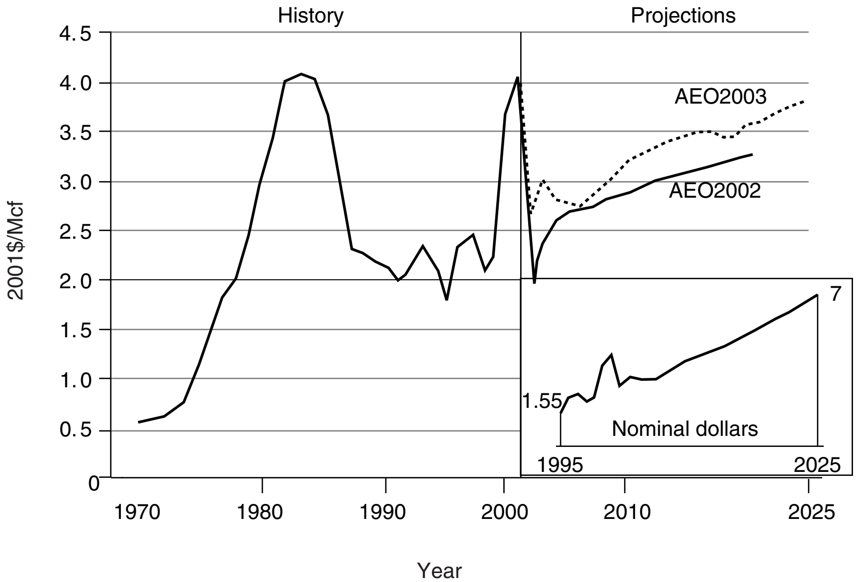

FIGURE 2.7 U.S. average annual natural gas wellhead prices for 1970 to 2025 in 2001 dollars per thousand cubic feet. SOURCE: Figure was prepared for Annual Energy Outlook 2003 Press Release, November, 2003. Data are from EIA (2002a, 2003a).

sumption behind the projected increase in natural gas consumption is that natural gas will continue to be used in already installed electric power plants and will win the lion's share of the expected new electric power capacity. High-efficiency natural gas combined-cycle power plants have, for some time, had a competitive advantage over new coal and nuclear power plants. This cost advantage is expected to generally remain in place through 2025 (EIA, 2003a) (see Figure 2.8). Regional differences in fuel prices, incentives (or requirements) for using renewable energy such as wind power, and a desire to maintain a mix of fuels, have enabled coal and renewables to capture a portion of the future market in electric power.

However, the cost advantage of natural gas in power generation begins to erode once wellhead natural gas prices climb above $4/Mcf, unless substantial progress continues to be achieved in the efficiencies of advanced gas combined-cycle power plants. With current wellhead natural gas prices above $5/Mcf and projected to be $4/Mcf in the year 2025, considerable uncertainty exists as to whether natural gas will continue to "win" in the power generation growth market (EIA, 2003a).

The past 2 years have also seen a loss in industrial demand for natural gas of 1.2 Tcf (over 3 Bcf/day), with a possibility that much of this loss is permanent due to high volatile natural gas prices. As such, the longer-term consumption of natural gas in the industrial sector may well be considerably less than projected by the EIA (Matt Simmons, Simmons and Company International, personal communication, 2003).

On the one hand, higher natural gas prices would shift the critical electric power and industrial markets toward other fuels. On the other, concerns about global warming and constraints on carbon emissions would tilt the balance back toward natural gas. Advanced carbon capture and storage technology could help the economic position of coal in a carbon-constrained world and help balance the competition.

Comparison with Other Forecasts

The projections for natural gas consumption and prices in the 2003 Annual Energy Outlook (EIA, 2003a) are, in general, quite comparable with other major forecasts, such as those by Global Insights, Inc. (GII) and the Petroleum Industry Research Association (PIRA) (see Table 2.2). This is due in part to the fact that the basic assumptions for economic growth, primary energy demand, electricity demand, and future natural gas prices in these forecasts are similar:

- The projection for year 2015 natural gas consumption of 29.5 Tcf in the 2003 Annual Energy Outlook is essentially the same as by GII and 2 percent higher than by PIRA.

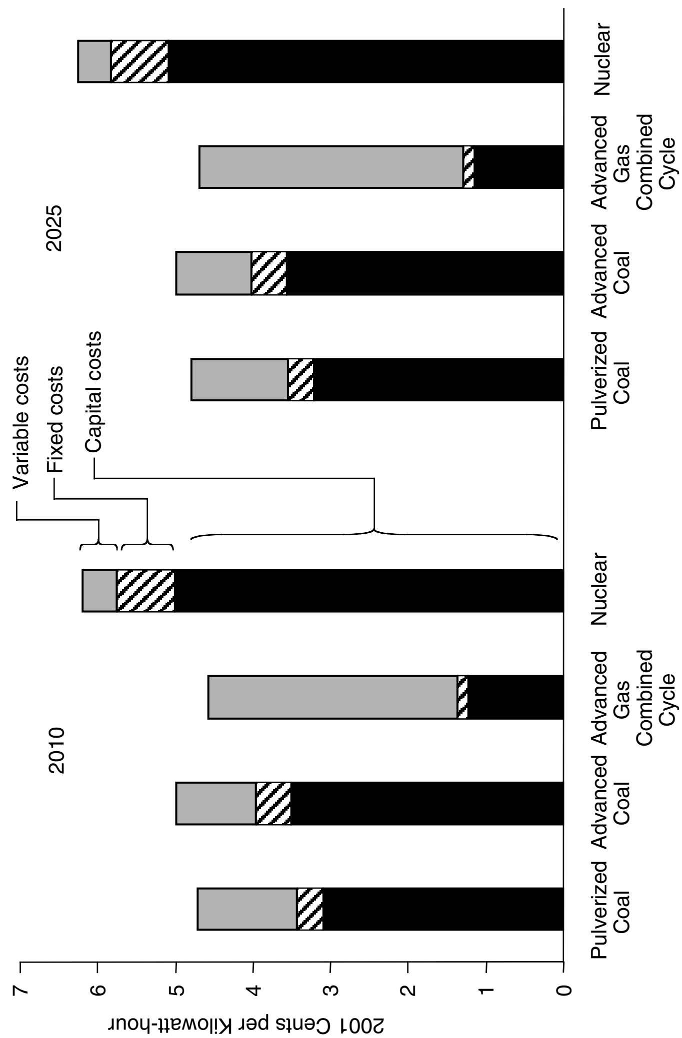

FIGURE 2.8 Projected levelized electricity generation costs for baseload technologies from 2010 to 2025 in 2001 cents per kilowatt-hour. SOURCE: EIA (2003a).

TABLE 2.2 Comparisons of Forecasts and Assumptions

Basic Demand Factors	Annual Energy Outlook 2003	GII	PIRA
Economic growth (%; average annual 2001-2025)	3.0	3.1	
Primary energy demand (%; average annual, 2001-2025)	1.5	1.3	
Electricity sales in 2015 (billion kwh)	4,481	4,583	
Natural gas in 2015 L-48 wellhead price (2001 $/Mcf)	3.55	3.14	N/A
Consumption (Tcf)	29.5	29.4	28.8

SOURCE: EIA (2003a).

- The 2003 Annual Energy Outlook expects somewhat (14 percent) higher gas prices in the year 2015 than does GII.

Given their relatively moderate expectations for natural gas prices, all three of these major forecasts expect that natural gas consumption will approach 30 Tcf in the middle of the next decade. Given the loss of industrial demand and the history of residential and commercial energy conservation when faced with high volatile prices, there is considerable uncertainty as to whether natural gas will meet these consumption expectations. Some workshop participants commented that, with higher gas prices, they were now questioning the 30-Tcf projections or thought there would be a delay in reaching the 30-Tcf level. Whether natural gas can meet these expectations requires that it remain reliable and affordable. The section titled "Sensitivity Analyses" will examine several of the forces that may shape the future price of and demand for natural gas.

OUTLOOK FOR CANADIAN AND MEXICAN NATURAL GAS DEMAND

To a large extent the United States is part of an integrated North American natural gas market with Canada and Mexico. As such, changes in demand for natural gas in these two countries will directly affect the outlook for the U.S. demand.

Changes in Canadian Natural Gas Demand

Currently, Canada consumes 3 Tcf (8 Bcf/day) of natural gas annually. With a productive capacity of 6.4 Tcf, this enabled Canada to export a net 3.6 Tcf/year (10 Bcf/day) to the United States in 2002, accounting for 16 percent of U.S. gas consumption (Greg Stringham, Canadian Association of Petroleum Producers, personal communication, 2003).

For the past decade or so, Canadian natural gas consumption has grown relatively moderately, from 2.1 Tcf (5.8 Bcf/day) in 1990 to its current level. However, because of increased growth in gas-fired electricity generation and significant expansions in oil sand development, Canada's internal demand for natural gas is expected to increase substantially in the next several years (Greg Stringham, Canadian Association of Petroleum Producers, personal communication, 2003).

In 2002, oil sands provided nearly 0.8 million barrels per day of production and consumed 300 million to 400 million cubic feet per day (MMcf/day) of natural gas, as part of the extraction, separation, and upgrading process. Approximately $7 billion (Canadian) is being spent on construction of new oil sand facilities and expansions, with another $25 billion (Canadian) announced. At a ratio of 0.5 to 1 Mcf of natural gas for every barrel of oil sands produced and assuming that natural gas remains the "fuel of choice," the use of natural gas by the oil sands industry is projected to reach 500 to 1,000 MMcf/day (0.3 Tcf /year) by 2010 and will be considerably higher in future years. Technology is key in the oil sands development. Recent promising advances in technology and greater use of petroleum coke could substantially reduce gas consumption in new oil sands projects (Greg Stringham, Canadian Association of Petroleum Producers, personal communication, 2003).

Changes in Mexican Natural Gas Demand

Currently, Mexico imports about 700 MMcf/day (0.26 Tcf/year) of natural gas from the United States. In the near term, from now to 2010, Mexico is expected to maintain its natural gas imports from the United States at about this level (EIA, 2003a). In the longer term, and particularly if LNG terminals are installed in Baja, California, Mexico's natural gas demand is expected to be met by growth in its internal production and by LNG imports, enabling the flow of gas to reverse (EIA, 2003a). However, considerable uncertainty surrounds the outlook for Mexico's natural gas consumption, particularly given its plans for economic growth and improved environmental practices (EIA, 2003f).

SENSITIVITY ANALYSES

The outlook for U.S. natural gas demand depends on numerous assumptions and expectations, including the rate of domestic economic growth, future natural gas and competing energy prices, pending energy legislation and policies, and the reliability of natural gas supplies. As shown by recent events, the factors governing gas demand can change dramatically as new information and conditions emerge.

Example of Rapid Changes in Demand Assumptions

An example of how rapidly and significantly basic assumptions on natural gas demand can change is illustrated by the events that followed the National Petroleum Council's 1992 study on natural gas (National Petroleum Council, 1992). This study set forth two bounding forecasts for the year 2000 gas demand. The "low case" scenario with a demand estimate of 18.5 Tcf for 2000 projected little growth in natural gas demand from 1990. The "high case" scenario with a demand estimate of 20.8 Tcf for 2000 had modest expectations for growth.

Actual natural gas consumption in 2000 was 24.3 Tcf, 2.6 Tcf higher than projected for the "high case." Clearly, many of the assumptions underlying the natural gas demand forecast in the study quickly became outdated. When the National Petroleum Council updated its study in 1999, it noted that the low case scenario "had proven to be so far from actual results that it did not merit further study or analysis." And even the high case scenario "had proved to be too low to capture the real growth that occurred in the 1992-98 period" (National Petroleum Council, 1999).

Assessment of Key Uncertainties

One approach for examining uncertainty in projections of demand is to use sensitivity (or "delta") analyses to evaluate the impact of assumptions or actions on the baseline projection. To gain insight on key uncertainties, sensitivity analysis is performed for three cases: (1) higher and lower economic growth; (2) changes in the pace of technological progress and the size of the accessible natural gas resource base; and (3) a carbon constrained future, similar to the expectations set forth in legislation proposed by Senators McCain and Lieberman.[1] A fourth sensitivity analysis,

[1]Senate bill 139. A bill to provide for a program of scientific research on abrupt climate change, to accelerate the reduction of greenhouse gas emissions in the United States by establishing a market-driven system of greenhouse gas tradeable allowances that could be

TABLE 2.3 Expectations for Natural Gas Demand and Long-Term Wellhead Prices Caused by Differences in Assumptions for Economic Growth

		2010			2025		
	Actual 2002	Reference Case	Low Growth	High Growth	Reference Case	Low Growth	High Growth
Demand (Tcf)	22.4	27.1	26.3	28.1	34.9	31.8	37.4
Wellhead Price ($/Mcf)	2.96	3.29	3.17	3.59	3.90	3.83	4.50

SOURCE: EIA (2003a).

examining the impact of alternative world oil prices on natural gas demand and prices, showed that even significant differences in world oil prices would have only very modest impacts on U.S. natural gas demand and prices (EIA, 2003a).

Sensitivity Analysis 1: Economic Growth

A fundamental uncertainty is future growth in the U.S. economy. While the 2003 Annual Energy Outlook (EIA, 2003a) reference case uses an average annual growth rate of 3 percent (from 2001 to 2025), the report also includes low (2.5 percent) and high (3.5 percent) economic growth cases. These relatively modest annual differences in expectations for economic growth have a major impact on long-term gas demand and prices (see Table 2.3):

- Higher or lower economic growth would cause gas demand to go up or down from the reference by about 1 Tcf in 2010 and by 2.5 to 3 Tcf in 2025.
- Higher economic growth would cause wellhead prices for natural gas in the year 2025 to increase by about 15 percent, from $3.90 to $4.50/Mcf (in constant 2001 dollars).

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used interchangeably with passenger vehicle fuel economy standard credits, to limit greenhouse gas emissions in the United States and reduce dependence upon foreign oil, and ensure benefits to consumers from the trading in such allowances.

Sensitivity Analysis 2: Technology and Resources

The rate of technological progress and the size of the accessible resource base are two factors that can be affected by energy policies and the level of research and development investment.

Technological Progress

In the past, investments in research and development have led to important advances in natural gas exploration and production technology. These technologies have improved exploration success rates, lowered well drilling and completion costs, and improved gas recovery per well. These advances have enabled the industry to access new natural gas supplies from geologically complex unconventional gas resources and deep offshore waters while keeping costs lower than they otherwise would have been. The analysis shows that a relatively modest change in the rate of technological progress, from the current trends imbedded in the reference case, would have significant impacts on future natural gas prices and demand (see Table 2.4 and Figure 2.9).

- In a low technology progress world (15 percent decline in the rate of technological progress from the technology trends imbedded in the reference case), the wellhead price for natural gas would be $4.60/Mcf (in the year 2025). This higher price drives out over 2 Tcf of annual gas demand (in the year 2025) and places natural gas in a much less favorable competitive position in the electric power market (Mary Hutzler, EIA, personal communication, 2003.).
- In a high technology progress world (15 percent increase in the rate of technological progress), the wellhead price for natural gas would be

TABLE 2.4 Expectations for Natural Gas Demand and Long Term Wellhead Prices Due to Low and High Rates of Technological Progress

		2010			2025		
	Actual 2002	Reference Case	Low Tech	High Tech	Reference Case	Low Tech	High Tech
Demand (Tcf)	22.4	27.1	26.4	27.6	34.9	32.7	36.7
Wellhead price (2001; $/Mcf)	2.96	3.29	3.64	2.97	3.90	4.60	3.76

SOURCE: Mary Hutzler, EIA, personal communication, 2003.

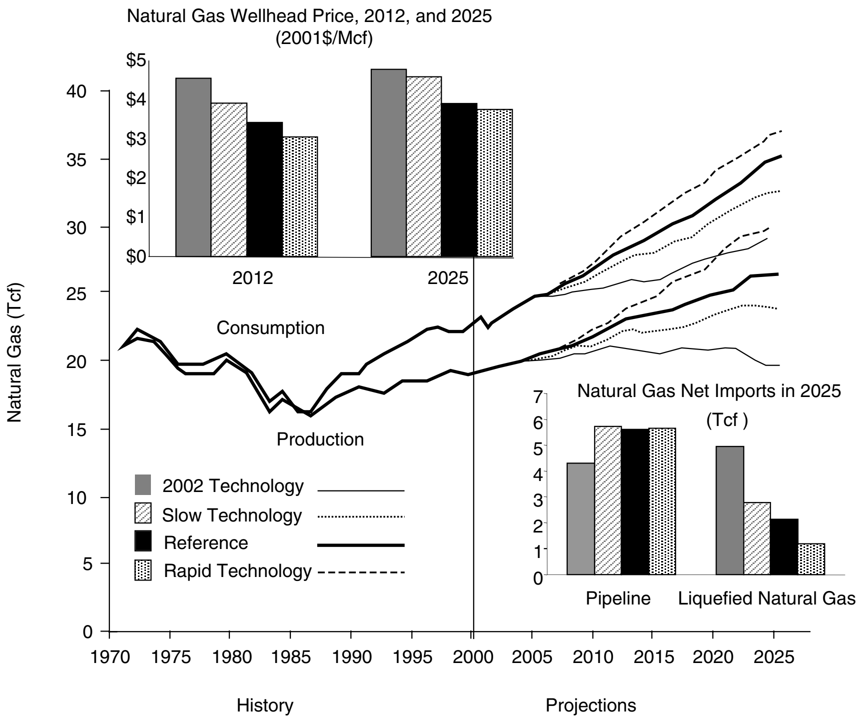

FIGURE 2.9 Natural gas production, consumption, and imports for 1970 to 2025 in trillion cubic feet as a function of technological progress. SOURCE: Mary Hutzler, EIA, personal communication, 2003. Data are from EIA (2003a).

considerably lower, at $3.76/Mcf (in the year 2025). This would provide significant savings to consumers (annual savings in costs of $18 billion in the year 2010 and $31 billion in the year 2025) as well as significantly lower finding and development costs for natural gas producers (Mary Hutzler, EIA, personal communication, 2003).

Resource Base

Considerable uncertainty and controversy exists with respect to the size of the underlying natural gas resource base, particularly with respect to unconventional natural gas (Keith Shanley, Stone Energy, personal communication, 2003; Ben Law, Pangea Hydrocarbon Exploration, personal communication, 2003). Equally uncertain is the portion of this resource that will ultimately be accessible, unconstrained by either physical or technical limits.

TABLE 2.5 Expectations for Natural Gas Demand and Long Term Wellhead Prices Caused By Differences in Assumptions for the Size of the Resource Base

		2010		2025	
	Actual 2002	Reference Case	Low Resource	Reference Case	Low Resource
Demand (Tcf)	22.4	27.1	26.6	34.9	32.9
Wellhead price (2001;$/Mcf)	2.96	3.29	3.54	3.90	4.84

SOURCE: Mary Hutzler, EIA, personal communication, 2003.

- The analysis shows that a 25 percent lower-than-expected U.S. natural gas resource base, due potentially to smaller or less accessible tight gas sand resources, would increase gas prices in 2025 by nearly $1.00/Mcf (see Figure 2.10) (Mary Hutzler, EIA, personal communication, 2003).
- With a low natural gas resource base and higher gas prices, gas consumption would decline by 2 Tcf in 2025, with an even larger drop in domestic production. Significantly increased reliance on natural gas imports would be required to balance demand and supply (see Table 2.5) (Mary Hutzler, EIA, personal communication, 2003).

Carbon Emission Constraints

The long-term outlook for natural gas could change substantially should constraints emerge on carbon emissions. As the cost of using higher carbon-based fuels (such as coal and oil) increases (or faces limits on its use), the preference for using natural gas would increase.

- The analysis shows that with carbon constraints, natural gas demand would increase by 2.4 Tcf in 2020 and 1.5 Tcf in 2025 (see Figure 2.11).
- With carbon constraints, natural gas wellhead prices would be about $0.50/Mcf higher in 2020 ($3.90/Mcf versus $3.42/Mcf in the reference case). By 2025 the price difference would narrow to about $0.30/Mcf ($4.21/Mcf versus $3.90/Mcf in the reference case) (see Table 2.6).
- In a special sensitivity run prepared for this study, the EIA showed

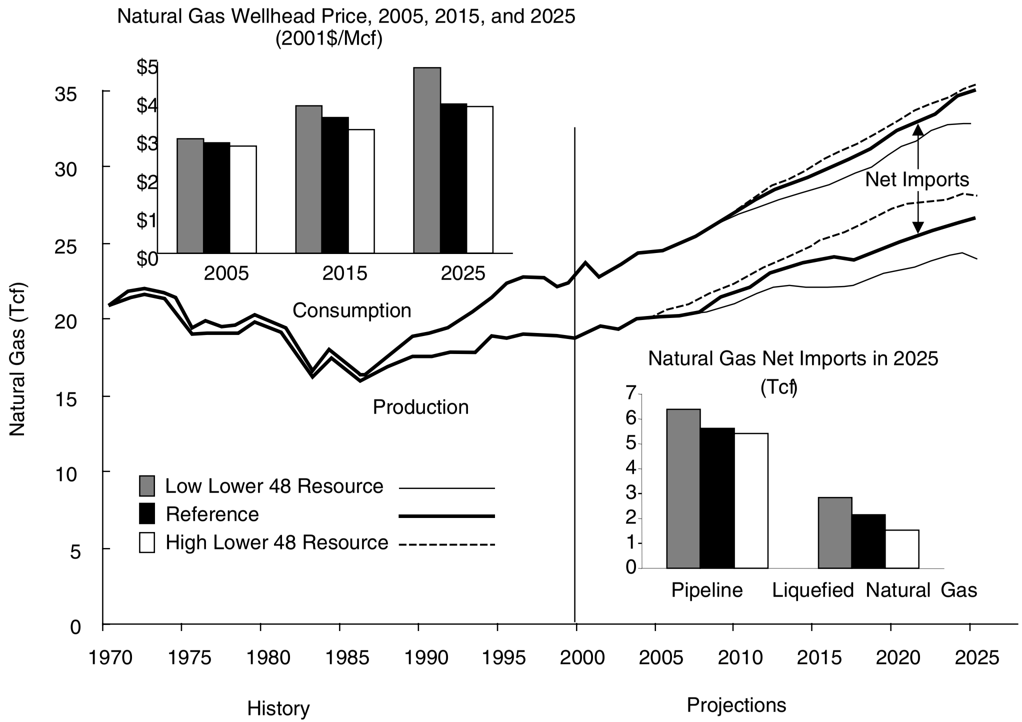

FIGURE 2.10 Natural gas production, consumption, and imports for 1970 to 2025 in trillion cubic feet as a function of the resource base. SOURCE: Mary Hutzler, EIA, personal communication, 2003. Data are from EIA (2003b).

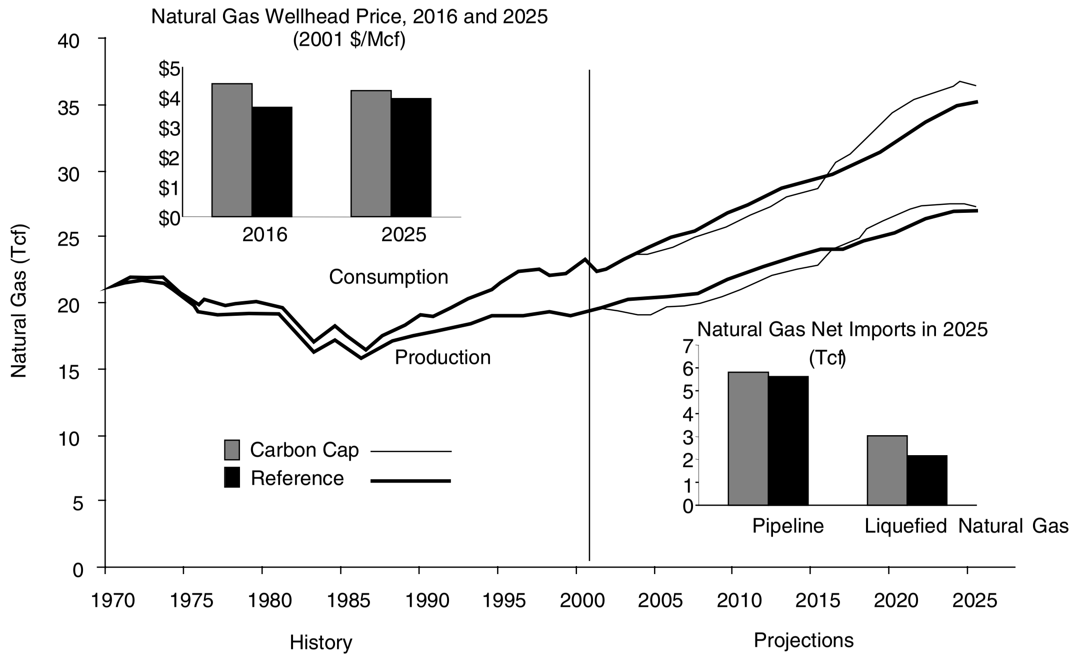

FIGURE 2.11 Natural gas production, consumption, and imports for 1970 to 2025 in trillion cubic feet as a function of carbon emission constraints. SOURCE: Mary Hutzler, EIA, personal communication, 2003. Data are from EIA (2003a).

TABLE 2.6 Expectations for Natural Gas Demand and Long-Term Wellhead Prices Caused By Differences in Assumptions for Carbon Emission Constraints

		2020		2025	
	Actual 2002	Reference Case	Carbon Constraints	Reference Case	Carbon Constraints
Demand (Tcf)	22.4	32.1	34.5	34.9	36.4
Wellhead Price (2001; $/Mcf)	2.96	3.42	3.90	3.90	4.21

SOURCE: Mary Hutzler, EIA, personal communication, 2003.

that higher levels of progress in natural gas supply technologies could significantly reduce the impact of carbon emission constraints on natural gas prices (Mary Hutzler, EIA, personal communication, 2003).

SUMMARY

Considerable expectations exist for natural gas to once again become and remain a reliable and affordable future source of energy supplies. The essential question is whether the expectations of moderate natural gas prices of $3.50/Mcf and the strong annual natural gas demand of 30 Tcf in the next decade can be realized. Considerable debate exists with respect to future industrial gas demand, competition among fuels in the electric power market, and the maturity and size of the remaining natural gas resource base. Still, the analysis above shows that factors over which the United States has significant influence, such as assuring a favorable pace of technological progress in natural gas exploration and production and providing reasonable access to the natural gas resource base will greatly determine future natural gas prices and demand. In addition, a strong underlying energy and natural gas database, and a continually improving analysis and modeling system will be essential for providing reliable, up-to-date guideposts on these issues of importance to the industry and the nation.

3

North American Natural Gas Supply

Assessment of a natural resource is a time-dynamic process. Because the process involves estimating the location and magnitude of an inherently unknown quantity, the accuracy of the assessment is limited by the perception and understanding of the origin and occurrence of the resource; the quality and distribution of available data from which to project estimates; and the methods employed to facilitate the assessment. Owing to these factors, a range of assessment values, not a single number, should be expected.

Estimates of potential gas resources change from year to year. Increases result from new discoveries in both producing areas and nonproducing frontier areas and reserve growth in producing areas. Decreases result from continued production, reclassification of potential resources to proven reserves, and condemnation or downgrading of an area due to unfavorable drilling results. Additionally, the effective date of an estimate must be considered. How any of these factors influence an estimator's judgment of resource potential relates directly to the amount and quality of information that becomes available through drilling and production and the application of new technologies or new concepts. Some activities may confirm industry's original expectations about a field or new play; others may not. The combined effect of these factors for any given geological province from one assessment to the next may be an overall net increase, a net decrease, or no substantial net change. With this background, the committee and workshop participants examined current assessments of the world and of North American natural gas resources.

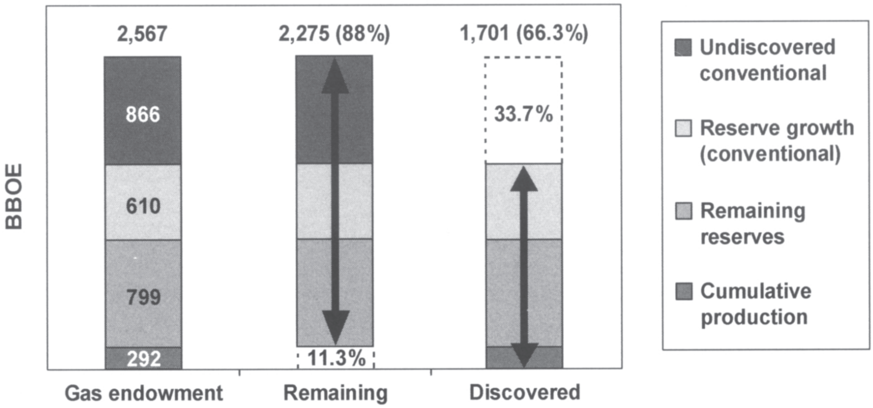

FIGURE 3.1 USGS World Petroleum Assessment 2000 for natural gas. Assessment is for 128 world provinces and the United States. Units are in billion barrels oil equivalent. SOURCE: Ahlbrandt (2002).

GAS RESOURCE ESTIMATES

The most recent assessment of the world's total natural gas resources is shown in Figure 3.1. The remaining potential supply of 2,275 billion barrels of oil equivalent corresponds to 13,649 Tcf of total natural gas resources. Reserves of various categories (proven, probable, and possible) account for 35 percent of the remaining potential supply. Outside the United States, undiscovered natural gas is concentrated in the former Soviet Union, the Middle East, and North Africa (see Figure 3.2) (USGS, 2000). Workshop presentations and discussions, summarized in this chapter, focused on the North American natural gas supply, including LNG and methane hydrates.

U.S. Supply

The North American natural gas supply represents a significant percentage of the total world supply. Total assessed gas resources for the United States have been increasing over the past 20 years, despite production and the transfer of potential resources to proven reserves. This is a change in our perception of the resource base, not an actual increase in the amount of gas reservoired in the Earth's crust (Scott Tinker, University of Texas at Austin, personal communication, 2003). The assessments have increased due to an improved understanding of the phenomenon of reserve appreciation or reserve growth, whereby gas (and oil) fields ultimately produce three to nine times the amounts initially estimated by

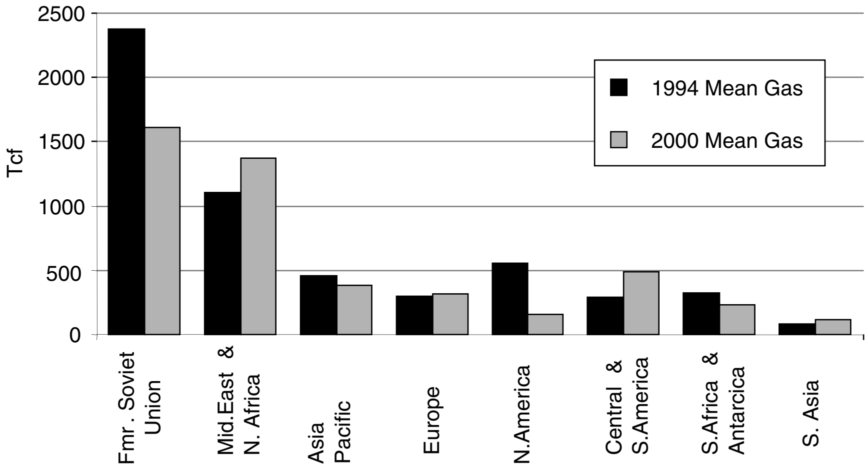

FIGURE 3.2 Comparison of USGS mean undiscovered gas by region (excluding the United States). SOURCE: Modified from Ahlbrandt et al. (2000).

standard engineering techniques, an understanding of the potential for new plays, and an evaluation of the role of current and advanced technology in gas exploration and production (Thomas Ahlbrandt, USGS, personal communication, 2003).

A total of 1,289 Tcf of technically recoverable resources has been reported for the United States by the EIA, using predominantly USGS and Minerals Management Service data (see Figure 3.3) (Mary Hutzler, EIA, personal communication, 2003). Proven reserves account for 14 percent of the remaining U.S. resource.

The largest single category (34 percent) is unconventional natural gas, comprising gas reservoired in tight (low-permeability) sands and carbonates in fractured shales and coalbeds (Mary Hutzler, EIA, personal communication, 2003) (see Figure 3.3). Controversy exists, however, as to the size and geological nature of the tight sands gas resource in the U.S. Rocky Mountains region (where the bulk of the assessed gas is thought to reside). A recent study (Keith Shanley, Stone Energy, personal communication, 2003) of new field discoveries (see Figure 3.4) and the character of reservoir rocks in the greater Green River Basin of Wyoming calls into question the nature and ultimate gas productivity of basin-centered gas deposits—a type of tight gas sand reservoir thought to contain free gas downdip of water, a reversal of the norm in more permeable and porous rocks. The significance of this study is that current resource estimates for this category of tight sands may be up to three times too large. The concept of basin-centered gas, however, is well established (Ben Law, Pangea

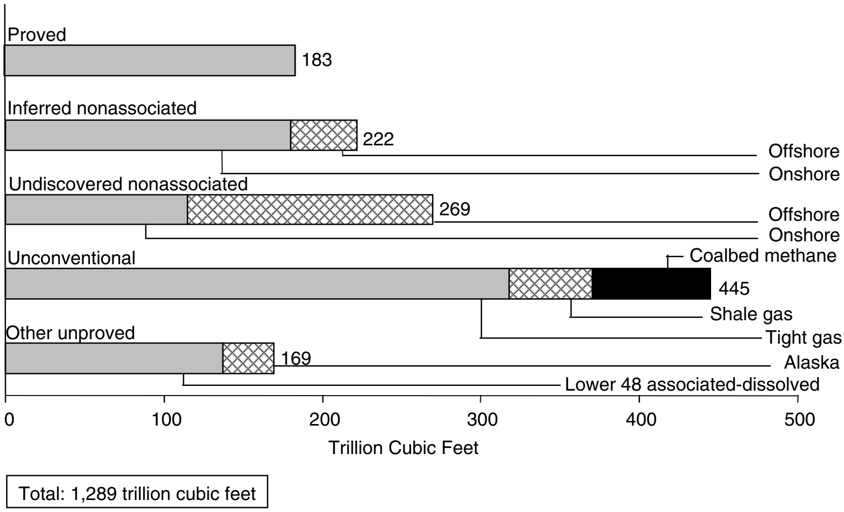

FIGURE 3.3 Technically recoverable U.S. natural gas resources as of January 1, 2002. SOURCE: EIA (2003a, p. 35)

Hydrocarbon Exploration, personal communication, 2003). This controversy rests on a single technical presentation at which only summary data were shown. However, the Unconventional Petroleum Systems committee of the American Association of Petroleum Geologists (AAPG) is proposing a Hedburg conference, devoted to this topic, to be held in 2004. Additionally, at least one research proposal was submitted, in August 2003, by a university to a consortium of industry and independent research organizations to verify the applicability of the basin-centered gas concept in the Piceance basin of Colorado.

There are nongeological reasons to consider that may not allow all of the large gas volumes assessed in the United States—and the rest of the world— to become usable energy by the customers. First, potential gas resources consist of two components—technically recoverable resources and a significantly smaller subset of economically recoverable resources. Proven reserves are, by definition, both technically and economically recoverable. However, other resources have less constrained (or unknown) costs to find, produce, and transport. An analysis of undiscovered conventional resources in the federal outer continental shelf indicates that, for the total Gulf of Mexico outer continental shelf, larger volumes of gas are modeled as becoming available only as wellhead prices significantly increase (see Figure 3.5). Similarly for the onshore United States, the USGS has reported much smaller volumes of gas avail-

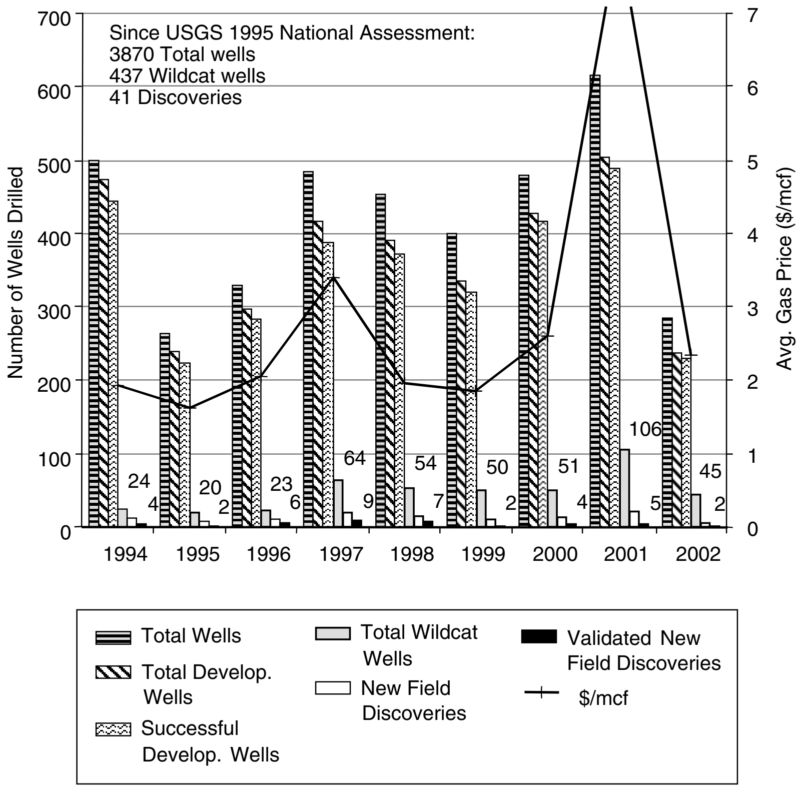

FIGURE 3.4 Greater Green River Basin drilling results for the period 1994 to 2002. SOURCE: Shanley et al., in press. Data are from IHS Energy (2002). Copyright AAPG, 2003. Reprinted by permission of the AAPG, whose permission is required for further use.

able at $3.34/Mcf in 1994 dollars, compared to the total assessed resource (see Figure 3.6).

Additionally, a significant percentage of the future gas resources of the United States is off-limits due to state and federal land-use restrictions. For example, 13 percent of the remaining gas resource of the federal outer continental shelf (eastern Gulf of Mexico and Straits of Florida, Atlantic, and Pacific) is essentially undrillable at this time (see Figure 3.7). The Departments of the Interior, Agriculture, and Energy have determined that, for five areas in the Rocky Mountains region with the largest remaining gas potential, 14 percent of the resource is closed to drilling, 4 percent has severe restrictions of 6 months or more per year, and the remaining 82 percent has relatively modest restrictions, due primarily to

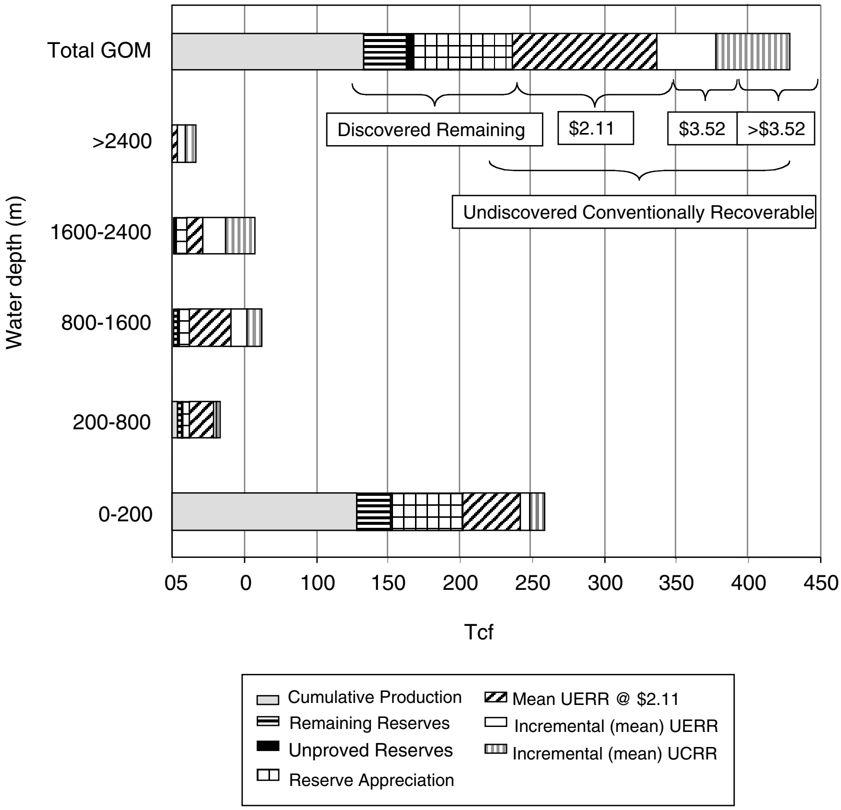

FIGURE 3.5 Mean total gas endowment and undiscovered economic recoverable resources (UERR) by water depth for the Gulf of Mexico region. SOURCE: Richie Baud, Minerals Management Service, personal communication, 2003. Data are from Lore et al. (2001).

migration and nesting season issues or is governed by standard lease terms (U.S. DOI et al., 2003). Finally, there are physical limitations to bringing gas to market in a timely fashion. For example, while 27 percent of the remaining gas resource in the federal outer continental shelf is assessed for Alaska, no pipeline exists or has even been approved to transport gas to the lower 48 states (Richie Baud, Minerals Management Service, personal communication, 2003).

Canadian Supply

Canada ranks third in the world in natural gas production, behind the former Soviet Union and the United States (Greg Stringham, Canadian

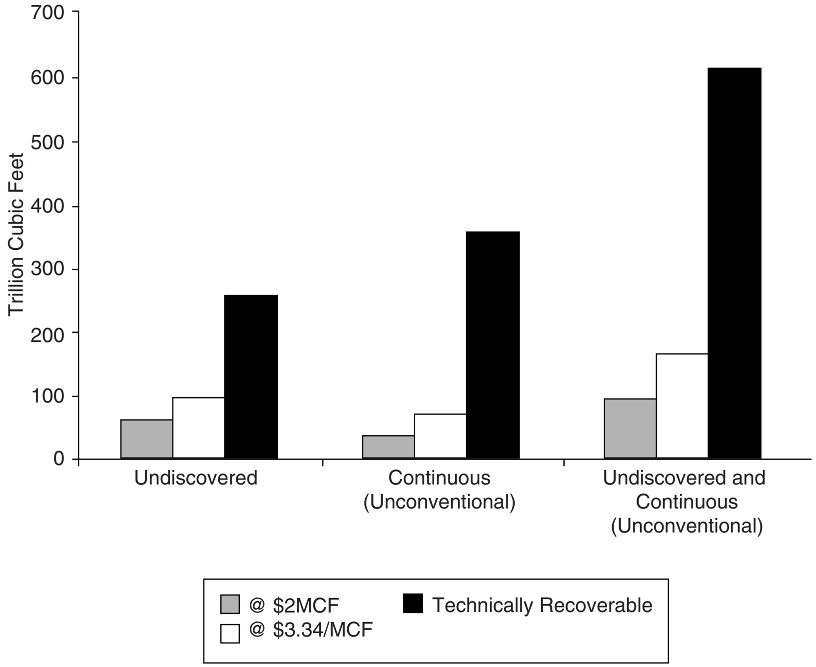

FIGURE 3.6 USGS economically recoverable gas estimates in trillion cubic feet for 1995. SOURCE: Thomas Ahlbrandt, USGS, personal communication, 2003. Data are from USGS (2000).

Association of Petroleum Producers, personal communication, 2003). The United States imports over 16 percent of its gas from Canada—3.8 Tcf in 2002—which accounts for 94 percent of U.S. imports (EIA, 2003a). Most forecasts for the next 15 to 20 years assume steadily increasing Canadian imports, in excess of 4 Tcf/year (Mary Hutzler, EIA, personal communication, 2003). However, growth in Canadian gas requirements (particularly for Albertan oil sands development), the size of the remaining resource base, and a decrease in the size of recently discovered gas pools might combine to limit Canada's future contribution to U.S. consumption to 4 to 4.5 Tcf/year (Greg Stringham, Canadian Association of Petroleum Producers, personal communication, 2003). The remaining resource base has been assessed by Canadian organizations as 235 to 462 Tcf (see Table 3.1). Much of this gas has frontier status (see Figure 3.8) and/or does not have pipeline access (Greg Stringham, Canadian Association of Petroleum Producers, personal communication, 2003). Additionally, about half of the gas to be delivered from the Mackenzie River Delta region, after a pipeline is built, could be consumed within Canada in conjunction with heavy

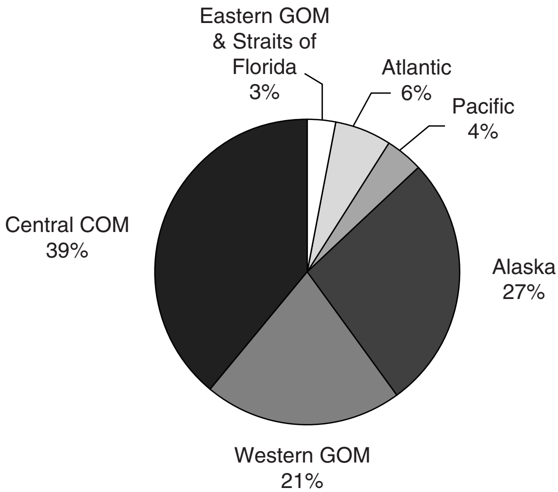

FIGURE 3.7 Distribution of remaining gas resources in the federal outer continental shelf by area (includes discovered remaining reserves, mean undiscovered conventionally recoverable resources, and 5.7 Tcf of discovered Alaska reserves that are currently uneconomical). SOURCE: Richie Baud, Minerals Management Service, personal communication, 2003. Data are from Lore et al. (2001), Sherwood and Craig (2001), and Sorensen et al. (2000).

TABLE 3.1 Range of Assessments by Canadian Organizations of the Remaining Natural Gas Resource Base as of Year End 2001

Region	Maximum (Tcf)	Minimum (Tcf)
Western Canada Sedimentary Basin[a]	209	138
Atlantic Canada[a,b]	59	33
Mackenzie Delta[a]	64	64
Coalbed Methane[c]	135	0
Total	462	235

[a]Data are from National Energy Board (Canadian National Energy Board, 1999).
[b]Data from Canada-Nova Scotia Offshore Petroleum Board (Canadian National Energy Board, 1999).
[c]Data are from Geological Survey of Canada (Heath and Associates, 2001).

SOURCE: Greg Stringham, Canadian Association of Petroleum Producers, personal communication, 2003.

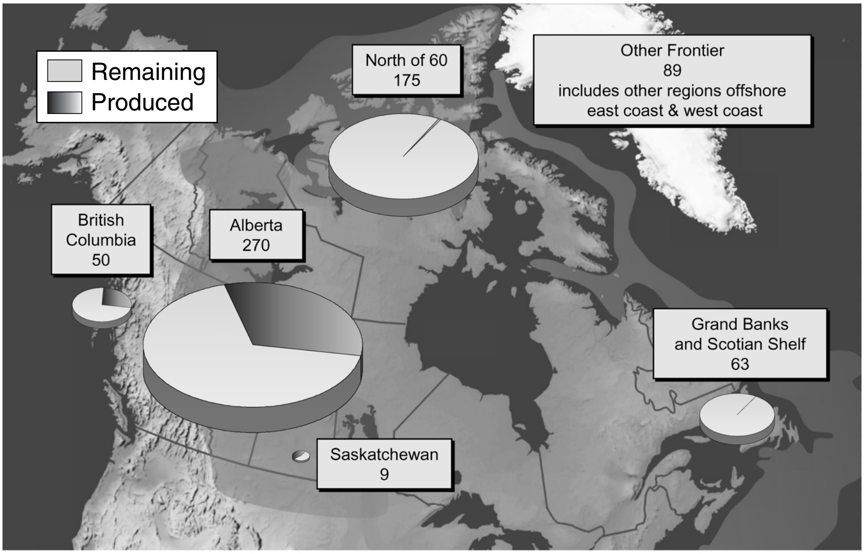

FIGURE 3.8 Ultimate potential of Canadian natural gas in trillion cubic feet. SOURCE: Greg Stringham, Canadian Association of Petroleum Producers, personal communication, 2003. Data are from Canadian National Energy Board (1999).

oil production. The other half of the Mackenzie Delta gas would be available to North American markets. Canadian producers face similar land access and regulatory issues as their U.S. counterparts. On a more positive note, the first coalbed gas production in Canada began in Alberta in 2003.

The Western Canada Sedimentary Basin of Alberta, British Columbia, and Saskatchewan is the premier gas-producing region of Canada and the basin that supplies almost all of the gas exported to the United States (Greg Stringham, Canadian Association of Petroleum Producers, personal communication, 2003). While the Canadian National Energy Board (1999) has assessed the remaining resources at 176 Tcf and the Canadian Gas Potential Committee (2001) estimates 122 Tcf, the USGS (2000) has determined a value of 15.6 Tcf (see Figure 3.9). The USGS estimates represent only a few years of supply. Clearly the methodology and assumptions of these three organizations need to be compared to better determine the remaining Western Canada Sedimentary Basin gas resource.

Mexican Supply

The United States has been a net exporter of natural gas to Mexico for the past 15 years (see Figure 3.10). Presently, the supply within Mexico is

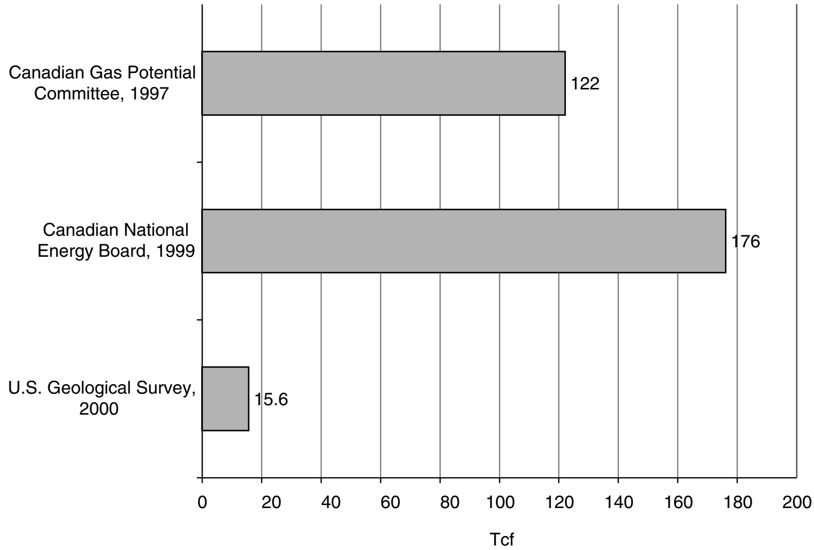

FIGURE 3.9 Estimates for undiscovered recoverable gas in the Western Canada Sedimentary Basin in trillion cubic feet. SOURCE: Thomas Ahlbrandt, USGS, personal communication, 2003. Data are from USGS (2000), Canadian Gas Potential Committee (1997), Canadian National Energy Board (1999), and Henry and Charpentier (2001).

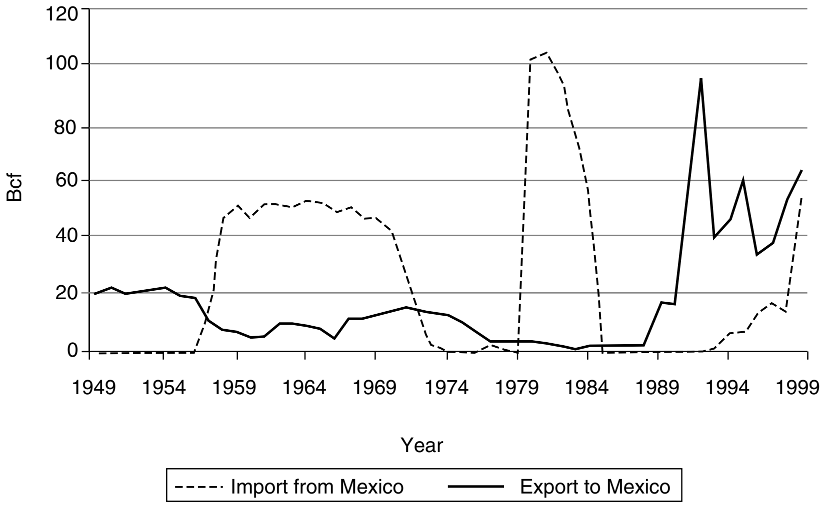

FIGURE 3.10 U.S. natural gas trade with Mexico for the period 1949 to 1999 in billion cubic feet. SOURCE: Scott Tinker, University of Texas at Austin, personal communication, 2003. Data are from EIA (2000b).

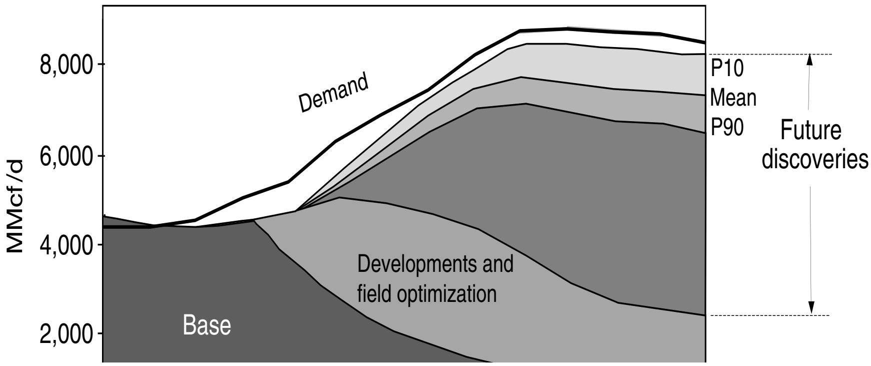

FIGURE 3.11 Natural gas production in Mexico for the period 2001 to 2010 in billion cubic feet per day. Mexican supply is not expected to meet demand. SOURCE: Alfredo E. Guzman, Petroleos Mexicanos, personal communication, 2003. Data are from Pemex Exploration and Production.

not projected to meet domestic demand and Mexico would have to increase its imports of gas, either from the United States or as LNG (see Figure 3.11). Petroleos Mexicanos is trying to reverse the low levels of internal investment and increase the number of prospects drilled by allowing foreign operators to participate, within the current legal framework, in all phases of the exploration and production value chain. Reported reserves of nonassociated gas range from 9 to 21 Tcf, with a total gas reserve base, including associated gas, of 76 Tcf (Alfredo E. Guzman, Petroleos Mexicanos, personal communication, 2003). The USGS (2000) has assessed an undiscovered total mean volume of 49.2 Tcf of which 26 percent is nonassociated gas. Even though it does not appear that Mexico will be able to export gas, EIA (2003a) projections include Mexico as a net potential source of imports (Mary Hutzler, EIA, personal communication, 2003).

Liquefied Natural Gas

LNG is natural gas in liquid form. It is produced by liquefying natural gas to –60°F (–162°C) using a low-temperature refrigeration process. LNG is a colorless, odorless liquid that consists mainly of methane (80 to 99 percent), with variable amounts of ethane, propane, and nitrogen. It occupies 600 times less volume than the same mass of gaseous methane at standard conditions, which allows for efficient transport of large quantities in cryogenic tankers to a receiving terminal. There it is con-

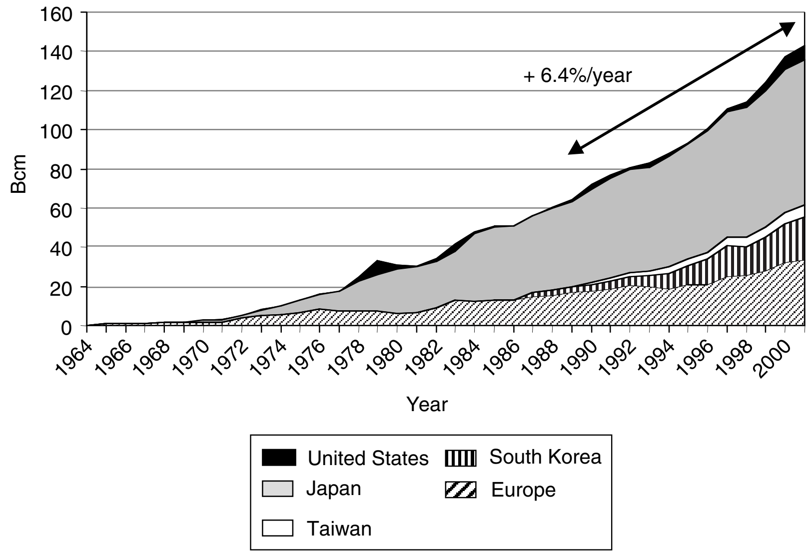

FIGURE 3.12 Evolution of world LNG trade for the period 1964 to 2001 in billion cubic meters. SOURCE: Colleen Sen, Gas Technology Institute, personal communication, 2003. Data are from Cedigaz (2002).

verted or "regasified" back into natural gas for consumption onsite or piped to end users as part of their normal gas supply (Potential Gas Committee, 2002).

Transport of natural gas as LNG allows demand to be met (and built) in countries where local supplies are insufficient (e.g., South Korea, Japan) and also permits expanded gas production from countries where gas supply far exceeds demand (e.g., Algeria, Qatar). There has been a rapid increase in LNG trade predominantly with Middle Eastern and Pacific Rim countries (see Figure 3.12 and Table 3.2). The U. S. currently imports less than 2 percent of its natural gas supply via LNG, and it exports LNG from Alaska to Japan (see Figure 3.13). Relatively small volumes of LNG are used in the United States for storage and peak shaving. U.S. demand for LNG is projected to grow to in excess of 2 Tcf/year by 2025 (Mary Hutzler, EIA, personal communication, 2003).

Natural Gas Hydrates

Methane in the form of natural gas hydrates represents a potential future supply of gas far in excess of known producible supplies, though uncertainty in the estimate is very high (see Figure 3.14). Efforts have been

TABLE 3.2 LNG Exports for 2001 in Billion Cubic Meters.

Country	Exports
Indonesia	31.80
Algeria	25.54
Malaysia	20.91
Qatar	16.54
Australia	10.20
Brunei	9.00
Nigeria	7.83
Oman	7.43
Abu Dhabi	7.08
Trinidad	3.65
United States	1.79
Libya	0.77
Taiwan (re-export)	.041
Total	142.95

SOURCE: Colleen Sen, Gas Technology Institute, personal communication, 2003. Data are from Cedigaz (2002).

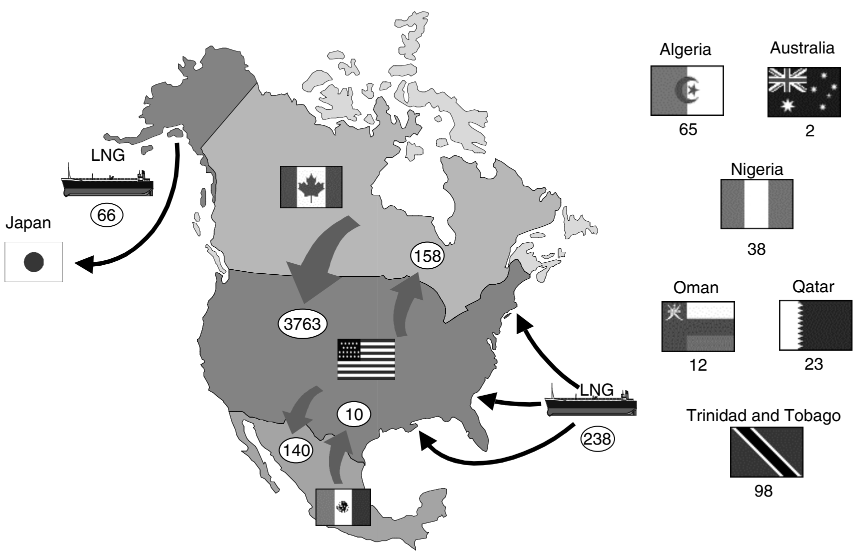

FIGURE 3.13 Natural gas imports and exports for 2001 in billion cubic feet. SOURCE: Thomas Ahlbrandt, USGS, personal communication, 2003. Data are from U.S. Department of Energy (2002).

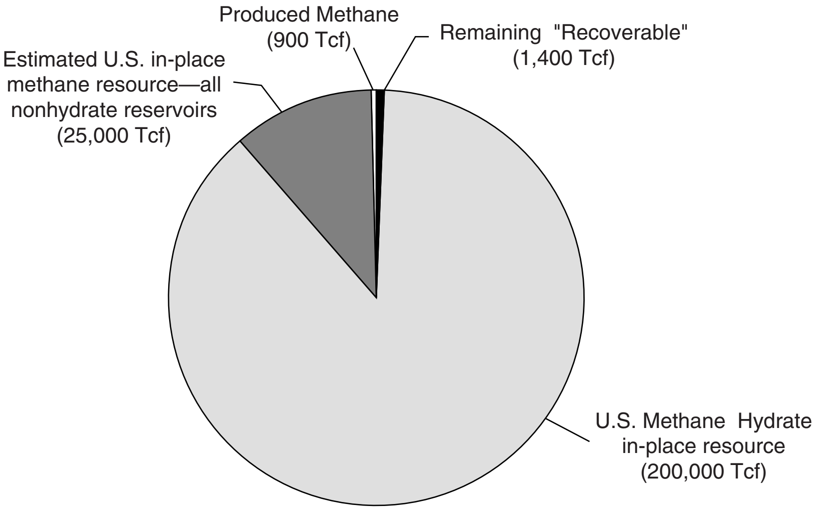

FIGURE 3.14 Methane hydrate resources in trillion cubic feet. Roughly 200,000 Tcf of the total U.S. methane resource of 227,500 Tcf resides in methane hydrates. SOURCE: Keith Millheim, Anadarko Petroleum Corporation, personal communication, 2003. Data are from National Energy Technology Laboratory (2002).

made, with international funding, to test the producibility of permafrost terrain deposits in the Mackenzie River Delta area of Canada. Detailed results, which did result in gas production via a flare, are embargoed until 2004. U.S. government-industry-academia consortia are conducting two research projects involving gas hydrate resources in the vicinity of Prudhoe Bay, Alaska. Other projects are or have been conducted offshore of Oregon and in the Gulf of Mexico. As a measure of the growing importance of gas hydrates to future supply planning, the Minerals Management Service is beginning to assess hydrate occurrence (Pulak Ray, Minerals Management Service, personal communication, 2003).

NORTH AMERICAN SUPPLY GOING FORWARD

Committee members and participants noted that assessments presented at the workshop of the future supply of natural gas in North America sent somewhat mixed signals. Some workshop participants believed that (1) the United States will continue to require increasing amounts of imported natural gas to meet projected demand and that North American pipeline imports and LNG will be required to meet U.S. demand; (2) Canada will increase its domestic consumption, with little excess export capacity beyond that of the present day; and (3) Mexico will most likely remain a net importer of natural gas. LNG imports and perhaps hydrates may be required to augment the North American gas supply.

4

Meeting U.S. Natural Gas Demand

America's appetite for natural gas is growing. As discussed in Chapter 2, current estimates suggest average growth in U.S. domestic demand of 2 percent per annum, approaching 30 Tcf/year by the middle of the next decade (EIA, 2003a). Given recent examples of extreme price and storage volume volatility, the workshop discussion focused on how the United States could secure stable supplies of natural gas to meet domestic demand. The committee and workshop participants discussed the role of and interplay among access, technology, and competitive market issues in securing new supplies of natural gas through both internal and external sources. U.S. energy policies and world market price fluctuations will drive the relative mix of internal and external supplies to meet demand.

U.S. PRODUCTION AND STORAGE TRENDS

The committee and workshop participants discussed U.S. natural gas production trends, storage trends, and storage variability. These discussions are summarized below.

In the past decade, daily natural gas production in the United States grew from about 40 Bcf/day in the early 1990s to about 48 Bcf/day in 1997 (see Figure 4.1). Production trends from 1997 through 2002 remained relatively flat despite a doubling in the gas rig count from 1999 to 2001 (Naresh Kumar, Growth Oil and Gas, personal communication, 2003).

Peak production rates for individual gas wells increased by more than

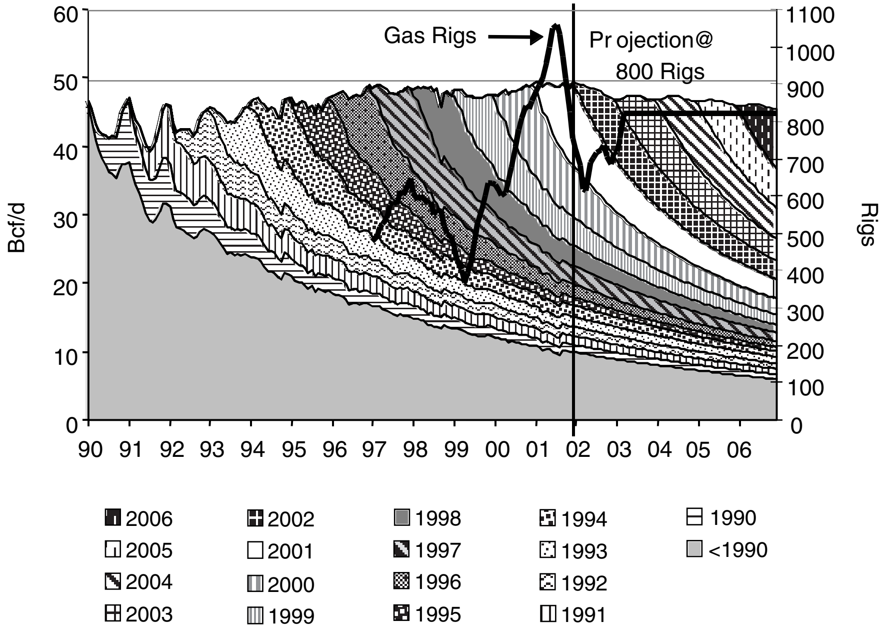

FIGURE 4.1 U.S. daily wet natural gas production from gas wells by year of production start for the period 1990 to 2006. SOURCE: Compiled by Anadarko Petroleum Corporation, 2003. Data are from IHS Energy (2003) and EIA (2003a).

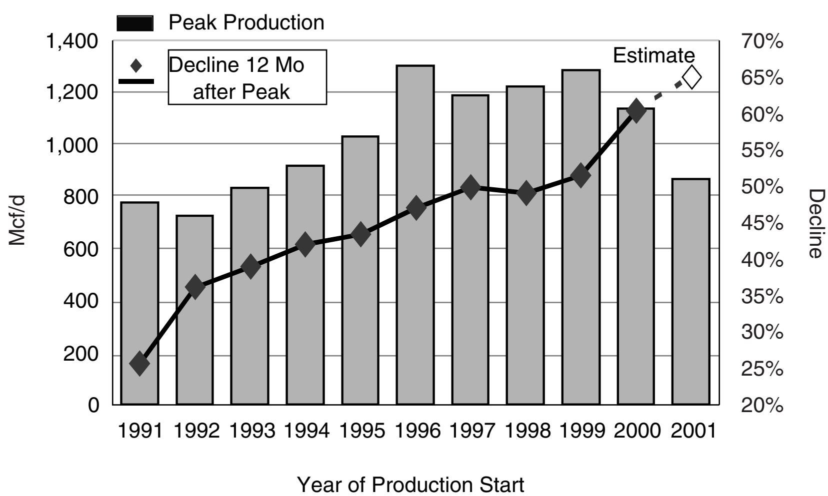

FIGURE 4.2 Average peak total U.S. natural gas production and first-year decline per well by year of production start for the period 1991 to 2001. SOURCE: Anadarko Petroleum Corporation, 2003. Data are from IHS Energy (2003) and EIA (2003a).

50 percent from 1991 to 1997 (see Figure 4.2), largely as a result of improved drilling and completion practices. Since 1997, average initial production rates leveled off and even showed signs of decline in 2001 and 2002. From 1991 to 2001, first-year decline rates for gas wells dramatically increased from about 25 percent to over 50 percent, while per-well reserves, other than for coalbed methane wells in the Powder River Basin, remained relatively flat (see Figure 4.3).

Ever-increasing decline rates are apparent in a recent Texas study of all gas completions in a 53-county area (Matt Simmons, Simmons and Company International, personal communication, 2003). In that study, gas wells completed in 2002 comprised 32 percent of the total 7.8 Bcf/day production for January 2003, while all 2001 vintage wells combined accounted for a mere 5 percent of total production (having already declined by 68 percent).

The Gulf of Mexico offshore area currently contributes 5+ Tcf/year, or about 25 percent of the total U.S. domestic natural gas production (Richie Baud, Minerals Management Service, personal communication, 2003). Deepwater and deep-shelf gas exploration activities are expected to bring new production volumes on-stream in the coming years (up to 1 Tcf/year). However, the Minerals Management Service projects flat overall production through 2006 from the Gulf of Mexico offshore area due to offsetting steep decline rates on the base shelf production.

Overall, near-term projections for U.S. gas production indicate that, even with a healthy rig count of about 800 rigs, production is expected to gradually decline through 2006 (see Figure 4.1). The EIA shows a more optimistic long-term production growth profile through 2025 (see Figure 2.6), though real growth is indicated only from onshore unconventional sources (see Figure 4.4) (Mary Hutzler, EIA, personal communication, 2003).

In any case, current U.S. production trends appear to be relatively stable. However, the seasonal cyclicity of demand was clearly demonstrated in the past 6 months when record-high storage volumes in October 2002 (over 3 Tcf) were drawn down to record lows (less than 700 Bcf) by March 2003 (see Figure 4.5). This extreme storage volatility can be attributed to an imbalance in supply and demand and to the interplay between factors such as wellhead price, weather, imports, domestic rig activity, deliverability of new wells, and availability and cost of external supplies (i.e., pipeline and LNG-sourced). These dynamics further emphasize the need to secure reliable future supplies of natural gas, not only to satisfy projected average U.S. demand growth (2 percent per annum) but also to fill short-term “gaps” during extreme demand cycles. Reliable supplies will require improved transportation networks and improved storage capacity (Colleen Sen, Gas Technology Institute, personal communication, 2003).

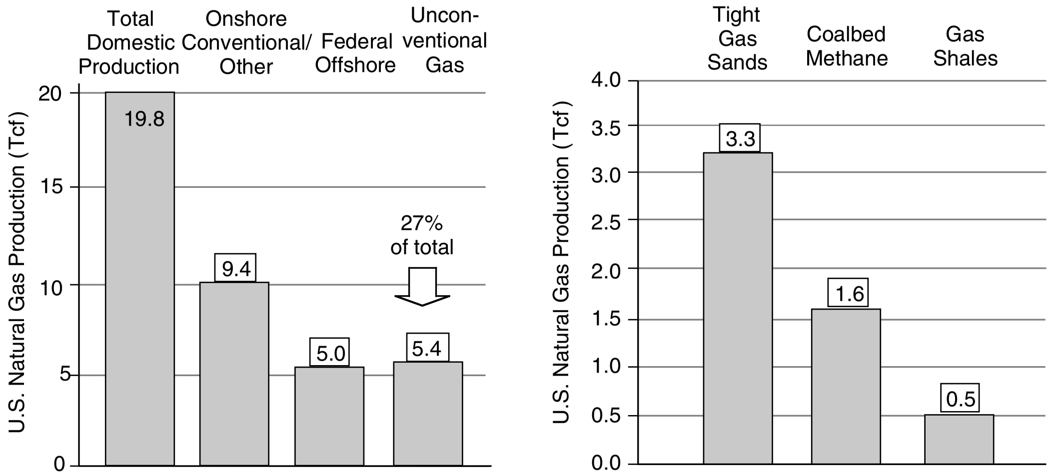

FIGURE 4.3 Sources of U.S. natural gas production in 2001 in Tcf. SOURCE: Kuuskraa (2003). Data are from EIA (2003a) and the Advanced Resources International, Inc., database.

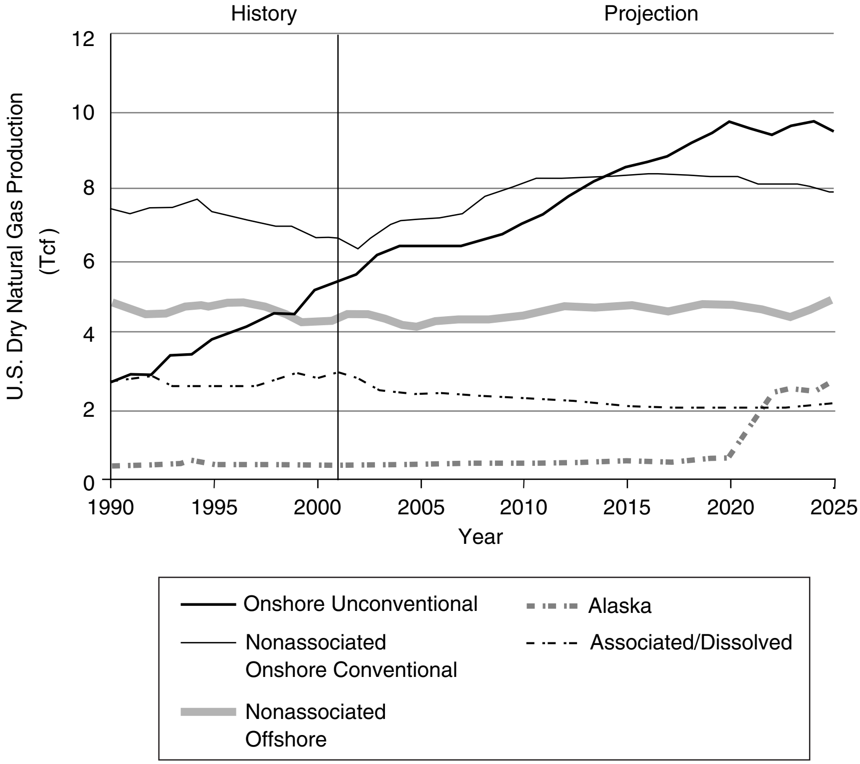

FIGURE 4.4 U.S. dry natural gas production in trillion cubic feet for the period 1990 to 2025. SOURCE: EIA (2003a, p. 76).

U.S. SOURCES OF NATURAL GAS

The committee and workshop participants discussed several critical factors that influence projected supplies of natural gas from U.S. sources:

- access to remaining resource areas and the regulatory environment in "leasable" areas;
- technological innovations enabling recognition of new resources and/or making new resources economically recoverable, including research and development funding;
- available workforce, including graduate degree trends; and
- economic incentives designed to accelerate investment in domestic natural gas projects.

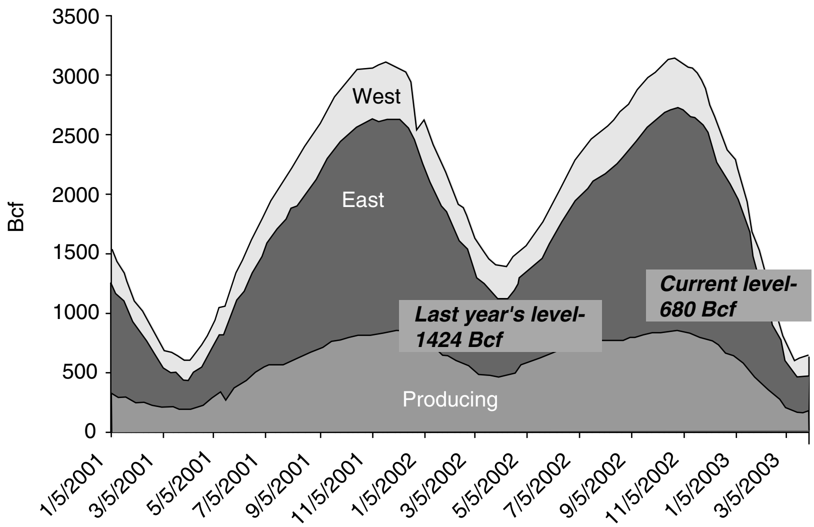

FIGURE 4.5 U.S. natural gas storage capacity for the period January 2001 to March 2003. SOURCE: Greg Stringham, Canadian Association of Petroleum Producers, personal communication, 2003.

Access and Regulatory Issues

As discussed at the workshop, access to remaining resource areas rich in natural gas in the United States is currently constrained by areas wholly or partially off-limits to leasing, including the offshore East Coast, offshore West Coast, portions of the offshore eastern Gulf of Mexico (including offshore Florida), portions of the onshore Rocky Mountains and western states, and portions of offshore and onshore Alaska (including the Alaska National Wildlife Refuge and portions of the National Petroleum Reserve Alaska). Some workshop participants believe that these areas contain significant remaining oil and gas resources that could be explored and developed using modern technologies. For the lower 48 federal outer continental shelf alone, the Minerals Management Service estimates the remaining conventionally recoverable natural gas resource at about 63 Tcf for the East Coast, West Coast and eastern Gulf of Mexico areas combined (see Figure 4.6). This resource estimate equates to about a 3-year supply of total U.S. natural gas consumption, at current annual rates.

Workshop participants also discussed the impact of operational and regulatory restrictions on the timing and economics of natural gas resources in "leasable" areas. In the Rocky Mountains, full-cycle exploration to first production on federal leases can take 7 years or more because of the time required to obtain permits, seasonal and wildlife restrictions

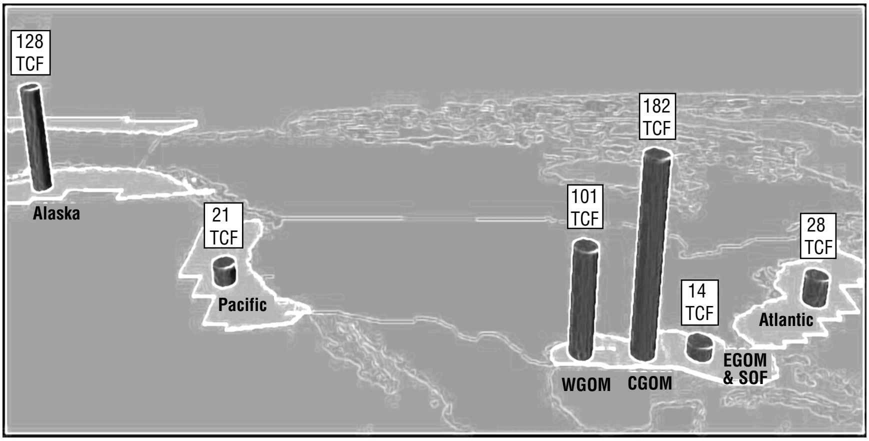

FIGURE 4.6 Remaining economic gas resources at $3.52/Mcf in the federal outer continental shelf (includes discovered remaining reserves and mean undiscovered economically recoverable resources). SOURCE: Richie Baud, Minerals Management Service, personal communication, 2003. Data are from Lore et al. (2001), Sherwood and Craig (2001), and Sorensen et al. (2000).

(e.g., operating "windows" of 2 to 4 months/year), and ensuing environmental impact studies and regulatory approvals (see Figure 4.7). The National Petroleum Council (2001) estimates that 137 Tcf, or about 40 percent of the remaining gas resource in the Rocky Mountains, is on federal lands currently closed to exploration or under restrictive provisions. Similar operational and regulatory challenges exist in Canada, where federal and provincial reforms are under way to create a more efficient regulatory "road map" (Greg Stringham, Canadian Association of Petroleum Producers, personal communication, 2003).

Technology

Technology is another critical factor discussed at the workshop that influences projected supplies of natural gas from U.S. sources. Technology has consistently had a significant positive influence on both technically and economically recoverable resource estimates. An historic compilation of natural gas resource estimates for the lower 48 states indicates that both public- and private-sector estimates ramped up considerably in the 1990s (see Figure 4.8). This three- to four-fold increase is largely attributable to previously underestimated resources from unconventional reservoirs, such as tight sands, basin-centered gas, shale gas, and coalbed

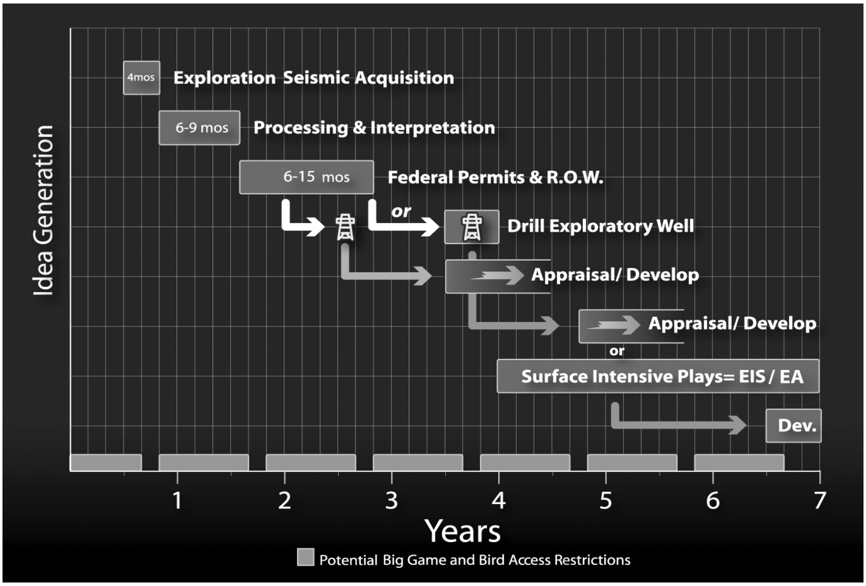

FIGURE 4.7 Natural gas resource development timeline for the Rocky Mountains. SOURCE: James Emme, Anadarko Petroleum Corporation, personal communication, 2003.

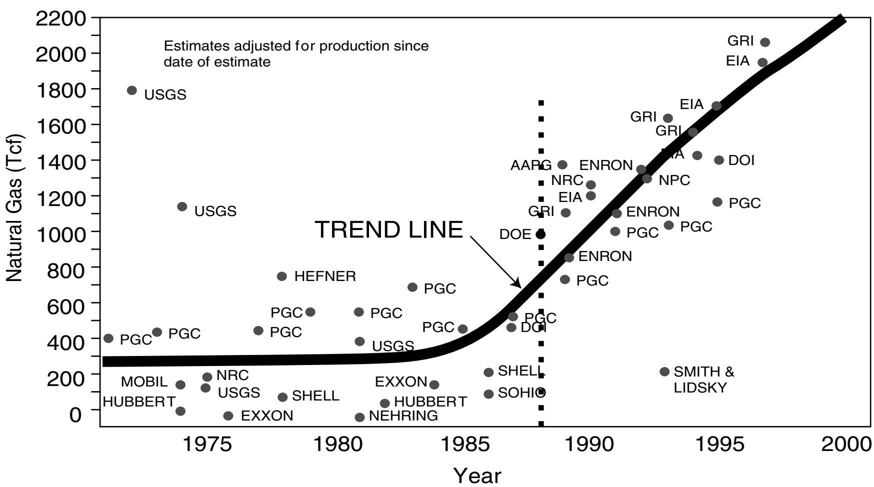

FIGURE 4.8 Estimates of remaining natural gas reserves in the lower 48 states in trillion cubic feet for the period 1970 to 2000. SOURCE: Kumar (2001).

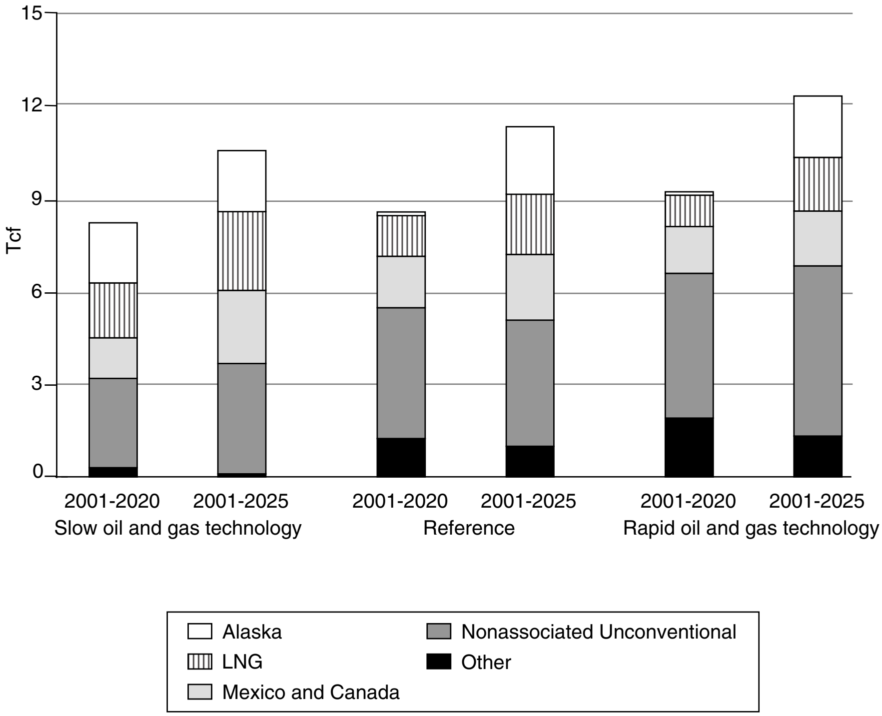

FIGURE 4.9 Major sources of incremental natural gas supply in three cases, 2001 to 2020 and 2001 to 2025. The first case is slow oil and gas technology growth. The second case is the reference case. The third case is rapid oil and gas technology growth. Volume is in trillion cubic feet. SOURCE: Mary Hutzler, EIA, personal communication, 2003. Data are from EIA (2003a).

methane. The timing of these increased estimates coincides with widespread development of unconventional reservoirs using new or improved drilling and completion technologies necessary for economic recoveries.

The EIA has modeled three scenarios of a combination of supply sources to meet future U.S. natural gas demand over the next 17 to 22 years (see Figure 4.9). By 2025 low- versus high-technology tracks could influence annual gas demand by 1.8 Tcf and wellhead price by $0.84/Mcf (EIA, 2003a) (see Figure 2.10). Rapid technological innovations favor the growth of unconventional sources at the expense of pipeline or LNG imports.

Technological improvements impact all facets of exploration and production activities, including but not limited to seismic acquisition, processing and interpretation, drilling and completion techniques, reservoir characterization, and basin modeling. Advances in computer power due to parallel processing have resulted in dramatically increased resolution of three-dimensional seismic data acquisition (i.e., fold and frequency content), processing (e.g., wave equation migration algorithms), and imaging and interpretation software (James Emme, Anadarko Petroleum Corporation, personal communication, 2003). Improved predrill seismic data obtained at ever-decreasing costs will continue to impact exploration efficiency, especially in difficult-to-image plays (e.g., the Gulf of Mexico subsalt).

Workshop participants noted that recent examples of important drilling and completion technology breakthroughs exist in virtually all U.S. operational areas, including onshore (unconventional reservoirs), offshore deepwater, deep-shelf, and subsalt settings and in the Arctic. A few of these are presented below.

Bossier Sands, Onshore East Texas and North Louisiana

Since 1996, significant new gas reserves have been discovered in the East Texas and North Louisiana salt basins. Jurassic-aged Bossier sands are tight, overpressured unconventional reservoirs that, prior to 1996, were considered a drilling hazard en route to deeper objectives and as such were rarely completed (James Emme, Anadarko Petroleum Corporation, personal communication, 2003). Lower costs and higher well productivities were subsequently achieved through a combination of (1) 25 to 40 percent improved drilling efficiencies (e.g., using top-drive rigs, poly-diamond carbon bits, mud motors); (2) lower-cost and higher-productivity fracture stimulations (e.g., staged, high-pressure, limited-entry fracture stimulations and use of coiled tubing); and (3) improved cycle time and decreased down time (e.g., use of remote monitoring) (James Emme, Anadarko Petroleum Corporation, personal communication, 2003). Future improvements are anticipated with the application of new, deep, and hostile environment drilling technologies as well as expandable liners (e.g., slim-hole concepts).

Current industry estimates of economically recoverable discovered reserves for the Bossier are at least 4 to 5 Tcf, and current production rates from Bossier sands exceed 600 Mcf/day (James Emme, Anadarko Petroleum Corporation, personal communication, 2003). USGS resource estimates for 1995 did not recognize Bossier sands in the assessment.

Nakika and Canyon Express Developments, Offshore Eastern Gulf of Mexico

The Nakika and Canyon Express developments in the eastern Gulf of Mexico illustrate how improved deepwater subsea technologies have linked relatively small discoveries to economically viable projects. The

Nakika development links five independent oil and gas fields in water depths of 5,800 to 7,000 feet. Subsea completions will tie back to a central, permanently moored floating production facility scheduled for start-up by the end of 2003 (with peak rate capacity of 425 Mcf/day and 110 thousand barrels of oil per day). A sixth field, Coloumb, in water depths of approximately 7,600 feet, will be tied back 22 miles to the host facility by about mid-2004. Ultimate recoverable reserves for the six-field complex are over 300 million barrels of oil equivalent (or 300 Bcf equivalent per field) (Luyties, 2003).

North of Nakika in the Mississippi and Desoto Canyon areas, the Canyon Express pipeline system is currently the world's deepest producing development (500 million cubic feet per day [MMcf/d] capacity, on line since September 2002), linking three separate gas fields totaling 900 Bcf equivalent recoverable (300 Bcf equivalent per field) (see *http://www.gomr.mms.gov/homepg/offshore/canyon/*). One of the fields, Aconcagua, holds the world's water depth production record at 7,210 feet and was on line just 40 months after the initial discovery well was drilled in April 1999.

Enabling technologies for these projects include subsea SMART well completions with commingled multiple reservoirs, use of multiphase flow meters and flow assurance systems (e.g., pipe-in-pipe, methanol cycling for hydrate inhibition), and modern floating production facilities. Enhanced capabilities, lower costs, and improved cycle times now allow fields as small as 250 Bcf to 300 Bcf to be economically developed. Minimum reserve thresholds will likely continue to drop over time, significantly increasing estimates of economically recoverable deepwater resources (James Emme, Anadarko Petroleum Corporation, personal communication, 2003).

Alpine Field and Arctic Platform, North Slope of Alaska

The Alpine field, located on the Colville Delta on the North Slope of Alaska, is the largest onshore discovery in more than a decade (430 million barrels of recoverable oil). Using modern long-reach horizontal drilling (up to 3+ miles), the field is currently producing about 100 million barrels of oil per day from surface facilities totaling only about 100 acres (even though the areal extent of the field in the subsurface is about 40,000 acres). Effective utilization of horizontal drilling techniques illustrates how acceptable low-impact development schemes can work for future oil and gas developments in sensitive arctic environments (James Emme, Anadarko Petroleum Corporation, personal communication, 2003).

Separately, on the North Slope during the winter of 2002 to 2003, a new drilling concept called the Arctic Platform was utilized as part of a

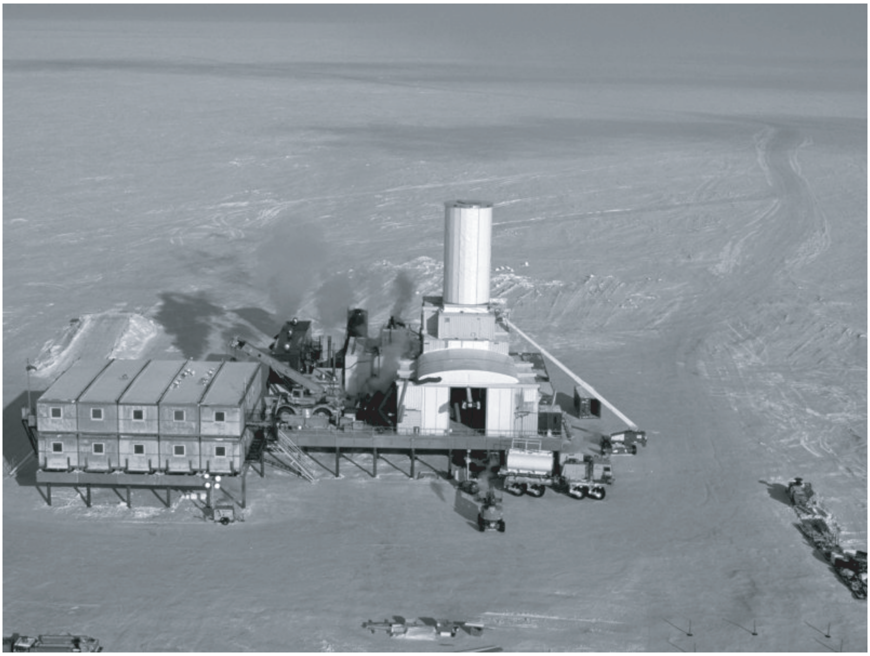

FIGURE 4.10 Anadarko's Arctic Drilling Platform in actual operation at Hot Ice #1 well site in Alaska, first quarter 2003. SOURCE: Keith Millheim, Anadarko Petroleum Corporation, personal communication, 2003.

test of onshore gas hydrate deposits funded by the U.S. Department of Energy and industry (estimated 590 Tcf resource; National Energy Technology Laboratory (2002). The Arctic Platform is designed like a scaled-down offshore platform, standing above the tundra and using piers set in the permafrost (see Figure 4.10). Current ice-pad technology allows for exploration drilling only during frozen winter months (about a 3- to 4-month window). If successful, the Arctic Platform might allow for expanded operational windows for both conventional and unconventional resource development without damaging sensitive tundra environments.

Research and Development Trends

Private funding for oil and gas research, historically the bastion of major oil companies, has dropped precipitously (by more than half) since the early 1990s (see Figure 1.4). This phenomenon has been fueled, in large part, by consolidation in the exploration and production sector,

FIGURE 4.11 Number of seismic land crews in the United States for the period 1994 to 2003. SOURCE: Anadarko Petroleum Corporation (2003).

including service companies. Workshop participants were particularly concerned about the number of seismic contractors. In 2002 three major seismic contractors exited in the onshore lower 48 states while the land seismic crew count has diminished to one-third of the 1998 to 1999 levels (see Figure 4.11).

In addition, public-sector funding for oil and gas research has also declined. The National Science Foundation indicates that petroleum-related research dollars account for less than 1 percent of total U.S. research and development dollars spent in the past decade (Hill, 2000; see Figure 4.12).

In the United States, the number of doctoral degrees granted in the fields of science and engineering has been in gradual decline since 1996 (see Figure 4.13) (Hill, 2002a). Undergraduate and graduate geoscience degrees show a more precipitous decline having dropped to one-third of the high levels experienced in the early to mid-1980s (see Figure 4.14).

Notwithstanding declining trends in both research and development funding and college degrees granted, technology continues to evolve. It was suggested at the workshop that the United States is "off pace" to achieve long-term goals without commitment and cooperation between both private and public sectors (Naresh Kumar, Growth Oil and Gas, personal communication, 2003). In essence, Kumar stated that the private sector should "pull" technology for short- to mid-term solutions (5- to 10-

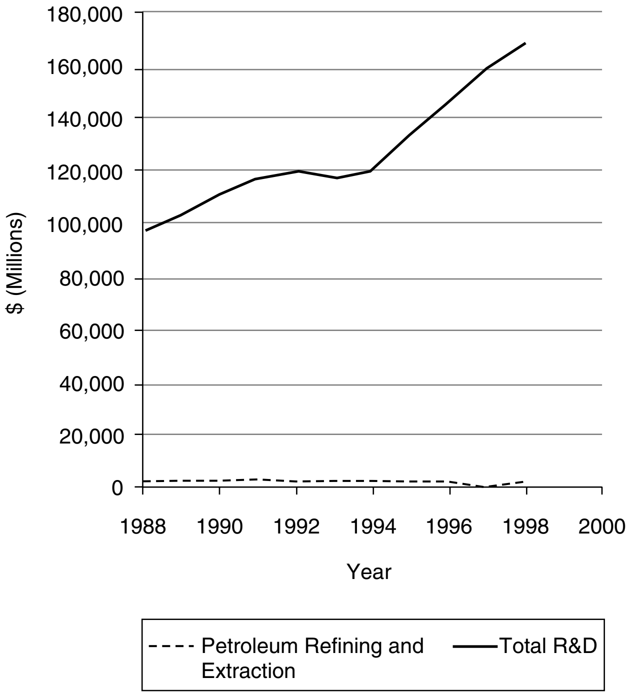

FIGURE 4.12 National research and development dollars for petroleum refining and extraction, and total research and development for the period 1988 to 2000. SOURCE: Naresh Kumar, Growth Oil and Gas, personal communication, 2003. Data are from Wolfe, 2000.

year horizon). And, the public sector, including academia and government-funded entities, would do well to focus and leverage its investments toward longer-term, larger-scale opportunities (e.g., gas hydrates, 10- to 20-year horizon) while maintaining programs that help graduate students become employable in the energy industry (see Figure 4.15).

Economic Incentives

Though somewhat difficult to quantify, economic incentives can provide stimulus to the exploration and production industry where risk-weighted and/or capital-intensive investments are lagging. These incentives can come directly in the form of tax credits and royalty holidays. Indirect incentives might include improved acreage access and regulatory process efficiencies (e.g., improved cycle time), lease extensions and

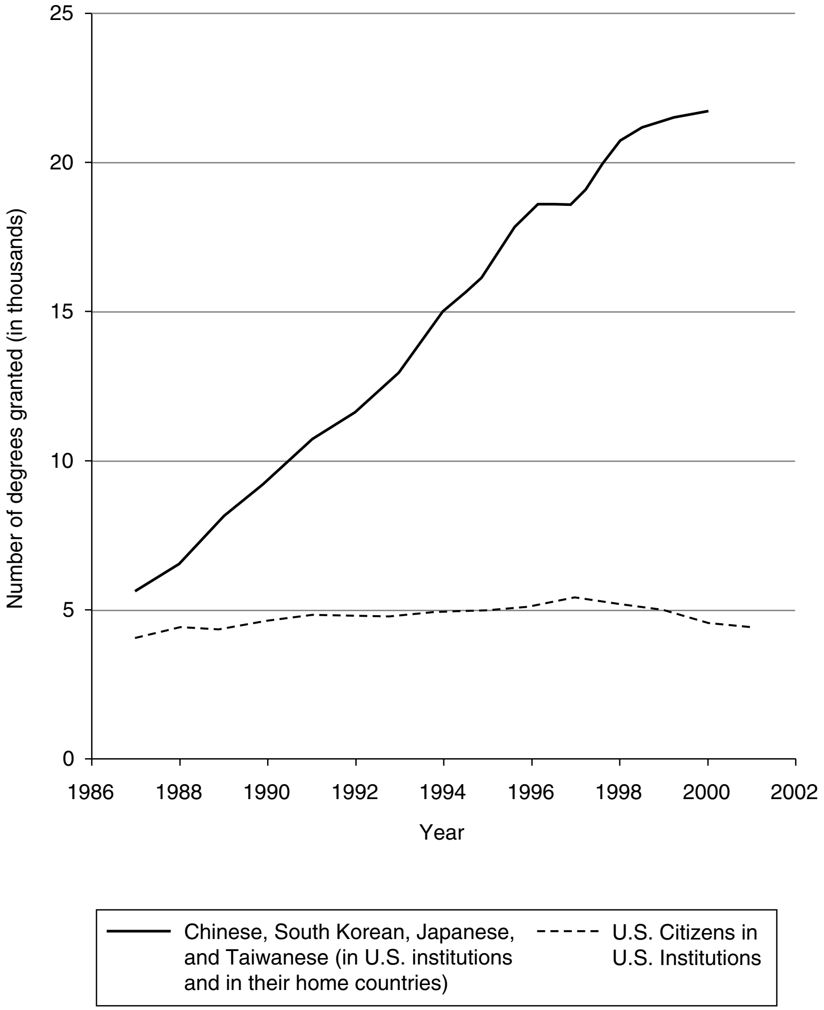

FIGURE 4.13 Doctoral science and engineering degrees for the period 1985 to 2000. Note: The U.S. curve includes physics, chemistry, astronomy, earth, atmospheric, and ocean sciences. Engineering includes aeronautical, astronautical, chemical, civil, electrical, industrial, materials, metallurgical, and mechanical. However, available data for Asian doctorate degrees distinguish the physical sciences from other sciences. This means that the Asian curve includes math, computer science, agricultural, and biological sciences. SOURCE: Richard Smalley and Emmanuelle Schuler, Rice University, personal communication, 2003. Data are from the National Science Board (2002), and Hill (1997, 2002b).

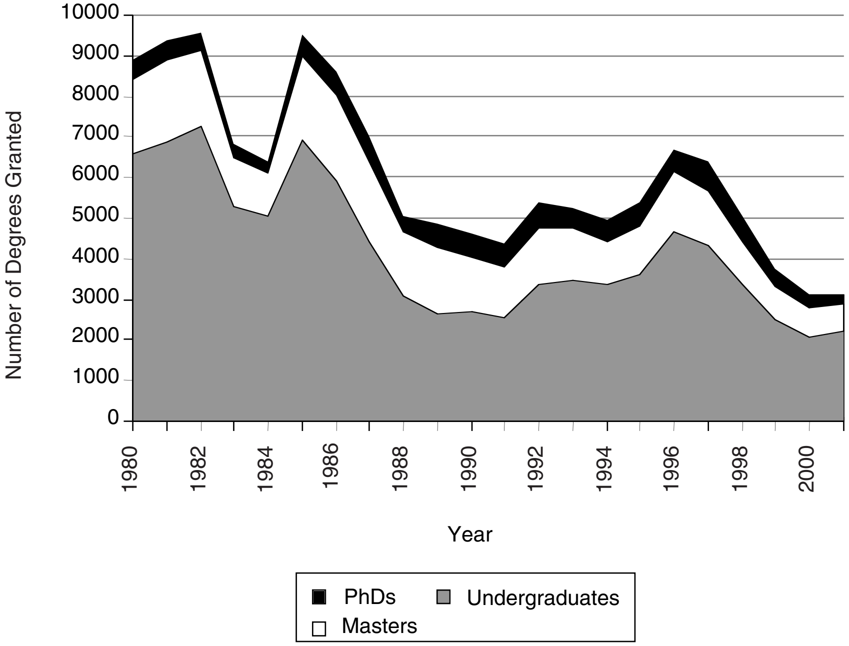

FIGURE 4.14 Geoscience degrees granted during the period 1980 to 2001. SOURCE: AGI (2001).

increasing maximum acreage chargeability limits (e.g., Bureau of Land Management state limitations).

Historic incentives affecting U.S. natural gas production include Section 29 and Section 43 tax credits and deepwater royalty relief. As an example, Section 29 gas credits were enacted in 1980 that created a $0.50/Mcf credit for gas produced from unconventional reservoirs (tight gas sands, coalbed methane, and Devonian shale). Success of the program is indicated by production growth from unconventional reservoirs from 2.0 Tcf in 1990 to 4.8 Tcf in 1999 (EIA, 2001a).

New economic incentives currently being considered include offshore deep-shelf royalty relief (Richie Baud, Minerals Management Service, personal communication, 2003) and in Alaska exploration credits and a gas tax credit or price floor guarantee for a future gas pipeline. These programs serve to incrementally improve economic returns (e.g., rates of return and net present value) or to guarantee minimum economic returns as a means to accelerate capital investment.

Examples of indirect incentives relating to access include the recent opening of federal acreage in the offshore eastern Gulf of Mexico (Sale 181)

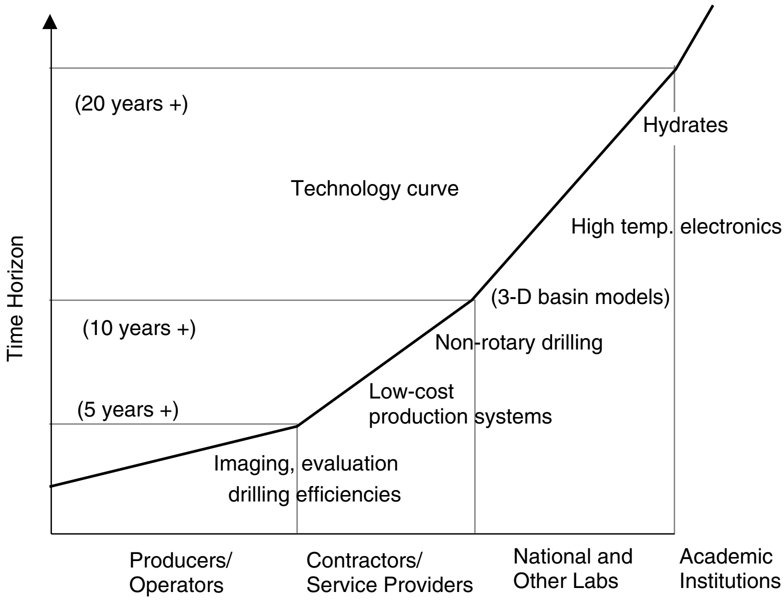

FIGURE 4.15 Likely short-term versus long-term research and development players. SOURCE: Naresh Kumar, Growth Oil and Gas, personal communication, 2003.

and on the North Slope in the eastern National Petroleum Reserve Alaska. Future considerations might include expanding these two areas as well as opening the Alaska National Wildlife Refuge. The Minerals Management Service has also recently adopted the Subsalt Extension Rule, which allows for offshore lease extensions beyond the primary term in exchange for additional high-technology seismic processing (James Emme, Anadarko Petroleum Corporation, personal communication, 2003).

EXTERNAL SOURCES OF NATURAL GAS

The United States currently imports about 11 Bcf/day, or about 18 percent of total consumption (EIA, 2003b). Ninety-four percent of that volume is provided via pipeline imports from Canada (Greg Stringham, Canadian Association of Petroleum Producers, personal communication, 2003), while LNG imports from various sources provide the remaining volumes. Net pipeline imports from Canada have grown since 1994 but remain flat to slightly declining since 2001 (see Figure 4.16). LNG imports have risen since 1998, though volumes are still modest and are constrained due to long-term commitments to other international markets and the significant cost of infrastructure.

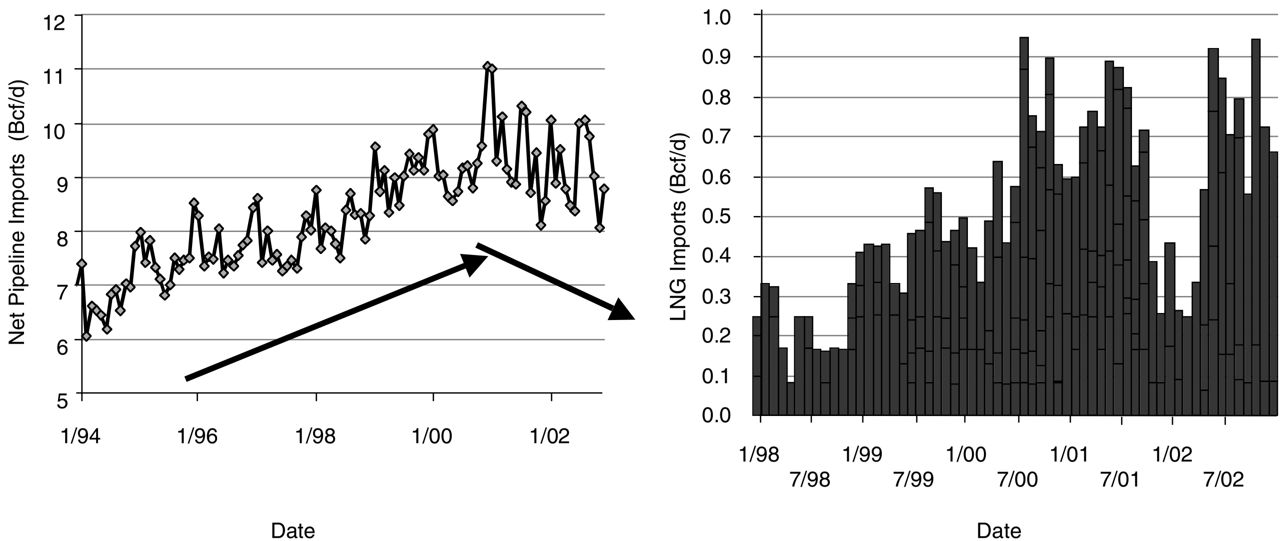

FIGURE 4.16 U.S. pipeline and LNG imports for the period 1994 to 2002. SOURCE: EIA (2003b).

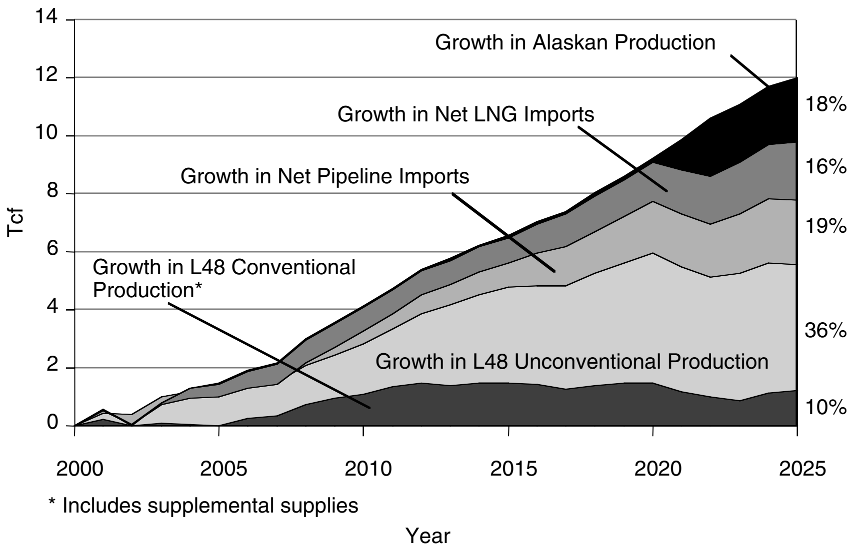

FIGURE 4.17 Sources of incremental natural gas supply for the period 2000 to 2025 in trillion cubic feet. The data include supplemental supplies. SOURCE: Mary Hutzler, EIA, personal communication, 2003. Data are from EIA (2003a).

The EIA (2003a) projects that by 2025 net LNG and pipeline imports (including Alaska) will account for more than 6 Tcf/year, or 53 percent, of new incremental gas supplies above the current base (4 Tcf/year) (see Figure 4.17). The same study indicates that Mexico will be a net gas importer from the United States until 2020, while relatively steady U.S. import growth will occur from LNG and Canadian pipeline sources throughout the period (see Figure 4.18).

Canada

Canada's ability to grow its domestic natural gas production will drive its role in supplying U.S. demand. Canada's pipeline network is well positioned to supply U.S. markets through various northern routes (see Figure 4.19). Canada's immediate production potential is tied to performance in the Western Canada Sedimentary Basin. Future natural gas production growth depends on accessing unconventional reservoirs, such as coalbed methane, in the Western Canada Sedimentary Basin and conventional resources in the Mackenzie Delta and offshore East Coast (Greg Stringham, Canadian Association of Petroleum Producers, personal communication, 2003).

In the past decade, Canada has grown Western Canada Sedimentary

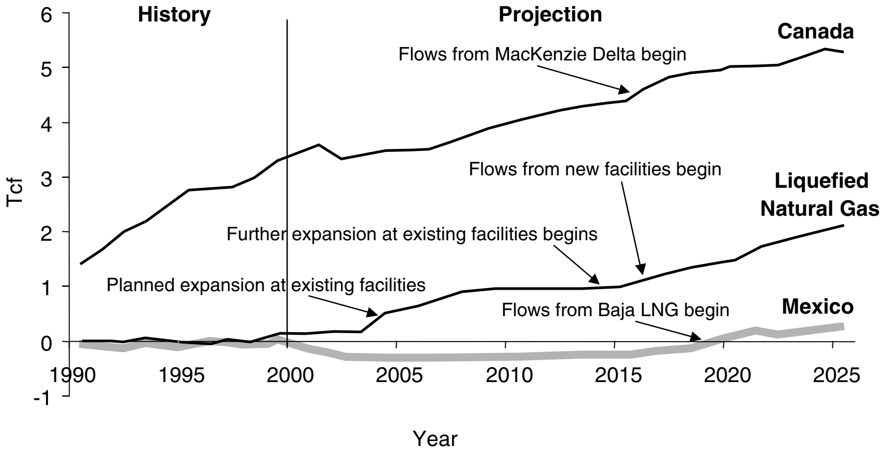

FIGURE 4.18 Net U.S. natural gas imports for the period 1990 to 2025 in trillion cubic feet per year. SOURCE: Mary Hutzler, EIA, personal communication, 2003. Data are from EIA (2003a).

Basin natural gas production from 10 to 12 Bcf/day to more than 17 Bcf/day (see Figure 4.20). Improving netback (the net price to producers after treatment and transport charges), gas prices, and infrastructure (e.g., Alliance pipeline) were key to this growth. Since 2001, however, Canadian natural gas production has been flat despite significant new discoveries (e.g., Ladyfern Field) (Greg Stringham, Canadian Association of Petroleum Producers, personal communication, 2003).

The Canadian National Energy Board estimates of Canada's total remaining natural gas resource range from 235 to 462 Tcf, with significant contributions from the Western Canada Sedimentary Basin, coalbed methane, Mackenzie Delta and the East Coast (see Figure 3.8). USGS estimates for the Western Canada Sedimentary Basin (16 Tcf) are an order of magnitude less than National Energy Board estimates (176 Tcf), suggesting huge disparities in the methodologies used (see Figure 3.19) (USGS, 2000). The USGS's estimates for the basin would imply an undiscovered reserve volume equivalent to only about a 2.5-year supply based on current production rates.

Future natural gas production from all Canadian sources is expected to grow incrementally about 1 Tcf/year by 2010 and then, depending on technology and environmental drivers, either decline or grow more gradually until 2020 to 1.5 Tcf/year above the current base (see Figures 4.21 and 4.22). Rapid technological advances and environmental preferences for natural gas might favor development of eastern Canada offshore resources and coalbed methane growth. Alternatively, slower technology (the supply

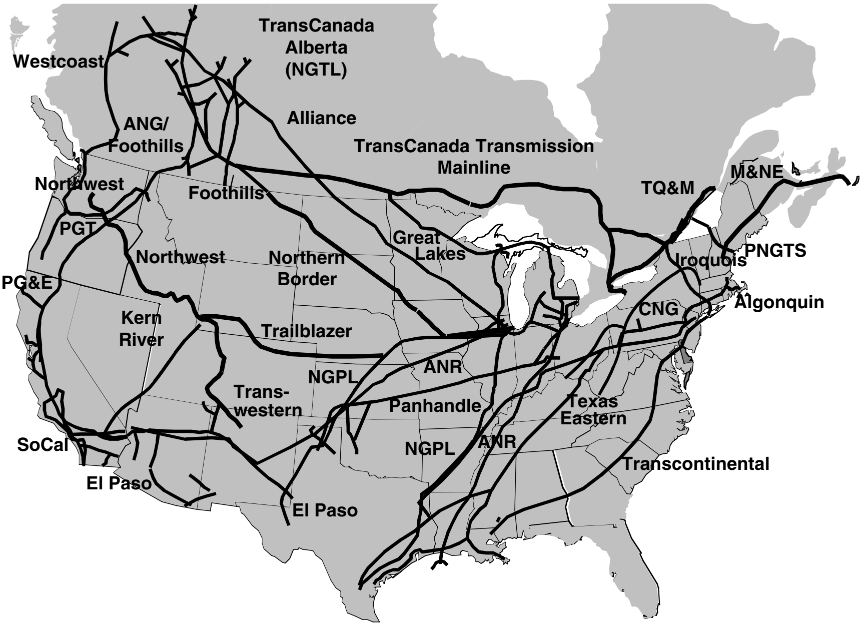

FIGURE 4.19 Canadian and U.S. natural gas pipelines. SOURCE: Greg Stringham, Canadian Association of Petroleum Producers, personal communication, 2003.

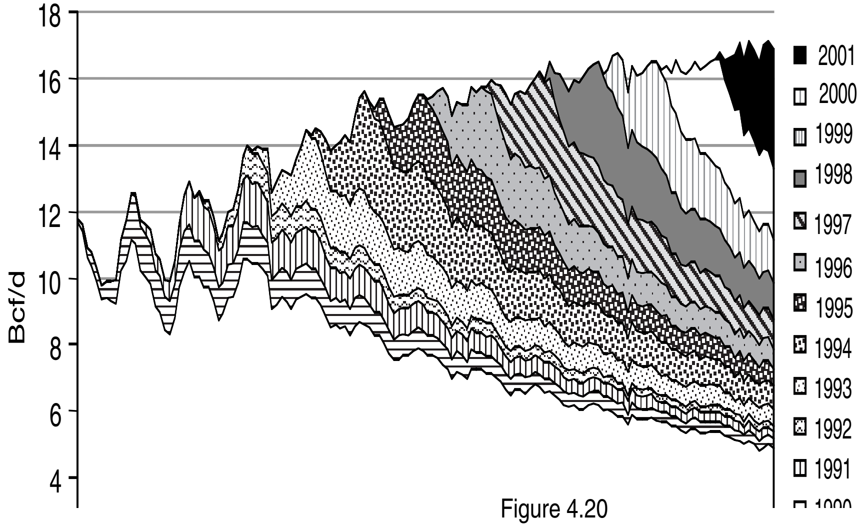

FIGURE 4.20 Western Canada Sedimentary Basin marketable gas production grouped by connection year for the period January 1990 to January 2001. SOURCE: Greg Stringham, Canadian Association of Petroleum Producers, personal communication, 2003. Data are from Canadian National Energy Board (2002).

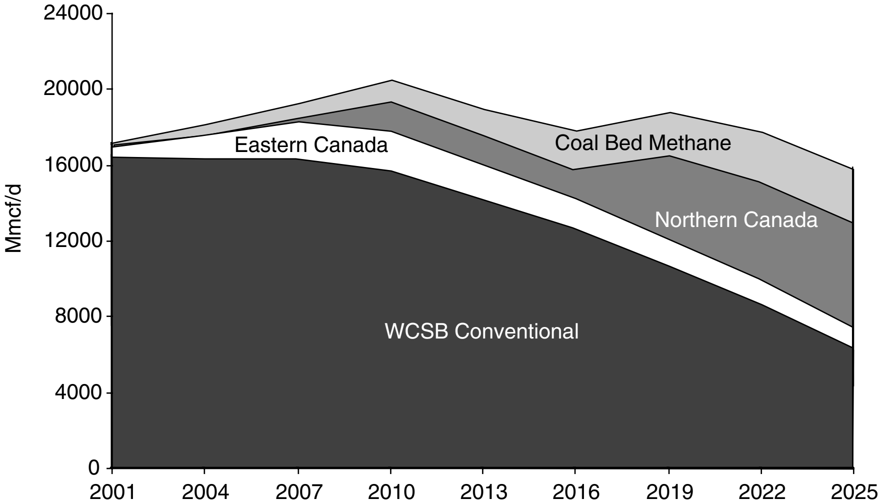

FIGURE 4.21 Canada's deliverable supply outlook by resource category for the supply push scenario. SOURCE: Greg Stringham, Canadian Association of Petroleum Producers, personal communication, 2003. Data are from the Canadian National Energy Board (2003).

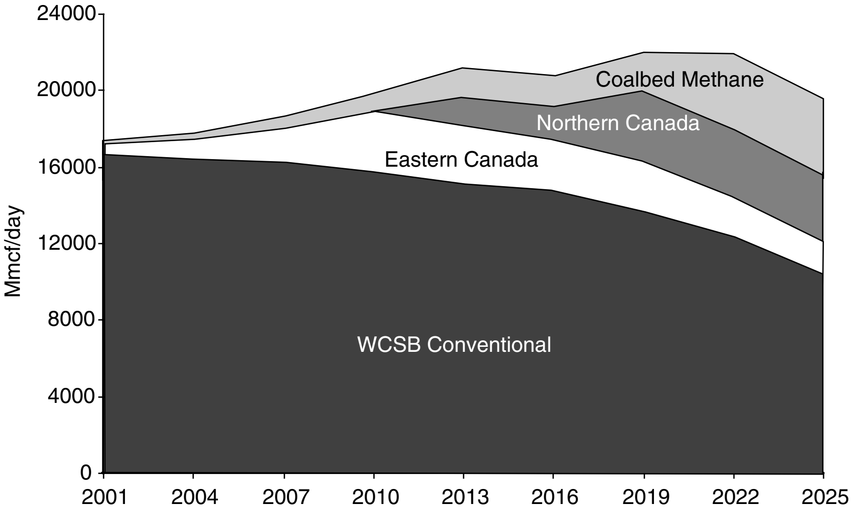

FIGURE 4.22 Canada's deliverable supply outlook by resource category for the rapid technological advances scenario. SOURCE: Greg Stringham, Canadian Association of Petroleum Producers, personal communication, 2003. Data are from the Canadian National Energy Board (2003).

push scenario) would favor early development of the MacKenzie Delta gas pipeline. The EIA's 2003 estimates of U.S. imports from Canada indicate incremental growth of 1.5 Tcf/year by 2025 (see Figure 4.17), which requires virtually all of the new (incremental) volumes in the Canadian Association of Petroleum Producers' most optimistic scenario.

The Canadian Association of Petroleum Producers' estimates of the first year of production for the Mackenzie Delta pipeline range from 2008 to 2011 (Greg Stringham, Canadian Association of Petroleum Producers, personal communication, 2003), while the EIA (2003a) indicates start-up by 2016. In either case, about half of the anticipated production of about 1 bcf/day could be consumed internally to fuel Canada's expanding heavy oil development (see Chapter 2).

As in the United States, Canada's challenges to grow its natural gas production will depend on access to resource, regulatory, and fiscal regimes and the pace of technological improvements.

Alaska Pipeline

The timing of a natural gas pipeline from the North Slope of Alaska linking the Canadian infrastructure with that of the lower 48 states will have a significant impact on North American markets. Thirty-five trillion cubic feet of discovered resource exists, largely in the Prudhoe Bay gas cap and Pt. Thompson Field (USGS, 1998). The USGS estimates that another 63 Tcf of remaining undiscovered resource exists in the onshore North Slope (excluding the Alaska National Wildlife Refuge, which would add an estimated 4 Tcf).

A North Slope gas pipeline capable of moving 4 Bcf/day (expandable to 6+ Bcf/day) to Alberta would require an initial nominal capital investment of $10 billion to $12 billion (National Petroleum Council, 2001). Estimates of the first year production range from as early as 2010 to as late as 2020+ (EIA, 2003a).

The National Petroleum Council (2001) suggests that stable U.S. natural gas prices of $3.50/Mcf for 3 years or more will be required to economically justify pipeline construction. Stakeholders in Prudhoe Bay's gas reserves are currently seeking federal loan guarantees for up to 80 percent of the pipeline's costs as well as a wellhead tax credit of up to $0.52/Mcf, depending on netback prices (which guarantees minimum returns of $1.82/Mcf at the wellhead). Earlier legislative discussions included a possible $3.25/Mcf gas floor price guarantee to ensure economic returns for the producer group (James Emme, Anadarko Petroleum Corporation, personal communication, 2003).

Liquefied Natural Gas

LNG could potentially satisfy U.S. demand not met by other sources of North American supply. Immense volumes of proven natural gas reserves exist worldwide, on the order of 5,501 Tcf (Sen, 2003). Much of this gas is "stranded" without current access to LNG export facilities (e.g., Russia). More than 5 Tcf was transported as LNG in 2001, led by Indonesia, Algeria, Malaysia, and Qatar (see Table 3.2). LNG world trade has grown since the early 1970s by about 6.4 percent/year and accounts for about 21 percent of all natural gas traded internationally, largely serving Asian and European markets (see Figure 3.12). Continued growth is anticipated with new worldwide liquifaction capacity of 6 Bcf/day currently under construction (Sen, 2003).

LNG currently supplies less than 2 percent of U.S. consumption, or about 229 Bcf in 2002 (Colleen Sen, Gas Technology Institute, personal communication, 2003). Historically, lack of growth in U.S. markets can be attributed to disadvantaged costs relative to domestic and Canadian supplies. About two-thirds of U.S. LNG imports are currently supplied by Trinidad, which has been more competitive due to shorter shipping distances.

The EIA (2003a) suggests that LNG imports to the United States could grow by 2 Tcf/year or more by 2025 (see Figure 4.17). Four 1970s vintage regasification terminals exist in the eastern United States and in total have underutilized capacity of about 2.1 Bcf/day (see Table 4.1). Expansions of these facilities could be carried out by 2005 and could increase capacity by another 2.2 Bcf/day (though adequate take-away pipeline capacity may not exist) (Sen, 2003). Nevertheless, 11 new U.S.-based LNG terminals are in the "planning stages" (see Figure 4.23). So far, the Federal Energy Regulatory Commission has received only one application for certification for a new terminal to be built in Hackberry, Louisiana. In total, all existing and potential U.S. terminal capacity could yield almost 18 Bcf/day, or more than 6 Tcf/year, with the expansion of existing facilities by 2005 and potential construction of 11 new facilities. In Figure 4.24, the timing of new construction is not defined. For various economic and regulatory reasons, it is considered unlikely that many of the recently announced projects will ever be built (Sen, 2003).

Though not all announced projects are expected to proceed, cost reductions in the LNG business promise a growing competitive niche in U.S. markets. Over the past 15 years, capital costs to build liquefaction plants and ships have declined 35 to 50 percent (Sen, 2003). Also, shorter-term contracts (5 to 10 years) and an emerging LNG "spot" market allow for more flexible marketing arrangements. As such, the Gas Technology Institute indicates that LNG in U.S. markets should be competitive at \$2.50/Mcf for Trinidad and Algeria and \$3.00 to \$3.50/Mcf for Middle

FIGURE 4.23 North American LNG plants. SOURCE: Sen (2003).

Eastern and Asian sources (Sen, 2003). The EIA (2003a) suggests a competitive range of \$3.25 to \$4/Mcf (see Figure 4.25).

The LNG industry faces challenges in the United States due to perceived environmental safety, security, and aesthetic concerns, despite a sterling safety record (Colleen Sen, Gas Technology Institute, personal communication, 2003). Recent protests of planned terminals in Radio Island, North Carolina, and Vallejo, California, have led to their subsequent withdrawals. Emerging LNG technologies offer promising alternatives to land-based terminals. In the Gulf of Mexico, various plans for floating offshore facilities are being considered whereby LNG shipments could be offloaded, regasified, and injected directly into the existing offshore pipeline infrastructure (Colleen Sen, Gas Technology Institute, personal com-

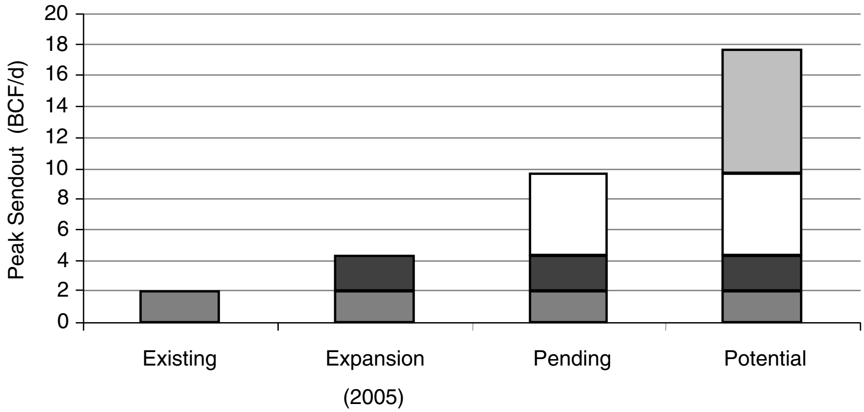

FIGURE 4.24 Existing and projected U.S. terminal capacity in billion cubic feet per day. SOURCE: Colleen Sen, Gas Technology Institute, personal communication, 2003.

TABLE 4.1 Status of LNG Terminals

Terminal Location	Owner	Peak Sendout Plus Expansion Capacity (Bcf/day)	Capacity Holder
Everett, MA	Tractebel NA	435 + 600	Tractebel
Cove Point, MD	Dominion Resources	0 + 750	Shell, 33%; British Petroleum, 33%; Statoil, 33%.
Elba Island, GA	Southern LNG	675 + 540	El Paso Merchant Energy, 59%; Marathon, 41%; Shell has expansion capacity.
Lake Charles, LA	Southern Union Panhandle	1,000 + 300	Duke, 20% until 2005, BG, 80% now, 100% from 2005
Total for lower 48 states		2,110 + 2,240	
Peñuelas, PR	EcoElectrica	186	EcoElectrica

SOURCE: Sen (2003).

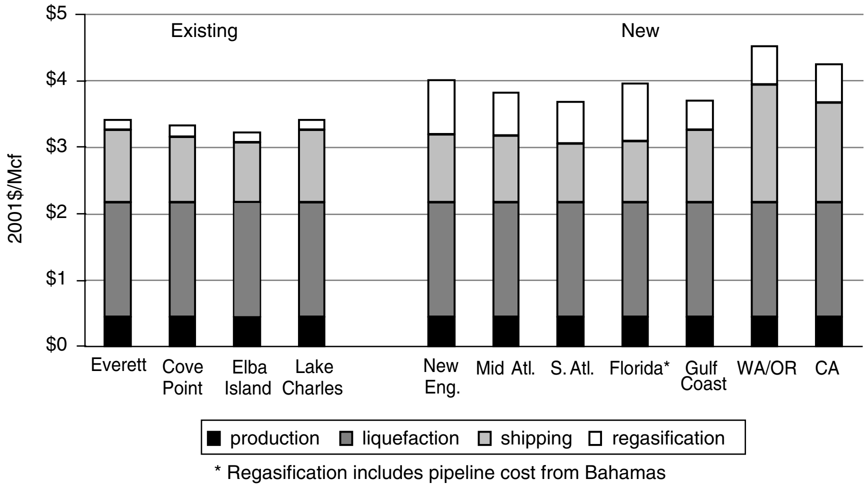

FIGURE 4.25 Minimum regional LNG costs in 2001 dollars per thousand cubic feet. Regasification includes pipeline costs from the Bahamas. SOURCE: EIA (2002b).

munication, 2003). Even though new LNG import terminals may be built, the United States will have to compete in the international marketplace for future LNG imports beyond current contracts.

SUMMARY OBSERVATIONS AND ISSUES

Long-term U.S. demands for natural gas can be adequately met by combined input from both internal and external supplies. It was a common theme among workshop participants that the remaining natural gas resource estimates in the United States and Canada vary widely and bear further scrutiny. In the short term (through 2006), most data suggest that both U.S.- and Canadian-sourced production will remain flat to slightly declining. Workshop participants suggested that some common keys to increasing mid- to long-term gas supplies from U.S. and Canadian basins include increased access to the resource, more efficient and competitive fiscal and regulatory regimes, rapid technological improvements (with emphasis on the development of unconventional reservoirs and conventional deepwater and frontier resources), and incremental incentives for construction. Rapid technological improvements could benefit from increased capital investments in oil- and gas-related research and development from both the private and public sectors. Sources of funding and expertise remain in question.

New external sources of natural gas from northern pipelines and/or LNG appear to be competitive in a sustained $3.25 or more/Mcf price environment. Both of these alternatives are capital intensive, and as such, up-front investments may lag near- to mid-term demand shortfalls (i.e., demand cycles will continue to result in price and storage volume volatility until these projects are in place). Pipeline and LNG investments will likely compete with each other, though common stakeholders have positions in both arenas and may exert strategic influence on preferred alternatives.

5

Summary and Overarching Issues

It is not feasible, in a one-day workshop, to cover all of the important supply and demand aspects of natural gas. By design, the workshop focused on natural gas demand forecasts and factors that cause uncertainty in demand, North American supply estimates and significant variability in those estimates, and ways to meet future U.S. natural gas demand with a focus on technology and LNG transportation.

Several additional issues were featured by speakers and/or during open discussion sessions. These included (1) the impact of tax incentives and royalties on the natural gas supply, (2) the growing need for research and technology as the natural gas resource base becomes increasingly unconventional, (3) the significant decrease in private-sector research and development funding, (4) the need for new federal-private research and technology models, and (5) the significant decline in the number of graduate students enrolled in the geosciences and petroleum engineering who will be available to replace retiring workers over the next decade as the oil and gas industry faces the loss of well over half its technical workforce.

Several important issues related to natural gas were not treated in a significant way during the workshop. These include but are not limited to (1) factors that influence private-sector investment in natural gas, (2) natural gas transportation infrastructure and pipeline capacity, (3) natural gas storage, (4) significant environmental benefits of natural gas over other fossil fuel energy sources, (5) the impact that U.S. policy has on perturbing the global trends of decarbonization of energy sources, (6) the impact on the U.S. and global economies of a transition to a natural gas economy,

(7) carbon sequestration, (8) the national security effects of a U.S. transition to natural gas, and (9) a review of the EIA models.

The primary workshop topics of natural gas demand, supply, and meeting the demand, reported in detail in Chapters 2 through 4, are summarized briefly here, followed by a discussion of overarching issues and a look ahead.

DEMAND

Even with the history of price volatility, some speakers and participants projected an overall increase in U.S. natural gas demand in the next 2 to 5 years, owing largely to an anticipated rebound in industrial production and continued growth in new natural gas-fired electric power. The longer-term outlook for natural gas was considered less certain by some workshop participants and will depend on its affordability in the industrial sector, its competitive position for new power facilities, its reliability as a fuel supply, its price volatility, and the creation of a global transportation and storage network. In addition, some workshop participants believe that proposed and pending energy policies, such as the Bush Administration's Clear Skies Initiative, and international pressures for addressing carbon emissions and global climate change will further influence the demand for and price of natural gas.

Demand for natural gas is projected by the EIA (2003a) to grow from 22.4 Tcf in 2002, to 27.1 Tcf in 2010, and to 34.9 Tcf in 2025. This trend equates to an average annual increase in demand of nearly 2 percent per year and is faster than the expected growth in overall primary energy consumption. The great bulk of the increase is from electricity generation, as the share of natural gas in this market is expected to increase from 17 percent in 2001 to 29 percent in 2025.

SUPPLY

Assessments of the future supply of natural gas in North America send somewhat mixed signals. Workshop participants laid out the following issues: (1) the United States will most likely continue to require increasing amounts of imported natural gas to meet projected demand; (2) Canada will increase its domestic consumption, with little excess export capacity beyond the present-day level; and (3) Mexico will most likely remain a net importer of natural gas. Some workshop participants believe that LNG imports—and perhaps hydrates in the longer term—will most likely be required to augment the North American supply. The accuracy of the supply assessments is limited by (1) perception and understanding of the origin and occurrence of the resource, (2) the quality and distribution of available data with which to conduct estimates, and (3) the methods used in the assessment. Some workshop participants believed that owing to these factors a range of assessment values can be expected as opposed to a single number.

According to USGS assessments, the remaining potential global supply of natural gas is more than 13,000 Tcf (Thomas Ahlbrandt, USGS, personal communication, 2003; USGS, 2000). Reserves of various categories (proven, probable, possible) account for 35 percent of the remaining potential supply. Outside the United States, undiscovered natural gas is concentrated in the former Soviet Union, the Middle East, and North Africa. A total of 1,289 Tcf of technically recoverable resources is reported for the United States by the EIA (2003a), using predominantly USGS and Minerals Management Service data, with proven reserves accounting for 14 percent. Unconventional natural gas—comprising tight (low-permeability) sands and carbonates, fractured shale gas, and coalbed gas—accounts for 34 percent of remaining U.S. resources (Mary Hutzler, EIA, personal communication, 2003). As noted by several workshop participants, controversy exists as to the size and geological nature of the tight sands gas resource in the U.S. Rocky Mountains region, where the bulk of the assessed unconventional gas is thought to reside (Ben Law, Pangea Hydrocarbon Exploration, personal communication, 2003; Keith Shanley, Stone Energy, personal communication, 2003).

Total assessed gas resources for the United States have been increasing over the past 20 years despite production and the transfer of potential resource to proven reserves (Scott Tinker, University of Texas at Austin, personal communication, 2003). As noted by some workshop participants, these assessments have increased as a result of (1) an improved understanding of the phenomenon of reserve appreciation or reserve growth, whereby gas (and oil) fields ultimately produce three to nine times the amounts initially estimated by standard engineering techniques, (2) an understanding of the potential for new plays, and (3) an evaluation of the role of current and advanced technologies in gas exploration and production (Thomas Ahlbrandt, USGS, personal communication, 2003).

MEETING U.S. DEMAND

In the near term, most data suggest that both U.S.- and Canadian-sourced production will remain flat. Some workshop participants suggested that to meet long-term U.S. demand for natural gas will require a combination of enhanced production, new production, and imports from Canada via pipeline and from the rest of the world as LNG. Although LNG transport and conversion facilities are common internationally, domestic facilities essential for offshore imports are limited. Furthermore, pipelines for imports and interstate transport are yet to be built. New sources of natural gas from Canada via pipelines and globally via LNG appear to be competitive in a sustained $3.25/Mcf or greater price environment and to some degree could help to stabilize price and storage volume volatility. The seasonal cyclicity of demand was clearly demonstrated during the past 6 months, when record-high storage volumes in October 2002 (over 3 Tcf of gas) were drawn down to record lows (less than 700 Bcf of gas) by March 2003 (Matt Simmons, Simmons and Company International, personal communication, 2003). This extreme storage volatility can be attributed to the interplay between price, weather, and rig activity. Workshop participants emphasized the need to secure reliable future supplies of natural gas.

Some workshop participants thought that common keys to increasing mid- to long-term gas supplies from United States and Canadian basins include increased access to currently off-limits lands, more efficient and competitive fiscal and regulatory regimes, transportation infrastructure, and rapid technological improvements—with emphasis on the development of unconventional reservoirs and conventional deepwater and frontier resources.

Although industry research facilities formed the core of oil and gas technology development in the past, private-sector research and development funding has dropped markedly since the early 1990s, and most major oil companies and private research labs in the United States have closed (see Figure 1.4) (Scott Tinker, University of Texas at Austin, personal communication, 2003). Rapid technological improvements—which have served to create unconventional gas resources such as tight gas, shale gas, and coal gas—have historically relied on large private-sector investments. According to some workshop participants, future creation of unconventional gas resources will also benefit from increased capital investments in oil- and gas-related research and development but will require both private- and public-sector involvement.

The $40 million proposed for oil and gas research by the U.S. Department of Energy marks a sharp decline in federal funding. Whereas oil and natural gas account for approximately 65 percent of the nation's energy supply, only 0.2 percent of the proposed fiscal year 2004 Department of Energy budget is for oil and gas research. University enrollments for geoscience graduates and petroleum engineers—the future workforce—have declined by more than 50 percent since 1985, with steeper declines for engineers. Significantly declining enrollments make future sources of human expertise uncertain. The challenge is to meet increasing natural gas demand and technological requirements at the same time oil and gas research and development funding, university science and petroleum engineering enrollments, and industry employment are all declining.

OVERARCHING ISSUES

Workshop presentations by several speakers, highlighted by Richard Smalley, Matt Simmons, and Thomas Ahlbrandt, and subsequent open-session discussions framed a series of overarching issues related to natural gas as a viable energy source and a bridge to a hydrogen economy.

1. Are the environmental expectations for natural gas—for the Clear Skies Initiative, for reduced carbon emissions, and for use as a bridge fuel to a hydrogen economy—realistic?
2. Can the forecasted strong growth in natural gas demand—growing to 35 Tcf by 2025—be realized?
3. Given the recent history of price volatility, will natural gas be viewed as an unreliable energy source?
4. Given the now-higher expectations for gas prices, at least for the near term, will natural gas-fired electric power lose its competitive edge?
5. Will technological progress and the domestic natural gas resource base prove adequate to temper gas prices and maintain growth in consumption?
6. What new private-public investment model will provide adequate support to development the research and technology necessary to realize natural gas supply?
7. How might databases and reporting systems for natural gas consumption and fuel switching be strengthened to provide timelier, more accurate information?
8. At what pace must transportation systems—pipeline and LNG—be built to meet future U.S. demand, and will economics bear such development?

In the context of these overarching issues, it seems relevant to recognize that all investment in all sources of energy—including (1) continued production and consumption of coal with positive impacts from advances in "clean coal" technology, (2) continued renewable and nuclear energy research, (3) enhanced oil recovery research and technology application, and (4) the complete spectrum of natural gas support, from incentives and access, to transportation and storage, to upstream research and technology—will be critical over the next 50 years as the world transitions out of a fossil fuel energy-dominated economy into a hydrogen economy. Because long-term global trends are toward a natural gas economy and away from coal and oil (Richard Smalley, Rice University, personal communication, 2003), the issue of meeting natural gas supply, in the face of decreased private and federal spending on technology, decreased graduate school enrollments, decreased employment, and an aging workforce in energy companies, provides the framework for a look ahead.

A LOOK AHEAD

U.S. energy consumption continues to rise. As underdeveloped nations industrialize, global energy consumption will also continue to rise. In the context of increasing global energy demand, natural gas as a dominant energy source presents a paradox. On the one hand, for well over a century the world has been predictably and steadily progressing away from solid and liquid forms of energy toward cleaner, more efficient, and ostensibly more abundant natural gas, nuclear energy, and renewable energy. On the other hand, considerable uncertainty in demand and supply forecasts, declining private and public investment in oil and gas research and technology, and slow development of a global natural gas transportation and storage network have combined with seasonal weather variations to cause significant natural gas price instability and volatility. Some question whether natural gas demand forecasts can be realized in such a way as to mitigate supply and price volatility.

Addressing this dichotomy is a critical national issue. The benefits of natural gas as a bridge to a hydrogen future—a more efficient fuel source, lower atmospheric emissions, less surface environmental disruption, broader global distribution, greater potential resource base—when compared to coal and oil, are known. What is less well known, as shown by the presentations and open discussions at this workshop, are the reasonable bounds of resource estimates, the economics of the required global transportation infrastructure, the source of funding and manpower to support needed research and technology, economic and technological solutions to the natural gas storage issue, and future volatility in price and supply.

Based on evidence presented at the workshop, further study certainly seems warranted. The goal of such a study would be an in-depth scientifically sound evaluation of natural gas as a viable energy bridge to a hydrogen economy. Such an evaluation would provide a basis for future energy policy.

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APPENDIXES

Appendix A

Biographical Sketches of Committee Members

Scott W. Tinker, *Chair,* is director of the Bureau of Economic Geology, University of Texas at Austin, a major international energy and environmental research organization. He is the state geologist of Texas, holds the Edwin Allday Chair of Subsurface Geology at the University of Texas Department of Geological Sciences, and is a member of the Executive Committee of the new John A. and Katherine G. Jackson School of Geosciences. Before joining the bureau in 2000, Dr. Tinker spent 18 years working in the oil and gas industry, most recently at Marathon Oil's Petroleum Technology Center in Littleton, Colorado, where he designed and implemented studies of large oil and gas fields. Dr. Tinker has experience managing energy and environmental research and expertise in energy resource issues, sequence stratigraphy, and reservoir characterization. He is a recipient of "best paper" awards in two major journals and is a former Association of American Petroleum Geologists Distinguished Lecturer and a Society of Petroleum Engineers Distinguished Lecturer. He serves as a member of many professional and honor societies, committees, boards, and foundations. Dr. Tinker holds a Ph.D. from the University of Colorado, an M.S. from the University of Michigan, and a B.S. from Trinity University and is a certified professional geologist and a certified petroleum geologist.

John B. Curtis, is director of the Petroleum Exploration and Production Center/Potential Gas Agency and associate professor with the Department of Geology and Geological Engineering at the Colorado School of

Mines. He has 15 years of experience in the petroleum industry with Texaco, Inc., SAIC, Columbia Gas, and Exlog/Baker-Hughes. He has served on and chaired several professional society and natural gas industry committees, which include the Supply Panel, Research Coordination Council, and the Science and Technology Committee of the Gas Technology Institute (Gas Research Institute). He currently cochairs the American Association of Petroleum Geologists Committee on Unconventional Petroleum Systems and is an invited member of the AAPG Committee on Resource Evaluation and the Committee on Research. He has organized multiple technical sessions on natural gas resource assessment for the AAPG, and the American Institute of Chemical Engineers. He is an associate editor of the *AAPG Bulletin* and *The Mountain Geologist* and has published and given numerous invited talks on studies concerning the size and distribution of U.S., Canadian, and Mexican natural gas resources and comparisons of resource assessment methodologies. As director of the Potential Gas Agency, he directs a team of 145 geologists, geophysicists, and petroleum engineers in their biennial assessment of remaining U.S. natural gas resources. Dr. Curtis teaches petroleum geology, petroleum geochemistry, petroleum design, and stratigraphy at the Colorado School of Mines, where he also supervises graduate student research. He holds a Ph.D. in geology from Ohio State University, and an M.S. and a B.A. in geology from Miami University.

James J. Emme, vice president of Exploration at the Anadarko Petroleum Corporation, oversees all of the company's exploration activities throughout North America, the Gulf of Mexico, and more than a dozen other international areas. Mr. Emme joined Anadarko in 1981 and was named manager of geology for Anadarko Algeria Corporation in 1990. In 1998 he was named manager of the offshore Gulf of Mexico and Alaska exploitation effort in Houston and was promoted to manager, domestic exploitation in 1999. In 2000, Mr. Emme was named vice president, Canada, and was based in Calgary, where he oversaw the exploration and development operations throughout the company's holdings in the western provinces of Canada and in the Beaufort Sea/MacKenzie Delta region. Prior to joining Anadarko, Mr. Emme was employed as a geologist with the Arco Oil and Gas Company. He is a graduate of the Colorado School of Mines, where he earned an M.S. in geology in 1981, and the University of California at Davis, where he earned a B.S. in geology in 1978. Mr. Emme is a member of the American Association of Petroleum Geologists, the Houston Geological Society, and the Rocky Mountain Association of Geologists.

Vello A. Kuuskraa, president of Advanced Resources, is internationally recognized for his work in energy economics, supply modeling, and new oil and gas recovery technologies. He served on the Secretary of Energy's Natural Gas Supply Task Force, was a member of the National Academy of Sciences Study Committee for Defining the National Energy Modeling System, and recently testified before the Federal Energy Regulatory Commission on the outlook for natural gas supplies. Mr. Kuuskraa is a recognized expert on the technologies of coalbed methane recovery and enhanced oil recovery and their adaptation for CO_2 sequestration. He served as the lead expert on coalbed methane for the Secretary of Energy's Trade and Development Missions to China, India, and South Africa and is working with numerous public and private entities to address greenhouse gas emissions using carbon sequestration. He currently serves as chairman of the Technical Advisory Board of the Department of Energy/European Union/Klimatek and industry consortium led by BP called the Carbon Capture Project. He has published over 100 technical papers, reports, and presentations on energy resources and future natural gas supplies. He received the 2001 Ellis Island Medal of Honor, which recognizes individuals for exceptional professional and patriotic contributions by America's diverse cultural ancestry and was a 1986-1987 Society of Petroleum Engineers Distinguished Lecturer. Mr. Kuuskraa holds an M.B.A. from the University of Pennsylvania and a B.A. in applied mathematics from North Carolina State University.

Dianne R. Nielson is executive director of the Utah Department of Environmental Quality, which safeguards public health and quality of life by protecting and improving environmental quality. Prior to this appointment in 1993, Dr. Nielson worked as an exploration geologist, served as senior manager for economic geology with the Utah Geological and Mineral Survey, and later directed the Utah Division of Oil, Gas, and Mining. She has worked closely with mining and oil and gas operators to minimize the environmental impacts of resource development and to ensure viable postproduction land use. She is a member of the National Academies Executive Committee of the Board on Earth Sciences and Resources and is a past member of the Committee on Earth Resources. Previously she served on the Committee on Future Roles, Challenges, and Opportunities for the U.S. Geological Survey and on a panel under the auspices of the Committee on Earth Resources, which wrote *Mineral Resources and Society: A Review of the U.S. Geological Survey's Mineral Resources Plan* (National Academy Press, 1996). She also worked on the report of the Committee on Onshore Oil and Gas Leasing. She is a member of the American Association of Petroleum Geologists and a fellow of the Geological Society of America. Dr. Nielson holds a Ph.D. and an M.A. in geology from Dartmouth College and a B.A. from Beloit College.

NRC Staff

Tamara L. Dickinson, *Study Director,* is a senior program officer with the National Research Council's Board on Earth Sciences and Resources, responsible for managing the Earth Resources activities of the Board. She was awarded the National Academies 2002 Distinguished Service Award. She has served as program director for the Petrology and Geochemistry Program, Division of Earth Sciences, National Science Foundation. She has also served as discipline scientist for the Planetary Materials and Geochemistry Program at National Aeronautics and Space Administration headquarters. As a postdoctoral fellow at the NASA Johnson Space Center, she conducted experiments on the origin and evolution of lunar rocks and highly reduced igneous meteorites. She holds a Ph.D. and an M.S. in geology from the University of New Mexico and a B.A. in geology from the University of Northern Iowa.

Monica R. Lipscomb is a research assistant for the National Academies Board on Earth Sciences and Resources. She earned a master of urban and regional planning degree at Virginia Polytechnic Institute, with a concentration in environmental planning. Previously, she served as a Peace Corps volunteer in Côte d'Ivoire and has worked as a biologist at the National Cancer Institute. She holds a B.S. in environmental and forest biology from the State University of New York, Syracuse.

Karen L. Imhof is a senior project assistant for the Board on Earth Sciences and Resources of the National Academies. She previously worked for the Board on Agriculture and Natural Resources. Earlier she worked as a staff and administrative assistant in diverse organizations, including the Lawyers' Committee for Civil Rights Under Law, the National Wildlife Federation, and the Three Mile Island nuclear facility.

Appendix B

Workshop Agenda

U.S. NATURAL GAS SUPPLY AND DEMAND: A WORKSHOP
THE NATIONAL ACADEMIES
500 FIFTH STREET NW
WASHINGTON, D.C. 20001

Monday, April 21, 2003

OPEN SESSION

8:00 a.m. Introductions and Purpose of Workshop — Scott Tinker, Chair

U.S. Natural Gas Demand

8:15 The Big Picture — Richard Smalley, Rice University

What are the trends that will shape and control U.S. natural gas consumption for the next 25 to 30 years?
Will natural gas be a bridge or a competitor to a hydrogen economy?

8:45 EIA's Outlook for U.S. Natural Gas — Mary Hutzler, Director, Office of Integrated Analysis and Forecasting

Assumptions and data used in the Annual Energy Outlook 2003 for U.S. natural gas demand
Recent trends in technology progress and the Annual Energy Outlook 2003
Integrated price and supply forecast
The U.S. greenhouse gas initiative and proposed legislation: How would these change the demand and price forecast for natural gas?

9:05 Open Discussion

U.S. Natural Gas Supply

9:35 Minerals Management Service — Richie Baud, New Orleans

Outer continental shelf natural gas resources
Progress in deepwater technology to make these resources economical
Recent discovery history for both the shelf and slope

9:55 U.S. Geological Survey — Thomas Ahlbrandt, Denver

Future natural gas resources
Why are today's USGS estimates of gas resources significantly larger than those made by the USGS 20 years ago?
How might the estimates for natural gas look 20 years from now?
Technically, economically, and environmentally recoverable resources

10:15 Break

Meeting U. S. Natural Gas Demand

10:45 Technology — Naresh Kumar, Growth Oil and Gas

What level of research and technology development will be required to meet future natural gas demand in the United States.? Are we on pace?
What are the barriers that prevent industry from making opti

mum (from a national perspective) research and development investments?

Is there a national benefit from advanced technology and lower prices that would justify a federal role in natural gas research and development?

What organizations could perform the research and development (federally assisted or otherwise) and is there an adequate supply of students in the United States?

11:05 Open Discussion

12:00p.m. Lunch

Meeting U.S. Natural Gas Demand

1:00 The Potential of Basin-Centered Gas — Keith Shanley, Stone Energy

1:20 Import/Export Picture

Greg Stringham—Canadian Association of Petroleum Producers
Will Canada be able to meet expectations for imports?
Alaskan and/or Mackenzie gas pipeline picture

Colleen Sen—Gas Technology Institute
Liquefied natural gas

2:00 Unconventional Gas

Ben Law—Pangea Hydrocarbon Explorations
Conventional unconventionals— coalbed methane, shale, tight gas
Resources, technology, and economic issues
Size and nature of in-place resource for unconventionals as well as deep gas

Keith Millheim—Anadarko Petroleum Corporation (Cancelled)
Unconventional unconventionals—deep gas, subsalt, hydrates, etc.
Resources, technology and economic issues

2:40 Break

3:10	Open Discussion
4:00	Perspectives on U.S. Natural Gas Supply and Demand
	Does natural gas really have a bright future or could the North American supply have already peaked? — Matt Simmons, Simmons and Company International
	Future of natural gas — Michael Lynch (Cancelled), MIT
4:40	Discussion
5:30	Adjourn