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EMF Report 20
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Natural Gas, Fuel Diversity and North American Energy Markets

Energy Modeling Forum
Stanford University
Stanford, CA 94305-4026

Preface

The Energy Modeling Forum (EMF) was established in 1976 at Stanford University to provide a structural framework within which energy experts, analysts, and policymakers could meet to improve their understanding of critical energy problems. The twentieth EMF study, "Natural gas, Fuel Diversity and North American Energy Markets," was conducted by a working group comprised of leading international energy analysts and decisionmakers from government, private companies, universities, and research and consulting organizations. The EMF 20 working group met four times between January 2002 to June 2003 to discuss key issues and analyze the longer-run implications of restructured electricity markets.

This report summarizes the working group's discussions of the modeling results on North American natural gas and related energy markets. During the study, the group had some interesting discussions of non-modeling analysis and issues, some of which are also included in this report. Inquiries about the study should be directed to the Energy Modeling Forum, 448 Terman Engineering Center, Stanford University, Stanford, California 94305-4026, USA (telephone: (650) 723-0645; Fax: (650) 725-5362). Our web site address is: *http://www.stanford.edu/group/EMF.*

We would like to acknowledge Glen Schuler for providing helpful comments on a previous draft of this report and Edith Leni and Susan Sweeney for their assistance in the production of this report. We also appreciate the Baker Institute for Public Policy at Rice University and Resources for the Future for allowing us to hold a meeting at their respective facilities.

EMF Sponsorship

Financial support from a wide range of affiliated and sponsoring organizations allows the Forum to conduct broad-based and non-partisan studies. During the 2002-2003 period, the Forum gratefully acknowledges the support for its various studies from the following organizations:

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Executive Summary

Recent volatile natural gas prices do not foreshadow a pending, long-term crisis in future natural gas supplies. This conclusion was highlighted in a study by Stanford University's Energy Modeling Forum, which included many leading energy experts from universities, government, and business.

Prices spiked in both 2001 and earlier this year when short-term seasonal bursts in natural gas consumption outstripped the industry's current capacity to deliver natural gas in the winter months. More natural gas storage facilities with higher inventories, longer-term contracts, and financial instruments would dampen future price spikes. Greater price stability would provide the much-needed incentives for long-term investment in new resources and would reduce the need for government subsidies.

Even with these changes for the near-term problems, the industry faces a longer-term challenge. Can North America rely upon increasing dependence on natural gas? The study focuses on these longer-term issues by examining supply and demand conditions that will influence the ability of natural gas to compete effectively with other energy sources over the next two decades. Previous studies have frequently focused upon the "most likely" outcome being projected by a single model. This study differs by comparing the results for seven different possible market scenarios (described below) as viewed by seven different expert modeling teams.

Direct subsidies for expensive projects are not necessary to maintain investment and supplies. However, the study does call for better integration of energy, environmental, and land-use policies to avoid higher future prices. The country needs to avoid a situation where industry and powerplants shift strongly to natural gas for environmental reasons, but where regulations on western land use and siting import facilities restrict investment.

An important conclusion is that both companies and the government will need to plan for a range of possible natural gas market outcomes. Total projected consumption could grow by an average of 0.8 to 2.8 percent per year between 2002 and 2020, depending upon market conditions, according to the EMF modeling experts. Higher growth in the economy and electricity demand will increase natural gas consumption and its price. More competitively priced supplies from Canadian and Alaskan frontier areas and liquefied natural gas imports will reduce natural gas prices and also increase consumption. Lower drilling productivity or lower world oil prices will decrease consumption.

Natural gas prices will remain very competitive with other fuel prices, if recent government projections are correct. However, the working group also examined other market conditions (identified above), where other fuels would challenge natural gas in different regions and end-use consumption sectors. Coal, oil, renewable energy, and overall energy efficiency, principally

within industrial facilities and power-plants, tend to replace some natural gas use in these alternative projections.

After removing the effects of inflation, the projected price received by U.S. producers in the year 2020 could be as low as 58 percent of today's level (June 2003) or as high as 118 percent depending upon the model and scenario. Higher natural gas prices result when oil prices are higher, drilling productivity is lower or economic growth is higher. Lower natural gas prices result when oil prices are lower and the cost of new frontier supplies are more competitive.

Investments in new natural gas supply resources and technologies play a critical role in these projections. Coalbed methane, tight sands, and other less traditional sources will become increasingly important in meeting the demand for natural gas. In addition, international trade will become more prevalent in the U.S. natural gas markets, either as liquefied natural gas or as larger import volumes from Canada.

While the report emphasizes the importance of long-term supplies, it also discusses the critical role of demand adjustments for a properly functioning market. Natural gas prices will be less sensitive to changes in market conditions when consumers have the opportunity to shift easily away from natural gas if it should become more costly. Combined with greater flexibility to supply and store natural gas, fuel-substitution opportunities could help to provide a more stable price path for the industry.

Technological advancements in other energy sectors could potentially reduce the future role played by natural gas. Coal, nuclear energy, renewable energy, and end-use energy efficiency are the most likely sources of change in the market. The study estimates that advanced renewable technologies will have a relatively minor impact on natural gas markets during the next twenty years but could become an important source in the several decades following 2020.

Natural Gas, Fuel Diversity and North American Energy Markets

1 Balancing the Old Optimism and the New Pessimism

Will natural gas be the bridge fuel to a more environmentally friendly future? This fuel has played a prominent role in many projections of future North American energy market conditions. Recent months, however, have cast a more gloomy view. Resource experts have reduced their estimates of how much natural gas might be coming from the Western Sedentary Basin of Alberta. Domestic U.S. production has dipped at a time when natural gas prices have been pushing upward. A new pessimism has supplanted the previous bullish outlook for this energy source.

In response to a need for a balanced evaluation of natural gas markets, Stanford University's Energy Modeling Forum organized an ad hoc working group 18 months ago. This working group was comprised of leading experts and advisors from government, companies, research organizations and universities. Rather than presenting one view of how markets might unfold, the process sought to explore the range of uncertainty and differences among experts. To help focus the discussion, the group organized their sessions around simulations from several models. This report summarizes the main findings of this working group's efforts.

2 Are Natural Gas Resources Depleted?

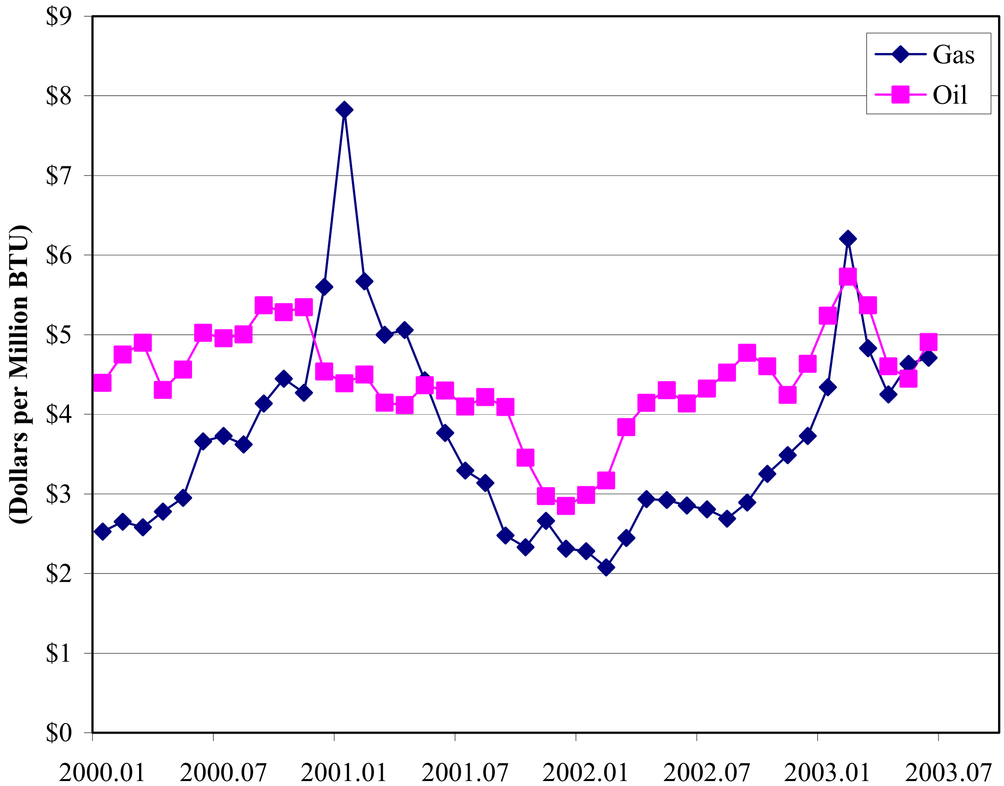
Today's natural gas market is confusing. After years of excess supply capacity, a natural gas "bubble", the industry has recently experienced higher and very volatile prices and declining production. Some people fear that natural gas may have reached its point of maximum production, much like the U.S. oil industry did some 30 years ago. North America cannot rely upon shifting its demand toward natural gas, without vastly more imports, if this view is correct.

It is easy to portray a pessimistic future for natural gas given today's conditions, just as it was relatively painless to suggest a bullish outlook for this fuel 18 months ago. What really has changed that would make one view more likely than another?

2.1 Are Prices Moving Steadily Higher?

Has North America entered a world of ever-rising natural gas prices? Figure 1 shows that wellhead natural gas prices have remained below $4 per thousand cubic feet for most months over the last few years. Although natural gas competes with many fuels, it has traditionally been compared with oil prices, because non-oil energy prices

Figure 1. Wellhead Natural Gas and Crude Oil Price



tend to move with oil prices. The wellhead natural gas price has remained below the average crude oil price and competitive with residual fuel prices for much of this period. At the same time, the price spiked in early 2001 and again in early 2003.

These trends underscore the volatility of natural gas prices but they do not harbinger either the long-run depletion of this resource or its long-term, relative abundance. Natural gas price volatility creates its own problems by creating uncertainty that discourages long-term investment and by threatening key industries dependent upon natural gas with "job destruction." Much of the concern about natural gas supply reflects that natural gas inventory levels appear low and have not adjusted to the seasonal shifts in natural gas demand.

Natural gas consumption has traditionally peaked in the winter months for heating homes and buildings. In more recent years, it has also been growing rapidly during summer months to meet the increased power demands for air conditioning in the warmer months. Prices spike because the existing pipeline and storage facilities cannot provide additional supplies quickly enough when severe weather events happen. In addition, pipeline constraints create problems over a longer period in certain areas, e.g., California.

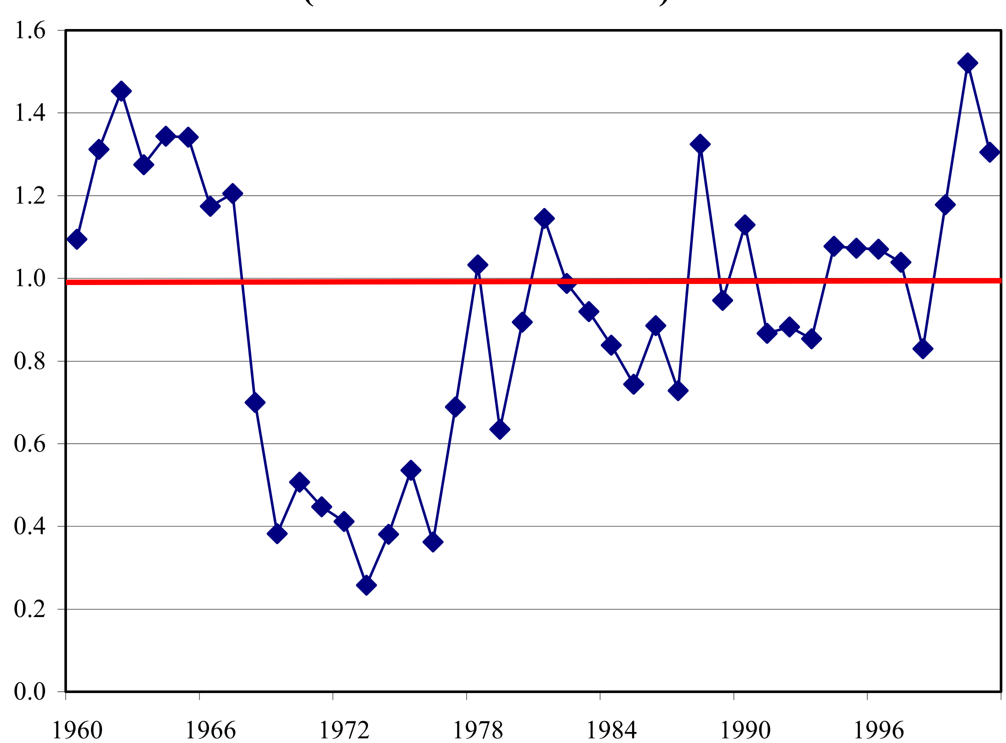
These near-term impacts can be cushioned significantly by increased natural gas storage, longer-term contracts, financial instruments, and other similar institutions. The industry needs these changes to provide the long-run incentives for sustained investment.

Even with these changes for the near-term problems, the industry faces a longer-term challenge about whether North America can rely upon increasing dependence on natural gas. This report addresses these important concerns by considering the long-term market fundamentals, which are quite different from price volatility, inventory problems and temporary pipeline constraints.

2.2 Are Supplies Constrained?

Questions have been raised about the industry's long-run capacity to supply natural gas. U.S. dry natural gas production declined by 2.7 percent between 2001 and 2002. These trends, however, may have little to do with supply conditions. When markets determine the price of any commodity, the amount sold equals the amount bought, plus some temporary changes in inventories. Since inventory changes are likely to be relatively small, total production will reflect demand as well as supply conditions. The recent decline in natural gas production began to emerge at the same time that U.S. economic growth slowed and the demand for natural gas and other fuels declined. Total U.S. natural gas consumption fell 6.8 percent between 2000 and 2001 and another 2.9 percent in the following year, even though the demand for natural gas for electricity generation increased over this period.

Figure 2: Natural Gas Replacement Rate (=Additions/Production)



A better indicator of the industry's supply capability is the recent experience with drilling for additional reserves. Active rigs, total wells and total footage dipped in 2002 when natural gas prices were lower, but have recovered with a lag when higher natural gas prices returned. Figure 2 shows that U.S. producers have found more natural gas from conventional and unconventional formations in the lower-48 states than they extracted in seven of the last eight years. In the last three years, they found 20% to 50% more than the natural gas that they extracted. The industry's supply response as measured by reserve additions rather than production appears to depict a much more active sector. However, once again, some caution is advisable. These trends could reflect several special circumstances including:

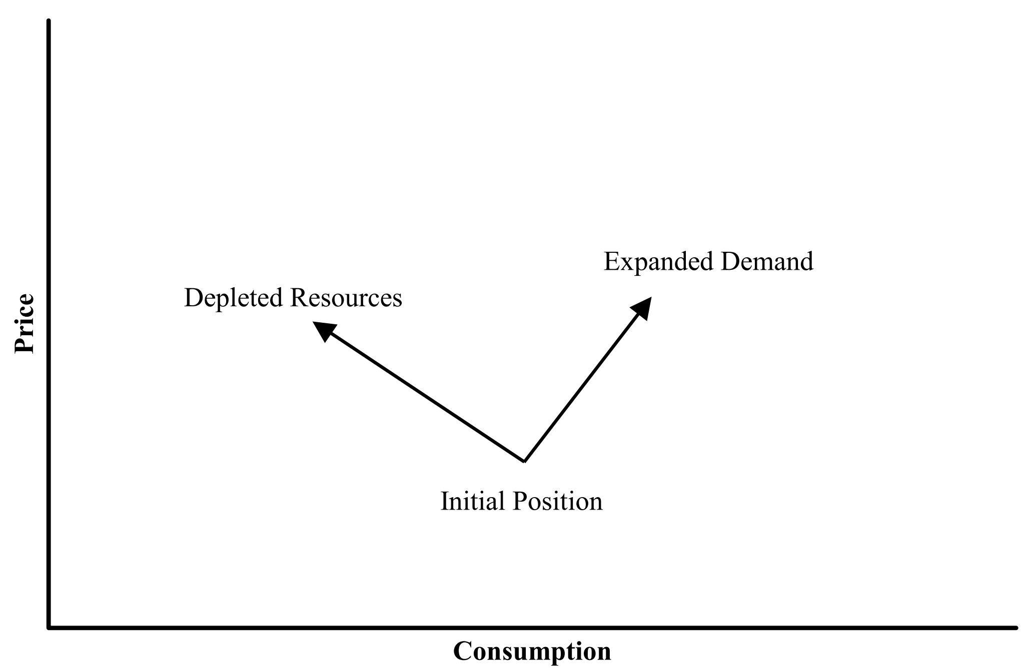
- Mergers and other conditions may have changed the way industry accounts for reserves.
- Some natural gas discoveries have been in the Rocky Mountain regions that may not be accessible by existing pipelines but that could be accessible to future expansions.
- Recent drilling has focused more upon finding natural gas from unconventional formations, where technical conditions may require the industry to produce smaller amounts each year and hold greater reserves.

The cyclical nature of this relationship between additions and production is evident throughout the period represented in this figure.

2.3 Depletion or Expanded Demand?

Another perspective would be to focus on both price and amount sold or used. If natural gas resources were becoming scarcer, natural gas quantities should be reduced and more costly to find. In rectifying the imbalance between too much natural gas consumption for too

Figure 3. Depleted Resources and Expanded Demand

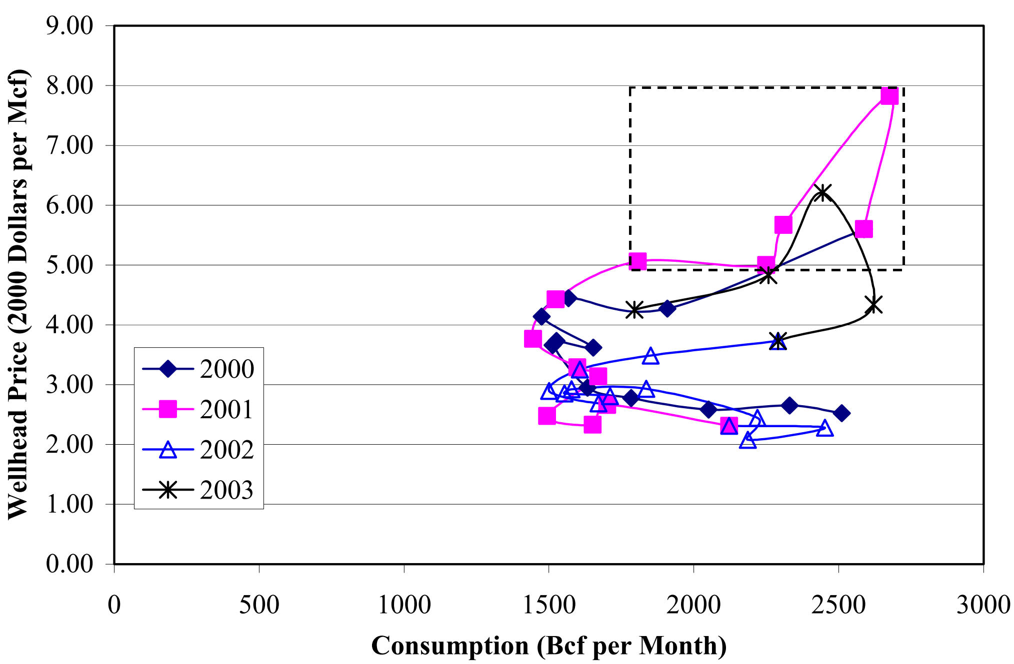


little natural gas production, the market would push through these higher costs into higher natural gas prices. Thus, one would expect both higher natural gas prices and lower natural gas quantities if resource depletion was dominant. The natural gas depletion arrow in Figure 3 represents this effect by showing declining natural gas quantities (measured along the horizontal axis) with rising natural gas prices (measured along the vertical axis).

Alternatively, if economic expansions or some similar stimulus to natural gas consumption were important, the market would resolve the imbalance between too much consumption and too little production by again raising natural gas prices. However, this time the higher prices would be accompanied by higher natural gas quantities bought and sold in the market. This economic expansion arrow in Figure 3 represents these conditions.

Figure 4 appears to support the second interpretation that natural gas quantities tend to be higher when natural gas prices are higher for the months since 2000. Measured prices along the vertical axis are the field or wellhead price that U.S. producers receive from pipelines after the natural gas has been extracted from the well. Measured quantities bought or sold along the horizontal axis are total U.S. natural gas consumption. The shaded area highlights those months in which natural gas prices were $5.00 per million BTU or higher. These months occurred during the winter heating season in early 2001 and 2003. Rapid demand growth for heating outstripped the available supplies in the pipeline and inventory storage, causing large and painful price spikes. Although the observations for these few months are limited, they do not fit the "scarce resource" conditions very well.

Figure 4. Recent Natural Gas Prices and Consumption



As a result, recent volatile natural gas prices do not foreshadow a pending, long-term crisis in future natural gas supplies. Instead, the long-run path of natural gas prices over the next few decades will depend upon supply investment and the response of demand to changed market conditions. This report discusses how these fundamental factors determine the industry's future.

Figure 3 is essential for understanding the response of natural gas markets to the different conditions in this study. Many of the results discussed later in this study are most easily interpreted by recalling this picture.

2.4 What Can Be Learned?

It has always been exceptionally difficult to forecast future natural gas trends from current market conditions. During the first OPEC shock, dry U.S. natural gas production peaked in 1973, leading the chairman of the Federal Power Commission to announce pending shortages. Later that decade, regulators banned the construction of new power plants using natural gas or oil in the Powerplant and Industrial Fuel Use Act of 1978. When prices remained relatively low throughout most of the 1990s and independent generators entered the electricity market, natural gas became the bridge fuel to the future.

Given the enormous uncertainty about today's conditions and our past experience in tracking the future, why should anyone spend much time on models and their simulation results? The EMF working group discovered that the simulations from each model represented an alternative set of views about how the markets might evolve over the long term. The model results lay out these views consistently and in considerable detail. When compared, these results reveal interesting insights about the long-term market fundamentals that will drive this important energy market. This report tries to identify the key factors that any organization should consider in developing its own long-run view of this industry's future.

Buyers and sellers of natural gas will need to protect themselves from market shifts influencing natural gas prices. Governments will need to develop policies that will make as much sense if natural gas is expensive as if it is relatively inexpensive. This emphasis on flexibility has always been important. It mattered two years ago when people were optimistically calling for increased natural gas use at only modestly increasing prices and it should concern decision makers today as well.

3 The Study Design

3.1 The Modeling Frameworks

Table 1 lists the seven different modeling systems that reported simulation results for the seven alternative scenarios in this study. Some frameworks focused on all energy markets, others analyzed the interaction between natural gas and electricity markets, and a final set represented natural gas markets only.

Among the energy models, US MARKAL is a large national model that represents detailed technologies or groups of technologies in all the end-use sectors. Each technology competes with other options on the basis of the initial capital costs and its energy performance.

Table 1. Models in EMF Study

Model Name	Symbol	Proprietor	Energy Markets
U.S. MARKAL	MARKAL	U.S. Department of Energy; Brookhaven National Laboratory	All U.S. energy markets including exports and imports
Energy 2020	E2020	Canadian Energy Research Institute	All Canadian and U.S. energy markets
National Energy Modeling System	NEMS	U.S. Energy Information Administration	All U.S. energy markets including exports and imports
Policy Office Electricity Modeling System	POEMS	U.S. Department of Energy; Onlocation, Inc.	All U.S. energy markets including exports and imports
NANGAS/IPM	NANGAS	U.S. Environmental Protection Agency; ICF Consulitng	U.S. electricity and gas markets including exports and imports
North American Regional Gas	NARG	California Energy Commission	Canadian and U.S. gas markets
Model for US and International Natural Gas Simulations (MUSINGS)	CRA	Charles River Associates	Canadian and U.S. gas markets

The Energy2020 (E2020) framework uses a systems dynamics approach similar to that used in a former U.S. Department of Energy Model called FOSSIL2 and later IDEAS. Operated by the Canadian Energy Research Institute, this model covers all energy markets in Canada and the United States. The National Energy Modeling System (NEMS) is a large engineering-economy model of all energy markets that provides forecasts released by the U.S. Energy Information Administration. This model combines considerable detail about technology options with a representation of end-use demand and the energy market and policy structure. The Policy Office Electricity Modeling System (POEMS) was developed initially to conduct electricity restructuring analysis in greater regional detail than is available in NEMS. The natural gas market is represented the same as in the 2002 version of the NEMS system.

Among the frameworks that combine natural gas and electricity markets, the U.S. Environmental Protection Agency uses a natural gas model (NANGAS) and an integrated planning model for electricity (IPM) jointly to conduct the environmental impacts of fuel market changes. Among the natural gas-only systems, the North American Regional

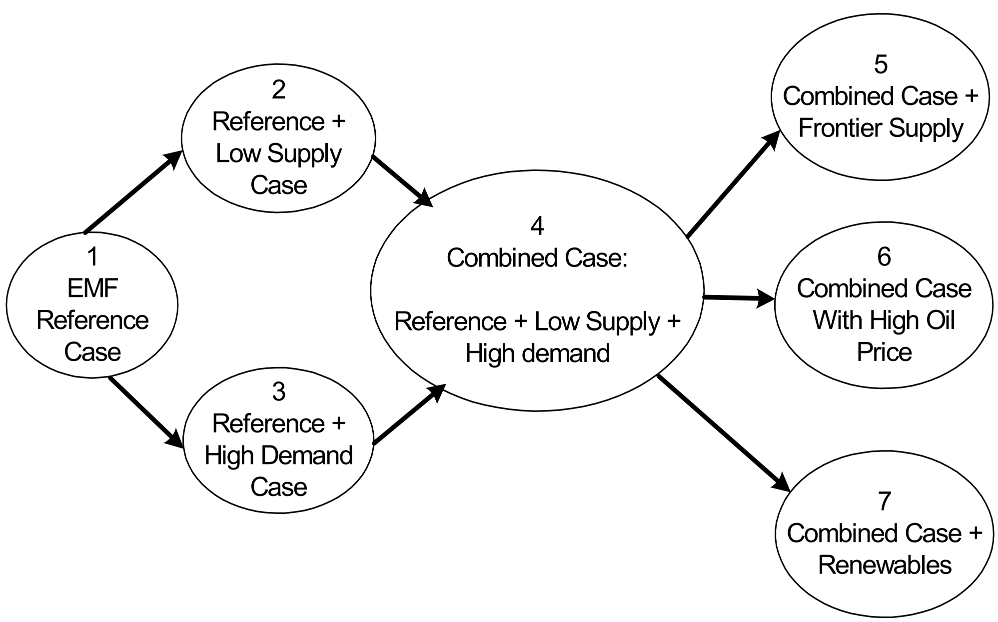
Natural Gas (NARG) model covers numerous natural gas regions. In using this model, the California Energy Commission pays close attention to recent electricity trends and their potential effects on the natural gas market. Charles River Associates (CRA) operates the Model for US and International Natural gas Simulations (MUSINGS) by calibrating natural gas supply and demand conditions with NEMS for the United States and with Canadian sources and the National Petroleum Council for Canada.

3.2 Stories, Not Projections

Combining the term "models" with "scenarios" often equals "projections of the most likely set of events" for many people. This view is understandable because modelers are seldom asked to do anything more than simply project the most likely outcome. However, this study asked the modelers to do something quite different. The working group wanted interesting stories that were internally consistent about how the natural gas and energy markets might evolve over a range of conditions. No one scenario or even the collective set of scenarios represents the best forecast by any individual on the working group, including the modelers themselves. Since the assumptions described in considerable detail in the study design may differ from those normally used by the modeling teams, the simulation results may be quite different from each group's most likely forecast of future market conditions.

The modeling teams simulated seven alternative scenarios based upon assumptions developed by the working group. Figure 5 shows that the low oil reference case serves as a benchmark scenario for comparing the low supply and high demand cases. The combined low-supply and high-demand conditions form a fourth scenario that serves as a benchmark for comparing the expanded frontier, high oil price path, and advanced renewable technology cases. Each scenario will be described more fully below.

Figure 5: EMF Study Scenarios



4 Natural Gas in a More Competitive World

4.1 AEO 2003 Reference

The EMF scenarios are best viewed as alternatives to the recent reference case released by the U.S. Energy Information Administration in their 2003 *Annual Energy Outlook* (AEO). The 2003 AEO projections are a reasonable statement of the conventional wisdom in energy projections. They represent a world in which natural gas use grows while its price competes effectively against other fuels. Natural gas expands its share of total energy use based upon both economics and its environmental advantages. Underlying these trends are the following set of important assumptions for the next two decades:

- Inflation-adjusted oil prices reach \$25 in today's prices.
- U.S. gross domestic product (excluding inflation) grows by 3.0% per year.
- Electricity sales expand by 1.8% per year.

A number of conditions forces oil prices to rise faster than inflation. The world economy and world oil demand begin to grow again. Investments in countries outside the OPEC region (including Russia) try to meet these demands, but the additional resources are more expensive. Production decisions remain largely under the control of governments that extract their oil resource more conservatively than the private sector. Additional privatization of these operations is limited. Producers may also be discouraged from selling their oil under the ground for financial assets by interest rates that remain near or below inflation rates. Middle Eastern governments provide the oil that cannot be supplied by other regions at the prevailing oil price. These nations recognize their mutual economic benefit in expanding their total supplies slowly. There is little fear of aggressive anti-oil actions by companies or governments in the oil-consuming regions.

As reasonable as this story may seem, it would be unwise to base all corporate and government decisions upon these trends alone. The EMF working group was particularly interested in developing alternative cases that would be both internally consistent and also reveal fundamentally different stories.

4.2 EMF Low Oil Reference

Most scenarios in this study are based upon a different world oil market outcome. After rising 49% between December 2001 and December 2002, oil prices begin to reflect increased certainty in the Middle East and revert to lower future levels. By 2005, oil in these scenarios is selling at just below \$18 per barrel in inflation-adjusted terms (\$17.64 in 2000 dollars) and remains at that price through 2020. (Comparable nominal oil prices, given today's inflation rate, would be \$18.60 per barrel in 2003 and \$25.30 per barrel in 2020.)

The conditions underlying these world oil market trends are different from the most recent AEO projections but are reasonable alternatives. World oil demand grows but not as rapidly. Non-OPEC (including Russian) supplies are not as expensive to expand. These countries yield their conservative approach to managing their resources and choose to have more active participation from the private sector. If interest rates rise above inflation rates, producers may be encouraged to sell their oil in the ground for financial assets. Middle Eastern governments find it more difficult to cooperate with each other to raise profits by limiting expansion. Meanwhile, companies and governments in oil-consuming countries become more aggressive in steering their economies away from oil.

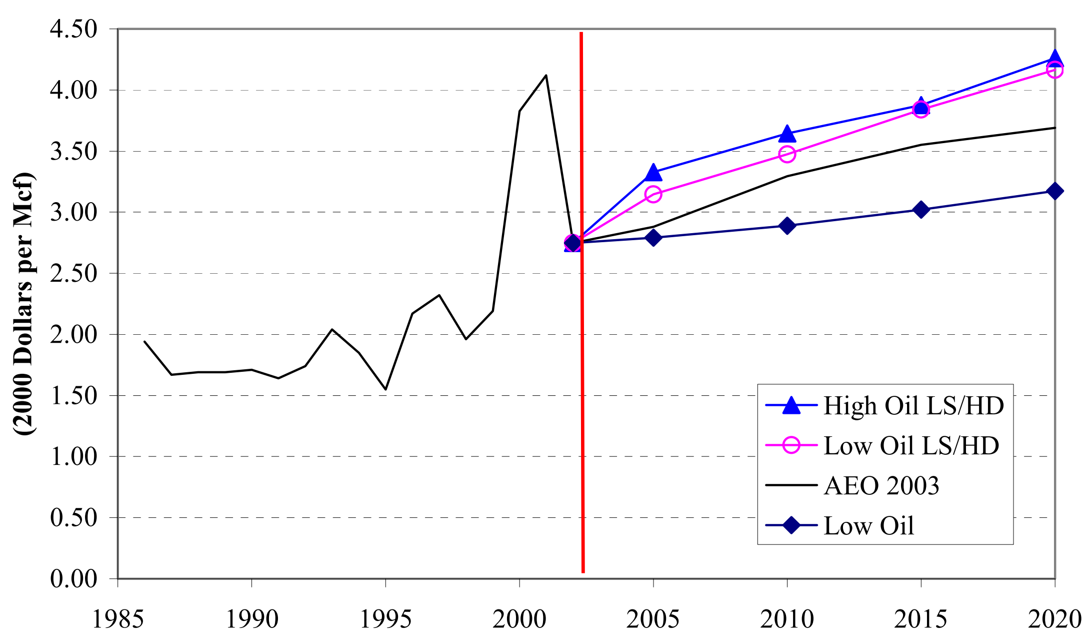
4.3 Natural Gas Wellhead Prices

Figure 6 shows the historical trend and several different projections for natural gas wellhead prices in the United States. All prices in the 2003 AEO and EMF simulations will be expressed in inflation-adjusted terms and linked back to the bundle of goods and services that could be bought in the year 2000. The plain solid line indicates the projection for the 2003 AEO made by the single model, National Energy Modeling System (NEMS). Wellhead prices rise faster than inflation and reach about $3.70 per thousand cubic feet by 2020.

The **average** projection for all models in the EMF low oil price reference case, indicated by a line with diamonds, lies well below the 2003 AEO trend. Although it too rises, wellhead prices are about $0.50 per thousand cubic feet lower by 2020. The modelers reported estimates for every 5 years rather than each individual year in order to reduce the data submission requirements to more manageable levels. Thus, the line connecting the 2005 and 2010 estimates does not indicate the level that they project for the intervening years, 2006-2009.

Although the economic and electricity growth assumptions are similar to the AEO 2003 case discussed above, the EMF low oil price reference case has more optimistic assumptions about the potential for inferred natural gas reserve appreciation and drilling technology improvement. Declines in drilling technology improvements are incorporated in a separate scenario. In addition, coal prices are somewhat lower than in the AEO 2003 case due to higher productivity growth in coal extraction.

Figure 6. Average Wellhead Natural Gas Prices Across Models



The other two price trends in this figure also measure the average projection for the models in the EMF study. Relative to the EMF low oil reference case, each trend incorporates both lower natural gas supply and higher natural gas demand conditions (and hence referenced as LS-HD in the figure). The line with the open circles maintains the lower oil price, while the line with triangles allows oil prices to rise to $24.68 per barrel by 2020, its level in the 2002 AEO reference projection. These conditions raise natural gas wellhead prices from their levels in the EMF low oil reference case, with a slightly higher price being generated in the higher oil price case.

In these lower-supply, higher-demand cases, natural gas supplies are reduced by a 25% decline in the rate of productivity improvements for: (1) finding rates, (2) success rates, and (3) drilling, equipment and operating costs. These changes affect North American natural gas excluding Alaskan and new frontier Canadian volumes. Natural gas demands are increased by raising the economic growth rate from 3.0% to 3.4% per year. Higher growth stimulates industrial natural gas demand and the demand for natural gas used in the power sector through its effect on electricity sales in all sectors. In NEMS, the growth rate in delivered electricity consumption increases from 1.77% per year in the reference growth case to 1.96% per year in the high-growth case. POEMS shows the rate increasing from 1.85% to 2.10%. Electricity grows more rapidly in both cases in NANGAS at rates of 2.13% and 2.40%, respectively.

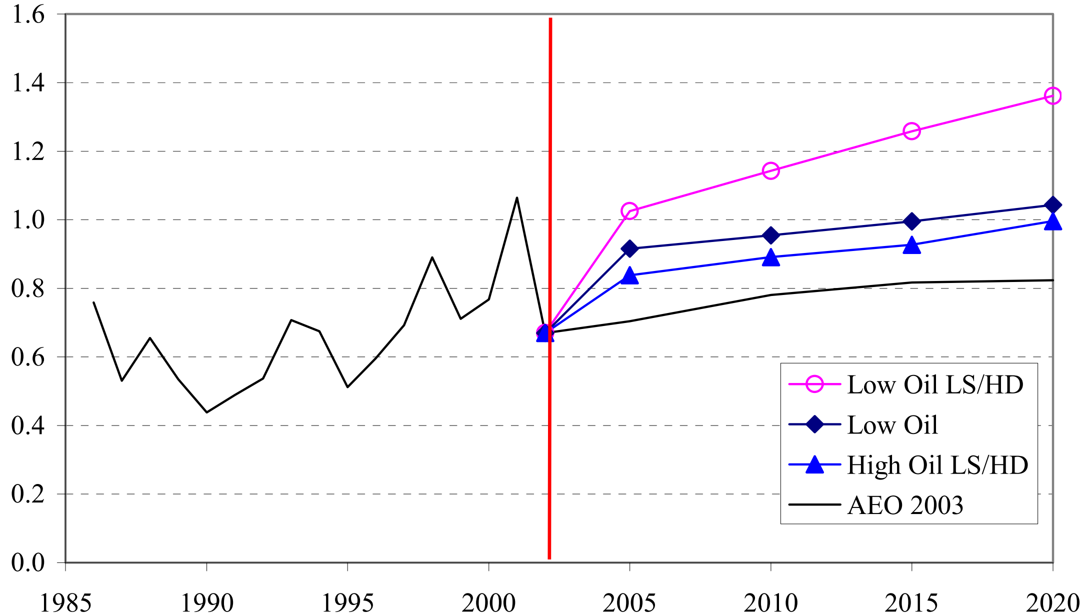
The EMF projections bound the 2003 AEO projection. The average wellhead price in a scenario across all models covers the $3.17 to $4.26 range for 2020 and thus provides incentives for the successful development of many new natural gas technologies. Variations in projected prices between models can be even larger than these averages. After removing the effects of inflation, the projected price received by U.S. producers in the year 2020 could be as low as $2.62 per million cubic feet, or 58 percent of current levels (June 2003), or as high as $5.32 per million cubic feet, or 118 percent of current levels.

Although wellhead natural gas prices in the EMF low oil price reference case lie below the 2003 AEO path, the full range of prices in the EMF scenarios is comparable to those used in the AEO and other studies. If the study had begun with the high oil price case, natural gas prices would have exceeded $4.00 in many scenarios and thus would have provided very large incentives to develop new natural gas sources.

4.4 Natural Gas Price Competition

The EMF projections call for a very different story about the competition between natural gas and other fuels. A future section of this report will discuss the substitution possibilities between natural gas and other fuels in more detail. For the moment, the discussion will focus upon Figure 7, which shows the historical trend and several different projections for the ratio of natural gas wellhead and crude oil prices in the United States. Historically, these two fuel prices appear to be related to each other. (See appendix for references.) In 2000, wholesale delivered prices for natural gas and residual oil were reasonably close to each other. In that same year, however, wellhead prices

Figure 7. Wellhead-Crude Oil BTU Price Ratio



were almost 80% of crude oil prices. The lower wellhead natural gas price reflected that:

1. residual oil was sold at a 10% discount below crude oil.
2. natural gas had higher transport costs than oil.

Thus, historically, one would expect natural gas wellhead prices to be lower than crude oil prices, as appears to be the case over the last 20 years shown in the historical section of this figure.

The plain solid line in Figure 7 indicates the projection for the 2003 AEO made by the single model, National Energy Modeling System (NEMS). Although the ratio rises by a small amount, natural gas wellhead prices tend to maintain their relationship with crude oil prices in this projection. This is a relatively easy story for natural gas producers and their desire to underprice their competition. The wellhead natural gas price rises to above $3.50 per million cubic feet by 2020, where it provides significant incentives to develop new natural gas resources and technologies. At the same time, producers can maintain their competition with many other fuels. Natural gas remains the fuel of choice for both economic and environmental reasons.

The EMF low oil reference case calls for a dramatically different set of conditions that will be less comfortable for natural gas producers and will shift end-use markets. Wellhead natural gas prices rise to about $3.20 by 2020. At this level, some resources and new technologies available under the 2003 AEO case may not be forthcoming. In addition, the consumption outlook will also change. Once consumers realize that lower world oil prices will remain as a long-run trend, oil will compete more aggressively against other fuels. Since lower oil prices decrease natural gas prices more than other energy prices, natural gas will benefit by becoming even more attractive in its competition with coal. However, natural gas prices do not fall as much as oil prices, so that natural gas faces tougher competition in some markets that were once thought safe for expanding natural gas sales. The line with diamonds in Figure 7 shows the shift in competition between natural gas and oil in this scenario.

As natural gas becomes scarcer, its price will move closer to the crude oil price. That adjustment does not mean that natural gas prices will be uncompetitive with oil prices in all regions. Although natural gas will become less competitive in some regions, it may remain competitive with residual oil in some regions and applications for several reasons:

1. Competition could focus in regions closer to the field where natural gas transport costs are less.
2. Refineries could increase residual oil production, but at a higher cost that would move residual oil prices closer to crude oil prices.

The disparity between natural gas and oil prices could be even higher under the low-supply, high-demand composite case than in the EMF low oil reference case. As natural gas resource costs rise and the power sector expands its use of natural gas, natural gas becomes even more expensive relative to other fuels. A more intermediate EMF scenario is the high oil case, which also assumes low natural gas supply and high economic growth. With higher oil prices, there are less incentives to switch towards oil, as indicated by the lower line marked with triangles.

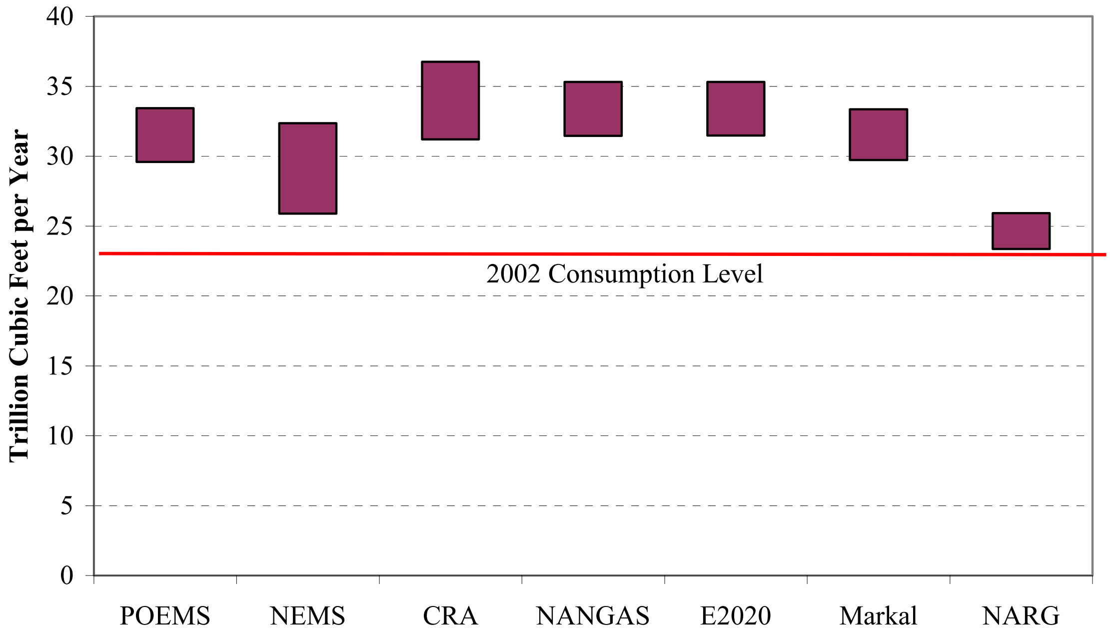
Figure 7 reports several different natural gas stories that are generated by internally consistent sets of conditions. It is reasonable to think that the 2003 AEO conditions may happen and that natural gas will maintain its preferred economic position among fuels. But the alternative cases are possible outcomes. Indeed, today's futures markets (September 2003) appear to expect that the natural gas price will rise relative to the crude oil price over the next few years. Moreover, if one extends the historical increasing trend of natural gas to oil prices between 1990 and 2001 into the future, this trend does not deviate that much from the low-oil reference and high-oil LS-HD paths in the later years of Figure 7.

4.5 Natural Gas Consumption and Production

Despite the range of conditions, all estimates call for some increases in total natural gas supply and consumption over the next several decades. Figure 8 shows that half of the models project total U.S. consumption to exceed 30 trillion cubic feet per year by 2020 in all scenarios. NEMS indicates lower estimates for the cases based upon the scenarios using a lower drilling productivity rate. The lower NARG consumption estimates reflect the greater switching from natural gas to oil and other fuels in this model, relative to the others.

Depending upon the expert in the study and future market conditions, total natural gas consumption for all sectors of the U.S. economy would grow by 0.8 to 2.8 percent each year on average between now and the year 2020. No projection called for the total level of natural gas use to peak during these

Figure 8. Range of Natural Gas Consumption in 2020



years. At the end of this period, total natural gas consumption would reach 25.9 to 36.7 trillion cubic feet per year if the lower NARG estimates are excluded temporarily from this range.

Investments in new natural gas supply resources and technologies play a critical role in these projections. Coalbed methane, tight sands and other less traditional sources will become increasingly important in meeting the demand for natural gas. In addition, international trade will become more prevalent in the U.S. natural gas markets, as greater import volumes will flow from Canada and liquefied natural gas.

4.6 Extensions to Other Important Topics

This study's scenarios depend upon some combination of lower oil prices, reduced natural gas supply, or higher demand for natural gas. Although the source of the lower supply in this study is reduced exploration and production productivity without any additional expansion of LNG and other frontier sources, supply could also be constrained by other factors such as:

- Reduced leasing in offshore areas or on restricted onshore lands;
- Rules that increased the costs of protecting the environment in natural gas-producing areas; and
- A lower geological resource base.

Additionally, although the source of the higher demand in this scenario is economic growth, demand could also be stimulated by other factors such as:

- A shift toward economic applications that require more electricity to be generated by natural gas;
- Higher prices for oil and coal and other substitute energy sources; and

- Environmental policies that restricted carbon dioxide, sulfur dioxide, nitrogen oxide, or mercury emissions that are more prevalent in other fuels than in natural gas.

For this reason, the EMF scenarios could be interpreted more broadly than they were implemented. The EMF low oil LS-HD case in Figures 6 and 7 could result from a strong policy stance to replace other fuels with natural gas in power-generation and end-use consumption, combined with restrictive policies for allowing producers to gain access to natural gas resources. Figure 6 would indicate a higher price for natural gas, while Figure 7 would underscore more competition from other fuel prices. Protecting the environment through encouraging shifts toward natural gas will become more expensive if policy also discourages natural gas production.

Protecting the environment and proper land-use planning are important considerations that need to be incorporated into a broader policy outlook. Our results cannot be used to resolve this policy dilemma, because the study has focused solely on how the natural gas market responds to these changed conditions. However, they do show that policies need to be coordinated if we are to develop successful strategies that expand natural gas use while meeting these other objectives.

5 Natural Gas Demand Adjustments

Industrial and powerplant demands account for most of the increased natural gas consumption. Until recently, historical data on energy use has included some fuel consumption for generating electricity incorrectly in the industrial sector, when a firm produces on-site electricity in addition to direct fuel for its own operations. A second critical factor influencing total energy consumption has been demand "destruction", where petrochemical, ammonia and other energy-critical outputs are produced overseas to take advantage of lower petroleum or natural gas prices.

The response of energy end-users can be an important brake on the increase in natural gas prices in the previous scenarios. If technology and policy allow energy-consuming groups considerable flexibility in curtailing their use of natural gas as prices rise, the balance between natural gas supplies and demands can be restored with smaller increases in the price of natural gas. Many policymakers and corporate leaders tend to underestimate the importance of these demand adjustments to a well-functioning natural gas market.

5.1 End-Use Substitution

There has been much interest in the immediate demand response to natural gas prices. A number of years ago, many industrial customers and power-plants had equipment that could use more than one fuel depending upon the relative fuel prices. These multi-fuel users were frequently substituting between natural gas and oil. In the interim period, many larger customers have not been maintaining their multi-fuel equipment and are choosing new single-fuel equipment in their investment decisions. Although substitution with multi-fuel equipment is not widely used in today's market, customers could return to this option if they feared volatile prices and if environmental controls allowed them the flexibility.

Estimates derived for this study were based upon the 2000-2001 period, when natural gas prices first swung above petroleum prices and then fell below these levels. This experience suggests that the combined immediate substitution between oil and natural gas in U.S. power plants with dual-fuel capability may currently be about 29 gigawatts (equivalent to slightly more than half of the total California electric power capacity), which is below 20% of the advertised potential nameplate capacity of 155 gigawatts for this type of substitution. These units are capable of burning either fuel in the same units. The 17 gigawatts of this capacity which fires distillate or natural gas, is primarily turbine-based technology. These units are likely used for peaking and intermediate dispatch. The remaining 12 gigawatts fires either residual fuel oil or natural gas. These units are steam boilers and some are advertised as also capable of burning distillate.

The loss in natural gas demand due to this switching will be very dependent upon the utilization of the electric power units. During the months studied, approximately 2.7 billion cubic feet per day of natural gas demanded by these units switched to petroleum. This estimate is slightly less than 5 percent of the average monthly level of total natural gas consumption in all sectors in 2002. It remains well below the level which would result if all multi-fuel electric power units were operating at 100% utilization rates.

Another short-term adjustment would be switching between separate, single-fuel plants using different energy sources. For example, an electric generator may choose to operate its combined-cycle natural gas plant more when natural gas prices are low and to operate its coal-fired plant more when natural gas prices are high. Although this adjustment is sometimes referred to as indirect substitution, it accomplishes the same objective as the direct substitution involved with multi-fuel equipment. This indirect switching may have a larger impact on natural gas consumption than direct switching between petroleum and natural gas.

Over time, the possibilities to substitute away from natural gas expand. When firms replace older equipment with newer vintages, they can also choose both the fuel for combustion and the efficiency of the equipment. Newer, more efficient natural gas combined-cycle plants can replace older coal plants if the economics favor natural gas. The multi-year response to a change in price is often many times the immediate response. Occasionally, policies will restrict the choice of fuel in new equipment, thereby making this adjustment less important than it would be otherwise.

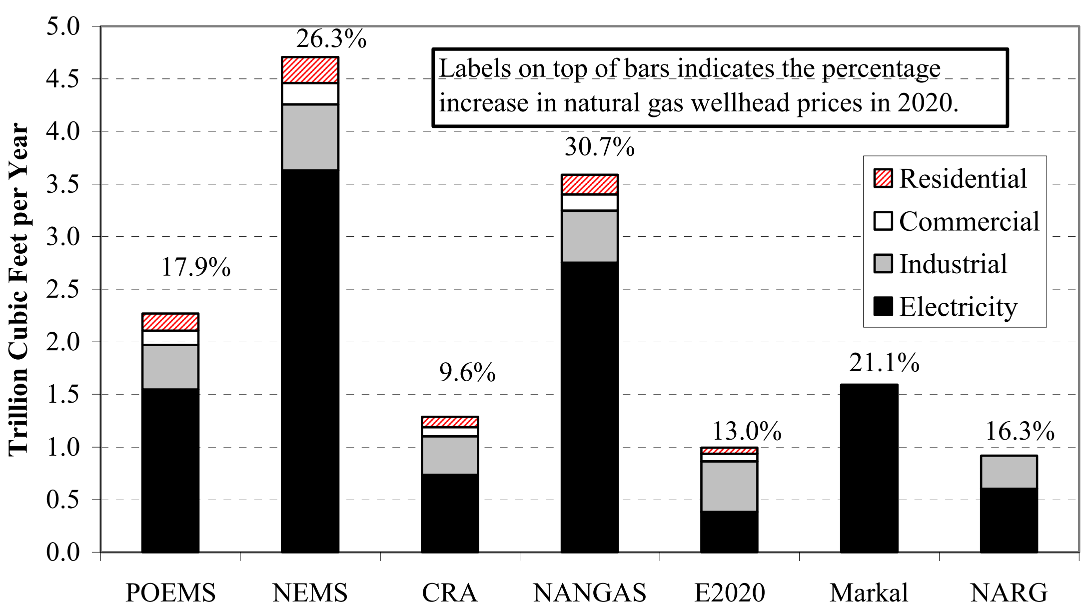
In addition to multi-fuel, indirect and multi-year substitutions, there is a fourth adjustment that can also be very important. When the price of natural gas rises, a customer may decide to reduce natural gas consumption without using another fuel as a replacement. Often, this adjustment will involve the replacement of natural gas with a non-energy input like labor or physical capital. Sometimes, the decline in energy use represents demand "destruction" and the relocation of the firm overseas. This study will refer to all these responses as aggregate adjustments to refer to the decline in the use of total energy in the United States. (A less precise term would be "efficiency improvements" to refer to the increased energy efficiency. However, economic efficiency for all inputs may not be improved and can even be worse, as would be the case if energy per square foot of floor space declined, but the equipment per unit of floor space increased.)

5.2 Total Economy Response

Natural gas competes with electricity in the residential and commercial sectors, with coal and renewables in electricity generation, and fuel oil in some industrial processes and several residential and commercial markets. The demand response can be better understood by considering how the market adjusts to the condition of lower natural gas supplies. In this scenario, lower productivity reduces the availability of natural gas. With consumption initially exceeding production under these conditions, producers will pass through the higher costs of their natural gas supplies. Natural gas consumers will pay higher delivered prices, causing them to adjust their consumption along the lines discussed above. The results will be higher prices and reduced consumption than before, just like the "depleted resources" arrow in Figure 3 that was discussed previously.

The electric power sector accounts for more than half of the total demand adjustment to low supply conditions in each model, as shown in Figure 9. Although the industrial response is also large, the two buildings sectors (residential and commercial) respond mildly. The response within the buildings sector represents reduced energy use rather than any significant shift in fuel choice. NEMS and NANGAS/IPM register the largest total

Figure 9. Reduction in Natural Gas Consumption Due to Low Supply, 2020



reductions of all the models. The large reduction in NEMS reflects the fact that natural gas consumers in all sectors are more responsive to natural gas price changes than they are in the other models. This model shows one of the larger changes in wellhead prices, which are labeled at the top of each bar. The large reduction in IPM reflects the fact that the natural gas price change is larger in this model than in the other models.

The economy reduces natural gas use by making aggregate adjustments and by expanding coal and oil, as summarized in Figure 10. Aggregate adjustments dominate the E2020 response, with only minor shifts towards both oil and coal. Both POEMS and NEMS have 1 quad or more of aggregate adjustments and both show large shifts toward coal and oil. NEMS shows more than 3 quads of increased coal use.

The group also considered the effect of introducing the low supply conditions when natural gas prices were initially higher than they were in Figures 8 and 9. To achieve these higher initial natural gas prices, a high demand case was simulated. Economic growth was expanded by 3.4% rather than 3.0% per year. Low-supply conditions were then applied separately to both the EMF reference and the high demand cases. Figure 11 indicates that except for NARG, total natural gas consumption declines more when prices and consumption are initially high (as in the high demand case) than when they are initially low (as in the EMF low oil reference case).

5.3 Electricity Substitution Response

Table 2 examines the fuel demand response within the all-important electricity generation sector of the economy to the reduced supply conditions. Higher natural gas prices reduce natural gas use for power in all models in favor of increased coal and oil use, depending upon the model.

Figure 10. Total Fuel Substitution and Efficiency Gains Due to Low Supply, 2020

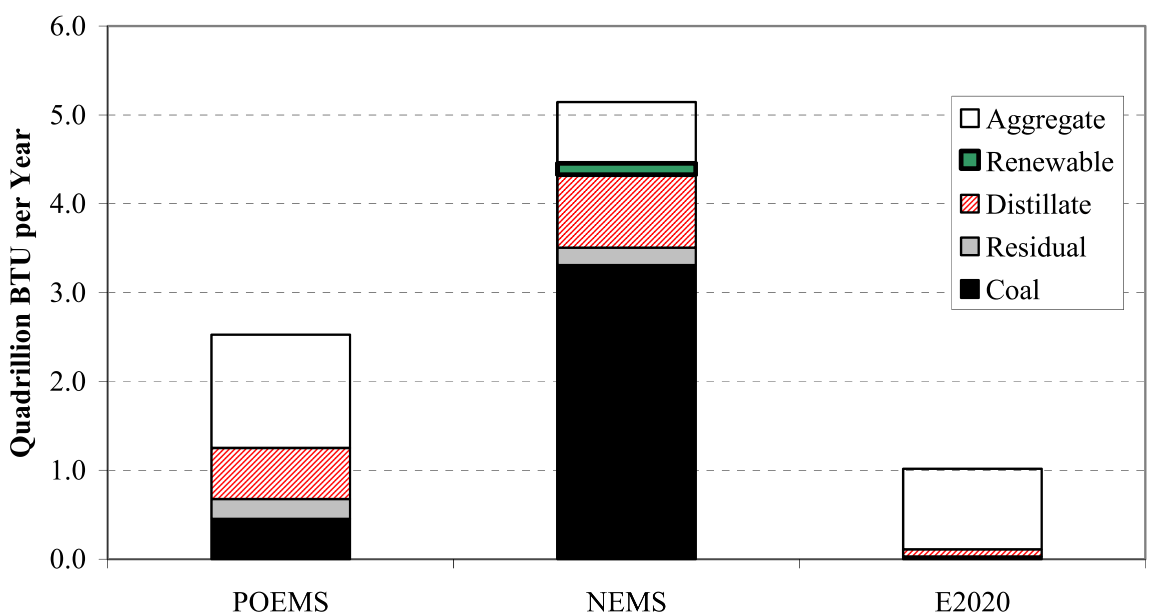


Figure 11. Reduction in Total Gas Consumption Due to Low Supply, 2020

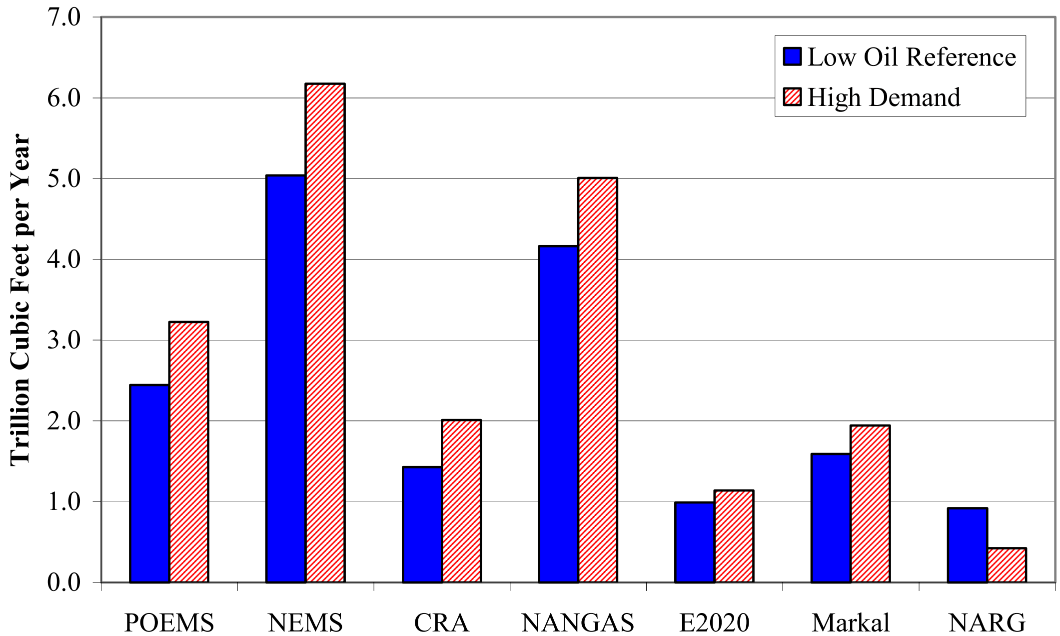


Table 2. Fuel Adjustments in Electricity Sector Due to Low Supply, 2020

(Quadrillion BTUs per Year)

	Total	Gas	Coal	Nuclear	Renewable	Oil
POEMS	-0.45	-1.58	0.41	0.00	-0.03	0.75
NEMS	0.64	-3.70	3.28	0.00	0.13	0.93
NANGAS	0.30	-4.29	4.28	0.30	0.00	0.02
E2020	-0.42	-0.39	0.00	0.00	0.00	-0.03
MARKAL	NR	-1.61	1.66	NR	NR	NR
NARG	NR	-0.62	NR	NR	NR	NR

The effect on total power generation is mixed. POEMS and E2020 show declining levels of total fuel for power generation. Higher natural gas prices increase power prices, thereby lowering power demand. In contrast, NEMS and NANGAS show rising levels of total fuel for power. The power sector reduces its use of higher-cost natural gas, constraining somewhat the upward push on power prices. At the same time, higher natural gas prices in other end-use sectors shift consumption away from natural gas and toward power.

Substitution toward coal is large in NEMS and NANGAS. The IPM response reflects that it begins with relatively low natural gas prices. Meanwhile, substitution toward oil is large in NEMS and POEMS.

5.4 Greenhouse Gas Emissions

Most scenarios in this study assumed a relatively low oil price path, which consumers will view favorably. These same conditions may present some policy problems.

Within the transportation sector, lower gasoline prices will increase carbon dioxide emissions, but many of the models in the study cannot estimate these effects because they exclude transportation activity. However, if future relative fuel prices cause consumers to replace natural gas with coal and some oil, carbon dioxide emissions in the non-transportation sector may grow more than otherwise. If these same conditions cause consumers to reduce their aggregate energy use or to substitute renewable energy for natural gas, carbon dioxide emissions, outside the transportation sector, will grow less than otherwise.

Table 3 provides an approximate estimate of the impact on sectors other than transportation in 2020 for four cases. These estimates exclude gasoline but include distillate oil consumption for trucks used for industry. They also replace natural gas with coal and some exclude liquid petroleum gases (LPG) and other types of petroleum used

Table 3: Inferred Growth Rate for Carbon Dioxide Emissions, 2000-2020
(Excluding Transportation Sector)

	Reference	Low Supply	Low Supply-High Demand	High Oil
Annual Growth Rate				
POEMS	1.53%	1.51%	1.81%	1.79%
NEMS	1.28%	1.39%	1.66%	1.61%
E2020	0.96%	0.91%	1.16%	1.08%
Growth Rate Difference				
POEMS		-0.03%	0.30%	-0.02%
NEMS		0.11%	0.26%	-0.05%
E2020		-0.05%	0.25%	-0.08%

Important Caveat and Notes:

*These approximate estimates may differ from what each model would report. They have been inferrred from each model's projections for total coal, oil and natural gas using the following carbon coefficients (metric tons per quadrillion BTU):

Coal	25.98
Natural Gas	14.47
Residual Oil	21.49
Distillate Oil	19.95
Crude Oil	20.29

*E2020 estimates include transportation.

*Growth rate difference is computed with respect to the scenario immediately to the left. Thus, for example, the difference under "low supply" equals the change from the "reference" to the "low supply" cases.

primarily by industry. Carbon dioxide emissions were computed for each model by applying each fuel's average carbon content per Btu to its projected level in the scenario. Although these estimates illustrate the basic trends, actual carbon emissions reported by each model may be different than what appears in this table.

The results emphasize that more pessimistic assessments about the prospects for natural gas have relatively modest effects on the nation's carbon dioxide emissions. Only the higher growth conditions appear to appreciably change the basic trend in carbon dioxide emissions outside the transportation sector for any model. The low natural gas supply conditions produce different results in the models. NEMS shows that carbon dioxide emissions increase by 0.1 percent per year, while POEMS and E2020 reveal smaller decreases. The improvement for both POEMS and E2020 probably reflects that these systems show relatively larger reductions in total energy use when natural gas prices increase as natural gas supplies are reduced.

Greenhouse gas emissions in North America could be even less of a problem if other technical developments could offset these natural gas market outcomes. The working group discussed the prospects for increased use of renewable energy, nuclear power, or coal, the latter through a successful clean-coal technology program. Technology and structural economic change will also shape future energy use decisions, providing opportunities to reduce energy consumption and greenhouse gas emissions. Significant supply and demand opportunities may be created, if natural gas becomes more expensive. Limitations on time and other resources prevented the group from considering the numerous opportunities from developing other energy sources (including energy-efficiency opportunities), but hopefully future efforts by other groups can build upon the underlying framework presented in this study.

6 Natural Gas Supply Adjustments

6.1 Resource Base Calibrations

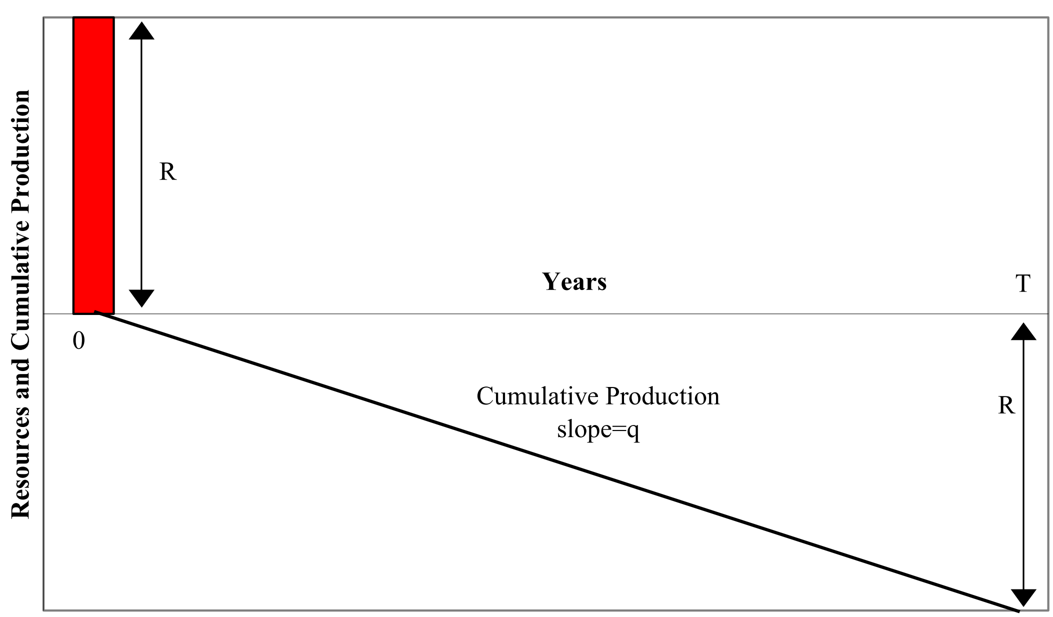
Most energy market models calibrate their supply estimates with the U.S. Geological Survey (USGS) evaluation of ultimately recoverable resources. This calibration provides legitimacy and also assures that the framework does not produce more natural gas than can be discovered. Even with this calibration, there appears to be some significant differences in natural gas availability in these and other projections. There are several reasons for this apparent inconsistency.

Resource estimates do not specify explicit costs for different volumes of natural gas. Consider the situation where two analysts both use the USGS estimate for the most likely amount of resources and both produce the same natural gas amount every year. Suppose that the first expert assigns 20% to future resources costing under \$3.00 per Mcf and 80% to resources costing above \$3.00 per Mcf. The second expert assigns 80% to volumes costing under \$3.00 and 20% above \$3.00. The first expert will expect a higher natural gas price path than the second expert, even though they both calibrate their outlooks to the USGS estimate of ultimately recoverable physical resource base.

A second major problem is that resource base estimates summarize the supply that geologists think will be available over the next thirty years given current economic conditions. If those conditions change because prices increase or technology advances more rapidly than expected, the resource estimates should also change. Essentially, resource base estimates are static while marketed supply is dynamic. Figure 12 captures the essence of the static or "one-shot" view of resources. Time is plotted along the horizontal axis. In the initial year (at the origin), the analyst calibrates the resource base at R, which equals the height of the solid horizontal bar to the far left. The amount R refers to the amount of additional resources that have not yet been produced. Each year, the analyst allows producers to extract the same amount of resources and calls it production. The solid downward-sloping line represents the cumulative amount produced from the beginning year until the current year. When the model reaches the year T in the figure, producers have extracted all resources. The cumulative-production line lies below the horizontal axis by a distance equal to the height of the original resource base estimate or R. If production each year is q, all resources are "gone" in R/q years.

Figure 13 captures the essence of a more realistic and dynamic or "evolving" view of resources. The same initial resource base and production path are contained in this figure as were included in the previous figure. However, this figure allows the resource base to grow over time, as the producing sector learns more about where resources are located and how best to extract them. A dashed line depicts how quickly resources grow as more discoveries are found. Small changes in the slope of this line could fundamentally alter one's perception of where the resource base will be in 20 or 30 years. High "reserve growth" could add to reserves faster than extraction will deplete the base. Low "reserve growth" could allow the resource base to be depleted, but at rates much slower than the simple "one-shot" case. The high

Figure 12. 'One-Shot'Approach to Resource Base Calibration

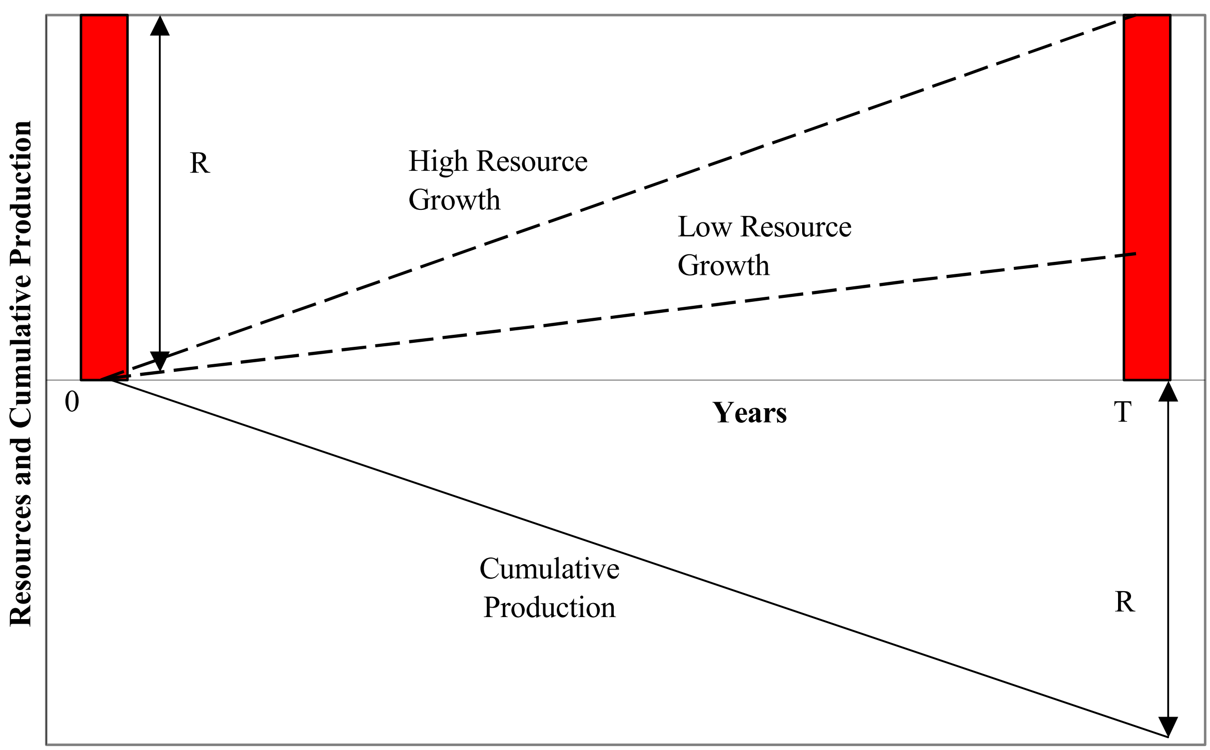


reserve growth path in Figure 13 has been constructed arbitrarily so that cumulative additional discoveries equal cumulative production by the year T. Under those conditions, a new geologic assessment would estimate that the remaining resources for future production would equal R, the level estimated in the initial year.

There has been considerable discussion and debate between resource optimists and pessimists. Although focused largely on oil, the same arguments carry over to natural gas. These two groups of experts are probably arguing more about the "reserve growth" line in Figure 13 than they are about the initial resource base estimate. Some analysts expect discoveries to grow modestly from these initial amounts, while others expect discoveries to grow multiple times. These different perceptions will have large effects on the future availability of natural gas. Having all analysts standardize to the same initial resource base in the beginning year does not eliminate these large differences.

Optimists and pessimists also differ on their assessment for relatively new resource formations that are called unconventional natural gas. These sources include such natural gas types as coalbed methane, tight sands and hydrates. More optimistic experts believe that these new formations will continue to penetrate the market, even now that the tax subsidies for such volumes are no longer on the books. More pessimistic experts are not convinced that these volumes will enter the market without substantially improved technology and higher natural gas prices.

Figure 13. 'Evolving' Approach to Resource Base Calibration



6.2 Natural Gas Availability in the EMF Low Oil Reference Case

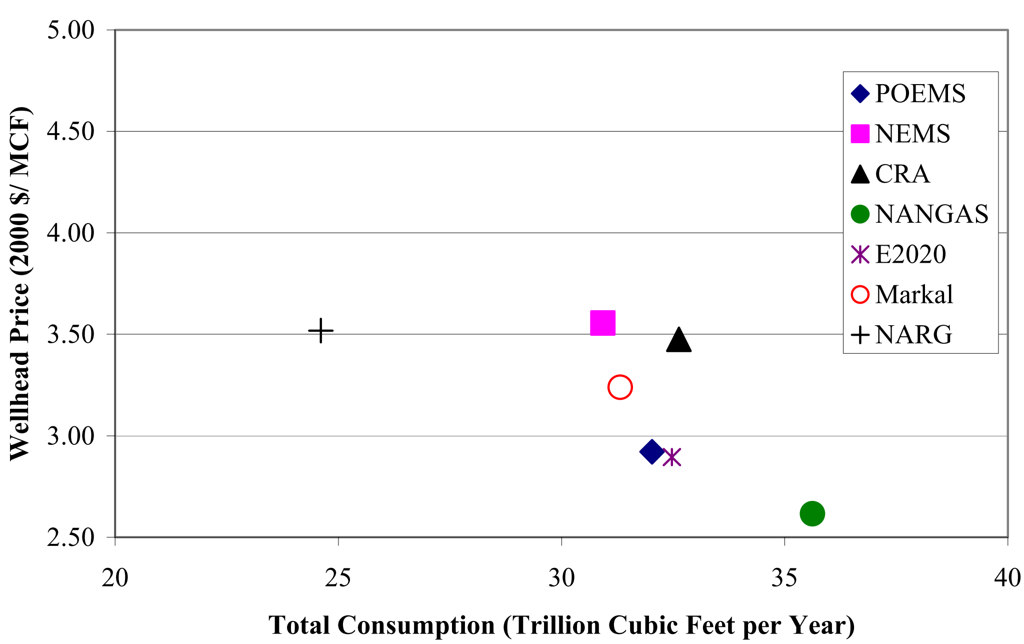
As a group, the models allow the future resource base to grow over time, although probably at rates that are less than what optimists would deem appropriate. The projections in this report also rely on significant growth in unconventional natural gas.

Differences in natural gas availability are reflected in the EMF low oil reference case. Displaying both prices and quantities jointly, Figure 14 shows the average U.S. wellhead price on the vertical axis with $2.50 per thousand cubic feet (Mcf) rather than zero being at the origin. It shows total U.S. natural gas consumption on the horizontal axis with 20 trillion cubic feet (Tcf) rather than zero being at the origin. Prices in the year 2020 range from $2.62 to $3.56 per million cubic feet, while annual consumption in that same year ranges from 24.6 to 35.6 trillion cubic feet per year.

NEMS, CRA and NARG anticipate wellhead prices in 2020 reaching the $3.50 per Mcf range, while POEMS, E2020 and NANGAS show prices falling slightly below $3.00 per Mcf. Resource assessments play some role in these different results. NANGAS appears to be more optimistic about future natural gas supplies, as price is lower and the natural gas volume greater in that model than in the others. This model builds the natural gas supply curves from simulations of individual reservoirs and undeveloped fields specified by geologic plays in a "bottom-up" assessment of the resource base.

With a higher price and lower natural gas volume, NARG may also be more pessimistic than NANGAS about future natural gas supplies. However, lower natural gas demands are definitely contributing to the observed outcome for this model. When oil prices are low relative to natural gas prices, more natural gas consumption is replaced by

Figure 14. Natural Gas Conditions in Reference Case, 2020



oil consumption than in some of the other models.

6.3 Supply Response When Demands Increase

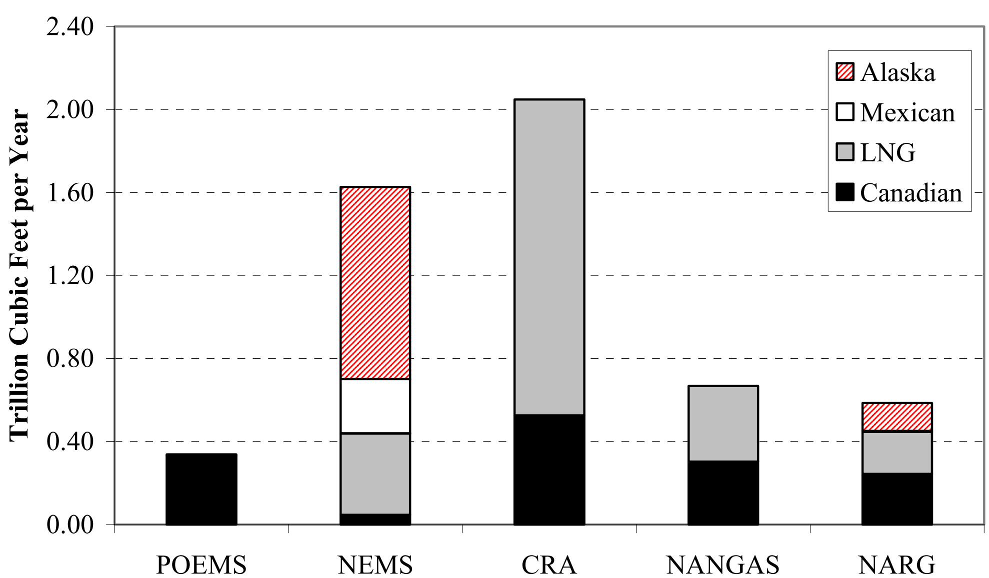
A greater supply response to higher wellhead prices will prevent natural gas prices from rising as much when economic conditions increase natural gas demand. This adjustment is extremely important in any case where policy, technology or economics favors the use of natural gas.

The supply response can be better understood by considering how the market adjusts to the condition of higher natural gas demands. In this scenario, higher economic growth stimulates the use of natural gas for generating more electricity as well as for meeting higher demand for natural gas in other sectors. With consumption initially exceeding production under these conditions, prices will move higher. Natural gas consumers will reduce their use and producers will increase their supplies as prices increase. The results will be higher prices and consumption than before, just like the "expanded demand" arrow in Figure 3 that was discussed previously.

Imports and Alaskan natural gas play an important role in meeting higher natural gas demands. In Figure 15, there is another 2 Tcf more in Canadian and LNG imports in CRA, in response to the higher natural gas demand. CRA is particularly bullish about additional LNG imports, as wellhead prices rise from \$2.69 to \$3.29 in 2010 and from \$3.48 to \$3.88 in 2020 per Mcf in that model.

Mexican imports expand and the Alaskan pipeline is built in NEMS in the high demand case. The Alaskan pipeline is also built in NARG under all scenarios and in NANGAS under the expanded frontier case (to be discussed).

Figure 15. Increase in Alaskan Gas and Natural Gas Imports Due to High Demand, 2020



Greater imports in NEMS replace some Rocky Mountain and Gulf Coast onshore production, which decline in Figure 16. Natural gas from other sources (Midcontinent, Northeast and West Coast) increase in this model. Rocky Mountain onshore production responds particularly strongly to the high demand conditions in the POEMS and CRA models**.**

As was the case with the natural gas demand response to price, the effect of higher natural gas prices on natural gas supply may be different if natural gas prices were initially higher. The low supply case includes lower drilling productivity, which increases natural gas prices above the EMF low oil reference case. Figure 17 compares the response of total U.S. natural gas supply to higher demands in the low supply case and in the reference case. When prices are initially less (indicated by the solid bars), supplies increase more in POEMS, NEMS and NANGAS than when prices are initially more (indicated by the diagonally marked bars). The reverse responses occur in E2020 and NARG.

7 Expanded Frontier

7.1 LNG, Alaska and the Canadian Frontier

If economics and environmental policies continue to expand the demand for natural gas in the power sector and other end uses, there will be increased pressure on traditional sources of North American natural gas. These conditions could provide the incentives for the development of new natural gas sources such as the Mackenzie Delta/Beaufort Sea basin in northern Canada or the

Figure 16. Increase in Natural Gas Production Due to High Demand, 2020

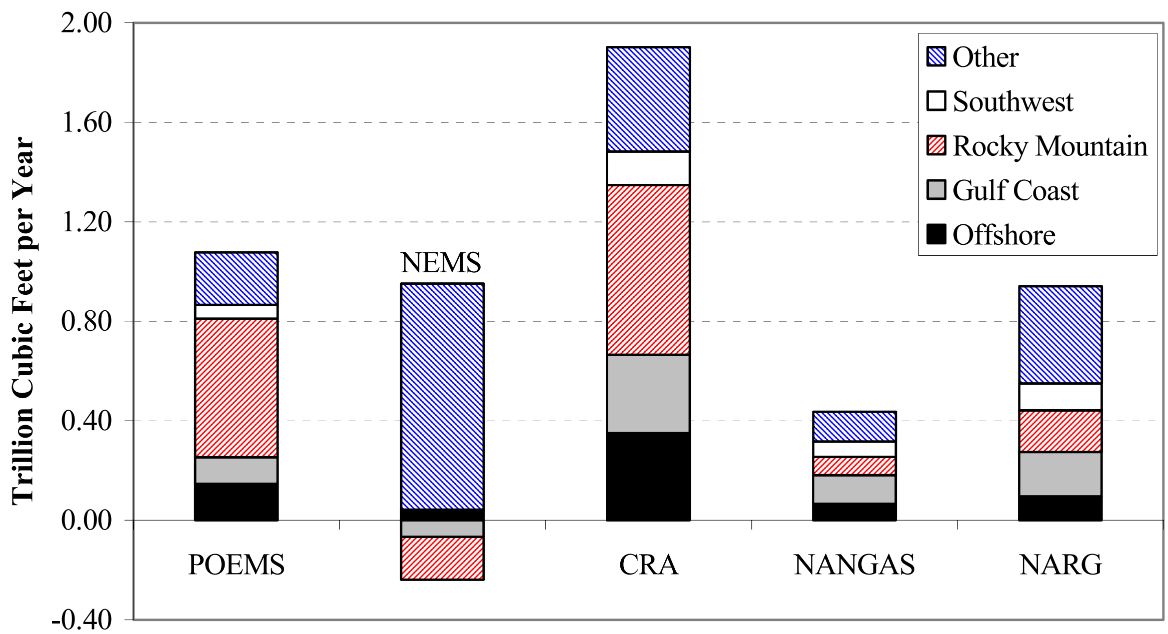
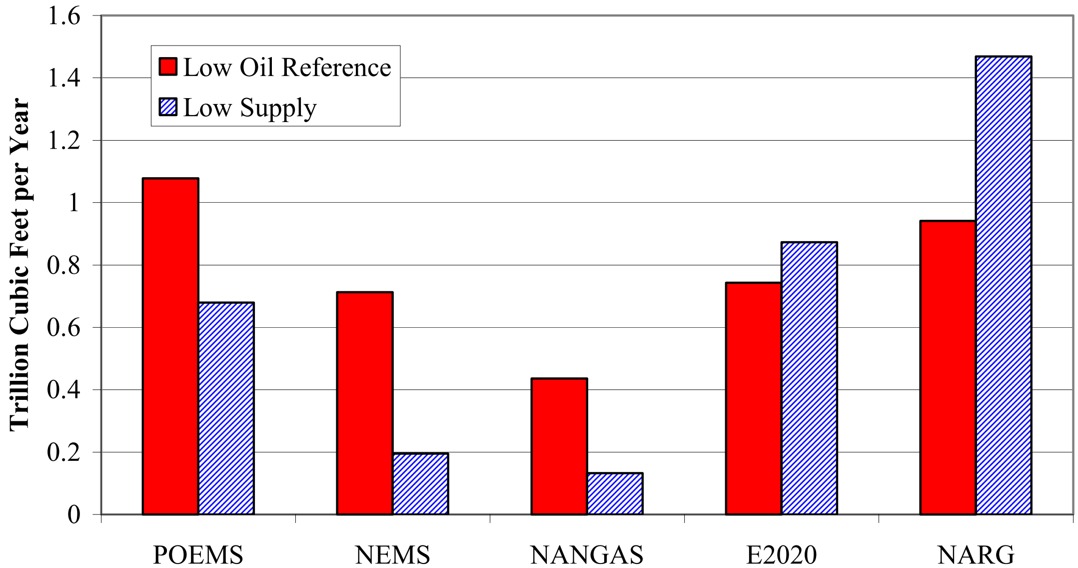


Figure 17. Increase in US Dry Gas Production Due to High Demand, 2020



offshore areas in eastern Canada. Other interesting possibilities include northern Alaskan natural gas that is piped through the state to be delivered in the lower-48 states and liquefied natural gas (LNG) projects that would require regasification plants located in various localities to service demand. All of these sources share the common requirement that any firms undertaking these projects will need to expose massive investment to the cruel risk of natural gas price uncertainty.

Considerable uncertainty exists about the type of natural gas market and institutions that would be needed to share risks appropriately to make these projects successful. Although large pipelines from frontier producing areas have similar characteristics, it is useful to consider the growing globalization of natural gas markets through expanding LNG trade. These projects depend upon the simultaneous siting of and investments in natural gas liquefaction plants in the producing region, dedicated ships for transporting the fuel, and regasification terminals in the receiving area. These plans must be coordinated, thereby converting LNG volumes into very large projects rather than simply incremental sources of natural gas offered on flexible terms. Siting the regasification terminals in consuming countries represents an important barrier to the development of this source.

At the same time, events are transforming these markets at record speed and in ways that could make natural gas much more of an international fuel in the future. The Atlantic basin for LNG appears to be moving towards a spot market for many of its transactions that will provide the basis, perhaps, for more flexibility in the trading and use of such natural gas. Participants may adopt floating terminals that allow natural gas to be delivered to a variety of regions depending upon local market conditions. As these institutions and technologies penetrate the market, producers will be able to search for new markets and find the flexibility to supply these volumes more economically.

Whether these trends can continue so that LNG can become an active and perhaps price-setting source in North American natural gas markets goes beyond what the working group could project in this study. There seemed to be some agreement among the participants that these new developments will grow in importance and that they will make natural gas prices more sensitive to increased LNG trade. Its ability to set North American natural gas prices depends upon not only the speed of these institutional changes but also how large LNG supplies become relative to the overall market.

7.2 Price Risks

The group developed the expanded frontier case to help market participants and policymakers understand the potential role and risks of such projects. This case envisioned an expanded frontier, in which about 4 trillion cubic feet per year of additional natural gas became available by 2020 from the combined sources of frontier Canadian natural gas, Alaskan natural gas, and LNG projects. This expansion occurred when natural gas markets were operating under the low-supply and high-demand conditions discussed above.

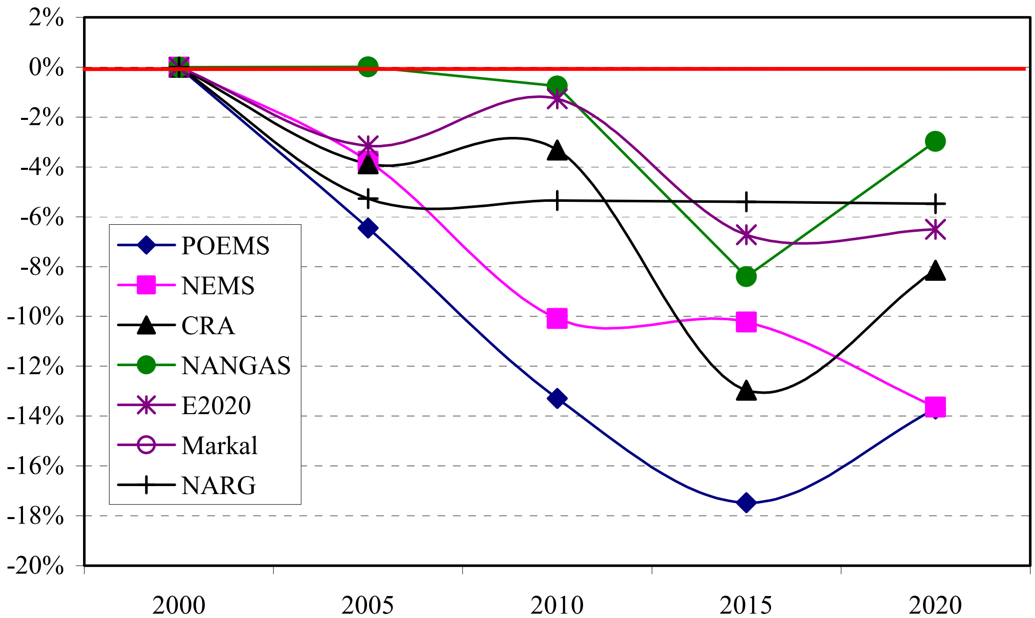
The domestic wellhead price continues to rise between 2005 and 2020 with the new frontier natural gas but at a slower rate. Figure 18 shows that these conditions will reduce the price of natural gas from their levels in the low-supply, high-demand case. Most of these volumes enter the market after 2010 and hence have their biggest impact in the year 2015. (Please recall that the study reports estimates only in five-year increments.) The initial entry of the frontier natural gas significantly reduces the rate of increase in the domestic wellhead price in the early years. Over time, natural gas demand will grow and the new frontier volumes will replace some domestic production. These adjustments will soften the impact on natural gas prices. At the end of the period, the wellhead price is closer to, but still remains below, its level without the frontier supplies than during the intermediate period.

The amount by which the expansion reduces prices differs widely across models. POEMS shows that the additional frontier natural gases reduce wellhead natural gas prices by 17.5% in 2015, while NARG reveals a much smaller price decline of 5.4%. The POEMS findings suggest the successful development of all these sources will have much larger price risks for any individual project than do the NARG or E2020 results. On average for all the models, U.S. wellhead prices fall from \$3.88 per Mcf to \$3.47 per Mcf. A decline of more than \$0.40 per Mcf will certainly cause a few large-scale investments difficult adjustment problems over this period. These results underscore how critical long-term contracts and other market-based, risk-sharing strategies will be to encourage these new sources to be developed.

7.3 Price Expectations

The actual response to these events may be more complicated than what the models reveal in Figure 18. Today a

Figure 18. Percent Deviation in Wellhead Price Due to Expanded Frontier



number of firms have plans to build new LNG and frontier facilities in various stages of development. As each firm sees more LNG and frontier supplies enter the market, they will adjust their future plans according to what they expect the future price to be. Some plans will be scrapped because the expected future price is too low. These expectations will reduce the supply expansion and result in smaller price adjustments. Producers in the NARG model in Figure 18 incorporate these expectations. As a result, prices in that model barely move after initially falling.

Despite the logical appeal of having producers who can correctly anticipate the future, companies in such industries as electric power and natural gas often do not anticipate future market conditions that well. Projects must be built over multiple years with large investments and uncertain completion times. Price cycles and volatility as well as uncertain market conditions hide long-term trends. Overcapacity can develop, leaving stranded assets for some companies. Figure 18 captures the potential for boom-and-bust conditions in natural gas markets.

7.4 Regional Effects

These expansions in frontier and LNG supplies could have varying impacts on different regions. The Alaskan and northern frontier Canadian supplies will be transported primarily to the mid-western and western regions of the United States and Canada. The LNG projects could be built either in regions that already have LNG facilities or in new sites in other regions. The EMF working group allowed each modeling team to use their own judgment about how much additional natural gas will enter the market and at what point. All models except MARKAL represented regional markets for natural gas.

In Figure 19, total natural gas consumption increases most strongly in the West South Central region in most models, followed by significant increases in the East North Central, East South Central and Pacific regions. Table 4 reports the states covered in each census region.

If natural gas is free to flow along an interstate pipeline system without any constraints on capacity, regional prices will tend to increase similarly across regions. If natural gas flows are constrained by capacities and other factors, there could be important differences in the increase in prices across regions. Figure 20 shows similar price effects for all regions, except Pacific, where pipeline constraints may limit trade into California.

8 Distributed Generation and Advanced Renewable Technologies

8.1 Distributed Generation

Distributed generation (DG) represents a new direction for electric power services that depends chiefly on small, modular generating technology fueled largely by natural gas or renewable resources. It is part of a broader move toward end-use applications, site generation, and more distributed power parks and small grids.

Its continued growth depends upon open wholesale and retail markets that prices power based upon its cost at each specific locality in the power system. Although it is sometimes considered as an alternative to the conventional wisdom of economies of scale, centralized power, and vertical integration, the key challenge appears to be how to integrate the smaller DG technologies into the centralized system in an openly competitive environment.

Figure 19. Change in Regional Gas Consumption Due to Expanded Frontier, 2020

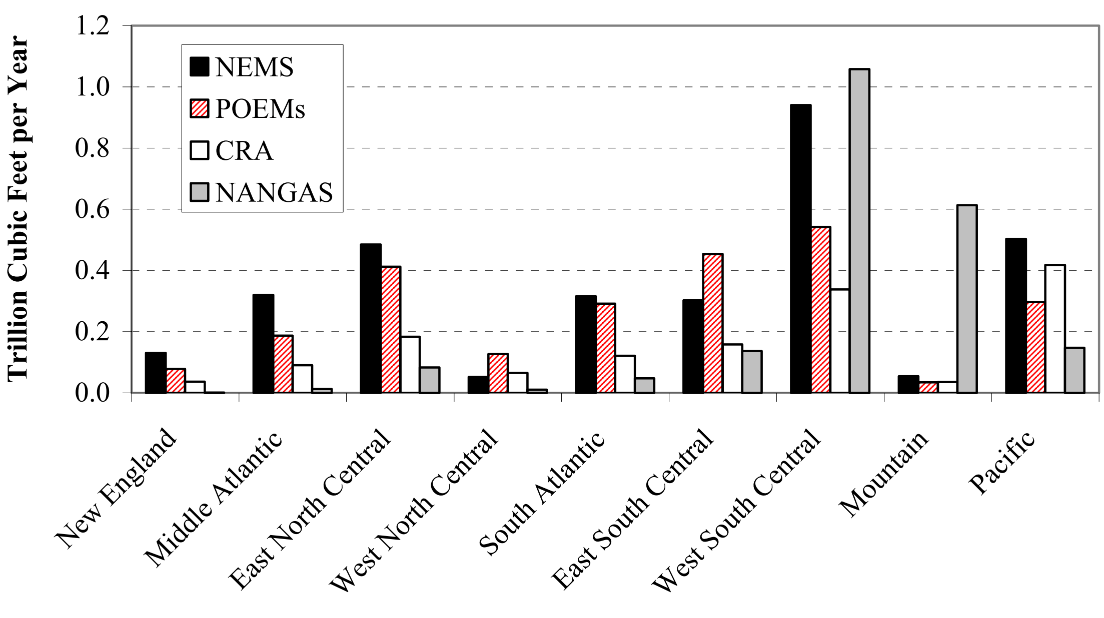
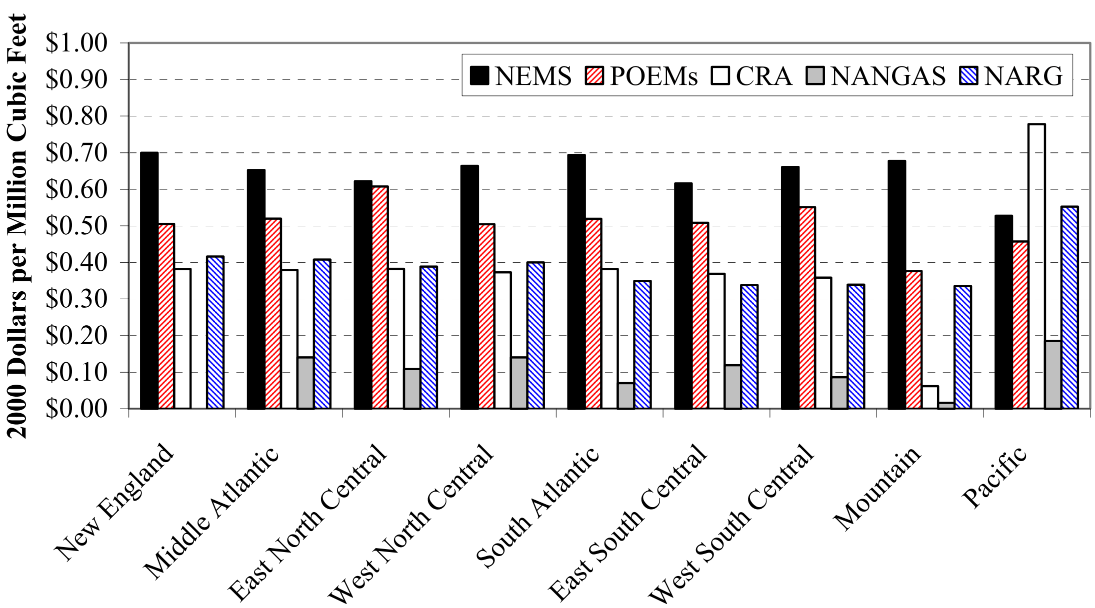


Table 4. Coverage of States in Each U.S. Census Region

New England	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont
Middle Atlantic	New Jersey, New York, Pennsylvania
East North Central	Illinois, Indiana, Michigan, Ohio, Wisconsin
West North Central	Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, South Dakota
South Atlantic	Delaware, District of Columbia, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, West Virginia
East South Central	Alabama, Kentucky, Mississippi, Tennessee
West South Central	Arkansas, Louisiana, Oklahoma, Texas
Mountain	Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, Wyoming
Pacific	Alaska, California, Hawaii, Oregon, Washington

Figure 20. Reduction in Regional Gas Price Due to Expanded Frontier, 2020



Since some DG applications use natural gas, its expansion may contribute to more natural gas use. However, other DG technologies will replace natural gas with other energy sources. In addition, DG technologies with waste heat recovery can reduce natural gas usage by operating more efficiently if there is also a need for heat. DG's improved performance relative to an efficient natural gas boiler occurs because it recovers the waste heat that central generators reject to the atmosphere. Also, DG and site generation reduces electricity transmission losses.

8.2 Advanced Renewable Technologies

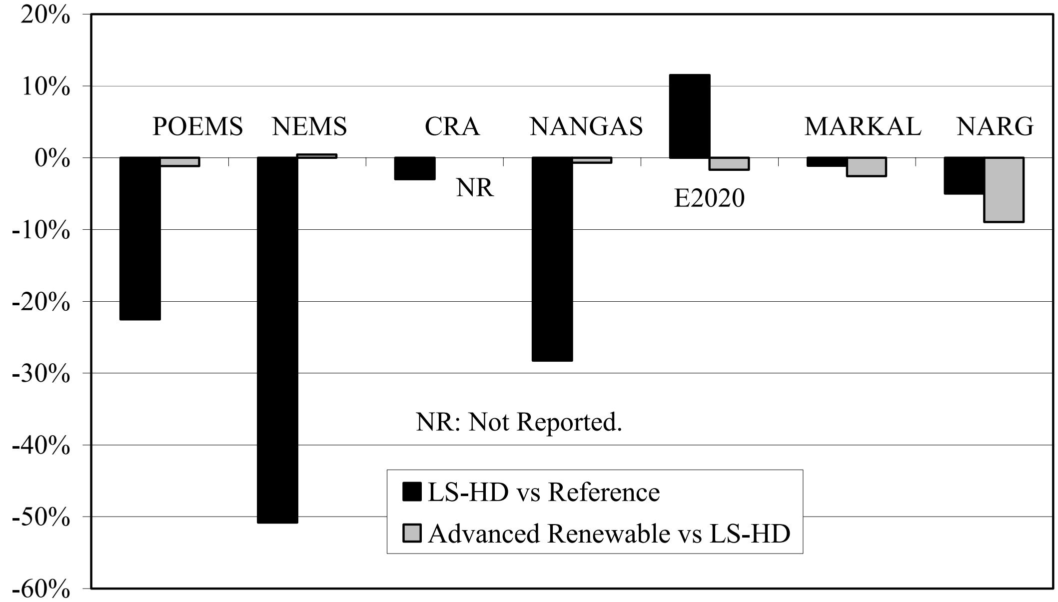
New technologies and a decentralized electricity system are also important characteristics of many renewable energy options. Renewable energy covers an incredibly wide range of options like solar, wind, biomass and geothermal and hydroelectricity. They may provide alternatives to natural gas-fired generation in the future.

An EMF scenario assuming lower costs and better performances for advanced renewable technologies was constructed to examine the interaction of natural gas prices and renewable generation. Advanced technology conditions were not applied to hydroelectricity, because this source has been widely available for many years and is not currently the focus of corporate technology strategy or government policy.

Results (not reported here) from MARKAL confirm that the renewable technology assumptions have a much bigger impact in the years after 2020 than in the intervening period. Prior to 2020, however, increased renewable penetration does not change the natural gas market picture much in most models. These costs and performances were added to the combined low-supply, high-demand conditions, which by themselves made natural gas much more expensive than in the reference case. The incremental effect of the combined low-supply, high-demand conditions on natural gas consumption for electricity, relative to the reference case, appears to be the dominant effect for NEMS, POEMS and NANGAS in Figure 21. However, the improved cost and performance characteristics do suggest slightly less natural gas use in 2020 in the power sector for most models. The gray-shaded bars indicate the change in natural gas consumption due to the accelerated renewable technology assumptions, relative to consumption levels in the combined low supply and high demand case.

Wind power shows a particularly strong growth in the advanced renewable technology case. Over the 2000-2020 period, total wind production in the United States grows by 12.0 percent per year in POEMS and by 18.2 percent per year in NEMS, compared to growth rates in the reference case of 6.4 and 9.1 percent, respectively. Wind's penetration is due not only to its improved cost and performances, but also to the higher natural gas price. Moreover, due to the accelerated renewable technology conditions (and ignoring the higher natural gas price), wind replaces coal rather than natural gas in the NEMS results. The interaction of wind with natural gas allows this combination to act as a baseload technology.

Figure 21. Percent Deviation in Gas Consumption for Electricity, 2020



9 Prices and Consumption Under Different Market Conditions

9.1 Higher Natural Gas Prices

In section 4, the report discussed the wellhead price trends in the EMF Low Oil Reference case and three alternative scenarios:

- A low-supply (LS) scenario, which assumed that the exploration and production drilling productivity was lower than in the reference case;
- A high-demand (HD) scenario in which the economy grew by 3.4% rather than 3.0% per year; and
- A combined low-supply, high-demand (LS-HD) scenario that placed the greatest upward pressure on natural gas prices.

Another perspective that is useful for understanding how the models respond to changed conditions can be gained by examining changes in wellhead prices and total consumption at the same time. It may be helpful to return to Figure 3 briefly, because that chart incorporates the two main responses that will be discussed in this section.

Figures 22a and 22b begin with the same basic structure of Figure 14, which compared the price and consumption levels for the EMF low oil reference case in 2020. The same reference values in that previous figure are included as one point for each model. In addition, the figures show the 2020 price and consumption estimates from these three additional scenarios. Connecting lines form a set of scenario results for each model.

Figure 22a. Natural Gas Conditions in 2020 in Alternative Cases

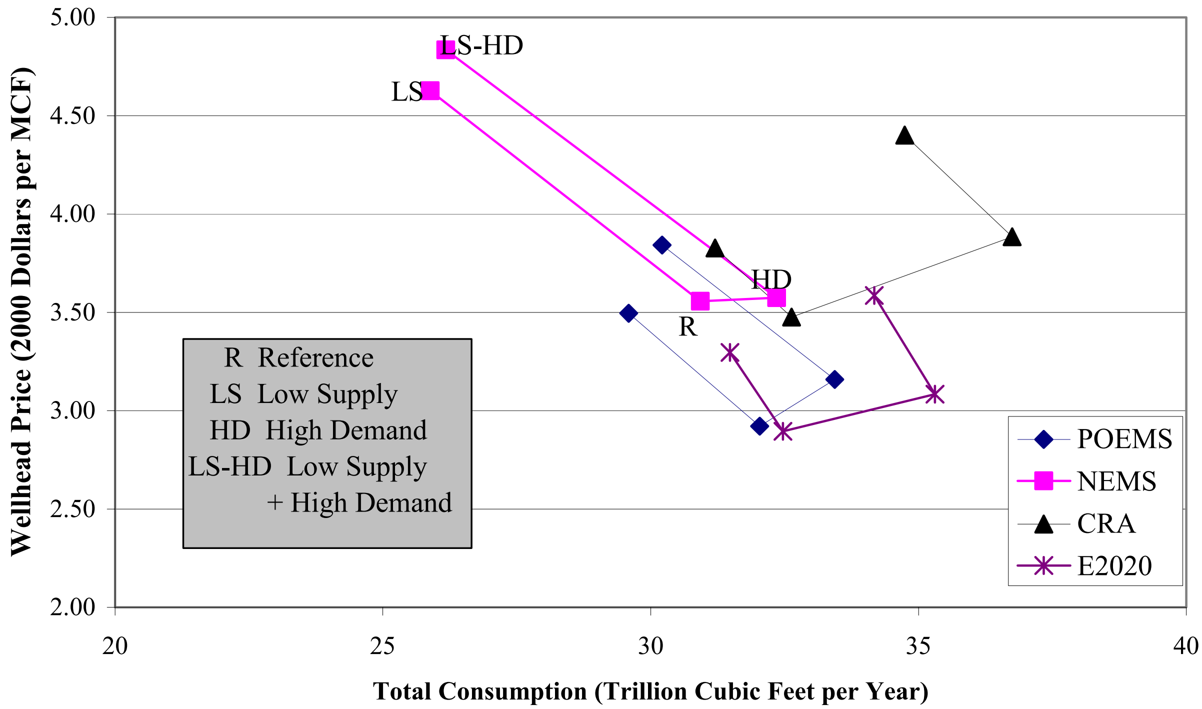
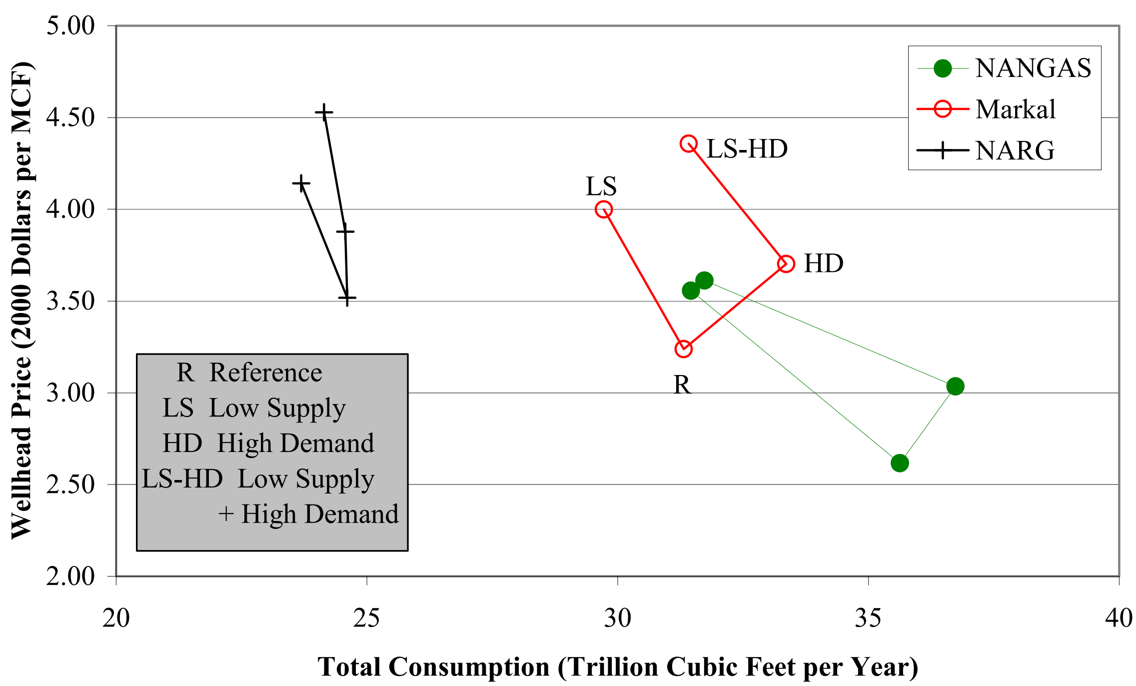


Figure 22b. Natural Gas Conditions in 2020 in Alternative Cases



The range of results across these scenarios for any one model appears considerably smaller than the range of results across all models. As only one example, the POEMS results show natural gas prices ranging from $2.92 to $3.84 per Mcf, while the full range of results cover a wider range ($2.89 to $4.83 per Mcf) that includes substantially higher natural gas prices. A similar observation applies to the range of consumption results. Corporate and government planners and decisionmakers need to acknowledge this uncertainty and seek ways to anticipate the full range of possible outcomes.

All the responses in Figure 22 are consistent with fundamental economic principles. All models show that low-supply conditions increase price and reduce consumption from their reference values. Lower productivity not only reduces availability, but it also makes it more costly to produce previous output levels. Markets respond by raising prices and making less natural gas available for final consumption. The point R designates the reference case price and consumption estimates for the NEMS model. Moving upward and to the left from that reference point, the LS results indicate the low-supply simulations. Natural gas quantities decline from R to LS because energy customers and power plants reduce their consumption when natural gas prices rise. Other models also exhibit these same trends, but the figure does not label each point for visual clarity.

The models also show that high-demand conditions increase price and consumption. Higher economic growth increases natural gas consumption, which can be met only if markets allow higher prices as incentives to produce more natural gas. Although higher growth will also increase the demand for other fuels, much of the expansion focuses on industrial applications and electricity sales, where natural gas tends to be more widely used. Moving upward and to the right from that reference point, the HD results indicate the high-demand conditions. Natural gas quantities increase from R to HD due to higher economic growth and higher natural gas prices provide incentives for more exploration and production.

For completeness, moving upward and to the left from the high demand conditions, the LS-HD results indicate the market conditions under the low supply-high demand case. The reason for this response is similar to the one associated with moving from the R point to the LS point. Lower supply conditions reduce consumption levels but increase price.

And finally, the LS-HD point indicates the highest price for each model, reflecting the joint effects of higher demands and reduced supplies. This point shows greater consumption than in the EMF low oil price reference case in CRA and E2020. These results indicate that demands are shifted more in a horizontal direction than are supplies in representing this composite scenario. Consumption declines from the reference level for other models, including POEMS, NEMS and NANGAS. For these models, the demands are shifted less in a horizontal direction than are the supplies for the LS-HD conditions. Both MARKAL and NARG reveal very similar consumption levels in the LS-HD and reference cases and hence reveal more equal shifts in supply and demand.

9.2 Reduced Drilling Productivity

Although natural gas prices in 2020 begin at a higher level under the high-demand case than under the reference case, the effects of reduced drilling productivity appear generally the same within a model for each case. The slope of the line connecting the R and LS points are comparable to the slope of the line connecting the HD and LS-HD points for most of the models except MARKAL and NANGAS. This observation means that at an aggregate level, energy customers and power plants in most models respond to higher natural gas prices in approximately similar ways in these two sets of cases. Interfuel substitution does not appear dramatically more intense when natural gas prices are higher (as they are in the high-demand cases). There also appears to be strong similarity in the demand response to price in these models, especially for NEMS, POEMS and CRA.

Table 5 indicates that declining exploration and production technology could raise wellhead prices by 10 to 30 percent above their levels in either base case by the year 2020. In NEMS, this productivity effect is quite strong on both prices and natural gas quantities consumed. The size of this effect in any particular model will depend not only upon the direct effects of productivity on production, but also upon how strongly higher prices will bring along additional production and reduce natural gas demand.

Table 5. Percent Deviation in Total Consumption and Wellhead Price With Low Supply

	Consumption		Price		Price Level	Elasticity	
	2010	2020	2010	2020	2020	2010	2020
Relative to Reference Case							
POEMS	-1.5%	-7.9%	7.3%	17.9%	2.92	-0.20	-0.44
NEMS	-5.5%	-17.8%	20.7%	26.3%	3.56	-0.26	-0.68
CRA	-2.5%	-4.5%	7.5%	9.6%	3.48	-0.33	-0.47
NANGAS	-5.5%	-12.4%	14.1%	30.7%	2.62	-0.39	-0.40
E2020	-1.2%	-3.1%	5.5%	13.0%	2.89	-0.22	-0.24
MARKAL	-3.4%	-5.2%	6.6%	21.1%	3.24	-0.52	-0.25
NARG	-7.2%	-3.8%	14.3%	16.3%	3.52	-0.50	-0.23
Relative to High Demand Case							
POEMS	-2.8%	-10.1%	12.6%	19.6%	3.16	-0.22	-0.52
NEMS	-6.3%	-21.2%	17.6%	30.2%	3.57	-0.36	-0.70
CRA	-1.3%	-5.6%	4.0%	12.5%	3.88	-0.33	-0.45
NANGAS	-5.4%	-14.7%	10.1%	17.4%	3.03	-0.54	-0.84
E2020	-1.0%	-3.3%	5.1%	15.1%	3.08	-0.20	-0.22
MARKAL	-4.0%	-6.0%	4.7%	16.3%	3.70	-0.86	-0.37
NARG	-4.8%	-1.7%	14.1%	15.5%	3.88	-0.34	-0.11

Note: Elasticity in the last columns equals the percent change in consumption divided by the percent change in price.

9.3 Higher Economic Growth

The slope of the upward line connecting the R and HD points in Figure 22 is not similar across models. This interesting point demonstrates that the models offer differing views about how much additional exploration and production will be achieved with higher natural gas prices. This finding is important because the natural gas supply response is a critical factor in determining how well natural gas markets can accommodate increasing demand for this fuel for either economic or environmental reasons. The points LS and LS-HD have not been connected in this figure but they could be. The slope of such a line would reveal the natural gas supply response when natural gas prices were initially higher (as they would be when resource drilling was less productive). The slope of such a line, if drawn in the figure, does not appear similar to the slope for the R and HD line for the NEMS model with the labels clearly indicated. A principal reason for this asymmetry is attributable to the triggering of the Alaskan pipeline expansion in the high demand case. The Alaskan supplies reduce the price impact in 2020 for the high-demand case. The other models generally show more conformity between these two cases when demand is expanded.

Table 6 indicates that higher economic growth could raise wellhead prices by the year 2020 by very little in the NEMS results to 13 and 15 percent in MARKAL and NANGAS, respectively.

Table 6. Percent Deviation in Total Consumption and Wellhead Price With High Demand

	Consumption Change		Price Change		Price Level	Elasticity	
	2010	2020	2010	2020	2020	2010	2020
Reference Case							
POEMS	4.0%	4.3%	7.1%	7.8%	2.92	0.57	0.55
NEMS	3.0%	4.5%	6.4%	0.5%	3.56	0.47	8.90
CRA	8.7%	11.9%	20.3%	11.1%	3.48	0.43	1.07
NANGAS	1.2%	3.1%	7.8%	14.8%	2.62	0.15	0.21
E2020	4.0%	8.4%	4.2%	6.3%	2.89	0.97	1.32
MARKAL	3.2%	6.3%	6.5%	13.4%	3.24	0.49	0.47
NARG	-2.3%	-0.2%	8.4%	9.7%	3.52	-0.28	-0.02
Low Supply Case							
POEMS	2.7%	2.1%	12.3%	9.5%	3.49	0.22	0.22
NEMS	2.2%	1.1%	3.4%	4.4%	4.63	0.66	0.25
CRA	9.9%	10.7%	16.7%	14.0%	3.83	0.59	0.77
NANGAS	1.3%	0.9%	3.8%	1.5%	3.56	0.33	0.55
E2020	4.2%	8.2%	3.7%	8.4%	3.30	1.15	0.97
MARKAL	2.5%	5.5%	4.6%	8.6%	4.00	0.55	0.64
NARG	0.1%	1.9%	8.2%	8.9%	4.14	0.01	0.21

Note: Elasticity in the last columns equal the percent change in consumption (quantity) divided by the percent change in price.

The size of this effect in any particular model will depend not only upon the direct effects of economic growth on consumption, but also on the effect of higher prices on production and demand.

10 Diversity and Volatility

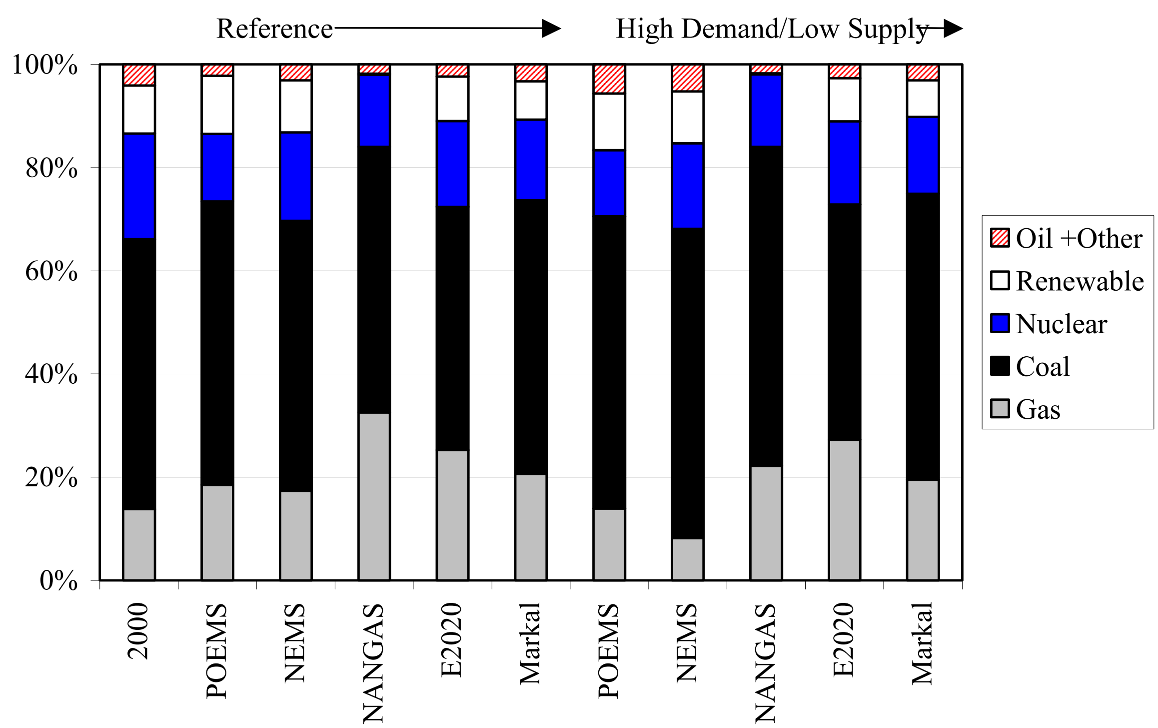
10.1 Dependence Upon Natural Gas

Although natural gas prices rise relative to other fuel prices in the reference case, electricity generators will depend more on natural gas over time. The combination of smaller capital costs and the projected natural gas prices keep natural gas generation competitive with other sources. Environmental considerations reinforce this trend.

Figure 23 displays the changing mix of electricity generation by fuel source in 2020. The bottom, light-gray component of each bar represents the natural gas share. It rises from its 2000 share (shown at the far left) for any model in the reference case. The growth is largest for NANGAS and the least for NEMS. Inspection of Figure 14 confirms that low natural gas prices in NANGAS combine with lower capital costs to allow generation based upon natural gas to compete very favorably with other sources.

Natural gas prices rise even more relative to other fuels in the low-supply, high-demand case. The second set of 2020 bars in the right half of Figure 23 indicates that natural gas shares in this case fall sharply below their reference shares in NEMS and POEMS. In fact, the natural gas share falls below its 2000 level. Natural gas shares are quite responsive to natural gas prices in these simulations, as generators shift away from natural gas and towards coal, oil

Figure 23. Fuel Source for Electricity (%), 2020



and other miscellaneous sources when the price of natural gas rises. The shifts are much smaller in E2020 and MARKAL.

These results underscore that the trend toward increased natural gas use in the power sector can be reversed if energy market conditions should raise natural gas prices significantly more than other fuel prices. If relative fuel prices shift dramatically, as they do in the low-supply, high-demand case, energy consumers and electricity providers will be searching for lower-cost alternatives.

10.2 The Risks of a Dominant Energy Source

The potential for a substantial shift in the relative price of natural gas poses one critical risk for electric generators and end users who commit to technologies that must use natural gas. In future years, these users may find themselves at a relative economic disadvantage if energy market conditions shift in the direction of higher natural gas prices caused by lower natural gas supplies or higher natural gas demands. Facilities or firms that can use more than one fuel might help to alleviate this problem. However, many users have not been constructing dual-fuel facilities either because they have been prevented by environmental policies restricting the use of other fuels or because they have found dual-fuel technology too expensive when their recent experience has been with relatively stable fuel prices.

In addition to these long-term price shifts, generators and customers can experience other risks associated with dependence upon a single energy source. Reliance upon a dominant fuel imposes costs on the firm or plant that will not be included in the *level* of the fuel price that it pays. Some costs will be associated with using a fuel that may need to meet new environmental regulations that have yet to be imposed. Other costs will relate to using a fuel whose price is much more sensitive to market conditions than other possible fuels. Some of these risks will favor greater natural gas use, as the fuel of choice while others will penalize natural gas use.

Environmental policy must be considered an important risk because federal and state regulators in the United States are proposing significantly different policies for controlling various pollutants. Regulators are implementing the controls in a staggered manner that prevents the firms from knowing how additional pollutants will be regulated. Controls on sulfur dioxide in the United States have preceded those on nitrogen oxides and mercury. Policies curbing greenhouse natural gas emissions appear to be in the very distant future. Firms may invest in strategies to reduce sulfur dioxide and mercury pollutants in coal plants that they might not make if they knew that carbon dioxide would be tightly regulated in the future. The lack of a coordinated environmental policy makes it very difficult for firms and generators to plan their response in the least-cost manner.

With the stringency of future controls unknown, firms may decide to shift away from coal and petroleum in favor of natural gas or renewables. Commitment to a dirtier fuel will leave the firm more exposed to future decisions to shift the nation's energy towards cleaner fuels. For many of the important environmental concerns, firms and generators may shift towards natural gas as one way to reduce their exposure to this risk.

Capital costs represent another risk that investors in large plants will want to hedge against. Although capital costs today are relatively low by historical standards, events could change the economic environment. A return to rapid inflation and high interest rates would make certain plants unattractive if they were using fuels requiring large capital expenditures. Here again, natural gas may have an advantage because natural gas-fired generation plants tend to require less capital than coal or nuclear plants.

In addition, some energy-using capital may be more flexible or malleable than other types of equipment. For example, combined-cycle natural gas turbines can be built in different sizes and in a sequential manner that allows the plant owner to invest more if later conditions appear promising. As the owner learns more about his market opportunities, he gains the option of investing in the next stage or delaying it until a later period. Under some conditions, a unit with less capacity may represent a better investment opportunity than one with more capacity, because future profitable investments can be made or future losses avoided. A firm might choose different technologies than they would if they used traditional net present valuation results to compare expected future costs and benefits.

10.3 Natural Gas Price Volatility

The major price risk associated with natural gas-fired generation and industrial applications has been the extreme price volatility of natural gas. If plants depend only on natural gas, they may lose some of their flexibility for managing fuel costs. As mentioned in the section on long-term price shifts, some access to facilities that can use more than one fuel may be particularly attractive. Some environmental controls restrict energy use to a single fuel like natural gas. These measures compound the problem of volatility because firms must operate with a fuel whose price is much more volatile than desired.

Volatility needs to be carefully defined. It normally refers to unexpected variation in prices rather than the predictable movement in those prices due to seasonal shifts. Since natural gas demand has historically been highest in the winter, spot natural gas prices have also been higher in that season. Large industrial customers and firms supplying smaller customers have been able to protect themselves from large swings in fuel prices by using inventories, contracts and other financial instruments.

Volatility needs to be carefully measured. Usually, prices should be normalized to remove the effect of different seasons and perhaps other expected price movements. In addition, risk managers typically measure volatility as the percentage change in the price rather than as the price level. (A convenient analytic shortcut procedure for calculating "returns" is to compute the ratio of this period's price relative to last period's price and convert the result to a logarithm.)

The "returns" approach to volatility provides sufficiently different results than the "nominal price" approach for the 2000-2001 winter price peak for wholesale wellhead natural gas prices, as measured by the Henry Hub price near Katy, Louisiana. The daily percentage differences for the returns did not show the same abnormal volatility for this period that the nominal price series did. One would conclude from the returns data that price volatility was not particularly different during this period relative to other periods, although this result could depend upon the measurement period and method. In addition, the "returns" data does not have as many observed points that exceed the average of all prices. (Technically, the data is not skewed as sharply as the price level.)

Price behavior changes as the analysis moves closer to the point of delivery (or "downstream"). There is more pooling and diversification of supply sources and large customers and firms representing smaller customers will use contracts of different lengths. There are also regulatory rules that amortize fixed charges over seasonal demands and that pass through supply costs with lags in customers' final bills. Only monthly data are available at the retail level.

Citygate prices measure the natural gas costs to the delivered region, after all natural gas transmission costs have been incorporated. The Massachusetts citygate volatility tends to be higher than the Henry Hub volatility when prices are low, but the two appear comparable when prices are higher. The Massachusetts residential price appears volatile, even though regulations allow delivered natural gas prices to lag wholesale natural gas prices.

Comparisons with other important commodities confirm that the Henry Hub natural gas forwards (for natural gas taken 2 months later) exhibit relatively high volatility and are strongly seasonal. Both volatility and seasonality were more pronounced for Henry Hub natural gas prices than for PJM electricity and Brent crude oil prices over the 1997-2001 period. These energy forwards appear more volatile and seasonal than their counterparts for aluminum, foreign currency, soybeans and treasury bills.

10.4 Natural Gas and Electricity Prices

Since risk managers are more concerned with unexpected than expected price changes, there is considerable interest in reducing the unexplained portion by explaining natural gas price movement by other factors, such as weather or seasonality. Another source of expected natural gas price movement may be electricity prices, because industry observers expect that the two prices will move together for a range of different outcomes. This "sparkspread" concept assumes that the price-setting generation unit in any area uses natural gas and is not displaced by an abundance of hydroelectricity or another source. It converts the natural gas price to an electricity price by applying an assumed heat rate. The heat rate measures how many British thermal units of natural gas are required to generate a kilowatt-hour of electricity.

One important issue is the direction of causality between natural gas and power prices. Do previous natural gas prices explain current power prices or do previous power prices cause current natural gas prices? No simple conclusions apply to these markets generally. A test of the causality between the two fuel prices was conducted using daily data for regional natural gas wellhead prices and the corresponding regional electricity pool prices in three regions of the United States. The two daily prices do move together over the 1996-2002 period. In the east and west, price shocks originate in both the electricity and natural gas markets and are transmitted to each other. In the south, electricity price shocks were caused more by electricity generating capacity constraints than by natural gas price shocks. There are fewer pipeline constraints in the south, thereby making natural gas more deliverable and less prone to shocks.

Natural gas pipeline capacity constraints can play an important role in sharply rising natural gas and electricity prices in a region, e.g., California in 2000-2001. Thus, pipeline capacity represents a challenge in the integration of continental natural gas markets.

10.5 Volatility and Public Policy

Under many circumstances, firms will be better than government entities in managing price risks. Governments often choose poor policies when prices are high. Sometimes they blunt unusually high prices with crude instruments like price controls to protect customers. Other times, they provide price subsidies to protect producers from the risk of a market correction. Neither approach rectifies the underlying conditions that cause the market imbalance.

Firms, including those representing retail customers, can use natural gas inventories and usually choose a variety of financial instruments and contracts to stabilize prices. The expansion of storage capacity and the increased use of contracts could be important responses to the price volatility issue. These adjustments would provide both producers and consumers with more price certainty for planning their long-term investments.

Although there is much concern about how well the electricity and natural gas financial markets work in practice, the risks for firms and customers would be greater if government authorities disbanded these trading operations. These markets will require constant government review, much like the securities exchange markets, in order to allow these institutions to mature.

11 Conclusions

Recent volatile natural gas prices do not foreshadow a pending, long-term crisis in future natural gas supplies. Instead, the long-run path of natural gas prices over the next few decades will depend upon supply investment and the response of demand to changed market conditions.

Rather than projecting the most likely outcome, the EMF working group has explored how North American natural gas and energy markets might evolve under a range of conditions. These alternatives should be helpful for corporate strategists and government policymakers who must make decisions in a very uncertain world. Although future prices and quantities may be very different from those simulated in this study, the scenarios in this report are internally consistent and possible.

For the most part, our stories adopt an oil price path that is lower than many projections. Although these conditions provide consumers and energy-using firms with significant benefits of lower energy prices, they also challenge energy-producing firms and governments. If these events materialize, natural gas producers would see a much more competitive world. Natural gas would be competing against higher-priced alternative energy forms but at prices that would be lower than if higher world energy price prevailed. Policymakers would have a more difficult time developing strategies to reduce dependence upon petroleum imports. These trends may also mean somewhat greater growth in carbon dioxide emissions, although preliminary estimates do not suggest that these impacts would be major.

These outcomes are not necessarily contingent upon a declining North American natural gas resource base, although a pessimistic resource evaluation would operate similarly to our case involving lower productivity rates. In general, it is difficult to calibrate market supply curves with resource base estimates. Market supply requires information about prices and costs and about how new discoveries grow into future reserves over time. For this reason, models will develop different market supply estimates even if they are successful in calibrating with an established resource base evaluation like those conducted by the USGS. In the short run, natural gas availability may be more like what the industry calls natural gas deliverability, the volumes that can be pumped from existing wells and transported to consuming regions with the existing pipelines. In the longer run, natural gas availability will depend upon the cost of finding additional supplies, the prospects for additional productivity gains in exploration and production, the access to lands and areas with offshore, onshore and frontier supplies, and the construction or expansion of the continent's pipeline system.

The globalization of the natural gas industry could begin to accelerate over the next several decades. Although LNG trade will grow, the group could not agree on how far that process would be in ten or twenty years. We do think that LNG trade will affect North American natural gas prices, although here again there is a range in its potential effects.

Although there exists considerable interest in LNG imports and the potential advances in its market structure and technology, it must be emphasized that the future natural gas industry will also depend upon continued improvement in the cost and performance of activities to find natural gas from unconventional formations like coalbed methane, tight sands and hydrates. Even without the tax subsidies some forms enjoyed over the last few years, these sources represent dramatic new developments on the natural gas frontier.

Related Reading

This report focuses primarily on the EMF 20 working group discussions without providing footnotes. This section mentions a few additional information sources that relate to some of the issues.

Regulations have entangled the North American natural gas markets for the last six decades. For a recent discussion, see Paul W. MacAvoy, *The Natural Gas Market: Sixty Years of Regulation and Deregulation,* New Haven, Connecticut: Yale University Press, 2000.

The Chairman of the Federal Power Commission called for severe shortages in 1974, as reported in "Severe Natural Gas Crisis Predicted For Next Five Years," *Washington Post*, June 13, 1974.

The U.S. Energy Information Administration within the U.S. Department of Energy releases an annual, long-term outlook for energy markets, including the natural gas industry. The *Annual Energy Outlook 2003 With Projections to 2025* is published as Report #: DOE/EIA-0383 (2003) and can be accessed at http://www.eia.doe.gov/oiaf/aeo/index.html.

The National Petroleum Council is completing another study on natural gas market outcomes and issues, called "21st Century Natural Gas." Preliminary information is available at http://www.npc.org/.

A previous Energy Modeling Forum study compared the simulation results of natural gas models available in late 1980s. See Energy Modeling Forum, *North American Natural Gas Markets,* Working Group Report 9, Stanford University, Stanford, California, 1989. Volume I provides a summary, Volume II includes the history of natural gas regulations and other topics, and Volume III contains individual chapters by the participating modelers. Many of the summary points also appear in Hillard Huntington and Glen Schuler, "North American Natural Gas Markets: A Summary of an Energy Modeling Forum Study," *Energy Journal*, April 1990, Vol. 11, No. 2, pages 1-21. Many of the key model comparison findings are discussed in Hillard Huntington, "U.S. Natural Gas Markets: A Structural Model Comparison," *Journal of Policy Modeling*, Volume 14, Issue 1, February 1992, Pages 13-39.

Currently, the futures markets indicate that natural gas prices may rise relative to crude oil prices over the next few years. *The Wall Street Journal* (September 3, 2003, page C12) reported that the natural gas price for June 2005 delivery was about 106% of the crude oil price, compared to its 87% level for October 2003.

There are numerous recent articles on the liquefied natural gas (LNG) trade. A discussion with good coverage of the main issues appears in James Jensen, "The LNG Revolution," *Energy Journal* Volume 24, Number 2, pages 1-45. Peter Hartley and Dagobert Brito emphasize that new institutions and changing industry structure could extend new opportunities for LNG suppliers. See their "Using Sakhalkin Natural Gas in Japan," Working Paper prepared for Baker Institute Study Number 18: *New*

Energy Technologies in the Natural Gas Sector: A Policy Framework for Japan. Available at http://www.rice.edu/projects/baker/.

Pessimists on future natural gas resources adopt similar views to those who believe that oil production has peaked as a result of declining resources. This position has recently been presented in Kenneth S. Deffeyes, *Hubbert's Peak: The Impending World Oil Shortage,* Princeton, New Jersey: Princeton University Press, 2001. Several critical reviews of that book offer a more optimistic assessment. See for example, Ronald R. Charpentier, "Locating the Summit of the Oil Peak," *Science*, Volume 295, February 22, 2002, page 1470.

The discussion of the value of flexibility in combined-cycle natural gas turbines draws upon research conducted at the Central Research Institute for the Electric Power Industry (CRIEPI) in Tokyo, Japan. Please see M. Takahashi, T. Hattori, N. Yamaguchi, K. Okada, and H. Asano, "Valuing a Medium-Scale Gas Fired Power Plant with Capacity Expansion Options Under a Competitive Environment," Proceedings of the Fourteenth Annual Conference of Power and Energy Society, IEE of Japan, August, 2003. This paper is also available as Energy Modeling Forum Working Paper 20.2, Stanford University, Stanford, CA.

The discussion of defining and measuring natural gas price volatility was based upon a presentation by Frank Graves to the working group.

Stephen P.A. Brown and Mine K. Yücel conducted the statistical research on the relationship between natural gas and electricity prices and on the relationship between natural gas wellhead and crude oil prices that were mentioned in the report. Although this research is currently unpublished, an earlier study on the link between oil and natural gas prices can be found in Mine K. Yücel and Shengyi Guo, "Fuel Taxes and Cointegration of Energy Prices," *Contemporary Economic Policy*, July 1994.

Estimates of the near-term substitution between oil and natural gas were based upon analysis of the 2001-2002 period. More details can be found in John Pyrdol and Robert Baron, "Fuel Switching Potential of Electric Generators: A Case Study," Energy Modeling Forum Working Paper 20.3, Stanford University, Stanford, CA.

In addition, the report discusses the concept of diversifying against assets with volatile prices or against fuels whose cost are subject to uncertainty due to pending environmental rule changes or other similar events. A textbook on finance will frequently cover the essence of this argument. For an example of the approach applied to the energy markets, see Brett Humphreys and Katherine McClain, "Reducing the Impacts of Energy Price Volatility Through Dynamic Portfolio Selection," *Energy Journal*, 1998, 19(3): 107-131. The Electric Power Research Institute is currently applying an options approach to understand the choice between natural gas and coal plants as strategies for dealing with pending climate change policy. The Lawrence Berkeley Laboratory is currently evaluating the value of renewables as a hedge against fossil fuel price volatility.