The Future of Natural Gas

AN INTERDISCIPLINARY MIT STUDY

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While the members of the advisory committee provided invaluable perspective and advice to the study group, individual members may have different views on one or more matters addressed in the report. They are not asked to individually or collectively endorse the report findings and recommendations.

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Foreword and Acknowledgements

The Future of Natural Gas is the third in a series of MIT multidisciplinary reports examining the role of various energy sources that may be important for meeting future demand under carbon dioxide emissions constraints. In each case, we explore the steps needed to enable competitiveness in a future marketplace conditioned by a CO_2 emissions price.

The first two reports dealt with nuclear power (2003) and coal (2007). A study of natural gas is more complex because gas is a major fuel for multiple end uses — electricity, industry, heating — and is increasingly discussed as a potential pathway to reduced oil dependence for transportation. In addition, the realization over the last few years that the producible unconventional gas resource in the U.S. is very large has intensified the discussion about natural gas as a "bridge" to a low-carbon future. We have carried out the integrated analysis reported here as a contribution to the energy, security and climate debate.

Our judgment is that an interim report on our findings and recommendations is a timely contribution to that debate. A full report with additional analysis addressing a broader set of issues will follow later this year.

Our primary audience is U.S. government, industry and academic leaders and decision makers. However, the study is carried out with an international perspective.

This study is better as a result of comments and suggestions from our distinguished external Advisory Committee, each of whom brought important perspective and experience to our discussions. We are grateful for the time they invested in advising us. However, the study is the responsibility of the MIT study group and the advisory committee members do not necessarily endorse all of its findings and recommendations, either individually or collectively.

Finally, we are very appreciative of the support from several sources. First and foremost, we thank the American Clean Skies Foundation. Discussions with the Foundation led to the conclusion that an integrative study on the future of natural gas in a carbon-constrained world could contribute to the energy debate in an important way, and the Foundation stepped forward as the major sponsor. MIT Energy Initiative (MITEI) members Hess Corporation and Agencia Naçional de Hidrocarburos (Columbia) provided additional support. The Energy Futures Coalition supported dissemination of the study results, and MITEI employed internal funds and fellowship sponsorship to support the study as well. As with the advisory committee, the sponsors are not responsible for and do not necessarily endorse the findings and recommendations. That responsibility lies solely with the MIT study group.

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Executive Summary

Natural gas has moved to the center of the current debate on energy, security and climate. This study examines the role of natural gas in a carbon-constrained world, with a time horizon out to mid-century.

The overarching conclusions are that:

- *Abundant global natural gas resources imply greatly expanded natural gas use, with especially large growth in electricity generation.*

- *Natural gas will assume an increasing share of the U.S. energy mix over the next several decades, with the large unconventional resource playing a key role.*

- *The share of natural gas in the energy mix is likely to be even larger in the near to intermediate term in response to CO_2 emissions constraints. In the longer term, however, very stringent emissions constraints would limit the role of all fossil fuels, including natural gas, unless capture and sequestration are competitive with other very low-carbon alternatives.*

- *The character of the global gas market could change dramatically over the time horizon of this study*.

The physical properties of natural gas, the high degree of concentration of the global resource and the history of U.S. energy policy have profoundly influenced the use of natural gas and the market structure governing its trade:

- the substantially lower carbon footprint of natural gas relative to other fossil fuels, combined with the development of North American unconventional natural gas supply and the high cost and slow pace of lower carbon alternatives, has focused attention on natural gas as a "bridge" to a low-carbon future;

- there are regionalized markets in North America, Europe and industrialized Asia, each with a different market structure; and

- "feast or famine" expectations for U.S. natural gas supply, associated with price swings and policy changes, have often led to costly investment decisions.

The confluence of these factors is central to today's energy and climate change policy debate. The primary motivation for this study is to provide integrated, technically grounded analysis that will inform this debate. The analysis must deal with multiple uncertainties that can profoundly influence the future of natural gas:

- the extent and nature of greenhouse gas mitigation (GHG) measures that will be adopted in the U.S. and abroad;
- the ultimate size and production cost of the natural gas resource base in the U.S. and in other major supplier countries;
- the technology mix, as determined by relative costs of different technologies over time and by emissions policy; and
- the evolution of international gas markets, as dictated by economics, geology and geopolitics.

This study analyzes various possibilities for the last three of these, principally by application of a well-tested global economic model, for different GHG policy scenarios.

Our audience is principally U.S. government, industry and academic leaders and decision-makers interested in the interrelated set of technical, economic, environmental and political issues that must be addressed in seeking to limit GHG emissions materially. However, the study is carried out with an international perspective.

FINDINGS

Supply

Globally, there are abundant supplies of natural gas, much of which can be developed at relatively low cost. The current mean projection of remaining recoverable resource is 16,200 Trillion Cubic Feet (Tcf), 150 times current annual global gas consumption, with low and high projections of 12,400 Tcf and 20,800 Tcf, respectively. Of the mean projection, approximately 9,000 Tcf could be economically developed with a gas price at or below $4/Million British thermal units (MMBtu) at the export point.

Unconventional gas, and particularly shale gas, will make an important contribution to future U.S. energy supply and carbon dioxide (CO_2) emission reduction efforts. Assessments of the recoverable volumes of shale gas in the U.S. have increased dramatically over the last five years. The current mean projection of the recoverable shale gas resource is approximately 650 Tcf, with low and high projections of 420 Tcf and 870 Tcf, respectively. Of the mean projection, approximately 400 Tcf could be economically developed with a gas price at or below $6/MMBtu at the well-head.

The environmental impacts of shale development are manageable but challenging. The largest challenges lie in the area of water management, particularly the effective disposal of fracture fluids. Concerns with this issue are particularly acute in those regions that have not previously experienced large-scale oil and gas development. It is essential that both large and small companies follow industry best practices, that water supply and disposal are coordinated on a regional basis, and that improved methods are developed for recycling of returned fracture fluids.

Policy Effects

In a carbon-constrained world, a level playing field — a CO_2 emissions price for all fuels without subsidies or other preferential policy treatment — maximizes the value to society of the large U.S. natural gas resource.

Even under the pressure of an assumed CO_2 emissions policy, total U.S. natural gas use is projected to increase in magnitude up to 2050.

Under a scenario with 50% CO_2 reductions to 2050, using an established model of the global economy and natural gas cost curves that include uncertainty, the principal effects of the associated CO_2 emissions price are to lower energy demand and displace coal with natural gas in the electricity sector. *In effect, gas-fired power sets a competitive benchmark against which other technologies must compete in a lower carbon environment*. A major uncertainty that could impact this picture in the longer term is technology development that lowers the costs of alternatives, in particular, renewables, nuclear and carbon capture and sequestration (CCS).

A more stringent CO_2 reduction of, for example, 80%, would probably require the complete de-carbonization of the power sector. This makes it imperative that the development of competing low-carbon technology continues apace, including CCS for both coal and gas. It would be a significant error of policy to crowd out the development of other, currently more costly, technologies because of the new assessment of gas supply. Conversely, it would also be a mistake to encourage, via policy and long-term subsidy, more costly technologies to crowd out natural gas in the short to medium term, as this could significantly increase the cost of CO_2 reduction.

Some U.S. regions that have not traditionally been gas producers do have significant shale gas resources and the development of these resources could change patterns of production and distribution of gas in the U.S.

To the degree that economics is allowed to determine the global gas market, trade in this fuel is set to increase over coming decades, with major implications for investment and for possible U.S. gas imports in a couple of decades and beyond.

Demand & Infrastructure

There is a degree of resilience in overall gas use in that less use in one of the three major sectors (power, heating, industry) will lead to lower gas prices and more use in another sector.

The electricity sector is the principal growth area for natural gas under CO_2 emission constraints.

The scale-up of intermittent electricity sources, wind and solar, significantly affects natural gas capacity and use in the electricity sector because of variability and uncertainty. The impacts are quite different in the short term, during which the response is through the dispatch pattern, and in the long term, during which capacity additions and retirements will be responsive to large-scale introduction of intermittent sources.

- In the short term, the principal impact of increased intermittent generation is displacement of generation with highest variable cost, which is natural gas in most U.S. markets.

- In the long term, increased intermittent generation will have two likely outcomes: more installed capacity of flexible plants, mostly natural gas, but typically with low utilization; and displacement of capacity of and production from baseload generation technologies. There will be regional variation as to how such effects are manifested.

In the U.S., there are opportunities for more efficient use of natural gas (and other fuels), and for coal to gas fuel switching for power generation. *Substitution of gas for coal could materially impact CO_2 emissions in the near term*, since the U.S. coal fleet includes a significant fraction of low-efficiency plants that are not credible candidates for carbon capture retrofit in response to carbon emissions prices, and since there is significant underutilized existing Natural Gas Combined Cycle (NGCC) capacity.

Development of the U.S. vehicular transportation market using compressed natural gas (CNG) powered vehicles offers opportunities for expansion for natural gas use and reduction of CO_2 emissions, but it is unlikely in the near term that this will develop into a major new market for gas or make a substantial impact in reducing U.S. oil dependence. However, significant penetration of the private vehicle market before mid-century emerges in our carbon-constrained scenario. Liquefied natural gas (LNG) does not currently appear to be economically attractive as a fuel for long-haul trucks because of cost and operational issues related to storage at –162 degrees Centigrade.

The conversion of natural gas to methanol, for which there is already large-scale industrial use and a well-established cost basis, is an option for providing a cost-competitive, room temperature liquid transportation fuel and reducing oil dependence. However, it would not materially affect carbon emissions relative to gasoline.

The expansion of shale gas development in areas that have not previously seen significant gas production will require expansion of the related pipeline, storage and processing infrastructure. Infrastructure limitations need to be taken into account in decisions to advance coal substitution with natural gas.

Markets & Geopolitics

There are three distinct regional gas markets — North America, Europe and Asia — resulting from the degree of market maturity, the sources of supply, the dependence on imports and the significant contribution of transportation to the total delivered cost.

The U.S. natural gas market functions well and, given even-handed treatment of energy sources, needs no special policy help to contribute materially to CO_2 emissions mitigation.

International natural gas markets are in the early stages of integration, with many impediments to further development. If a more integrated market evolves, with nations pursuing gas production and trade on an economic basis, there will be rising trade among the current regional markets and the U.S. could become a substantial net importer of LNG in future decades.

Greater international market liquidity would be beneficial to U.S. interests. U.S. prices for natural gas would be lower than under current regional markets, leading to more gas use in the U.S. Greater market liquidity would also contribute to security by enhancing diversity of global supply and resilience to supply disruptions for the U.S. and its allies. These factors moderate security concerns about import dependence.

As a result of the significant concentration of conventional gas resources globally, policy and geopolitics play a major role in the development of global supply and market structures. Consequently, since natural gas is likely to play a greater role around the world, natural gas issues will appear more frequently on the U.S. energy and security agenda. Some of the specific security concerns are:

- Natural gas dependence, including that of allies, could constrain U.S. foreign policy options, especially because of the unique American international security responsibilities.

- New market players could introduce impediments to the development of transparent markets.

- Competition for control of natural gas pipelines and pipeline routes is intense in key regions.

- Longer supply chains increase the vulnerability of the natural gas infrastructure.

Research, Development and Demonstration

New science and technology, particularly in the case of unconventional resources, can significantly contribute to the long-term economic competitiveness of domestic supplies of natural gas with imports, by helping to optimize resource use, to lower costs, and to reduce the environmental footprint of natural gas.

Some government and quasi-government Research, Development and Demonstration (RD&D) programs have had important successes in the development of unconventional gas resources. These programs, combined with short-term production tax incentives, were important enablers of today's unconventional natural gas business.

HIGH-LEVEL RECOMMENDATIONS

1. To maximize the value to society of the substantial U.S. natural gas resource base, U.S. CO_2 reduction policy should be designed to create a "level playing field," where all energy technologies can compete against each other in an open marketplace conditioned by legislated CO_2 emissions goals. A CO_2 price for all fuels without long-term subsidies or other preferential policy treatment is the most effective way to achieve this result.

2. In the absence of such policy, interim energy policies should attempt to replicate as closely as possible the major consequences of a level-playing-field approach to carbon emissions reduction. At least for the near term, that would entail facilitating energy demand reduction and displacement of some coal generation with natural gas.

3. Notwithstanding the overall desirability of a level playing field, and in anticipation of a carbon emissions charge, support should be provided through RD&D and targeted subsidies of limited duration, for low-emission technologies that have the prospect of competing in the long run. This would include renewables, carbon capture and sequestration for both coal and gas generation, and nuclear power.

4. Coal generation displacement with NGCC generation should be pursued as a near-term option for reducing CO_2 emissions.

5. In the event of a significant penetration of intermittent renewable electricity production, policy and regulatory measures should be developed (e.g. ancillary services compensation) or adapted (e.g. capacity mechanisms) to facilitate adequate levels of investment in natural gas generation capacity.

6. Regulatory and policy barriers to the development of natural gas as a transportation fuel (both CNG and natural gas conversion to liquid fuels) should be removed, so as to allow it to compete with other technologies. This would reduce oil dependence, and CNG would reduce carbon emissions as well.

7. For reasons of both economy and global security, the U.S. should pursue policies that encourage an efficient integrated global gas market with transparency and diversity of supply, and governed by economic considerations.

8. Since natural gas issues will appear more frequently on the U.S. energy and security agenda as global demand and international trade grow, a number of domestic and foreign policy measures should be taken, including:

   - integrating energy issues fully into the conduct of U.S. foreign policy, which will require multiagency coordination with leadership from the Executive Office of the President;

   - supporting the efforts of the International Energy Agency (IEA) to place more attention on natural gas and to incorporate the large emerging markets (such as China, India and Brazil) into the IEA process as integral participants;

   - sharing know-how for the strategic expansion of unconventional resources;

   - advancing infrastructure physical- and cyber-security as the global gas delivery system becomes more extended and interconnected; and

   - promoting efficient use of natural gas domestically and encouraging subsidy reduction for domestic use in producing countries.

9. There is a legitimate public interest in ensuring the optimum, environmentally sound utilization of the unconventional gas resource. To this end:

   - Government-supported research on the fundamental challenges of unconventional gas development, particularly shale gas, should be greatly increased in scope and scale. In particular, support should be put in place for a comprehensive and integrated research program to build a system-wide understanding of all subsurface aspects of the U.S. shale resource. In addition, research should be pursued to reduce water usage in fracturing and to develop cost-effective water recycling technology.

   - The United States Geological Survey (USGS) should accelerate efforts to improve resource assessment methodology for unconventional resources.

   - A concerted coordinated effort by industry and government, both state and Federal, should be organized so as to minimize the environmental impacts of shale gas development through both research and regulation. Transparency is key, both for fracturing operations and for water management. Better communication of oil- and gas-field best practices should be facilitated. Integrated regional water usage and disposal plans and disclosure of hydraulic fracture fluid components should be required.

10. The Administration and Congress should support RD&D focused on environmentally responsible, domestic natural gas supply, through both a renewed Department of Energy (DOE) program weighted towards basic research and a synergistic "off-budget" industry-led program weighted toward technology development and demonstration and technology transfer with relatively shorter-term impact. Consideration should also be given to restoring a public-private "off-budget" RD&D program for natural gas transportation and end use.

Section 1: Context

Natural gas has moved to the center of the current debate on energy, security and climate. This study examines the potential role of natural gas in a carbon-constrained world, with a time horizon out to mid-century.

Natural gas has moved to the center of the current debate on energy, security and climate.

We start by noting some basic considerations that have shaped both the debate and our analysis.

The first point concerns the unique characteristics of the product. Natural gas possesses remarkable qualities. Among the fossil fuels, it has the lowest carbon intensity, emitting less carbon dioxide per unit of energy generated than other fossil fuels.[1] It burns cleanly and efficiently, with very few non-carbon emissions. Unlike oil, gas generally requires limited processing to prepare it for end-use. These favorable characteristics have enabled natural gas to penetrate many markets, including domestic and commercial heating, multiple industrial processes and electrical power.

Natural gas also has favorable characteristics with respect to its development and production. The high compressibility and low viscosity of gas allows high recoveries from conventional reservoirs at relatively low cost, and also enables gas to be economically recovered from even the most unfavorable subsurface environments, as recent developments in shale formations have demonstrated.

These physical characteristics underpin the current expansion of the unconventional resource base in North America, and the potential for natural gas to displace more carbon-intensive fossil fuels in a carbon-constrained world.

On the other hand, because of its gaseous form and low energy density, natural gas is uniquely disadvantaged in terms of transmission and storage. As a liquid, oil can be readily transported over any distance by a variety of means and oil transportation costs are generally a small fraction of the overall cost of developing oil fields and delivering oil products to market. This has facilitated the development of a truly global market in oil over the past 40 years or more.

By contrast, the vast majority of gas supplies are delivered to market by pipeline, and delivery costs typically represent a relatively large fraction of the total cost in the gas supply chain. These characteristics have contributed to the evolution of somewhat inflexible regional markets rather than a truly global market in natural gas. Outside North America, this somewhat inflexible pipeline infrastructure gives strong political and economic power to those countries that control the pipelines. To some degree, the evolution of the spot market in Liquefied Natural Gas (LNG) is beginning to introduce more flexibility into global gas markets and the beginning of real global trade. The way this trade may evolve over time is a critical uncertainty which is explored in this work.

The second point of context is to place our discussion of natural gas in its historical setting.

The somewhat erratic history of natural gas in the U.S. over the last three decades or so provides eloquent testimony to the difficulties of forecasting energy futures, particularly for gas, and is a reminder of the need for caution in the current period of supply exuberance.

This history starts with a perception of supply scarcity. In 1978, convinced that the U.S. was running out of natural gas, Congress passed the Power Plant and Industrial Fuel Use Act (FUA) which essentially outlawed the building of new gas-fired power plants.

Between 1978 and 1987 (the year the FUA was repealed) the U.S. added 172 Gigawatts (GW) of net power generation capacity. Of this, almost 81 GW was new coal capacity, around 26% of today's entire coal fleet. About half of the remainder was nuclear power.

There then followed a prolonged period of supply surplus. By the mid 1990s, wholesale electricity markets had been deregulated; new, highly efficient and relatively inexpensive combined cycle gas turbines had been deployed; and new upstream technologies had enabled the development of offshore gas resources. This all contributed to the perception that natural gas was abundant, and new gas-fired power capacity was added at a rapid pace.

Since the repeal of the FUA in 1987, the U.S. has added 361 GW of power generation capacity, of which 70% is gas fired and 11% coal fired. Today, the name-plate capacity of this gas-fired generation is significantly underutilized.

By the turn of the 21st century, a new set of concerns arose about the adequacy of domestic gas supplies. For a number of reasons, conventional supplies were in decline, unconventional gas resources remained expensive and difficult to develop, and overall confidence in gas was low. Surplus once again gave way to a perception of shortage and gas prices started to rise, becoming more closely linked to the oil price, which itself was rising. This rapid buildup in gas price, and perception of long term shortage, created the economic incentive for the accelerated development of an LNG import infrastructure.

Since 2000, North America's rated LNG capacity has expanded from approximately 2.3 Bcf/day to 22.7 Bcf/day, around 35% of the nation's average daily requirement. This expansion of LNG capacity coincided with the market diffusion of technologies to develop affordable unconventional gas. The game-changing potential of these technologies has become more obvious over the last three years, radically altering the U.S. supply picture. The LNG import capacity goes largely unused at present, although it provides valuable optionality for the future. We have once again returned to a period of supply surplus.

This cycle of feast and famine demonstrates the genuine difficulty of forecasting the future, and underpins the efforts of this study to account for this uncertainty in an analytical manner.

Looking forward, we anticipate policy and geopolitics, along with resource economics and technology developments, will continue to play a major role in determining global supply and market structures. Thus, any analysis of the future of natural gas must deal explicitly with multiple uncertainties:

Policy and geopolitics, along with resource economics and technology developments, will continue to play a major role in determining global supply and market structures.

- The extent and nature of the GHG mitigation measures that will be adopted: the U.S. legislative response to the climate threat has proved quite challenging, with potential Environmental Protection Agency (EPA) regulation under the Clean Air Act a possibility if Congress does not act. Moreover, reliance upon a system of voluntary national pledges of emission reductions by 2020, as set out in the Copenhagen Accord, leaves great uncertainty concerning the likely structure of any future international agreement that may emerge to replace the Kyoto Protocol. The absence of a clear international regime for mitigating GHG emissions also raises questions about the likely stringency of national policies over coming decades.

- The likely technology mix in a carbon-constrained world, particularly in the power sector: the relative costs of different technologies may shift significantly in response to RD&D, and a CO_2 emissions price will affect the relative costs. Moreover, the technology mix will be affected by regulatory and subsidy measures that will skew economic choices.

- The ultimate size and production cost of the natural gas resource base, and the environmental acceptability of production methods: much remains to be learned about the performance of shale gas plays, both in the U.S. and in other parts of the world. Indeed, even higher risk and less well-defined unconventional gas resources, such as methane hydrates, could make a contribution to supply in the later decades of the study's time horizon.

- The evolution of international natural gas markets: very large natural gas resources are to be found in several areas outside the U.S., and the role of U.S. gas will be influenced by the evolution of this market — particularly the growth and efficiency of trade in LNG. Only a few years back, U.S. industry was investing in facilities for substantial LNG imports. The emergence of the domestic shale resource has depressed this business in the U.S., but in the future the nation may again look to international markets.

Of these uncertainties, the last three can be explored by applying technically grounded analysis, and we explore: lower cost for CCS, renewables and nuclear power; producible resources of different levels; and regional versus global integrated markets. In contrast, the shape and size of GHG mitigation measures is likely to be resolved only through complex ongoing political discussions at the national level in the major emitting countries and through multilateral negotiations.

The analysis in this study is based on three scenarios:

1. A business-as-usual case, with no significant carbon constraints;

2. GHG emissions pricing, through a cap-and-trade system or emissions tax, leads to a 50% reduction in U.S. emissions below the 2005 level, by 2050.

3. GHG reduction via U.S. regulatory measures without emissions pricing: a renewable portfolio standard and measures forcing the retirement of coal plants.

Our analysis is long term in nature, with a 2050 time horizon. We do not attempt to make detailed short-term projections of volumes or prices, but rather focus on the long-term consequences of the carbon mitigation scenarios outlined above, taking account of the manifold uncertainties in a highly complex and interdependent energy system.

NOTES

[1] Whereas a typical coal power plant emits about 0.9 kg-CO_2/kWh-e, an NGCC power plant emits about 0.4 kg-CO_2/kWh-e.

Section 2: Supply

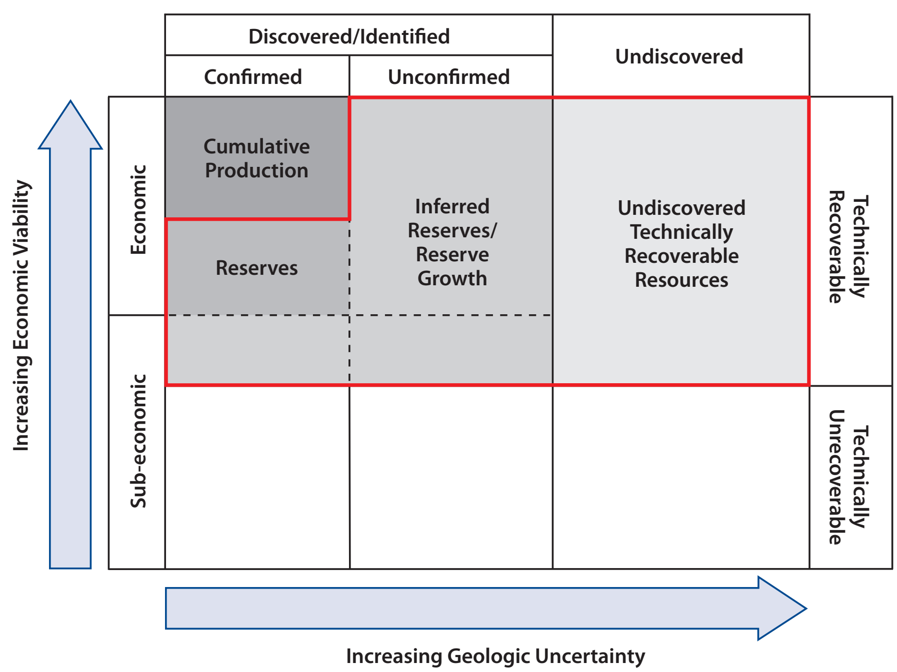
INTRODUCTION AND CONTEXT

Natural gas supply is a complex subject. For any discussion of the topic to be relevant and useful it must be framed by certain geological, technological and economic assumptions. This section addresses the global supply of natural gas in such a manner, paying particular attention to the U.S. supply picture and the impact of shale gas on that supply.

The complex cross-dependencies between geology, technology and economics mean that the use of unambiguous terminology is critical when discussing natural gas supply. In this study the term "resource" will refer to the sum of all gas volumes expected to be recoverable in the future, given specific technological and economic conditions. The resource can be disaggregated into a number of sub-categories; specifically, "proved reserves," "reserve growth" (via further development of known fields), and "undiscovered resources," which represents gas volumes that will be discovered in the future via the exploration process.

The diagram shown in Figure 2.1 illustrates how proved reserves, reserve growth and undiscovered resources combine to form the "technically recoverable resource," i.e., the total volume of natural gas that could be recovered in the future, using today's technology, ignoring any economic constraints.

Figure 2.1 Modified McKelvey Diagram – Remaining Technically Recoverable Resources are Outlined in Red



In addition to the sub-categorization of the gas resource described on the previous page, it can also be further partitioned into either "conventional" or "unconventional" resources. This categorization is geologically dependent.

Conventional resources generally exist in discrete, well-defined subsurface accumulations (reservoirs), with permeability[1] values greater than a specified lower limit. Such conventional gas resources can usually be developed using vertical wells, and often yield economic recovery rates of more than 80% of the Gas Initially in Place (GIIP).

Gas resources are an economic concept — a function of many variables, particularly the price that the market will ultimately pay for them.

By contrast, unconventional resources are found in accumulations where permeability is low. Such accumulations include "tight" sandstone formations, coal-beds, and shale formations. Unconventional resource accumulations tend to be distributed over a much larger area than conventional accumulations and usually require well stimulation in order to be economically productive; recovery factors are much lower — typically of the order of 15% to 30% of GIIP.

The methodology used in analyzing natural gas supply for this study places particular emphasis in two areas:

1. Treating gas resources as an economic concept — recoverable resources are a function of many variables, particularly the ultimate price that the market will pay for them. A set of supply curves has been developed, which describes how the volume of gas that is economically recoverable varies with gas price. The widely used ICF Hydrocarbon Supply Model and the ICF World Assessment Unit Model were used to generate the curves, based on volumetric and fiscal input data supplied by ICF and MIT. These curves form a primary input to the integrated economic modelling described later in this report.

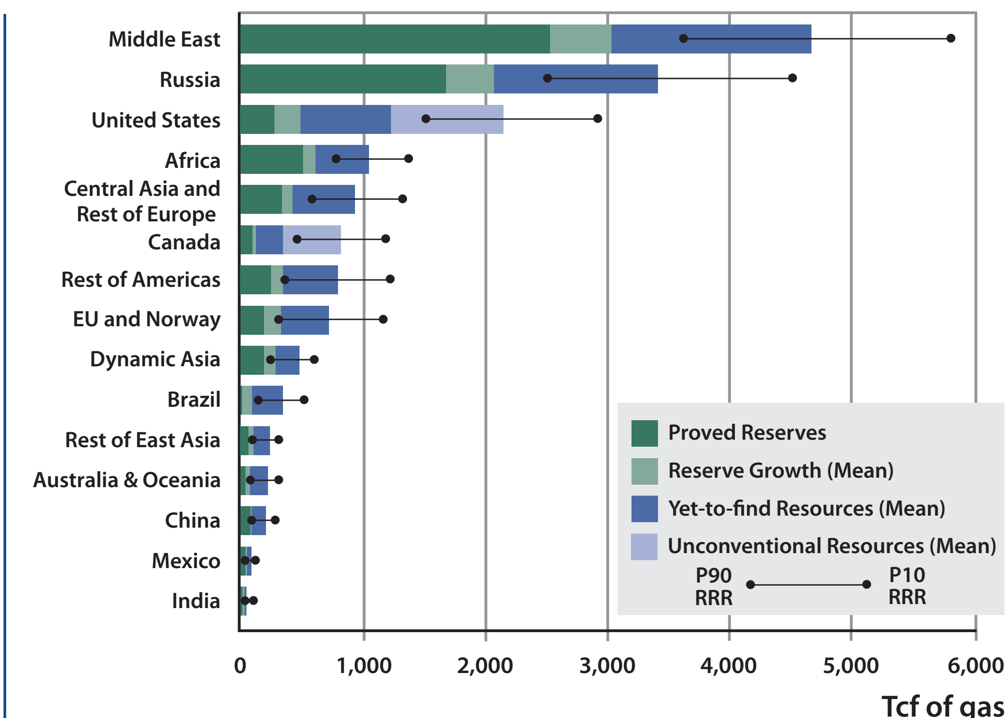
2. Recognizing and embracing uncertainty — uncertainty exists around all resource estimates due to the inherent uncertainty associated with the underlying geologic, technological and other inputs. The analysis of natural gas supply in this study has been carried out in a manner that frames any single point resource estimate within an associated uncertainty envelope, in order to illustrate the potentially large impact this ever-present uncertainty can have.

The volumetric data used as the basis of the analysis for both the supply curve development and the volumetric uncertainty analysis was compiled from a range of sources. In particular, use has been made of data from work at the USGS, the Potential Gas Committee (PGC), the Energy Information Agency (EIA), the National Petroleum Council (NPC) and the consultancy, ICF International.

GLOBAL SUPPLY

Global supplies of natural gas are abundant. There is an estimated remaining resource base of 16,200 Tcf, this being the mean projection of a range between 12,400 Tcf (with a 90% probability of being exceeded) and 20,800 Tcf (with a 10% probability of being exceeded). The mean projection is 150 times the annual consumption of 108 Tcf in 2009. Except for Canada and the U.S., this estimate does not contain any unconventional supplies. The global gas supply base is relatively immature; outside North America only 11% of the estimated ultimate recovery of conventional resources has been produced to date.

Figure 2.2 Global Remaining Recoverable Gas Resource (RRR) by EPPA Region, with Uncertainty[2] (excludes unconventional gas outside North America)



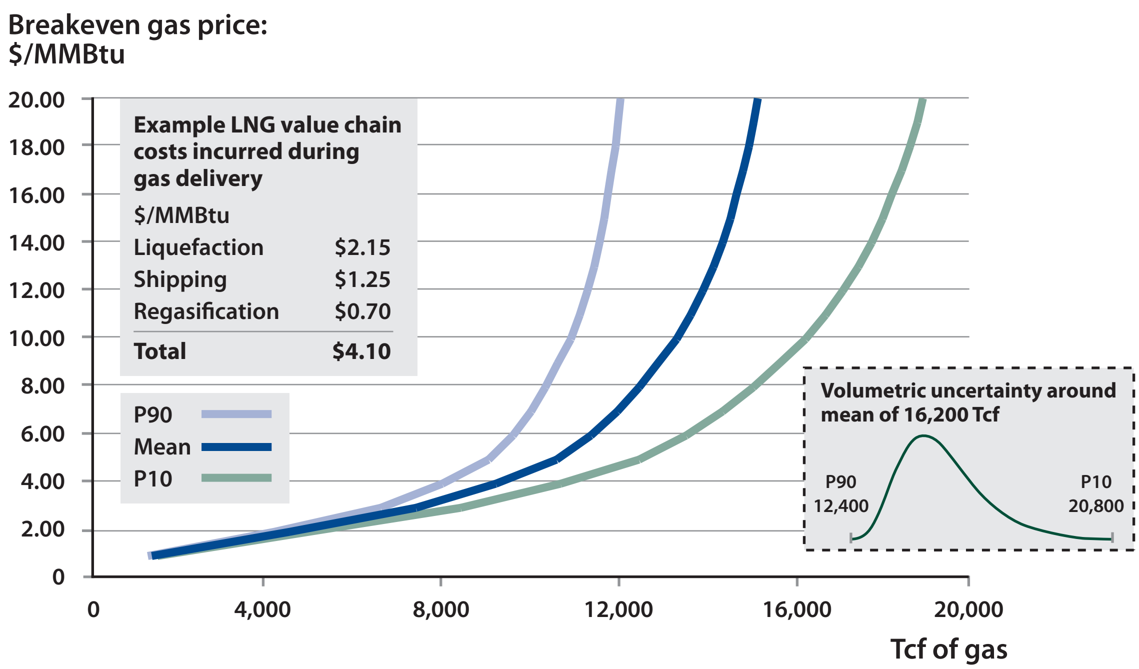
As illustrated in Figure 2.2, although resources are large, the supply base is concentrated, with an estimated 70% in only three regions: Russia, the Middle East (primarily Qatar and Iran) and North America. Political considerations and individual country depletion policies play at least as big a role in global gas resource development as geology and economics, and will dominate the evolution of the global gas market.

Figure 2.3 is a set of global supply curves, which describe the resources of gas that can be developed economically at given prices at the point of export. The higher the price, the more gas will ultimately be developed. Much of the global supply can be developed at relatively low cost at the well-head or the point of export.[3] However, the cost of delivering this gas to market is generally considerably higher.

In contrast to oil, the total cost to deliver gas to international markets is strongly influenced by transportation costs; costs that are also a significant factor in the evolution of the global gas market.

In contrast to oil, the total cost to deliver gas to international markets is strongly influenced by transportation costs, either via long distance pipeline or as LNG. Transportation costs will obviously be a function of distance, but by way of illustration, resources which can be economically developed at a gas price of $1 or $2/Mcf may well require an additional $3 to $5/Mcf to get to their ultimate destination. These high transportation costs are also a significant factor in the evolution of the global gas market.

Figure 2.3 Global Gas Supply Cost Curve, with Uncertainty; 2007 Cost Base (excludes unconventional gas outside North America)



Outside of Canada and the U.S., there has been very little development of the unconventional gas supply base. This is largely a function of supply maturity — there has been little need to develop unconventional supplies when conventional resources are abundant. Due to this lack of development, unconventional resource estimates are sparse and unreliable.

Based on an original estimate by Rogner[4], there may be of the order of 24,000 Tcf of unconventional GIIP outside North America. Applying a nominal 25% recovery factor, this would imply around 6,000 Tcf of unconventional recoverable resources. However, these global estimates are highly speculative, almost completely untested and subject to very wide bands of uncertainty. There is a long-term need for basin-by-basin resource evaluation to provide credibility to the GIIP estimates and, most importantly, to establish estimates of recoverable resource volumes and costs.

Given the concentrated nature of conventional supplies and the high costs of long-distance transportation, there may be considerable strategic and economic value in the development of unconventional resources in those regions that are currently gas importers, such as Europe and China. It would be in the U.S. strategic interest to see these indigenous supplies developed, and as a market leader in this technology, the U.S. could play a significant role in facilitating this development.

RECOMMENDATION

U.S. policy should encourage the strategic development of unconventional gas supplies outside North America, with a particular focus on Europe and China.

UNITED STATES

Table 2.1 illustrates mean U.S. resource estimates from a variety of resource assessment experts. These numbers have tended to grow over time, particularly as the true potential of the unconventional resource base has started to emerge over the past few years.

For this study, we have assumed a mean remaining resource base of around 2,100 Tcf — about 92 times the annual U.S. consumption of 22.8 Tcf in 2009. We estimate the low case at 1,500 Tcf, and the high case at 2,850 Tcf.

Around 15% of the U.S. resource is in Alaska; full development of this resource will require major pipeline construction to bring the gas to market in the lower 48 states (L48). Given the current abundance of L48 supplies, development of the pipeline is likely to be deferred yet again, but this gas represents an important resource for the future.

In the L48, some 55% to 60% of the resource base is conventional gas, both onshore and offshore. Although mature, the conventional resource base still has considerable potential. Around 60% of this resource is comprised of proved reserves and reserve growth, with the remainder — of the order of 450 to 500 Tcf — from future discoveries.

Table 2.1 U.S. Resource Estimates by Type, from Different Sources[5]
Gas Volumes (Tcf)

	NPC	USGS/MMS	PGC		ICF
	(2003)	(Various Years)	(2006)	(2008)	(2009)
Lower 48					
Conventional	691	928	966	869	693
Tight	175	190			174
Shale	35	85		616	631
CBM	58	71	108	99	65
Total Lower 48	**959**	**1,274**	**1,074**	**1,584**	**1,563**
Alaska					
Conventional	237	357	194	194	237
Tight	–	–			
Shale	–	–		–	–
CBM	57	18	57	57	57
Total Alaska	**294**	**375**	**251**	**251**	**294**
Total U.S.					
Conventional	929	1,284	1,160	1,063	930
Tight	175	190			174
Shale	35	85		616	631
CBM	115	89	165	156	122
Total U.S.	**1,253**	**1,648**	**1,325**	**1,835**	**1,857**
Proved Reserves	**184**	**245**	**204**	**245**	**245**
Grand Total	**1,437**	**1,893**	**1,529**	**2,080**	**2,102**

Figure 2.4a represents the supply cost curves for all U.S. resources, depicting the mean estimate and the considerable range of uncertainty in these estimates. Figure 2.4b illustrates the mean supply curves, broken down by resource type. It clearly shows the large remaining conventional resource base, although it is mature and some of it will require high gas prices to become economical to develop. These curves assume current technology; in practice, future technology development will enable these costs to be driven down over time.

Figure 2.4b also demonstrates the considerable potential of shale supplies. Using a 2007 cost base, a substantial portion of the estimated shale resource base is economic at prices between $4/Mcf and $8/Mcf. As we see at present, some of the shale resources will displace higher cost conventional gas in the short to medium term, exerting downward pressure on gas prices.

Figure 2.4a Volumetric Uncertainty of U.S. Gas Supply Curves; 2007 Cost Base

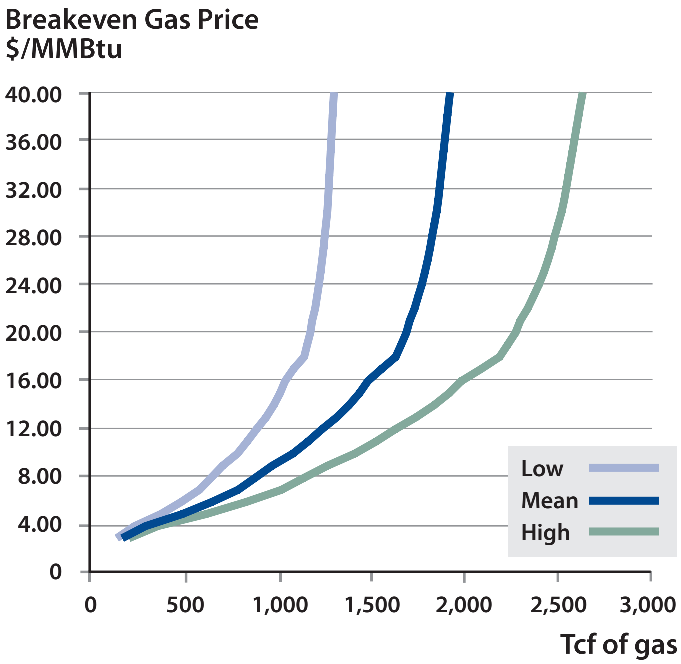
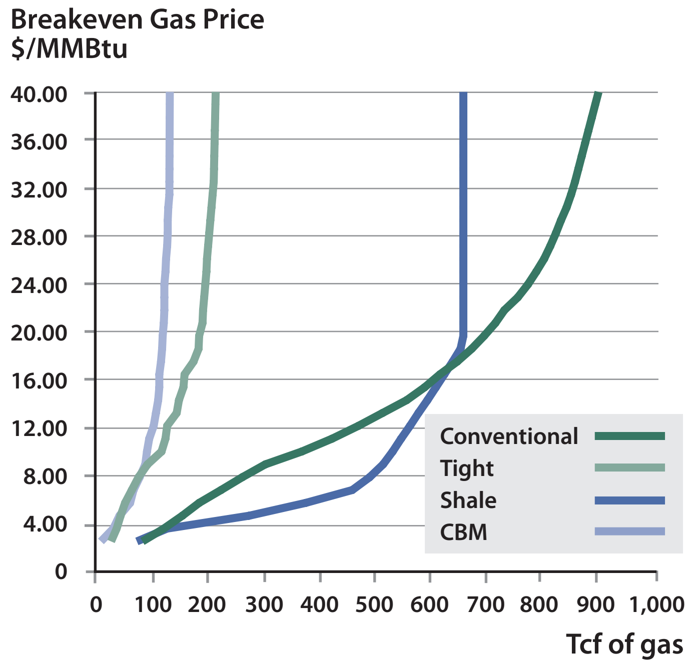


Figure 2.4b Breakdown of Mean U.S. Gas Supply Curve by Type; 2007 Cost Base



Despite the relative maturity of the U.S. gas supply, estimates of remaining resources have continued to grow over time — with an accelerating trend in recent years. As the conventional resource base matures, much of the resource growth has occurred in unconventional gas, especially in the shales.

The PGC, which evaluates the U.S. gas resource on a biannual cycle, provides perhaps the best historical basis for looking at resource growth over time. According to this data, resources have grown by 77% since 1990, despite a cumulative production volume (i.e., resource depletion) during that time of 355 Tcf.

As a subset of this, the application of horizontal drilling and hydraulic fracturing technology to the shales has caused resource estimates to grow over a five-year period from a relatively minor 35 Tcf (NPC, 2003), to a current estimate of 615 Tcf (PGC, 2008), with a range of 420–870 Tcf. This resource growth is a testament to the power of technology application in the development of resources, and also provides an illustration of the large uncertainty inherent in all resource estimates.

The new shale plays represent a major contribution to the resource base of the U.S. However, it is important to note that there is considerable variability in the quality of the resources, both within and between shale plays. This variability in performance is illustrated in the supply curves on the previous page, as well as in Figure 2.5. Figure 2.5a shows initial production and decline data from three major U.S. shale plays, illustrating the substantial differences in average well performance between the plays. Figure 2.5b shows a probability distribution of initial flow rates from the Barnett formation. While many refer to shale development as more of a "manufacturing process" than the conventional exploration, development and production process, this manufacturing still occurs within the context of a highly variable subsurface environment.

According to PGC data, U.S. natural gas resources have grown by 77% since 1990, illustrating the large uncertainty inherent in all resource estimates.

Figure 2.5a Variation in Production Rates between Shale Plays[6]

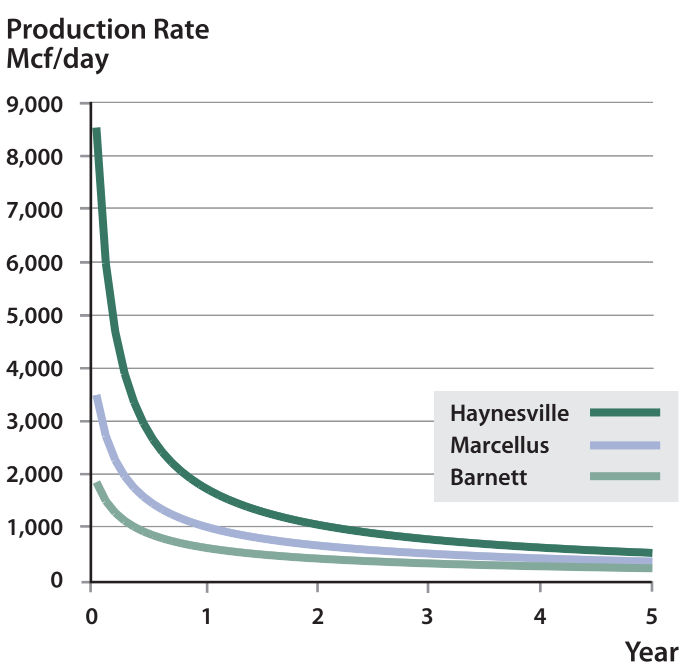
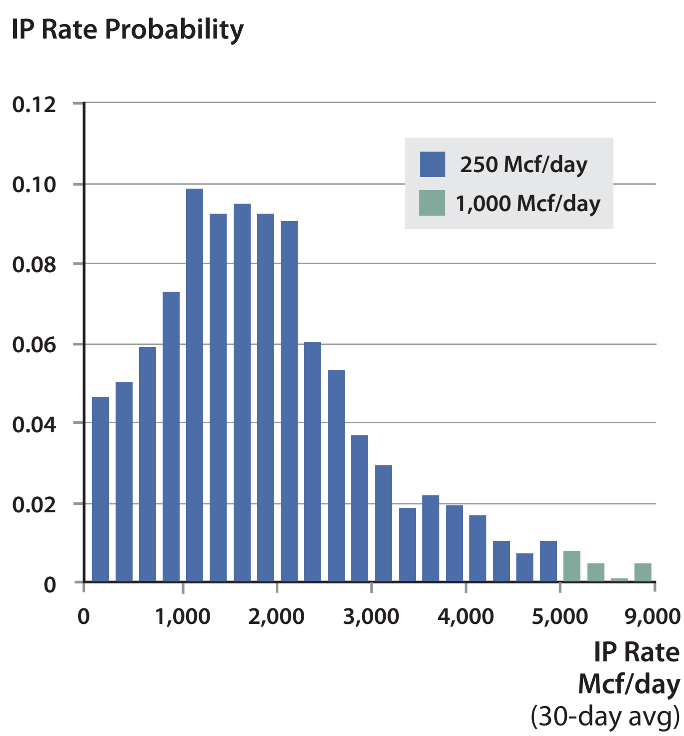


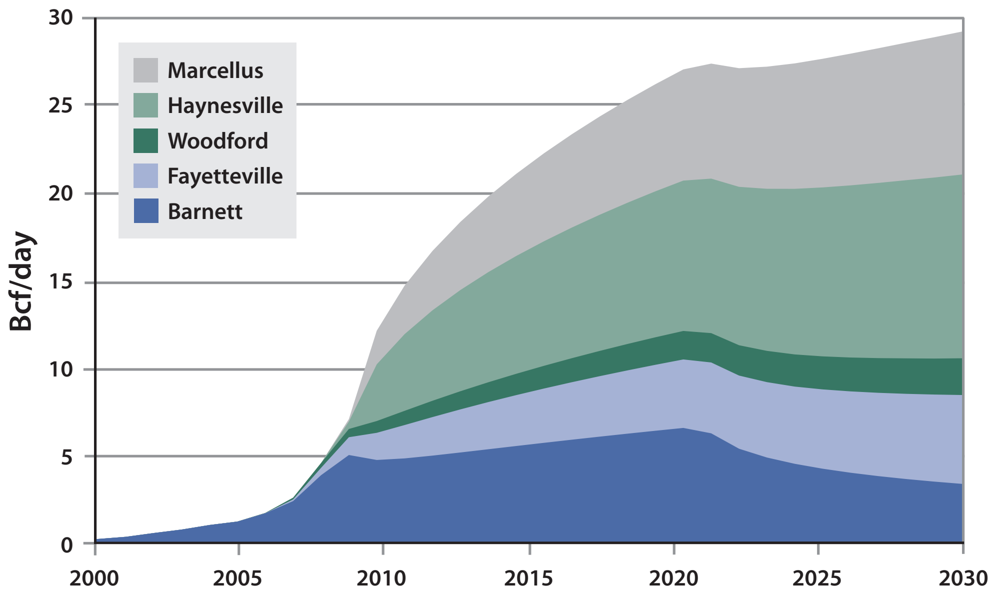
Figure 2.5b Variation in IP Rates of 2009 Vintage Barnett Wells[7]



In this section we do not attempt to make independent forecasts of future gas production — such forecasts are generated by the Emissions Prediction and Policy Analyses (EPPA) modelling efforts described later. However, in addition to understanding the resource volumes, it is important to understand the contribution that the new shale resources can make to the overall production capacity within the U.S.

Figure 2.6 indicates how production from the top five shale plays might grow, if drilling were to continue at 2010 levels for the next 20 years. This illustrates the very significant production potential of the shale resource. The current rapid growth in shale production can continue for some time — but in the longer run production growth tapers off as high initial production rates are offset by high initial decline rates.

Figure 2.6 Potential Production Rate that Could Be Delivered by the Major U.S. Shale Plays Up To 2030 – Given Current Drilling Rates and Mean Resource Estimates[8]



The large inventory of undrilled shale acreage, together with the relatively high initial productivity of many shale wells, allow a rapid production response to any particular drilling effort. However, this responsiveness will change over time as the plays mature, and significant drilling effort is required just to maintain stable production against relatively high inherent production decline rates.

UNCONVENTIONAL GAS SCIENCE AND TECHNOLOGY

In terms of fundamental reservoir flow characteristics, and the consequent production performance, the unconventional gas resource types — tight gas, coal-bed methane and shale — are different from each other, and different from conventional gas resources. Each resource type presents it own production challenges.

Shale resources represent a particular challenge, because of their complexity, variety and lack of long-term performance data. In conventional reservoirs, there is a long history of production from a wide variety of depositional, mineralogical, and geo-mechanical environments, such that analogues can be developed and statistical predictions about future performance can be made. This is not yet the case in the shale plays.

It is in the national interest to have the best possible understanding of the size of the U.S. natural gas resource. The assessment methodology for the "continuous" unconventional resources is less well developed than is that for conventional resources.

In order to ensure the optimum development of these important national assets, it is necessary to build a comprehensive understanding of geochemistry, geological history, multiphase flow characteristics, fracture properties and production behavior across a variety of shale plays. It is also important to develop tools which can enable the upscaling of pore-level physics to reservoir-scale performance prediction, and to improve core analysis techniques to allow accurate determination of reservoir properties.

RECOMMENDATION

DOE should sponsor additional Research and Development (R&D), in collaboration with industry and academia, to address some of the fundamental challenges of shale gas science and technology, with the goal of ensuring that this national resource is exploited in the optimum manner.

It is in the national interest to have the best possible understanding of the size of the U.S. natural gas resource. For conventional reservoirs, statistically based resource assessment methodologies have been developed and tested over many years. In contrast, the assessment methodology for the "continuous" unconventional resources is less well developed. There would be real benefit in improving the methodology for unconventional resource assessments.

RECOMMENDATION

The USGS should continue, and even accelerate, its efforts to develop improved assessment methodologies for unconventional resources.

SHALE GAS ENVIRONMENTAL CONCERNS

The production, transport and consumption of natural gas are accompanied by a range of environmental and safety risks.[9] In this interim report, we will focus on production, particularly from shale formations.

Effective mitigation of these risks is necessary in order for the industry to operate. Historically, government regulation, along with the application of industry-developed best practice, has served to minimize environmental impact from gas production for the most part. The recent rapid expansion of activity in unconventional gas plays, particularly shale plays, has understandably led to increased concern regarding the environmental impacts of such activity. This is particularly so in those areas that have not previously witnessed large-scale oil and gas development. The primary concerns are to do with potential risks posed to different aspects of water resources:

1. Risk of shallow freshwater aquifer contamination, with fracture fluids;

2. Risk of surface water contamination, from inadequate disposal of fluids returned to the surface from fracturing operations;

3. Risk of excessive demand on local water supply, from high-volume fracturing operations;

4. Risk of surface and local community disturbance, due to drilling and fracturing activities.

With over 20,000 shale wells drilled in the last 10 years, the environmental record of shale gas development is for the most part a good one — one must recognize the inherent risks and the damage that can be caused by just one poor operation.

With over 20,000 shale wells drilled in the last 10 years, the environmental record of shale gas development is for the most part a good one. Nevertheless, one must recognize the inherent risks of the oil and gas business and the damage that can be caused by just one poor operation; the industry must continuously strive to mitigate risk and address public concerns. Particular attention should be paid to those areas of the country that are not accustomed to oil and gas development, and where all relevant infrastructure, both physical and regulatory, may not yet be in place.

The protection of freshwater aquifers from fracture fluids has been a primary objective of oil and gas field regulation for many years. As indicated in Table 2.2, there is substantial vertical separation between the freshwater aquifers and the fracture zones in the major shale plays. The shallow layers are protected from injected fluid by a number of layers of casing and cement — and as a practical matter fracturing operations cannot proceed if these layers of protection are not fully functional. Good oil-field practice and existing legislation should be sufficient to manage this risk.

Table 2.2 Vertical Separation of Shale Formations from Freshwater Aquifers[9]

Basin	Depth to Shale (ft)	Depth to Aquifer (ft)
Barnett	6,500–8,500	1,200
Fayetteville	1,000–7,000	500
Marcellus	4,000–8,500	850
Woodford	6,000–11,000	400
Haynesville	10,500–13,500	400

The effective disposal of fracture fluids may represent more of a challenge, particularly away from established oil and gas areas, although again it must be put into the context of routine oil field operations. Every year the onshore U.S. industry safely disposes of around 18 billion barrels of produced water. By comparison, a high-volume shale fracturing operation may return around 50 thousand barrels of fracture fluid and formation water to the surface. The challenge is that these relatively small volumes are concentrated in time and space.

Water supply and disposal issues, where they exist, could be addressed by requiring collaboration between operators on a regional basis to create integrated water usage and disposal plans. In addition, complete transparency about the contents of fracture fluids, which are for the most part benign, and the replacement of any potentially toxic components where they exist, could help to alleviate public concern.

RECOMMENDATION

Improve the transparency of fracturing operations through better communication of oil and gas-field practices and the role of existing legislation and regulation; require integrated regional water usage and disposal plans; require the complete disclosure of all components of hydraulic fracture fluids; conduct collaborative R&D to reduce water usage in fracturing and develop cost-effective water recycling technology.

METHANE HYDRATES

Methane hydrates are not considered in the resource estimates and supply curves described above, as they are still at a very early stage in terms of resource definition and understanding. Nevertheless, hydrates may represent a very significant long-term resource option, both in North America and in other parts of the world.

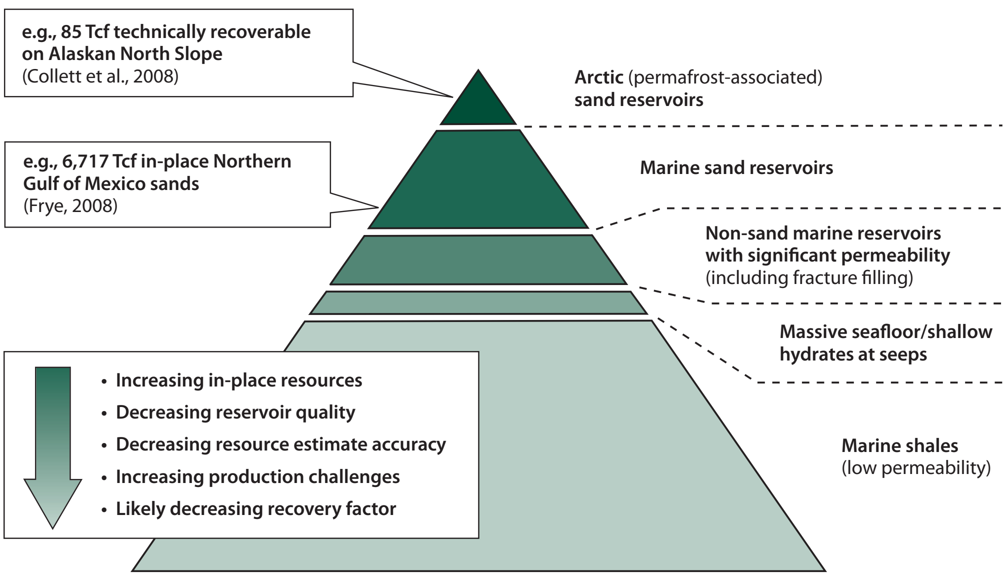
Methane hydrates are an ice-like form of methane and water stable at the pressure-temperature conditions common in the shallow sediments of permafrost areas and continental margins. Globally, the total amount of methane sequestered in these deposits probably exceeds 1,000,000 Tcf of which ~99% occurs in ocean sediments. Most of this methane is trapped in highly disseminated and/or low saturation gas hydrates that will never be commercially viable gas sources. An estimated 100,000 Tcf may be technically recoverable from high-saturation gas hydrate deposits[11] (Boswell and Collett, 2010).

There have been few formal quantitative assessments of methane sequestered in gas hydrates. A recent assessment of in-place resources in northern Gulf of Mexico yielded 6,717 Tcf (median) for sands[12] (Frye, 2008). The only technically-recoverable assessment ever completed calculated 85.4 Tcf (median) for permafrost-associated gas hydrates on the Alaskan North Slope[13] (Collett et al., 2008).

Providing the data necessary for assessments will require geophysical methods (e.g., electromagnetic techniques) that can detect concentrated gas hydrates more reliably than seismic surveys alone and less expensively than direct drilling and borehole logging.

Methane hydrates are unlikely to reach commercial viability for global markets for at least 15 to 20 years.

Figure 2.7 The Methane Hydrate Resource Pyramid



Methane hydrates are unlikely to reach commercial viability for global markets for at least 15 to 20 years. Through consortia of government, industry, and academic experts, the U.S., Japan, Canada, Korea, India, and other countries have made significant progress on locating resource-grade methane hydrates. Before 2015, the first research-scale, long-term production tests will be carried out by the U.S. DOE on the Alaskan North Slope and by the Japanese MH21 project for Nankai Trough deepwater gas hydrates.

RECOMMENDATION

Continue hydrates research program to: develop methods for remote detection of highly concentrated deposits; conduct formal resource assessments; and prove the resource potential through long-term production testing.

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NOTES

[1]Permeability is a measure of the ability of a porous medium, such as that found in a hydrocarbon reservoir, to transmit fluids, such as gas, oil or water, in response to a pressure differential across the medium.

[2]Resource estimates and uncertainty ranges are based on data and information from: Ahlbrandt et al., *Global Resource Estimates from Total Petroleum Systems*; United States Geological Survey, "National Oil and Gas Assessment, USGS-ERP"; National Petroleum Council, *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy*; United States Geological Survey, "World Petroleum Assessment-Information, Data and Products, USGS-ERP"; Potential Gas Committee, *Potential Supply of Natural Gas – 2008*; Attanasi and Coburn, "A Bootstrap Approach to Computing Uncertainty in Inferred Oil and Gas Reserve Estimates"; Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves Report*. Details will be provided in full report.

[3]Cost curves are based on oil field costs in 2007. There has been considerable oil field cost inflation, and some recent deflation, in the last 10 years. We have estimated cost curves on a 2004 base (the end of a long period of stable costs) and a 2007 base (70% higher than the 2004 level, and reasonably comparable to today's costs, which continue to decline).

[4]Rogner, "An Assessment of World Hydrocarbon Resources."

[5]National Petroleum Council, *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy*; United States Geological Survey, "National Oil and Gas Assessment, USGS-ERP"; Minerals Management Service, *Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf, 2006 (Summary Brochure)*; Potential Gas Committee, *Potential Supply of Natural Gas – 2006*; Potential Gas Committee, *Potential Supply of Natural Gas – 2008*; Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves Report*.

[6]HPDI production database, various industry sources.

[7]IP rates of 2009 Barnett Shale well vintage as reported by HPDI production database.

[8]Illustration based on future drilling rates remaining constant at January 2010 levels, with 65 rigs operating in the Barnett, 35 rigs in the Fayetteville, 25 rigs in the Woodford, 110 rigs in the Haynesville and 70 rigs in the Marcellus.

[9]A detailed description of the nature, and scale of the environmental and safety risks inherent with gas production, along with the regulations and procedures used to mitigate against them will be found in the "Supply" chapter of the full "MIT Future of Natural Gas" report.

[10]Modern Shale Gas – A Primer, U.S. Department of Energy Report, April 2009.

[11]Boswell and Collett, "Current Perspectives on Gas Hydrate Resources."

[12]Frye, *Preliminary Evaluation of In-Place Gas Hydrate Resources: Gulf of Mexico Outer Continental Shelf*.

[13]Collett et al., *Assessment of Gas Hydrate Resources on the North Slope*.

Section 3: U.S. Gas Production, Use and Trade: Potential Futures

INTRODUCTION

As discussed in other sections of this report, many factors will influence the future role of natural gas in the U.S. energy system. Here we consider the most important of these: GHG mitigation policy, technology development, size of gas resources and global market developments. And we examine how they will interact to shape future U.S. gas use, production and trade over the next few decades.

We investigate the importance of these factors and their uncertainties by applying established models of the U.S. and global economy (see Box 3.1). Alternative assumptions about the future allow us to create a set of scenarios that provide bounds on the future prospects for gas and illustrate the relative importance of different factors in driving the results.

The conditions explored include the High, Mean and Low range of gas resource estimates described in Section 2. We show the impacts of various policy alternatives including: no new climate policy; a GHG emission reduction target of 50% by 2050, using a price-based policy (such as a cap-and-trade system or emissions tax); and an emissions policy that uses a set of non-price regulatory measures.

Several assumptions have a particularly important effect on the analysis. Long-term natural gas supply curves, distinguishing the four gas types for the U.S. and Canada, are drawn from Section 2. U.S. economic growth is assumed to be 0.9% per year in 2005–2010, 3.1% in 2010–2020 (to account for recovery) and 2.4% for 2020–2050.

BOX 3.1 GLOBAL AND U.S. ECONOMIC MODELS

Projections in this section were made using the MIT EPPA model and the U.S. Regional Energy Policy (USREP) model.[1] Both are multi-region, multi-sector representations of the economy that solve for the prices and quantities of energy and non-energy goods and project trade among regions.

The core results for this study are simulated using the EPPA model — a global model with the U.S. as one of its regions. The USREP model is nearly identical in structure to EPPA, but represents the U.S. only — segmenting it into 12 single and multi-state regions. In the USREP model, foreign trade is represented through import supply and export demand functions, broadly benchmarked to the trade response in the EPPA model. Both models account for all Kyoto gases.

The advantage of models of this type is their ability to explore the interaction of those factors underlying energy supply and demand that influence markets. The models can illustrate the directions and relative magnitudes of influences on the role of gas, providing a basis for judgments about likely future developments and the effects of government policy. However, results should be viewed in light of model limitations. Projections, especially over the longer term, are naturally subject to uncertainty. Also, the cost of technology alternatives, details of market organization and the behavior of individual industries (e.g., various forms of gas contracts, political constraints on trade and technology choice) are beneath the level of model aggregation. The five-year time step of the models means that the effects of short-term price volatility are not represented.

Table 3.1 Levelized Cost of Electricity (2005 cents/kWh)

	Reference	Sensitivity
Coal	5.4	
Advanced Natural Gas (NGCC)	5.6	
Advanced Nuclear[2]	8.8	7.3
Coal/Gas with CCS[3]	9.2/8.5	6.9/6.6
Renewables		
Wind	6.0	
Biomass	8.5	
Solar	19.3	
Substitution elasticity (Wind, Biomass, Solar)	1.0	3.0
Wind+Gas Backup	10.0	

Influential cost assumptions are shown in Table 3.1 for the reference case and sensitivity tests. We vary the costs of competing generation technologies (nuclear, coal and gas with carbon capture and storage and renewables). The intermittent renewables (wind and solar) are distinguished by scale. At low penetration levels, they enter as imperfect substitutes for conventional electricity generation, and the estimates of the levelized cost of electricity (LCOE[4]) apply to early installations when renewables are at sites with access to the best quality resources and to the grid and storage or backup is not required. Through the elasticity of substitution the model imposes a gradually increasing cost of production as their share increases, to be limited by the cost with backup. These energy sector technologies, like others in the model, are subject to cost reductions over time through improvements in labor, energy and (where applicable) land productivity.

The potential role of compressed natural gas in vehicles is considered separately, drawing on estimates of the cost of these vehicles from Section 4 of this report.

We also consider two possible futures for international gas markets: one where they continue in their current pattern of regional trading blocs; and an alternative where there develops a tightly integrated global gas market similar to that which now exists for crude oil.

THE ROLE OF U.S. GAS POLICY — THREE ALTERNATIVE SCENARIOS

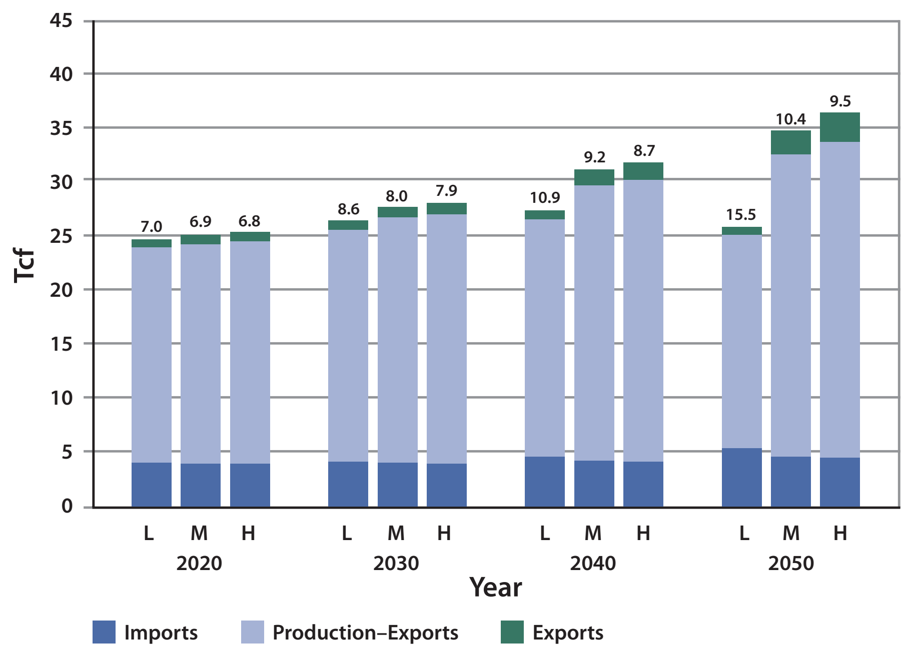
Scenario 1 — With No Additional Policy Demands for GHG Mitigation

Unless gas resources are at the low end of the resource estimates in Section 2, domestic gas use and production are projected to grow substantially between now and 2050. This result is shown in Figure 3.1, from EPPA model simulations, on the assumption that global gas markets remain fragmented in regional trading blocs. Under the Mean resource estimate, U.S. gas production rises by around 40% between 2005 and 2050, and by a slightly higher 45% under the High estimate. It is only under the Low resource outcome that resource availability substantially limits growth in domestic production and use. In that case, gas production and use plateau around 2030 and are in decline by 2050.

The availability of shale gas resources has a substantial effect on these results. If the Mean estimate for other gas resources is assumed, and this same projection is made omitting the shale gas component of supply, U.S. production peaks around 2030 and declines to its 2005 level by 2050.

Given the continued existence of regional trading blocs for gas, there is little change in the role played by imports and exports of gas. Imports (mainly from Canada) are roughly constant over time, though they increase when U.S. resources are Low. Exports (principally to Mexico) also are maintained over the period and grow somewhat if U.S. gas resources are at the High estimate.

Figure 3.1 U.S. Gas Use, Production and Imports & Exports (Tcf), and U.S. Gas Prices above Bars ($/1000 cf) for Low (L), Mean (M) and High (H) U.S. Resources. No Climate Policy and Regional International Gas Markets



Gas prices (2005 U.S. dollars), shown at the top of the bars in the figure on the previous page, rise gradually over time as the lower cost resources are depleted; the lower the resource estimate the higher the prices. The difference in prices across the range of resource scenarios is not great for most periods. In 2030, for example, the High resource estimate yields a price 2% below that for the Mean estimate while the Low resource condition increased the price by 7%. The difference increases somewhat over time, especially for the Low resource case. By 2050, for example, the price is 8% lower if the High resource conditions hold, but 50% higher if domestic resources are at the Low estimate.

Underlying these estimates are developments on the demand side. Under Mean resources, electricity generation from natural gas would rise by about 70% over the period 2010 to 2050 though coal would continue to dominate, with only a slightly growing contribution projected from nuclear power and renewable sources (wind and solar). National GHG emissions rise by about 40% from 2005 to 2050.

Scenario 2 — With Climate Policy Creating a Level Playing Field

An incentive (or price) based GHG emissions policy that establishes a national price on GHG emissions serves to level the emissions reduction playing field by applying the same penalty to emissions from all sources and all uses.

The policy explored here gradually reduces total U.S. GHG emissions to 50% below the 2005 level by 2050. The scenario is not designed to represent a particular policy proposal and no provision is included for offsets.

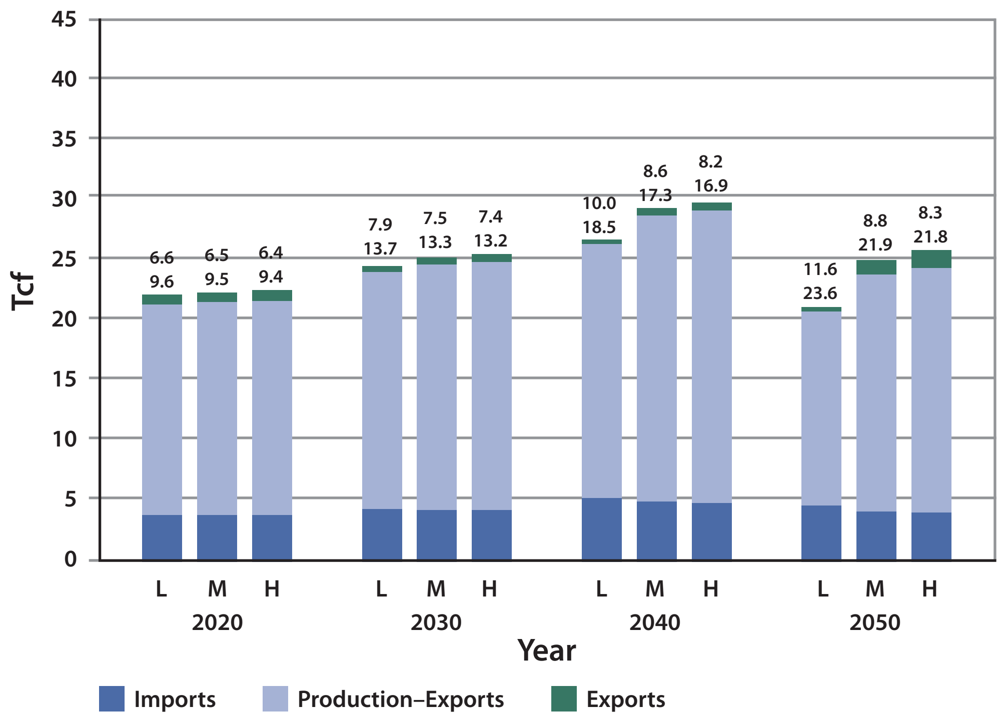
While measures taken abroad are not of direct interest for this study, such policies or the lack of them will affect the U.S. energy system through international trade. If the U.S. were to pursue this aggressive GHG mitigation policy, we assume that it would need to see similar measures being taken abroad. Thus, a similar pattern of reductions is assumed for other developed countries, with lagged reductions in China, India, Russia, Mexico and Brazil that start in 2020 on a linear path to 50% below their 2020 levels by 2070. The rest of the developing countries are assumed to delay action to beyond 2050. We assume no emissions trading among countries.

The broad features of U.S. gas markets under the assumed emissions restriction are not substantially different from the no-policy scenario, at least through 2040 (Figure 3.2). Gas production and use grows somewhat more slowly, reducing use and production by a few Tcf in 2040 compared with the case without climate policy. After 2040, however, domestic production and use begin to fall. This decline is driven by higher gas prices, CO_2 charge inclusive, that gas users would see. The price reaches about $22 per thousand cubic feet (cf) with well over half of that price reflecting the CO_2 charge. While gas is less CO_2 intensive than coal or oil, at the reduction level required by 2050, its CO_2 emissions are beginning to represent an emissions problem.

However, even under the pressure of the assumed emissions policy, total gas use is projected to increase from 2005 to 2050 even for the Low estimate of domestic gas resources.

Even under the pressure of an assumed CO_2 emissions policy, total U.S. gas use is projected to increase up to 2050.

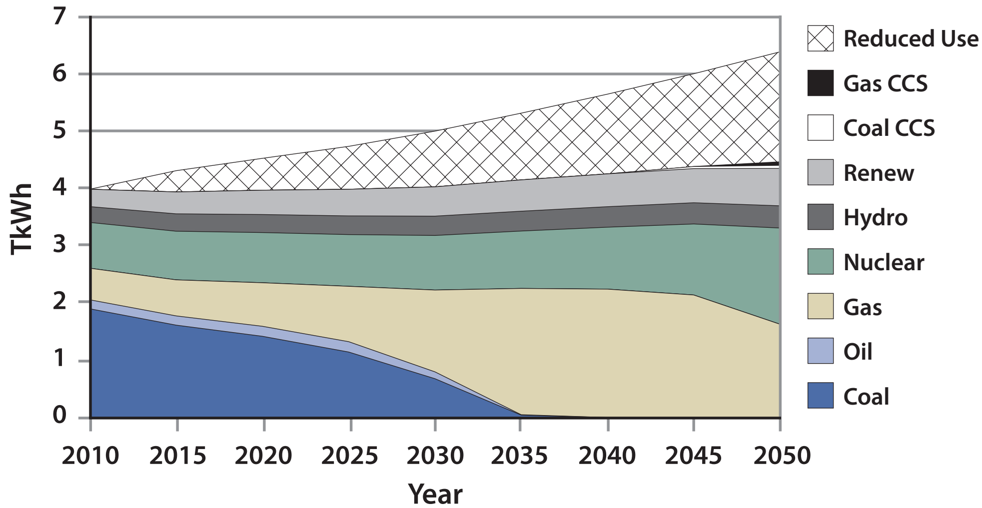
Figure 3.2 U.S. Gas Use, Production and Imports & Exports (Tcf), and U.S. Gas Prices ($/1000 cf) for Low (L), Mean (M) and High (H) U.S. Resources, Price-Based Climate Policy and Regional International Gas Markets. Prices Are Shown without (top) and with (bottom) the Emissions Charge



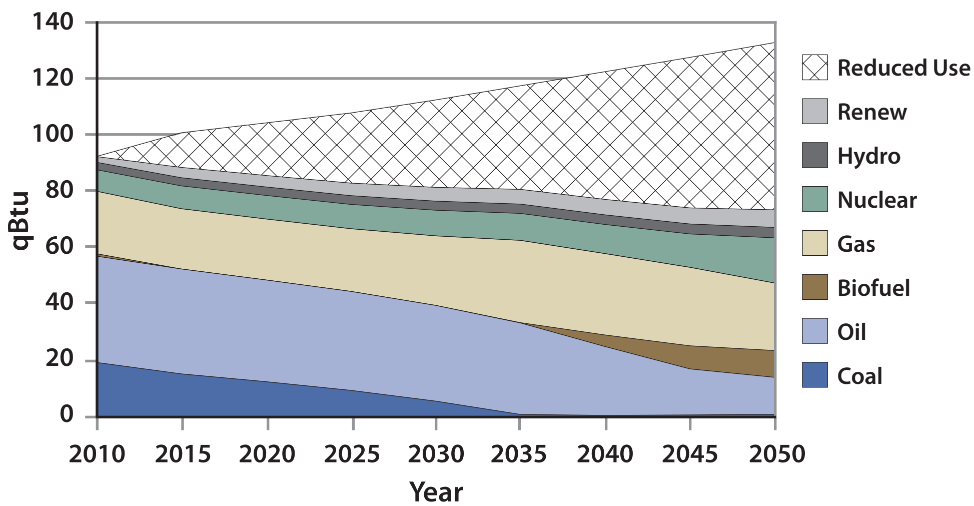
A major effect of the economy-wide, price-based GHG policy is to reduce energy use (Figure 3.3). The effect in the electric sector is to effectively flatten demand, holding it near its current 4 TkWh level (Figure 3.3a). Based on the cost assumptions underlying the simulation (see Table 3.1) nuclear, CCS and renewables are relatively expensive compared with generation from gas. Conventional coal is driven from the generation mix by the CO_2 prices needed to meet the economy-wide emissions reduction targets. Natural gas is the substantial winner in the electric sector: the substitution effect, mainly gas generation for coal generation, outweighs the demand reduction effect. For total energy (Figure 3.3b) the demand reduction effect is even stronger, leading to a decline in U.S. energy use of nearly 20 quadrillion (10^{15}) Btu. The reduction in coal use is evident, and oil and current-generation biofuels (included in oil) begin to be replaced by advanced biofuels. Because national energy use is substantially reduced, the share represented by gas is projected to rise from about 20% of the current national total to around 40% in 2040.

Figure 3.3 Energy Mix under Climate Policy, Mean Natural Gas Resources

3.3a Electric Sector (TkWh)



3.3b Total Energy Use (qBtu)

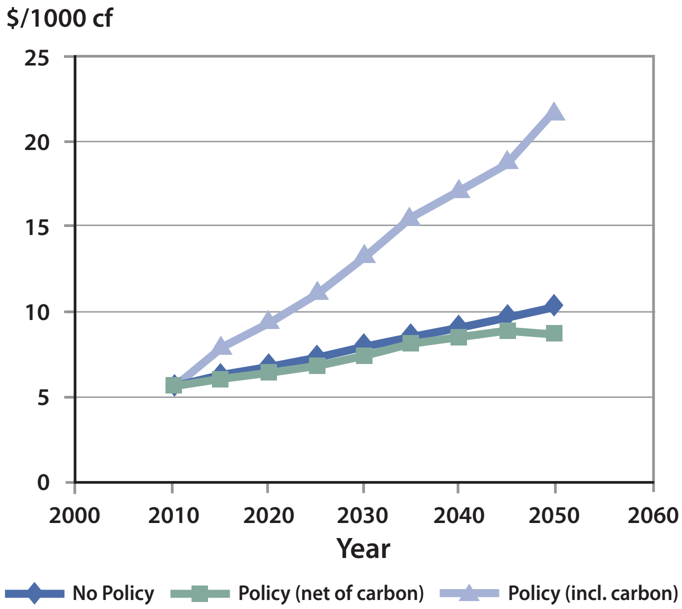


Under this policy scenario, the U.S. emissions price is projected to rise to approximately \$100 per ton CO_2-e in 2030 and to approach \$240 by 2050. The macroeconomic effect is to lower U.S. Gross Domestic Product (GDP) by nearly 2% in 2030 and somewhat over 3% in 2050. A selection of resulting U.S. domestic prices is shown in Figure 3.4. Natural gas prices, exclusive of the CO_2 price, are reduced slightly by the mitigation policy, but the price inclusive of the CO_2 charge is greatly increased (Figure 3.4a). The CO_2 charge is nearly half of the user price of gas.[5]

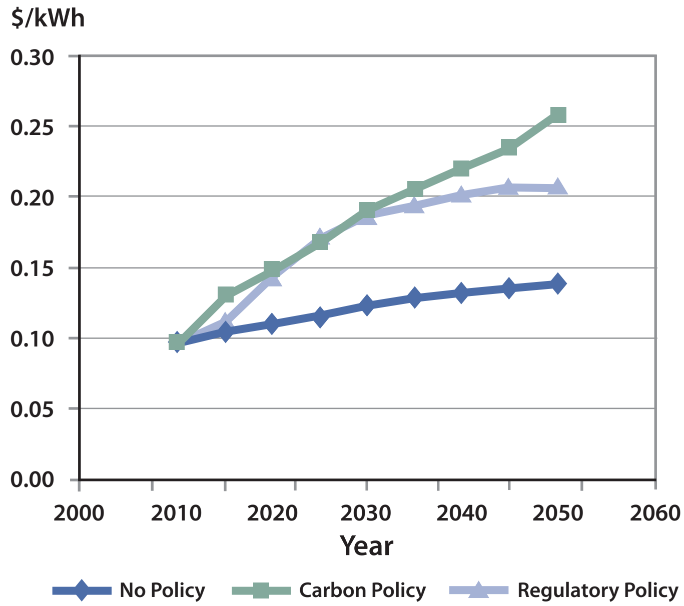
Even in the No-Policy case electricity prices are projected to rise by 30% in 2030 and about 45% over the period to 2050 (Figure 3.4b). The assumed emissions mitigation policy is projected to cause electricity prices to rise by almost 100% in 2030 and more than double by 2050 compared with current prices. (Also shown in the Figure 3.4b is the electricity price increase under a sample regulatory regime, to be discussed below.)

Figure 3.4 U.S. Natural Gas and Electricity Prices

3.4a Natural Gas ($/1000 cf)



3.4b Electricity Prices ($/kWh)



As noted earlier, a set of alternative cost assumptions was explored for low-carbon technologies in the electricity sector, including less costly CCS, nuclear and renewables (Table 3.1).

The biggest projected impact on gas use in electricity results from an assumption of low-cost nuclear generation.

Of these, the biggest impact on gas use in electricity results from the low-cost nuclear generation. Focusing on 2050, when the effects of alternative assumptions are the largest, a low-cost nuclear assumption reduces annual gas use in the electric sector by nearly 7 Tcf. Economy-wide gas use falls by only about 5 Tcf, however, because the resulting lower demand for gas in electricity leads to a lower price and more use in other sectors of the economy.

Lower-cost renewables yield a reduction in gas use in the electric sector by 1.8 Tcf in 2030, but total gas use falls by only 1.2 Tcf. In 2050 a difference in gas use is smaller, 0.5 Tcf and 0.1 Tcf respectively, as availability of cheaper renewables displaces nuclear power which by that time starts to replace gas in the electric sector.

With less-costly CCS gas use increases in the electric sector by nearly 3 Tcf, because both gas and coal generation with CCS become economic and share the low-carbon generation market. Gas use in the economy as a whole increases even more, by 4.2 Tcf.

Many other combinations of technological uncertainties could be explored. For example, a breakthrough in large-scale electric storage would improve the competitiveness of intermittent sources. A major insight to be drawn from these few model experiments, however, is that, under a policy based on emissions pricing to mitigate greenhouse gas emissions, natural gas is in a strong competitive position unless competing technologies are much less expensive than we now anticipate.

The simulations on the previous page do not include the CNG vehicle. When this policy case is repeated with this technology included, applying optimistic cost estimates drawn from Section 4 of this report, the result depends on the assumption about the way competing biofuels, and their potential indirect land-use effects, are accounted. Even with advanced biofuels credited as a zero-emissions option, however, CNG vehicles rise to about 15% of the private vehicle fleet by 2040–2050. They consume about 1.5 Tcf of gas at that time which, because of the effect of the resulting price increase on other sectors, adds approximately 1.0 Tcf to total national use.[6]

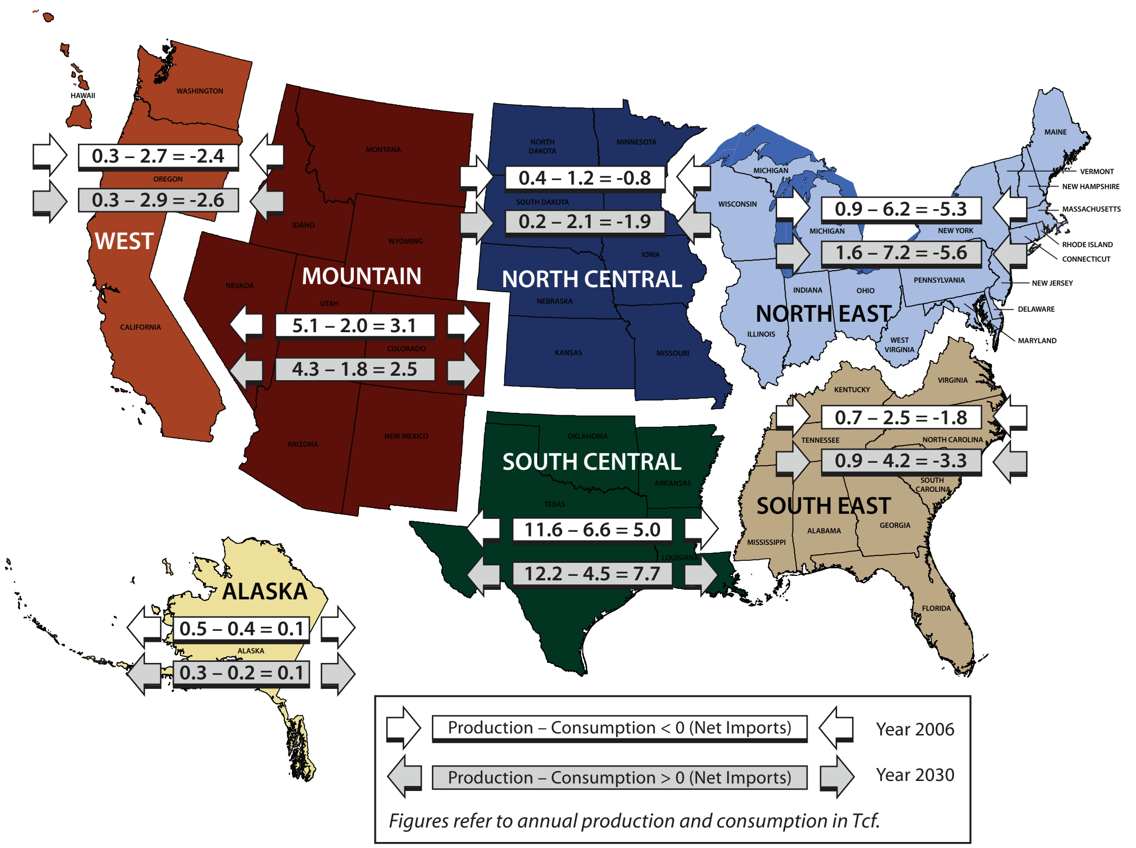
Some U.S. regions that have not traditionally been gas producers do have significant shale gas resources. To the extent these resources are developed, it could change patterns of production and distribution of gas in the U.S.

Some U.S. regions that have not traditionally been gas producers do have significant shale gas resources and their development could change patterns of production and distribution of gas in the U.S.

To identify regional patterns of production and use within the U.S., we apply the USREP model and report results for seven regions of the country for 2006 and 2030 under the 50% climate policy target and the Mean gas resources (Figure 3.5). Gas production increases most in those regions with the new shale resources — by more than 78% in the Northeast region (New England through the Great Lakes States), by about 50% in the South Central area that includes Texas. In regions without new shale resources, production changes little, showing slight increases or decreases. In the Northeast the production increase comes close to matching the projected growth in gas use.

The most substantial potential need for additional interregional gas flows, on the regional definition of Figure 3.5, is from the Texas/South Central region which increases net exports by a combined 2.7 Tcf, with shipment to other regions except the Northeast.[7] Compared to the 2030 interregional flows absent climate policy, the assumed emissions target lowers the need for new capacity largely because of the expansion of supply in the Northeast.

Figure 3.5 Natural Gas Production and Consumption by Region in the U.S., 2006 and 2030, Price-Based Climate Policy Scenario



Scenario 3 — U.S. Gas with Regulatory Emissions Reductions

If emissions reductions are sought by regulatory and/or subsidy measures, with no price on emissions, many alternatives are available.

Among the most obvious measures that could have a direct impact on CO_2 emissions would be those requiring renewable energy and one encouraging a phase-out of existing coal-fired power plants.

Among the most obvious measures that could have a direct impact on CO_2 emissions would be those requiring renewable energy and one encouraging a phase-out of existing coal-fired power plants.

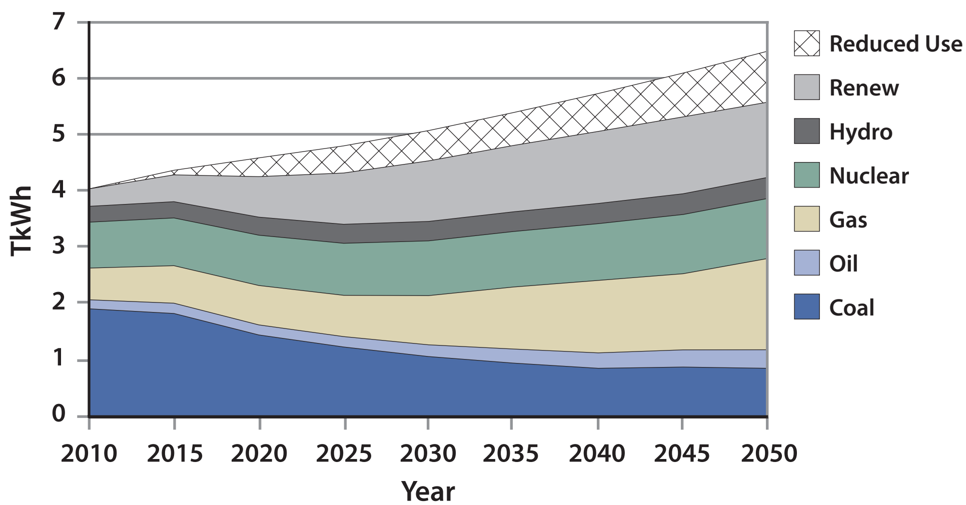
To explore this prospect, we formulate a scenario with a renewable energy standard (RES) mandating a 25% share of electric generation by 2030, and holding at that level through 2050, and measures to force retirement of coal-fired power plants starting in 2020, so that coal plants accounting for 55% of current production are retired by 2050. Mean gas resources are assumed, as are the reference levels of all technology costs. The case results in approximately a 50% reduction in carbon emissions in the electricity sector by 2050, but it does not provide incentives to reduction in non-electric sectors so these measures only hold total national GHG emissions to near the 2005 level.

One evident result of these mitigation measures is that the reduction in energy demand is less than under the assumed price-based policy, either in the electric sector (Figure 3.6a) or in total energy (Figure 3.6b). This lower reduction in the electric sector results from the lower electricity price, shown in Figure 3.4b.

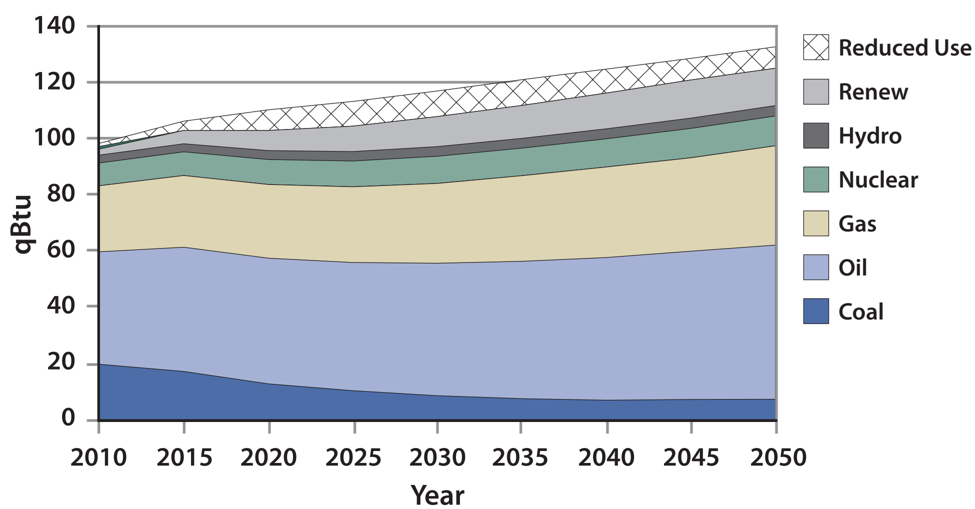
While a regulatory approach would, for the same emissions goal, be expected to be more costly than one using prices, the measures represented here achieve less emissions reduction in the electricity sector than does the price-based policy. In the price-based policy, reductions in the electricity sector are about 70% even though the national target is a 50% reduction, because it is less costly to abate there than in the rest of the economy. The difference in total national energy use is more dramatic (Figure 3.6b compared with Figure 3.3b) because the all-sector effect of the universal GHG price is missing.

Figure 3.6 Results for a Regulatory Policy

3.6a Electric Sector (TkWh)



3.6b Total Energy Use (qBtu)



The rapid expansion of renewables tends to squeeze out gas-based electric generation in the early decades of the period while the reduction in coal use opens up opportunities for gas. The net impact on gas use in the electric sector depends on the relative pace of implementation of the two regulatory measures, and compared to the assumed price-based approach, they have the potential to reduce the use of gas in the sector. However, for the economy as whole, the reduced use of gas in the electric sector results in increased uses in other sectors. Thus, U.S. natural gas demand remains fairly resilient, continuing to make a major contribution to national energy use.

THE ROLE OF INTERNATIONAL GAS MARKETS

Currently world gas trade is concentrated in three regional markets: North America, Europe (served by Russia and Africa) and Asia (with a link to the Middle East). There are significant movements of gas within each of these markets, but limited trade among them.

Different pricing structures hold within these regional markets. For some transactions, prices are set in liquid competitive markets; in others they are dominated by contracts linking gas prices to prices of crude oil and oil products. As a result, gas prices can differ substantially among the regions.

These relatively isolated, regionalized markets could be sustained for many more decades. On the other hand, it is possible that LNG or pipeline transport could grow, linking these three regions, with the effect of increasing interregional gas competition, loosening price contracts tied to oil products and moderating the price deviations among the regions.

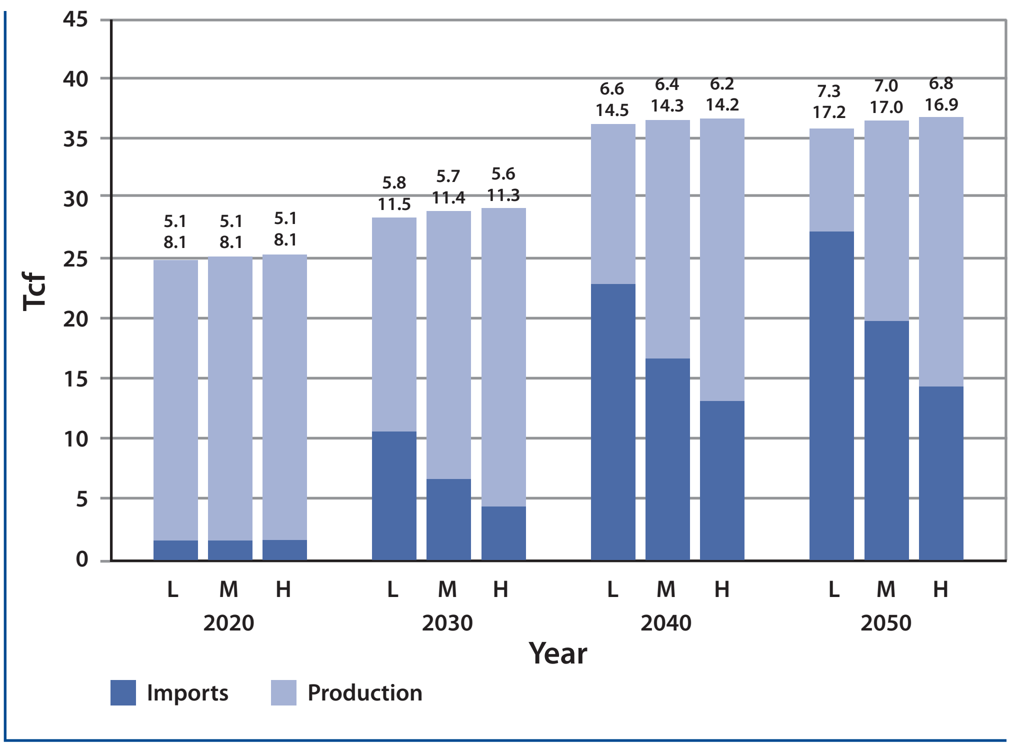
Such a process could go in many directions depending on the development of supply capacity by those nations with very large resources (mainly Russia and countries in the Middle East) or perhaps the expansion of nonconventional sources elsewhere. To the extent the structure evolves in this direction, however, there are major implications for U.S. natural gas production and use.

To investigate the end-effect of possible evolution of an integrated global market akin to crude oil, we simulate a scenario where market integration and competition lead to equalization of gas prices among markets except for fixed differentials that reflect transport costs. In this scenario, gas suppliers and consumers are assumed to operate on an economic basis. That is, no effective gas cartel is formed, and suppliers exploit their gas resources for maximum national economic gain.

Projected effects on U.S. production and trade are shown in Figure 3.7 for the 50% reduction and High, Mean and Low gas resources cases. This result may be compared with the Regional Markets case shown in Figure 3.2.

Beginning in the period 2020 to 2030, the cost of U.S. gas begins to rise above that of supplies from abroad and the U.S. becomes more dependent on imports of gas. By 2050, the U.S. depends on imports for about 50% of its gas in the Mean resource case. U.S. gas use rises to near the level in the no-policy case because prices are lower. U.S. gas use — and prices — are much less affected by the level of domestic resources, for the emergence of an integrated global market would lead ultimately to greater reliance on imports. Thus, the development of a highly integrated international market, with decisions about supply and imports made on an economic basis, would have complex effects: it would benefit the U.S. economically, limiting the development of domestic resources but lead to growing import dependence.

Figure 3.7 U.S. Gas Use, Production and Imports & Exports (Tcf) and U.S. Gas Prices ($/1000 cf) for Low (L), Mean (M) and High (H) U.S. Resources, Price-Based Climate Policy and Global Gas Markets. Prices Are Shown without (top) and with (bottom) the Emissions Charge



Possible international gas trade flows that are consistent with U.S. and global demand under the Regional and Integrated Global Markets cases are shown in Figure 3.8. Under Regional Market conditions (Figure 3.8a), we can see that trade flows are large within gas market regions but small among them. To avoid a cluttered map, small trade flows (less than 1 Tcf) are not shown. Except for the Middle East — Europe flow of 1.8 Tcf, interregional movements among the three regions specified above are less than 0.6 Tcf in any direction in 2030.

Trade flows can be particularly sensitive to the development of transportation infrastructure and political considerations, and so projections of bilateral trade in gas are highly uncertain. The Regional Markets case tends to increase trade among partners where trade already exists, locking in patterns determined in part by historical political considerations.

If a highly integrated Global Market is assumed to develop (Figure 3.8b), a very different pattern of trade emerges. The U.S. is projected to import from the Middle East as well as from Canada and Russia, and movements from the Middle East to Asia and Europe would increase — implying a substantial expansion of LNG facilities. Russian gas would begin to move into Asian markets, via some combination of pipeline transport and LNG.

Figure 3.8 Major Trade Flows of Natural Gas among the EPPA Regions in 2030, No New Policy (Tcf)

3.8a Regional Markets

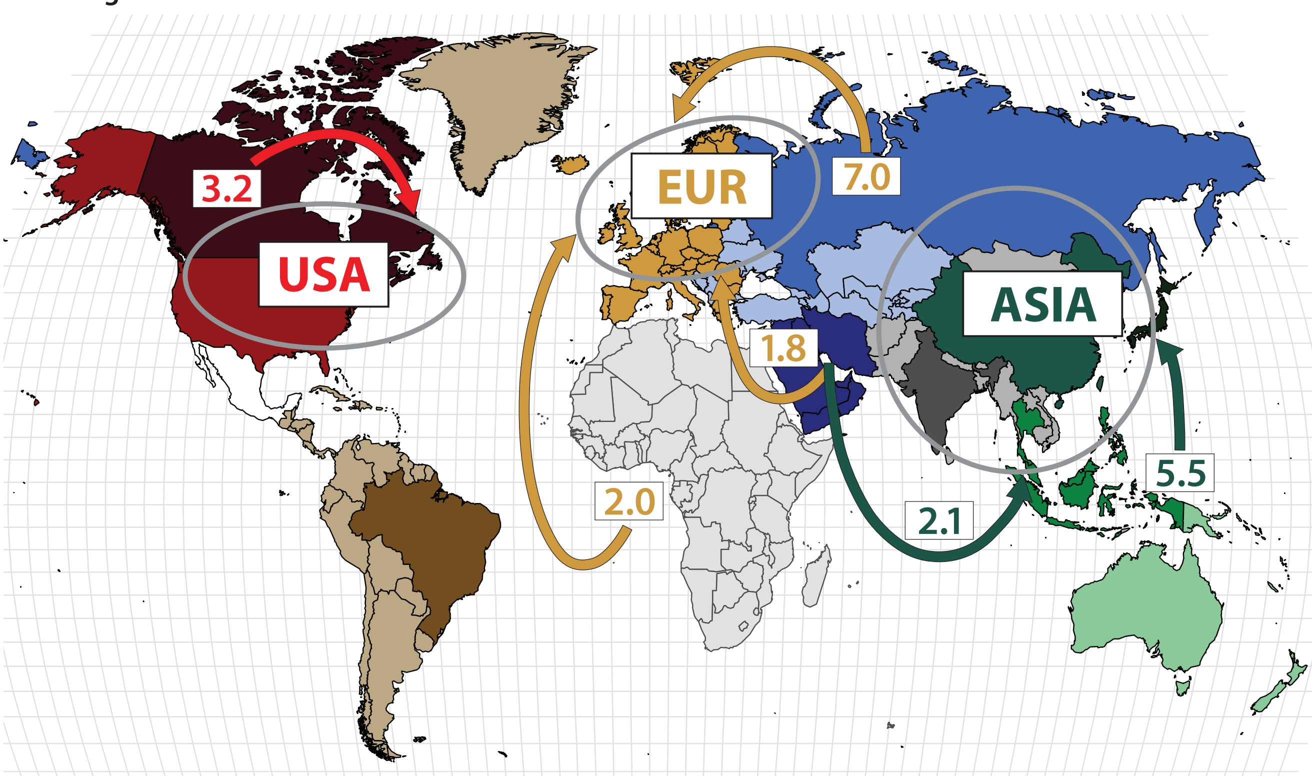
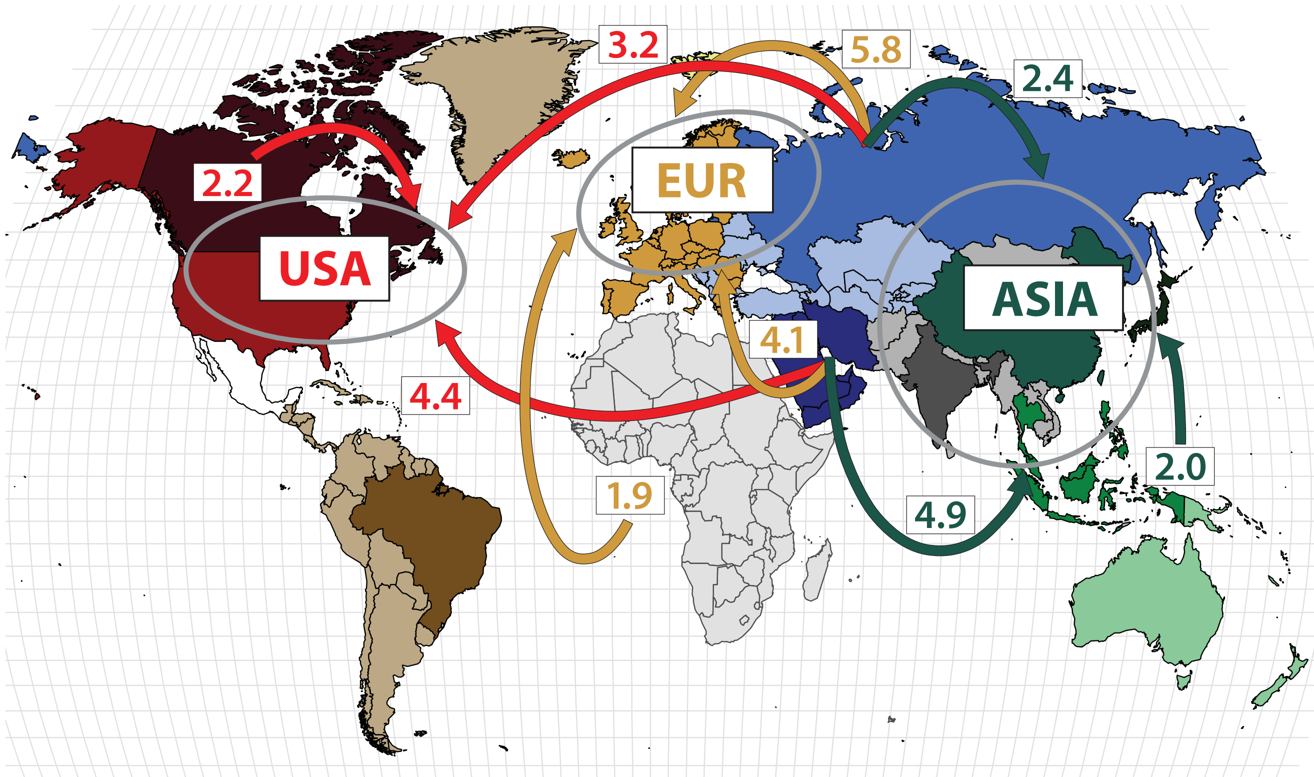


Figure 3.8 Major Trade Flows of Natural Gas among the EPPA Regions in 2030, No New Policy (Tcf) (*continued*)

3.8b Global Market



To the degree that economics are allowed to determine the global gas market, trade in this fuel is set to increase over coming decades, with implications for investment, and import dependence.

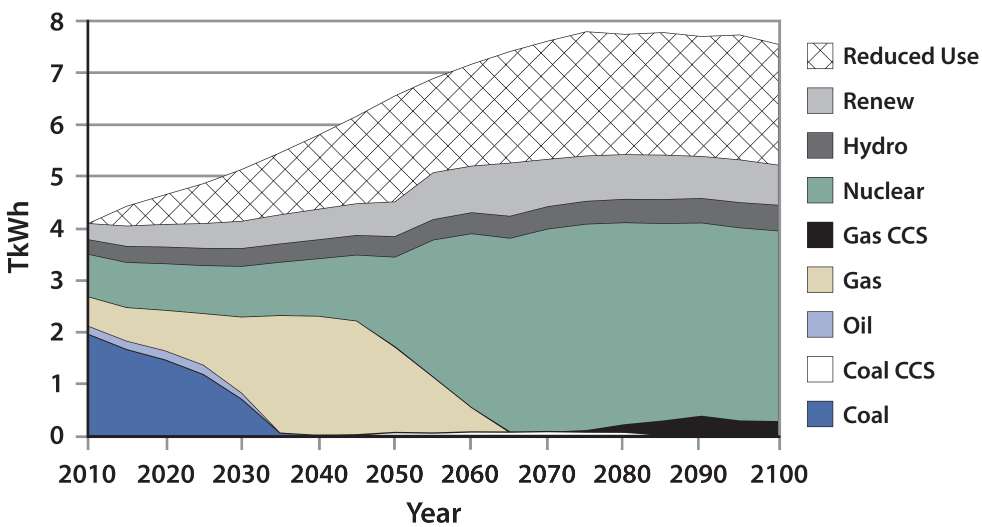
The precise patterns of trade that might develop to 2030 and beyond will be influenced by the economics of the energy industry, as captured by the EPPA model, and also by national decisions regarding gas production, imports and transport infrastructure. Therefore, the numbers shown are subject to a number of uncertainties, prominent among which is the willingness of Middle East and Russian suppliers to produce and export on the modeled economic basis. If potential supplies are not forthcoming, then global prices would be higher and the U.S. would import less than projected and perhaps increase exports. The broad insight to be drawn is nonetheless evident: to the degree that economics are allowed to determine the global gas market, trade in this fuel is set to increase over coming decades, with implications for investment and potential concerns about import dependence.

LONGER-TERM PROSPECTS FOR GAS UNDER DEEPER EMISSIONS CUTS

While current investment and policy decisions appropriately focus on a shorter horizon, policy decisions related to atmospheric stabilization of GHG concentrations inevitably involve a very long term perspective. Though gas frequently is touted as a "bridge" to the future, continuing effort is needed to prepare for that future, lest the gift of greater domestic gas resources turn out to be a bridge with no landing point on the far bank.

To explore this issue, we conducted model simulations extending the horizon to 2100 assuming GHG emissions cuts that deepen to 80% below 2005 levels. The result is that, until gas with CCS begins to penetrate after 2060, the cost of CO_2 emissions from gas generation becomes too high to support its use in generation (Figure 3.9). Nuclear is cheaper than coal or gas with CCS for much of the period and so it expands to meet the continuing electricity demand. Different cost assumptions well within the range of uncertainty would lead to a different mix of low CO_2 generation, but the picture for gas without CCS would remain the same.

Figure 3.9 Energy Mix in Electric Generation under a Price-Based Climate Policy, Mean Natural Gas Resources and Regional Natural Gas Markets (TkWh)



An implication to be drawn from this longer-term experiment is that plentiful supplies of domestic gas in the near term should not detract from preparation for the longer-term emissions challenge. Barriers to the expansion of nuclear power or coal and/or gas generation with CCS must be resolved over the next few decades so that they are capable of expanding to replace natural gas in generation. If facilitating policies are not pursued — by means of RD&D and development of regulatory structures — because of comfort with the gas cushion, then the longer-term sustenance or strengthening of an emissions mitigation regime will not be possible.

IN CONCLUSION

The outlook for gas over the next several decades is in general very favorable. In the electric generation sector, given the unproven and relatively high cost of other low-carbon generation alternatives, gas could well be the preferred alternative to coal.

A broad GHG pricing policy would increase gas use in generation but reduce its use in other sectors, on balance increasing gas use substantially from present levels.

International gas resources are likely less costly than those in the U.S. except for the lowest-cost domestic shale resources, and the emergence of an integrated global gas market could result in significant U.S. gas imports.

The shale gas resource is a major contributor to domestic resources but far from a panacea over the longer term. Under deeper cuts in CO_2 emissions, cleaner technologies are needed. Gas can be an effective bridge to a lower CO_2 emissions future but investment in the development of still lower CO_2 technologies remains an important priority.

NOTES

[1]Citations to documentation of the EPPA model and features related to this study are provided in Paltsev, S., H. Jacoby, J. Reilly, O. Kragha, N. Winchester, J. Morris and S. Rausch, 2010: The Future of U.S. Natural Gas Production, Use, and Trade. MIT Joint Program on the Science and Policy of Global Change, *Report 186*, Cambridge, MA. The USREP model is described by Rausch, S., G. Metcalf, J. Reilly and S. Paltsev, 2010: Distributional Impacts of Alternative U.S. Greenhouse Gas Control Measures. MIT Joint Program on the Science and Policy of Global Change, *Report 185*, Cambridge, MA.

[2]Reference costs are based on the data for capital and O&M cost from U.S. Energy Information Administration (EIA) *Annual Energy Outlook* 2010 Early Release. The lower sensitivity estimate is based on Update of the 2003 Future of Nuclear Power: An Interdisciplinary MIT study, Massachusetts Institute of Technology, Cambridge, MA.

[3]Reference costs are based on the EIA *Annual Energy Outlook* (see endnote 3). The lower sensitivity estimate for coal with CCS draws on The Future of Coal: An Interdisciplinary MIT study, Massachusetts Institute of Technology, Cambridge, MA; that for gas with CCS comes from McFarland, J., S. Paltsev and H. Jacoby, 2009: Analysis of the Coal Sector under Carbon Constraints, *Journal of Policy Modeling*, 31(1), 404–424.

[4]LCOE is the cost per kWh that over the life of the plant fully recovers operating, fuel, capital and financial costs.

[5]Because of the limited opportunities for gas-oil substitution the current price premium in the U.S. of oil products over gas (on an energy basis) is maintained and even grows over time. One substitution option not modeled here is the possibility of conversion of gas to liquids, which might become economic and perhaps be further stimulated by security concerns, even though making no contribution to CO_2 reduction. Such a development would raise U.S. gas use and prices, and lower oil demand with some moderating effect on the world oil price.

[6]Substitution for motor fuel is the likely target of possible expansion of gas-to-liquids technology (see Section 4). Its market penetration would depend on competition not only with oil products but also with direct gas use, biofuels and electricity which reduce CO_2 emissions while liquids from gas would not.

[7]Gas production and use with the USREP model is somewhat lower than the EPPA projection. Compared to EPPA, the USREP model has the advantage of capturing inter-regional differences in coal and gas prices, and better reflecting differences in renewable costs among regions, but it does not represent foreign trading partners. This variation introduced by the different model structures is well within the range of other uncertainties.

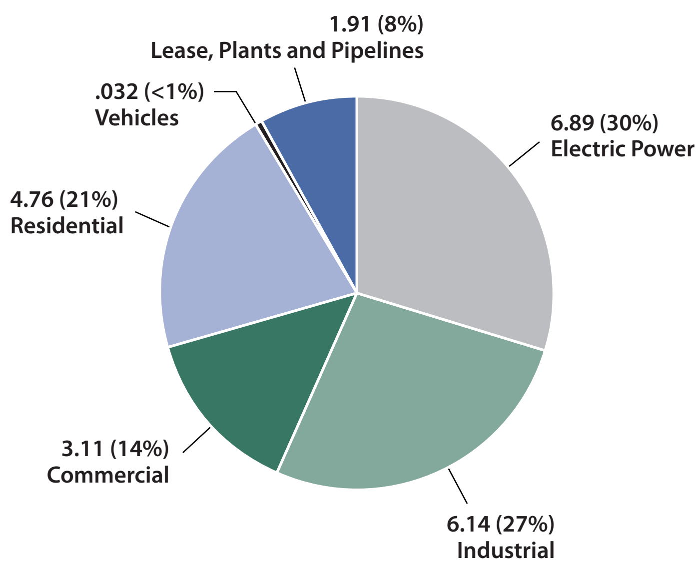
Section 4: Demand

The pervasiveness of natural gas use throughout the economy highlights both its flexibility as a fuel as well as its overall importance in the U.S. energy system. Natural gas supplies 24% of total U.S. energy consumption, or close to 23 Tcf per year. With the exception of the transportation sector, natural gas plays an important role in all end use sectors — residential, commercial and industrial — as well as in power generation (cf. Fig. 4.1).

The versatility of natural gas and its environmental performance relative to other fossil fuels enhances its desirability in a carbon-constrained environment, particularly in the near to mid term. While the full and final report will analyze the role of gas in all demand sectors, this section of the interim report focuses on power generation and transportation; these sectors represent the two most significant opportunities for additional market share for natural gas.

Figure 4.1 2009 Natural Gas Consumption by Sector (Tcf)

Net Total: 22.8



Source: EIA/Monthly Energy Review, March 2010

BOX 4.1

The MARKAL (MARket ALlocation) model of the U.S. electricity sector enables a granular understanding of generation technologies, time-of-day and seasonal variations in electricity demand and the underlying uncertainties of demand. It was originally developed at Brookhaven National Laboratory (Hamilton LD, Goldstein G, Lee JC, Manne A, Marcuse W, Morris SC, and Wene C-O, "MARKAL-MACRO: An Overview," Brookhaven National Laboratory, #48377, November 1992). The database for the U.S. electric sector was developed by the National Risk Management Laboratory of the U.S. Environmental Protection Agency.

The Renewable Energy Deployment System (ReEDS) model is used to project capacity expansions of generation, incorporating transmission network impacts, associated reliability considerations and dispatch of plants as operating reserves. It also captures the stochastic nature of intermittent generation as well as temporal and spatial correlations in the generation mix and demand. It has been developed by the National Renewable Energy Laboratory (NREL) (Logan, J., Sullivan, P., Short, W., Bird, L., James, T.L., Shah, M. R., "Evaluating a Proposed 20% National Renewable Portfolio Standard," 35 pp. NREL Report No. TP-6A2-45161, 2009).

The Memphis model realistically simulates the hourly operation of existing generation plants in the presence of significant volumes of wind and solar generation. It was developed by the Institute for Research in Technology of Comillas University (Madrid, Spain) for the Spanish Electricity Transmission System Operator (Red Eléctrica de España) to integrate renewable energies. (A. Ramos, K. Dietrich, J.M. Latorre, L. Olmos, I.J. Pérez-Arriaga, "Sequential Stochastic Unit Commitment for Large-Scale Integration of RES and Emerging Technologies," 20th International Symposium of Mathematical Programming (ISMP) Chicago, IL, USA, August 2009.

DEMAND FOR NATURAL GAS IN THE ELECTRIC POWER SECTOR

Three issues are of particular interest in influencing potential changes in the role of natural gas in electricity generation: (1) the power generation mix under carbon constraints, (2) the effect of expansion in intermittent renewable electricity generation, and (3) a possible near-term opportunity for reducing CO_2 by displacing coal generation with natural gas. In this section, we employ three models, the MARKAL model, the ReEDS model and the Memphis model to examine these issues (see Box 4.1).

As noted, this interim report focuses on areas in which there is potential for substantial increases in gas demand. The potential for demand reduction through conservation and efficiency measures as well as uncertainties surrounding demand increases in general will modify overall demand for natural gas. These issues will be discussed in greater detail in the final report.

PROFILE OF NATURAL GAS IN ELECTRIC POWER GENERATION

Natural gas used in electricity generation in the U.S. in 2009 was 30% of total gas consumption and accounted for 21% of all electricity generation.

There is currently 384 GW of installed natural gas generation capacity, 40% of the total installed generation capacity in the U.S. The natural gas generation fleet is comprised of three principal technologies. Of the total, 190 GW is NGCC, which employs two stages: a gas turbine generator and a steam turbine that recovers waste heat from the gas turbine cycle. The NGCC fleet is highly efficient, i.e., heat rates of 7,500 Btu per kWh, capable of operating at high utilization rates (e.g., capacity factors of up to 85%), and relatively new.

Another 80 GW are older steam boilers originally built for oil or dual fuels. Because these units have lower efficiencies and higher operating costs than NGCCs, they are typically utilized at lower rates. The third technology consists of 112 GW of open (or single) cycle combustion turbines, typically used for short periods during times of peak load demand and as operating reserves.[1] All three technologies are capable of "cycling," ramping production levels up or down to meet changes in electricity demand. Gas combustion turbines have the greatest cycling flexibility and thus are mainly employed during periods of peak demand, which may occur for only several hours of the day. Combined cycle technology and steam turbine technology also can be cycled, but the steam cycle typically requires more time to ramp up and down.

The order in which generation is dispatched, the so-called economic merit order, depends on the marginal cost of generation and the flexibility of different plants to efficiently follow the variability in demand, as well as other requirements. Because nuclear and large coal-based generation sources typically have low variable costs and incur performance and economic penalties in transient operation, they operate as base load units. Renewable electricity technologies such as wind and solar are intermittent generation sources, because their production levels vary with time of day and weather conditions. Intermittent wind and solar not only have virtually zero variable costs, but may also garner valuable renewable energy credits if renewable energy standards are applicable. Thus, they are normally placed at the top of the dispatch merit order when available, subject to operational constraints.

As described more fully in Section 1, the repeal of the FUA in 1987 and the deregulation of natural gas markets, spurred the growth of NGCC capacity. Of the current NGCC capacity of 190 GW, 164 GW was added after 1987. Lower than expected growth in electricity demand and a period of higher gas prices led to excess reserves in several U.S. electricity markets and left a substantial fraction of this NGCC capacity operating at much lower capacity factors than its original design basis.

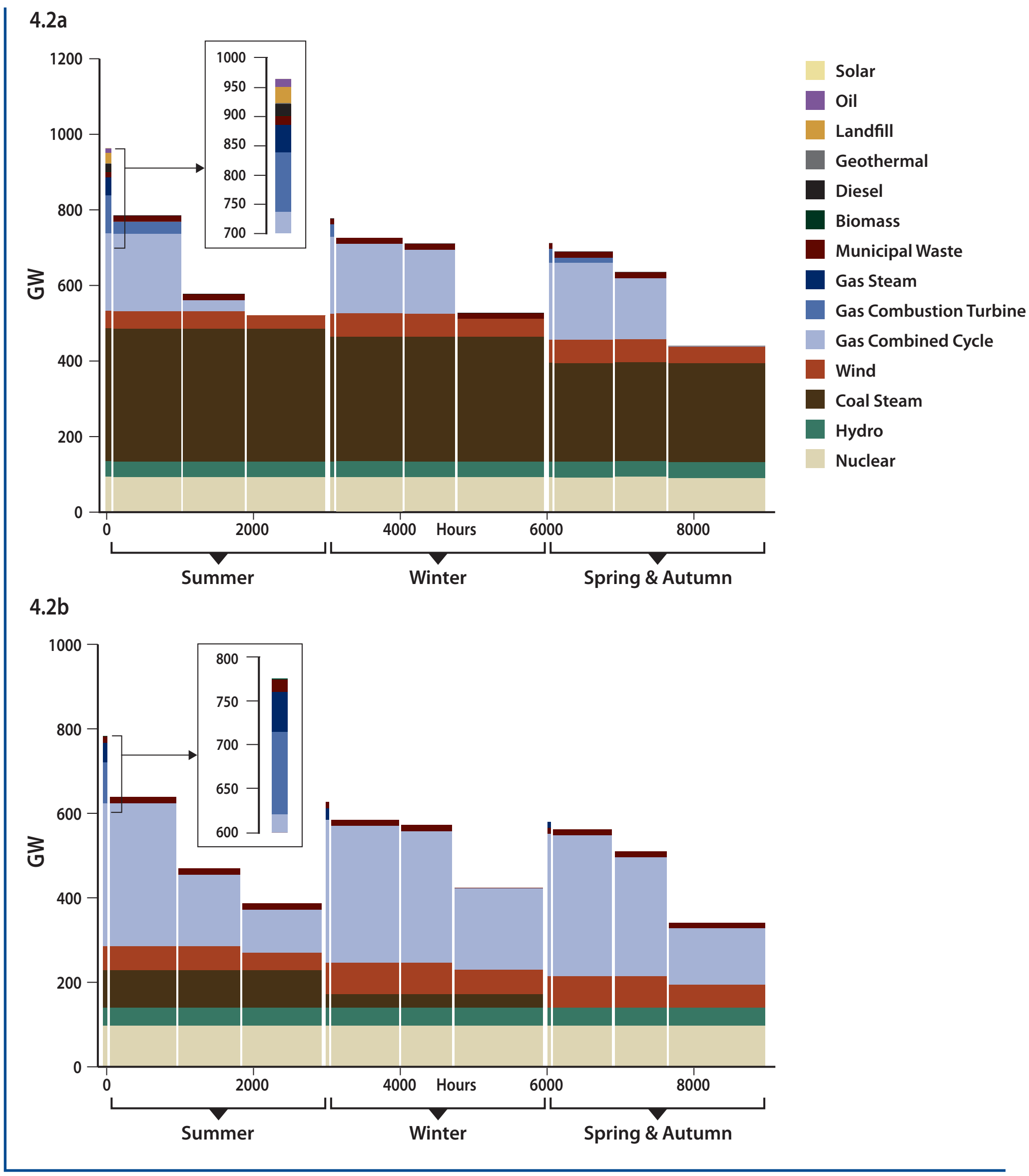
POWER GENERATION MIX

EPPA simulations described in the Section 3 of this report provide key insights about the overall use and market share of natural gas in power generation in both "no policy" and "carbon price" scenarios. Here we employ the MARKAL model to look more specifically at the power generation technology mixes.

Clearly, the amount of natural gas use in power generation is subject to numerous uncertainties in the longer term, especially the level of overall electricity demand. For consistency we have constrained the MARKAL simulations to reproduce the EPPA electricity demand and emissions results presented in Section 3. We illustrate the underlying technology mix computed by the MARKAL analysis by means of annual load duration curves, which show the mix of generation dispatched at different times to meet changes in the level of electricity demand over the course of a year. The estimated load duration curves for the year 2030, with and without a policy of carbon constraints, are shown in Fig. 4.2 on the next page. In the absence of a carbon policy (panel a), generation from coal and nuclear occur at all times of the year while generation from wind and hydro are supplied whenever they are available.

Natural gas generation from combined cycle and steam turbines occurs for less than half of the time over the course of the year during periods of increased demand, and natural gas combustion turbines are used for only a few hours per year at the peak demand hours. Under the carbon price policy (panel b), natural gas combined cycle technology largely substitutes for coal to provide base load generation along with nuclear.

Figure 4.2 Load Duration Curve for the (a) No Policy and (b) 50% Carbon Reduction Policy Scenarios in 2030. There are three seasonal categories: summer, winter and spring/autumn. Within each seasonal grouping, there are four time slices: peak time, day time PM, day time AM, and night time, corresponding to the four blocks within each seasonal category as shown in the graphs. The peak time slice is very narrow.



INTERMITTENT RENEWABLE ELECTRICITY SOURCES AND NATURAL GAS DEMAND

The introduction of significant amounts of intermittent wind and solar power to the electricity generation mix adds variability and uncertainty to the dispatch of other generating technologies. Our analysis focuses on the impact of this variability and uncertainty on both the levels and patterns of demand for natural gas in power generation. The impacts are quite different in the short term, during which the response to intermittency is through the dispatch pattern of existing generation capacity, and in the long term, during which capacity additions and retirements are also responsive to large-scale introduction of intermittent capacity:

- In the **short term**, the principal impact of increased generation from intermittent renewable energy sources is the displacement of the existing generation with the highest variable cost, which in most U.S. markets is natural gas.

- In the **long term**, more production with wind and solar will reduce and alter the pattern of demand to be met by the remaining technologies, adapted to the system requirements. The composition of this mix will critically depend on the energy policy scenario.

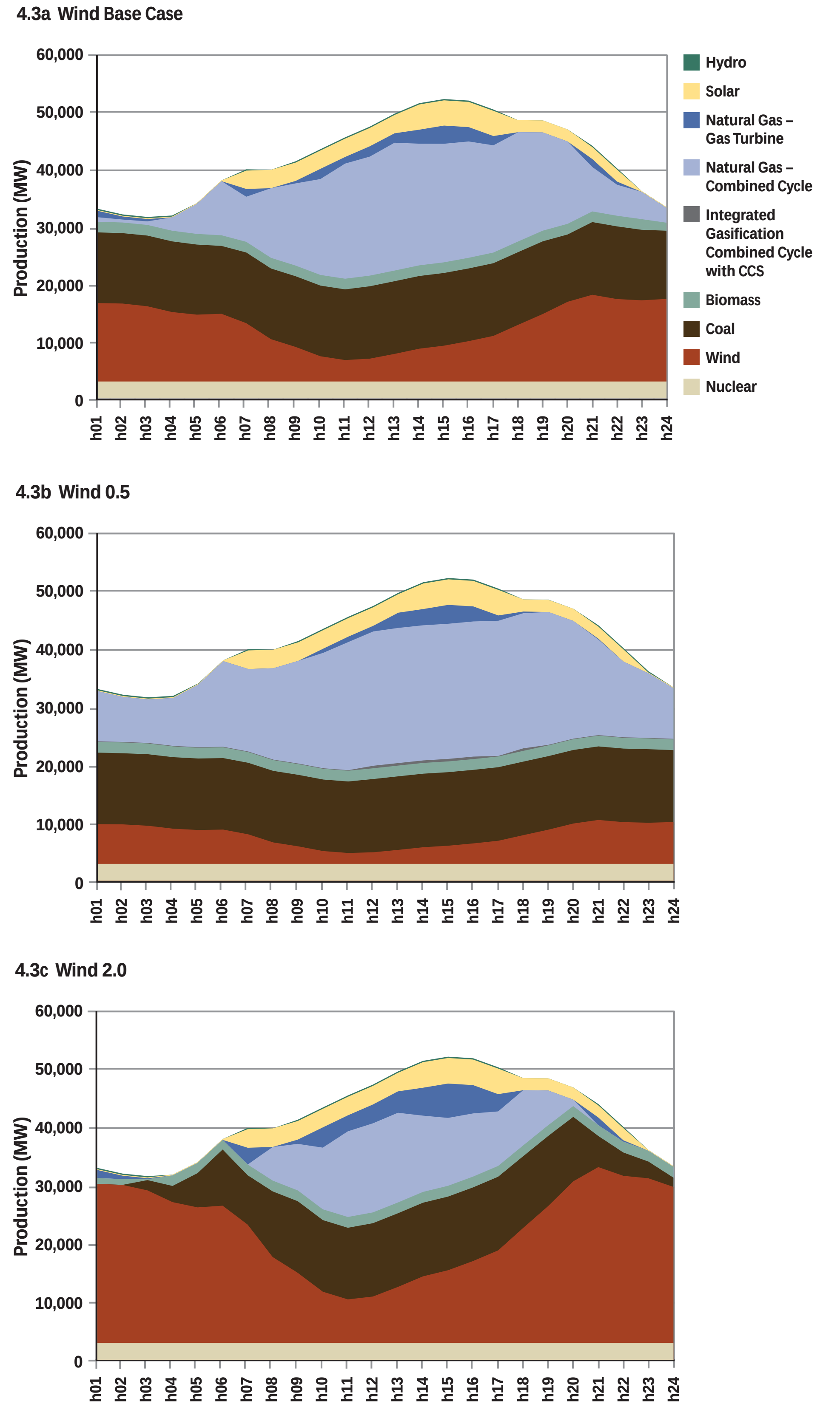
As a general rule, more production with renewable generation will have two likely outcomes in the long term: First, increased intermittent renewable electricity generation will be accompanied by more installed capacity of flexible plants — mostly natural gas — but typically with low utilization. Second, this combination of intermittent renewable and flexible electricity plants will displace future installed capacity and production of base load generation technologies.

To elucidate the short-term effects, we used the Memphis model to analyze daily dispatch patterns for the Electric Reliability Council of Texas (ERCOT). The ERCOT region is advantageous to analyze, since it is largely independent of the transmission grid connecting other parts of the country, but the results should not be taken as representative for every region.

For this analysis, we used a projected 2030 generation portfolio, obtained from a ReEDS carbon price policy scenario. The 2030 generation portfolio includes nuclear and coal (including some with CCS) base load contributions, natural gas, wind, solar plus some additional contributions that are not material to our discussion. Wind and solar contribute 23% and 5%, respectively, of total annual generation.

In the base case, the night time load for a representative day is met by base load plus wind generation, without appreciable gas (because of its higher variable cost). This is seen in panel (a) of Figure 4.3.

Figure 4.3 Impact of Wind on a One-Day Dispatch Pattern



Panels (b) and (c) of Figure 4.2 show the hourly dispatch results when wind produces half or twice the base case amount, respectively:

- With less wind, natural gas combined cycle capacity is employed to meet the demand and the base load plants continue to generate at full availability.
- With twice as much wind, natural gas generation is reduced significantly and the base load coal plants will be forced to cycle because of the relatively low night time demand.[2]

The pattern with solar is somewhat different, because the solar generation output coincides with the period of high demand. Not surprisingly, the natural gas plants are used more when solar output is less, and vice versa. The base load plants are largely unaffected. These results will be discussed more completely in the full report.

Table 4.1 summarizes these short-term dispatch impacts for an entire year with the same 2030 generation portfolio. The reductions in generation for coal and gas are shown for an additional unit of output (e.g., 1 GWh) of wind or solar generation in a year, for the specific energy technology mix that was analyzed. The largest effect is that gas, with the highest variable cost, is displaced; this displacement is greater for solar (0.90 GWh) than for wind (0.65 GWh). Increased wind also displaces some coal production (0.33 GWh).

Table 4.1 Short term sensitivity of the annual production of various generating technologies to an increment of +1 GWh in the production of wind or concentrated solar power (CSP) for the ERCOT example. Only technologies that change are listed.

	Old Coal No Scrubber	Old Coal Biomass	Coal IGCC CCS	Gas GT	Gas NGCC	Gas NGCC CCS	Oil-Gas	Biomass
Wind (GWh)	-0.18	-0.11	-0.04	-0.01	-0.63	0 .00	-0.01	-0.03
CSP (GWh)	-0.07	-0.02	0.00	-0.22	-0.60	-0.01	-0.07	0 .00

In the **longer term**, large-scale penetration of intermittent renewable electricity supply, regardless whether it is policy or economically driven, assumes a base load role, which must be complemented with flexible natural gas generation as it reduces the need for other base load technologies. In particular, this will result in less new installed capacity of and production from the base load generation technology "at the margin," which, depending on costs and environmental targets, would typically be nuclear or coal. It could also be NGCC, if new investment in coal happens to be limited because of CO_2 restrictions or if the economics or additional investment restrictions favor gas over nuclear generation.

In this scenario of large growth of renewables, the increased need for natural gas capacity — because of its cycling capability and lower capital cost to provide reserve capacity margins — does not necessarily translate into a sizeable utilization of these gas plants. This new operation regime raises concern about attracting sufficient investment in gas-fueled plants under competitive market conditions, so that an acceptable system reliability level can be maintained.

This issue is presently being addressed by several European countries with significant penetration of wind generation, where the patterns of production of NGCC and gas turbines (GT), and also of some base load technologies, have already been affected. Similar situations are already developing in some parts of the U.S. Presently there is no consensus on a suitable regulatory response to this situation, which could include enhancements of any capacity mechanisms such as those already in place in most U.S. wholesale markets, new categories of remunerated ancillary services or other instruments.

RECOMMENDATION

In the event of a significant penetration of intermittent renewable production in the generation technology mix, policy and regulatory measures should be developed (e.g., ancillary services compensation) or adapted (e.g., capacity mechanisms) to facilitate adequate levels of investment in natural gas generation capacity to ensure system reliability.

NEAR-TERM OPPORTUNITIES FOR REDUCING CO_2 EMISSIONS: DISPLACING LESS EFFICIENT COAL GENERATION WITH GAS GENERATION

We have seen that displacement of coal by natural gas in the power sector is an important contributor to CO_2 emissions reduction. The overbuilding of natural gas combined cycle plants starting in the mid-1990s may present an opportunity for reducing CO_2 emissions in the near term without major capital investment in new generation capacity.

The current fleet of NGCC units has an average capacity factor of 41%, relative to a design capacity factor of up to 85%. However, with no carbon constraints, coal generation is generally dispatched to meet demand before NGCC generation because of its lower fuel price.

As previously noted, there must always be capacity that has the ability to respond to variations in demand and production as well as to forecast errors, even if that generation capacity is used well below its overall generation potential. Nevertheless, there may be a significant opportunity for reducing emissions by displacing less efficient coal generation through the increased utilization of existing NGCC plants.

In this section, we seek to explore:

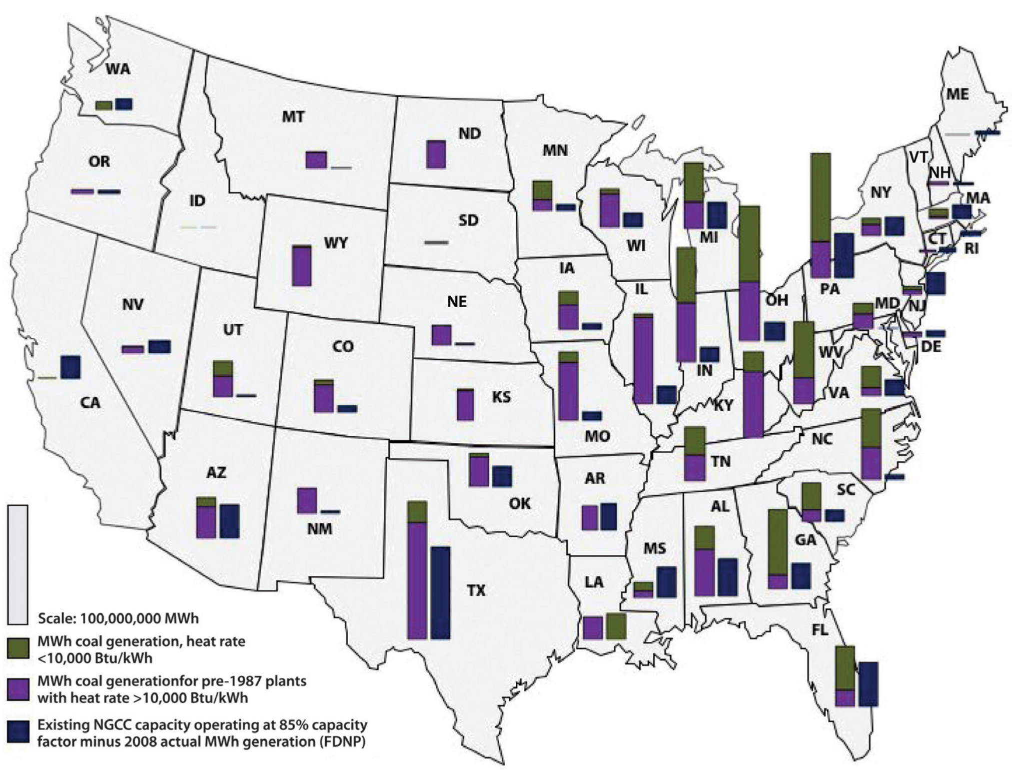
- on a national basis, the location and upper limits of potential opportunities for coal generation displacement;

- then for a particular case study of the ERCOT market;
  – the impact on the dispatch order if a carbon price or limitation of some sort were imposed on the electricity sector;
  – the degree to which gas generation might displace coal, while still meeting peak requirements;
  – the level of CO_2 emissions reductions that might be achieved; and
  – the incremental natural gas supply that would be needed to satisfy the associated increase in demand.

Figure 4.4 sets a scale and location of this potential opportunity. It shows the geographic distribution of fully dispatched NGCC potential (FDNP), defined as the difference between the electricity that would be produced by NGCC plants at an 85% capacity factor and the 2008 actual MWh generated by NGCCs.[3]

Figure 4.4 also shows the geographic distribution of coal generation. For purposes of this figure, we divided the coal generation into less and more efficient coal generation, where "less efficient" is defined as a coal unit with a heat rate over 10,000 Btu/kWh built before 1987,[4] when the FUA was repealed.

Figure 4.4 Scale and Location of Fully Dispatched NGCC Potential and Coal Generation (MWh, 2008)



We stress that FDNP does not equate to "surplus" generation capability, as the figure represents only the average potential available over the course of the year and does not reflect demand for NGCC generation to meet peak loads. Therefore, FDNP only provides an upper limit of the substitution potential.

Even with these qualifications, however, Figure 4.4 indicates that, in many instances, FDNP generation matches well with less efficient coal capacity, suggesting that there may be opportunities to displace inefficient coal capacity in certain geographic locations. It also shows locations where there are few displacement opportunities. For example, Southeastern states such as Texas, Louisiana, Mississippi, Alabama and Florida appear to have relatively larger opportunities, while the opportunities in Midwestern states such as Illinois, Indiana and Ohio appear to be relatively smaller. Clearly, further fine-grained analysis is needed to understand actual displacement potential.

To explore this potential, we have used the ReEDS model that more closely approximates a dispatch profile that might occur over the course of a year. We carried out an initial case study using the ERCOT market, both because the ERCOT transmission system is practically isolated and, as indicated in the Figure 4.4, there appears to be significant potential for displacing less efficient coal with gas in ERCOT.

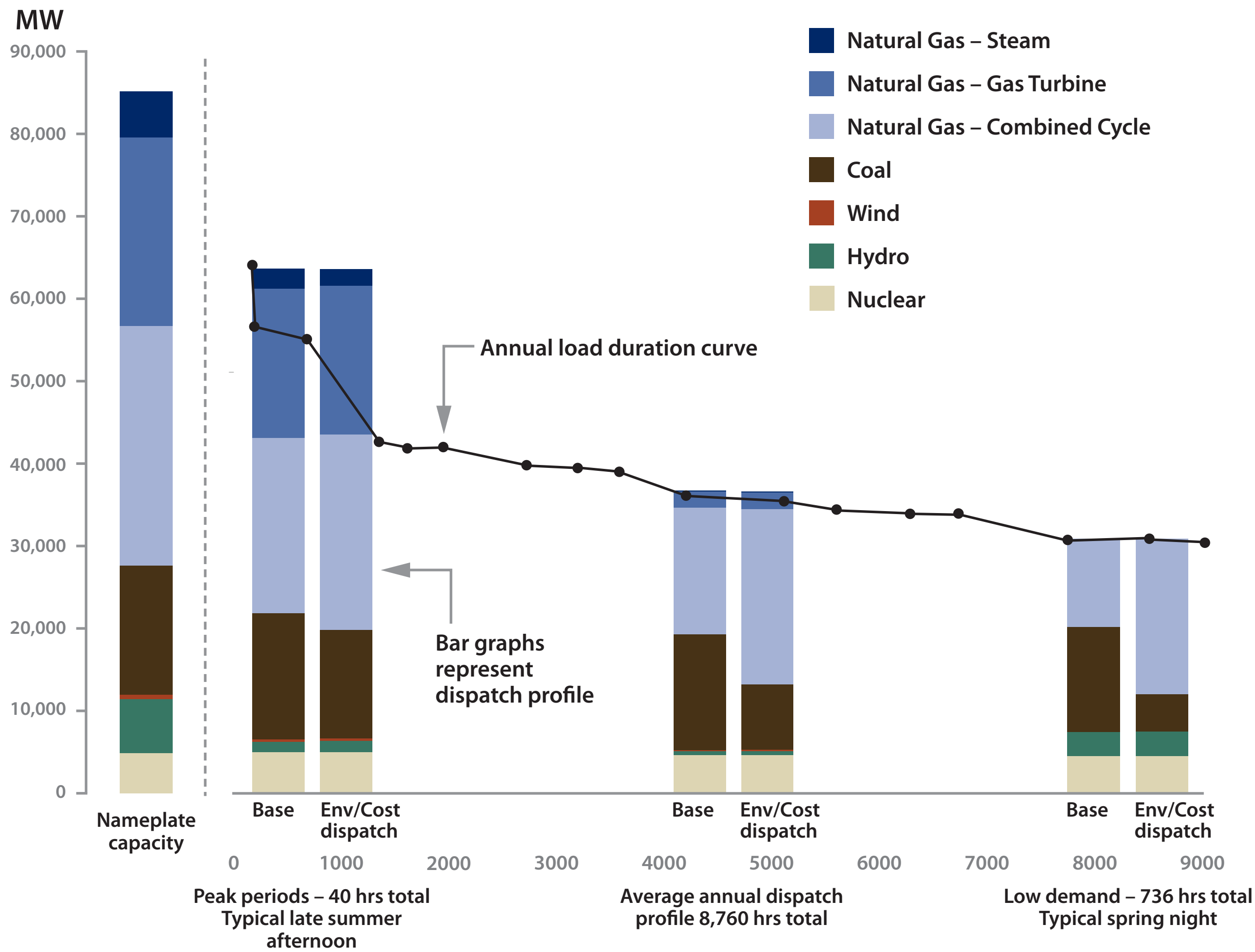
The potential for transmission over multi-state areas by Regional Transmission Operators (RTO) in other regions, especially in the Eastern interconnect, implies increased opportunities for NGCC displacement. On the other hand, ERCOT has significant reserve capacity and atypical amounts of FDNP generation capacity.

We represent 2008 electricity demand by an annual load duration curve, comprised of 17 blocks that correspond to the average level of demand during representative periods of time over the course of a year.

We then tested the potential for displacement of coal with NGCC generation by using ReEDS as a dispatch model under both an unconstrained scenario and a carbon constrained scenario.[5]

Figure 4.5 compares how existing capacity would be dispatched to meet 2008[6] actual demand with and without carbon constraints for (a) the annual average and (b) two selected slices of the annual load duration curve (i.e., the annual peak load period plus a time period of low demand). The results indicate that *opportunities for displacement of coal generation exist in all demand periods*. The greatest opportunity occurs during periods of low demand, where the largest amount of coal capacity can be displaced by additional natural gas generation. Even during periods of peak demand, however, there is an opportunity for some displacement of coal by gas, albeit small.

Figure 4.5 Changes in Dispatch Order to Meet ERCOT's 2008 Demand Profile with and without Carbon Constraint



The analysis also shows that some portion of existing coal capacity is dispatched during all demand periods, while some is shifted, in general, to seasonal operation.

In the short-term time horizon of this analysis, it is assumed that all existing coal capacity remains in service but is dispatched less frequently. Over a longer period of time, as new capacity additions of various technologies enter into service, some of this coal capacity could be permanently retired and replaced with new generation capacity additions, the choice of technology depending upon demand requirements and the cost effectiveness of the new generation alternatives. We note that new natural gas units, whether NGCC or open cycle gas turbines, have low capital costs and short construction times compared to coal or nuclear generation so that new natural gas capacity can be added relatively easily to meet demand.

For this ERCOT case study, results indicate that a coal to gas displacement strategy could reduce power sector CO_2 emissions by about 22%, and demand for natural gas in the ERCOT electricity generation market would increase by 0.36 Tcf/year. The cost of CO_2 reductions in this option directly depends on the differential in fuel and variable O&M costs between natural gas and coal.

Increased utilization of NGCC capacity presents an opportunity to achieve significant carbon reductions in the electric power sector in the near term, while ensuring adequate capacity to meet peak demand.

While the quantitative results of the ERCOT modeling work cannot be extrapolated to the entire U.S. market, the direction of the analysis appears to be representative. Preliminary results from extending this modeling analysis nationwide suggests that a near-term initiative to displace coal generation with additional generation from existing natural gas combined cycle capacity could result in reductions in power sector CO_2 emissions on the order of 10%.

An additional potential benefit of displacement of coal generation with gas will be the reduction in mercury and criteria pollutants regulated under the Clean Air Act.

This is of sufficient scale in the context of near-term GHG emissions reduction to merit detailed analysis for the national power system. Extending this modeling to the entire U.S. market requires further analysis of transmission constraints, dispatch operations, natural gas deliverability and economic impacts, and other technical issues. Several policy measures could be used to implement a coal to gas shift.

RECOMMENDATION

Coal generation displacement with NGCC generation should be pursued as a near-term option for reducing CO_2 emissions.

DEMAND FOR NATURAL GAS AS A TRANSPORTATION FUEL

Transportation fuel currently accounts for only 0.15% of total U.S. demand for natural gas. However, this sector represents an area of possible growth in natural gas consumption.

CNG Powered Vehicles

Use of CNG as a vehicular fuel is well established and growing worldwide. Increased use of natural gas to provide a vehicular fuel in the U.S., either directly or perhaps indirectly by conversion into a liquid fuel, could be driven by lower prices for natural gas relative to oil and by policies aimed at reducing oil dependence and GHG emissions. CNG use reduces GHG emissions by around 25% relative to gasoline.

Although CNG is less expensive than gasoline on an energy basis, use of CNG requires significant additional upfront vehicle costs (mainly the cost of onboard CNG storage). Thus, a key factor in CNG vehicle market penetration is the time to pay back the higher cost of a CNG vehicle with lower-priced natural gas. There are two vehicle market segments likely to offer an attractive payback period in the near term: high-mileage, light-duty fleet vehicles (e.g., taxis, government vehicles) and high-mileage, non-long-haul, heavy-duty vehicles (e.g., urban buses, delivery trucks). These two market segments have a total potential (assuming 100% penetration in these market segments and current vehicle efficiencies) of approximately 3 Tcf/year (equivalent to around 1.5 million barrels of oil/day), of which approximately $1/3$ is for light-duty vehicles and $2/3$ for heavy-duty vehicles.[7]

CNG personal transportation vehicles in the U.S. currently have very high incremental costs. The only factory-produced CNG vehicle, the Honda GX, has an incremental cost relative to a gasoline vehicle of around $5,500 in comparison to around $3,700 for the European VW Passat TSI Eco-fuel. In addition, the Honda GX offers only natural gas operation, whereas VW and Fiat offer bi-fuel natural gas-gasoline operation, which significantly increases flexibility, particularly for non-fleet drivers. U.S. certified aftermarket conversions of gasoline engine vehicles to provide CNG operation cost around $10,000, in contrast to around $2,500 for conversions meeting European standards.

The economic attractiveness of CNG vehicles is determined by vehicle incremental cost, mileage driven per year and gasoline-CNG fuel price spread. Table 4.2 illustrates the effects of these factors on payback time for light-duty vehicles. Previous studies have shown that payback times of three years or less are needed for substantial market penetration.[8] For recent fuel price spreads, low vehicle incremental cost (e.g., $3,000) and high mileage are necessary to meet this requirement. Also, the rate of penetration of CNG vehicles, even if economic, will depend on the provision of refueling infrastructure.

Table 4.2 Payback times in years for CNG light-duty vehicle for low- and high-incremental costs and U.S. fuel price spreads over the last 10 years. Fuel price spreads between gasoline and CNG are on a gallon of gasoline equivalent (gge) basis. The present fuel price spread, assuming $2.75 per gallon for gasoline and residential gas at the consumer level of $12 per Mcf, is around $1.30/gge. Payback periods are provided for average and high-mileage cases. The table assumes 30 miles per gallon.

		12,000 miles per year		35,000 miles per year	
Fuel Price Spread	Incremental Cost	$3,000	$7,000	$3,000	$7,000
	$0.50	15	35	5.2	12
	$1.50	5	11.7	1.8	4

The table does not include the effect of a carbon tax or a subsidy (although a subsidy can be accounted for by including it in the incremental cost to the consumer). For the illustrative case in Table 4.2, the use of CNG rather than gasoline reduces CO_2 emissions by about 1 ton/year for the average mileage (12,000 miles/year) light-duty vehicle. Even for a high CO_2 price of $100/ton, the impact would be only around $100/year and would thus have a only a small impact on the achievement of a three-year payback time for a $3,000 incremental cost.

If the gasoline-CNG price spread were to increase beyond recent levels, the payback time for the average mileage CNG vehicle could decline and support greater penetration in this large market segment. An increase in the gasoline-CNG fuel price spread could occur either through an increased oil-natural gas price spread, or a CO_2 price, or availability of natural gas for CNG vehicles at lower than residential rates. The carbon policy scenario explored in Section 3, using optimistic cost estimates for CNG vehicles, leads to a 20% penetration into the private vehicle fleet by 2040–2050.

RECOMMENDATION

The U.S. should review its current policies on aftermarket certification of CNG conversions with a view to reducing CNG vehicle upfront costs to comparable European levels.

LNG Powered Long-Haul Trucks

LNG has been proposed as a fuel for long-haul trucks since it provides greater range than CNG. However, present opportunities for LNG-powered long-haul trucks appear to be very limited. This is due to high incremental costs (e.g., $70,000), operational issues related to fuel storage at -162° C (particularly venting of natural gas) and fueling infrastructure requirements. The American Trucking Association, representing concerns of the user community, has stated that natural gas powered trucks are currently not a viable solution for most long-haul trucking operations for these technical reasons and because of the concern that the high cost of LNG fueling infrastructure will limit competition in LNG fuel supply.[9] Industry is working on reducing the incremental cost and improving the operational features of cryogenic storage.

Conversion to Liquid Fuels

Natural gas use in transportation could potentially develop into a substantial market and have an important impact in reducing U.S. oil dependence if natural gas could be economically converted into a (room temperature) liquid fuel that could be used in a way similar to present liquid fuels (diesel, gasoline and ethanol). In this case, there would be at most a minimal incremental vehicle cost and a relatively modest required modification to the present fueling infrastructure.

A range of liquid fuels can be produced by thermochemical conversion of natural gas to a synthesis gas followed by catalytic conversion to the liquid fuel. These fuels include diesel produced by the Fischer-Tropsch process, methanol, mixed alcohols (methanol, ethanol and others), ethanol, gasoline and dimethyl ether (which, like propane, requires modest pressurization to remain liquid).[10] Among these conversion processes, the only one that has been established at large industrial scale over a long period, with well established costs, is the natural gas to methanol conversion (for purposes other than transportation). It is the liquid fuel that is most efficiently and inexpensively produced from natural gas. Overall GHG emissions are basically the same as gasoline, but natural gas derived methanol could also serve as a bridge to low-carbon methanol from a variety of biomass feedstocks. In contrast, natural gas derived diesel is considerably more costly, and there is a substantial increase in GHG emissions from the conversion process and the higher carbon content of diesel. In addition, methanol has high-octane numbers and can be used like gasoline and ethanol in spark ignition engines, which have very low emissions of nitrogen oxides and other pollutants.

Natural gas based methanol may offer an option to substantially increase natural gas use in transportation and add support to decrease oil dependence. It is essentially CO_2 emissions neutral relative to gasoline.

Dimethyl ether (DME) is another fuel that is produced with relatively high efficiency, with methanol as an intermediate step. DME is a cleaner burning fuel than diesel for compression ignition engines. However, DME has the drawback of requiring pressurization, similar to propane. Natural gas can also be converted into gasoline, but this conversion reduces efficiency and increases cost.

Because of the low energy cost of natural gas relative to oil, natural gas derived methanol could be an economically attractive fuel for both light- and heavy-duty vehicles at present oil prices. In contrast to advanced biofuels (such as cellulosic ethanol) and electrically powered vehicles, the basis for the economic viability for methanol as a transportation fuel is much better established.

Methanol could be used in flexible-fuel, light-duty vehicles in a manner similar to present ethanol utilization with minimal incremental vehicle cost.[11] The incremental cost relative to gasoline-only operation would likely be less than $300. These flexible-fuel vehicles could be operated on various mixtures of methanol, ethanol and gasoline. Presently flexible-fuel vehicles are not equipped to operate on methanol. Removing this barrier through the adoption of some type of open fuel standard would be needed for methanol use to be pursued on a level playing field.

Methanol could also be used in various combinations with gasoline and ethanol to power heavy-duty vehicles, utilizing high compression ratio, turbocharged direct injection spark ignition engines for diesel-like efficiency and torque, at lower cost, and with lower emissions and more power. These advantages can be used to compensate for the much lower energy density of methanol relative to gasoline.[12] The energy security benefit of methanol use would be reduced oil dependence and the ability to substitute alternative liquid fuels for gasoline in flexible-fuel, light-duty vehicles and for diesel in heavy-duty vehicles.

DEMAND FOR NATURAL GAS IN THE INDUSTRIAL SECTOR

Industrial uses of natural gas accounted for 6.1 Tcf in 2008, (excluding natural gas used in oil and gas field production and processing operations). The sector is characterized by a very large number of end users and a few dominant industries. The chemicals sector is the most important component of industrial natural gas consumption, consuming 35% of industrial gas, followed by food production (9%), paper production (7%) and iron and steel mills (6%).[13] Natural gas is used in the industrial sector both as a source of fuel and as a chemical feedstock.

Demand for natural gas in this sector has exhibited the greatest changes over time of any market sector, decreasing significantly in early 1980s, then increasing late in the decade and into the early 1990s, and steadily decreasing from a peak in 1997.

In this interim report, we identify several trends and issues that will affect demand for natural gas in this sector. We will provide estimates of the magnitude of the impact on gas demand in the final report.

- **Off-shoring of the chemicals industry:** We illustrate the issues of off-shoring with ammonia, chosen for a case study because it is the largest industrial consumer of natural gas. Indeed in the U.S. in 2007, the manufacturing of ammonia represented 5.7% of industrial consumption and 1.6% of total consumption, even though domestic production accounted for only 60% of domestic consumption. Between 1990 and 2007, the number of producing ammonia plants in the U.S. decreased from 45 to 22. In the full report, we will provide more details on this case study, including implications for ethanol production. Off-shoring has not only reduced U.S. industrial demand for natural gas, but also has diminished an important export industry in value-added chemical products. While the prospect of increased domestic supply at reasonable prices offers the prospect of stabilizing the industry, our initial assessment is that any new capacity construction in the U.S. will likely be limited to the needs of the domestic market and not sized for exports. Other fundamentals, such as distance to market, will offset any advantage of lower domestic natural gas prices.

- **Increased energy efficiency in industry:** Many businesses have come to recognize that energy efficiency is a business opportunity in its own right and have become aggressive in pursuing energy efficiency opportunities.[14] An example is Dow Chemical Company, which undertook an aggressive 20% reduction in energy use per pound of product during the decade ending in 2005, and is now embarked on a second 10-year project of reducing energy consumption per pound of product by an additional 25%.[14] The importance of these energy reductions to Dow are underscored by their allocating half of their costs to energy molecules, one-third for energy and two-thirds for feedstocks. Many industries are examining opportunities to convert wastes into electricity and process steam. These trends will reduce industrial demand for both electricity and natural gas.

In discussing natural gas supplies for the chemical industry, it is important to consider the composition of the gas as a feedstock and the amount of natural gas liquids (NGLs). Industry is the principal customer for natural gas liquids, an important value-added by-product from the production of "wet" natural gas resources.

Historically, the principal market for NGLs has been in the production of ethylene, which is currently the largest-volume petrochemical produced worldwide and is a basic building block for a wide variety of chemical products. Ethylene can be produced from either natural gas liquids or naphtha, and most U.S. facilities are equipped to handle either feedstock. The choice of feedstock has been a function of price. Given ample supplies of natural gas liquids, the U.S. cost advantage over Europe and Asia in producing and exporting ethylene is likely to continue.

Given ample supplies of natural gas liquids, the U.S. cost advantage over Europe and Asia in producing and exporting ethylene is likely to continue.

DEMAND FOR NATURAL GAS IN THE RESIDENTIAL AND COMMERCIAL SECTORS

In 2009, the residential and commercial sectors accounted for 7.9 Tcf/year, or 34% of total U.S. natural gas use. Space and hot water heating account for over 90% of use in the residential sector and 78% in commercial. About 70% of total electricity demand is in service to residential and commercial buildings, so taking into account the natural gas used in electricity generation, the direct and indirect natural gas demand associated with buildings accounts for 55% of total U.S. demand.[15]

There is a long-term historical trend toward increased efficiency in natural gas use in buildings. Since 1980, natural gas consumption per residential customer declined by 1% annually, doubling to 2.2% annually in the period 2000–2006.[16] Improvements in end-use efficiency, combined with population shifts to warmer climates, have offset increased demand associated with population growth and new household formation. Consequently, overall demand for natural gas in the residential sector has been relatively flat. In the commercial sector, a review of historical trends indicates that increases in commercial space due to population and GDP growth have been partly offset by improvements in end-use efficiency.

In this section, we summarize the results of initial analyses of effect of potential future improvements in energy efficiency on natural gas demand in the residential and commercial sectors. Our analysis, which will be presented in greater detail in the final report, focuses on government regulatory policies to improve energy efficiency. Financial incentives, including direct federal subsidies, tax credits and subsidized financing arrangements, also play an important role.

Initial analysis suggests that energy-efficiency policies and regulations will likely lead to demand reductions in the range of 1–2 Tcf/year by 2030. These could take place even if there were no policy on carbon emission reductions. Three examples are summarized here:

- Natural gas heating and hot water are subject to increasingly stringent federal efficiency standards. Residential gas furnaces sold today meet or exceed the current 80% annual fuel utilization efficiency (AFUE) standard, and at least one state has requested DOE permission to raise the standard to 90% AFUE. A complete stock turnover of gas furnaces at the 90% AFUE level could reduce natural gas consumption by about 0.4 Tcf/year.

- Model building codes are becoming more stringent. States and local governments generally follow the model codes recommended by technical organizations, and some states are adopting "stretch" codes that exceed the model code recommendations.[17] Initial analysis suggests that adoption of stretch model codes to all new buildings and major rehabilitation projects could reduce demand for natural gas in buildings (including demand for natural gas in electricity generation) by about 1 Tcf/year by 2030.

- Some states have set state-level targets for local natural gas distribution companies to reduce demand. Twenty-four states have adopted Energy Efficiency Resource Standards (EERS) for electricity, and most have separate targets for natural gas savings. Michigan, for example, set an annual natural gas savings target of 0.75% of sales by 2012, whereas Delaware has a goal of 10% natural gas consumption savings by 2015.[18]

As part of the final study, we will report on analyses of: other energy efficiency policy and regulatory options; full fuel cycle efficiency standards for appliances using either natural gas or electricity; the impacts of technologies that may increase the demand for natural gas in residential and commercial applications, including deployment of small scale combined heat and power and the suite of technologies, such as fuel cells, that comprise distributed generation.

NOTES

[1]An additional 1,971 MW of natural gas fired internal combustion engines are also included in the statistics on the U.S. electric power generation fleet.

[2]Note that a block representation of the demand duration curve, as in Figure 4.2, can only capture the average value of the many hours comprising each block, whereas Fig. 4.3 shows the chronological hourly production pattern of wind for a representative day.

[3]Both the NGCC data and coal plant data are from EIA's 2008 database and are based on MWh of generation of over 16,000 plants in the U.S. Data exclude NGCC units with nameplate capacity of under 50 MW.

[4]This is in contrast to NGCC units, which have an average heat rate of 7500 Btu/kWh.

[5]In the carbon constrained scenario, the constraint on carbon emissions results, in the near term (where existing capacity is fixed), in the dispatch of additional natural gas combined cycle generation from existing plants, displacing coal generation.

[6]In 2008, the U.S. economy was in recession, raising concerns that generation in that year might be low. In 2008 there was 404 TWh of total generation in Texas, which predominantly falls under ERCOT. This compares to 405 TWh in 2007 and an average over the 2004–2008 period of 400 TWh.

[7]P.J. Murphy, "Natural Gas as a Transportation Fuel," MS Thesis, MIT, June 2010.

[8]Yeh, S. "An Empirical Analysis on the Adoption of Alternative Fuel Vehicles: The Case of Natural Gas Vehicles," Energy Policy, 35(11): 5865-5875, 2007.

[9]American Trucking Association, Statement submitted to the U.S. Senate Committee on Energy and Natural Resources on the use of natural gas as a diesel fuel substitute, November 10, 2009.

[10]A.K. Stark, "Multi-criteria Lifecycle Evaluation of Transportation Fuel Derived from Biomass Gasification," MS Thesis, MIT, January 2010.

[11]Pearson, R.J. et. al., "Extending The Supply of Alcohol Fuels for Energy Security and Carbon Reduction," Society for Automotive Engineers (SAE) Paper 2009-01-2764, 2009.

[12]L. Bromberg and D.R. Cohn, "Alcohol Fueled Heavy-Duty Vehicles Using Clean High Efficiency Engines," Society of Automotive Engineers Technical Paper, Powertrains: Fuels and Lubricants Meeting, October 25–27, 2010, San Diego, to be published.

[13]2006 Manufacturing Energy Consumption Survey (MECS), U.S. Energy and Information Administration (http://www.eia.doe.gov/emeu/mecs/mecs2006/2006tables.html).

[14]The Pew Center on Global Climate Change, "From Shop Floor to Top Floor: Best Business Practices in Energy Efficiency," April 2010.

[15]EIA/DOE November 2008 Building Energy Data book.

[16]Frederick Joutz and Robert P. Trost, "An Economic Analysis of Consumer Response to Natural Gas Prices," prepared for the American Gas Association, March 2007.

[17]See for example, Massachusetts Department of Public Safety "780 CMR Appendix 120 AA: Stretch Energy Code."

[18]American Council for an Energy-Efficient Economy, "State Energy Efficiency Resource Standard (EERS) Activity, April 2010.

Section 5: Infrastructure

The availability, reliability and price of natural gas are inextricably linked to its production and delivery infrastructure. In the U.S., this system is both mature and robust, supplying American consumers with 64 billion cubic feet (64 Bcf) of gas each day.

As seen in Figure 5.1, major components of the system include inter-state and intra-state transmission pipelines, storage facilities, LNG regasification terminals and gas processing units, all of which establish the link between gas producers and consumers.

Major changes in U.S. gas markets have prompted significant additions to the U.S. pipeline network over the last several years. Between 2005 and 2008, for example, pipeline capacity additions totaled over 80 Bcf/day, exceeding those from the previous four year period by almost 100%.

THE U.S. NATURAL GAS PIPELINE NETWORK

The U.S. natural gas pipeline network includes:

- gathering pipelines at, or adjacent to, production sites;
- inter-state and intra-state transmission pipelines which move processed gas over long distances from production sites to major centers of demand; and
- smaller diameter distribution pipelines, which carry natural gas on to end users.

Figure 5.1 The U.S. Natural Gas Infrastructure, Including Gas Consuming Sectors

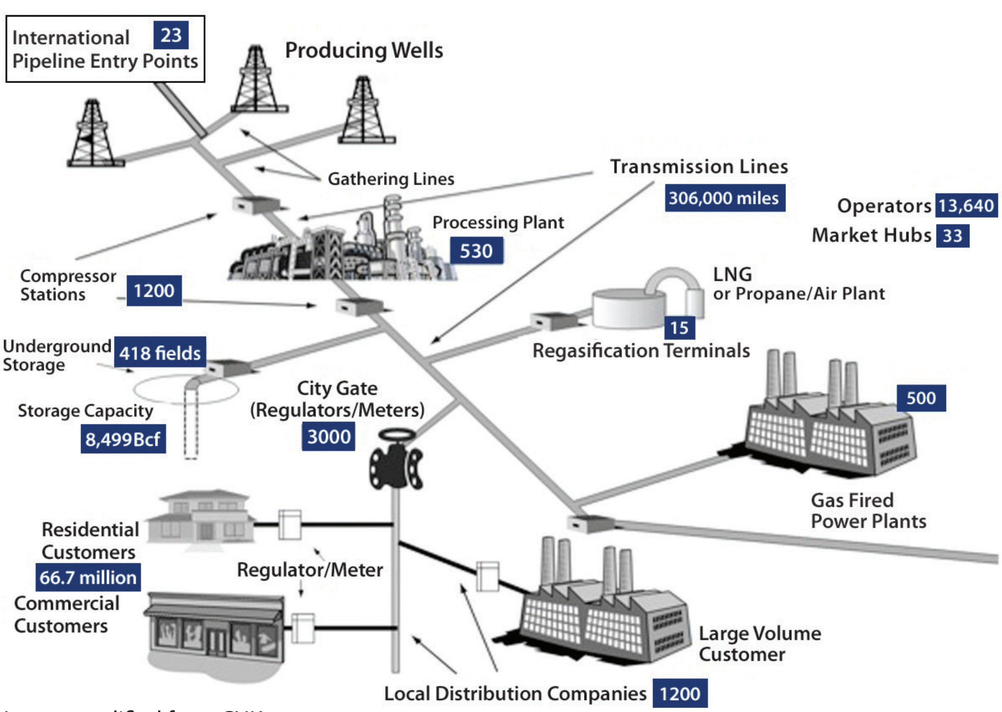


Image modified from CHK

Major changes in U.S. gas markets have prompted significant additions to the country's pipeline network over the last several years. Between 2005 and 2008, for example, pipeline capacity additions totaled over 80 Bcf/day, exceeding those from the previous four-year period by almost 100%. Additions of 44.5 Bcf/day in 2008 alone, exceeded total additions in the five-year period between 1998 and 2002.

This growth is attributed in part to the changing geography of U.S. gas production, the locus of which has moved from offshore central and western Gulf of Mexico (GOM), where it has been for the last two decades, back to onshore regions, particularly in the Rocky Mountains and in the shale basins in the south west/south central U.S.

The largest single addition to the pipeline system, between 2005 and 2008, was the Rocky Mountain Express pipeline (REX). With its 1.8 Bcf/day capacity, this pipeline has effectively linked western producer markets to eastern consumer markets. Other additions, with a combined total of over 6.0 Bcf/day, are largely moving gas from the shale regions in Texas and Oklahoma to south east markets. These west to east expansions are contributing to major changes in the general direction of pipeline flows in the U.S., which have historically moved from south to north.[1]

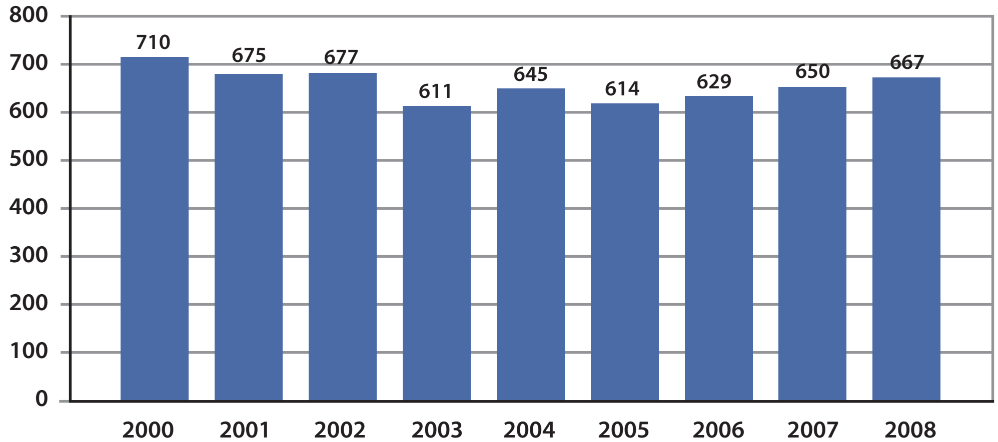
GAS PROCESSING

Every year in the U.S., 530 natural gas processing plants process around 15 Tcf of raw natural gas. Removing impurities such as sulfur, CO_2 and water to produce pipeline quality gas[2] is the primary role of these processing facilities.[3]

Natural gas can also contain heavier hydrocarbons or NGLs. This "wet gas" can be processed to produce value-added products, including butane, propane, and ethane, which can enhance the economics of production. According to IEA, the average liquids ratio of natural gas is 19.2%.

Currently, around 82% of gas processing capacity is in six states: Louisiana, Texas, Wyoming, Kansas, New Mexico and Oklahoma. As seen in Figure 5.2, there are wide swings in NGL production, which is a low-margin business, where production is closely tied to market conditions.

Figure 5.2 NGL Production, 2000–2008 (million barrels per year)



Source: EIA 64-A

NATURAL GAS STORAGE

Natural gas is stored in underground storage facilities to help meet demand fluctuations, accommodate supply disruptions and hedge price variations. Depleted reservoirs account for most storage facilities (80%), followed by aquifers (16%), with salt caverns making up the remainder. Working gas storage capacity nationwide is around 4.2 Tcf. Over 42% of this capacity is found in just four states: Michigan, Illinois, Pennsylvania and Texas.

There has been a great deal of interest in the relationship between storage and short term price volatility.[4] In 2006, the Federal Energy Regulatory Commission (FERC) chairman noted that gas storage capacity had increased only 1.4% in almost two decades, while U.S. natural gas demand had risen by 24% over the same period, and suggested a link to the record levels of price volatility that were being experienced.[5] In that year, FERC issued Order 678 which, among other things, sought to incentivize the building of more storage by changing its regulations on market power requirements for underground storage. Since the order was issued, total storage capacity has increased by 169 Bcf, or 2% of overall storage capacity. This compares to a 1% increase in the previous three-year period.

The availability of certain types of storage could become an issue as demand for gas-fired power generation increases. Gas generation places a premium on peak load (as opposed to base load) gas storage facilities, demanding high deliverability for short periods of time to meet the daily and hourly fluctuations of power plants. High-deliverability storage, typically in salt caverns, is only about 4% of overall gas storage, although capacity increased 36% between 2005 and 2008, compared to 3% for all gas storage.[6]

LIQUEFIED NATURAL GAS REGASIFICATION FACILITIES

LNG is produced from a process that transforms natural gas into a liquid in order to transport it by ship over long distances. Regasification facilities convert LNG back to its gaseous form so that it can be distributed via pipeline networks to end users.

In the U.S., LNG regasification facilities link the U.S. markets to the global gas trade. In 2000, the U.S. had four LNG regasification facilities: Maryland, Massachusetts, Georgia and Louisiana, with a combined capacity of 2.3 Bcf/day. Following a wave of construction of new LNG regasification terminals and expansions of existing facilities in the early part of this century, North America now has 22.7 Bcf/day of rated import capacity either operating or under construction, 86% of which is in the U.S.

In 2009, U.S. consumption of imported LNG was 1.2 Bcf/day, but demand was geographically uneven. The Everett regasification facility in Boston, for example, met around half of New England's gas demand, but Gulf Coast terminals were forced to re-export gas.[7] Even assuming peak or sustainable capacity factors[8] for LNG regasification terminals of under 50%, there is still significant underutilized capacity in the U.S.

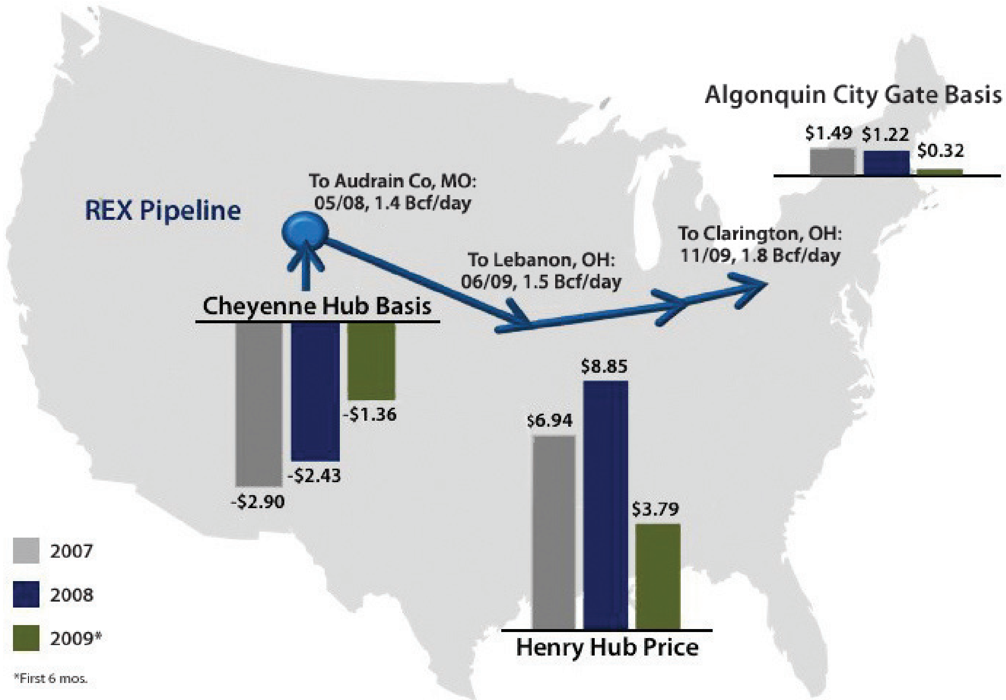
PIPELINES AND REGIONAL PRICES

In general, the difference between daily prices at regional hubs compared to Henry Hub prices — the market center in Louisiana that serves as the price point for New York Mercantile Exchange (NYMEX) futures contract — is the basis differential or "basis". The basis differentials are often small, reflecting the short-run variable cost of transporting gas or of displacing shipments of gas to one market center instead of another. Occasionally, when transportation bottlenecks are long term, the basis differentials become large and reflect the different prices at which demand is being rationed in the different locations.

Basis differential changes over time at the Cheyenne hub and Algonquin city gates seen in Figure 5.3 demonstrate the price impacts of a gas transportation bottleneck. Before REX, transportation from the Rockies region was constrained, leading to lower prices relative to most other natural gas market centers. After the opening of REX, which was built in the stages indicated in the figure, the basis differentials at the Algonquin city gates and Cheyenne hub were substantially reduced.[9]

The long lead times required to site and build gas infrastructure, driven in part by the complex regulatory decision-making structures for gas infrastructure siting, means that many of the additions and expansions we are seeing today were originally contemplated as much as a decade ago.

Figure 5.3 Impacts of Pipeline Capacity on Price/Average Basis



Source: Porter Bennett lecture, MIT Gas Study Seminar Series, 09/24/09

These lead times — as much as 10 years for an interstate transmission pipeline — also add significantly to transportation costs. It is estimated that securing the necessary permits for constructing a large diameter interstate pipeline comprises around a quarter of the overall costs of construction.[10]

This delay places a high premium on the efficiency of the marketplace and the accuracy of the data and forecasts on which both industry and the government rely to make strategic policy and investment decisions. These decisions will play a major role in two new opportunities for U.S. natural gas markets, the development of the Marcellus shale and the potential for displacing coal with NGCC gas generation to lower CO_2 emissions.

DEVELOPMENT OF THE MARCELLUS SHALE

We focus on infrastructure issues for the Marcellus shale, as it is the least developed of major U.S. shale basins. It is also located in four states — Pennsylvania, New York, Ohio and West Virginia — that are generally more densely populated and less accustomed to natural gas production than Texas, Oklahoma, Arkansas and Louisiana, the locations of other major producing shale basins.

The economics of shale production and the sheer size of the Marcellus shale basin have created enormous interest in its development. The proximity of Marcellus production to the Northeast, with the implied lower transportation costs to this market, could translate into lower gas prices for the region's consumers, who have typically relied on LNG imports, and Canadian and GOM gas via pipeline. It could also shift GOM gas movements to the south east,[11] an attractive option for the region's consumers who are on the high-priced end of the Western coal supply chain.

The Marcellus break-even wellhead gas prices are lower than those in most other U.S. shale regions that are currently being produced.[12] The Marcellus, however, in addition to resolution of environmental and "Not In My Backyard" (NIMBY) concerns, needs substantial infrastructure additions to move its gas to markets. There are three transmission pipelines either under construction or certified for construction with a combined capacity of over 1 Bcf/day, and another 4.8 Bcf/day of planned additions to existing pipelines. These additions are essential: Marcellus producers estimate that less than half of the Pennsylvania wells have pipeline access[13] at present.

In addition, there is wet gas in the Marcellus, particularly in southwestern Pennsylvania. The lack of processing capacity and outlets for wet gas products could place constraints on the production of pipeline quality gas, and could effectively shut-in significant gas production in the Marcellus. Two NGL pipeline projects have been proposed from Pennsylvania to Chicago and Ontario which could ease the pressure for NGL outlets, but additional processing options are still needed.

Market analysts of the Marcellus shale stress the importance of infrastructure for its development and view infrastructure as a significant obstacle to Marcellus production growth. In Pennsylvania, for example, the Marcellus Shale Coalition has noted that the state is lacking in the infrastructure needed for Marcellus shale gas to compete with other states and sources of supply.

The speed at which infrastructure is added is important. Marcellus production is competing for premium northeast gas market share. This market is currently served by both REX and several LNG import facilities: LNG import capacity for the East Coast is 7.1 Bcf/day with an average delivered price for 2009 of $4.76 per Mcf,[14] and short-term delivered prices in the first two months of 2010 ranging from $3.81 to $6.65 per MMBtu at the Everett, Cove Point and Northeast Gateway LNG regasification facilities.[15] Also, REX pipeline capacity destined for the northeast is currently sold out under long-term binding commitments.[16]

FULLY DISPATCHED NGCC POTENTIAL FOR CO_2 EMISSIONS REDUCTIONS: INFRASTRUCTURE LIMITATIONS

As noted, displacing less-efficient coal generation, through increased utilization of existing high-efficiency NGCC generation, provides a near-term opportunity for reducing CO_2 emissions. In addition to system constraints described in the demand section of this report, there are also possible constraints on the possible exercise of this option imposed by the capacities and flexibility of the gas and power transmission infrastructures.

Infrastructure constraints and limitations need to be fully taken into account when considering policy options which aim to reduce near-term CO_2 emissions by displacing some coal generation with existing NGCC generation capacity.

On the gas infrastructure side, concerns have been raised about the availability of gas pipeline capacity for the additional gas requirements of this option, but preliminary analysis indicates that the industry has the ability to meet the needs for additional pipeline capacity.[17]

Storage, on the other hand, could present an infrastructure constraint. As noted earlier, gas-fired power generation relies on high-deliverability storage, of which capacities are limited. Displacing coal with gas generation could increase demand for high-deliverability gas storage.

It is also worth noting that re-firing coal-fired boiler systems with gas or replacing coal plants with NGCC are additional options for coal-to-gas substitution as a near-term carbon emissions mitigation strategy. There are a substantial number of inefficient coal plants (heat rates above 10,000 Btu) that are not credible candidates for post-combustion carbon capture retrofit, because associated parasitic efficiency losses using current technologies would take plant efficiencies to around 20% or lower.[18] For such plants, replacement with modern NGCC capacity would provide a near-term reduction of CO_2 emissions by about a factor of three for an equivalent capacity. New pipeline and storage infrastructure would likely be needed to supply fuel to these plants.

Infrastructure constraints and limitations need to be fully taken into account when considering policy options that aim to reduce near-term CO_2 emissions by displacing some coal generation with existing NGCC generation capacity.

RECOMMENDATION

Policies developed to displace less-efficient coal plants with NGCC units should consider and accommodate the impacts on, and adequacy of, the gas infrastructure in order to assess the full potential for coal-to-gas substitution.

NOTES

[1]Bentek Energy, LLC, Market Alert: The Beast in the East, 3/19/2010.

[2]According to EIA, pipeline quality gas must fall within a specific Btu range, be delivered at a specified hydrocarbon dew point temperature level, contain only trace amounts of certain contaminants and be free of particulate solids and liquid water.

[3]EIA, Natural Gas Processing: The Crucial Link Between Natural Gas Production and Its Transportation to Market, 2006.

[4]Volatility is defined by EIA as the degree of price variation in the market, measured by percent differences in the day-to-day price of natural gas.

[5]Statement of Former FERC Chairman Joseph T. Kelliher on Gas Storage Pricing Reform.

[6]EIA Website, Natural Gas Storage, Overview/Regional Breakdowns.

[7]FERC state of the markets, 2009.

[8]According to Jim Jensen, JAI, " the capacity of the storage tanks and the tanker off-loading facilities may…limit how much LNG the terminal can handle on an ongoing basis. Thus it is also common to report "annual" or"sustainable" capacity, which might be a much lower figure than peak capacity."

[9]Bennett, Porter, U.S. Natural Gas Market Outlook: Boom and Bust, or New Beginning?, 09/24/09,MITEI Future of Natural Gas Seminar Series.

[10]"Natural Gas Pipeline and Storage Infrastructure Projections Through 2030," by Interstate Natural Gas Association of America.

[11]In 2008, north east gas consumption was 11 bcfd, south east was 8 bcfd.

[12]MIT supply group internal analysis.

[13]Bentek Energy, LLC, Beast in the East, Market Alert, March 2010.

[14]EIA Website, Price of Natural Gas LNG Imports, release date 05/28/10.

[15]DOE Office of Fossil Energy, Short Term Imports of LNG.

[16]Kean, Steve, Natural Gas Pipelines, Kinder Morgan presentation, 2010.

[17]Kaplan, Stan, Displacing Coal with Generation from Existing Natural Gas-Fired Power Plants, CRS, 01/2010, Wash.

[18]MIT Energy initiative report of the symposium Retrofitting Existing Coal Plants for Emissions Reduction, June, 2009.

Section 6: Markets and Geopolitics

Today, there are three distinct regional gas markets — North America, Europe and Asia. Each has a different market structure resulting from the degree of market maturity, the sources of supply, the dependence on imports and other geographical and political factors. This is in contrast to the global oil market, and it is instructive to understand the fundamentals of the difference between oil and gas markets.

The physical characteristics of oil — a very high energy density at normal conditions of temperature and pressure — allow it to be readily transported over long distances, by a variety of means, at moderate cost. This has allowed the development over time of a sophisticated global market, where multiple supply sources serve multiple markets at transparent spot prices. Notwithstanding dependence on imports, this marketplace adds significantly to security of supply for consumers and to security of markets for producers.

By contrast, the characteristics of natural gas constrain transportation options. Transportation costs constitute a significant fraction of the total delivered cost. As markets formed, long-term contracts were necessary to underwrite the cost of infrastructure development and to ensure a market for the supplier. These arrangements have inhibited the development of a global gas market that links the major demand centers, with significant security ramifications. In many markets, long pipeline connections create dependency between buyers and sellers and give substantial power to those who control pipelines.

In addition, the geological realities of natural gas resources are similar to those of oil in terms of the degree of concentration of conventional resources, with Russia, Iran and Qatar having the largest conventional natural gas resource base. As with oil, at issue is the extent to which major resource holders (MRHs), over time, will use these resources as an instrument to advance political, not just economic, objectives.

Consequently, the future structure of these markets and the degree of integration that may develop have both economic and security implications. Several factors could lead to greater market integration and diversity of supply:

- the competition for supply from regions that can serve multiple major markets, such as the Caspian;
- growth in LNG trade and the development of a market in which cargoes seek favorable prices, a trend that has been seen in the Atlantic basin;
- development of major unconventional gas resources in strategic locations, such as Europe and China.

Of course, there are many unknowable factors that can impede market integration, including the geopolitical aims of MRHs.

MARKET STRUCTURES

The U.S. natural gas market is the most mature of the world's three major regional markets. Significant exploitation of natural gas began in the latter half of the 19th century centered in Appalachia, with much larger production and consumption starting in the 1920s after discoveries in the Southwest. This expansion was aided by advances in pipeline technology, eventually creating a continent-wide integrated natural gas market.

The U.S. natural gas market functions well, with infrastructure development more or less keeping pace with changing market needs.

The regulatory institutions governing the natural gas markets in the U.S. have undergone their own historical evolution. New Deal initiatives in the 1930s broke the control of the holding companies over local utilities and established the Federal Power Commission as a regulator of the interstate sale and shipment of natural gas. The Natural Gas Act of 1938 and its subsequent amendments provided Federal eminent domain authority for the construction of new interstate natural gas pipelines and natural gas storage. These policies facilitated the robust growth of a continent-wide network.

Initially, long-term contracts were the rule. There was no single benchmark price for natural gas in the U.S. This changed with the passage of the Natural Gas Policy Act of 1978, which gradually led to the removal of price controls on the interstate sale of natural gas in the U.S. Starting in 1985, ceilings were removed on the sale of new gas and the FERC issued a series of Orders between 1985 and 1993 that served to create an open and transparent continent-wide market in natural gas. This market-based focus was extended to gas storage in the Energy Policy Act of 2005.

Since then, a robust spot market has developed in the U.S. and Canada, with a price set by the forces of supply and demand. Contracts continue to play a role, albeit diminished, in the market, where price clauses typically reference the spot market. This expansion has been supported by an expanded pipeline network and associated midstream gas facilities. The U.S. natural gas market functions well, with infrastructure development more or less keeping pace with changing market needs (see Section 5).

At present, North America is largely self sufficient in natural gas, and this situation is likely to continue for some time, as indicated in Section 3. The substantial surplus of LNG import capacity, discussed in Section 5, effectively provides back-up capacity in the event of unanticipated supply shortfalls or high prices.

It should also be noted that the U.S. exports gas. LNG exports from Alaska to Japan have been in place for 40 years, but are likely to face additional competition in the Asian market, particularly as the Cook Inlet production tapers off. Part of this competition may come from Canada, which has a large shale gas resource. The U.S. also exports to Mexico and Canada, although with a significant net import from Canada. Especially since passage of the North American Free Trade Agreement (NAFTA), there has been increased North American energy market integration.

The large Canadian shale gas resource adds to the diversity of supply within the functioning North American market.

The European gas market developed later than that in the U.S. The initial impetus started with the discovery of the Groningen fields in the Netherlands starting in 1959. In the early 1960s, Algeria began LNG shipments to the U.K., then to France. Small quantities of natural gas from the Soviet Union flowed into the other countries of Europe beginning with Austria in 1968.

The current structure of Europe's gas markets is shaped by the 1973 Organization of the Petroleum Exporting Countries (OPEC) oil embargo. The European reaction was to explicitly tie the delivered price of natural gas to the price of crude oil or crude products. This inhibited the development of a deep and liquid spot natural gas market in Europe.

There have been moves in the EU to liberalize gas markets, starting with the U.K. in 1986. As part of a larger energy market liberalization effort, the EU in 1998 sought to create common rules for an internal gas market. The result has been the development of a small spot market on the European continent. Ultimate success will depend upon the future course of the European Community's regulatory reform. Progress is slow.

Currently, almost half the gas for Organization for Economic Cooperation and Development (OECD) Europe is imported, mostly by pipeline from Russia and North Africa, sometimes traversing other countries. LNG also supplies parts of Europe and is especially important to Spain and Portugal, which are on the far end of the Russian pipeline system.

The long supply chains into Europe, the prevalence of pipeline gas and the relative inflexibility of the markets create much more significant security of supply concerns than are experienced in North America. Diversification of supply is a high priority. However, even though the U.S. is not significantly dependent on imports, American security interests can be strongly affected by the energy supply concerns of its allies.

Industrialized Asia led the way in setting LNG prices through oil-indexed long-term contracts and remains bound to this market structure. This does not appear likely to change in the near term. With few indigenous gas resources, industrialized Asia and the emerging economies in that region are almost totally dependent on imported LNG from Southeast Asia, Australia and the Middle East. This dependence places a high premium on security of supply, which is reflected in the region's dependence on long-term, relatively high-priced contracts indexed to oil.

Finally, we note that domestic markets in some major supplier countries, such as Russia, operate with very large subsidies. This leads to inefficient use that impacts gas trade.

IMPLICATIONS OF MARKET INTEGRATION

Extrapolating from the lessons learned from the North American market, an interconnected delivery system combined with price competition are essential features of a "liquid" market. This system would include a major expansion of LNG trade with a significant fraction of the cargoes arbitraged on a spot market, similar to today's oil markets.

As described in Section 3, the EPPA model was used to investigate the consequences of equalized gas costs, with cost differentials only for transportation. We emphasize that this is not a prediction that such a market will emerge, but rather an exploration of the implications of global market integration. For the U.S., with the median expectations for both North American and global gas resources, the U.S. becomes a substantial net importer of gas in future decades in an integrated market and long-term domestic prices are lower than in the regionalized market structure. Also, greater diversity of supply is seen for all the major markets in this scenario. Clearly other scenarios could result from changes in resource estimates or from geopolitical realities.

Extrapolating from the lessons learned from the North American market, an interconnected delivery system combined with price competition are essential features of a "liquid" market.

In addition, a functioning integrated market can help overcome disruptions, whether political in origin or caused by natural disasters. An example of this was seen in the U.S. oil markets, which recovered quickly following the 2005 hurricanes in no small part because of international market adjustments.

Overall, a global "liquid" natural gas market is beneficial to U.S. and global economic interests and, at the same time, advances security interests through diversity of supply and resilience to disruption. These factors moderate security concerns about import dependence.

NATURAL GAS SECURITY CONCERNS AND RESPONSES

Transparent markets with diverse supply, whether global in reach or within large regions that encompass both major suppliers and large demand centers, do much to alleviate security risks. Nevertheless, the anticipated growth in gas use, combined with the geological realities of conventional gas resources, inevitably will produce continuing concerns, such as:

1. **Natural gas dependence could constrain U.S. foreign policy options.**
   U.S. freedom of action in foreign policy is tied to global energy supply. Iran, for example, presents many security challenges in the Middle East and is in confrontation with the West over a developing nuclear weapons capability. Iran's oil exports and its potential for gas exports, create tension between imposition of economic sanctions to influence Iran's foreign policy and the risk of inducing an Iranian response that interrupts oil and eventually gas supply to world markets.

In addition, the U.S., with its unique international security responsibilities, can be constrained in pursuing collective action if its allies are limited by energy security vulnerabilities.[1]

A global "liquid" natural gas market is beneficial to U.S. and global economic interests and, at the same time, advances security interests through diversity of supply and resilience to disruption.

2. **New market players could introduce impediments to the development of transparent markets.** The new large consuming economies, such as China and India, are increasingly seeking bilateral arrangements that include non-market concessions. Such arrangements have the potential to influence long-term political alignments, move away from open, transparent natural gas markets and have the potential to work against the interests of consuming nations as a whole. Major gas producers have shown some interest in forming a cartel to control supply, but this movement is not yet very advanced.[2]

3. **Competition for control of natural gas pipelines and pipeline routes is intense in key regions.** Control of pipeline routes gives gas suppliers tremendous leverage over consuming nations. Not surprisingly, there is competition and competing pressures on the governments in Central Asia and the Caspian region over pipelines out of the region. Russian primacy in pipeline trade with Europe helps it retain its historical hegemony in the region, which is not necessarily in the best interest of countries in the Caspian, which are seeking to maximize the value of their gas resources and expand trade opportunities.

4. **Longer Supply Chains Increase the Vulnerability of the Natural Gas Infrastructure.** As supply chains multiply and lengthen, these infrastructures have become increasingly vulnerable to both malevolent attacks and natural disasters. Pipelines, processing facilities, LNG terminals and tankers are "soft targets," i.e. easy to locate and destroy, usually undefended and vulnerable to attacks, including cyber attacks.

As the use and trade of natural gas grow over the coming decades, with an uncertain global market structure, U.S. policymakers must be well informed and manage the interrelationship between natural gas markets, both domestic and international, and security in order to limit adverse effects on U.S. and allied foreign policy. Our recommendations are:

1. The U.S. should sustain North American energy market integration and support development of a global "liquid" natural gas market with diversity of supply. A corollary is that the U.S. should not erect barriers to gas imports or exports.

2. A multi-agency coordinating body should be established to better integrate domestic and international implications of natural gas market developments with foreign and security policy. Numerous agencies (Energy, State, Treasury, Defense, Commerce, …) have a major stake in this integration, so the Executive Office of the President must exercise the necessary convening power and leadership. To be successful, strong energy policy support for the coordinating group must be established in the Department of Energy.

3. The IEA should be supported in its efforts to place greater emphasis on natural gas and security concerns. To do so meaningfully, it must bring the large emerging gas-consuming economies (such as China, India, Brazil, …) into the IEA process as integral participants. The process should promote open and transparent energy markets, including the natural gas market.

A multi-agency coordinating body should be established to better integrate domestic and international implications of natural gas market developments with foreign and security policy.

4. The U.S. should continue to provide diplomatic and security support for the siting, construction and operation of global natural gas pipelines and LNG facilities that promote the strategic interest in diversity and security of supply and global gas market development.

5. The U.S. government, in concert with the private sector, should strengthen its recent international initiative to share experience in the characterization and development of unconventional natural gas resources in strategic locations.

6. The U.S. should take the lead in international cooperation to reduce the vulnerability of natural gas infrastructure, to set security standards for facilities and operations and, through technical assistance, to develop procedures for sharing threat information, joint planning and exercises for responding to incidents.

7. Domestically, the U.S. should adopt policies to promote more efficient use of natural gas, so as to minimize dependence (as with oil). Internationally, the U.S. should encourage efficient use of natural gas through elimination or reduction of subsidies for domestic usage in producing countries.

NOTES

[1] National Security Consequences of U.S. Oil Dependency; J. Deutch and J. Schlesinger, chairs, D. Victor, project director; Council on Foreign Relations Independent Task Force Report No. 58 (2006).

[2] What is the Gas Exporting Country Forum (GECF) and what is its objective"? EIA 2009 http://www.eia.doe.gov/oiaf/ieo/cecf.html.

Section 7: Research, Development and Demonstration

The future of natural gas, at least for the next decade or two, appears robust even in the absence of major R&D advances. However, there are a number of areas where RD&D could strengthen the position of natural gas as a bridge to a low-carbon future, namely, innovation that:

- improves the economics of resource development;
- reduces the environmental footprint of gas production and delivery;
- improves conversion processes;
- lowers the cost of gas transportation systems; or
- improves the efficiency of gas use.

For this interim report, enhanced utilization of the unconventional gas resource is our principal focus. Other areas will be discussed in the full report.

The DOE is the primary federal sponsor of energy technology RD&D in the U.S. Over the years, the DOE natural gas program has supported programs in exploration and production, unconventional gas, environmental protection, gas hydrates, advanced turbines and stationary fuel cells, among others.

The program has been relatively small, providing cumulative support of about a billion dollars (as-spent dollars) over 30 years. This is small in comparison with private sector RD&D, but nevertheless, the program has had some notable achievements, encompassing early research on unconventional gas during the Department's start-up period, to significant industry partnerships for development of advanced efficient gas turbine systems in more recent times.[1]

Development of unconventional gas supply, and the application of gas turbines for electricity generation, are arguably the two most significant gas-related technology developments of the last few decades. At the same time, there has been significant "off-budget" (that is, not attached to the standard annual Congressional appropriations process) support for natural gas RD&D.

These approaches have been enabled by the Federal government through regulation or statute, and implemented through dedicated non-profit research organizations. These programs are generally more applied than the DOE programs, suiting the applied research and technology development, demonstration and transfer nature of much of the natural gas research portfolio needs.

The Gas Research Institute (GRI) was established in 1976 (and ended in 2000 following gas deregulation) as a government/private partnership to advance natural gas technologies across supply, transportation and end use. Its funding peaked at over $200M/year, considerably more than the DOE natural gas program, through a small FERC-approved surcharge on interstate NG transportation. The DOE and GRI often collaborated closely and effectively on gas RD&D, including coordinated portfolio planning.

More recently, the Research Partnership to Secure Energy for America[2] (RPSEA) was chosen to manage (starting in 2007) an RD&D fund of $37.5M/year (substantially less than originally planned) with an exclusive focus on U.S. natural gas supply (unconventional, ultra-deep water, small producer technologies).

This Royalty Trust Fund (RTF) is provided from a small part of Federal royalties on oil and gas production and was established by Congress in the 2005 Energy Policy Act. An additional $100M/year was authorized for annual appropriations, but this has not been funded. Administrations have not been enthusiastic about the RTF since its inception and this has impeded the effectiveness of DOE – RPSEA collaboration.

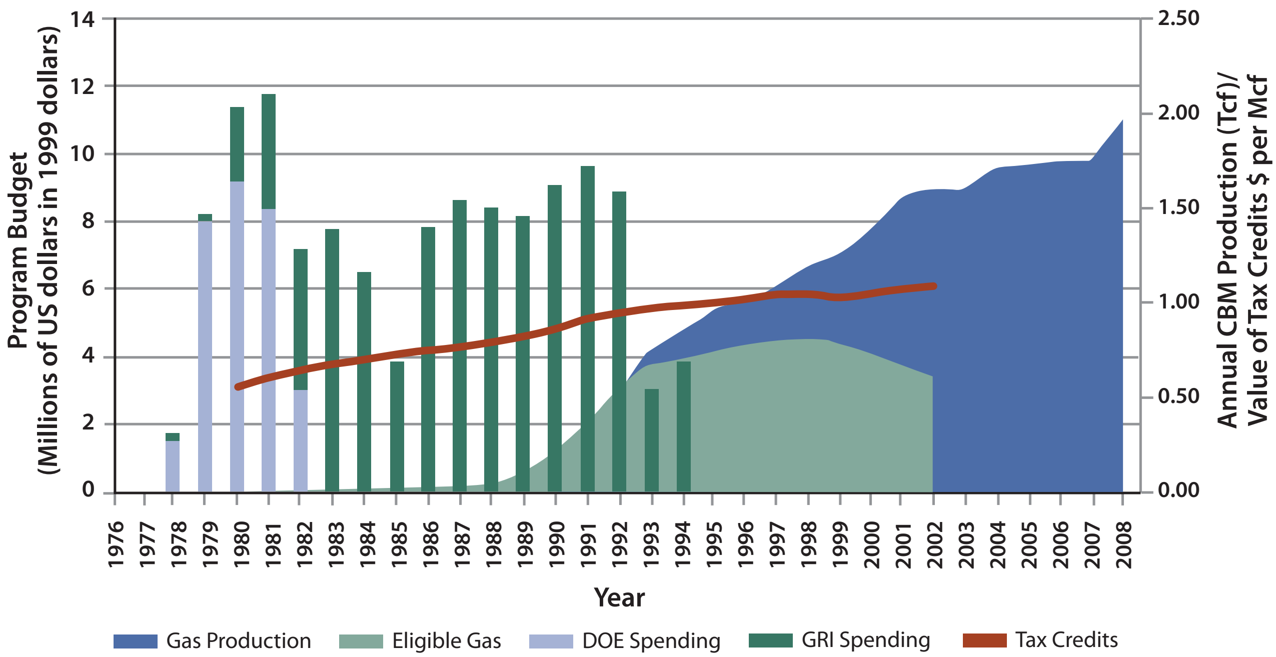
Both of these programs were created with explicit mechanisms for strong industry input to the RD&D portfolio development, including the requirement for industry matching funds and government review of the research plan.

The nature of the funding encourages multi-year, stable commitments from both the funder and the industry partners to technology development and demonstration with well-defined goals. The applied research and demonstration projects that are supported directly address industry needs, yet the research performers are drawn from a broad base of universities, laboratories and industry. For example, in its first two years, RPSEA supported 28 projects for on-shore unconventional gas R&D, of which 18 are led by universities, and only 2 by industry.[3] It has also supported several projects to enable environmentally safe ultradeepwater operations, which could be a source of natural gas in the future.

The history of coalbed methane development provides a good model of how DOE, off-budget RD&D and policy incentives have worked together. This is illustrated in Figure 7.1. The DOE supported a small program in reservoir characterization. This was followed by a larger fifteen year Gas Research Institute program with industry cost-share. The roadmap was guided by industry input, particularly the independent producers who led unconventional gas production, and accomplished technology development, transfer and testing. Many universities took part in the R&D.

At the same time, tax credits were put in place for wells drilled from 1980 to 1992 (the so-called Section 29 credits), with the credits extending to gas produced from those wells through 2002. The gas eligible for the tax credit is shown in Figure 7.1. The result of all this is a 2 Tcf/year domestic resource today, with a cumulative production of about 25 Tcf. This represents a very large return on the RD&D investment.

Figure 7.1 CBM RD&D Spending and Supporting Policy Mechanisms



The GRI and the DOE invested more than $120 million (1999 dollars) combined in their respective RD&D programs for Coal Bed Methane (CBM) beginning in 1978 and ending in 1994,[1,2] as shown in Figure 7.1 above. Initial Section 29 tax credits for CBM were equal to $0.52 per Mcf ($3 Bank of England) and were annually adjusted to inflation. Approximately 9 Tcf of the CBM produced in 1980 through 2002 was eligible for the Section 29 tax incentives as shown above; this estimate ignores gas that was produced from wells that were drilled before 1993, but came online after 1993. The use of Section 29 tax credits was limited somewhat by tax liability issues that had to be taken into account. For instance, producers were not able to offset their Alternative Minimum Tax (AMT) obligations and approximately 50% of companies were in AMT.[3] The total value of the tax credit was equal to $760 million in 1993, shared mainly by CBM and tight gas producers.

1. Energy Research at DOE: "Was It Worth It? Energy Efficiency and Fossil Energy Research 1978 to 2000." 2001, National Research Council.

2. Gas Research Institute 1979–1983 to 1994–1998, Research and Development Plans. Chicago, Ill. , Gas Research Institute.

3. M.R. Haas and A.J. Goulding, ICF Resources Inc., "Impact of Section 29 Tax Credits on Unconventional Gas Development and Gas Markets," P8.

SUPPLY

Although continuing strong domestic gas supply for the next couple of decades is practically assured, optimization of the resource and long-term supply at lower cost, with decreasing environmental footprint, will call for new technology for unconventional resources. This can have a material impact on the long-term economic competitiveness of domestic supplies with imports.

Although continuing strong domestic gas supply for the next couple of decades is practically assured, optimization of the resource and long-term supply at lower cost, with decreasing environmental footprint, will call for new technology for unconventional resources.

There are a number of important areas for supply-side RD&D:

Analysis and Simulation of Gas Shale Reservoirs — A DOE program should be aimed at the basic science that governs shale formations in order to maximize gas recovery. Such a program could help develop a better understanding of the physics that underlies fluid flow and storage in gas shales, facilitate the development of more accurate reservoir models and simulation tools; and develop imaging tools and models for characterizing the geologic, geochemical and geophysical shale rock properties.

Environmental Protection — A comprehensive program is needed to address issues of water use and produced water in unconventional gas production. Such a program could lead to improved treatment, handling, re-use and disposal of fluids; more sustainable and beneficial use of produced water; and more effective stimulation techniques that require less water and other fluids to be injected into the subsurface.

Methane Hydrates — More basic research issues need to be resolved for methane hydrates than for other gas sources. RD&D might usefully focus on: the systematic remote detection of highly concentrated deposits; long-term production tests, particularly in permafrost-associated hydrates; and geo-hazard modeling to determine the impact of extracting free gas on the stability of associated hydrate-bearing sediments.

The Administration has not sought funding for unconventional resource RD&D (except for methane hydrates) for several years.

Consideration should also be given to restoring an off-budget, industry-led private-public partnership to support a broad-based natural gas RD&D program, including delivery systems and end use. There are many possible mechanisms. To set a scale, we note that a one cent charge per Mcf of gas (equivalent to much less than 1% of the delivered price to end users) would yield over $200M/year for research.

RECOMMENDATION

The Administration and Congress should support RD&D focused on environmentally responsible, domestic natural gas supply. This should entail both a renewed DOE program, weighted towards basic research and a synergistic continuing "off-budget" industry-led program, weighted towards applied research, development and demonstration. In particular, the Royalty Trust Fund should be continued and increased in its allocation commensurate with the promise and challenges of unconventional gas. Furthermore, consideration should be given to restoring a public-private "off-budget" RD&D program for natural gas transportation and end use as well.

CCS

Up to now, most of the CCS RD&D focus has been on coal use, which is appropriate because of its carbon intensity and its dominant role in the U.S. power sector (and widespread use in China and India — both expanding energy consumers). The work spans both post-combustion and pre-combustion (mainly gasification) capture. However, to date, activity around CCS worldwide has been slow to reach the level of demonstration needed to establish utility-scale sequestration in a timely fashion. And as carbon emissions constraints grow tighter, natural gas combustion will also need CCS (as indicated in Section 3 of this report).

Clearly, much of the CCS research is applicable to any fossil fuel source, especially for post-combustion capture. For pre-combustion capture, there are technical simplicities in starting with natural gas, since the conversion to synthesis gas is much simpler than for solid fuels. Consequently, consideration should be given to natural gas CCS demonstration as part of the portfolio of demonstration projects needed to establish this important technology for a very low carbon future.

NOTES

[1]Energy Research at DOE: Was It Worth It? Energy Efficiency and Fossil Energy Research 1978 to 2001. National Research Council ISBN 0-309-07448-7 (2001).

[2]RPSEA is a consortium of U.S. universities, industry and independent research organizations.

[3]One member of the MIT study group (MAK) serves on the Board of the non-profit RPSEA. MIT has not received research funding from the program.

Appendix A: Units

Bcf	Billion cubic feet
Btu	British thermal units
cf	Cubic feet
GW	Gigawatt
GWh	Gigawatt per hour
kWh	kilowatt per hour
Mcf	Thousand Cubic Feet
Mj	Megajoule
MMcf	Millions of cubic feet
MMBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt per hour
Tcf	Trillion Cubic Feet
TkWh	Trillion Kilowatt hours
TWh	Terawatt hours

Appendix B: Seminar Series Dates and Speakers

February 20, 2009
Kent Perry:
"Unconventional Gas: The Resource and Technology Needs"

March 19, 2009
James T. Jensen:
"LNG: Expanding the Horizons of International Gas Trade"

March 30, 2009
Peter Terzakian:
"A New Energy Break Point: The Evolving Character of Natural Gas in North America"

April 29, 2010
Christian von Hirschhausen:
Perspectives of International Natural Gas Trade: Competition – Contracts – Cartel"

May 14, 2009
Robert Kleinberg:
"Principles and Methods of Gas Shale Production Enhancement"

July 22, 2009
Donald Gautier:
"USGS Circum-Arctic Resource Appraisal: Estimating Undiscovered Oil and Gas in the Highest Northern Latitudes"

Loring "Red" White:
"A Cost Appraisal of Arctic Oil and Gas Resources"

Jack Schuenemeyer:
"Aggregation Methodology for the Circum Arctic Petroleum Assessment"

September 24, 2009
Porter Bennett:
"U.S. Natural Gas Market Outlook: Boom and Bust, or New Beginning?"

October 19, 2009
Eric Gebhardt:
"The History of GE Gas-Fired Power Plants"

Appendix C: List of Acronyms

AFUE	Annual Fuel Utilization Efficiency
AMT	Alternative Minimum Tax
BOE	Bank of England
CBM	Coal Bed Methane
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Sequestration
CH_4	Methane
CHP	Combined Heat and Power Units
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
CO_2-e	Carbon Dioxide Equivalent
DME	Dimethyl Ether
DOE	Department of Energy
EERS	Energy Efficient Resource Standard
EIA	Energy Information Agency
ENS	European Nuclear Society
EPA	Environmental Protection Agency
EPPA	Emissions Prediction and Policy Analysis (model)
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FNDP	Fully Dispatched NGCC Potential
FUA	Fuel Use Act
GDP	Gross Domestic Product
GECF	Gas Exporting Country Forum
Gge	Gasoline Gallon Equivalent
GHG	Greenhouse Gas
GIIP	Gas Initially in Place
GOM	Gulf of Mexico
GRI	Gas Research Institute
GT	Gas Turbine
GTL	Gas to Liquids
ICF	ICF International
IEA	International Energy Agency
IECC	International Energy Conservation Code
IGCC	Integrated Gasification Combined Cycle
IP	Initial Production
ISO	Independent System Operator
L48	Lower 48
LCOE	Levelized Cost of Electricity
LNG	Liquefied Natural Gas
MARKAL	Market Allocation (model)
mD	Mendelevium
MECS	Manufacturing Energy Consumption Survey
MITEI	MIT Energy Initiative
MRH	Major Resource Holders
N_2O	Nitrous Oxide
NAFTA	North American Free Trade Agreement
NG	Natural Gas
NGCC	Advanced Natural Gas/Natural Gas Combined Cycle
NGLs	Natural Gas Liquids
NIMBY	Not In My Backyard
NO_X	Generic Term for the Mono-Nitrogen Oxides NO and NO_2
NPC	National Petroleum Council
NREL	National Renewable Energy Laboratory
NYMEX	New York Mercantile Exchange
OECD	Organization for Economic Co-Operation and Development
OPEC	Organization of the Petroleum Exporting Countries
PFC	Perfluorinated Compounds
PGC	Potential Gas Committee
R&D	Research and Development
RD&D	Research, Development, and Deployment
ReEDS	Renewable Energy Deployment System (model)
RES	Renewable Energy Standard
REX	Rocky Mountain Express Pipeline
RPSEA	Research Partnership to Secure Energy for America
RTF	Royalty Trust Fund
RTO	Regional Transmission Operators
SAE	Society for Automotive Engineers
SF_6	Sulfur Hexafluoride
SO_2	Sulfur Dioxide
TTF	Title Transfer Facility
USGS	United States Geological Survey
USREP	United States Regional Energy Policy