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Natural Gas 1998

Issues and Trends

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Preface

Natural Gas 1998: Issues and Trends provides a summary of the latest data and information relating to the U.S. natural gas industry, including prices, production, transmission, consumption, and the financial and environmental aspects of the industry. The report consists of seven chapters and five appendices.

Chapter 1 presents a summary of various data trends and key issues in today's natural gas industry and examines some of the emerging trends. Chapters 2 through 7 focus on specific areas or segments of the industry, highlighting some of the issues associated with the impact of natural gas operations on the environment.

Unless otherwise stated, historical data on natural gas production, consumption, and price through 1997 are from the Energy Information Administration (EIA) publication, *Natural Gas Annual 1997*, DOE/EIA-0131(97) (Washington, DC, November 1998). Similar annual data for 1998 and monthly data for 1997 and 1998 are from EIA, *Natural Gas Monthly* (*NGM*), DOE/EIA-0130 (99/02) (Washington, DC, February 1999).

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- Chapter 6. "Contracting Shifts in the Pipeline Transportation Market," Barbara Mariner-Volpe (202/586-5878).
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Figures 1 through 19 (Chapter 1) are composed of multiple illustrations. Below each figure title for Chapter 1, there is a list of subtitles describing each illustration. The subtitles are listed in the order in which the illustrations appear in the figure, from left to right moving down the page. The remaining figures (20 through 57) are single illustrations with no subtitles.

Executive Summary

Natural Gas 1998: Issues and Trends examines the current natural gas marketplace from a series of vantage points, providing insight into continuing and developing trends and a look at market and regulatory issues that have emerged as the industry has had to adapt to a growing and changing economy. A major issue that has emerged over the past several decades, and which is becoming closely integrated with natural gas growth, is its role in meeting future environmental concerns.

From 1990 through 1998, natural gas consumption in the United States increased by 14 percent. Its greater use as an industrial and electricity generating fuel can be attributed, in part, to its relatively clean-burning qualities in comparison with other fossil fuels. Lower costs resulting from greater competition and deregulation in the gas industry and an expanding transmission and distribution network have also helped expand its acceptance and use.

Several trends cited in this study indicate a substantial expansion of the natural gas market. Transmission deliverability on the national network has grown significantly since 1990 and greater investment for expansion is expected over the next several years. A steady growth in upstream supply, especially in the Gulf of Mexico and from Canada, and increased levels of consumption in all regions of the country, primarily in the industrial and electricity generation sectors, have motivated these expansions.

Use of Natural Gas To Address Electricity Growth Is Key to Gas Industry Expansion After 2000

In 1998, the parties to the Kyoto Protocol to the U.N. Climate Change Convention recommended measures aimed at decreasing the global level of greenhouse gases. Implementation of the Kyoto Protocol, or its recommendations as working parts of an accepted global effort, remains uncertain. However, it seems certain that natural gas will be a key factor in efforts to improve overall global environmental conditions.

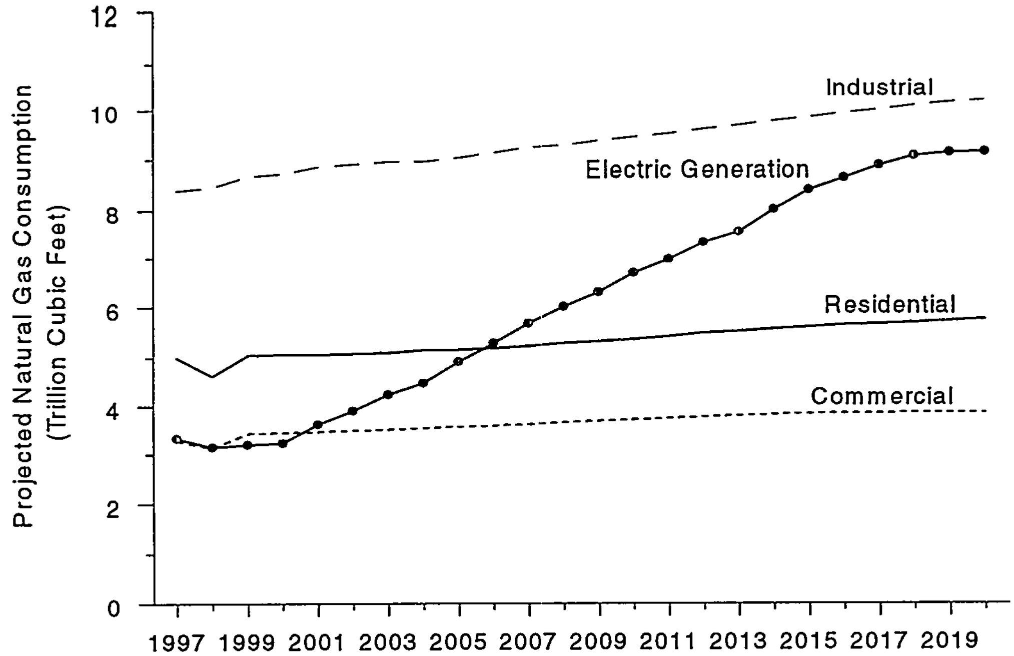
While environmental concerns could drive expansion of the use of natural gas, the direction of the natural gas marketplace in the near term generally will be determined more by traditional economic forces. Evolution of a restructured and more competitive natural gas industry during the past 10 years has been partly responsible for lower overall prices for natural gas. This trend of low prices could continue as long as demand does not outpace supply, the delivery system for natural gas grows, and enough capital investment is forthcoming to support expected growth.

Industrial consumption of natural gas reached an historic peak of 8.9 trillion cubic feet (Tcf) in 1996 but has declined somewhat since then. In 1998, the industrial sector consumed an estimated 8.5 Tcf, accounting for 44 percent of all end-use consumption, the largest share of any sector. Roughly one-quarter of the natural gas used by the industrial sector is consumed by companies that have been classified as nonutility generators (NUGs). Most NUGs are cogenerators, although this classification also includes independent power producers whose consumption of natural gas is solely for generation of electricity. By contrast, cogenerators typically use the heat from natural gas combustion both in manufacturing processes and to generate electricity. From 1992 through 1997, nonutility natural gas consumption accounted for 25 to 28 percent of total industrial consumption. Nonutility consumption grew at an annual rate of 4 percent from 1992 through 1997, while total industrial consumption increased at a 3-percent annual rate.

Electric utilities are expected to be the only end-use sector that increased its consumption of natural gas from 1997 to 1998, according to preliminary estimates. Data for the first 11 months of 1998 show that electric utility consumption of natural gas was 11 percent above that of 1997 for the same period. The average price paid for natural gas by electric utilities in 1998, available through October, was 13 percent below that in 1997. Annual natural gas consumption by electric utilities during the 1990s has been in the range of 2.7 to 3.2 Tcf.

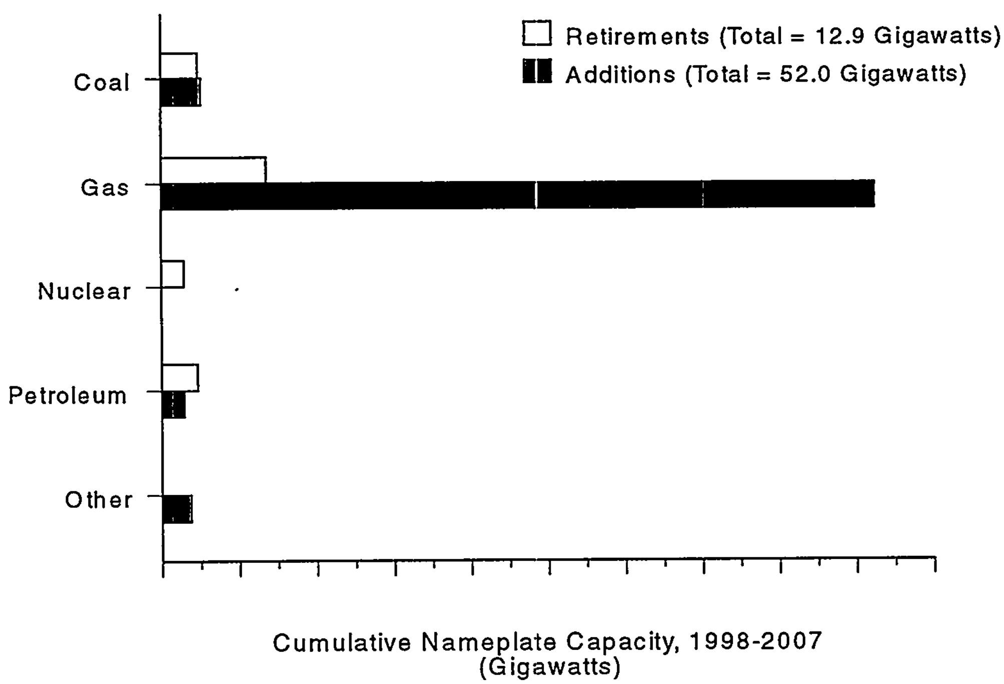
A major contributor to the increasing use of natural gas in the electric utility sector is the lower capital costs and shorter construction lead times of advanced combined-cycle plants in comparison with conventional coal-fired plants. Part of the push for lower-cost generation and shorter construction lead times can be attributed to the impact of the restructuring of the electric generation and transmission industry, particularly in light of growing electricity demand and the continued retirement of nuclear plants.

Figure ES1. Strong Growth in Natural Gas Usage Is Projected in Electricity Generation



Source: Energy Information Administration, *Annual Energy Outlook 1999*, National Energy Modeling System run AEO99B.D100198A.

Figure ES2. Most Electric Generation Capacity Additions Will Be Gas-Fired



Notes: "Gas" is natural gas; refinery, blast-furnace, and coke-oven gases; and propane. Other consists mostly of waste heat and includes renewables, most of which is hydroelectric power.

Source: Energy Information Administration, *Inventory of Power Plants in the United States As of January 1, 1998.*

Natural gas use by electric utilities and NUGs to generate electricity is projected to reach 9.2 Tcf by 2020, a little more than three times the 1998 level (Figure ES1). A principal factor in this is that nearly all future electric utility capacity additions in the United States are expected to be fueled by natural gas (Figure ES2). A growing trend in the development of gas-fired electric generation is the evolving independent ("merchant") power plant sector of the electric industry. These enterprises, which are expected to be primarily gas-fired facilities, are built without prior long-term sales commitments and therefore are very dependent upon fuel efficiencies and energy market economics.

Gas Resources Are Substantial But Continued Supply Growth Is Unlikely Without Price Recovery

While domestic natural gas production generally increased from 1994 through 1997, reserve additions replaced nearly 107 percent of production, arresting a long-term decline in total proved reserves. The majority of proved gas reserves in the Lower 48 States are located in the onshore and offshore Gulf Coast region, an area that is characterized by expanding development of the Outer Continental Shelf. Natural gas reserves in the Gulf region now represent 51.6 percent, or 80.9 Tcf, of proved reserves in the Lower 48 States.

Natural gas production in 1998 is estimated to be 19.0 Tcf, essentially the same as in 1997, despite lower overall demand. In 1997, natural gas from onshore conventional sources accounted for the largest share of U.S. production, about 39 percent, while production from onshore unconventional sources, such as coalbeds, Devonian shale, and tight sands, accounted for 19 percent. Production from unconventional sources became the largest contributor to increased natural gas production during the 1990s, growing at an annual rate of 4 percent between 1990 and 1997.

Natural gas well completions increased to nearly 12,000 in 1997. Generally higher wellhead prices in 1997, averaging $2.34 per thousand cubic feet compared with $1.62 in 1995 (prices in constant 1998 dollars), served as an incentive for increased drilling. Completions increased 8.9 percent in 1998 to 11,907; however, monthly completions declined during the year as wellhead prices fell to near or below $2.00 per thousand cubic feet in most months. The even greater fall in oil prices during 1998 helped redirect resources toward gas, thus supporting the higher gas well count for the year.

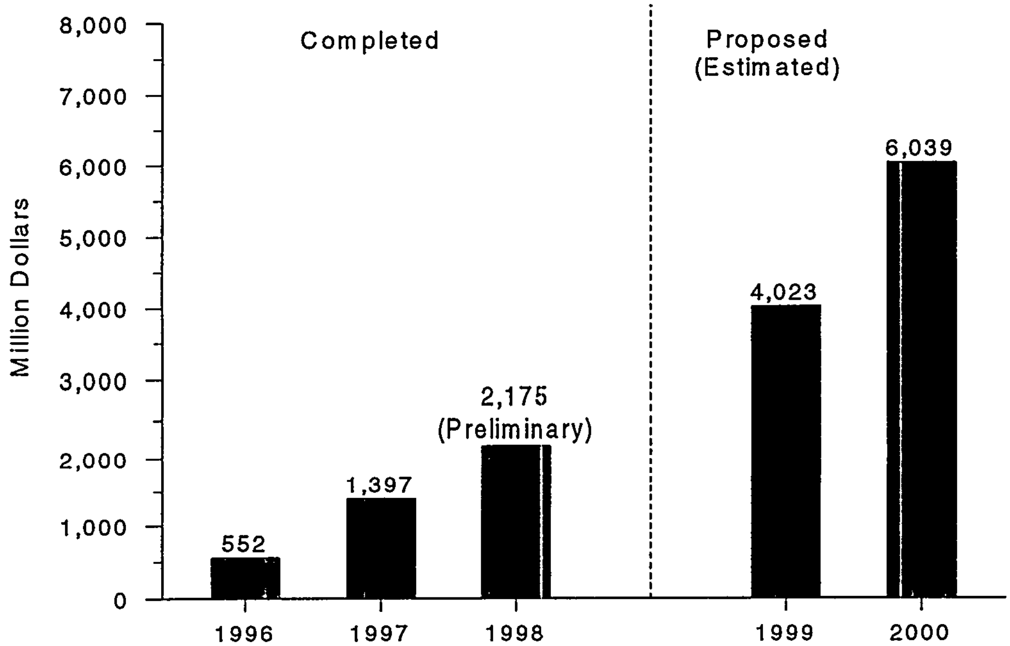
End-use natural gas consumption reached a record high of 20.0 Tcf in 1996 and 1997, then declined 4 percent in 1998 to 19.3 Tcf. After 7 years of sustained growth, natural gas consumption in 1998 fell below its previous year level for the first time this decade. Relatively mild weather throughout the year across most of the Lower 48 States can be cited as the primary cause for the reduced demand in the residential and commercial sectors. The net consumption falloff, along with abundant foreign supplies to the United States and competition driven by the overall slump in petroleum prices, resulted in a significant drop in natural gas prices.

The weather situation also resulted in lower withdrawals from storage during the 1997–98 heating season, and by its close, the remaining working gas storage level was 1.2 Tcf, the highest end-of-season level in 3 years. Reduced demand for storage replenishment created an additional downward pressure on prices since the lower market demand increased gas-on-gas competition (between supplies normally flowing into storage and normal seasonal base-load supplies). Wellhead prices fell about 15 percent in 1998 compared with 1997 levels, contributing to price drops of 1 and 5 percent in the residential and commercial sectors, respectively, and 12 and 13 percent (estimated) in the industrial and electric utility sectors.

The current low levels for natural gas prices could have a longer-term impact on natural gas exploration, development, production, and even anticipated pipeline expansions. Lower oil prices have dampened oil drilling activities and thus have affected the future production levels of natural gas associated with oil production. Lower natural gas prices and demand could create similar fallout in the gas industry. If natural gas demand growth levels off, then it is likely that some proposed pipeline expansions, especially those into highly competitive markets, might be postponed or even canceled.

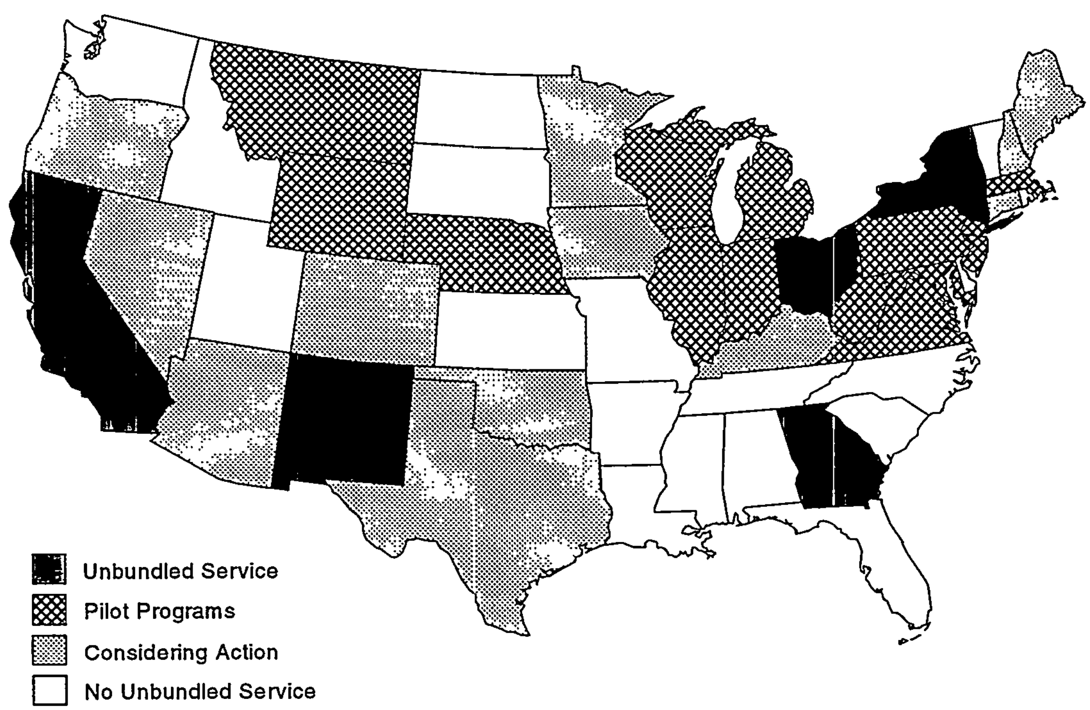
The potential for bountiful long-term natural gas supplies is strong in light of the expected remaining recoverable U.S. gas resources. These include 167 Tcf in proved natural gas reserves at the end of 1997 and roughly 1,300 Tcf as technically recoverable natural gas resources. In addition, Earth's vast deposits of natural gas hydrates would provide a very significant new source of natural gas if future technology should enable the commercial recovery of the methane in these deposits. Natural gas hydrates are solid, crystalline, ice-like substances composed of water, methane, and usually smaller amount

Figure ES3. Annual Pipeline Investment Could Reach $6 Billion in 2000



Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Pipeline Construction Database through December 1998.

Figure ES4. Eighteen States and the District of Columbia Have Some Form of Residential Choice Program



Source: Energy Information Administration (EIA), Office of Oil and Gas, derived from General Accounting Office, *Energy Deregulation: Status of Natural Gas Customer Choice Programs* (December 1998) and information gathered by EIA analysts.

of other gases. The naturally occurring version is primarily found in ocean-bottom sediments at water depths that exceed 450 meters (approximately 1,476 feet) and in permafrost regions onshore. The U.S. Geological Survey's 1995 mean (expected value) estimate is that in aggregate these deposits contain 320,222 Tcf of methane-in-place. Even if only a small percentage of the large in-place volume could be commercially produced, the impact would be dramatic. Recovery of only 1 percent of the hydrate resource would more than double the domestic gas resource base.

Significant Pipeline Expansion and Investment Will Be Needed To Support a Projected 32 Tcf Market

Interstate pipeline capacity has increased by more than 16 percent (on an interregional basis) during the past decade. Average daily use of the network was 72 percent in 1997, compared with 68 percent in 1990. More than 17 new interstate pipelines were constructed, as well as numerous expansion projects, between 1990 and the end of 1998. In 1998, at least 47 projects were completed adding approximately 10 billion cubic feet (Bcf) per day of overall capacity to the national grid.

For 1999 and 2000, more than 75 pipeline projects (20.1 Bcf per day) have been proposed for development in the Lower 48 States. While some of these projects are only in the initial planning stage with no firm cost estimates available, based upon preliminary estimates, as much as $10.0 billion could be spent on natural gas pipeline expansions in the next 2 years (1999–2000) (Figure ES3). The largest expenditures, about $6.0 billion, would include several large projects now scheduled for completion in 2000, such as the Alliance Pipeline ($2.9 billion), the Independence Pipeline ($680 million), and the Columbia Gas System's Millennium project ($678 million). In all likelihood, however, some of the 75 proposed projects may be canceled or postponed until the next decade, because of competition, changed market conditions, and/or regulatory actions.

A major factor underlying the network expansion is the growing availability of new production from Canada. U.S. access to Canadian supplies, as measured by crossborder pipeline capacity, increased by 75 percent (from 6.5 to 11.4 Bcf per day) between 1990 and 1997 and by another 9 percent, or 997 million cubic feet per day, in 1998. An additional 3.7 Bcf per day of capacity could be in place by 2000 if all currently planned projects are completed. This would amount to a 132-percent increase in import capacity between 1990 and 2000. Put another way, capacity to import gas from Canada in 1990 was only 19 percent as large as capacity to export gas from the U.S. Southwest, the major producing region in the United States. But by the end of 2000, import capacity from Canada could be as much as 42 percent of the Southwest's export capacity.

Regulatory Reform Has Altered Markets at Both the Interstate and State Levels

Numerous transportation service contracts written prior to market regulatory reform contain terms and conditions that are no longer deemed economic by shippers. Consequently, some of the contracts are not being renewed or the terms are being revised upon renewal. Some firm capacity is being "turned back" to the pipeline company. It is estimated that 20 percent of firm service capacity under these older contracts has not been renewed. Some of this capacity has been resold, but a significant amount remains uncommitted or has been resold at discounted rates, which could impede the pipeline companies' cost recovery. Costs not recovered from new customers then fall on either the remaining pipeline customers or the shareholders. Potential capacity turnback actions between 1998 and 2003 represent about 8.0 trillion Btu per day, or 8 percent of currently committed capacity. If the capacity is not remarketed at maximum rates, pipeline company revenues could be reduced.

State unbundling of services continued in 1998 although at a relatively slow pace. As of July 31, 1998, only five States had implemented complete unbundling programs for core customers (Figure ES4) or passed legislation to give customers the right to choose their own gas supplier, only two more than at the end of 1996. The approximately 14 million residential customers covered in these States represent about 20 percent of the Nation's natural gas customers. Another 13 States and the District of Columbia have pilot programs underway, 12 States are considering action, and 18 States have yet to take any significant action.

Corporate Combinations Are Reaching All-Time Highs as Companies Look for Opportunities in Both Gas and Electricity

A number of major market participants are engaging in various forms of corporate combinations, such as mergers, acquisitions, and strategic alliances. The value of mergers and acquisitions within the natural gas industry has risen nearly fourfold in this decade, from $10.4 billion in 1990 to $39 billion in 1997. This increase parallels an enormous surge in corporate combinations (mergers, acquisitions, joint ventures, and strategic alliances) across the energy sector, from $21.4 billion in 1990 to $106.4 billion in 1997. In 1998, the value of energy sector combinations more than doubled, to $220 billion, with the announcement of such blockbuster mergers as British Petroleum with Amoco and Exxon with Mobil.

The growth in natural gas industry combinations does not indicate a decrease in competition, however. For example, between 1992 and 1997, the share of sales by the top four marketers declined by one-third to 21 percent, while their sales volumes more than doubled. Sales by the top 20 slipped only from 69 to 66 percent, but yearly sales volumes more than tripled to 40 Tcf.

The current wave of corporate combinations appears set to continue as companies throughout the energy sector jockey for position not only in North America but worldwide with both the number and size of combinations increasing. Nevertheless, combinations in the energy sector remained a relatively small part of corporate combinations for the United States in general, representing only about 11 percent of the total value of all combinations in 1997.

Corporate combinations in the natural gas industry have become an integral part of the strategies developed to address changing conditions in the industry. Specific objectives behind the combinations vary, but many combinations share the goal of expanding beyond a single commodity or a single function to encompass a broad spectrum of energy sources, products, and services, thus becoming a "one-stop energy center."

Outlook

U.S. reliance on fossil hydrocarbon fuels (mainly coal, natural gas, and petroleum products) is projected to increase during the next two decades. In 1997, 85.3 percent of the domestic energy was produced by fossil fuels. By 2020, fossil fuel usage is expected to account for 89.7 percent of domestic energy production with 28 percent attributable to natural gas. Concurrent projections also are that natural gas consumption will move above the historical peak of 22 trillion cubic feet (Tcf) (reached in 1972) in 1999, increase another 6 Tcf by 2010, and reach 32 Tcf by 2020. This growth is expected to come about largely as a result of increased use of natural gas for electricity generation by both electric utilities and nonutility generators.

The expected use of natural gas could become higher than current projections if the United States were to adopt the Kyoto Protocol. The agreement would specify a greenhouse gas target during the commitment period 2008 to 2012 that, on average, would be 7 percent below 1990 levels, or about 1,250 million metric tons. Natural gas use would likely expand while coal and oil consumption and production would decrease, primarily because the carbon content per Btu of natural gas is only 55 percent of that for coal and 70 percent of that for oil. Under the protocol, natural gas consumption would be 0.6 to 3.5 Tcf higher by 2010 under a number of alternative scenarios.

A major amount of new pipeline capacity is expected to be built over the next several years to accommodate projected growth. In addition, complementary facilities, such as market centers and storage facilities, are also expected to expand to support it. Although only a few new market centers are likely to become operational during the next few years, the services and flexibility offered at many existing sites can be expected to be expanded and improved, especially those located in the Midwest and Northeast that could support the expanded growth of Canadian supplies. Underground storage operations, which facilitate both market center services and efficient pipeline operations, will also be selectively expanding over the next several years although not at the scale seen earlier in the decade. A number of the major proposed pipelines slated to carry additional gas from Canada and the Midwest are associated with already scheduled storage expansions.

Not only have the capabilities of the natural gas production, transmission, and distribution network grown significantly since 1990, but the quality and flexibility of service have improved as well. Additional substantial growth and improvement are expected over the next several years. Expanding interconnectivity within the pipeline grid, accompanied by improved services, will further integrate the natural gas production and delivery system, thereby helping to accommodate anticipated future demand.

1. Overview

Natural gas use in the United States has shown substantial gains during the past decade, returning to the upward growth trend experienced prior to 1972 when consumption peaked at 22.1 trillion cubic feet (Tcf) (Figure 1). In 1996 and 1997, the Nation again consumed about 22.0 Tcf of natural gas, close to the 1972 record level. For the past 25 years, however, the development and structure of the industry contrasted sharply with the industry prior to 1972. From 1950 to 1972, natural gas use grew at an annual rate of 6.3 percent. This growth was reversed in the mid-1970s as the market, saddled with a regulatory and contractual structure that did not allow price signals to be quickly or effectively transmitted throughout the system, began to decline. Curtailments of natural gas supplies to some high priority users, such as hospitals and schools, in the winter of 1976-77 highlighted the market imbalances and difficulties. Natural gas was increasingly viewed as a scarce and unreliable resource.

Congress reacted to the 1976–77 curtailments with legislation to encourage additional supplies of natural gas and to conserve natural gas for nonboiler fuel applications. This legislation, which included the Natural Gas Policy Act of 1978 (NGPA), initiated a major restructuring of the industry: a restructuring that is still evolving. The NGPA gradually removed price controls on much of the gas produced domestically, a process completed with the Natural Gas Wellhead Decontrol Act of 1989.

From 1972 to 1986, natural gas use dropped to less than three-quarters of the peak level. From the 1986 low of 16.2 Tcf, consumption has recovered, growing at an annual rate of 2.3 percent through 1998. This average rate of growth has occurred despite the leveling off of consumption in 1996 and 1997 at approximately 22 Tcf, followed by a 3-percent decline in 1998. This recent decline in consumption reflects the impact of moderate weather with lower heating demand during the past two heating seasons and the lower oil prices during the past year. The return of natural gas consumption to levels close to the peak of 25 years ago has been accompanied by dramatic market and regulatory restructuring. Some of these events include:

- Federal Energy Regulatory Commission (FERC) Orders 436 (1985) and 636 (1992) have altered the market for natural gas, splitting off or "unbundling" the commodity purchase from the transmission service.

- An entirely new contracting structure has developed for purchases of the commodity and also for services. Purchases of natural gas were once typically arranged under contracts of 20 or more years, but new "long-term" contracts may have terms of 1 or a few years.

- Gas production has shown a long-term increase, rising from 16.1 Tcf in 1986 to an estimated 19.0 Tcf in 1998, despite an average wellhead price of $2.03 per thousand cubic feet (in constant 1998 dollars) during the 1990s—49 percent below the 1983 peak of $3.99. Technological advances have enhanced the industry's ability to find and develop new gas reserves at competitive prices.

- Pipeline deliverability has increased sharply. At least 17 new interstate pipeline systems have been constructed since 1990, adding more than 8 billion cubic feet per day of capacity by the end of 1998. In addition, several pipeline expansions have been completed to bring greater flows from Canada. Today, the interstate pipeline system is a national grid with sufficient flexibility to move gas in many directions.

- New England, which for many years has been served principally by fuel oil, now has significantly greater access to natural gas. The expected flow of gas in late 1999 from the Sable Island project in the northern Atlantic off eastern Canada will further expand the potential for growth in the Northeast market.

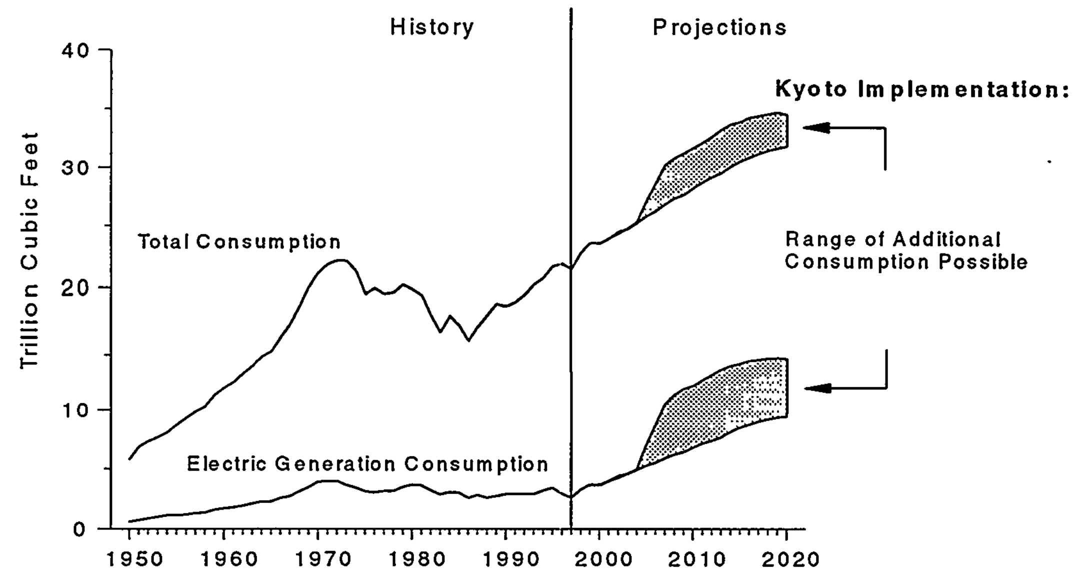
- Imports have taken a greater role in meeting supply. They supplied 4 to 5 percent of U.S. natural gas consumption in the early 1980s but provided about 14 percent in 1998.

- Price volatility has become a significant characteristic of the market, and financial markets have developed to facilitate the trade of natural gas and the hedging of prices.

Most notably, the perception of the availability of natural gas has changed from that of concern about scarce supplies to an assessment that the United States has relatively abundant resources. In the near term (1999–2000), growth in natural gas consumption will likely be related to the effect of more normal weather patterns and continued, although slowing, economic growth. Through 2020, the outlook for natural gas is robust with demand projected to

Figure 1. Natural Gas Consumption Is Expected To Increase About 50 Percent by 2020 . . .

. . . And even more if the Kyoto Protocol is implemented



Note: The Energy Information Administration report *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity* examines a series of six cases looking at alternative carbon emission levels. The reference case represents projections of energy markets and carbon emissions without any enforced reductions and is presented as a baseline for comparison of the energy market impacts in the reduction cases. The highest consumption patterns for natural gas are seen in some of the intermediate cases, principally the "Stabilization at 1990 Levels" and the "3 Percent Below 1990 Levels." For this figure, the reference case and the "3 Percent Below 1990 Levels" are used to illustrate a potential range of additional demand.

Source: Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity* (October 1998), AEO98 National Energy Modeling System runs KYBASE.D080398A and FD03BLW.D080398B.

grow to about 32 Tcf, an increase of about 50 percent from the 1998 level.[1] Further, as environmental concerns have led to proposals (such as the Kyoto Protocol) to limit carbon emissions worldwide, interest has heightened in the role that natural gas can play in meeting environmental goals. Natural gas is viewed as a relatively benign fossil fuel for the environment and is projected to play a large role in meeting targets associated with the reduction of greenhouse gases. If the Kyoto Protocol is implemented, gas usage could move as high as 35 Tcf by 2020.[2]

The concern about scarce natural gas supplies in the late 1970s led to limits on expansion of the gas market, particularly in the boiler fuel market. Since 1990, yearly consumption of natural gas for use in electricity generation has varied from 2.7 to 3.2 Tcf, down from 4 Tcf in the early 1970s. Now the future of natural gas is expected to be closely tied to electric generation, with consumption in that sector projected to climb to more than 9 Tcf in 2020—an annual rate of 4.5 percent from 1997. In 2020, electricity generation is expected to account for about 28 percent of natural gas consumption, slightly below the 32 percent consumed by the industrial sector. By contrast, in 1997, electricity generation accounted for about 15 percent of total natural gas consumption compared with 38 percent by industrial consumers of natural gas.

New generation capacity will be needed to meet growing electricity demand and to offset the expected retirement of nuclear plants. Major factors behind the increased use of natural gas in the electric generation sector are the lower capital costs, shorter construction lead times, and higher efficiencies associated with advanced combined-cycle plants in comparison with conventional pulverized coal plants. Part of the push for lower-cost generation and shorter construction lead times can be attributed to the impact of the restructuring of the electric generation and transmission industry. If the impacts of Kyoto implementation are taken into account, assuming no changes in domestic laws and policies, electric generation use of natural gas by 2020 could range from 12 to 15 Tcf. In some cases by 2010, electric generators could consume more natural gas than that consumed in any other sector.

Natural Gas 1998: Issues and Trends attempts to put industry developments within an environmental perspective, highlighting some of the issues associated with the impact of natural gas operations on the environment, as well as developments that will be necessary for natural gas to fulfill the role that has been projected. Some of the major topics addressed in the report are:

- **Near-term market effects of relatively mild winters the past 2 years.** The market for natural gas leveled off in 1997 and then declined by 3 percent in 1998 as mild winters have dampened seasonal gas demand. The lower-than-usual seasonal demand has contributed to lower prices, lower price variation, and flat domestic production levels. Storage operations are showing higher inventories than have been seen in several years. Additional pipeline and storage development has been slowing. A synopsis of these and other current data trends and developing issues is contained in Chapter 1 of the report.

- **Environmental effects of using natural gas.** Natural gas is a cleaner burning fuel than other fossil fuels. While natural gas does emit greenhouse gases, particularly carbon dioxide, the level of pollutants associated with its use is lower than for other fossil fuels. Chapter 2 summarizes and compares the emissions of natural gas relative to other fuels. It also provides a summary of other ways that the exploration, development, drilling, and use of natural gas affect the environment. And lastly, it illustrates some of the technology developments and other ways that natural gas can be used to reduce emissions.

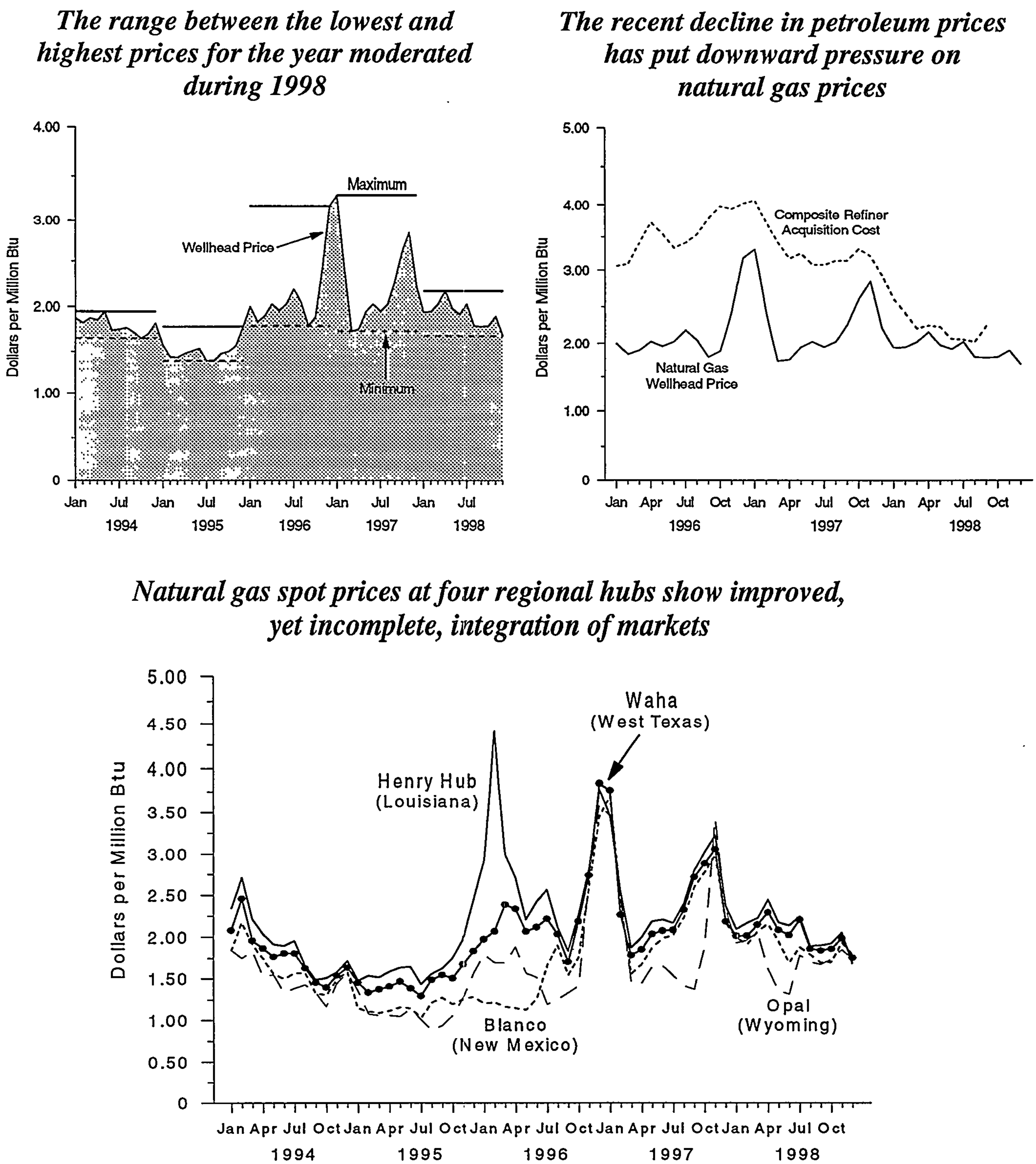
- **Potential supply of natural gas.** With projections of a 50-percent expansion of the domestic natural gas market, questions arise about the sources of these additional supplies and technological developments that may be critical to meeting these projections. Some of the issues being addressed in the report include the expansion of the offshore production potential by the use of deep-water technology and the much longer-term potential of natural gas hydrates. As discussed in Chapter 3, gas hydrate resources are massive and dwarf current fossil fuel resources. The advent of gas hydrate production could have a major impact on energy supply patterns, energy consumption patterns, and prices of crude oil and products and conventional natural gas worldwide and in the United States. In the nearer term, the production of natural gas from deep water has increased significantly as technology has developed to facilitate and reduce costs associated with drilling in offshore water deeper than 1,000 feet (approximately 305 meters). This area has great potential and is seen as important to expanding domestic production levels. Chapter 4 analyzes recent production trends in the offshore Gulf of Mexico and examines the economics of offshore projects.

- **Marketing and distribution of natural gas.** In competitive energy markets, the pricing of natural gas and related services is critical to the marketability of natural gas, particularly to the expanding electric generation industry. With generation-dispatch decisions made continuously based on fuel costs, the cost and deliverability of natural gas to electric generation units is a critical component of the decision. The institutional and pipeline infrastructures associated with the delivery of natural gas are undergoing substantial adjustment and investment. Pipeline construction can require long lead times and large investments. Analysis of pipeline expansions requirements and accompanying investment requirements is presented in Chapter 5.

  Contractual arrangements for transporting natural gas that have been in place for 10 to 20 years are expiring and being renegotiated. These new contracts will provide more flexibility to shippers of natural gas, allowing them to adjust contractual terms to their needs, and potentially lower the cost of transmission services to many consumers. Chapter 6 presents analyses of developing trends in new contracts and capacity trading. In addition to the financial and contractual needs of the expanding market, new pipeline companies will be required to match supply sources with developing markets. Mergers of natural gas companies in all aspects of the industry from production through distribution with other natural gas companies or with other energy entities portend a new era in the provision of natural gas services. Chapter 7 presents an analysis of what is behind these mergers and how service to consumers is likely to be affected.

The opportunities available to the industry are substantial. The natural gas market is projected to show significant growth over the next 20 years because North American natural gas resources are considered both plentiful and secure and their increased use relative to other fossil fuels can reduce levels of harmful emissions.

Figure 2. Price Variation Is a Significant Characteristic of the Market



Sources: Energy Information Administration (EIA), Office of Oil and Gas. **Wellhead Prices:** derived from EIA: 1980-1982—*Historical Monthly Energy Review 1993*, October 1998—*Natural Gas Monthly* (December 1998), November and December 1998—*Short-term Energy Outlook 4th Quarter* (1998). **Refiner Acquisition Cost:** *Monthly Energy Review* (December 1998). **Spot Market Prices:** Financial Times Energy, Inc., *Gas Daily*.

Wellhead and Spot Market Prices

Prices are an important indicator of the industry's capability relative to current market requirements. Prices also are a bellwether of future trends, and so the decline in natural gas prices from 1997 to 1998 is interesting both as a measure of current industry performance and for the implications for likely developments in the next few years. The average wellhead price in 1998 was $1.92 per million Btu (MMBtu), which is $0.34 or 15 percent less than in 1997.[3] Prices declined from 1997 to 1998 at least in part because of mild weather that lowered demand. Additional downward pressure on prices was provided by abundant gas supplies from both domestic and foreign sources, as well as interfuel competition driven by lower oil prices.

- **After significant increases in the previous 2 years, the average wellhead price declined in 1998 as warmer-than-normal weather and abundant stock levels dominated the marketplace.** The 15-percent warmer-than-normal temperatures in 1998 helped reduce consumption by an estimated 683 billion cubic feet (Bcf) or 3 percent from the previous year. Domestic production increased only slightly, by 75 Bcf, which was somewhat surprising in light of continually weakening prices in the latter half of the year. Foreign supplies also increased, with estimated net imports rising 134 Bcf as crossborder capacity expansion increased. These factors combined to produce a generally downward price trend from the monthly peak of $2.85 per MMBtu in November 1997 to the low of $1.69 in December 1998.[4] Along with the decline in the wellhead price, the range of monthly prices in 1998 was only $0.48 per MMBtu, compared with $1.37 in 1996 and $1.57 in 1997 (Figure 2).

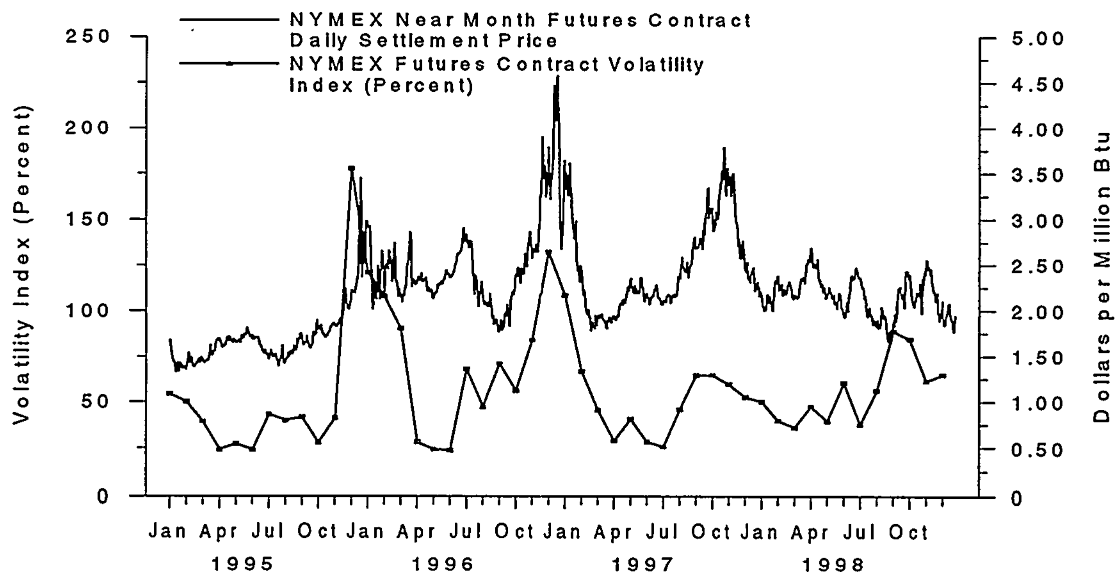
- **A counterseasonal pattern similar to that in 1997-98 is evident in the 1998-99 winter as monthly prices declined after an increase early in the season.** During the past few years, storage-related concerns have led to price increases before or at the start of the heating season. As the 1997-98 heating season approached, prices were driven upward by expectations related to storage levels. Working gas in storage at the end of October 1997 was 2.89 trillion cubic feet (Tcf), only slightly above the initial 2.80 Tcf for the previous heating season, during which average prices peaked at $3.31 per MMBtu in January. This price increase was driven at least partially by the reluctance of storage operators to draw down stock levels heavily in the initial portion of the heating season. However, temperatures were unusually warm in late 1997, unlike in the prior year, reducing demand. The lack of market fundamentals supporting higher prices caused prices to fall from November 1997 to January 1998. Prices then began to climb to a peak of $2.16 in April. After the heating season, firms began to refill storage at accelerated rates in response to forecasts calling for unusually hot summer weather in many parts of the United States. The forecasts, however, proved accurate only for the Southwest, and so prices subsequently declined. The low prices did contribute to high storage refill rates, resulting in the highest stock levels in 4 years at the start of the 1998-99 heating season. High storage levels and warm weather were primary factors contributing to a sharp decline ($0.21) in the average wellhead price from $1.90 per MMBtu in November to $1.69 in December 1998.

- **Competitive pressure from a steady decline in petroleum prices during 1998 has contributed to the relative "softness" of gas prices.** The composite refiner acquisition cost of a barrel of crude oil averaged 33 percent less in the first three quarters of 1998 compared with the corresponding period of 1997. As prices for the raw product fell, refined petroleum product prices declined but to a lesser degree. The 15-percent decline in yearly natural gas prices between 1997 and 1998 is consistent with the expected downward pressure from petroleum competition. Monthly gas and oil prices were unusually close to parity for much of 1998 (Figure 2).

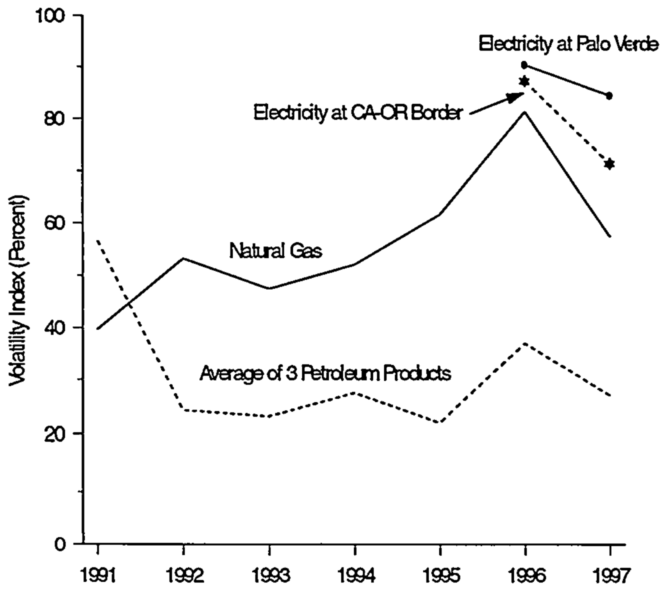
- **Monthly spot prices show increased convergence as the network expands to improve interconnections between regional markets.** Market hub prices in the initial years of open-access transportation were rather strongly correlated.[5] As markets evolved, however, the physical network did not reflect the growing needs of the system. By 1996, obvious examples of price divergence between regions appeared. In February, prices spiked at the Henry Hub as a sudden cold snap caused demand to soar in northern markets, but other markets were relatively unaffected. Prices at Blanco and Opal in 1995 and most of 1996 were persistently below and not conforming to the patterns seen elsewhere. Major capacity expansions in mid-1996 helped to alleviate transmission bottlenecks at the San Juan Basin (near Blanco) and allowed more New Mexico gas to get to Midwest and Eastern markets. Additionally, daily pipeline capacity for moving gas from the central Rocky Mountain area (Opal, WY) to the Southwest has grown by more than 60 percent since 1990. These actions have helped to improve interconnections between regional markets, however, continuing price disparities indicate that further adjustments are necessary to achieve an integrated North American network (Figure 2).

Figure 3. Futures Trading Is a Key Component of Efficiently Functioning Natural Gas Markets

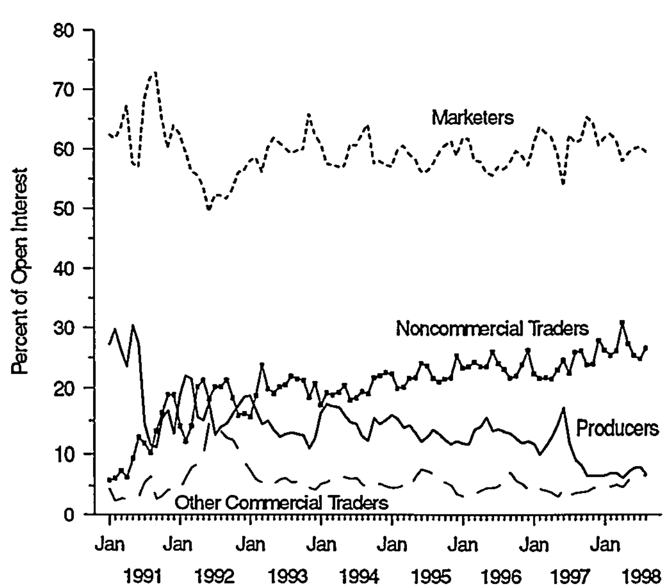
The volatility of natural gas futures prices at the Henry Hub declined over the past 2 years



Natural gas is second only to electricity in energy futures price volatility



Marketers and noncommercial traders dominate trading in natural gas futures contracts



NYMEX = New York Mercantile Exchange.

Note: The price volatility illustrated in these graphs is the annualized standard deviation of daily price changes expressed in percentage terms. This volatility measure is "annualized" by multiplying the standard deviation corresponding to the series of daily prices being examined (here, monthly and annually) by the square root of 250, the approximate number of trading days in a year. For lower right graph, see endnote 7 for descriptions of trader categories.

Sources: **NYMEX Near-Month Futures Contract Settlement Prices:** Commodity Futures Trading Commission. **Volatility Indices:** Energy Information Administration (EIA), Office of Oil and Gas. **Reportable Interest in Natural Gas Futures Contracts:** New York Mercantile Exchange.

Natural Gas Futures Market

The range of settlement prices of the New York Mercantile Exchange (NYMEX) near-month futures contract for delivery at the Henry Hub[6] narrowed markedly in 1998 with respect to the previous 3 years. The spread between the highest and lowest prices in 1998 was just over $1.00 per million Btu (MMBtu), while in each of the previous 3 years this spread exceeded $2.00, reaching an all-time high of $2.81 in 1996. In fact, only 1991 had a narrower spread than 1998, but only by $0.035. Contrary to the normally expected pattern of prices peaking in the third or fourth quarter, 1998 futures prices reached their highest level in the spring; from there the trend was down. Despite rallies in the summer and at the beginning of the heating season, the futures price dropped nearly one-third from its April high of $2.689 per MMBtu, ending the year at $1.945.

- **During the past 2 years, the price volatility of the NYMEX futures contract has declined** (Figure 3). Not surprisingly, the price volatility of the near-month futures contract tends to be greater during heating season months and less in the summer months, reflecting the increased levels of and swings in demand together with greater uncertainty about the availability of supply. In the three heating seasons prior to 1998-99, colder-than-normal November weather and concerns about the adequacy of storage levels contributed to futures prices spiking to peaks in the fourth quarter. Despite these peaks, price volatility has been declining since the 1995-96 heating season. This decline is partly attributable to the fact that the December-through-March periods of both 1996-97 and 1997-98 had somewhat milder weather than average. By contrast, 1998 futures prices peaked at the beginning of the second quarter. From this point to the end of the year, the general trend was down, as market fundamentals of large and uninterrupted supplies, moderate demand, and a robust stock build prevailed. The beginning of the 1998-99 heating season saw a run of warmer-than-normal weather in November and early December, and, with storage inventories on November 1 at a 6-year high, futures prices collapsed in the final 2 months of 1998.

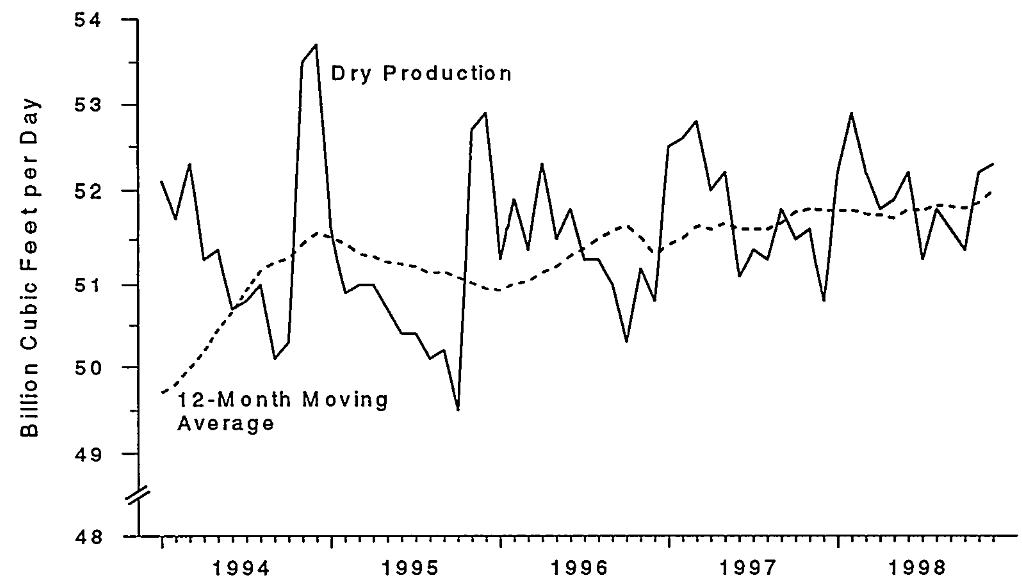
- **Despite the decreased volatility during 1998, natural gas futures price volatility is the second highest of all energy sources.** Price volatility in the natural gas market generally exceeds volatility in markets for other energy as well as other commodity markets (Figure 3). A number of characteristics of the gas market contribute to this volatility. For instance, the variability of end-use consumption of natural gas directly affects gas flow in the transmission and distribution network, requiring constant adjustment of market supplies to maintain system integrity under changing delivery conditions. Further, pipeline capacity can be constrained under certain conditions. Also, about 86 percent of annual gas consumption is supplied by domestic production, yet production offers limited flexibility in flow rates. During the heating season, storage is the primary source of swing supply, satisfying as much as 80 percent of demand in some areas on peak days. Thus, markets are particularly sensitive to stock levels leading up to, as well as during, heating seasons. Yet storage levels can be quite variable, since stocks at any point during the heating season reflect the outcome of myriad decisions to withdraw or replenish stored gas, which affect, and are affected by, any number of economic factors regarding supply and price and the market's perception of these factors.

- **Since the launch of the Kansas City Board of Trade (KCBOT) futures contract in 1995, its trading volume has leveled off at less than half the level of its first month of trading, while the NYMEX Henry Hub trading volume has continued to grow.** The monthly number of KCBOT contracts traded has yet to return to the level recorded in that contract's first month, when over 19,000 contracts were traded. Since February 1996, monthly trading volumes have fallen in a range of about 4,000 to 10,000. By contrast, trading of the NYMEX Henry Hub contracts has continued to grow. The yearly total of NYMEX contracts traded increased by 9 percent from 1995 to 1996, by 35 percent the following year, and by 34 percent in 1998. There continues to be an order of magnitude difference in trading between the two contracts, as monthly trading volumes of the NYMEX contracts have exceeded 1 million since August 1997.

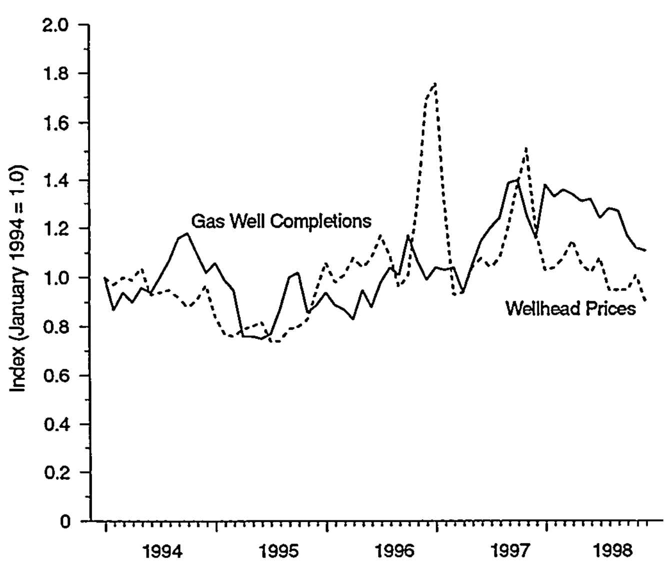
- **Natural gas marketers control the largest proportion of open interest in NYMEX Henry Hub futures contracts.** They typically hold around 60 percent of total monthly reportable open interest (Figure 3).[7] The share of open interest held by noncommercial traders, such as financial firms and mutual and hedge funds, has steadily increased since the beginning of natural gas futures trading. Today, they hold about 25 percent of monthly reportable open interest. Producers' proportion of open interest has tended to decline over the years and since October 1997 has remained at about 7 percent. The share held by all other commercial traders has held fairly constant over the past 5 years at just over 5 percent. Based on current NYMEX Henry Hub trading levels alone, on any given trading day, marketers control the disposition of about 2.2 to 2.6 trillion cubic feet of gas, speculators about 1 trillion cubic feet, and producers and other hedgers about 200 to 300 billion cubic feet.

Figure 4. Annual Natural Gas Production Is at its Highest Level Since 1981, 19.0 Trillion Cubic Feet in 1998

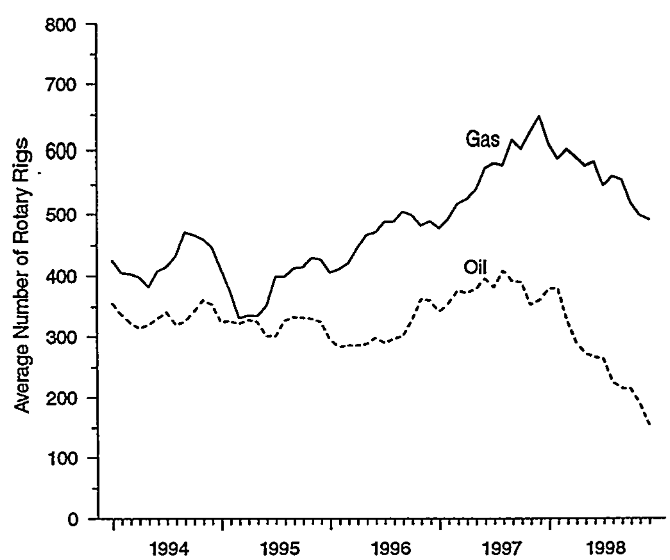
Dry natural gas production has been slowly increasing . . .



. . . But the growth in gas well completions slowed in 1998



Still, the gap between gas and oil drilling rigs continued to increase in 1998



Sources: Energy Information Administration (EIA), Office of Oil and Gas. **Production and Wellhead Prices:** derived from EIA, *Natural Gas Monthly*, various issues. **Gas Well Completions:** EIA's Well Completion Estimation Procedure (WELCOM) as of April 5, 1999. **Rotary Rigs:** EIA, *Monthly Energy Review*, various issues.

Natural Gas Production

Dry natural gas production has been increasing slowly during the past several years. Production in 1998 is estimated to be 19.0 trillion cubic feet, 75 billion cubic feet (Bcf) more than in 1997. The 1998 level is the highest since 1981 when 19.2 trillion cubic feet was produced.[8] As production has grown in recent years, the differences in daily production rates in each month have narrowed (Figure 4). During 1994, production in any month was between 50.1 to 53.7 Bcf per day, a difference of 3.6 Bcf per day. For 1998, the estimated low and high rates are 51.3 and 52.9 Bcf per day, respectively, for a difference of only 1.6 Bcf per day. More stable production rates during the year may be attributable to increased availability and use of storage by producers, and slightly lower monthly peak consumption levels because of less severe temperatures during recent winters.

- **Conventional nonassociated production in the onshore Lower 48 States was 7.4 trillion cubic feet (Tcf) in 1997, accounting for the largest share of U.S. production, 39 percent.**[9] The 1997 level was virtually unchanged from that of 1996. Conventional nonassociated production has been in the range of 7 to 9 Tcf since the mid-1980s after experiencing a strong downturn the previous 10 years. Production from this source had peaked at nearly 14 Tcf in 1973. In recent years, the natural decline in production from mature fields has been countered, in part, by technological improvements. Horizontal drilling and 3-D seismic studies have slowed the rate of production declines and found new natural gas resources.

- **Dry natural gas production from the offshore Lower 48 States increased about 91 Bcf (2 percent) in 1997, reaching 5.6 Tcf.** Because of drilling restrictions in the Atlantic and the Pacific, almost all domestic offshore production comes from the Gulf of Mexico. Deep water areas of the Gulf are a prime growth area for domestic gas production. In June 1997, Shell Deepwater set a new water-depth record for production as gas began to flow from Shell's Mensa field located in 5,376 feet of water.[10]

- **Natural gas production from unconventional sources in the onshore Lower 48 States grew by 32 Bcf (1 percent), reaching 3.7 Tcf in 1997.** Unconventional production includes natural gas from coalbeds, Devonian shale, and tight sands. It has been the largest contributor to increased gas production during the 1990s, growing at an average annual rate of 4.3 percent from 1990 through 1997. The outlook for continued production growth is uncertain, however, because the qualifying period for new wells to receive a special production tax credit ended in the early 1990s.[11]

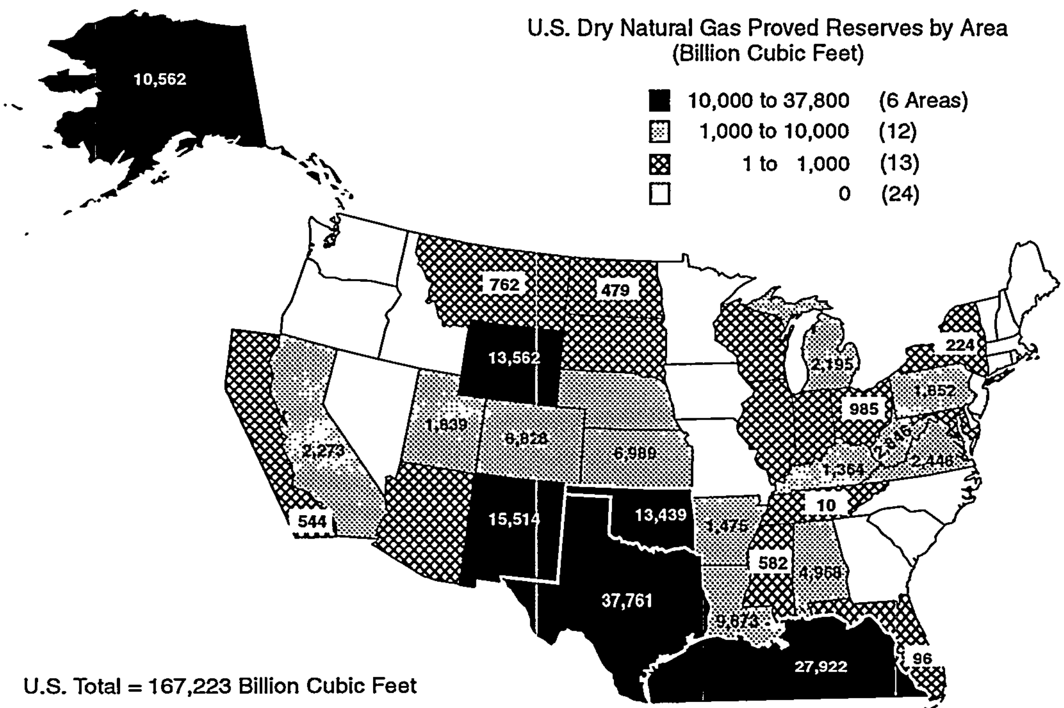
- **Monthly natural gas well completions gradually declined during 1998 in response to generally lower wellhead prices** (Figure 4). Monthly completions[12] have risen since mid-1995 as wellhead gas prices increased, although that trend reversed itself as market conditions worsened in 1998. Gas well completions in 1997 were 19.6 percent higher than in 1996. The 10,937 wells reflect the growth in average wellhead price, which rose to $2.32 per thousand cubic feet (Mcf) in 1997—its highest yearly level during the 1990s. Despite a slight price peak of $2.22 per Mcf in April 1998, the highest level for all months in 1998, prices generally have been below the average of the previous 2 years. Drilling began at a relatively high level in the early months of 1998. However, it declined thereafter as wellhead prices declined to $1.73 per Mcf in December and to $1.96 per Mcf for the year. Although gas wells in 1998 grew to 11,907, the low gas prices projected for 1999 are likely to result in reduced gas drilling at least in the short term.

- **The Gulf Coast region saw the largest number of natural gas wells drilled in 1998, while the Rocky Mountain region had the largest increase compared with 1997.**[13] Gas well drilling in the Gulf Coast region (including offshore) has generally increased since 1992.[14] The 19-percent increase in 1998 brought the number of new gas wells in this region to 2,837. Gas well completions in the Rockies reached 2,733 wells in 1998, an increase of 881 wells or 48 percent. This was the second year of drilling increases for the area after 3 years of decline. Overall, gas well completions in the Lower 48 States increased by 9 percent in 1998, reaching an estimated 11,902 wells. Drilling in the Northeast has generally declined throughout the 1990s. The Northeast is the only region where drilling declined in 1998, falling by 394 wells or 15 percent.

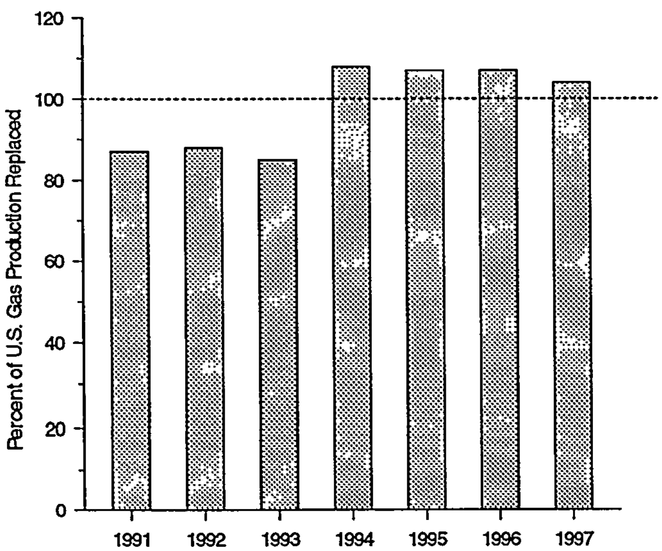
- **The gap between the number of drilling rigs directed toward natural gas and crude oil generally increased during 1998** (Figure 4). Natural gas rotary rigs have exceeded oil rigs for several years, but the gap has grown since early 1997.[15] Relatively weaker crude oil prices have led the push toward natural gas drilling domestically. Rig counts for 1998 show that the average number of rotary rigs for both oil and gas has fallen, but while gas rigs exceeded oil rigs by only 60 percent in January 1998, they were triple the oil rigs running in December 1998—491 gas rigs compared with 155 oil rigs.

Figure 5. U.S. Proved Reserves Totaled 167.2 Trillion Cubic Feet at Year-End 1997

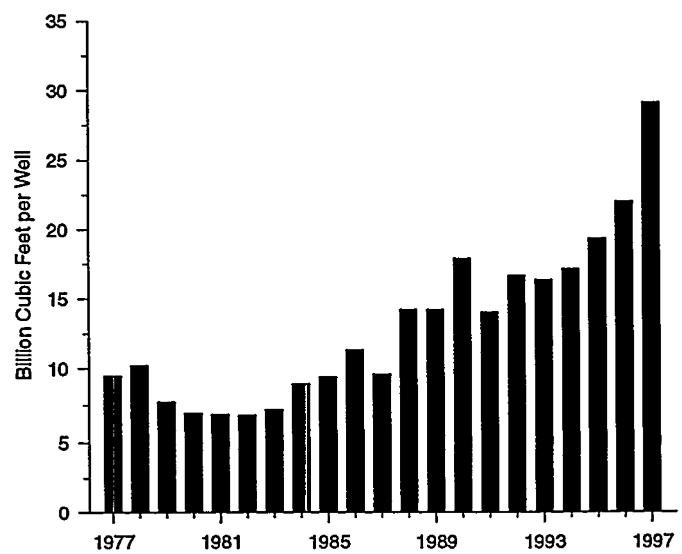
Six areas contain 71 percent of U.S. dry natural gas proved reserves



Reserve additions exceeded U.S. natural gas production 4 years in a row



Gas discoveries per exploratory gas well have been trending up since the mid-1980s



Source: Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves: 1997 Annual Report* (December 1998).

Reserves and Resources

U.S. proved reserves of natural gas moved 0.4 percent higher in 1997 to 167.2 trillion cubic feet (Tcf). Proved reserves are in effect the on-the-shelf inventory of natural gas from which production is obtained, and thus are an important indicator of near-future gas production potential.[16] This was the fourth consecutive increase in natural gas reserves, following a downward trend evident since the early 1980s. Via the exploration and development process, proved reserves are replenished from the natural gas resources that exist as unproven volumes either in known fields or in fields yet to be discovered. Estimates of unproven natural gas resources are less certain than those of proved reserves and are the object of considerable study owing to the important role they play in formulating the future energy outlook.

- **Proved reserves of dry natural gas showed yearly increases of 1.3 to 1.4 Tcf from 1994 through 1996, with a smaller (0.8 Tcf) increase in 1997.** The smaller 1997 increase was primarily caused by a combination of negative adjustments and higher production. The 4-year increase in reserves of almost 3 percent brought the level to 167.2 Tcf at year-end 1997. The majority of proved gas reserves are located in the onshore and offshore Gulf Coast area. Texas, Louisiana, Mississippi, Alabama, and the Gulf of Mexico Federal Outer Continental Shelf (OCS) had 80.9 Tcf, which is 51.6 percent of the total for the Lower 48 States.

- **Proved reserves increased despite an almost 8 percent increase in production during the 4-year period.** Reserve additions replaced nearly 106.5 percent of production (1994 through 1997), arresting the prior long-term decline in proved reserves. Total discoveries[17] in the period were 51.2 Tcf, and the net sum of revisions and adjustments was 27.9 Tcf. Reserve additions associated with the phenomenon of ultimate recovery appreciation (i.e., field growth)[18] were 71.5 Tcf, representing 90.2 percent of total reserve additions. New field discoveries of 7.7 Tcf made up the rest.

- **The average volume of discoveries per exploratory well increased by 32 percent from 1996 to 1997.** The net 4-year increase of proved gas reserves in the Lower 48 States was nearly 4 Tcf, and in Alaska 0.8 Tcf. The element underlying this performance has been a substantial increase in discoveries per exploratory gas well completion (Figure 5). Exploratory wells include new field tests (wildcats), which discover new fields, new reservoir tests, which discover new reservoirs in previously discovered fields, and extension tests, which expand the proved areas of previously discovered reservoirs.

- **Recovery from coalbed methane deposits, located principally in New Mexico, Colorado, Alabama, and Virginia, has grown rapidly in recent years.** Coalbed methane reserves accounted for nearly 7 percent of 1997 proved gas reserves, and coalbed gas constituted over 5 percent of 1997 gas production. Most of the increase of coalbed methane proved reserves and production occurred before 1995, subsequent to which they have increased only about 9.2 and 14 percent, respectively.

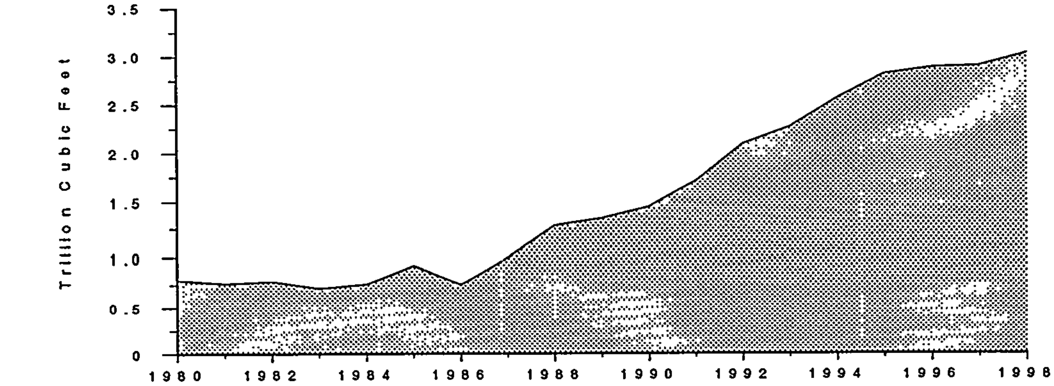
- **The Nation has a technically recoverable natural gas resource base of 1,156 Tcf remaining to be tapped (exclusive of proved reserves and Alaskan gas).**[19] Estimates of the Nation's oil and gas resources are periodically developed by the U.S. Geological Survey (USGS) for onshore lands and those under State-jurisdiction waters, and by the Minerals Management Service (MMS) for those lands under Federal OCS waters. These estimates are substantially better founded than those produced just a few years ago. For natural gas, they are confirmed at the national level by estimates developed independently by the industry-based Potential Gas Committee using different methods and data sources.

- **The mean estimates of undiscovered technically recoverable *conventional* natural gas resources in the onshore Lower 48 States and State waters are 155.9 Tcf for nonassociated gas and 34.5 Tcf for associated-dissolved gas.**[20] However, not all technically recoverable resources are likely to be economically recoverable. For example, the USGS has estimated that only 79 Tcf of the nonassociated gas accumulations in the onshore Lower 48 States has unit costs (inclusive of discovery, development, and production) no greater than $2.45 per thousand cubic feet.[21] A large proportion of remaining undiscovered resources are expected to be in small fields, which have inherently higher unit costs.

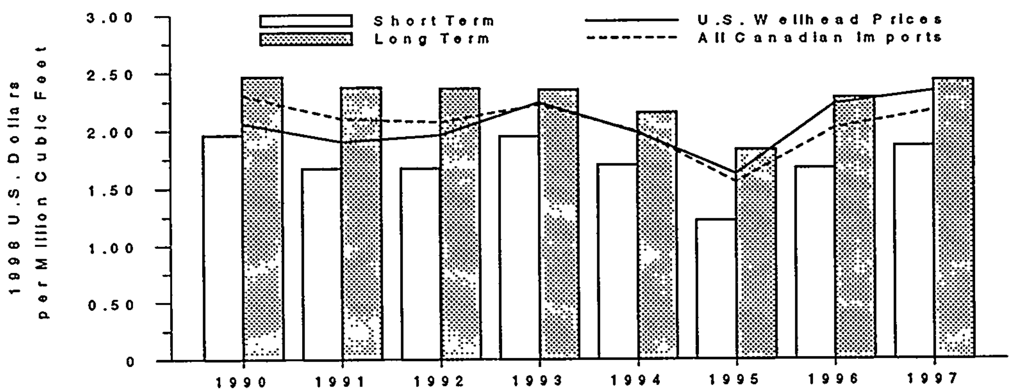
- **Approximately one-half of the remaining untapped natural gas resource base underlies federally owned lands,[22] which has important implications for future supply.** These resources are split about evenly between onshore and offshore locations. However, in recent years environmentally motivated concerns have led to the imposition of leasing and/or drilling moratoria in many Federal onshore and offshore areas. Oil and gas drilling is presently prohibited along the entire U.S. East Coast, the west coast of Florida, and all of the U.S. West Coast except a few areas off the coast of southern California. Drilling in Alaska is allowed off the Arctic Coast in the Gulf of Alaska and in Cook Inlet/Shelikoff Strait.

Figure 6. U.S. Gas Trade with Canada Reflects Growing Competition

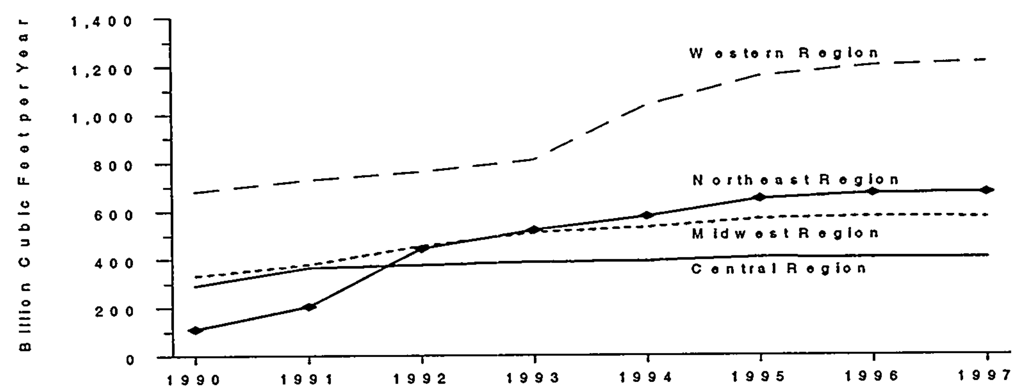
After growing almost 16 percent yearly from 1986 to 1995, imports from Canada have grown only 1.5 percent since 1995



Competitive prices are a key factor in growing Canadian sales to the United States



Growth in imports from Canada in recent years has been led mainly by greater imports to the Western Region



Note: The regions shown in the bottom figure are identified in the map on page 18.

Sources: Energy Information Administration (EIA). **Imports of Canadian Gas:** EIA, *Natural Gas Monthly* (February 1999) and *Monthly Energy Review* (December 1998). **U.S. Wellhead Price and Average for All Canadian Imports:** EIA, *Natural Gas Monthly* (August 1998) and *Natural Gas Annual 1997.* **Average Prices Under Short-term and Long-term Authorizations:** EIA, derived from Office of Fossil Energy, *Natural Gas Imports and Exports*, various issues.

Foreign Trade—Canada

Canada remains by far the largest foreign supplier of natural gas to the United States, achieving a record volume of 3.0 trillion cubic feet (Tcf) in 1998. This represented 96.7 percent of all natural gas imports to the United States and 14 percent of total U.S. consumption. This record volume was achieved although annual growth has slowed substantially since 1995 (Figure 6). Gas imports are bounded by the available crossborder capacity, which increased again in 1998 with the opening of new facilities, such as the major expansion project along the Northern Border system. This project increased import capacity by 0.7 billion cubic feet (Bcf) per day at a cost of roughly $800 million. Virtually all Canadian gas (99 percent in 1997) is produced from the Western Canadian Sedimentary Basin (WCSB), which is located primarily in Alberta but extends into British Columbia, Saskatchewan, and Manitoba. The expected late-1999 opening of the Sable Island project in the northern Atlantic is seen as a change with potentially far-reaching consequences as it will be the first commercial production of natural gas from a major Atlantic field off North America.

- **The price of natural gas imports from Canada has declined relative to U.S. wellhead prices during the 1990s.** The average border price for gas imports from Canada exceeded U.S. gas wellhead prices by 10 percent in 1990. However, by 1997, the average import price of $2.15 per thousand cubic feet (Mcf) was 7 percent below the U.S. wellhead price. The increasing competitiveness of Canadian supplies may be attributed to two related factors. First, operators of the capacity expansions during the period, especially in the West, have relied on price-responsive short-term authorizations to market the incremental flows from Canada. The share of imports purchased under short-term authorizations rose from 28 to 52 percent during this period. Secondly, although long-term authorizations tend to exhibit relatively stable average prices, more price flexibility even in these arrangements seems apparent in recent years (Figure 6).

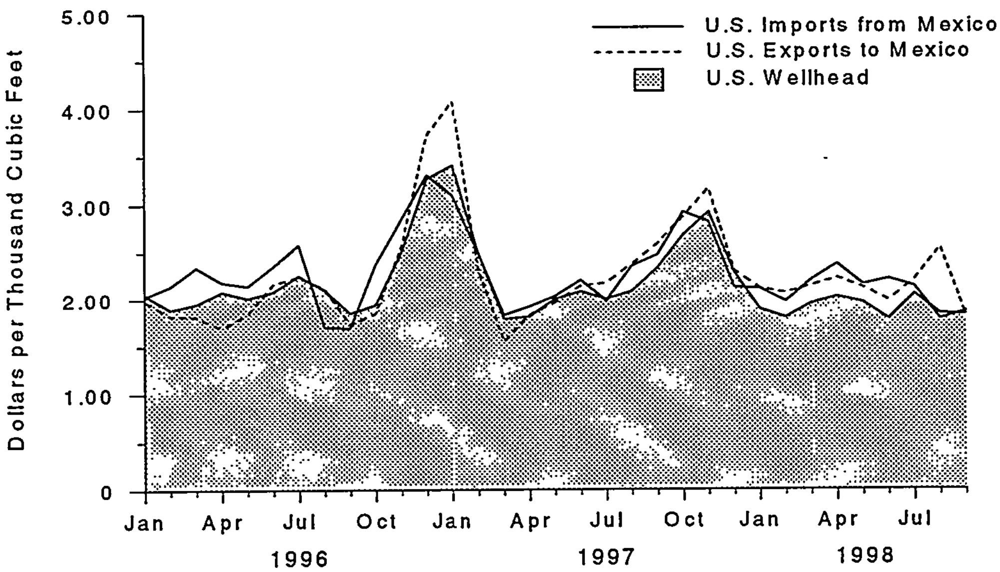
- **Capacity limitations in recent years have slowed the growth of U.S. imports from Canada.** Canadian gas volumes volumes imported into the United States during 1997, only 2.9 percent more than the 1995 level, likely would have been considerably greater had more mainline transmission capacity been available to shippers. U.S. imports of Canadian gas grew by 4.5 percent to 3.0 Tcf in 1998 as additional capacity became available. Almost all large-capacity crossborder pipelines from Canada have shown high utilization rates in recent years. Given a typical seasonal utilization pattern, it is very likely that these lines were utilized at or in excess of their certificated capacity levels during peak demand periods. In fact, according to 1996 usage patterns, import lines with capacity of more than 250 million cubic feet (MMcf) per day, with the exception of the Empire Pipeline (a "Hinshaw" pipeline),[23] had an overall average utilization rate of 92 percent. The rate for those large-capacity lines dwarfs the 59-percent utilization of the smaller lines. The low utilization rates for smaller lines often reflect their intended use for peak-season requirements, dedicated use for a single customer, or support of storage operations, rather than a lack of demand itself. Another sign of significant pent-up demand for additional imports from Canada is the great interest in proposed expansions during the open-season exercises held by pipeline companies testing potential markets.

- **The largest import volumes from Canada flow toward West Coast markets, principally in California.** Imports directed to West Coast markets are transacted mainly under short-term authorizations, 76 percent in 1997, which significantly exceeds the next highest regional fraction of 46 percent for the Central Region. This reliance on short-term arrangements contributed to continued or expanded flows by allowing prices to respond competitively as conditions changed (Figure 6). Import volumes to all regions have increased during the 1990s, with the largest growth by far, both absolutely and proportionally, in the Northeast, where annual gas receipts from Canada increased more than 550 Bcf from 1990 to 1997. Expanded flows to the Northeast were facilitated by construction and expansion of crossborder transmission capacity.

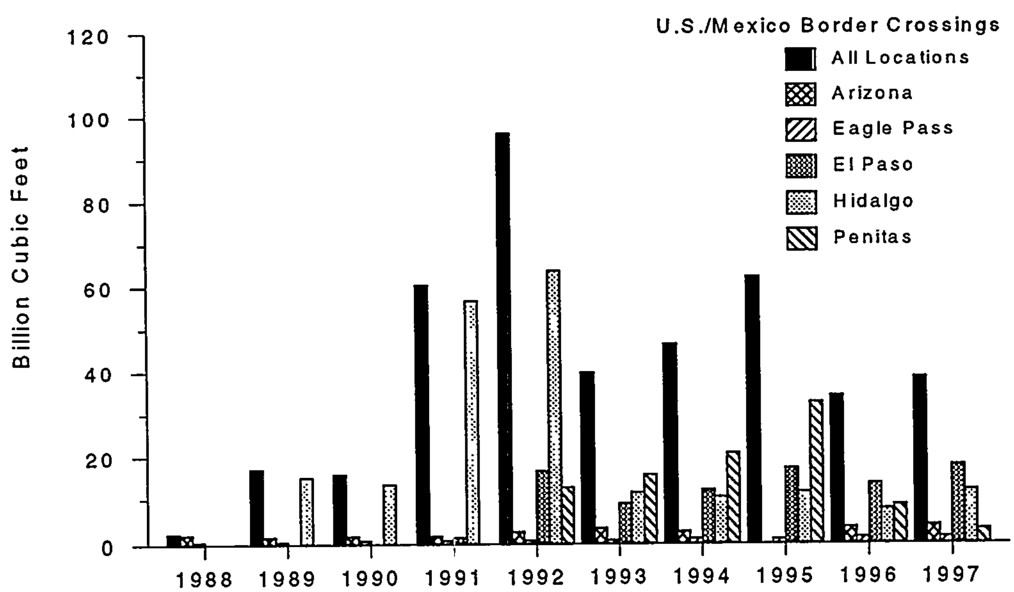
- **Planned expansions would add approximately 3.7 Bcf per day to crossborder pipeline capacity during 1999 and 2000.** The largest project is the Alliance pipeline, which was designed to bypass the capacity-constrained existing system. Alliance was originated by a group of western Canadian producers, although most of their interests have been bought out since by pipeline companies and other shipping concerns. Producers thought that the market potential was present for greatly expanded sales of gas from the WCSB. The economics of the Alliance pipeline is enhanced by its fairly unique ability to ship "wet" natural gas, which is natural gas that has not been processed to remove hydrocarbon liquids. The liquids will be removed at the terminus of the line, just south of Chicago, Illinois. The natural gas liquids then will be sold at the generally higher U.S. prices, thus enhancing the total return to producers.

Figure 7. U.S. Gas Trade with Mexico Is Expected To Grow as the Industry Expands on Both Sides of the Border

Price movements show the substantial interrelatedness of North American gas markets



U.S. gas exports to Mexico from El Paso, Texas, were roughly 40 percent of all exports during 1996 and 1997



Note: Border crossing data in lower figure exclude volumes exported at Calexico, CA, and Clint, TX, both of which began flows in 1997 and comprised only 1 percent of the total volume

Source: Energy Information Administration, Office of Oil and Gas, derived from data collected quarterly by Department of Energy, Office of Fossil Energy.

Foreign Trade—Mexico

Mexico has been a net importer of small volumes of U.S. natural gas in the 1990s, with considerable variation in yearly net flows. Mexico has faced significant economic difficulties that have affected its yearly gas imports. Although U.S. gas exports are estimated to have reached 50 billion cubic feet (Bcf) in 1998, they remain only 52 percent of the 1992 peak. However, Mexican consumption of natural gas could grow at unprecedented rates, driven by demand growth and regulatory reform that is opening up parts of the industry to foreign investment. Additional demand growth also is expected as the Mexican tariff on imported U.S. gas declines. The North American Free Trade Agreement (NAFTA) established a 10-percent tariff, commencing in 1993, that is reduced 1 percent annually. Removal of the tariff, which was 5 percent in 1998, was the subject of unsuccessful negotiations in 1998.

- **Prices paid for gas traded between the United States and Mexico have differed on average by less than 7 percent on a monthly basis since January 1997, after average discrepancies of almost 16 percent in 1996.** Discrepancies in monthly prices for 1996 were caused by major macroeconomic fluctuations that affected Mexico's gas markets. By early 1997, competitive forces had reasserted themselves and prices again moved in tandem. The strong price correlation between the border and the U.S. wellhead markets is indicative of the increasing integration of gas markets across North America.

- **While U.S. natural gas exports to Mexico fell from a high of 96 Bcf in 1992 to a recent low of 34 Bcf in 1996, export volumes have increased since and reached an estimated 50 Bcf in 1998.** If the turnaround continues, it is possible that several postponed proposals to expand capacity would proceed. At least six projects (totaling about 1.4 Bcf per day) are awaiting regulatory approval or improvements in market conditions. In 1998, daily utilization rates averaged about 12 percent of the beginning-of-year export capacity between the United States and Mexico, which totaled 1.1 Bcf per day. Mexican imports of U.S. gas of 50 Bcf in 1998 are 31 percent greater than during 1997 (Figure 7).

- **After several years of almost no activity, U.S. imports of Mexican gas have risen slowly but steadily since December 1993.** While recent U.S. import volumes represent the equivalent of less than 0.5 percent of the gas consumed in Texas alone, the 18.5 Bcf in 1998 is almost triple the 6.7 Bcf in 1995. The 1998 volume represented only about 13 percent of available capacity at the border. Energy officials from Petroleos Mexicanos (PEMEX), the state-owned Mexican national energy company, indicated that they could have exported more but could not find shipping capacity available on the U.S. side of the border. This problem could have been due at least in part to PEMEX's inexperience with acquiring rights to capacity in the new U.S. open-access marketplace. U.S. imports of Mexican gas in 1998 are 7 percent above the 17.2 Bcf recorded in 1997.

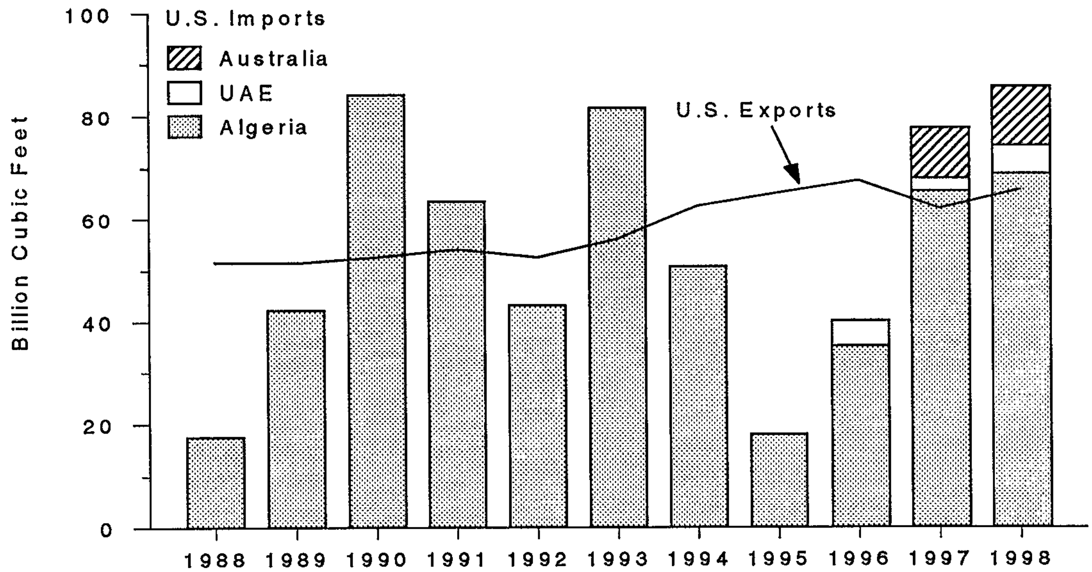
- **Exports of U.S. natural gas to Mexico primarily provide supplies to manufacturing/service industries and a growing number of electric generating plants in the northern states of Mexico.** Despite the substantial indigenous gas resources further south in Mexico, these northern states can be served most efficiently from the readily available supplies on the U.S. system. The largest export volume location since 1995 is adjacent to El Paso, Texas (Chihuahua State), about 40 percent of total exports (Figure 7). This figure is expected to grow significantly with the completion of El Paso Energy Company's Samalayucca project (212 million cubic feet (MMcf) per day). While the line initially transported only about 70 MMcf per day, it is expected to become fully utilized in 1999 with the completion of an electric generating plant in Chihuahua State.

- **Since 1996, Mexico's national energy regulatory agency, the Comisión Reguladora de Energía (CRE), has approved projects in at least 10 Mexican states or districts to improve the distribution of natural gas to residents and industries.** Most of these projects are joint ventures, often with one or more U.S. energy companies representing a major, although not a controlling, interest. As Mexico expands its efforts to privatize, or at least relax its regulatory control over the gas distribution infrastructure, it is likely that more such ventures will develop, which would increase gas demand.

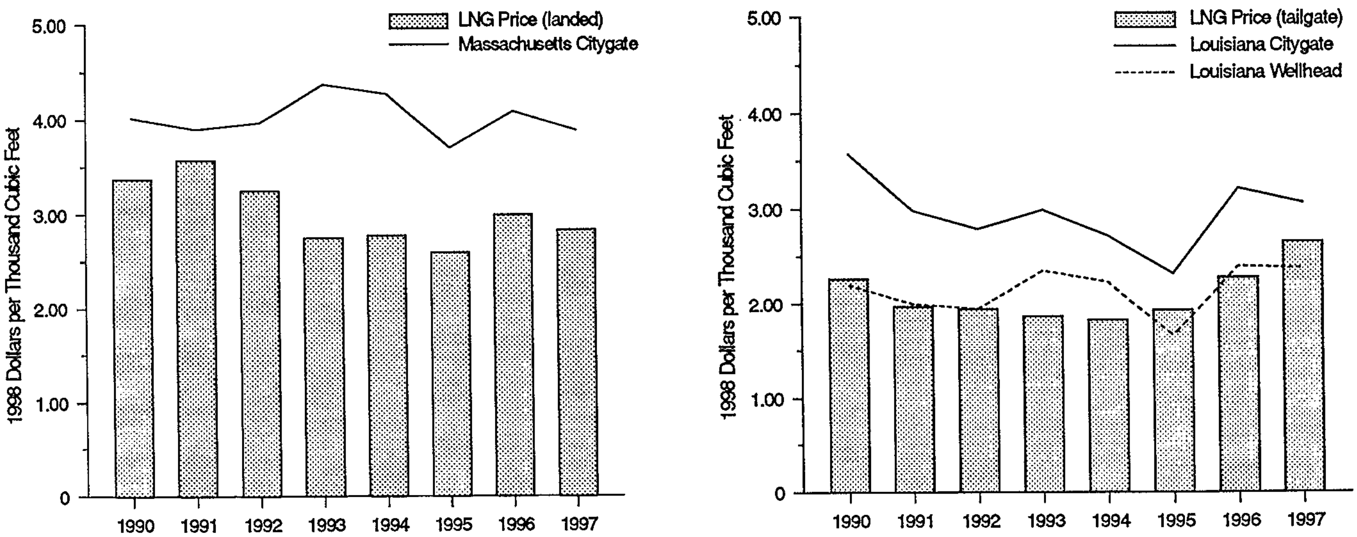
Mexico holds substantial promise for expansion on both the demand and supply sides of the market, although the short-term prospects for increased domestic production have become more uncertain as low oil prices in 1998 have forced spending cutbacks, affecting gas field development. Despite Mexico's endowment of natural gas resources of an estimated 70 trillion cubic feet in reserves with an additional 180 trillion cubic feet in remaining undiscovered recoverable gas resources, it likely will remain an active purchaser of U.S. gas supplies owing to the transportation logistics in each country. Thus, the future of Mexico's gas markets and that of U.S. markets along the southern border likely will continue to become increasingly interwoven.

Figure 8. Liquefied Natural Gas (LNG) Provides the United States With Access to Global Markets

The UAE and Australia have recently entered U.S. markets through spot transactions



LNG import prices are competitive with local supplies in both Massachusetts and Louisiana



UAE = United Arab Emirates.

Notes: LNG prices in Louisiana are measured at the "tailgate," where the gas has been regasified. LNG prices in Massachusetts are on a "landed" basis, so the gas is still in liquid form. Regasification costs vary widely depending on numerous factors including throughput, but representative values of \$0.26-\$0.46 per thousand cubic feet may be used for reference. This range is based on information provided in *The Potential for Natural Gas in the United States: Source and Supply*, National Petroleum Council, Volume II, Appendix F (December 1992).

Sources: Energy Information Administration (EIA). **LNG Import Volumes:** 1988-1997—*Natural Gas Monthly*, Table SR4 (August 1998). 1998—Office of Fossil Energy. **LNG Export Volumes:** 1988-1997—*Natural Gas Monthly*, Table SR5 (August 1998). 1998—*Natural Gas Monthly* (February 1999). **LNG Import Prices, Citygate Prices, and Wellhead Prices:** *Natural Gas Annual* (various issues).

Foreign Trade—Liquefied Natural Gas

The United States has been importing increasing volumes of liquefied natural gas (LNG), exceeding 85 billion cubic feet (Bcf) in 1998, compared with 18 Bcf in 1995. In 1998, LNG accounted for 2.7 percent of all U.S. natural gas imports (double the 1996 share), although less than 1 percent of total U.S. gas consumption. LNG imports are shipped to the United States via ocean-going tankers from Algeria, the United Arab Emirates (UAE), and Australia. U.S. LNG exports, from south Alaska to Japan, compete primarily with higher-priced petroleum liquids and thus command a higher price than U.S. LNG imports; from 1992 through 1997, the export price on average was 41 percent above the import price.

- **LNG imports into the United States have increased significantly since 1986-87, when they were suspended because of a contract dispute with Algeria.** They reached relative peaks of 84 and 82 Bcf in 1990 and 1993, then dropped to only 18 Bcf in 1995 while liquefaction facilities in Algeria were being refurbished. As liquefaction capacity was restored and supplies from the UAE and Australia became available, LNG imports to the United States resumed with steady growth, reaching slightly more than 85 Bcf in 1998. One reason for the increase has been the competitive LNG import prices relative to domestic prices (Figure 8).

- **The amount of LNG exported by the United States tends to be quite stable, being generally constrained to the level of available liquefaction capacity in south Alaska.** From 1995 through 1998, LNG exports from Alaska averaged roughly 65 Bcf annually. Despite the economic downturn affecting much of Asia, LNG exports from the United States remained fairly strong in 1998, rising 6 percent to 66.0 Bcf (Figure 8).

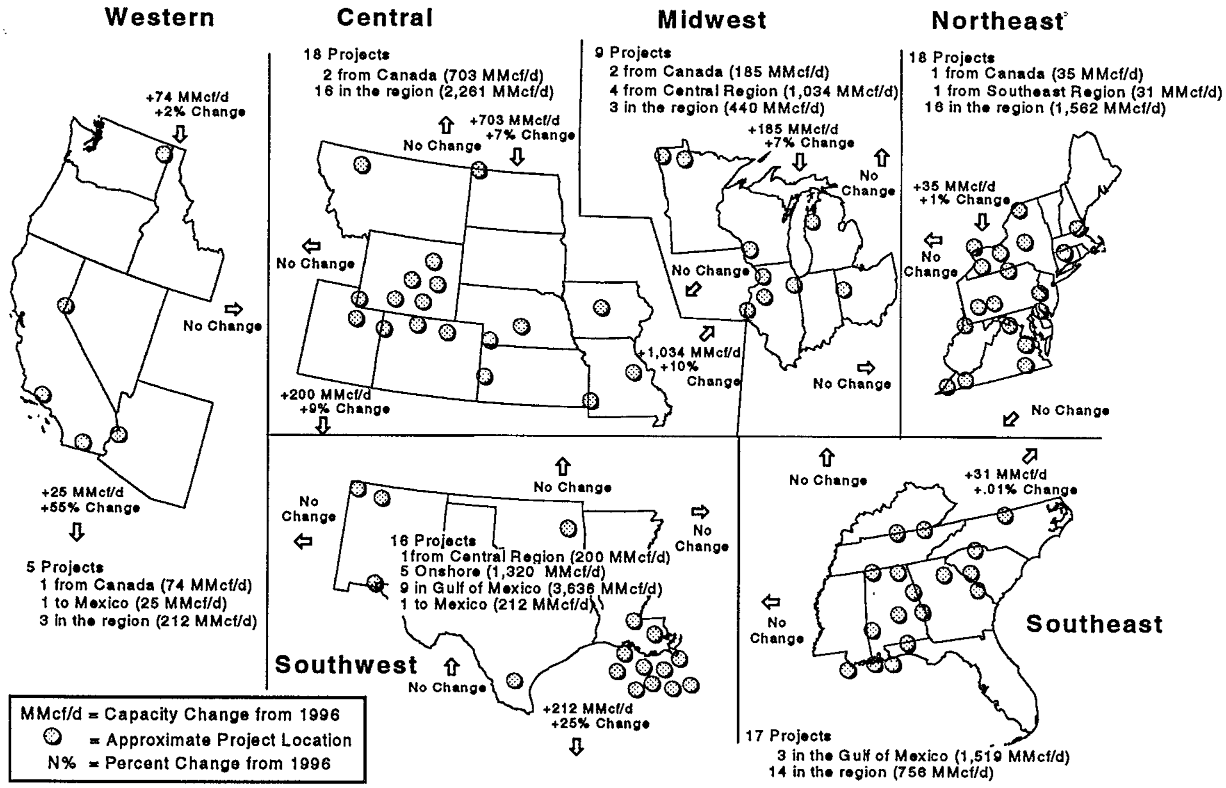
- **U.S. LNG imports can continue expanding for many years, based on current capacity and planned expansion.** LNG imports serve as supplemental gas supplies for regional systems. In Massachusetts, LNG imports comprise the equivalent of about 12 percent of the State's natural gas consumption, based on deliveries to all consumers of 378 Bcf in 1997. The LNG received at Lake Charles, Louisiana (almost 43 Bcf in 1998) is sold almost entirely to Florida Power and Light as fuel for electric generation. A third facility at Cove Point, Maryland, is currently operating as a peak-service storage facility using gas received from the transmission network, although reopening for importation is being considered. A fourth U.S. facility designed for LNG importation is located at Elba Island, Georgia, but it is not operational and there are no plans at present for it to reopen. Although each of these sites has substantial unused capacity, the Massachusetts facility is expected to expand its regasification capacity by 50 percent to 450 million cubic feet (MMcf) per day in early 1999.

- **The economic difficulties in many countries of Asia have altered the relative supply and demand balances for global LNG trade.** The macroeconomic difficulties in eastern Asia have resulted in reduced demand for energy in general and LNG in particular. The net impact of these difficulties will depend greatly on Japan, which consumed about 57 percent of LNG worldwide in 1997. Korea, the second largest purchaser of LNG, reduced imports in the first quarter of 1998 by 17.5 percent compared with the first quarter of 1997. Korea Gas (Kogas) has both canceled planned purchases and delayed purchases of 770 million tons, equivalent to 36 Bcf.[24] Concern about future market conditions has led to the suspension of a number of proposed projects, including development off Natuna Island in Indonesia (46 trillion cubic feet in reserves) and a 450-MMcf-per-day export project in western Canada, which was scheduled to start operation in late 1999.

- **In 1998, U.S. importers received eight LNG cargoes that were purchased under spot sales.** The presence of a spot market is a substantial development in global LNG trade, as it promotes a more dynamic system that can be a very important element in the resolution of current trading difficulties precipitated by the Asian economic crisis. LNG trade has been conducted primarily on the basis of direct, long-term arrangements between a supplier and particular customers. The spot market provides LNG suppliers holding excess fuel the opportunity to reach interested buyers. Current surpluses are expected to produce lower prices than otherwise, which may stimulate additional or new market penetration by LNG. Expanded trade under short- or long-term arrangements will be promoted with the 7 new tankers placed in service at the end of 1997, bringing the total to 103. This is 45 percent more than the 71 in 1991.

- **Further growth in global LNG trade is expected as Asian economies recover.** LNG's attractiveness as a fuel of choice is indicated by the fact that global LNG trade increased more than 2 percent in 1997 despite pipeline exports being virtually unchanged. Additional liquefaction projects are expected to begin operations in the next few years, adding to potential market growth. These projects include the Atlantic LNG Co. plant (400 MMcf per day) in Trinidad and Tobago, and the Bonny LNG project in Nigeria (425 MMcf per day), both expected to begin LNG shipments by the end of 1999.

Figure 9. More Than 80 Natural Gas Pipeline Projects Were Completed Between January 1997 and December 1998



. . . Adding 2.5 billion cubic feet per day to interregional interstate pipeline capacity

Interregional Natural Gas Pipeline Capacity as of December 31, 1998

Receiving Region	Sending Region[a] (Volumes in Million Cubic Feet per Day)								
	Central	Midwest	Northeast	Southeast	Southwest	Western	Canada	Mexico	Total Entering Capacity
Central	--	2,354	--	--	8,609	298	2,266*	--	13,527
Midwest	10,913*	--	2,038	9,821	--	--	3,234*		26,006
Northeast	--	4,887	--	5,180*	--	--	2,428*	--	12,495
Southeast	--	--	520	--	20,846	--	--	--	21,366
Southwest	2,314*	--	--	405	--	--	--	350	3,069
Western	1,194	--	--	--	5,351	--	3,860*	--	10,405
Canada	66	2,543	--	--	--	--	--	--	2,609
Mexico	--	--	--	--	1,056*	70*	--	--	1,126
Total Exiting Capacity	**14,487**	**9,784**	**2,558**	**15,406**	**35,862**	**368**	**11,788**	**350**	**--**

[a]Includes only the sum of capacity levels for the States and Canadian Provinces bounding the respective region.

*Includes increase in capacity since 1996.

MMcf/d = Million cubic feet per day. -- = Not applicable.

Sources: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System: Natural Gas PipelineConstruction Database through December 1998; Natural Gas State Border Capacity Database (preliminary 1998).

Interstate Pipeline Capacity

During 1997 and 1998, the interstate natural gas pipeline network in the United States experienced more upgrades and installation of new pipeline capacity than occurred in most of the previous 6 years. The completion of more than 80 projects (Figure 9) during these 2 years resulted in 14.2 billion cubic feet (Bcf) of new daily deliverability being added to the national network. Of this, 6.8 Bcf per day represented expansions to existing facilities and the rest installation of new pipeline routes. The largest amount of new capacity (5.4 Bcf per day, 16 projects) and new pipeline development was in the Southwest, where 9 new systems were completed, 4 of which were 600 million cubic feet (MMcf) per day or larger. Nationally, 13 projects (totaling about 2.6 Bcf per day) that were originally scheduled to be completed in 1998 were postponed until 1999, and another 4 were canceled mainly because of changed market conditions.

Yet only about 18 percent (2.5 Bcf per day) of this new pipeline capacity directly increased interregional transmission capacity. Compared with 1990 through 1996, when interregional capacity grew by about 15 percent (2.5 percent annually), additions between regions during 1997 and 1998 resulted in an increase of less than 1.5 percent.[25] This trend reflects the recent emphasis on improving and expanding pipeline service within the region and/or increasing access to new or expanding production facilities.

- **With the completion of nine separate projects associated with the expanding production areas of Wyoming and Montana, producers in the area can reach customers in the Midwest,** in addition to their traditional markets in the Western Region. These projects, including the new Pony Express project (KN Interstate Pipeline, 250 MMcf per day) and Trailblazer System expansion (190 MMcf per day), helped relieve an eastward capacity constraint problem that had existed in the Rocky Mountain area for several years.

- **Another capacity-constrained production area, the San Juan Basin of New Mexico, experienced some relief in 1997 and 1998 with the completion of several key projects.** The two major pipeline transporters operating in the basin, Transwestern Pipeline and El Paso Natural Gas Company, completed projects that improved deliverability out of the basin (mostly through increased compression) by about 400 MMcf per day. Several additional projects were approved, which would bring pipeline capacity more in line with productive capacity in the area. In mid-1997, El Paso completed its Havasu Crossover expansion project. This project expanded capacity on the westward-bound portion of the system to move supplies that are redirected eastward (either physically or by displacement) just east of the California border. This increased El Paso's deliverability in the Waha area of west Texas by an additional 180 MMcf per day.

- **During 1997 and 1998, 12 natural gas pipeline projects were completed in the Gulf of Mexico, representing a total of 5.2 Bcf per day of new pipeline capacity.** Seven of these projects now bring an additional 3.6 Bcf per day to onshore Louisiana; the others are gathering systems linking producing platforms in the Gulf with mainlines directed to onshore facilities. The largest of the lines to onshore Louisiana were three new pipelines: the Destin Pipeline (1 Bcf per day) and the Nautilus and Discovery, each representing 600 MMcf per day of new capacity.

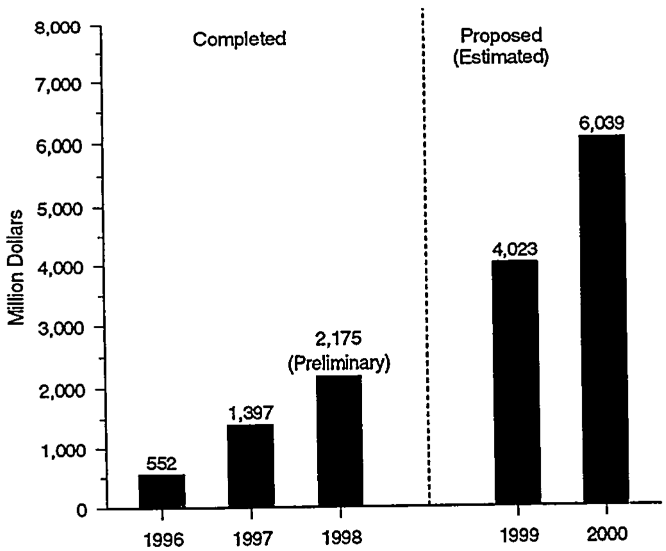
- **After expanding by more than 69 percent between 1990 and 1996, very little new import capacity from Canada was added in 1997 and 1998.** The largest addition, 700 MMcf per day, was the Northern Border Pipeline expansion, which began service in December 1998. Only one expansion project, Viking Gas Transmission Company (60 MMcf per day), was placed in service during 1997, although TransCanada Pipeline Company increased capacity on its side of the border by a total of 170 MMcf per day (at four points: three in Quebec (to New York) and one to the Viking System in Minnesota).

- **Regional service improvements dominated in the Northeast and Southeast regions.** The majority of projects (30 of 35) and 59 percent of the new capacity added in these regions expanded existing pipeline deliverability to local customers in 1997 and 1998. In the Northeast, added service to underground storage sites and for storage customers along several major sections of mainline, accounted for nearly half of the capacity added during the period.

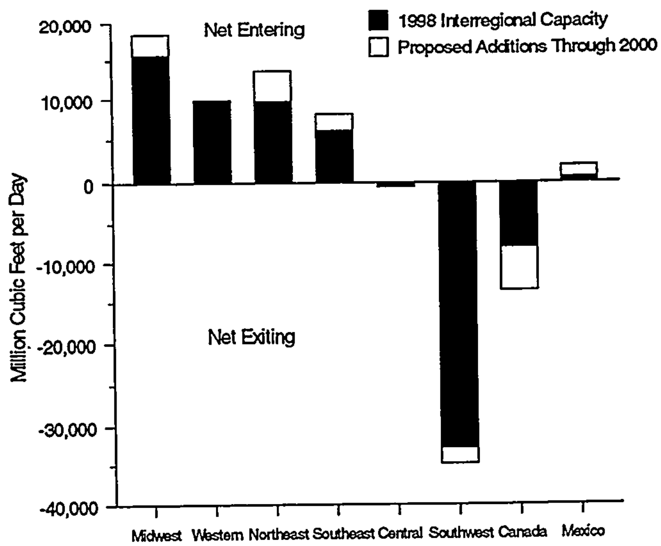
These past 2 years also saw the completion of new natural gas export lines to Mexico for the first time in 5 years. Installation of the two new export points, one from California (25 MMcf per day) and one from Texas (212 MMcf per day) increased U.S. natural gas export capabilities to Mexico by 27 percent. In the late 1980s, the Mexico market was expected to provide a major outlet for Southwest production. But the approval and execution of a number of early proposals has been slow, primarily because of regulatory delays and the smaller-than-expected growth in natural gas demand in northern Mexico.

Figure 10. The Interstate Natural Gas Pipeline Network Is Expected To Grow Significantly Through 2000

Annual pipeline investment could reach $6 billion in 2000 . . .



. . . Spurred by growing import capacity from Canada and Northeast expansions



Total added capacity in 1999 and 2000 could exceed 20 million cubic feet per day

Proposed Additions to Interstate Natural Gas Pipeline Capacity, 1999 and 2000

Proposed for Region	1999		2000		Total		
	Number of Projects	Capacity Addition (MMcf/d)	Number of Projects	Capacity Addition (MMcf/d)	Number of Projects	Capacity Addition (MMcf/d)	Canadian Import Portion[a] (probable)
Central	4	910	5	1,330	9	2,240	253
Midwest[b]	10	1,956	7	3,865	17	5,821	1,394
Northeast	17	2,253	9	4,293	26	6,546	2,027
Southeast	5	1,161	1	200	6	1,361	--
Southwest[b]	10	3,099	2	398	12	3,497	--
Western[b]	5	562	1	130	6	692	0
U.S. Total	51	9,941	25	10,216	76	20,157	3,674
Canada[c]	4	1,564	3	2,675	7	4,239	--

[a]EIA estimate of how much import capacity will actually be built. Some proposals are competing for or are within the same markets, and therefore some may be consolidated, downsized, or canceled.

[b]Includes export projects to Mexico or Canada.

[c]Includes Canadian projects that may support expanded exports to the United States.

MMcf/d = Million cubic feet per day. -- = Not applicable.

Notes: Excludes projects on hold as of January 1999. In the table, a project that crosses interregional boundaries is included in the region in which it terminates.

Source: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System, Natural Gas Pipeline Construction Database through December 1998.

Potential Interstate Pipeline Capacity

The large annual increase in natural gas pipeline capacity expansions seen in 1998 should continue through the turn of the century. In 1998 alone, 47 pipeline expansion projects in the United States were completed and placed in service, adding more than 10 billion cubic feet (Bcf) per day of new capacity on the national pipeline grid. Moreover, a similar level of increase may occur in both 1999 and 2000.[26] The greatest amount of pipeline expansion activity is expected to occur in the Midwest and the Northeast regions as demand for greater Canadian export capabilities continues to grow. More than 3.7 Bcf per day of Canadian export capacity expansion has been proposed for completion during 1999 and 2000. For the most part, the proposals are driven by Canadian natural gas producers seeking markets for their expanding production capabilities.

- **Annual investments in pipeline expansions could reach the $6 billion level by 2000 (Figure 10) with the scheduled completion of several major new pipeline systems.** Among the largest will be the Alliance ($2.9 billion), Independence ($676 million), Millennium ($684 million) and Vector ($447 million) pipeline systems. After 2000, however, the level of additional investment is scheduled to drop off, as very few projects have been proposed whose inservice dates extend beyond the close of the decade.

- **Several new pipelines, as well as expansions to existing systems, will begin in western Canada and route supplies to the Chicago, Illinois, area.** But a sizable portion of gas delivered there will actually be destined for the Ontario, Canada, market and/or the U.S. Northeast. As much as 1.8 Bcf per day of new capacity is scheduled to reach the Chicago area by 2000. At least four pipeline systems (two of which are new), accounting for 3.2 Bcf per day, have been proposed to pick up Chicago area supplies and carry them eastward.

- **Construction of the first phase of the Maritimes and Northeast Pipeline began in 1998.** When finished in late 1999, the project will have the capability of bringing 440 Bcf per day of Sable Island gas (off Nova Scotia) directly to the New England marketplace. While it will account for only about 3 percent of total Canadian export capabilities to the United States, it represents the first major gas supply project off the east coast of North America and the first Canadian supply project in close proximity to New England markets.

- **The expanding deep-water development in the Gulf of Mexico will necessitate the building of additional new natural gas systems to bring the new production onshore.** At least two supporting natural gas gathering systems are slated for expansion in 1999 (about 349 million cubic feet (MMcf) per day). These systems will link expanding or new production deep-water platforms to several new offshore mainlines, which in turn will tie the new supply sources to onshore processing plants and interconnections with major interstate pipelines. The largest proposed deep-water project is the new Sea Star Pipeline (Koch Gateway Company, 600 MMcf per day), which, if approved, could link up with the interstate system in Louisiana by the end of 1999.

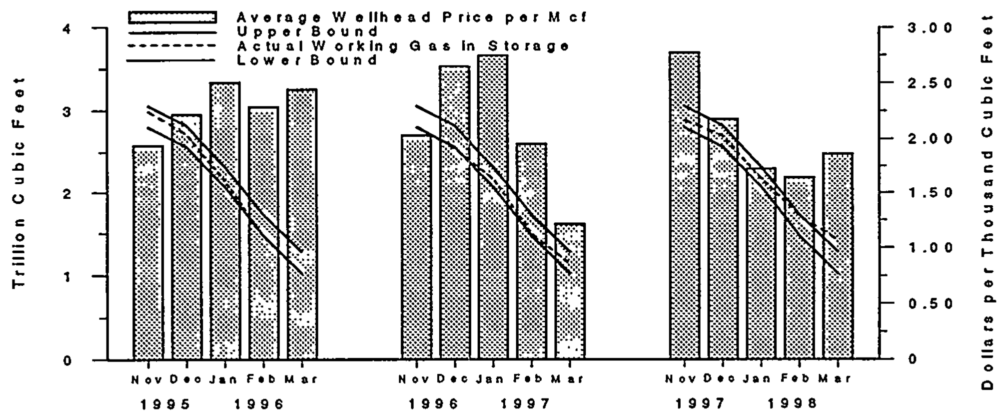
- **The Southeast Region, which is adjacent to the growing Gulf Coast production and hosts most of the longhaul pipelines serving the Midwest and Northeast regions, will probably be the destination of a substantial portion of the new Gulf supplies.** As new development in the Gulf of Mexico has moved to deeper waters and further eastward, the Southeast Region has also been experiencing a growing demand for natural gas. Several of the regional inter- and intrastate pipelines have announced plans for system expansions. Although not as large (in capacity) as the offshore projects, about 40 percent of the new capacity in the region (0.6 of 1.4 Bcf per day) is slated to serve local customers directly.

- **Pipeline expansions in the Western Region, while small in comparison with those in other regions, are unique in several respects.** First, Northwest Pipeline Company has plans to deliver Canadian-produced gas to the Vancouver, British Columbia, area via transshipments from Alberta, Canada, southward through PG&E Transmission-NW with interconnections to Northwest Pipeline in Washington State. This would be the first time natural gas would move back across the border in significant quantities in the West. Second, Colorado Interstate Gas has a proposed project that, for the first time, would institute gas deliveries to northern Nevada from fields located in the Powder River Basin of Wyoming.

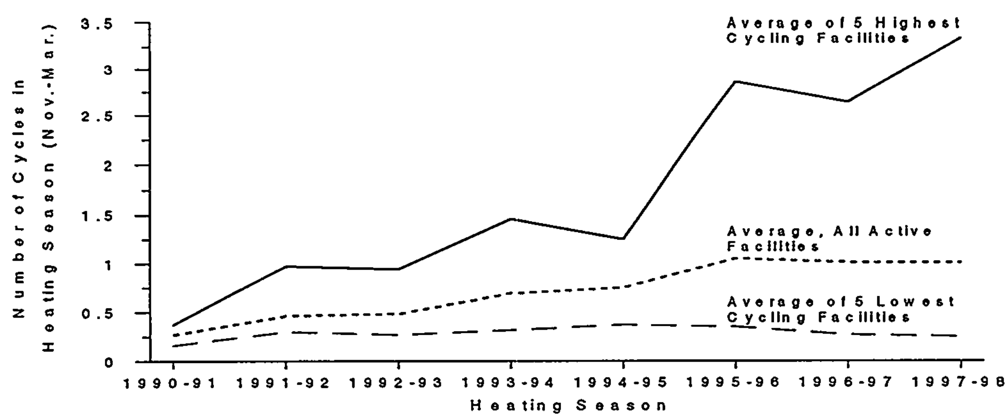
- **Several projects are scheduled for completion in 1999 that would increase export capacity to Mexico by 260 MMcf per day, 23 percent above the 1998 level.** The Tennessee Gas Pipeline's Reynosa project would deliver U.S. gas to the Petroleos Mexicanos (PEMEX) pipeline system in Mexico for delivery to the local distribution system in the state of Nuevo Leon. A second project, which would deliver supplies to industrial customers south of the Arizona border, would be installed by El Paso Energy and connected to a new 65-mile pipeline being built within Mexico by Mexcobre Pipeline.

Figure 11. Underground Storage Operations Are Crucial to Meeting Seasonal Customer Demands

As stocks move below normal ranges, prices generally move up



Cycling rates increased sharply at some salt cavern facilities in recent winters but on average showed no growth



The Midwest and Southwest regions have the most storage capacity

	Aquifer			Depleted Gas/Oil Field			Salt Cavern			Total		
Region	Number of Facilities	Working Gas Capacity (Bcf)	Deliverability (MMcf/day)	Number of Facilities	Working Gas Capacity (Bcf)	Deliverability (MMcf/day)	Number of Facilities	Working Gas Capacity (Bcf)	Deliverability (MMcf/day)	Number of Facilities	Working Gas Capacity (Bcf)	Deliverability (MMcf/day)
Central	8	98.2	1,565	40	473.3	4,534	1	2.1	160	49	573.7	6,259
Midwest	28	224.9	6,091	98	870.3	17,649	2	2.1	78	128	1,097.3	23,818
Northeast	0	0.0	0	119	710.5	11,799	2	1.8	185	121	712.3	11,984
Southeast	2	6.0	67	27	145.1	2,722	4	22.6	2,430	33	173.8	5,220
Southwest	1	8.3	10	48	886.7	12,458	18	92.8	9,033	67	987.8	21,501
West	1	15.2	550	11	162.9	6,590	0	0.0	0	12	178.1	7,140
Total	40	352.6	8,283	343	3,249.1	55,755	27	121.6	11,886	410	3,723.5	75,925

Bcf = Billion cubic feet. MMcf/day = Million cubic feet per day.

Note: The regions in the table conform to those shown in the map on page 24.

Sources: Energy Information Administration (EIA), Office of Oil and Gas. **Working Gas Inventories and Capacities:** EIA, Form EIA-191 "Monthly Underground Gas Storage Report" and EIAGIS Geographic Information System, Existing Underground Storage Database as of December 1998. **Wellhead Prices:** EIA, *Natural Gas Monthly* (February 1999).

Storage Operations

At the end of the first month of the 1998-99 heating season, working gas inventories stood at 3,143 billion cubic feet (Bcf), the highest level for November 30 since 1990 and 16 percent more than last year. Storage stocks have been at unusually high levels since last winter, when warmer-than-normal temperatures prevailed across most of the Lower 48 States.[27] Working gas inventories at the end of the 1997-98 heating season were 1,184 Bcf, or 17 percent greater than the average for the preceding 5 years for that point in the year. The refill season was quite robust, reinforced by low prices, moderate demand, no significant supply disruptions, and apparent expectations of normally cold temperatures in the upcoming winter. By the start of the 1998-99 heating season, storage stocks were 3,172 Bcf, the highest level since 1992 and only the third time in this decade that inventories were above the 3,100 mark.

- **Between February and December 1998, stock levels exceeded the seasonally adjusted normal range[28] in every month but one.** Since the implementation of Order 636 in November 1993, it appears that inventories are being managed more efficiently by operators and their customers. As one indication, monthly average storage levels over the past 6 years (1992-1997) have generally shifted downward compared with the previous 6 years (1986-1991). However, 1998 ran counter to this trend. Beginning with May end-of-month inventories, 1998 monthly levels were the highest of the past 6 years, and were consistently above the seasonally-adjusted normal range from March through December. Although stocks were at their second-lowest level in the past 6 years entering the 1997-98 heating season, the mild winter, with a particularly warm January, left stock levels at the end of March at their second-highest level in the past 6 years. From this point, net injections were strong, boosting inventories above the upper bound of the normal range.

- **In the past three heating seasons, signs of upward pressure on wellhead prices have appeared when inventories fall below a "normal" range** (Figure 11). In 1995-96, ample storage levels early in the season served to limit price increases in the wellhead markets until storage levels later fell relative to normal. In 1996-97, working gas storage levels were relatively low as the heating season began because of generally higher wellhead gas prices during the 1996 refill season in combination with low futures prices for the upcoming heating season. The lessened supplies available to the market throughout the heating season resulted in a price surge, which only diminished as weather warmed. Yet a third scenario was played out in 1997-98. Storage levels began the heating season at close to the mid point of normal, yet wellhead prices were relatively high from the middle of the year into November. Limited demand owing to the El Ninó-driven warm winter and the ample supplies in storage led to declining prices through most of the heating season. The relative gas abundance signaled by the low prices led to low storage withdrawals, leaving a hefty inventory balance at the end of March 1998.

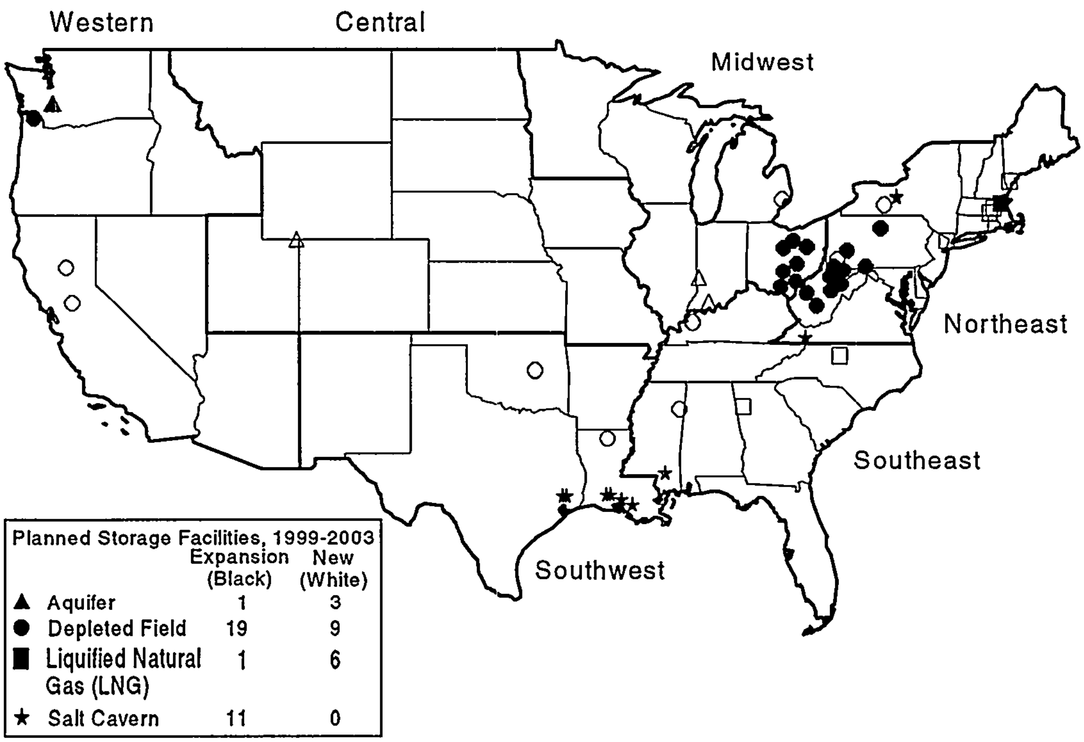
- **Salt cavern storage utilization dropped slightly in the past two heating seasons.** The average heating-season cycling rate for salt cavern storage facilities had increased every year between 1990 and 1996, quadrupling from 0.27 to 1.05 (Figure 11). However, the rate dropped slightly for the 1996-97 heating season and remained flat during the 1997-98 heating season. Warmer-than-normal temperatures, with fewer and less extreme episodes of frigid temperatures, contributed to the lower utilization of salt cavern storage in these two heating seasons. Further, decreasing price volatility (see Figure 3, p. 6) has likely meant fewer or less potentially profitable arbitrage opportunities, further reducing usage of high-cycle storage capacity. Still, contrasting with the overall average for salt cavern facilities,[29] average utilization of the top five (by cycle rate) facilities increased by 27 percent to over 3 cycles per heating season (2.64 to 3.34).

- **A large number of storage facilities appear to be inactive.** Of the 410 facilities included in the EIA-191 monthly survey, "Underground Gas Storage Report," 38 facilities have had either no activity whatsoever, or withdrawals of gas only, for at least the past 2 years. These fields comprise about 107 Bcf of working gas capacity and 824 MMcf per day of deliverability, or about 3 and 1 percent, respectively, of national totals as of November 1, 1998. The largest amounts of inactive capacity are in the Southwest and Midwest regions (71 and 21 Bcf of working gas capacity, respectively, and 485 and 219 MMcf per day of deliverability).[30]

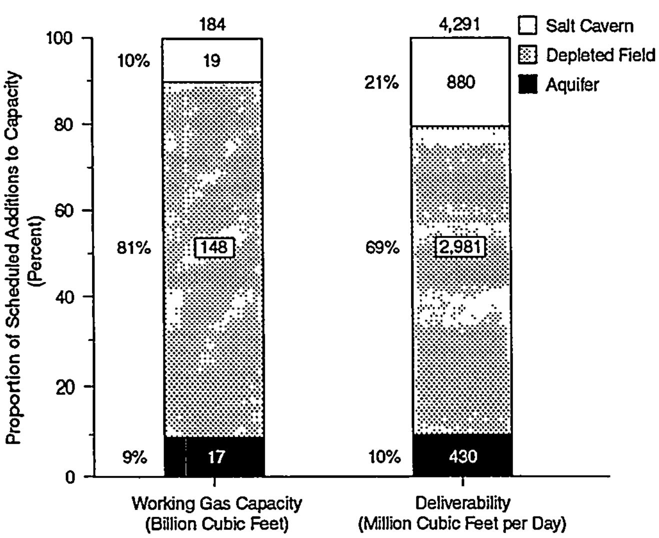
- **The Midwest and Southwest regions together comprise 56 percent of working gas capacity and nearly 60 percent of deliverability** (Figure 11). Though similar in terms of capacities, the two regions are very different with respect to storage asset profiles and utilization. Midwest storage is primarily market area storage, while much of the storage in the Southwest is an adjunct of production. Average per-facility working gas capacity and deliverability for the Southwest is over 60 percent greater than for the Midwest, largely because of the preponderance of high-deliverability storage and relatively large depleted fields in the Southwest.

Figure 12. Interest in Storage Development Has Slowed But 50 Projects Are Planned Between 1999 and 2003

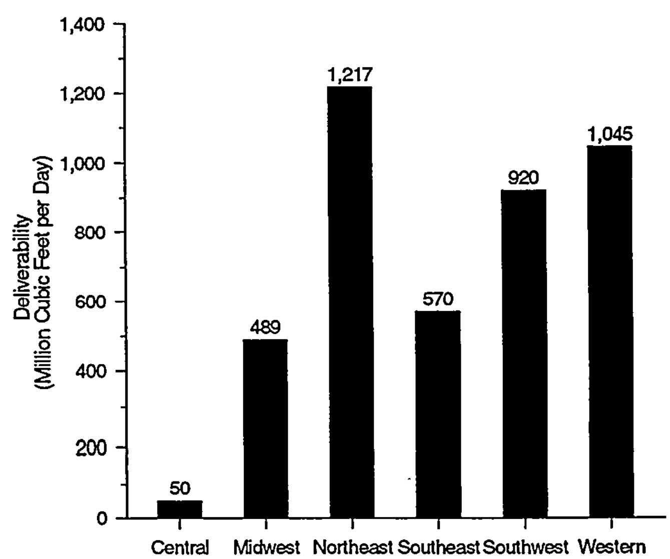
Over half of the scheduled projects are in the Midwest and Northeast



As with existing capacity, traditional depleted-reservoir storage is the largest source of new capacity



The Northeast is slated for the largest amount of new deliverability



Source: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System, Proposed Underground Natural Gas Storage Database, as of December 1998.

Storage Development

Twenty-two storage-facility expansion projects were completed in time for the beginning of the 1998-99 heating season. These projects added more than 28 billion cubic feet (Bcf) of working gas capacity and 1,120 million cubic feet (MMcf) per day of storage deliverability.[31] Still, as of November 1, 1998, and taking into account capacity adjustments at existing facilities that were reported to the Energy Information Administration, working gas capacity was 43 Bcf less (just over 1 percent) than the year-earlier level of 3,767 Bcf, although daily deliverability increased by 1,346 MMcf (almost 2 percent) from 74,579.[32] Interest in storage development has slowed substantially during the past 2 years. Since July 1997, only 19 storage development projects have been proposed.[33] These are offset by the attrition of previously announced projects; 10 of which have been canceled outright, while another 15 are on hold or inactive.

- **Since the decade's banner year of 1993, development of additional storage capacity has slowed.** In that year, about 103 Bcf of working gas capacity and nearly 4 Bcf per day of deliverability were added. The years since then have seen a significant drop in expansion activities. In 1996, only about 12 Bcf of working gas capacity and 680 MMcf per day of deliverability were added and, in 1997, only another 12 Bcf of working gas capacity and about 269 MMcf per day of deliverability.[34] During 1998, expansions were only marginally higher (see above).[35] The absence of new-facility development suggests that few clearly profitable sites currently exist. The industry is likely to continue to focus primarily on expansions of proven facilities (Figure 12), unless demand or prices grow sharply or a breakthrough in storage technology is achieved.

- **The development slowdown includes salt cavern storage.** Of the six proposed new salt cavern storage facilities as of 1997, none has been realized to date. Three have been canceled and three are currently on "hold." One project that once appeared attractive was the Avoca site in southeastern New York. Avoca was one of only four salt cavern storage facilities either planned for or in operation in the Northeast. Plagued by brine disposal problems, the project filed for bankruptcy in July 1997. Another Northeast project involved CNG's plan to lease salt caverns formerly used for petroleum liquids storage by Bath Petroleum Storage. However, the idea was dropped when the Federal Energy Regulatory Commission (FERC) ruled that the proposal violated pertinent regulations. What once may have been the most promising of potential new salt cavern facilities is the Tioga project in Pennsylvania. Although approved by FERC, it has been stalled owing to legal interventions by other parties.[36] While recent reports indicate that the opposing parties may be nearing a resolution, the project was still on hold in early 1999.

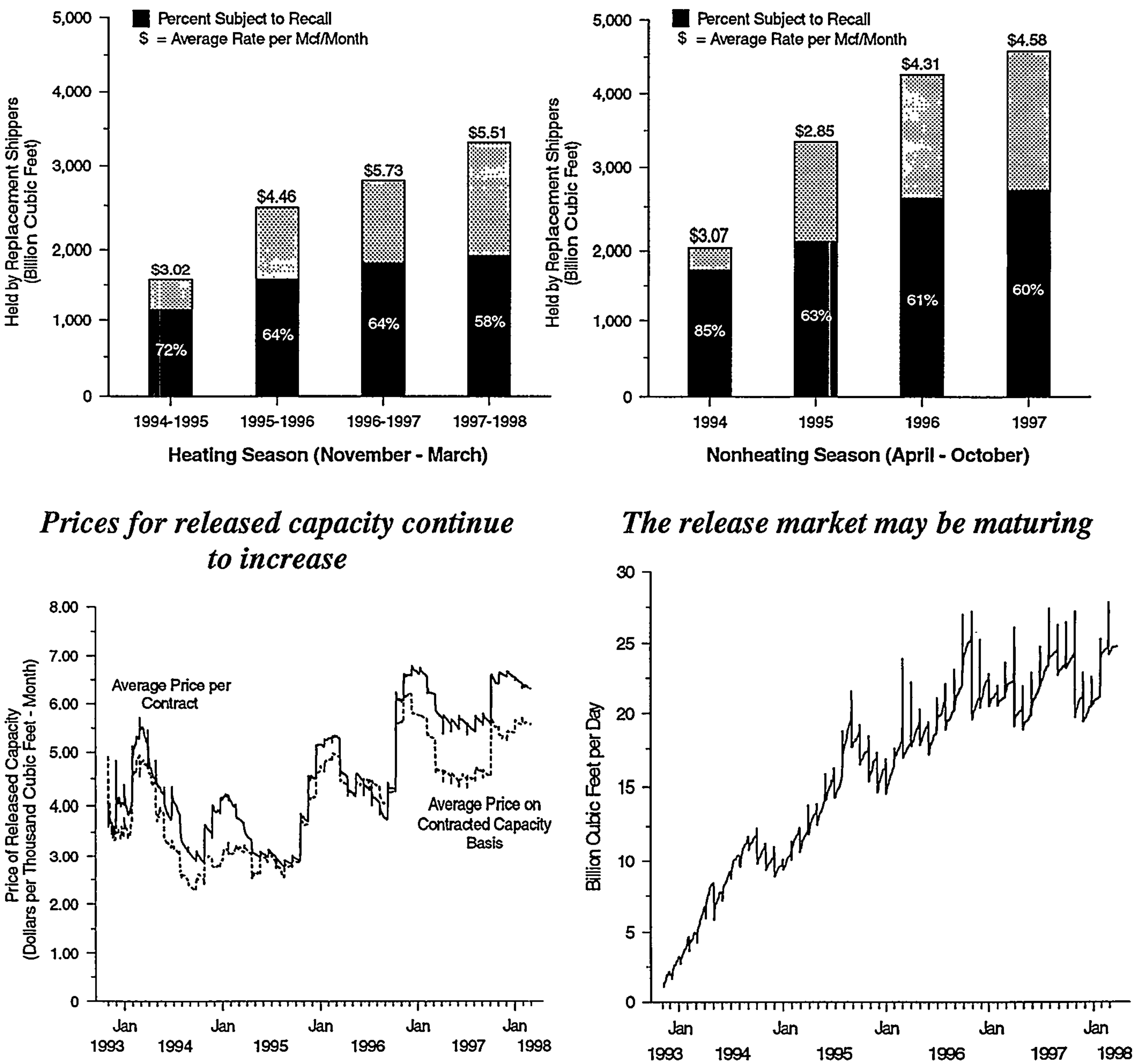
- **Interest continues in developing alternative methods for high-deliverability peaking service.** High deliverability is most often associated with salt-cavern storage facilities, whose share of currently-scheduled deliverability additions (Figure 12) is out of proportion to the relatively small number of sites or their total share of working gas capacity. Nonetheless, suitable sites for salt cavern development are limited, particularly near the expanding market areas along the Eastern Seaboard. This limitation may help explain an apparent growing interest in liquefied natural gas (LNG) projects. Although high deliverability has always been a characteristic of LNG facilities, as recently as 1997 only four LNG storage projects were planned. Since then, at least five additional projects have been proposed, with three of them in the Northeast.[37] The newer facilities are being designed and built with larger capacities; many can sustain deliverability rates for as long as 10 days, which is comparable to salt cavern performance (albeit with much smaller capacities). Though a relatively expensive source of supply, high deliverability and the ability to cycle LNG capacity multiple times in a given season make it an excellent peaking supply source while helping to lower the per-unit cost of operations.

- **Horizontal wells in depleted-reservoir storage may be another high-deliverability alternative.** Horizontal drilling is not a new technology (it has been used extensively in exploration and production applications), but its application to enhance the performance of reservoir storage is still somewhat experimental.[38] To date, only a few companies have used horizontal drilling at storage facilities and with mixed results.[39] However, there have been some instances that were quite successful. At least one storage company is currently working on applying this technology at a site in Pennsylvania and is also scouting other potential sites in the Northeast.

As of November 1998, 50 storage projects are scheduled through 2003 (Figure 12). If all were implemented as proposed, working gas capacity would increase by close to 5 percent to approximately 3,908 Bcf, and deliverability would increase by more than 5 percent to over 80 Bcf per day. The Northeast, with high concentrations of gas consumers and significant wintertime swing demand, ranks first in planned additions to deliverability at about 1.2 Bcf per day, or almost 30 percent of scheduled deliverability additions.

Figure 13. The Capacity Release Market Appears To Be a Reliable Source for Transportation Capacity

The release market has witnessed significant seasonal growth



Mcf/Month = Thousand cubic feet per month.

Sources: Energy Information Administration, Office of Oil and Gas, derived from: **November 1993 - July 1994:** Pasha Publications, Inc. **July 1994 - March 1998:** Federal Energy Regulatory Commission, Electronic Data Interchange (EDI) data.

Capacity Release

In today's competitive natural gas market with increased marketer presence and a demand for flexibility in contracting, capacity release provides a mechanism for shippers to improve transportation flexibility and react more quickly to market changes. This mechanism became available to shippers with the Federal Energy Regulatory Commission (FERC) implementation of Order 636 in 1993, which gave firm transportation contract holders the right to sell all or part of their transportation capacity for any length of time during the contract. Over the period November 1993 through March 1998, capacity release saved releasing shippers up to $3.6 billion, or about 6 percent of the U.S. transportation revenues to interstate natural gas pipeline companies during the same period.

- **The capacity release market continues to grow but at a slower pace.** The amount of capacity held by replacement shippers grew between seasons and years from November 1993 through March 1998.[40] The most rapid growth occurred in the first few years under Order 636 with increases of 1 trillion cubic feet between each heating season from November 1993 through March 1996. The growth then slowed to about half that pace between the 1995-96 and 1997-98 heating seasons (Figure 13). The same general pattern of rapid growth followed by a slowdown was evident during the nonheating seasons 1994 through 1997. During the 12 months ending March 31, 1998, the capacity held by replacement shippers was 8.0 Tcf, or the equivalent of 40 percent of the gas delivered to U.S. markets during the same period.[41]

- **The evolution of trading mechanisms and standards since 1993 has made the release market easier to use.** In the early years of the release market, each pipeline company developed its own electronic nonstandardized bulletin board. The market has since moved to using the Internet with protocols established by the Gas Industry Standards Board.

- **Rates received by shippers for released capacity were discounted, on average, almost 70 percent below the maximum rate for 1995 through 1998.[42]** Discounts for the year ending March 31, 1998, averaged about 50 percent, considerably less than the average discount of about 90 percent for the comparable period in 1995. The total revenue generated by the capacity release market in the year ending March 31, 1998, is estimated at $1.3 billion or about 10 percent of the transportation revenues for 1997.

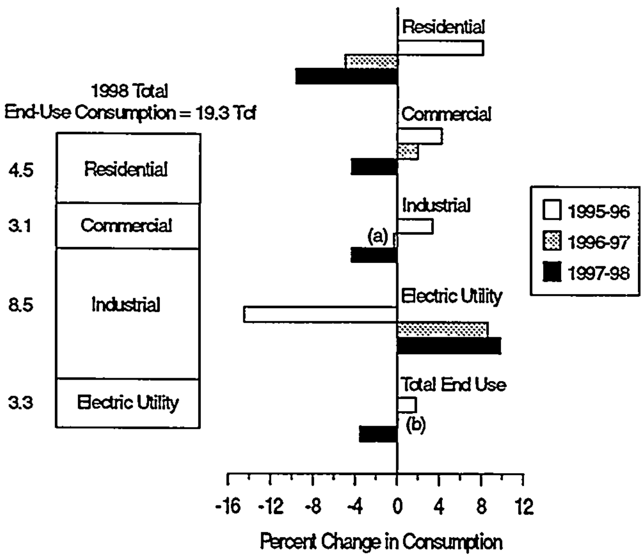
- **The price of released capacity has increased on both a per contract and a contracted capacity basis.** Between 1994 and 1998, the average price of released capacity measured across all active contracts increased by 61 percent, from $3.75 per thousand cubic feet (Mcf) per month during the 12 months ending March 31, 1995 (heating year 1995) to $6.04 in heating year 1998 (Figure 13).[43] Comparable rates on a contracted capacity basis, although lower than those averaged across contracts, increased from $3.05 to $4.97 per Mcf per month (63 percent) during the same period. The difference between the two price series is apparent particularly during the heating season when relatively small, higher-priced parcels of capacity are being traded on the release market.

- **The decline in the amount of capacity subject to recall and the increasing average price for released capacity from 1994 through 1998 may indicate that shippers perceive the release market as a reliable source for transportation capacity.** About 58 percent of the released capacity was subject to recall during the 1997-98 heating season (November through March), down from the 64 to 72 percent levels for the three previous heating seasons. At the same time, the amount of awarded released capacity increased by 18 percent between the 1996-97 and 1997-98 heating seasons. The decrease in recall provisions and the increase in awarded capacity between those two heating seasons may be the result of warmer-than-normal weather.[44] However, the general trend in recall provisions indicates that firm capacity holders are comfortable with unconditional release of capacity.

- **The leveling-off of capacity held by replacement shippers may indicate that the release market has matured** (Figure 13). As older, long-term contracts expire and new contracts more representative of current market conditions are put in place, there could be less capacity available for the release market. Market behavior during the 12 months ending March 1998 suggests that this may be happening. The slowdown in the growth rate of capacity released, coupled with a modest 2-percent growth in average price during the 12 months, suggests that the release market may be entering a phase of more stable operations without large, rapid shifts in market conditions. However, changes in market operations, such as the removal of the price cap, could draw new players to the market.

Figure 14. End-Use Consumption in 1998 Fell 4 Percent from Its Record High in 1997

Only electric utilities increased consumption in 1998

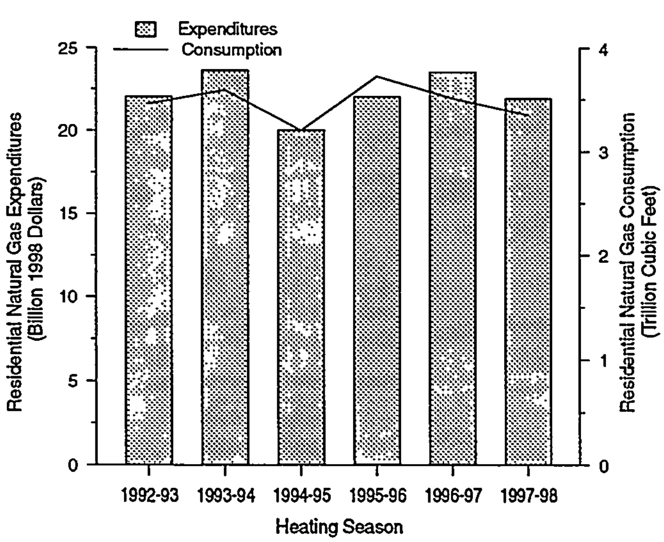


The residential price in 1997 caught up with wellhead price increases in 1996

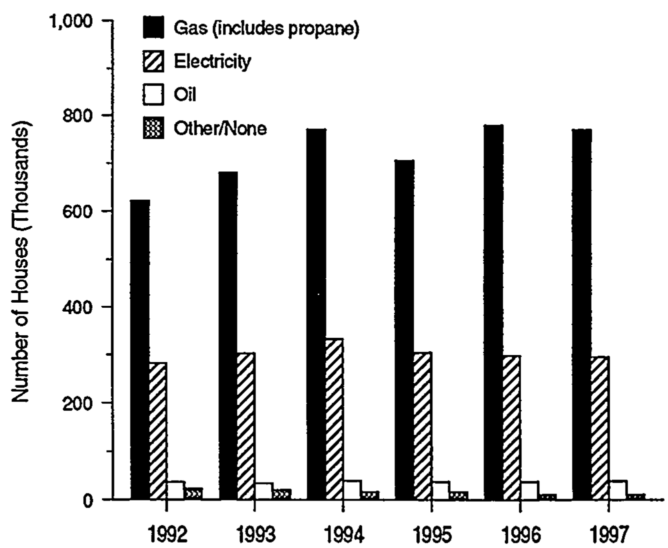
Natural Gas Prices
(1998 Dollars per Thousand Cubic Feet)

Year	Well-head	City-gate	Resi-dential	Com-mer-cial	Indust-trial	Electric Utility
1995	1.62	2.91	6.35	5.29	2.84	2.12
1996	2.23	3.44	6.52	5.56	3.52	2.77
1997	2.34	3.65	7.01	5.85	3.63	2.77
	Change in Prices					
1995-96	0.61	0.52	0.17	0.26	0.68	0.65
1996-97	0.11	0.21	0.49	0.29	0.11	0.00
	Percentage Change in Prices					
1995-96	37.4	17.9	2.7	4.9	23.9	30.7
1996-97	5.0	6.1	7.5	5.3	3.1	0.0

Residential users paid more but consumed less in the 1996-97 heating season



Gas heats most new single-family houses



(a) Industrial consumption declined 0.3 percent from 1996 to 1997.
(b) Total end-use consumption rose 0.1 percent from 1996 to 1997.
Tcf = Trillion cubic feet.

Notes: Sum of end-use consumption does not equal the total because of independent rounding. End-use prices for all but the electric utility sector are for onsystem sales only. The heating season is from November through March.

Sources: Energy Information Administration (EIA), Office of Oil and Gas. **Consumption, Prices, and Expenditures:** derived from EIA, *Natural Gas Monthly*, various issues and Chain-Type Price Indices for Gross Domestic Product from U.S. Department of Commerce, Bureau of Economic Analysis. **New Housing:** U.S. Department of Commerce, Bureau of the Census, *Characteristics of New Housing*, 1996 and 1997.

End-Use Consumption and Price

End-use natural gas consumption is estimated to have been 19.3 trillion cubic feet (Tcf) in 1998. This is 4 percent lower than in 1997, but consumption in both 1997 and 1996 had set all-time records at just over 20.0 Tcf.[45] The largest decline in 1998, in both quantity and percentage terms, occurred in the residential sector. Residential consumption in 1998 is estimated to have been 4.5 Tcf, 477 billion cubic feet, or 10 percent, lower than in 1997 (Figure 14). The decline can be attributed to milder weather in 1998 resulting in part from the El Niño event in the Pacific.[46] Warmer temperatures reduced the demand for natural gas for space heating, the major use of natural gas in both the residential and commercial sectors. Natural gas consumption in the commercial sector in 1998 is estimated to have been 3.1 Tcf, 4 percent lower than in 1997. The industrial sector saw the second-largest drop in natural gas consumption between 1997 and 1998, falling by 381 billion cubic feet, or 4 percent, to an estimated 8.5 Tcf.

The electric utility sector is the only sector that had an increase in natural gas consumption in 1998. Consumption for the full year 1998 is estimated to have been 3.3 Tcf, 10 percent above that of 1997. Extremely high summer temperatures in the Southwest boosted the demand for electric-powered air conditioning. Utilities met much of this peak in demand by burning natural gas.

Estimates of natural gas prices in 1998 are available through October for electric utilities and through November for the other sectors.[47] Cumulatively, average prices, unadjusted for inflation, are lower than in 1997 for all sectors. Residential and commercial users paid an estimated $6.91 and $5.50 per thousand cubic feet (Mcf), respectively, during the period, 1 and 5 percent below that of 1997. The average prices paid by the industrial and electric utility sectors were $3.10 and $2.38 per Mcf, respectively, 12 and 13 percent lower than in 1997.

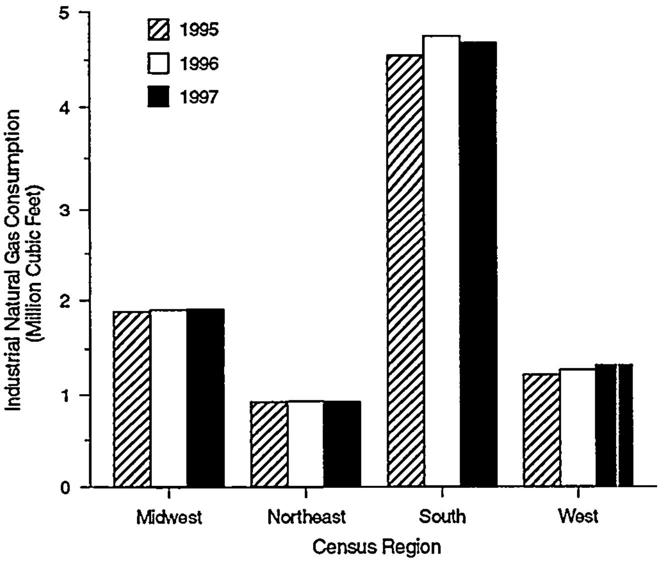
- **The average residential price of natural gas rose $0.49 per Mcf in 1997, reflecting the sharp rise in the average wellhead price in 1996** (Figure 14). (All prices are in 1998 dollars.)[48] Increases that occurred in the monthly average wellhead price late in 1996 were not fully passed on to residential consumers until 1997, in part because of the billing practices of many local distribution companies. These companies tend to base their charges to residential and commercial customers on long-term average costs in order to cushion the blow from sharp increases in wellhead prices. For example, between 1995 and 1996, the average residential price rose by only $0.17 per Mcf, even though the average wellhead price rose $0.61. Then in 1997, the average residential price rose $0.49 per Mcf to $7.01, while the average wellhead price rose only $0.11 to $2.34 per Mcf. Prices in the industrial and electric utility sectors are much more sensitive to changes in the wellhead price. The price paid by both sectors rose over $0.60 per Mcf in 1996, yet in 1997 the electric utility price was unchanged and the industrial price rose by only $0.11.

- **Residential expenditures for natural gas increased during the 1996-97 heating season even though consumption declined** (Figure 14). Residential expenditures were $23.5 billion (in 1998 dollars) during the 1996-97 heating season, 7 percent higher than in the prior heating season, even though consumption had declined by 6 percent. In contrast, both residential expenditures and consumption declined in the 1997-98 heating season. A combination of factors contributed to the higher expenditures during the 1996-97 heating season.[49] Unusually cold weather in November 1996 caused many natural gas providers to acquire higher-priced gas for their customers rather than withdraw supplies from storage, out of fear that storage supplies would not last through the winter. The prior heating season had been colder than normal, and the amount of natural gas in storage at the beginning of the 1996-97 heating season was lower than the previous season. The weather returned to normal, and for some months warmer than normal, later in the 1996-97 heating season, resulting in a net decline in natural gas consumption for the season. The strong demand in November 1996, however, had put pressure on wellhead prices, which rose from $1.94 per Mcf in October 1996 to $3.40 in January 1997. Although the impacts of this increase were somewhat delayed in the residential sector, they were felt before the heating season ended in March 1997.

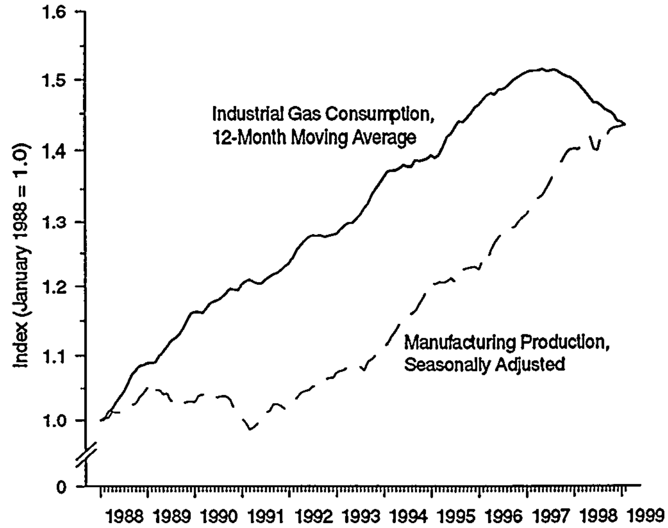
- **Gas continues to be the fuel of choice for heating most new single-family houses** (Figure 14).[50] Approximately two-thirds of the new single-family houses built from 1992 through 1997 were heated by gas, while nearly 30 percent were heated by electricity. The Midwest Census Region has the largest percentage of new single-family houses heated by gas, 91 percent, but only 21 percent of the 1.1 million new single-family houses constructed in 1997 were in the Midwest. The largest share of new home construction, 45 percent, was in the South where 52 percent of new houses were heated by gas.

Figure 15. Industrial Natural Gas Consumption Was 8.5 Trillion Cubic Feet in 1998, 4 Percent Below the 1996 Peak

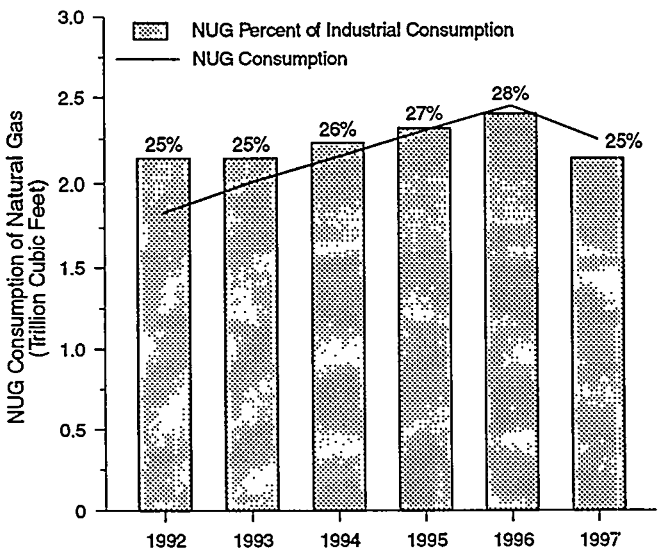
The South dominates industrial consumption



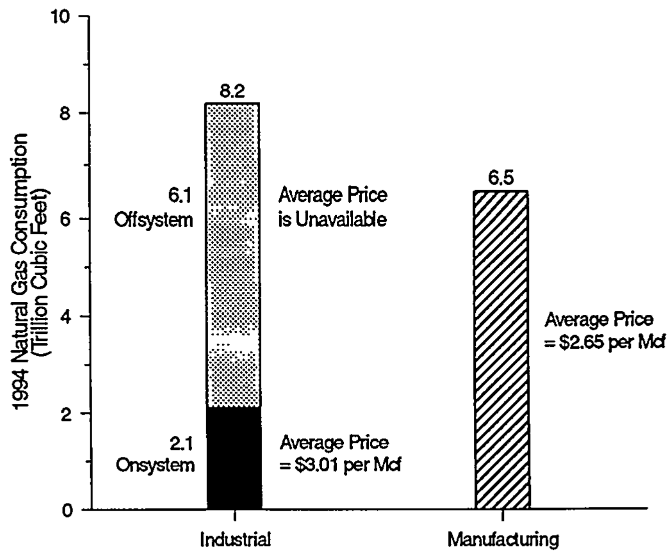
Industrial gas consumption is driven by manufacturing activity



NUGs account for a significant share of industrial consumption



Manufacturers paid less than the onsystem industrial price for natural gas in 1994



NUG = Nonutility generator.

Source: Energy Information Administration (EIA), Office of Oil and Gas. **Industrial Consumption:** EIA, *Natural Gas Annual 1997.* **Index of Manufacturing Production:** derived from: Board of Governors of the Federal Reserve System. **Index of Industrial Consumption:** derived from EIA: 1988-1992—*Historical Monthly Energy Review 1973-1992,* 1993-1999—*Natural Gas Monthly,* various issues. **NUG Consumption:** EIA: 1992—*Annual Energy Review 1997,* 1993-1997—*Electric Power Annual 1997,* Vol. II. **NUG Percent:** derived from EIA: NUG consumption and industrial natural gas consumption—*Natural Gas Annual 1997.* **Manufacturing Data:** EIA, *Manufacturing Consumption of Energy 1994.*

Industrial Gas Consumption

The industrial sector consumes more natural gas than any other sector, accounting for an estimated 44 percent of end-use consumption in 1998. Industrial consumption reached an historical peak of 8.9 trillion cubic feet (Tcf) in 1996 and has declined somewhat since then.[51] Consumption in 1998 is estimated to have been 8.5 Tcf, a 4-percent decline from the 1997 level of 8.8 Tcf. Monthly industrial consumption during 1998 ranged from 3 to 7 percent lower than in 1997 in all months except July, when levels were virtually the same. The South Census Region has long dominated industrial gas consumption, accounting for over half the total in 1997 (Figure 15). Industrial consumption in both the South and Northeast declined by 1 percent from 1996 to 1997, was unchanged in the Midwest, and increased by 4 percent in the West.

Industrial users paid an estimated $3.10 per thousand cubic feet for natural gas on average for January through November 1998.[52] This is 12 percent lower than the average of $3.54 paid during the same period in 1997. Industrial prices were lower in 1998 than in 1997 during most months of the year, with the most significant declines occurring at the beginning and end of the year. For example, the industrial price in January 1998 was 21 percent below that of January 1997 and the November 1998 price was 31 percent below that of 1997.

- **Industrial consumption of natural gas generally follows the trend in manufacturing activity** (Figure 15). From March 1991 (the bottom of the last recession)[53] through March 1997, the seasonally adjusted indices of industrial consumption and manufacturing production increased annually by 3.8 and 5.1 percent, respectively.[54] Since then, generally lower crude oil prices, fluctuating natural gas prices, and periods of warmer-than-normal weather have contributed to a leveling off and lowering of industrial natural gas consumption, yet the strong economy has continued to boost manufacturing output. From March 1997 to March 1998, the industrial gas consumption index declined by 1.5 percent while the manufacturing index rose by 5.6 percent.

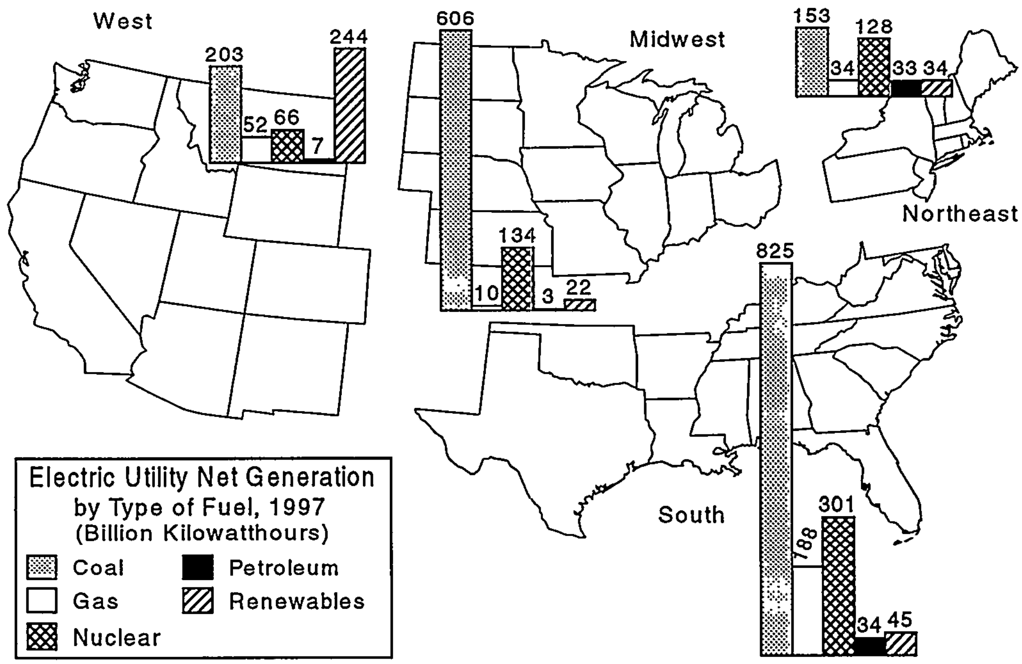
- **Nonutility generator consumption of natural gas accounts for a significant share of total industrial consumption—25 percent in 1997** (Figure 15).[55] Nonutility generators (NUGs) consist mainly of cogenerators, but also include independent and small power producers. Cogenerators use one source of energy to produce both electric power and another useful form of energy, such as heat or steam. Cogeneration can take several different forms. For example, natural gas may be used to generate electricity directly, with the waste heat used for another purpose, or the natural gas may be used in a boiler to generate steam, which in turn is used in manufacturing processes and to generate electricity. Nonutilities consumed an estimated 2.2 Tcf of natural gas in 1997. Natural gas consumption by nonutilities grew at an average rate of 4 percent annually from 1992 through 1997, while total industrial consumption grew 3 percent annually. However, nonutility consumption had grown at a 7-percent annual rate from 1992 through 1996 before falling by 8 percent in 1997. Nonutilities generate more electricity using natural gas than any other fuel. In 1997, natural-gas-fired nonutility gross generation was 206 billion kilowatthours, 54 percent of total nonutility generation. Coal was second, responsible for 15 percent of nonutility gross generation.

- **Manufacturing data provide insight into the average price paid for natural gas in the industrial sector.** As the interstate natural gas transportation system was restructured during the 1980s, large consumers, such as industrial firms, were among the first to seek alternatives to their traditional providers of natural gas. The Energy Information Administration (EIA) collects pricing information from the companies that actually deliver natural gas to the end user, typically a pipeline company or a local distribution company. The purchasing of natural gas from alternative providers, such as marketers, has been so strong in the industrial sector that by 1997 price data were available to EIA for only 18 percent of natural gas deliveries to industrial users.[56] EIA's quadrennial survey of manufacturers, last conducted in 1994, provides additional information on the average price that this portion of the industrial sector pays for natural gas.[57] In 1994, EIA's average industrial price was $3.01 per thousand cubic feet (Mcf), but this applied to only 26 percent of natural gas deliveries to industrial firms (Figure 15). In 1994, manufacturers paid an average of $2.65 per Mcf for natural gas. Total manufacturing purchases were 6.5 Tcf, or 79 percent of total industrial consumption in 1994.[58]

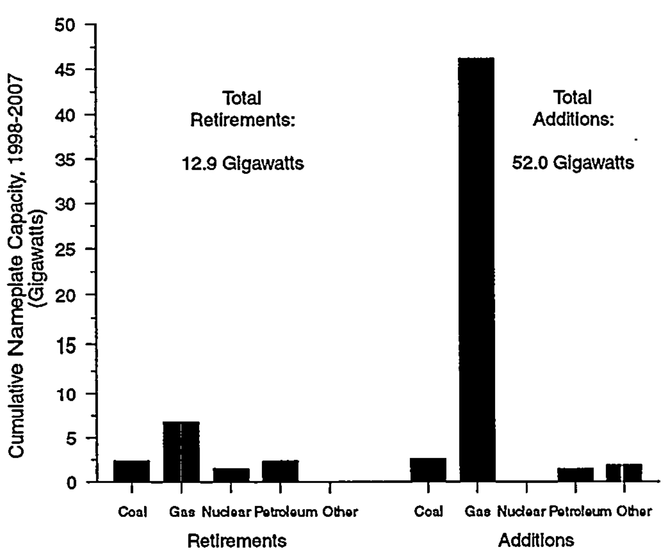
- **Electricity generation may be a growth area for natural gas in the industrial sector as distributed power becomes more economic.**[59] The use of natural gas to generate electricity may increase among manufacturers that are able to take advantage of distributed power technologies, many of which may be fueled by natural gas.[60] Distributed power consists of small generation units located closer to the user than the typical electric utility. Such units usually have a capacity of 30 kilowatts to 50 megawatts, compared with 500 to 1,000 megawatts for a central power plant (see p. 33).

Figure 16. The Use of Natural Gas To Generate Electricity Is Expected To Grow

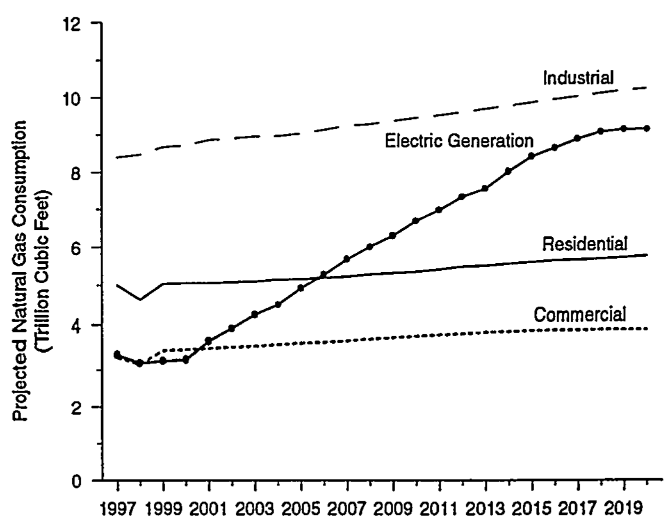
Most electricity is generated by coal . . .



. . . But most capacity additions will be fueled by gas . . .



. . . Resulting in strong growth in natural gas for electricity generation



Notes: "Gas" in Net Generation and Capacity Retirements and Additions is natural gas; refinery, blast-furnace, and coke-oven gases; and propane. Renewables consist mostly of hydroelectric power. Other consists mostly of waste heat and includes renewables. The regions are the U.S. Census regions and the West includes Alaska and Hawaii.

Sources: Energy Information Administration (EIA). **Net Generation:** *Electric Power Annual 1997*, Vol. 1. **Capacity Retirements and Additions:** *Inventory of Power Plants in the United States As of January 1, 1998.* **Projected Natural Gas Consumption:** *Annual Energy Outlook 1999*, National Energy Modeling System run AEO99B.D100198A.

Electricity Generation

The electric utility sector is the only end-use sector that showed strong growth in natural gas consumption in 1998. Estimates for the first 11 months of 1998 show that electric utility consumption of natural gas was 11 percent above that of 1997 for the same period. The average price paid for natural gas (available through October 1998) was $2.38 per thousand cubic feet, 13 percent below that of 1997. Annually, natural gas consumption by electric utilities during the 1990s has been in the range of 2.7 to 3.2 trillion cubic feet (Tcf). Consumption in 1997 was 3.0 Tcf, 9 percent above the 1996 level but short of the historical peak of 4.0 Tcf set in 1972.

Several nuclear plant outages in 1997 helped boost net electricity generation by all types of fossil fuels. Total net generation set a record in 1997 at 3,123 billion kilowatthours (kWh), 45 billion kWh higher than in 1996. Electric power from nuclear plants declined by 46 billion kWh (7 percent) in 1997, but generation from coal increased by 50 billion kWh (3 percent) and from gas[61] by 21 billion kWh (9 percent).[62]

- **Although coal is used for most electricity generation, nearly all anticipated capacity additions will be fueled by gas** (Figure 16).[63] Sixty-three percent of the gas-fired additions are planned for the South Census Region, which generates more electricity than any other region. The South Census Region also generates the most electricity using gas. The 188 billion kWh generated by gas in the region in 1997 accounted for 13 percent of the region's total generation.

  From 1998 through 2007, 52 gigawatts of generating capacity is planned to be built in the United States, 89 percent of which will be gas-fired (Figure 16). Gas-fired units also dominate planned retirements during the period, accounting for 53 percent, but the total retirement capacity is only 13 gigawatts. Gas-fired capacity additions of 46 gigawatts planned for the period will more than offset the 7 gigawatts of gas retirements. The increase in gas-fired capacity will have environmental benefits because natural gas has much lower emissions of many pollutants than do coal or oil per Btu of fuel consumed (see Chapter 2, Table 2). For example, consumption of natural gas generates less than half the carbon dioxide of coal and approximately one-third less than that of oil.

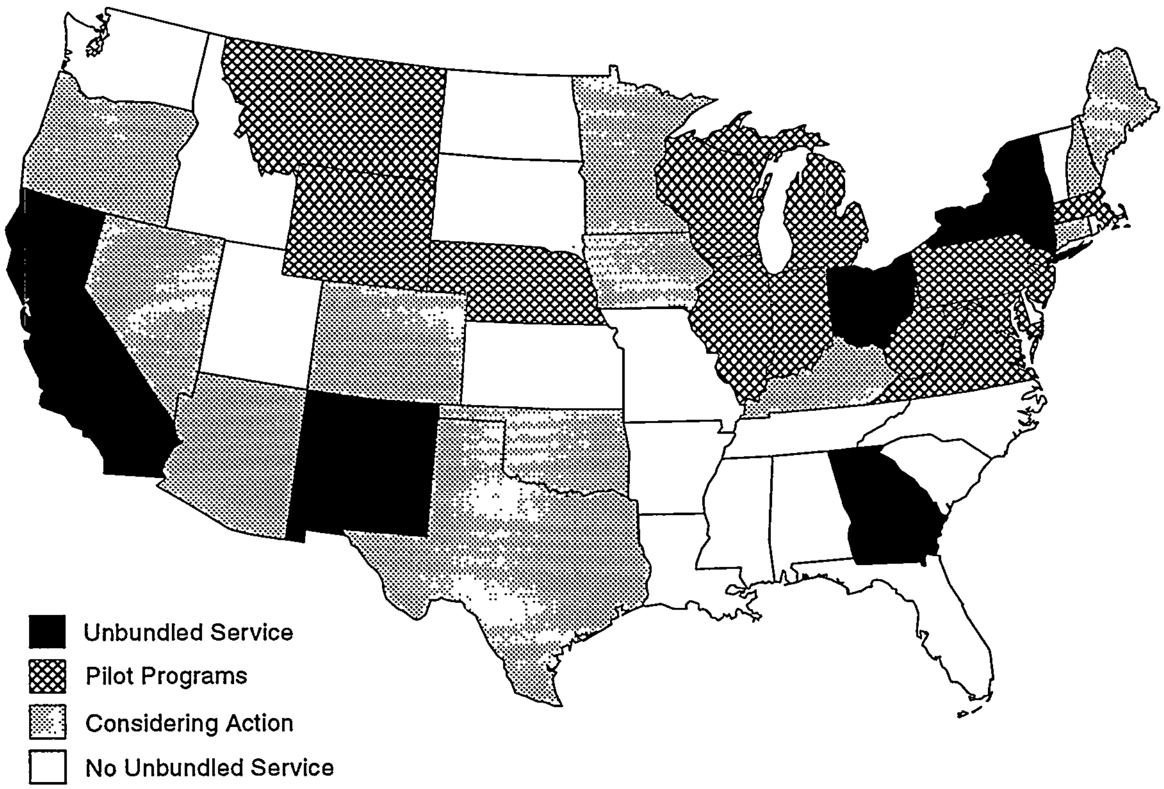
- **Natural gas used to generate electricity is projected to reach 9.2 Tcf in 2020, almost three times the 1997 level** (Figure 16).[64] The use of natural gas to generate electricity is expected to grow 4.5 percent annually from 1997 through 2020. This growth is spurred by the increased utilization of gas-fired plants and the addition of new turbines and combined-cycle facilities that are less capital-intensive than building new coal, nuclear, or renewable plants. The restructuring of the electric utility industry is also expected to open up new opportunities for gas-fired generation.[65] The South Census Region is expected to see the most growth in natural gas use by electric generators, accounting for 38 percent of the increase projected from 1997 through 2020.[66]

- **New "merchant" power plants, many of which are gas-fired, are coming on line.** The restructuring of the electric power industry[67] allows the construction of generation facilities without first acquiring long-term commitments for sale of the power generated. Several plants are being constructed in Texas where the State public utility commission is discouraging traditional electric utilities from building new generation facilities. An 85-megawatt plant, the first exempt wholesale generator in Texas, has been operating since 1997; a 240-megawatt plant came on line in the summer of 1998, in time to serve the unusually high demand for air conditioning; and a 500-megawatt plant is expected to come on line in 1999. These plants are among the first merchant plants in the United States. Florida's first merchant plant, a 500-megawatt gas-fired facility, is being planned by Duke Energy Power Services and is expected to come on line in late 2001. When providing peak generation, a 500-megawatt facility could use as much as 100 million cubic feet of gas per day.[68]

- **Distributed power generation may provide a new niche for natural gas, but there are different views on the role electric utilities should play.** Distributed power generation utilizes small (50 megawatts or less) generating units situated near the end user. Many of the new units may use natural gas, while others will use petroleum products or renewables.[69] Increased use of distributed power generation would help mitigate the need for utilities to increase their own generation capacity. However, while advocates agree that an open market with the ability to send clear price signals is crucial to the acceptance and development of distributed power generation, the ownership of the distributed units is a controversial issue that needs to be addressed. Some view ownership of these units by electric utilities as speeding the acceptance of distributed power generation. Others oppose utility ownership, fearing that such relationships could retard competition. Not all endorse the concept of distributed power generation. Critics, including some utilities, oppose the concept, arguing that the lack of clear standards could degrade system integrity.[70]

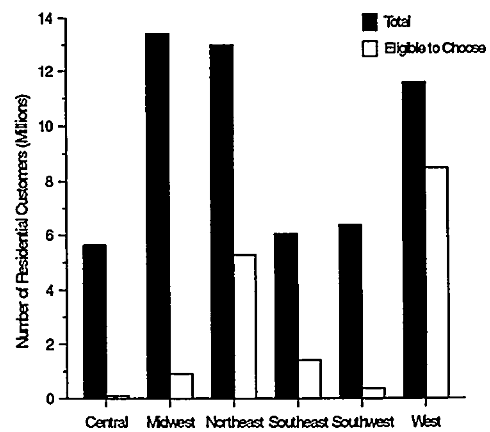
Figure 17. Eighteen States and the District of Columbia Have Some Form of Residential Choice Program

Five States have unbundled service



There is wide regional variability in residential customers' access to and participation in choice programs

Region	Number of Residential Natural Gas Customers (thousands)			Annual Residential Natural Gas Purchases (billion cubic feet)			Estimated Unbundled Purchases in 1998 as a Percent of 1997 Total
	1997 Total	Eligible to Purchase Offsystem Gas	Participating in Retail Restructuring Programs	1997 Total	Eligible to Purchase Offsystem Gas	Estimated 1998 Unbundled Purchases	
Central	5,647	92	63	558	10	6.7	1.2
Midwest	13,428	905	139	1,665	108	16.7	1.0
Northeast	13,004	5,280	307	1,249	498	31.1	2.5
Southeast	6,056	1,400	141	412	103	10.4	2.5
Southwest	6,366	380	0	439	31	0.0	0.0
West	11,571	8,494	44	645	449	2.3	0.4
Total	56,072	16,552	694	4,968	1,199	67.2	1.4



Note: Estimated Unbundled Purchases assumes each residential customer participating in a State's retail unbundling program purchased from a third-party service provider the same amount as the State's annual average consumption per residential customer.

Sources: Energy Information Administration (EIA), Office of Oil and Gas. **1997 Total Residential Gas Customers and Purchases:** derived from *Natural Gas Annual 1997* (October 1998). **Number of Eligible Residential Customers and Number Participating in Retail Restructuring Programs:** derived from General Accounting Office, *Energy Deregulation: Status of Natural Gas Customer Choice Programs* (December 1998) and information gathered by EIA analysts.

Retail Unbundling

The continuation of industry restructuring at the State level has important implications for residential and small commercial natural gas consumers. Retail unbundling, or restructuring, is division of the services required to provide gas to the end user into various components, and the ability of the customer to purchase those components separately. Large commercial and industrial consumers have had the option to purchase natural gas from offsystem providers for years,[71] whereas a "choice" for residential and small commercial customers (traditionally known as "core" customers) has only recently been available.[72] State regulators and lawmakers, who are responsible for designing and implementing retail restructuring programs, have delayed implementing customer choice until they could ensure reliable service and protect the interests of captive residential and commercial customers. As of July 31, 1998, 5 of the Lower 48 States have implemented complete unbundling programs for core customers, 13 States plus the District of Columbia have customer choice pilot programs, 12 States are considering action, and 18 have no plans to implement even pilot programs (Figure 17).[73]

- **About 65 percent of U.S. residential gas consumers live in States that have either completely unbundled retail service or have active pilot programs in place.** The degree to which these core customers are eligible and participating in choice programs varies. Currently, 78 percent (14.3 million) of the residential customers living in the five States with complete retail unbundling are eligible to choose their natural gas provider.[74] However, only 2 percent (301,721) of the eligible customers are participating. There is a larger participation rate for the 2.3 million residential customers who are eligible for the pilot programs underway in 14 States, with over 17 percent (392,448) participating. These 2.3 million customers represent 13 percent of the residential customers in those 14 States.

- **Unbundled residential gas purchases could have reached an annualized level of 67 billion cubic feet (Bcf) in 1998, or 1.4 percent of the 5.0 trillion cubic feet (Tcf) of gas consumed by residential customers in 1997, based on current customer choice participation levels.**[75] However, the amount of unbundled gas purchases varies significantly by region (Figure 17). The largest estimated offsystem purchases exist in the Northeast where 31 Bcf is associated with customers participating in choice programs. While end-use services in New Mexico are completely unbundled, customers are not participating in a choice program because third-party service providers have not offered service in the State.[76]

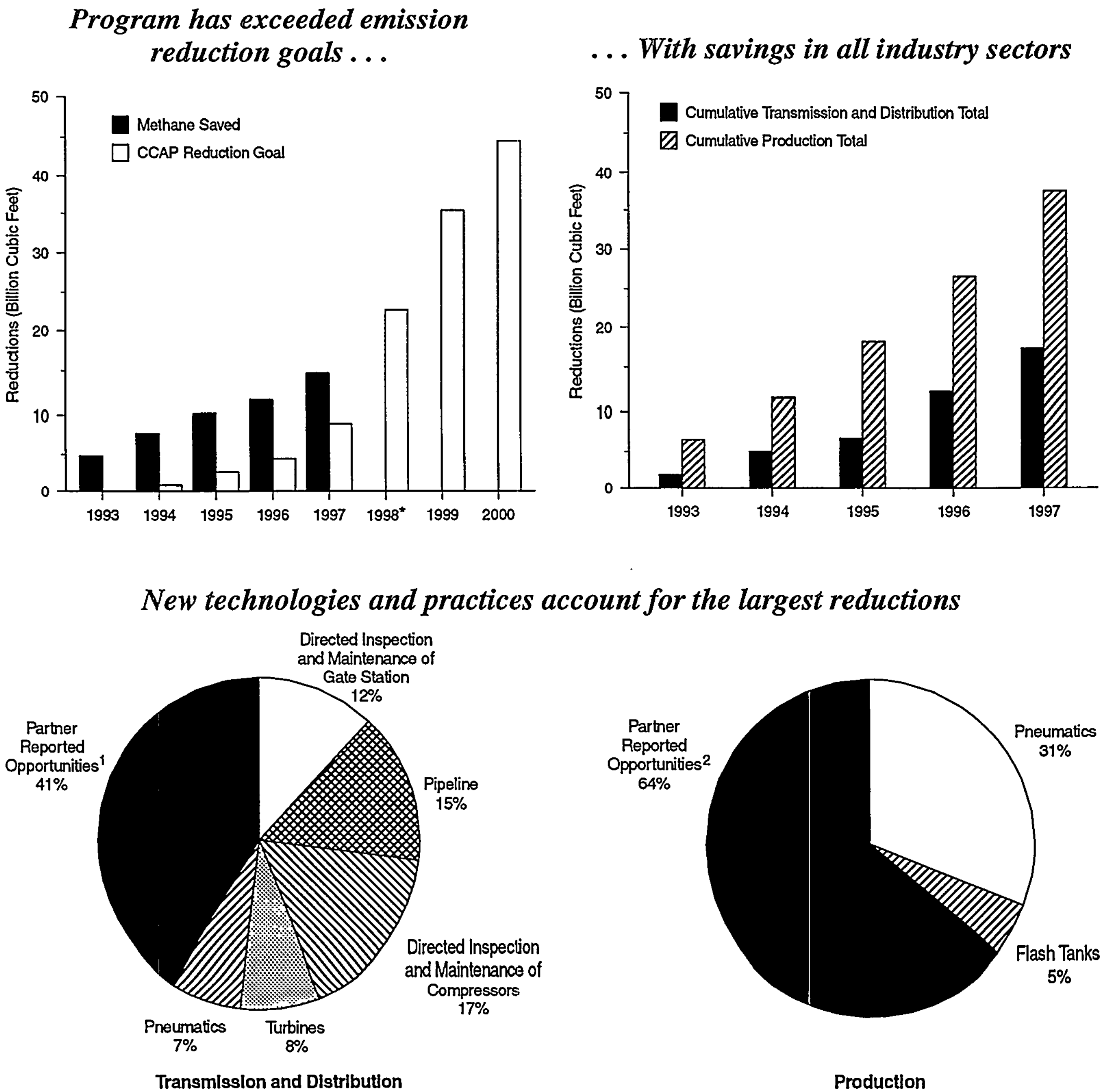
- **Residential customers have not fully embraced retail unbundling programs when given the opportunity.** Customers and State regulators have raised questions about the benefits of retail unbundling. There does not appear to be systematic monitoring or measurement of the overall impact of retail restructuring. In addition, the ability to measure price and customer savings may degrade as more LDC customers purchase offsystem gas.[77] Some rural communities are particularly concerned that they will face radically increased costs and fewer purchasing options as a result of restructuring. In response, marketers have offered incentives to attract retail customers, such as a guaranteed fixed percentage or dollar savings as compared with the LDC's gas cost.[78]

- **Some marketers have withdrawn from participation in retail restructuring programs as a result of the lack of customer participation.**[79] Marketers fear that the staffing and administrative costs of providing retail service may not be recovered without enough customer participation. Marketers are also concerned that direct assignments of LDC transportation capacity will erode the profitability of providing retail services. One way marketers have been able to lower costs is to use more interruptible service in their transportation portfolio. If they are required to accept responsibility for the LDC's firm transportation contracts, the marketers' profit margins may suffer.[80] Conversely, if the LDCs are required to retain unneeded firm transportation capacity, the stranded costs may have to be recovered from LDC shareholders, the pipeline company, or other customers within the LDC's service area.

- **Service reliability and supplier performance are two issues of general concern to State regulators as they determine how to capture the benefits of unbundled service for core customers.** Questions relate to supplier qualifications, access to information, allocation of upstream pipeline capacity, and the LDC's obligation to serve core customers if a "third party" service provider fails to deliver gas. A number of States are examining these and other retail restructuring issues.

- **In an effort to protect consumers, some States[81] require marketers to agree to certain business practices and standards in order to operate in the State.** Currently these standards vary by State, although there has been a proposal to establish national standards of conduct for marketers.[82] Under the proposal, the marketer[83] would be able to use a seal of approval, "Certified Energy Marketer," if it agrees to abide by these "fair marketing" practices.

Figure 18. Natural Gas Industry Partners with EPA To Reduce Methane Emissions to the Atmosphere



EPA = Environmental Protection Agency. CCAP = Climate Change Action Plan.

*The 1998 goal was recently increased from 18.9 to 22.7 billion cubic feet.

[1]The partner reported opportunities in the transmission and distribution sectors include: replacing engine gas starters with air starters, lowering pipeline pressure prior to maintenance, installing 3-phase separators on dehydrator reboilers, and other operational practices.

[2]The partner reported opportunities in the production sector include: utilizing down-hole plunger lifts in wells, using lower heater treater temperature, inspecting and replacing tank vent seals, eliminating and consolidating excess dehydrators, and numerous other operational practices.

Source: Environmental Protection Agency, *1997 Natural Gas STAR Annual Report*.

New Technology and the Environment

Several new natural gas technologies and initiatives could lead to environmental improvement. The natural gas industry in partnership with the Environmental Protection Agency (EPA) established the "Natural Gas STAR program" in 1993 to reduce methane emissions to the atmosphere. In the program, companies agree to implement technologies and management practices designed to minimize or prevent gas loss and to improve system efficiency. Reducing methane emissions can have an impact on slowing the rate of climate change and can also save money for the industry. In another program, research and testing efforts are underway to use liquefied natural gas (LNG) in place of diesel fuel, which could significantly reduce nitrogen oxide, carbon dioxide, and hydrocarbon emissions in comparison with those of current diesel fuel. In addition, gas-to-liquids technology may be coming of age, with much activity in the research end of the industry, potentially reducing methane flaring.

- **Partners in the Natural Gas STAR program exceeded their emission reduction goal for 1997 (9.1 billion cubic feet (Bcf)) by 75 percent, or 6.8 Bcf.** STAR partners have prevented the release of about 54.8 Bcf of methane through the program from 1993 to 1997 (Figure 18). This success prompted the 1998 goal to be changed from 18.4 to 22.7 Bcf. EPA has worked with several States and program partners to adjust regulations so as to facilitate use of "best management practices" (BMPs) that reduce methane emissions. Other technologies and management practices initiated since the STAR program was implemented ("partner reported opportunities") have resulted in 41 percent of the methane reductions in transmission and distribution operations and 64 percent of those in production-related activities.

- **The Natural Gas STAR program has two BMPs to reduce methane emissions from natural gas dehydration facilities, which emit about 22 Bcf of methane per year into the atmosphere.** These dehydrators were ranked as the fourth greatest source of toxic emissions of hazardous air pollutants in 1993 (the latest year available). EPA has a proposed rulemaking regarding reduction of hazardous air pollutants from oil and gas operations that specifically addresses dehydrators. The BMPs include the installation of flash tank separators and a reduction of the triethylene glycol (TEG) circulation rates. As TEG absorbs water from natural gas, it also absorbs the methane that is vented to the atmosphere when the glycol is regenerated. Economic analyses demonstrate that dehydration units circulating between 150 and 450 gallons of TEG per hour can achieve payback of costs in 6 months to 2.5 years of the installation of a flash tank separator. Depending on the size of the unit and the percent of overcirculation, a reduction in TEG circulation rates can save between 130 and 13,140 thousand cubic feet of methane per year.

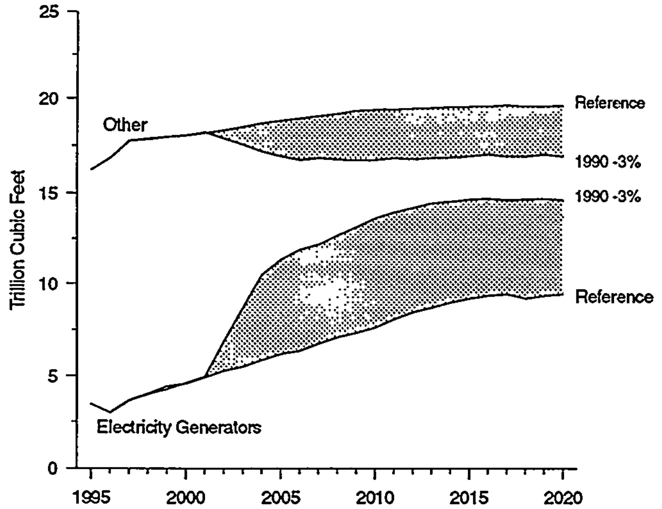
- **LNG has been tried in a locomotive engine.** Engineers at the Southwest Research Institute working for GasRail USA, a cooperative industry research project of industry, Federal, and State participants, have achieved a 75-percent reduction in nitrogen oxide emissions on a 4,200-horsepower, 16-cylinder, natural-gas-fueled engine for use in passenger engines.[84] The selected system used small amounts of diesel fuel as an ignition source for the high-pressure natural gas that is injected late into the combustion cycle. The engine also reduced carbon dioxide emissions by 25 percent. EPA has called for railroad locomotives to meet a 25-percent reduction in nitrogen oxides and a 40-percent reduction in hydrocarbons and particulate matter by 2000.

- **Gas-to-liquids technology has taken significant steps towards commercial operation in specific producing areas in the United States.** Gas-to-liquids (GTL) projects have been announced in several locations around the world, with BP and Exxon considering it for Alaskan North Slope gas. In October 1997, ARCO announced a joint project with Syntroleum Corporation to build a pilot plant of about 70 barrels per day at an ARCO refinery near Bellingham, Washington.[85] The Syntroleum Corporation effort is to develop GTL systems that are economic at the level of 50,000 to 2,000 barrels per day.[86] The Department of Energy has selected Air Products and Chemicals, Inc. to develop a ceramic membrane, which could reduce greatly the cost of converting natural gas to transportation-grade liquid fuels and premium chemicals.[87] Praxair Inc., Amoco Corp., BP, Sasol, and Statoil have a technical alliance to study ceramic membranes for GTL.[88] Several other companies have shown an interest in GTL plants.[89]

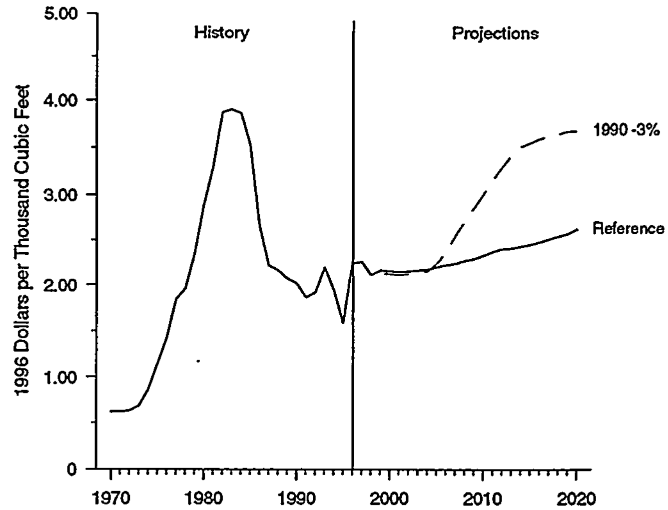
- **New developments in fuel cell technology could lead to substantially lower carbon dioxide emission levels.** Liquid methanol as a hydrogen carrier to power a fuel cell was developed for the military by the National Aeronautics and Space Administration's (NASA) Jet Propulsion Laboratory and the University of Southern California. This direct methanol fuel cell runs relatively cool, is highly efficient, and can be supported by existing gasoline fueling infrastructure. A full fuel-cycle analysis[90] shows that the carbon dioxide emissions released by a methanol fuel cell will be less than half that of today's gasoline internal combustion engines.

Figure 19. Kyoto Implementation Could Have Far-Reaching Impacts on Gas Use and Prices

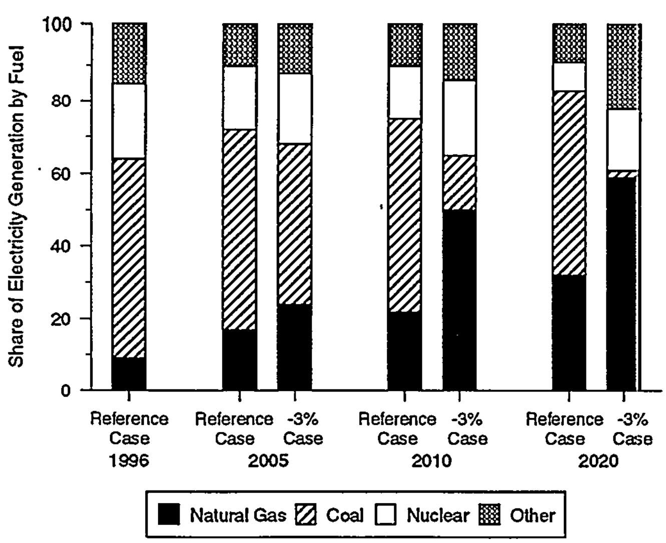
Gas use for electricity generation climbs above the reference case, but other uses fall below



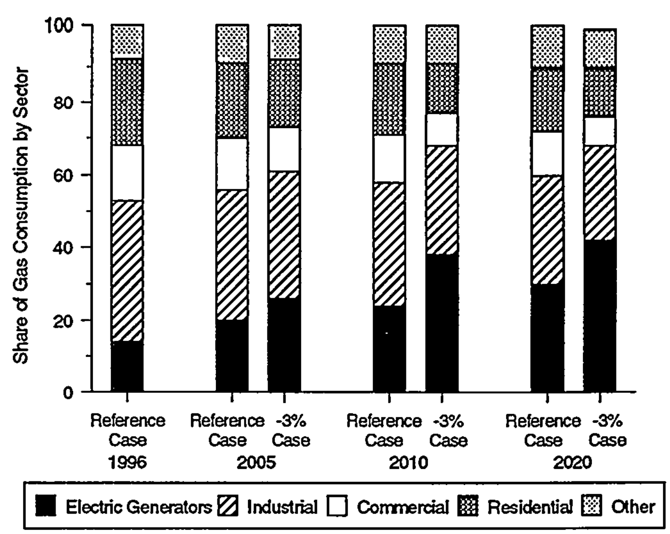
Wellhead prices are projected to move up, perhaps sharply, but to remain below peak of 1980s



Gas share of generation offsets declines in coal



Electric generation could command largest share of gas consumption by 2010



Note: The Energy Information Administration report *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity* examines a series of six cases looking at alternative carbon emission levels. The reference case represents projections of energy markets and carbon emissions without any enforced reductions and is presented as a baseline for comparison of the energy market impacts in the reduction cases. The highest consumption patterns for natural gas are seen in some of the intermediate cases, principally the "Stabilization at 1990 Levels" and the "3 Percent Below 1990 Levels." For these figures, the reference case and the "3 Percent Below 1990 Levels" are used to illustrate the potential range of additional demand.

Source: Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity* (October 1998), AEO98 National Energy Modeling System runs KYBASE.D080398A and FD03BLW.D080398B.

Overall natural gas consumption is projected to increase about 10.3 trillion cubic feet (Tcf) from 1997 to 2020,[91] mainly because of its increased use as a fuel for electricity generation. The expected use of natural gas for generation is even higher when the potential impact of the Kyoto Protocol is considered. This agreement, which has been signed but not ratified by the United States, sets carbon emission reduction targets relative to 1990 for the "Annex I" countries,[92] which include the United States, Canada, and other developed countries. For the United States, the target is 7 percent below 1990 carbon emission levels. In 1997, U.S. energy-related carbon emissions from fossil energy consumption were 1,480 million metric tons, about 10 percent above the 1990 level. Without new policies, these emissions are projected to increase at an annual rate of 1.3 percent through 2020, according to the *Annual Energy Outlook 1999* (*AEO*).

Electricity use is a major cause of carbon emissions. Although electricity produces no emissions at the point of use, its generation currently accounts for 36 percent of total carbon emissions. According to the *AEO*, that share is expected to increase to 38 percent in 2020. Coal, which accounts for about 52 percent of electricity generation in 2020 (excluding cogeneration), is projected to produce 81 percent of electricity-related carbon emissions. In 2020, natural gas is expected to account for 30 percent of electricity generation but only 18 percent of electricity-related carbon emissions.

Findings in a recent Energy Information Administration (EIA) Service Report, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity* (*Kyoto*), highlight the significant role that natural gas may play in any approach to reduce carbon emissions.[93] The report was undertaken at the request of Congress using the same methodologies and assumptions in the *AEO 1998*, with no changes in assumptions about policy, regulatory actions, or funding for energy and environmental programs. In 1990, U.S. energy-related carbon emissions were 1,346 million metric tons. The Kyoto target is 1,250 million metric tons, on average, in the commitment period 2008 to 2012. While the details of the final implementation are not fully decided, countries have some flexibility in how they can meet these targets. Joint implementation projects are permitted among the Annex I countries, allowing a Nation to take emissions credits for projects in other countries that reduce emissions or enhance emission-absorbing sinks, such as forests and other vegetation. Meeting the target entirely by domestic reduction is the most constrained option for the United States. Some results of the *Kyoto* study include:

- **If the emission reduction target of the Kyoto Protocol were imposed, the U.S. coal and oil industries would see lower consumption and production whereas the natural gas industry would expand.** Compared with the reference case (which does not incorporate the Protocol), natural gas consumption would be 0.6 to 3.5 Tcf higher in 2010 and 1.8 to 3.3 Tcf higher in 2020 under a number of alternative scenarios. Natural gas wins out over coal and oil in the carbon reduction cases, because its carbon content per Btu is only 55 percent of that for coal and 70 percent of that for oil.

- **When carbon emission limits are first imposed in 2005, rapid growth in natural gas electricity generation is projected in scenarios with rapid increases in carbon prices.**[94] The scenario presented in Figure 19 (1990 -3%) results in one of the higher gas consumption projections in the *Kyoto* study. In this case, gas-fired generation ramps up quickly in 2005, because the rising carbon price makes existing natural gas plants more economical than existing coal plants and because new natural gas plants can be quickly brought on line. In this case, after the initial shift to natural gas, the growth in natural gas generation continues, but at a slower rate. In the later years of the forecast period, natural gas generation does not increase as rapidly, because carbon-free renewable technologies become economical as the demand for electricity grows and natural gas prices increase. Under this scenario, natural gas could hold as much as a 60-percent share of electric generation in 2020, compared with one-third of the generation in the reference case, which excludes the Protocol (Figure 19).

- **Higher natural gas prices lead to conservation and the penetration of more efficient technologies.** Natural gas prices are higher in the carbon reduction cases than in the reference case, both at the wellhead (Figure 19) and at the burner tip. At the wellhead, higher production to satisfy increased natural gas consumption, in the face of increasingly expensive resources, boosts prices. At the burner tip, some consumers may see more than double the prices they could have expected without the carbon reduction polices. This results in lower consumption levels for the nongeneration sectors of the economy.

- **Pressure to merge gas and electricity companies could mount as the advantages of arbitraging the two markets become apparent.** Powerplant use of natural gas (excluding industrial cogeneration) in the carbon reduction cases is projected to rise from roughly 3 Tcf in 1996 to between 8 and 12 Tcf in 2010 and between 12 and 15 Tcf in 2020. By 2010, the electric generators could become the largest consumers of natural gas (Figure 19).

Chapter 1 Endnotes

1. Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998).

2. Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998).

3. Average wellhead prices were converted to a Btu-basis using 1,026 Btu per cubic foot, which is the estimated heat content for dry gas production as reported in: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(98/12 (Washington, DC, December 1998), Table A4, "Approximate Heat Content of Natural Gas."

4. The December 1998 wellhead price of $1.69 per million Btu was not available in the February edition of the Energy Information Administration's *Natural Gas Monthly*, DOE/EIA-0130(99/02), but it appears in subsequent issues.

5. Correlation coefficients were 0.77 or more. A correlation coefficient measures the degree of linear association between two random variables, and its values range from –1 to +1. Four trading centers were chosen because they are located in geographically separated markets. They are Henry Hub, LA; Waha, TX; Opal, WY; and Blanco, NM.

6. There are currently two other natural gas futures contracts traded on NYMEX. One is the NYMEX Division Permian Basin contract, designed to reflect more closely conditions in the Western United States. This contract was initiated on May 31, 1996. Physical delivery on this contract occurs at El Paso Natural Gas Company's Permian Pool facility in West Texas. The other is the so-called Alberta contract, based on delivery in Alberta, Canada (Nova Gas Transmission Ltd. pipeline system or specified interconnect points). That contract began trading on September 27, 1996.

7. Traders must disclose all futures positions consisting of 100 or more contracts. The standardized delivery volume for a contract is 10,000 million Btu. Marketers fall into the category of "Commercial Trader," or industry participants that actually trade in the physical commodity. Other entities that are classified as commercial traders include producers, pipeline companies, gas processors, local distribution companies, and end users. The category "Noncommercial Trader" consists of entities that have no interest in actual receipt of the physical commodity but are either trading on a very short-term basis in order to facilitate trades of others (market makers) or are attempting to profit from futures contract price fluctuations (speculators). Noncommercial traders consist of financial companies, mutual and hedge funds, floor traders, and individual investors.

8. The historical peak in dry natural gas production was 21.7 trillion cubic feet in 1973.

9. Natural gas production from different resources in 1997 was estimated by the Energy Information Administration's (EIA), Office of Oil and Gas. The estimated proportion of production from each resource was derived from data input to EIA's National Energy Modeling System (NEMS) for the *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, November 1998), NEMS run, AEO99B.D100198A. These proportions were applied to the total U.S. dry production for 1997 in EIA's *Natural Gas Annual*, DOE/EIA-0131(97) (Washington, DC, October 1998), Table 1.

10. A new water depth record was set on August 13, 1997, when Petroleo Brasileiro SA began producing crude oil from its South Marlin 3B off the coast of Brazil in 5,607 feet of water. See Pedro J. Barusco and others, "Water depth production record set off Brazil," *Oil & Gas Journal* (September 29, 1997), p. 59. For more information on offshore production issues, see Chapter 4, "Offshore Development and Production."

11. The production tax credit is available for gas produced from geopressurized brine, Devonian shale, coal seams, or tight formations. The gas must be produced from wells drilled after December 31, 1979, and by December 31, 1992. To receive the credit, the gas must be produced and sold before January 1, 2003.

12. Natural gas well completions are the sum of gas exploratory and developmental wells. Data are from the Well Completion Estimation Procedure (WELCOM) as of April 5, 1999, which is maintained by the Energy Information Administration's Office of Oil and Gas.

13. These regions conform to those used for the onshore Lower 48 States in the Oil and Gas Supply Model in the Energy Information Administration's National Energy Modeling System. They are defined as: (1) Northeast: CT, DC, DE, GA, IL, IN, KY, MA, MD, ME, MI, NC, NH, NJ, NY, OH, PA, RI, SC, TN, VA, VT, WI, and WV; (2) Gulf Coast: AL, FL, LA, MS, State and Federal waters of the Gulf of Mexico, and Eastern and Southern TX (Railroad Commission Districts 1-6); (3) Midcontinent: AR, IA, KS, MN, MO, NE, OK, and the TX Panhandle (Railroad Commission District 10); (4) Southwest: Eastern NM and West TX (Railroad Commission Districts 7B, 7C, 8, 8A, and 9); (5) Rocky Mountain: AZ, CO, ID, MT, ND, NV, SD, UT, WY, and Western New Mexico; (6) West Coast: CA, OR, and WA.

14. Energy Information Administration, Well Completion Estimation Procedure (WELCOM) as of April 5, 1999.

15. Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(99/01) (Washington, DC, January 1999), Table 5.1.

16. *Proved reserves* of natural gas are the estimated quantities that analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

17. *Total discoveries* are the sum of extensions to the proved volume of old reservoirs in old fields, the proved volume of new reservoir discoveries in old fields, and the proved volume of new field discoveries.

18. *Ultimate recovery appreciation* (URA) refers to the commonly observed phenomenon that the estimated ultimately recoverable volume of oil or gas in most oil and gas fields tends to increase (appreciate) over post-field discovery time. This occurs for a wide variety of reasons.

19. The stated volume represents the sum of onshore and offshore Lower 48 States undiscovered resources in conventional reservoirs, continuous-type resources, and the expected proved ultimate recovery appreciation in known fields. Alaskan gas is neither now nor in the foreseeable future expected to be marketed in the Lower 48 States. Resource estimates are from: D.L. Gautier and others, U.S. Geological Survey Digital Data Series, *1995 National Assessment of United States Oil and Gas Resources — Results, Methodology, and Supporting Data*, [CR-ROM] DDS-30, Release 2 (1996); and Minerals Management Service, Resource Evaluation Program, *An Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf*, OCS Report MMS 96-0034 (Washington, DC, 1996).

20. *Nonassociated natural gas* is natural gas not in contact with significant quantities of crude oil in the reservoir. *Associated gas* is the volume of natural gas that occurs in crude oil reservoirs either as free gas (associated) or in solution with crude oil (dissolved). E.D. Attanasi, D.L. Gautier, and D.H. Root, *Economics and Undiscovered Conventional Oil and Gas Accumulations in the 1995 National Assessment of U.S. Oil and Gas Resources: Coterminous United States*, U.S. Geological Survey Open File Report 95-75H (Washington, DC); and E.D. Attanasi, *Economics and the 1995 Assessment of United States Oil and Gas Resources*, U.S. Geological Survey Circular 1145 (Washington DC, 1998).

21. These unit cost estimates are based on assumptions reflecting the technology and economic conditions existing as of the mid-1990s and an assumed 12 percent after-tax rate of return. U.S. Geological Survey Open File Report 95-75H (Washington, DC); and U.S. Geological Survey Circular 1145 (1998).

22. At least 551 trillion cubic feet of the remaining untapped natural gas resource base underlies federally owned lands.

23. A Hinshaw pipeline is exempt from regulation by the Federal Energy Regulatory Commission (FERC). Although it imports natural gas from Canada, Empire State Pipeline operates within New York State and is subject to regulation by the New York Public Service Commission. Nonetheless, FERC authorization was required for Empire to construct import facilities at the U.S./Canada border.

24. The conversion value used is 47,063 cubic feet per metric ton of LNG. Source: *Costs for LNG Imports into the United States*, prepared by Energy and Environmental Analysis, Inc. for the Gas Research Institute (August 1988), p. 7.

25. For more information on interstate pipeline expansion during the early 1990s, see Energy Information Administration, *Deliverability on the Interstate Natural Gas Pipeline System*, DOE/EIA-0618 (Washington, DC, May 1998).

26. The potential capacity levels for 1999 and 2000 in this section include adjustments and updates to data presented in Chapter 5, which covered project proposals and completions only through the first 8 months of 1998. In general, these adjustments reflect the postponement of 13 projects originally scheduled for completion in 1998 to 1999 or beyond. They also reflect the addition of several new projects announced in late 1998 and scheduled for completion in 1999 or 2000.

27. Temperatures during the winter of 1997-98 were warmer than normal for 43 of the Lower 48 States; 13 States experienced average winter temperatures that were more than 10 percent warmer than normal. For the 27 States east of the Mississippi River, which account for 60 percent of working gas inventories on average at the beginning of the heating season, there were 9.4 percent fewer heating degree days than normal for the 1997-98 winter.

28. A seasonal adjustment technique, developed by the Bureau of the Census (designated "Census X-11") and adapted to natural gas storage data, is used to remove annual variation from the data. The procedure calculates "seasonal factors" that determine the upper and lower bounds of the expected monthly inventory ranges.

29. National average utilization rates for the past two heating seasons are based on data reported to the Energy Information Administration on the EIA-191, "Monthly Underground Gas Storage Report" for 26 salt cavern facilities.

30. In 1998, at least three companies made application to the Federal Energy Regulatory Commission to abandon operations at eight storage fields. ANR Pipeline Co. plans to abandon five storage fields in Michigan, two of which it owns and three that it leases from its affiliate Mid Michigan Gas Storage Company. Columbia Gas Transmission Corporation has applied to abandon one field each in West Virginia (Derricks Creek) and Pennsylvania (Munderf–inactive since 1992). Williams Gas Pipelines Central plans to close the Craig storage field near Kansas City, KS. In most cases, the companies assert that the abandoned capacity will not be missed and that their respective systems will be more efficient and less expensive to operate without them. The eight abandoned fields comprise about 10.7 billion cubic feet of working gas capacity and 154 million cubic feet of daily deliverability.

31. One company—Columbia Gas Transmission Corporation—accounted for 14 of the 22 projects, comprising over 6 billion cubic feet of added working gas capacity and almost 120 million cubic feet per day of added deliverability.

32. According to annual capacity reports filed by respondents to the Energy Information Administration's monthly EIA-191 survey, "Monthly Underground Storage Report," 19 companies made capacity adjustments to a total of 98 existing storage facilities, effective for 1998. These adjustments amounted to a net decrease in working gas capacity of about 82 billion cubic feet and a net decrease in deliverability of about 94 million cubic feet per day.

33. Eleven of these are expansions to existing facilities. Of the eight proposed new facilities, five are LNG projects, two of which are new only in the sense that they will offer interstate storage services for the first time.

34. Does not include annual capacity adjustments filed by EIA-191 respondents.

35. Particularly notable is the lack of additional capacity from new storage facilities in the past 2 years, after having been the leading source for added capacity earlier in the decade.

36. Northeast Hub Partners' Tioga salt cavern project involves development in a salt formation that happens to lie directly beneath CNG's Tioga depleted reservoir storage field. CNG maintains that project development could seriously damage or even destroy its reservoir storage. The Federal Energy Regulatory Commission certificated the project in April 1998, contingent upon the two parties reaching a mutually agreeable arrangement requiring Northeast Hub Partners to indemnify CNG from any losses that might result from project construction. The fight therefore most recently centered on issues of asset valuation and types and amounts of insurance.

37. The unique thing about these projects is that they all propose to connect to interstate pipelines and to offer some if not all of their storage capacity to customers on an open-access basis. Until recently, most LNG facilities were "captive" assets of individual LDC's' distribution systems and were primarily held in reserve for peaking needs.

38. Horizontal wells can vastly increase the deliverability and cycling characteristics of certain reservoirs because the well bores expose a much greater surface area to the stored gas than traditional vertical wells that pass through or terminate in the pay zone. The Gas Research Institute has funded research in this technology and its application to gas storage operations for a number of years.

39. Companies that have experimented with the technology include ANR Pipeline Co., CNG Transmission, Colorado Interstate, Columbia Gas Transmission, and Tejas at facilities in CO, MI, OK, PA, and WV.

40. Annual information and comparisons are represented on a "heating year" basis or for the 12 consecutive months ending March 31. The total volume of released capacity held by replacement shippers during a season is the sum of the capacity effective on each day of the season. For example, if a 60-day contract for Z thousand cubic feet per day is effective within a season, then the sum of capacity held for the season would include Z thousand cubic feet 60 times for that contract. If that 60-day contract were only effective, for example, for the last 20 days of the season, then the sum for the season would include Z thousand cubic feet 20 times, and the sum for the next season would include Z thousand cubic feet 40 times for that contract.

41. It is assumed that each unit of pipeline capacity held by a replacement shipper was used fully (100 percent load factor) to deliver natural gas to market.

42. The percent-of-maximum rates were derived from a subset of capacity release transactions, representing 85 percent of all capacity release transactions, that contained reliable maximum rate information.

43. Capacity reservation rates are stated in units to identify the cost to reserve a specified amount of capacity on each day for an entire month. For example, $1.00 per Mcf-Mo. indicates that it would cost $1.00 to reserve 1 thousand cubic feet of capacity each day for a given month.

44. Based on heating degree days from the *Natural Gas Monthly*, DOE/EIA-0130(98/04) (Washington, DC, April 1998), Table 26.

45. Total natural gas consumption, which is end-use consumption plus lease and plant fuel, and pipeline fuel, was 21.4 trillion cubic feet in 1998. The highest level of total natural gas consumption ever recorded was 22.1 trillion cubic feet in 1972.

46. January and November, in particular, were warmer in 1998 than in 1997. Heating degree days were 18 percent lower in January 1998 than in January 1997 and 14 percent lower in November.

47. Energy Information Administration prices paid for natural gas in the electric utility sector are the average for all deliveries to the sector. However, prices paid for natural gas in the residential, commercial, and industrial sectors are for onsystem sales only. Nearly all deliveries are onsystem in the residential sector. During 1995 through 1997 (and for preliminary monthly data in 1998), onsystem sales were roughly 65 to 80 percent of commercial deliveries and roughly 15 to 25 percent of industrial deliveries.

48. Prices and expenditures were adjusted to 1998 dollars by the Energy Information Administration, Office of Oil and Gas, using chain-type price indices for gross domestic product from the U.S. Department of Commerce, Bureau of Economic Analysis Internet site <http://www.bea.doc.gov>, as of August 13, 1998, Table 7.1.

49. For a more detailed discussion of events during the 1996-97 heating season, see Energy Information Administration, "Natural Gas Residential Pricing Developments during the 1996-97 Winter," *Natural Gas Monthly*, DOE/EIA-0130(97/08) (Washington, DC, August 1997).

50. U.S. Department of Commerce, Bureau of the Census, Current Construction Reports— *Characteristics of New Housing*, 1996 and 1997, C25/96-A and C25/97-A (Washington, DC, June 1997 and July 1998), Table 10. Note that in these data, "gas" includes natural gas and propane.

51. Industrial consumption of natural gas in both 1996 and 1997 exceeded the previous peak of 8.7 trillion cubic feet set in 1973. Annual consumption data go back to 1930.

52. The estimated price paid by industrial users for natural gas in 1998 (through November) is applicable to only 15 percent of natural gas deliveries in this sector.

53. As determined by the National Bureau of Economic Research.

54. Original data on manufacturing production were the Manufacturing Indices, Code B00004, from the Internet site of the Board of Governors of the Federal Reserve System <http://www.bog.frb.fed.us/releases/G17/ipdisk/ip.sa>, as of January 19, 1999.

55. Energy Information Administration. Prior to 1992, data on nonutilities were collected for facilities of 5 megawatts or more. In 1992 the threshold was lowered to include facilities with capacities of 1 megawatt or more. Nonutility data for 1992 are from the *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998), Table 8.14. Information on cogeneration and nonutility data for 1993-1997 are from the *Electric Power Annual 1996*, Vol. II, DOE/EIA-0348(96/2) (Washington, DC, December 1997), p. 82, Figure 14 and Table 51.

56. That is, 18 percent of the natural gas that was delivered to industrial users was sold by the delivering company. This is referred to as "onsystem" gas. The other 82 percent was only transported by the delivering company, thus the company did not have information on the purchase price of the natural gas. This is referred to as "offsystem" gas.

57. In 1994, the industrial sector included manufacturing, mining, construction, and all nonutility generators of electricity.

58. Energy Information Administration, *Manufacturing Consumption of Energy 1994*, DOE/EIA-0512(94) (Washington, DC, December 1997), p. 16.

59. Information on manufacturer's use of natural gas is found in Energy Information Administration, *Manufacturing Consumption of Energy 1994*, DOE/EIA-0512(94) (Washington, DC, December 1997).

60. Distributed Power Coalition of America, Internet site <http://www.dpc.org/faq.html>, as of August 6, 1998.

61. "Gas" includes natural gas, refinery gas, blast-furnace gas, coke oven gas, and propane for data on net electricity generation and for retirements and additions of generation capacity.

62. Many of the nuclear plant outages extended through much of 1997 and were due to scheduled refueling, maintenance, or repair. Net electricity generation from coal also set a record in 1997. Energy Information Administration, *Electric Power Annual 1997*, Vol. 1, DOE/EIA-0348(97)/1 (Washington, DC, July 1998), p. 1 and Table 10.

63. Data on electricity generation capacity retirements and additions are from the Energy Information Administration's *Inventory of Power Plants in the United States: As of January 1, 1998*, DOE/EIA-0095(98) (Washington, DC, December 1998), Tables 1, 11-13, and 16.

64. Energy Information Administration, *Annual Energy Outlook 1999* (*AEO99*), DOE/EIA-0383(99) (Washington, DC, December 1998), Table A13. In the projections, natural gas used for the generation of electricity includes that used by electric utilities and nonutility generators except for cogenerators. In the data presented elsewhere in *Natural Gas 1998: Issues and Trends*, all nonutility consumption of natural gas is included in the industrial sector. Also, in the *AEO99*, 1997 data were based on preliminary estimates and 1998 is the first year of projected data.

65. Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998), p. 72.

66. Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998), National Energy Modeling System, reference case, run AEO99B.D100198A.

67. See Energy Information Administration, *The Changing Structure of the Electric Power Industry: Selected Issues, 1998*, DOE/EIA-0562(98) (Washington, DC, July 1998).

68. Barbara Shook, "CSWE Plans New Merchant Plant To Increase ERCOT Reliability," *Natural Gas Week* (July 13, 1998), p. 8. "Capline's Pasadena Power Plant Feeds Big, Hungry Texas Market," *Natural Gas Week* (July 13, 1998), p. 11. "Duke to Build Merchant Plant To Serve Florida Power Market," *Natural Gas Week* (August 24, 1998), pp. 14-15.

69. Distributed Power Coalition of America, Internet site <http://www.dpc.org/faq.html>, as of August 6, 1998. Distributed power technologies include "small combustion turbine generators, internal combustion engine/generators, photovoltaic solar panels, wind turbines, and fuel cells."

70. For a discussion of these issues in the California market, see: California Alliance for Distributed Energy Resources, *Collaborative Report and Action Agenda* (January 1998).

71. Local distribution companies (LDCs) traditionally provided the commodity "bundled" with a package of related services, including interstate transportation, storage, and distribution service to all customers on its distribution system. In the early 1980s, large volume consumers were permitted access to service providers who operate outside the LDC's service area or "offsystem."

72. The Iowa Public Utility Commission adopted small customer unbundling in 1986, however, marketer and consumer participation has been slight. As a result, the commission did not renew the pilot program and is now considering further action.

73. This analysis is based on data from a variety of industry reports and information gathered by Energy Information Administration analysts. The principal reports used in this analysis are: *Energy Deregulation: Status of Natural Gas Customer Choice Programs*, Government Accounting Office (December 1998) and *Providing New Services to Residential Natural Gas Customers: A Summary of Customer Choice Pilot Programs and Initiatives 1998 Update*, American Gas Association Issue Brief 1998-03 (July 31, 1998).

74. A customer who lives in a State that has complete retail unbundling may not be eligible to select its natural gas provider if it resides in (1) a local jurisdiction that has decided not to institute customer choice, (2) a service area of an LDC that has not yet received approval to unbundle services by State regulators, or (3) an area where third-party providers have not offered service.

75. The estimated annual unbundled gas purchases are derived by multiplying the State's average residential consumption (from EIA's *Natural Gas Annual 1997*, DOE/EIA-0131(97)) by the number of residents participating in the respective State's unbundling program. State levels are summed to arrive at regional amounts, and regional amounts are summed to arrive at national levels. Since actual unbundled purchases by residential customers are not available and many choice programs have been active for only a short time, the derived purchases are used to approximate customer activity.

76. According to the Government Accounting Office report, *Energy Deregulation: Status of Natural Gas Customer Choice Programs*, marketers are unable to compete with the low gas prices available in New Mexico.

77. The price a local distribution company (LDC) charges its customers for gas is reported to the State regulatory body and is commonly used as a benchmark by which marketer prices are compared. Marketers, as nonregulated entities, are not required to disclose their prices to regulatory bodies. The benchmark LDC prices may become less representative as customers move their purchases from LDCs to marketers.

78. Marketers are able to guarantee savings in most States because they are not required to pay the same State taxes that the local distribution companies pay.

79. "Discouraged by 'Numbers Game,' Texaco Exiting Retail Market," *Natural Gas Week*, Vol. 14, No. 22 (June 1, 1998), p. 4.

80. Local distribution companies have traditionally been required to contract for large amounts of relatively expensive, firm transportation capacity to serve their retail customers.

81. For example, Massachusetts, New Jersey, and New York.

82. The proposed "Certified Energy Marketer" (CEM) seal would be an indication to consumers that the marketer has agreed to operate by a series of fair marketing practices and is committed to providing reliable service. These standards are intended to protect residential and commercial customers in both the natural gas and electricity markets and to promote competition and integrity of emerging gas markets.

83. Marketer in this context refers to marketers, aggregators, or suppliers, including utility affiliates marketing or otherwise selling natural gas (or electricity) and arranging for interstate transportation or transmission capacity to residential and commercial customers eligible to participate in customer choice programs.

84. According to Southwest Research Institute, "a locomotive engine that produces approximately 12 grams of nitrogen oxides per horsepower hour (g/bhp-hr) using diesel fuel only produces 2.8 g/bhp-hr using this new liquefied natural gas (LNG) engine technology. Southwest Research Institute (SWRI) News, "*GasRail USA reduces Nox by 75 percent*" News Release (May 29, 1998). (Http://www.swri.org/9what/releases/rail.htm)

85. "ARCO,SYNTROLEUM begin joint development of synfuels reactor technology: ARCO to build pilot-scale plant facility on West Coast," Press Release (October 24, 1997).

86. "New Combustion Technology Facilitates Smaller Capacity GTL Plants," Syntroleum Corporation Press Release (September 16, 1998).

87. "DOE selects research partner for project to make liquids from natural gas," *DOE Fossil Energy Techline* (May 20, 1997).

88. "GTL technologies focus on lowering costs," *Oil and Gas Journal* (September 21, 1998), Vol. 96, No. 38, p. 76.

89. For example, Statoil, Texaco, Marathon, and Conoco.

90. The full fuel-cycle analysis includes the carbon dioxide released from actual use of fuel in the vehicle as well as the additional gases released during the finding, manufacture, and transport of the fuel.

91. Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998).

92. The "Annex I" countries include: Australia, Austria, Belgium, Bulgaria, Canada, Croatia, Czech Republic, Denmark, Estonia, European Community, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Liechtenstein, Lithuania, Luxembourg, Monaco, Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russian Federation, Slovakia, Slovenia, Spain, Sweden, Switzerland, Ukraine, United Kingdom of Great Britain and Northern Ireland, and the United States of America. Turkey and Belarus are Annex I nations have not ratified the Convention and have not committed to quantifiable emissions targets.

93. The report *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity* (*Kyoto*), SR/OIAF/98-03 (Washington, DC, October 1998), examines a series of six cases looking at alternative carbon levels. The reference case represents projections of energy markets and carbon emissions without any enforced reductions and is presented as a baseline for comparison of the energy market impacts in the reduction cases. The most extreme case examined is the "7 Percent Below 1990 Level" (1990-7%), which essentially assumes that the 7-percent target in the Kyoto Protocol must be met entirely by reducing energy-related carbon emission, with no net offsets from sinks, other greenhouse gases, or international activities. The highest consumption patterns for natural gas are seen in some of the intermediate cases, principally the "Stabilization at 1990 Levels" and the "3 Percent Below 1990 Levels."

    The reference case used for the *Kyoto* report is different from the *AEO99* reference case. The results for 2010 and 2020 are very similar for the natural gas sector (usually within 2 to 3 percent for the major variables). Because of these differences, the discussion generally focuses on differences from the reference case. When volumes are used, they are generally cited as ranges.

94. To reduce emissions, a carbon price is applied to the cost of energy. The carbon price is applied to each of the energy fuels relative to its carbon content at its point of consumption. Electricity does not directly receive a carbon fee; however, the fossil fuels used for generation receive the fee, and this cost, as well as the increased cost of investment in generation plants, is reflected in the delivered price of electricity. In practice, these carbon prices could be imposed through a carbon emissions permit system. In this analysis, the carbon prices represent the marginal cost of reducing carbon emissions to the specified level, reflecting the price the United States would be willing to pay in order to purchase carbon permits from other countries or to induce carbon reductions in other countries. In the absence of a complete analysis of trade and other flexible mechanisms to reduce international carbon emissions, the projected carbon prices do not necessarily represent the international market-clearing price of carbon permits or the price at which other countries would be willing to offer permits.

The Energy Information Administration analysis assumes that the Government would hold an auction of carbon permits. The cost of the permits is reflected in energy prices, and the revenues collected from the permits are recycled either to individuals by means of an income tax rebate or to individuals and businesses through a social security tax rebate.

In 2010, the carbon prices projected to be necessary to achieve the carbon emissions reduction targets range from $67 per metric ton (1996 $) in the "1990+24%" Case to $348 per metric ton in the "1990-7%" Case.

2. Natural Gas and the Environment

Currently, natural gas represents 24 percent of the energy consumed in the United States. The Energy Information Administration (EIA) *Annual Energy Outlook 1999* projects that this figure will increase to about 28 percent by 2020 under the reference case as consumption of natural gas is projected to increase to 32.3 trillion cubic feet. In addition, a recent EIA Service Report, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, indicates that the use of natural gas could be even 6 to 10 percent higher in 2020 if the United States adopts the Kyoto Protocol's requirement to reduce carbon emissions by 7 percent from their 1990 levels by the 2008–2012 time period, without other changes in laws, regulations, and policies. These increases are expected because emissions of greenhouse gases are much lower with the consumption of natural gas relative to other fossil fuel consumption. For instance:

- Natural gas, when burned, emits lower quantities of greenhouse gases and criteria pollutants per unit of energy produced than do other fossil fuels. This occurs in part because natural gas is more easily fully combusted, and in part because natural gas contains fewer impurities than any other fossil fuel. For example, U.S. coal contains 1.6 percent sulfur (a consumption-weighted national average) by weight. The oil burned at electric utility power plants ranges from 0.5 to 1.4 percent sulfur. Diesel fuel has less than 0.05 percent, while the current national average for motor gasoline is 0.034 percent sulfur. Comparatively, natural gas at the burner tip has less than 0.0005 percent sulfur compounds.

- The amount of carbon dioxide produced for an equivalent amount of heat production varies substantially among the fossil fuels, with natural gas producing the least. On a carbon-equivalent basis, energy-related carbon dioxide emissions accounted for 83.8 percent of U.S. anthropogenic greenhouse gas emissions in 1997. For the major fossil fuels, the amounts of carbon dioxide produced for each billion Btu of heat energy extracted are: 208,000 pounds for coal, 164,000 pounds for petroleum products, and 117,000 pounds for natural gas.

Other aspects of the development and use of natural gas need to be considered as well in looking at the environmental consequences related to natural gas. For example:

- The major constituent of natural gas, methane, also directly contributes to the greenhouse effect through venting or leaking of natural gas into the atmosphere. This is because methane is 21 times as effective in trapping heat as is carbon dioxide. Although methane emissions amount to only 0.5 percent of U.S. emissions of carbon dioxide, they account for about 10 percent of the greenhouse effect of U.S. emissions.

- A major transportation-related environmental advantage of natural gas is that it is not a source of toxic spills. But, because there are about 300,000 miles of high-pressure transmission pipelines in the United States and its offshore areas, there are corollary impacts. For instance, the construction right-of-way on land commonly requires a width of 75 to 100 feet along the length of the pipeline; this is the area disturbed by trenching, soil storage, pipe storage, vehicle movement, etc. This area represents between 9.1 and 12.1 acres per mile of pipe which is, or has been, subject to intrusion.

Natural gas is seen by many as an important fuel in initiatives to address environmental concerns. Although natural gas is the most benign of the fossil fuels in terms of air pollution, it is less so than nonfossil-based energy sources such as renewables or nuclear power. However, because of its lower costs, greater resources, and existing infrastructure, natural gas is projected to increase its share of energy consumption relative to all other fuels, fossil and nonfossil, under current laws and regulations.

The vast majority of U.S. energy use comes from the combustion of fossil hydrocarbon fuels. This unavoidably results in a degree of air, land, and water pollution, and the production of greenhouse gases that might contribute to global warming and certain public health risks. To address these health and environmental concerns, the United States has many laws and regulations in place that are designed to control and/or reduce pollution. In the United States, natural gas use is projected to increase nearly 50 percent by 2020.[1] This is because North American natural gas resources are considered both plentiful and secure, are expected to be competitively priced, and their increased use can be effective in reducing the emission of pollutants.

While the use of natural gas does have environmental consequences, it is attractive because it is relatively clean-burning. This chapter discusses many environmental aspects related to the use of natural gas, including the environmental impact of natural gas relative to other fossil fuels and some of the potential applications for increased use of natural gas. On the other hand, the venting or leaking of natural gas into the atmosphere can have a significant effect with respect to greenhouse gases because methane, the principal component of natural gas, is much more effective in trapping these gases than carbon dioxide. The exploration, production, and transmission of natural gas, as well, can have adverse effects on the environment. This chapter addresses the level and extent of some of these impacts on the environment.

Air Pollutants and Greenhouse Gases

The Earth's atmosphere is a mixture primarily of the gases nitrogen and oxygen, totaling 99 percent; nearly 1 percent water; and very small amounts of other gases and substances, some of which are chemically reactive. With the exception of oxygen, nitrogen, water, and the inert gases, all constituents of air may be a source of concern owing either to their potential health effects on humans, animals, and plants, or to their influence on the climate.

As mandated by The Clean Air Act (CAA), which was last amended in 1990, the Environmental Protection Agency (EPA) regulates "criteria pollutants" that are considered harmful to the environment and public health:

- **Gases.** The gaseous criteria pollutants are carbon monoxide, nitrogen oxides, volatile organic compounds,[2] and sulfur dioxide (Figure 20). These are reactive gases that in the presence of sunlight contribute to the formation of ground level ozone, smog, and acid rain.

- **Particulates.** The nongaseous criteria pollutant particulate matter consists of metals and substances such as pollen, dust, yeast, mold, very tiny organisms such as mites and aerosolized liquids, and larger particles such as soot from wood fires or diesel fuel ignition.

- **Air Toxics.** The CAA identifies 188 substances as air toxics or hazardous air pollutants, with lead being the only one that is currently classified as a criteria pollutant and thus regulated. Air toxic pollutants are more acute biological hazards than most particulate or criteria pollutants but are much smaller in volume. Procedures are now underway to regulate other air toxics under the CAA.

The greenhouse gases are water vapor, carbon dioxide, methane, nitrous oxide, and a host of engineered chemicals, such as chlorofluorocarbons (Figure 21). These gases regulate the Earth's temperature. When the natural balance of the atmosphere is disturbed, particularly by an increase or decrease in the greenhouse gases, the Earth's climate could be affected.

The combustion of fossil fuels produces 84 percent of U.S. anthropogenic (created by humans) greenhouse emissions.[3] When wood burning is included, these fuels produce 95 percent of the nitrogen oxides, 94 percent of the carbon monoxide, and 93 percent of the sulfur dioxide criteria pollutants (Figure 20). Most of these emissions are released into the atmosphere as a result of fossil fuel use in industrial boilers and power plants and in motor vehicles.

Emissions from Burning Natural Gas

Natural gas is less chemically complex than other fuels, has fewer impurities, and its combustion accordingly results in less pollution. Natural gas consists primarily of methane (see box, p. 52). In the simplest case, complete combustive reaction of a molecule of pure methane (which comprises one carbon atom and four hydrogen atoms) with two molecules of pure oxygen produces a molecule of carbon dioxide gas, two molecules of water in vapor form,

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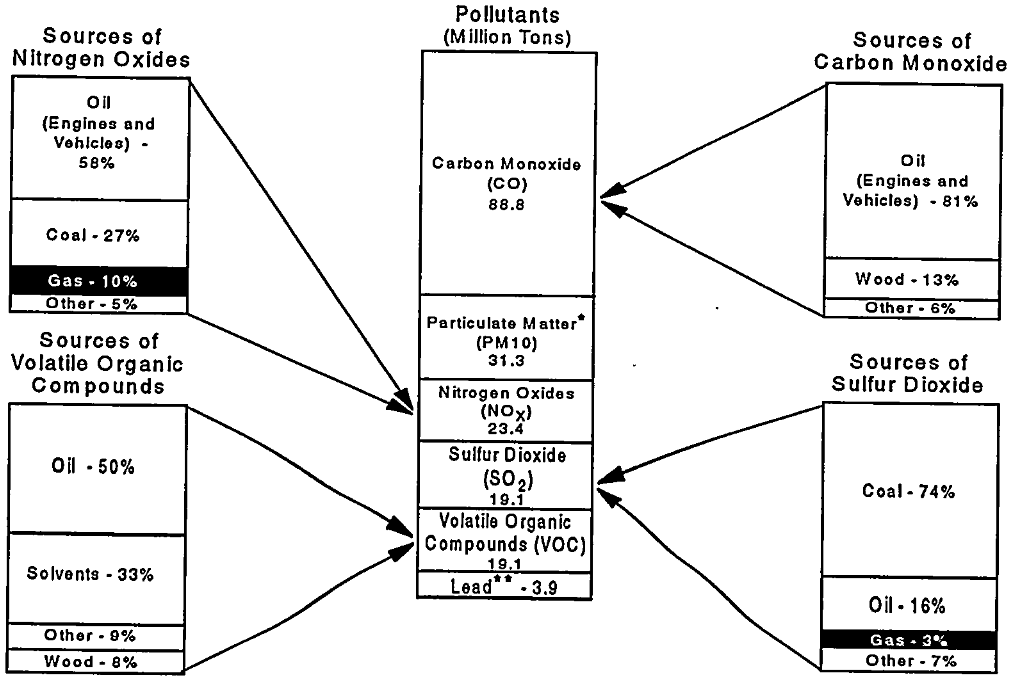
[1]Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998).

[2]Note that methane, the principal ingredient in natural gas, is not classed as a volatile organic compound because it is not as chemically reactive as the other hydrocarbons, although it is a greenhouse gas.

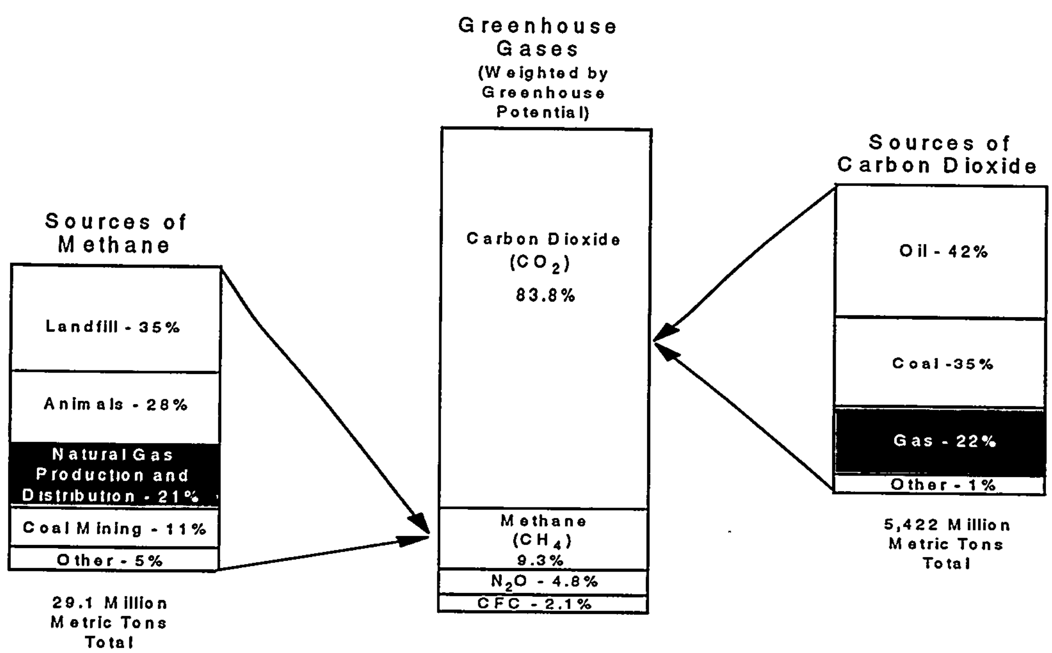
[3]Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1997*, DOE/EIA-0573(97) (Washington, DC, October 1998).

Figure 20. U.S. Criteria Pollutants and Their Major Sources, 1996



*Wood and other fuels account for only 9 percent of particulate matter.
**Oil accounts for 25 percent of lead and other fuels 2 percent.
Source: Energy Information Administration, Office of Oil and Gas, derived from: Environmental Protection Agency, *National Air Pollutant Emission Trends 1990-1996*, Appendix A (December 1997).

Figure 21. U.S. Anthropogenic Greenhouse Gases and Their Sources, 1997



N_2O = Nitrous oxide. CFC = Chlorofluorocarbon.
Source: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1997* (October 1998).

Sources and Chemical Composition of Natural Gas

Natural gas is obtained principally from conventional crude oil and nonassociated gas reservoirs, and secondarily from coal beds, tight sandstones, and Devonian shales. Some is also produced from minor sources such as landfills. In the future, it may also be obtained from natural gas hydrate deposits located beneath the sea floor in deep water on the continental shelves or associated with thick subsurface permafrost zones in the Arctic.

Natural gas is a mixture of low molecular-weight aliphatic (straight chain) hydrocarbon compounds that are gases at surface pressure and temperature conditions. At the pressure and temperature conditions of the source reservoir, it may occur as free gas (bubbles) or be dissolved in either crude oil or brine. While the primary constituent of natural gas is methane (CH_4), it may contain smaller amounts of other hydrocarbons, such as ethane (C_2H_6) and various isomers of propane (C_3H_8), butane (C_4H_{10}), and the pentanes (C_5H_{12}), as well as trace amounts of heavier hydrocarbons. Nonhydrocarbon gases, such as carbon dioxide (CO_2), helium (He), hydrogen sulfide (H_2S), nitrogen (N_2), and water vapor (H_2O), may also be present in any proportion to the total hydrocarbon content.

Pipeline-quality natural gas contains at least 80 percent methane and has a minimum heat content of 870 Btu per standard cubic foot. Most pipeline natural gas significantly exceeds both minimum specifications. Since natural gas has by far the lowest energy density of the common hydrocarbon fuels, by volume (not weight) much more of it must be used to provide a given amount of energy. Natural gas is also much less physically dense, weighing about half as much (55 percent) as the same volume of dry air at the same pressure. It is consequently buoyant in air, in which it is also combustible at concentrations ranging from 5 percent to 15 percent by volume.

and heat.[4] In practice, however, the combustion process is never that perfect as it takes place in air rather than in pure oxygen, resulting in some pollutants.[5]

The reaction products include particulate carbon, carbon monoxide, and nitrogen oxides, in addition to carbon dioxide, water vapor, and heat. Carbon monoxide, the nitrogen oxides, and particulate carbon are criteria pollutants (regulated emissions). The proportions of the reaction products are determined by the efficiency of combustion. For instance, when the air supply to a gas burner is not adequate, the produced levels of carbon monoxide and other pollutants are greater. This situation is, of course, similar to that of all other fossil hydrocarbon fuels—insufficient oxygen supply to the burner will inevitably result in incomplete combustion and the consequent production of carbon monoxide and other pollutants.

Since natural gas is never pure methane and air is not just oxygen and nitrogen, small amounts of additional pollutants are also generated during combustion of natural gas. For example, all fossil fuels contain sulfur; its removal from both oil and gas is a major part of the processing of these fuels prior to distribution. However, not all sulfur is removed during processing. When the fuel is burned, several oxides of sulfur are produced, consisting primarily of sulfur dioxide, some other sulfur-bearing acids, and traces of many other sulfur compounds depending on what other trace compounds are present in the fuel. Additionally, since natural gas is both colorless and odorless, sulfur-bearing odorants[6] are intentionally added to the gas stream by gas distributors so that residential consumers can smell a leak. Besides sulfur, natural gas can include other trace impurities and contaminants.[7]

Yet the emittable pollutants resulting from combustion of natural gas are far fewer in volume and number than those from the combustion of any other fossil fuel (Figure 22). This occurs in part because natural gas is more easily fully combusted, and in part because natural gas has fewer impurities than other hydrocarbon fuels. For example, the amount of sulfur in natural gas is much less than that of

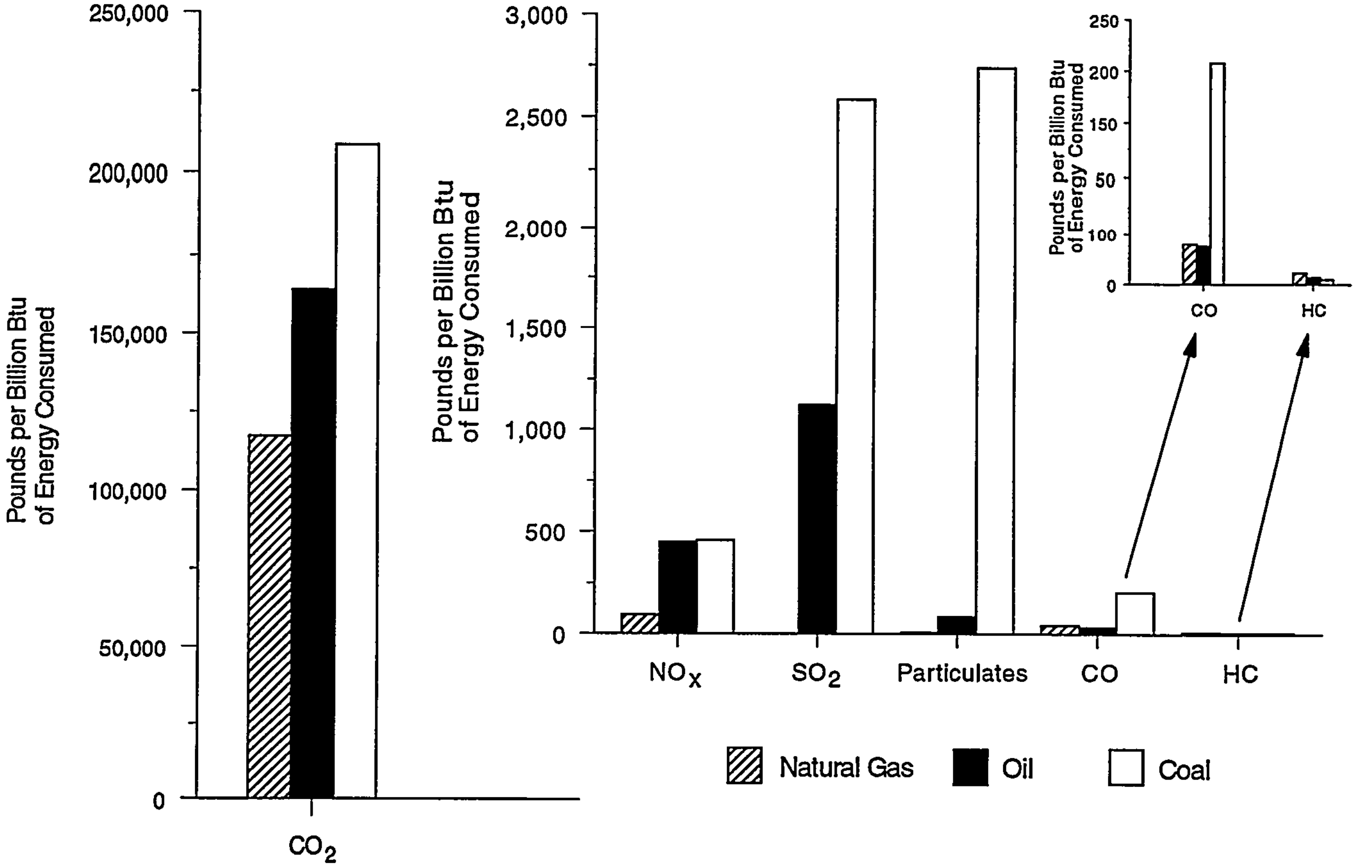
[4]As described by $CH_4 + 2\,O_2 \rightarrow CO_2 + 2\,H_2O$ + heat.

[5]Since the process takes place in air rather than pure oxygen, the practical result is more like: $CH_4 + O_2 + N_2 \rightarrow C + CO + CO_2 + N_2O + NO + NO_2 + H_2O + CH_4$ (unburned) + heat (exact proportions depend on the prevailing combustion conditions).

[6]These odorants are compounds such as dimethyl sulfide, tertiary butyl mercaptan, tetrahydrothiophene, and methyl mercaptan.

[7]Trace impurities can include radon, benzene, toluene, ethylbenzene, xylene, and organometallic compounds such as methyl mercury. The list of combustion byproducts can include fine particulate matter, polycyclic aromatic hydrocarbons, and volatile organic compounds including formaldehyde.

Figure 22. Air Pollutant Emissions by Fuel Type



CO_2 = Carbon dioxide. No_x = Nitrogen oxides. SO_2 = Sulfur dioxide. CO = Carbon monoxide. HC = Hydrocarbon.
Note: Graphs should not be directly compared because vertical scales differ.
Source: Energy Information Administration (EIA) Office of Oil and Gas. **Carbon Monoxide:** derived from EIA, *Emissions of Greenhouse Gases in the United States 1997*, Table B1, p. 106. **Other Pollutants:** derived from Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors*, Vol. 1 (1998). Based on conversion factors derived from EIA, *Cost and Quality of Fuels for Electric Utility Plants* (1996).

coal or oil. U.S. coals contain an average of 1.6 percent sulfur by weight,[8] and the oil burned at electric utility power plants ranges from 0.5 percent to 1.4 percent sulfur.[9] Diesel fuel has less than 0.05 percent sulfur by weight (or 500 parts per million (ppm)) and the current national average for motor gasoline is 340 ppm sulfur (includes California where the regulated statewide average is 30 ppm).[10] Comparatively, natural gas at the burner tip has less than 5 ppm of all sulfur compounds, typically comprising about 1 ppm hydrogen sulfide and less than 2 ppm of each sulfur-bearing odorant.[11]

Toxic and Particulate Emissions

The combustion of natural gas also produces significantly lower quantities of other undesirable compounds,

[8]U.S. coals burned at Clean Air Act Phase I electric power plants contain an average of 0.3 percent sulfur for western coals and 2.5 percent for eastern coals, yielding a consumption-weighted national average of 1.6 percent sulfur by weight.

[9]Energy Information Administration, *Electric Power Annual, 1996*, Vol. 2, DOE/EIA-348(96) (Washington, DC, 1997), p. 41.

[10]Gerald Karey, "EPA leaves sulfur verdict for another day," *Platts Oilgram News*, 76/78 (April 24, 1998), p. 4.

[11]Washington Gas Light Company personnel stated that its system hydrogen sulfide (H_2S) levels are 1.8 parts per million (ppm) and the sulfur-bearing odorants are 2.0 ppm. Institute for Gas Technology tests of trace constituents in two intrastate pipeline samples and two Canadian interstate samples supplied by the Pacific Gas and Electric Company had less than 5 ppm total H_2S (usually between 1 and 1.5 ppm). Sulfur content by contract for pipeline-quality natural gas varies from 0.25 grains to 1.0 grain per 100 standard cubic feet (1.9 ppm to 7.6 ppm), in many cases 0.25 grains or 1.9 ppm. Dr. John M. Campbell, Chapter 7, "Product Specifications," *Gas Conditioning and Processing*, Vol. 1 (Norman, OK, 1979).

particularly toxics, than those produced from combustion of petroleum products or coal. Toxic air pollutants are those compounds that are not specifically covered under other portions of the CAA (i.e., the criteria pollutants and particulate matter) and are typically carcinogens, reproductive toxics, and mutagens. The United States emits 2.7 billion pounds of toxics into the atmosphere each year. Motor vehicles are the primary source, followed by residential wood combustion. Section 112 of the CAA of 1990 lists 188 toxic compounds or groups as hazardous air pollutants (HAPs), including various compounds of mercury, arsenic, lead, nickel, and beryllium and also organic compounds, such as toluene, benzene, formaldehyde, chloroform, and phosgene, which are expected to be regulated soon. Presently, only lead is regulated.

The toxic compound benzene can be a component of both petroleum products and natural gas, but whereas it can comprise up to 1.5 percent by weight of motor gasoline, the levels in natural gas are considered insignificant and are not generally monitored by gas-processing plants and most pipeline companies.[12] As required by California Proposition 65, the Safe Drinking Water and Toxic Enforcement Act, gas pipeline companies that operate in California continuously monitor for toxic substances. These companies have found that the benzene and toluene content of the natural gas they carry varies by source and can range from less than 0.4 ppm to 6 ppm for interstate gas and up to 100 ppm for intrastate gas.[13] Depending on the efficiency of the combustion, some will be oxidized to carbon dioxide and water, some will pass through unburned, and some will be converted to other toxic compounds.

The particulates produced by natural gas combustion are usually less than 1 micrometer (micron) in diameter and are composed of low molecular-weight hydrocarbons that are not fully combusted.[14] Typically, combustion of the other fossil fuels produces greater volumes of larger and more complex particulates. In 1998, the Environmental Protection Agency set a new standard for very fine (less than 2.5 microns) particulates as an add-on to the existing regulation of suspended particulates that are 10 microns or larger, set in 1987.[15] Although power plants and diesel-powered trucks and buses are major emitters of particulate matter, the bulk of 10-micron-plus particulate matter emissions is composed of "fugitive" dust from roadways (58 percent) and combined sources of agricultural operations and wind erosion (30 percent).[16]

Acid Rain and Smog Formation

Natural gas is not a significant contributor to acid rain formation. Acid rain is formed when sulfur dioxide and the nitrogen oxides chemically react with water vapor and oxidants in the presence of sunlight to produce various acidic compounds, such as sulfuric acid and nitric acid. Electric utility plants generate about 70 percent of SO_2 emissions and 30 percent of NO_x emissions in the United States; motor vehicles are the second largest source of both. Natural gas is responsible for only 3 percent of sulfur dioxide and 10 percent of nitrogen oxides (Figure 20). Precipitation in the form of rain, snow, ice, and fog causes about half of these atmospheric acids to fall to the ground as "acid rain," while about half fall as dry particles and gases. Winds can blow the particles and compounds hundreds of miles from their source before they are deposited, and they and their sulfate and nitrate derivatives contribute to atmospheric haze prior to eventual deposition as acid rain. The dry particles that land on surfaces are also washed off by rain, increasing the acidity of runoff.

Natural gas use also is not much of a factor in smog formation. As opposed to petroleum products and coal, the combustion of natural gas results in relatively small production of smog-forming pollutants. The primary constituent of smog is ground-level ozone created by photochemical reactions in the near-surface atmosphere involving a combination of pollutants from many sources, including motor vehicle exhausts, volatile organic compounds such as paints and solvents, and smokestack emissions. The smog-forming pollutants literally cook in the air as they mix together and are acted on by heat and

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[12]Based on communications with personnel at the Gas Processors Association and the Columbia Gas Pipeline Company.

[13]Institute for Gas Technology test of trace constituents in two intrastate pipeline samples and two Canadian interstate samples supplied by the Pacific Gas and Electric Company.

[14]The aerosolized particulate matter resulting from combustion of fossil fuels is a mixture of solid particles and liquid droplets inclusive of soot, smoke, dust, ash, and condensing vapors.

[15]The larger particles are usually trapped in the upper respiratory tract, whereas those smaller than 10 microns can penetrate further into the respiratory system. The most infamous cases of extreme particulate matter pollution, in Donora, Pennsylvania, and in London, England, during the 1930s-1950s, killed thousands of people, and recent studies have indicated that a relatively small rise in 2.5-micron particulates causes a 5-percent rise in infant mortality and greater risk of heart disease. Michael Day, "Taken to Heart," *New Scientist* (May 9, 1998), p. 23.

[16]Environmental Protection Agency, *National Air Pollution Trends Update, 1970-1997*, EPA-454/E-98-007 (December 1998), Table A-5 "Particulate Matter (PM-10) Emissions."

sunlight. The wind can blow smog-forming pollutants away from their sources while the reaction takes place, explaining why smog can be more severe miles away from the source of pollutants than at the source itself.

Greenhouse Gases and Climate Change

The Earth's surface temperature is maintained at a habitable level through the action of certain atmospheric gases known as "greenhouse gases" that help trap the Sun's heat close to the Earth's surface. The main greenhouse gases are water vapor, carbon dioxide, methane, nitrous oxide, and several engineered chemicals, such as chlorofluorocarbons. Most greenhouse gases occur naturally, but concentrations of carbon dioxide and other greenhouse gases in the Earth's atmosphere have been increasing since the Industrial Revolution with the increased combustion of fossil fuels and increased agricultural operations. Of late there has been concern that if this increase continues unabated, the ultimate result could be that more heat would be trapped, adversely affecting Earth's climate. Consequently, governments worldwide are attempting to find some mechanisms for reducing emissions or increasing absorption of greenhouse gases.[17]

On a carbon-equivalent basis, 99 percent of anthropogenically-sourced carbon dioxide emissions in the United States is due to the burning of fossil hydrocarbon fuels, with 22 percent of this attributed to natural gas (Table 1). Carbon dioxide emissions accounted for 83.8 percent of U.S. greenhouse gas emissions in 1997. Between 1996 and 1997, total estimated U.S. carbon dioxide emissions increased by 1.5 percent (22.0 million metric tons) to about 1,501 million metric tons of carbon, representing an increase of about 145 million metric tons, or almost 10.7 percent over the 1990 emission level. The increase between 1996 and 1997 was the sixth consecutive one. Increasing reliance on coal for electricity generation is one of the driving forces behind the growth in carbon emissions in 1996 and 1997.

The major constituent of natural gas, methane, also directly contributes to the greenhouse effect. Its ability to trap heat in the atmosphere is estimated to be 21 times greater than that of carbon dioxide, so although methane emissions amount to only 0.5 percent of U.S. emissions of carbon dioxide, they account for about 10 percent of the greenhouse effect of U.S. emissions. In 1997, methane emissions from waste management operations (primarily landfills), at 10.4 million metric tons, and from agricultural operations, at 8.6 million metric tons, substantially exceeded those from the oil and gas industries combined, estimated to be 6.2 million metric tons.[18]

Water vapor is the most common greenhouse gas, at about 1 percent of the atmosphere by weight, followed by carbon dioxide at 0.04 percent and then methane, nitrous oxide, and manmade compounds such as the chlorofluorocarbons (CFCs). Each gas has a different residence time in the atmosphere, from about a decade for carbon dioxide to 120 years for nitrous oxide and up to 50,000 years for some of the CFCs. Water vapor is omnipresent and continually cycles into and out of the atmosphere. In estimating the effect of these greenhouse gases on climate, both the global warming potential (heat-trapping effectiveness relative to carbon dioxide) and the quantity of gas must be considered for each of the greenhouse gases.

Since human activity has minimal impact on the atmosphere's water vapor content, unlike the other greenhouse gases it is not addressed in the context of global warming prevention. The criteria pollutants specified in the CAA are reactive gases that, although they decay quickly, nevertheless promote reactions in the atmosphere yielding the greenhouse gas ozone. These gases indirectly affect global climate because they produce undesirable lower atmosphere ozone, as opposed to the desirable high-altitude ozone that shields Earth from most of the Sun's ultraviolet radiation. Carbon dioxide, on the other hand, directly contributes to the greenhouse effect; it presently represents 61 percent of the worldwide global warming potential of the atmosphere's greenhouse gases.

The United States is the largest producer of carbon dioxide among the countries of the world, both per capita (5.4 tons in 1996) and absolutely (Figure 23).[19] The amount of carbon dioxide produced for an equivalent amount of heat production substantially varies among the fossil fuels, with

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[17]In December 1997, representatives from more than 160 countries met in Kyoto, Japan, to establish limits on greenhouse gas emissions for participating developed nations. The resulting Kyoto Protocol established annual emission targets for countries relative to their 1990 emission levels. The target for the United States is 7 percent below 1990 levels.

[18]Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1997*, DOE/EIA-0573(97) (Washington, DC, October 1998), pp. 27 and 29.

[19]U.S. Department of Energy, Oak Ridge National Laboratory, G. Marland and T. Broden, "Ranking of the World's Countries by 1995 Total CO_2 Emissions from Fossil Fuel Burning, Cement Production, and Gas Flaring,"<http://cdiac.esd.ornl.gov/trends/emis/top95.tot>.

Table 1. U.S. Carbon Dioxide Emissions from Energy and Industry, 1990-1997
(Million Metric Tons of Carbon)

Fuel Type or Process	1990	1991	1992	1993	1994	1995	1996	P1997
Natural Gas								
Consumption	273.2	278.1	286.3	296.6	301.5	319.1	319.7	319.1
Gas Flaring	2.5	2.8	2.8	3.7	3.8	4.7	4.5	4.3
CO_2 in Natural Gas	3.6	3.7	3.9	4.1	4.3	4.2	4.5	4.6
Total	**279.3**	**284.6**	**293.0**	**304.4**	**309.6**	**323.0**	**328.1**	**328.0**
Other Energy								
Petroleum	591.4	576.9	587.6	588.8	601.3	597.4	620.6	627.5
Coal	481.5	475.7	478.1	494.4	495.6	500.2	520.9	533.0
Geothermal	0.1	0.1	0.1	0.1	*	*	*	*
Total	**1,073.0**	**1,052.7**	**1,065.8**	**1,083.3**	**1,096.9**	**1,097.6**	**1,141.5**	**1,160.5**
Other Sources								
Cement Production	8.9	8.7	8.8	9.3	9.8	9.9	9.9	10.1
Other Industrial	8.0	8.0	8.0	8.0	8.1	8.9	9.1	9.2
Adjustments[a]	-13.2	-13.2	-14.9	-11.3	-10.7	-11.2	-9.8	-7.1
Total	**3.7**	**3.5**	**1.9**	**6.0**	**7.2**	**7.6**	**9.2**	**12.2**
Total from Energy and Industry	**1,355.9**	**1,340.8**	**1,360.6**	**1,393.6**	**1,413.8**	**1,428.1**	**1,478.8**	**1,500.8**
Percent Natural Gas of Total	**20.6**	**21.2**	**21.5**	**21.8**	**21.9**	**22.6**	**22.2**	**21.9**

[a]Accounts for different methodologies in calculating emissions for U.S. territories.

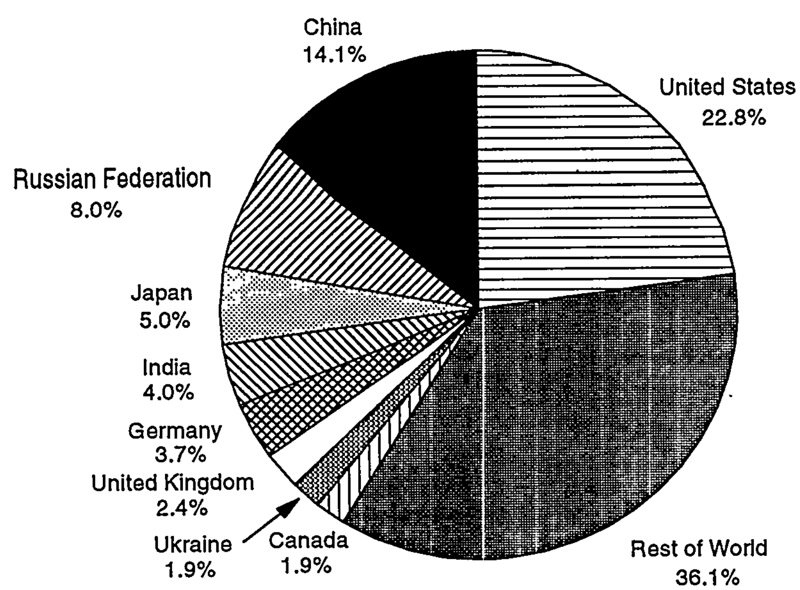
*Less than 0.05 million metric tons.

P = Preliminary data.

Notes: Emission coefficients are annualized for coal, motor gasoline, liquefied petroleum gases, jet fuel, and crude oil. Includes emissions from bunker fuels. Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1997* (October 1998).

Figure 23. Carbon Dioxide Emission Share by Country, 1995



Total 1995 emissions = 6,173 million metric tons of carbon

Note: Sum of percentages does not equal 100 because of independent rounding.

Source: U.S. Department of Energy, Oak Ridge National Laboratory, G. Marland, T. Broden, "Ranking of the World's Countries by 1995 Total CO2 Emissions from Fossil Fuel Burning, Cement Production, and Gas Flaring," <http://cdiac.esd.ornl.gov/trends/emis/top95.tot>.

natural gas producing the least. For the major fossil fuels, the amounts of carbon dioxide produced for each billion Btu of heat energy extracted are: 208,000 pounds for coal, 164,000 pounds for petroleum products, and 117,000 pounds for natural gas (Table 2).

Effect of Greater Use of Natural Gas

Electric Power Generation

Projections of increased use of natural gas center principally on the increased use of natural gas in electric generation. For example, the *Annual Energy Outlook 1999* reference case projects natural gas consumption to rise by 10.3 trillion cubic feet (Tcf) from 1997 to 2020. Of this increase, 56 percent (5.8 Tcf) is expected to come as a result of increased use of natural gas for electricity generation. A recent Energy Information Administration (EIA) Service Report (prepared at the request of the House of Representatives Science Committee assuming no changes in domestic policy) analyzed the consequences of U.S. implementation of the Kyoto Protocol. In the carbon reduction cases cited in this report, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity,*[20] power plant use of natural gas (excluding industrial cogeneration) could increase to between 8 and 12 Tcf in 2010 and 12 to 15 Tcf in 2020. This growth is expected to develop as many of the new generating units brought on line are gas-fired. Some repowering of existing units may be undertaken as well.

Since electricity generation is the major source of U.S. sulfur dioxide (SO_2) and carbon dioxide (CO_2) emissions,[21] as well as a major source of all other air pollutants excepting the chlorinated fluorocarbons, substitution of natural gas for other fossil fuels by utilities and nonutility generators would have a sizable impact on emission levels. However, if increased natural gas generation were to replace nuclear power or delay the commercialization of renewable-powered generation, this would represent a negative impact on emission levels.

In 1997, there were 10,454 electric utility generating units in the United States, with a total net summer generation capacity of 712 gigawatts.[22] Of that capacity, 19 percent listed natural gas as the primary fuel and 27 percent listed it as either the primary or secondary fuel. But natural gas was actually used to generate only 9.1 percent of the electricity generated by electric utilities in 1997, down 1.2 percent from the 1995 value of 10.3 percent and one of the lowest proportions in the past 10 years. Coal was listed as the primary fuel source for almost 43 percent of the utility generating capacity and as a secondary source for only about 0.5 percent. But in 1997, it was the fuel used for 57.3 percent of net generation from electric utilities, up from 55.3 percent in 1995 and 56.3 percent in 1996.

A utility typically has a base-load generating capacity that is essentially continuously on line and capable of satisfying most or all of the minimum service-area load. The base-load capacity is supplemented by intermediate-load generation and peak-load generation capacities, which are used to meet the seasonal and short-term fluctuating demands above base load; reserve or standby units are also maintained to handle outages or emergencies. The majority of non-nuclear base-load units are coal-fired, yet many utilities have gas turbines, which are primarily used as peak-load generators.

Once the initial cost of a generating unit is paid for, fuel cost per unit of energy produced controls how electricity is generated. In 1997, the cost at steam-electric utility plants per million Btu for coal was less than half that for natural gas, \$1.27 versus \$2.76, and petroleum was even higher at \$2.88.[23] The per Btu natural gas cost to utilities increased by over one-third from 1995 to 1997, while the per Btu coal cost continued a 15-year decline, contributing to the decreased market share for natural gas. However, new technologies creating higher efficiency natural gas electric

[20]Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998), p. 76. This Service Report was requested by the U.S. House of Representatives Science Committee to provide information on the costs of the Kyoto Protocol without other changes in laws and regulations. The report relied on assumptions provided by the Committee.

[21]In 1996, electric utilities accounted for 12,604 thousand short tons of sulfur dioxide emissions out of a total of 19,113 thousand short tons (Environmental Protection Agency, *National Air Pollutant Emission Trends, 1990-1996*, EPA-454R-97-011 (December 1997), Table 2-1, p. 2-4); and for 532.4 million metric tons of carbon as carbon dioxide, exceeding the 482.9 and 473.1 million metric tons from the industrial and transportation sectors, respectively (Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1997*, DOE/EIA-0573(97) (October 1998), Table 7, p. 21).

[22]Excludes nonutility generators. Energy Information Administration, *Inventory of Power Plants in the United States as of January 1, 1998*, DOE/EIA-0095(98) (Washington, DC, December 1998). Nonutility generators totaled 78 gigawatts of capacity in 1997, with 42 percent utilizing natural gas. Energy Information Administration, *Electric Power Annual 1997*, Vol. II, DOE/EIA-348(97) (Washington, DC, July 1998), Table 54.

[23]Energy Information Administration, *Electric Power Annual 1997*, Vol. 1, DOE/EIA-348(97) (Washington DC, July 1998), Table 20, p. 37.

Table 2. Pounds of Air Pollutants Produced per Billion Btu of Energy

Pollutant	Natural Gas	Oil	Coal
Carbon Dioxide	117,000	164,000	208,000
Carbon Monoxide	40	33	208
Nitrogen Oxides	92	448	457
Sulfur Dioxide	0.6	1,122	2,591
Particulates	7.0	84	2,744
Formaldehyde	0.750	0.220	0.221
Mercury	0.000	0.007	0.016

Notes: No post combustion removal of pollutants. Bituminous coal burned in a spreader stoker is compared with No. 6 fuel oil burned in an oil-fired utility boiler and natural gas burned in uncontrolled residential gas burners. Conversion factors are: bituminous coal at 12,027 Btu per pound and 1.64 percent sulfur content; and No. 6 fuel oil at 6.287 million Btu per barrel and 1.03 percent sulfur content—derived from Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants* (1996).

Source: Energy Information Administration (EIA), Office of Oil and Gas. **Carbon Monoxide:** derived from EIA, *Emissions of Greenhouse Gases in the United States 1997*, Table B1, p. 106. **Other Pollutants:** derived from Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors*, Vol. 1 (1998).

generators can overcome the current price differential between the fuels.

The new power plants scheduled to come on line during the 10 years from 1998 through 2007 are 88 percent natural-gas-fired and only 5 percent coal-fired, but they will add only about 6 percent to total net generation capacity.[24] Thus, in order to make significant reductions in the volume of greenhouse gases and other pollutants produced by electricity generation, a significant amount of new unplanned gas-fired or renewable generation capacity would have to be built, or the existing generating equipment having natural gas as a fuel option would have to be utilized more and many of the existing coal plants would have to be repowered to burn gas.

The utilities have many supply-side options at their disposal to reduce or offset carbon dioxide emissions from power generation. These options include repowering of coal-based plants with natural gas, building new gas plants, extension of the life of existing nuclear plants, implementation of renewable electricity technologies, and improvement of the efficiency of existing generation, transmission, and distribution systems.

There are two principal conversion opportunities for utility power plants. The simplest and most capital-intensive approach is site repowering with an entirely new gas-turbine-based natural gas combined-cycle (NGCC) system. The more complex, less capital-intensive approach is steam turbine repowering where a new gas turbine and a heat recovery steam generator are integrated with the existing steam turbine and auxiliary equipment. This option can have lower capital costs if site redesign costs are low, but entails a higher operating cost because it is less efficient than total state-of-the-art repowering.

As of January 1, 1998, there are 20 repowering projects planned in nine States that will primarily convert current oil-fired facilities to natural gas or co-firing capability; most of the projects are driven by economics with a secondary impetus as a response to the emission reduction requirements of the Clean Air Act Amendments of 1990 (see box, p. 59).

Complete conversion may not be a practical goal for a number of plants without expansion of the transportation pipeline network. Most of the candidate plants are located in primary gas-consuming regions served by major trunk lines. It appears that converted plants may have sufficient access to firm transportation capacity on these systems during the heating and nonheating seasons, during which between 16 and 24 percent of average national system capability is available for firm transportation, respectively.[25] The ability of a plant to use firm transportation capacity for gas supply will depend on the location and specific load characteristics of the pipelines serving that plant. However, because of recent regulatory reforms, electric generation plants may no longer be required to use firm transportation to serve their supply

[24]Energy Information Administration, *Inventory of Power Plants in the United States as of January 1, 1998*, DOE/EIA-0095(98) (Washington, DC, December 1998), pp. 9 and 13.

[25]Energy Information Administration, *Deliverability on the Interstate Natural Gas Pipeline System*, DOE/EIA-0618(98) (Washington, DC, May 1998), Table 14.

Clean Air Act Amendments of 1990: Emission Reduction Requirements for Utilities

The 1990 amendments to the Clean Air Act (CAA) require that electric utilities reduce their sulfur dioxide (SO_2) emissions by 10 million tons from the 1980 levels to attain an absolute cap of 8.9 million tons of SO_2 by 2000. Comparatively, SO_2 emissions from fossil-fueled electric generating units ranged from 15.0 million tons in 1993 to 11.6 million tons in 1995, with 12.2 million tons emitted in 1996. The same units also emitted 2,047.4 million tons of carbon dioxide (CO_2) in 1996, up from 1,967.7 million tons in 1995. Nonutility power producers added another 1.2 million tons of SO_2 and 556 million tons of CO_2 in 1995, the latest year for which data are available. Phase 1 of the CAA, 1995 through 1999, requires the largest polluters (110 named power plants) to reduce emissions beginning in 1995. The top 50 polluting plants produced 5,381 million tons of SO_2 emissions in 1996, 44 percent of the electric generation total. The second phase, effective January 1, 2000, will require approximately 2,000 plants to reduce their emissions to half the level of Phase I. The affected plants are required to install systems that continuously monitor emissions in order to track progress and assure compliance, and are allowed to trade emission allowances within their systems and with the other affected sources. Each source must have sufficient allowances to cover its annual emissions. If not, the source is subject to a $2,000 per ton excess emissions fee and a requirement to offset the excess emissions in the following year. Bonus allowances can be earned for several reasons including early reductions in emissions and re-powering with a qualifying clean coal technology.

The CAA also requires the utilities to reduce their nitrogen oxide (NO_x) emissions by 2 million tons from the 1980 levels. In September 1998, the Environmental Protection Agency issued a new source performance standard for NO_x emissions from new (post-July 1997) electric utility and industrial/commercial/institutional steam generating units, including those that may become subject to such regulation via modification or reconstruction. The performance standard for new electric utility steam-generating units is 1.6 pounds per megawatthour of gross energy output regardless of fuel type, whereas that for modified/reconstructed units is 0.15 pounds per million Btu (MMBtu) of heat input. The standard for new industrial/commercial institutional steam generating units is 0.2 pounds per MMBtu of heat input, although for low heat-rate units firing natural gas or distillate oil the present limit of 0.1 pounds per MMBtu is retained. The switch from input-based to output-based accounting favors increased generating efficiency and the use of natural gas over distillate oil and especially coal, without the need to prescribe specific pollution control options.

needs. Under Federal electric restructuring, power plants may be able to use significantly more interruptible capacity or be able to use released capacity to satisfy their supply needs.

Nonutility generation (NUG) of electric power is a relatively recent and rapidly growing industry. The share of total electricity generated by NUGs has increased from 6.2 percent in 1989 to 11.5 percent in 1997.[26] Nonutilities are generally smaller than utilities and were encouraged by the passage of the Public Utility Regulatory Policies Act in 1978. Natural gas is the primary fossil fuel used in these applications, accounting for over 72 percent in 1997.

Transportation Sector

The second largest source of air pollution in the United States is the transportation sector, and in particular gasoline- and diesel-powered motor vehicles. As the U.S. automobile industry first developed, experimentation with compressed natural gas (CNG) and other alternative fuels was conducted. But as petroleum products became increasingly plentiful, accessible, and inexpensive, these alternatives were largely pushed aside and U.S. transportation systems became petroleum-based. While few Americans have driven or owned a natural-gas-powered vehicle (NGV), people in other nations have been driving them since World War II when severe petroleum shortages curtailed gasoline availability. About 1,000,000 NGVs are presently in use worldwide, with Italy alone having more than 400,000 on the road. In contrast, fewer than 75,000 NGVs can be found on U.S. roads, not quite 0.04 percent of the more than 200 million U.S. vehicles. NGVs had a minuscule share of the U.S. vehicle fuel

[26] Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(99/02) (Washington, DC, February 1999).

market in 1997, less than 1 billion cubic feet in a market equivalent to 30 trillion cubic feet.

Interest in clean-burning alternative fuels has increased in recent years. After two oil embargoes, several oil price spikes, and the 1991 Gulf War, both petroleum prices and security of supply remain major concerns. The environmental problems associated with tailpipe emissions have also become a prime motivating factor. The Environmental Protection Agency estimated that motor vehicle tailpipe emissions are the source of more than half of all urban air pollution in the United States. These issues, along with the failure of many large U.S. metropolitan areas to meet the 1987 deadline for achievement of the National Ambient Air Quality Standards (primarily for ozone and carbon monoxide), have led to increased interest in alternative transportation fuels. There are a number of alternatives to gasoline, among which are electricity, methanol (produced from natural gas and butane), ethanol (produced from agricultural products), propane, liquefied natural gas, and compressed natural gas. In the future, these alternatives will compete with each other and with the "cleaner" reformulations of gasoline now being tested and other more flexible new technologies, such as hybrid gasoline-electric or diesel-electric vehicles. The relative success of these alternatives depends on numerous factors: automobile performance, ability to adapt the fuel distribution and marketing system, environmental impacts, safety, the economics of both fuel and vehicle, changes in technology, and public awareness and acceptance.

A number of legislative measures and regulatory initiatives have sought to ameliorate the automotive emissions problem. The Clean Air Act Amendments of 1990 mandate that in the 22 cities with 1988 populations of greater than 250,000, where ozone and/or carbon monoxide levels are most serious (nonattainment areas), owners of fleets of 10 or more vehicles must begin purchasing clean-burning vehicles by model year 1998. In 1995 these urban areas, inclusive of their suburbs, were home to more than 85 million Americans (almost one-third of the U.S. population). They also have more than 30 percent of all registered vehicles.

Most observers agree that the primary competition in the evolving alternative fuels market is among three alternative carbon-based fuels (methanol, ethanol, and compressed natural gas (CNG)), electric vehicle technology, and reformulated gasoline (RFG). While liquefied petroleum gas (LPG or "propane") has essentially the same qualities as CNG with respect to emissions, range, safety, and fuel cost, and is widely used in U.S. rural agricultural areas, its supply probably could not meet broad expansion of demand. Less than 50 percent of LPG production is derived from natural gas; the majority of it is a byproduct of the oil refining process. Therefore, any significantly expanded use of LPG would require increased oil imports.

Widespread use of CNG as a transportation fuel would entail substantial new investment to expand the natural gas delivery infrastructure, largely involving massive addition of refueling stations at a cost of at least $165,000 each. The CNG vehicles presently used in the United States, mostly fleet vehicles, are supported by fewer than 1,300 refueling stations as compared with more than 200,000 refueling stations serving gasoline and diesel powered vehicles. Fewer than 700 of the latter offer CNG to the general public, and then often by appointment only. EIA and other forecasters project limited growth in the use of CNG as an automotive fuel with most projections for 2010 consumption falling in the range of 250 to 440 billion cubic feet and less than 2.5 million vehicles (Table 3). It is quite likely that future NGV use will remain restricted to fleet vehicles.

Table 3. Forecasts of Natural Gas Consumption as a Vehicle Fuel

Source	In 2000		In 2010	
	Consumption (billion cubic feet)	Number of Vehicles (thousands)	Consumption (billion cubic feet)	Number of Vehicles (thousands)
Energy Information Administration (EIA)	125	80	250	1,280
American Gas Association (AGA)	210	110	355	1,660
Gas Research Institute (GRI)	280	140	440	2,300

Sources: **Energy Information Administration:** *Annual Energy Outlook 1999*, Base Case Scenario (December 1998). **AGA:** American Gas Association, 1998 AGA-TERA Base Case (July 1998). **GRI:** Draft of GRI04 Baseline Projections (November 1998).

Air Conditioning Market

The primary opportunity for air pollution reduction in the space-conditioning market is use of natural gas in lieu of electricity for cooling. This would include gas-fired air conditioning for commercial, institutional, and industrial buildings and gas-fired heat pumps for residential and small commercial applications. In space-conditioning applications, natural gas competes with electricity and with energy conservation alternatives. Electricity currently dominates commercial and industrial cooling with a market share of more than 90 percent, while gas cooling's share is in the 3 to 7 percent range; consumption of gas for space cooling in 1997 was less than 100 billion cubic feet. This was not always the case. From the mid-1950s through the early 1970s, the gas cooling (often called gas absorption) equipment share of the large-tonnage cooling market ranged between 20 and 30 percent, with annual load additions ranging from 2 to over 4 billion cubic feet supplying 200 to 300 thousand tons of cooling. The load declined precipitously in the mid-1970s because of energy supply/price dislocations, regulatory restrictions on gas industry marketing, and consequent reductions in support activities by many manufacturers; shipments of large-tonnage absorption equipment declined to less than 50 thousand tons per year.

Gas absorption technology and market development continued in Japan, where gas serves more than half of the large-tonnage cooling market. The absorption share of chiller unit shipments in Japan continues to increase; in 1991 it accounted for over 90 percent of new units. Several Japanese companies have become major worldwide suppliers of absorption equipment, and gas-cooling research and development (R&D) expenditures by the Japanese government and manufacturers continue to grow. In the United States, R&D conducted by the natural gas industry, the Gas Research Institute, and gas equipment manufacturers has led to commercialization of a variety of new gas engine-drive, absorption, and desiccant technologies. In addition, equipment and technologies from the major Japanese companies are being imported or licensed by U.S. firms. Over the past 2 to 3 years, all of the major U.S. chiller manufacturers have substantially increased their activity in gas cooling.

Despite the increased interest in using natural gas for space cooling, electric cooling equipment is strongly established (with more than 90 percent of the market) and well supported by substantial R&D funding and strong marketing. However, with the Federal government phasing out the use of chlorofluorocarbons (CFCs or chlorine-based refrigerants) used in electric cooling systems, natural gas absorption systems, which operate free of CFCs, and engine-driven and other natural-gas-based systems, which typically operate on non-CFC refrigerants, should gain some additional advantage.[27]

Environmental Impacts of Gas Production and Delivery

The extraction and production of natural gas, as well as other natural gas operations, do have environmental consequences (Figure 24) and are subject to numerous Federal and State laws and regulations (see box, p. 63). In some areas, development is completely prohibited so as to protect natural habitats and wetlands. At present, oil and gas drilling is prohibited along the entire U.S. East Coast, the west coast of Florida, and the U.S. West Coast except for the area off the coast of southern California. Drilling is also generally prohibited in national parks, monuments, and designated wilderness areas.

Natural Gas Exploration and Production

The environmental side-effects of natural gas production start in what is called the upstream portion of the natural gas industry, beginning with selection of a geologically promising area for possible future natural gas production. An upstream firm will collect all available existing information on the geology and natural gas potential of the proposed area and may decide to conduct new geologic and geophysical studies. It will usually need to acquire permission to enter the area by obtaining permits for Federal, State, or local government land or by leasing right of access on private lands. If the road network is dense enough, some area studies may only require access along public right-of-way.

The most common new study is a seismic survey. Onshore seismic surveys are done using either a small explosive charge as the acoustic source or special vibrator trucks that literally shake the ground. In water, the source is either a small explosive charge or an air or gas gun. The primary environmental disturbances involved with land operations are the laying of cable and geophones. Sometimes this

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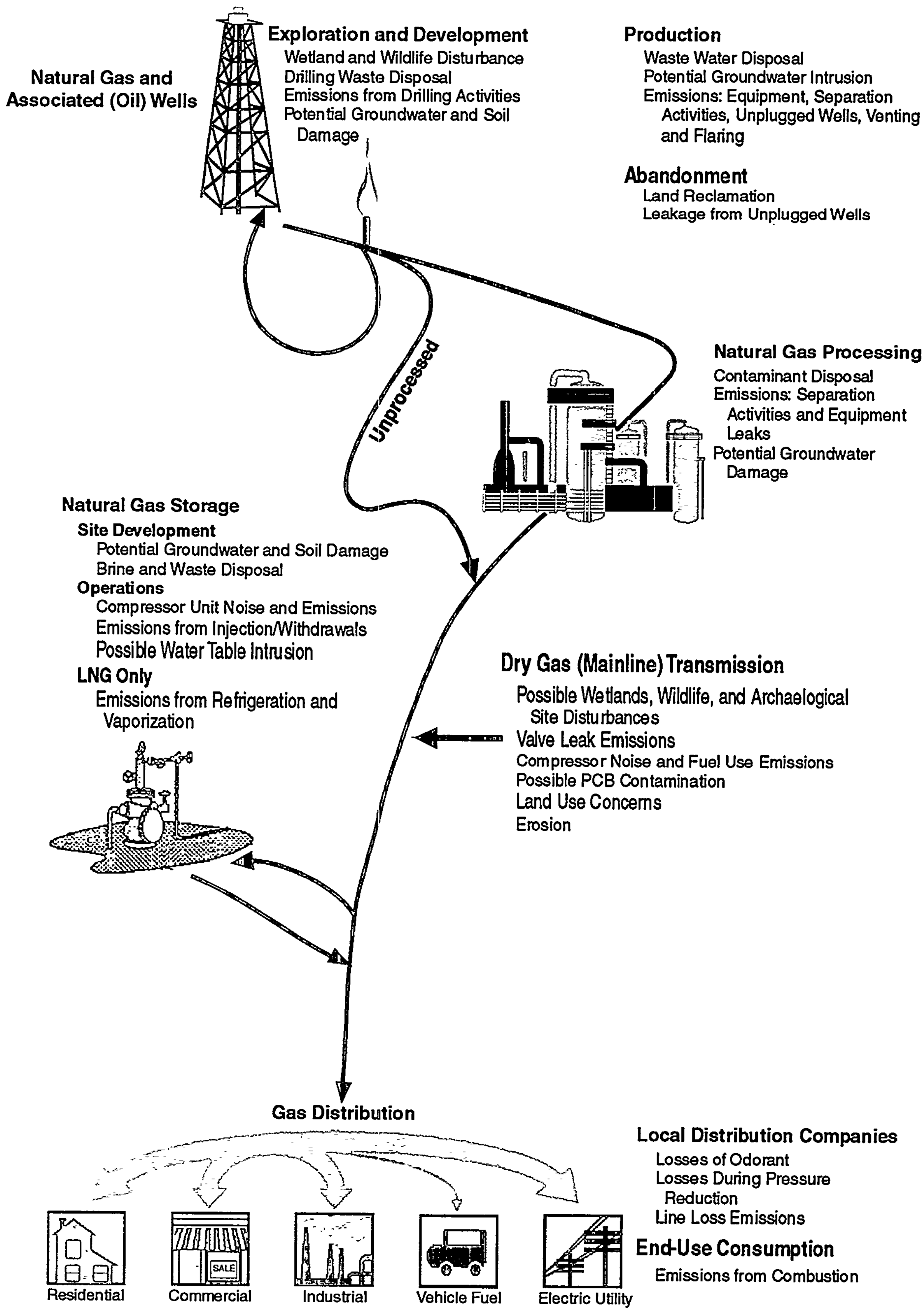
[27]American Gas Association, Gas Industry Online: Gas Technology Summer '97, "New Directions in Natural Gas Cooling," <http://www.aga.com/events/gtsu97/directions.html>.

Figure 24. Environmental Impacts of Natural Gas Production, Transmission, and Distribution



LNG = Liquefied natural gas. PCB = Polychlorinated biphenyl
Source: Energy Information Administration, Office of Oil and Gas.

Environmental Laws Affecting Natural Gas Operations

Date	Legislation	Effect on Natural Gas Operations
1966	National Historic Preservation Act	Major construction projects must avoid damaging or destroying designated National Historic Landmarks.
1969	National Environmental Policy Act	Requires a detailed environmental review before any major or controversial Federal action, such as approval of an interstate pipeline or interstate gas storage facility.
1970 Amended 1977 and 1990	Clean Air Act	Regulates air emissions from area, stationary, and mobile sources. Affects operations of gas plants and is expected to cover glycol dehydrator operations.
1970	Occupational Safety and Health Act	Governs worker exposure to toxic chemicals, excessive noise levels, mechanical dangers, heat or cold stress, or unsanitary conditions.
1973	Endangered Species Act	Nesting areas of endangered species must not be disturbed by construction or operations. Drilling mud pits if used may have to be screened to prevent endangered species from landing in them by mistake. Pipelines and gas storage sites should avoid endangered species areas.
1974 Amended 1986	Safe Drinking Water Act	Regulates underground injection wells and directs the protection of sole source aquifers.
1976	Toxic Substance Control Act	Gives the Environmental Protection Agency authority to require testing of chemical substances, both new and old, and to regulate them where necessary. Limits or prohibits the use of certain substances.
1976 Amended 1984	Resource Conservation and Recovery Act	Encourages the conservation of natural resources through resource recovery. Defines hazardous waste as waste which may cause an increase in mortality or poses a substantial hazard to human health or the environment when improperly disposed. A waste is: (a) hazardous if it is ignitable at less than 140 degrees F; (b) reactive if it reacts violently with water, is normally unstable, generates toxic gases when exposed to water or corrosive materials or is capable of detonation when exposed to heat or flame; and, (c) corrosive if it has a pH $\leq$ to 2 or $\geq$ to 12.5 and toxic if it meets or exceeds a certain concentration of pesticides/herbicides, heavy metals or organics.
1977	Clean Water Act	Regulates discharges of pollutants to U.S. waters. Wetlands are protected under this act. Permits are required, conditioned to force either avoidance or mitigation banking. Affects construction of pipelines and facilities in wetlands and dredging for drilling barge movement in coastal wetlands. Provides for delegation of many permitting, enforcement, and administrative aspects of the law to the States.
1980 Amended 1986	Comprehensive Environmental Response, Compensation, and Liability Act. Superfund Amendments and Reauthorization Act.	Acts on hazardous waste activities that occurred in the past. Material does not have to be a "waste." Covers all environmental media: air, surface water, ground water and soil.
1982	Federal Oil and Gas Royalty Management Act	Among other requirements, oil and gas facilities must be built in a way that protects the environment and conserves Federal resources.
1986	Emergency Planning and Community Right-to-Know Act	Facilities (gas plants and compressor stations) must report on the hazardous chemicals they use and store, providing information on a chemical's physical properties and health effects, and a listing of chemicals that are present in excess of certain amounts.
1990	Oil Pollution Act	Offshore drilling requires posting of significant pollution bonds.
1990	Pollution Prevention Act	Prevents pollution through reduction or recycling of source material. Requires facility owners or operators to include toxic chemical source reduction and recycling report for any toxic chemical.
1992	Energy Policy Act	Encourages development of clean-fuel vehicles; encourages energy conservation and integrated resource planning.

requires the cutting of roads or trails and, when explosives are used, the drilling of a small, short hole to encase them. Explosives are rarely used in water anymore since they can stun or kill marine life in the immediate vicinity; the now commonly used gas or air gun source was developed to ameliorate these effects, as well as increase personnel safety.

Following analysis of the geologic and geophysical data, the firm may proceed to acquire the right to drill and produce natural gas from owners of the land and relevant government permitting authorities. In making leasing and permitting decisions involving Federal lands, the potential environmental impacts of future development are often considered. Such considerations include the projected numbers and extent of wells and related facilities, such as pipelines, compressor stations, water disposal facilities, as well as roads and power lines.

Disposal of Drilling Waste

The drilling of a gas well involves preparing the well site by constructing a road to it if necessary, clearing the site, and flooring it with wood or gravel. The soil under the road and the site may be so compacted by the heavy equipment used in drilling as to require compaction relief for subsequent farming. In wetland areas, such as coastal Louisiana, drilling is often done using a barge-mounted rig that is floated to the site after a temporary slot is cut through the levee bordering the nearest navigable stream. However, the primary environmental concern directly associated with drilling is not the surface site but the disposal of drilling waste (spent drilling muds and rock cuttings, etc.). Early industry practice was to dump spent drilling fluid and rock cuttings into pits dug alongside the well and just plow them over after drilling was completed, or dump them directly into the ocean if offshore. Today, however, the authority issuing the drilling permits, in coordination with the EPA, determines whether the operator may discharge drilling fluids and solids to the environment or whether they must be shipped to a special disposal facility. Drilling of a typical gas well (6,000 feet deep) results in the production of about 150,000 pounds of rock cuttings and at least 470 barrels of spent mud.[28]

At onshore and coastal sites, drilling wastes usually cannot be discharged to surface waters and are primarily disposed of by operators on their lease sites. If the drilling fluids are saltwater- or oil-based, they can cause damage to soils and groundwater and on-site disposal is often not permitted, so operators must dispose of such wastes at an off-site disposal facility. The disposal methods used by commercial disposal companies include underground injection, burial in pits or landfills, land spreading, evaporation, incineration, and reuse/recycling. In areas with subsurface salt formations, such as Texas, Louisiana, and New Mexico, disposal in man-made salt caverns is an emerging, cost-competitive option. Such disposal poses very low risks to plant and animal life because the formations where the caverns are constructed are very stable and are located beneath any subsurface fresh water supplies. Water-based drilling wastes have been shown to have minimal impacts on aquatic life, so offshore operators are allowed to discharge them into the sea. They are prohibited from so discharging oil-based drilling wastes, and these are generally hauled to shore for disposal.

In recent years, new drilling technologies such as slimhole drilling, horizontal drilling, multilateral drilling, coiled tubing drilling, and improved drill bits, have helped to reduce the generated quantity of drilling wastes. Another advanced drilling technology that provides pollution-prevention benefits is the use of synthetic drilling fluids which combine the superior drilling performance of oil-based fluids with the more favorable environmental impacts of water-based drilling fluids. Their use results in a much cleaner well bore and less sidewall collapse, such that the cuttings volume is reduced.

Emissions

Exploration, development, and production activities emit small volumes of air pollutants, mostly from the engines used to power drilling rigs and various support and construction vehicles. An indication of the level of air emissions from these operations is available from wells in the Federal Offshore off California (Table 4). As the number of wells increases, such as in the Gulf of Mexico, so do the emissions for exploratory drilling and development drilling, while emissions from supporting activities rise less directly. Offshore development entails some activities not found elsewhere (i.e., platform construction and marine support vessels), but the environmental effects from onshore activities, which include drilling pad and access road construction, especially for development drilling, are many times larger because of the much higher level of activity.

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[28]Assumes a 20-inch diameter hole to 200 feet followed by an 8-inch (average) hole diameter for the next 5,800 feet, plus a mud pit volume of 35 barrels.

Table 4. Typical Annual Air Pollutant Emissions from Exploration, Development, and Production Activities Offshore California

	Type of Air Pollutant Emission (short tons per year)				
Activity	**Volatile Organic Compounds**	**Nitrogen Oxides**	**Sulfur Dioxide**	**Carbon Monoxide**	**Total Suspended Particulates**
Exploratory Drilling - Assumes four 10,000-foot wells drilled at 90 days per well; includes emissions from support vessels on site and in transit.	28.0	175.6	14.0	34.0	14.5
Platform Installation - Includes emissions from support vessels.	8.5	192.0	13.0	34.4	10.7
Pipeline Installation - Includes emissions from support vessels.	1.8	31.6	2.1	6.1	2.0
Development Drilling - Assumes eight 10,000-foot wells drilled per year; includes emissions from support vessels.	7.9	106.2	4.6	40.4	5.1
Offshore Platform - Assumes annual production of 4.38 million barrels of oil and 5,840 million cubic feet of natural gas.	25.7	99.0	0.7	69.3	5.5
Support Vessels - Assumes one crew boat trip and one supply boat every 2 days; includes emissions in transit for 50-mile round trip.	0.9	42.4	2.9	6.4	1.9
Onshore Gas Processing - Assumes processing of 21,900 million cubic feet of natural gas annually.	13.6	39.8	21.0	4.8	3.5

Notes: The number of exploratory and development wells drilled annually in the Gulf of Mexico Offshore and onshore in the United States is much larger than in the California Offshore. Total U.S. exploratory wells numbered 3,024 in 1997 while developmental wells numbered 23,453 (Energy Information Administration, *Monthly Energy Review*, Table 5.2). Offshore operations in the Gulf of Mexico include emissions from helicopter crew support flights as well as crew and supply boats. Onshore drilling includes emissions during construction of drilling pads and access roads.

Sources: **Nitrogen Oxides:** Radian, "Assessment of No_x Control Measures for Diesel Engines on Offshore Exploratory Vessels and Rigs - Final Report" presented to Joint Industries Board (1982). **Other Emissions:** Form and Substance, Inc. for Minerals Management Service, *A Handbook for Estimating the Potential Air Quality Impacts Associated with Oil and Gas Development Off California* (October 1983).

Disposal of Produced Water

Coproduction of a variable amount of water with the gas is unavoidable at most locations. Because the water is usually salty, its raw disposal or unintentional spillage on land normally interferes with plant growth. Since the produced water represents the largest volume waste stream generated by exploration and production activities, its disposal is a significant problem for the industry. The disposal process varies depending on whether the well is onshore or offshore, the local requirements, and the composition of the produced fluids. Most onshore-produced water is disposed of by pumping it back into the subsurface through on-site injection wells. In some parts of the United States, injection is not practical or economically viable and the produced water is therefore piped or trucked to an off-site treatment facility. The disposal methods used by commercial disposal companies include injection, evaporation, and treatment followed by surface discharge. For example, the water produced from onshore coal bed methane wells in Alabama is disposed of by land application or by discharge into streams after treatment; because of the elevated levels of total dissolved solids, the water is tested by biomonitoring for acute toxicity.[29]

Offshore, during a typical year of operations in the Gulf of Mexico, it is estimated that approximately 685,000 barrels of produced water are discharged, about half of which is piped to onshore locations where it is treated and subsequently discharged to onshore waters.[30] Studies have found few impacts of produced water disposal in the deeper waters of the Gulf of Mexico or off Southern California. In very shallow coastal areas (2 to 3 meters deep), more extensive impacts from long-term discharges are suggested.[31] One of the original environmental concerns regarding oil and gas drilling and production involves undesirable movement of fluids along the well bore from deeper, often salty, formations to formations near the surface that contain fresh water. Operators are generally required to cement casing from the wellhead through all rock layers containing fresh water. While oil will obviously contaminate fresh groundwater, entry of natural gas into fresh water zones used for human or agricultural supply will not, but it can create an explosion or suffocation risk.

Downhole separators are a new technology that promises to reduce the environmental risk from produced water as well as reduce industry's cost of handling it. These devices separate oil and gas from produced water within the well bore, such that most of the produced water can be safely injected into a subsurface formation without ever being brought to the surface.

Condensate Production Hazards

There are an estimated 13,000 condensate tank batteries which separate, upgrade, store, and transfer condensate streams from natural gas produced in the United States and its offshore areas.[32] The separation is done using glycol dehydration units, which the EPA has identified as a potential source of hazardous air pollutants (as well as tanks and vessels storing volatile oils, condensate, and similar hydrocarbon liquids). The EPA has published a Notice of Proposed Rulemaking seeking to reduce these emissions by 57 percent for oil and natural gas production facilities and by 36 percent from glycol dehydration units in natural gas transmission and storage facilities. The final rule is not expected until May 1999.

Venting, Flaring, and Fugitive Emissions

It is sometimes necessary either to vent produced gas into the atmosphere or to flare (burn) it. Worldwide, most venting and flaring occurs when the cost of transporting and marketing gas co-produced from crude oil reservoirs exceeds the netback price received for the gas. This practice is by no means as common in the United States as it was a few decades ago when oil was the primary valuable product and there was no market for much of the co-produced natural gas until the interstate pipeline system was developed after World War II. The minor venting and flaring that does occur now is regulated by the States and may happen at several locations: the well gas separator, the lease tank battery gas separator, or a downstream natural gas plant.

The total amount of methane vented in 1996, 1.14 million metric tons, was the second largest component of methane emissions from natural gas operations (Table 5). Throughout the entire process of producing, refining, and distributing natural gas there are losses or fugitive emissions. Production operations account for about 30 percent of the fugitive emissions, while transmission, storage, and distribution account for about 53 percent. All systems of pipes that transmit any fluid are subject to leaks. In the case of natural gas, any leak will escape to the atmosphere. The total methane emissions from all natural gas operations in 1996 was 6.66 million metric tons, or 22 percent of all U.S. anthropogenic methane emissions. When weighted by the global warming potential of

[29]K.R. Drotter, D.R. Mount, and S.J. Patti, "Biomonitoring of Coalbed Methane Produced Water from the Cedar Cove Degasification Field, Alabama," in Proceedings of the 1989 Coalbed Methane Symposium, The University of Alabama (April 17-20, 1989), p. 363.

[30]U.S. Department of Interior, National Oceanic and Atmospheric Administration, Gianessi and Arnold, "The Discharge of Water Pollutants from Oil and Gas Explorations and Production Activities in the GOM Region" (April 1982), as cited in "Oil and Gas Program: Cumulative Effects," U.S. Department of the Interior, Minerals Management Service, *Outer Continental Shelf Report*, MMS 88-0005 (1988), p. V-19.

[31]J.G. Mackin, "A Study of the Effect of Oilfield Brine Effluents on Benthic Communities in Texas Estuaries" (College Station, TX, Texas A&M Research Foundation, 1971), Proj. 735, p. 72, cited by Minerals Management Service in "Oil and Gas Program: Cumulative Effects," *Outer Continental Shelf Report* (1988).

[32]Environmental Protection Agency, Federal Register Notice, Part II, 40 CFR Part 63, *National Emissions Standards for Hazardous Air Pollutants: Oil and Natural Gas Production and Natural Gas Transmission and Storage; Proposed Rule* (February 6, 1998), p. 6292.

Table 5. U.S. Methane Emissions by Source, 1989-1996
(Million Metric Tons of Methane)

Source	1989	1990	1991	1992	1993	1994	1995	1996
Natural Gas Operations								
Natural Gas Wellhead Production	0.28	0.29	0.30	0.30	0.30	0.31	0.30	0.32
Gathering Pipelines	1.08	1.07	1.03	1.03	0.92	0.84	0.74	0.74
Gas-Processing Plants	0.55	0.62	0.69	0.68	0.70	0.70	0.72	0.72
Heaters, Separators, etc.	0.17	0.17	0.17	0.17	0.18	0.19	0.19	0.19
Total Production	**2.08**	**2.15**	**2.19**	**2.18**	**2.10**	**2.04**	**1.96**	**1.97**
Gas Venting	0.77	0.75	0.81	0.83	0.97	1.01	0.68	1.14
Gas Transmission and Distribution	3.51	3.56	3.60	3.64	3.57	3.56	3.55	3.55
Total Natural Gas Operations	**6.36**	**6.46**	**6.60**	**6.65**	**6.64**	**6.61**	**6.19**	**6.66**
Natural Gas Stationary End-Use Combustion								
Residential	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Commercial	0.004	0.003	0.004	0.004	0.004	0.004	0.004	0.004
Industrial	0.012	0.013	0.013	0.013	0.014	0.014	0.015	0.015
Electric Utility	*	*	*	*	*	*	*	*
Total Natural Gas Combustion	**0.021**	**0.021**	**0.022**	**0.022**	**0.023**	**0.023**	**0.024**	**0.024**
Total from Natural Gas	**6.381**	**6.481**	**6.622**	**6.672**	**6.663**	**6.633**	**6.214**	**6.684**
Percent of U.S. Methane Emissions	**20%**	**21%**	**21%**	**21%**	**22%**	**21%**	**20%**	**20%**
Other Energy Sources								
Coal Mining	4.31	4.63	4.38	4.28	3.50	3.90	3.98	3.93
Oil Well Production	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Oil Refining and Transportation	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09
Non-Natural-Gas Stationary Combustion	0.80	0.50	0.53	0.55	0.48	0.47	0.52	0.52
Mobile Sources	0.29	0.27	0.26	0.26	0.25	0.24	0.25	0.25
Total Other Energy	**5.52**	**5.55**	**5.29**	**5.21**	**4.35**	**4.74**	**4.88**	**4.83**
Non-Energy Sources								
Waste Management	11.04	11.11	11.00	10.89	10.83	10.73	10.60	10.44
Agricultural Sources	8.18	8.29	8.55	8.77	8.79	9.11	9.05	8.75
Other Industrial Processes	0.12	0.12	0.11	0.12	0.12	0.13	0.13	0.13
Total Non-Energy	**19.34**	**19.52**	**19.66**	**19.78**	**19.74**	**19.97**	**19.78**	**19.32**
Total U.S. Methane Emissions	**31.29**	**31.59**	**31.63**	**31.74**	**30.82**	**31.38**	**30.93**	**30.90**

*Less than 500 metric tons of methane.

Notes: Data for 1997 from Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 1997* (October 1998) were not used because the report groups gas operations in a less detailed format. The report states that U.S. methane emissions totaled 29.11 million metric tons in 1997, with natural gas systems accounting for 6.03 million metric tons, or 21 percent. Totals may not equal sum of components because of independent rounding.

Source: EIA, *Emissions of Greenhouse Gases in the United States 1996* (October 1997).

methane, this amounts to 2 percent of total U.S. greenhouse gas emissions in 1996.

Removal of Carbon Dioxide

Almost 500 billion cubic feet of the 24.2 trillion cubic feet of gross withdrawals of natural gas in the United States in 1997 was in fact carbon dioxide (Table 6). The carbon dioxide content of natural gas has been increasing over recent years. This is mostly attributable to the growth of production in fields with a relatively high carbon dioxide component, such as in the Midwest, the Green River Basin in Wyoming, and the San Juan Basin and Piceance Basin coal bed gas fields, as a result of increased natural gas demand in recent years. Since 1990, the volume of carbon dioxide coproduced with natural gas has risen by 23.4 percent.

More carbon dioxide (CO_2) is produced with nonassociated natural gas than with associated-dissolved natural gas primarily because about 85 percent of U.S. gas production is from nonassociated gas wells. Also, the chemical processes involved in the formation of natural gas lead to a higher CO_2 content in nonassociated gas. In 1997, the

Table 6. U.S. Carbon Dioxide Inherent in Domestic Natural Gas Production, 1990-1997
(Billion Cubic Feet, Unless Otherwise Noted)

Carbon Dioxide	1990	1991	1992	1993	1994	1995	1996	P1997
Produced								
With Nonassociated Gas	362.8	371.9	386.6	406.5	422.5	415.1	441.2	451.7
With Associated-Dissolved Gas	14.7	15.0	15.8	15.8	14.8	14.2	13.8	14.1
Total	**377.6**	**386.9**	**402.4**	**422.3**	**437.3**	**429.3**	**455.0**	**465.8**
Emitted								
Production Activities	248.8	256.7	271.1	286.8	300.2	293.8	312.9	321.3
Pipeline Consumption	5.4	4.9	4.8	5.1	5.6	5.7	5.8	5.8
End-Use Consumption	123.4	125.4	126.4	130.5	131.5	129.8	136.3	138.7
Total[1]	**377.6**	**386.9**	**402.4**	**422.3**	**437.3**	**429.3**	**455.0**	**465.8**
Total (Million Metric Tons of Carbon)[2]	**5.4**	**5.6**	**5.8**	**6.1**	**6.3**	**6.2**	**6.5**	**6.7**

P = Preliminary data.
[1]Includes small amount carbon dioxide reinjected in Texas and Wyoming that is ultimately retained in the reservoir.
[2]Energy Information Administration, *Emissions of Greenhouse Gases in the United States, 1997* (October 1998), p. 119.
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Office of Oil and Gas estimates, unless otherwise noted.

CO_2 component of nonassociated gas produced was 2.5 percent as compared with 0.2 percent for associated-dissolved natural gas.

The CO_2 content of produced natural gas has numerous possible dispositions. For example, it can be left in the natural gas that is returned to reservoirs to repressurize them, thereby increasing the oil recovery factor, or it can be left in the natural gas used for fuel in well, field, and lease operations, or vented, etc. When processing of the raw natural gas stream is economically warranted, the CO_2 is typically extracted by amine scrubbing and then vented to the atmosphere. The remaining carbon dioxide left in the finished natural gas stream becomes a fugitive emission somewhere during transmission, distribution or consumption.

Of the 500 billion cubic feet of carbon dioxide produced along with U.S. natural gas (Table 1), most is emitted to the atmosphere. Almost 69 percent of carbon dioxide emissions occur during gas production, with the remainder in transmission, distribution, and consumption. The largest single point of emissions is at natural gas plants, where at least 200 billion cubic feet is emitted.[33]

Ancillary Production Activities

Gas exploration and production also result in a number of other, relatively minor environmental consequences. For example, gas production and processing operations sometimes accumulate naturally occurring radioactive materials (NORM). Over a 20-year period, the Environmental Protection Agency estimates that the combined production of natural gas and crude oil in the United States resulted in accumulation of 13 million metric tons of NORM, as opposed to 1.7 billion tons in coal ash and more than 21 billion metric tons associated with metal, uranium, and phosphate mining and processing.[34] NORM can accumulate as scale or sludge in natural gas well casing, production tubing, surface equipment, gas gathering pipelines, and by-product waste streams.[35] NORM concentrations vary from background levels to levels exceeding those of some uranium mill tailings.[36] Traditionally, these materials have been regulated by the States.

[33]Energy Information Administration, Office of Oil and Gas analysis (September 1998).

[34]Environmental Protection Agency, "Disposal of Naturally Occurring and Accelerator-Produced Radioactive Materials," EPA 402-K-94-001 (August 1994), <http://www.epa.gov/radiation/radwaste radwaste/narm.htm>.

[35]The sources of most of the radioactivity are isotopes of uranium-238 and thorium-232 which are naturally present in the subsurface formations from which natural gas is produced. The primary radionuclides of concern are radium-226 in the uranium-238 decay series and radium-228 in the thorium-232 decay series. Other radionuclides of concern include those resulting from the decay of radon-226 and radon-228, such as radon-222. Pipe scale and sludge accumulations are dominated by radium-226 and radium-228, while deposits on the interior surfaces of gas plant equipment are predominantly lead-210 and polonium-210.

[36]Stephen A. Marinello and Mel B. Hebert, "Minimizing NORM Generation Most Cost-Effective Approach," *The American Oil & Gas Reporter* (December 1995), p. 101.

Proper precautions must be taken during disposal of contaminated casing and pipes to ensure that they are not converted into such things as furniture or playground equipment. The production waste streams most likely to be contaminated by elevated radium concentrations include produced water, scale, and sludge. Spillage or intentional release of these waste streams to the ground can result in NORM-contaminated soils that must also be disposed of. Most produced water containing NORM is disposed of on-site through injection wells for onshore locations and is discharged into the sea at offshore locations. Other types of NORM waste are presently disposed of at gas and oil production sites and at off-site commercial disposal facilities, mostly by underground injection. Smaller quantities of NORM are disposed of through burial in landfills, encapsulation inside the casing of plugged and abandoned wells, or land spreading.

The physical appearance of a drilling rig or a wellhead is offensive to some people. In the oil-productive urban portions of onshore California, drilling rigs and wellheads are routinely hidden inside mock buildings in part for this reason and in part to muffle the noise of operations. Unfortunately an offshore platform cannot be hidden in the same way. Aside from this "viewshed" issue, an offshore rig precludes commercial fishing operations on an average of 500 acres because of it and its anchors' presence.[37] Offshore noise and light pollution are also a concern because noise can carry for long distances over and underwater and offshore rigs and platforms operate round-the-clock and are very well-lit at night.

When drilling is conducted in remote areas on land, the roads and airfields constructed by the well operators can later provide easier public access for other purposes such as hunting, fishing, and other outdoor activities unless special provisions are made to prevent it. Access is generally a bigger problem relative to oil wells since the transportation cost per unit of value for natural gas is higher than that for crude oil, which makes natural gas development in remote areas less likely.

Natural Gas Processing

The processing of natural gas poses low environmental risk, primarily because natural gas has a simple and comparatively pure composition. There are 697 natural gas processing facilities in the United States.[38] Their purpose is to remove the heavier hydrocarbons such as ethane, propane, pentanes, and hexanes, as well as contaminants such as carbon dioxide and water, in order to bring the natural gas stream into conformity with pipeline Btu content and other specifications. Typical processes performed by a gas plant are separation of the heavier-than-methane hydrocarbons as liquefied petroleum gases, stabilization of condensate by removal of lighter hydrocarbons from the condensate stream, gas sweetening, and consequent sulfur production and dehydration sufficient to avoid formation of methane hydrates in the downstream pipeline.[39] The EPA-identified hazardous air pollutant (HAP) emission points at natural gas processing plants are the glycol dehydration unit reboiler vent, storage tanks,[40] and equipment leaks from components handling hydrocarbon streams that contain HAP constituents. Other potential HAP emission points are the tail gas streams from amine-treating processes and sulfur recovery units.

Methods vary for removing natural gas contaminants, such as hydrogen sulfide gas, carbon dioxide gas, nitrogen, and water. Commonly the hydrogen sulfide is converted to solid sulfur for sale. Likewise the carbons and nitrogen are separated for sale to the extent economically possible but otherwise the gases are vented, while the water is treated before release. Compressor operation at gas plants has a similar impact to that of compressors installed at other locations.

Pipeline Construction and Expansion

Gas gathering pipeline systems move natural gas from the well to a gas plant or transmission pipeline. The diameter of the gathering pipe depends on the number and deliverability of the wells served. Construction involves clearing and grading right-of-way (ROW), trenching, pipe welding and coating, pipe burial, and restoration of the disturbed surface (although gathering pipelines are sometimes laid on the ground surface). Operation of the system involves supporting compressor stations and, in the case of water-producing wells, water collection, pumping, pipelining, and disposal according to State or local

[37] U.S. Department of the Interior, Minerals Management Service, "Oil and Gas Program: Cumulative Effects," *Outer Continental Shelf Report*, MMS 88-0005 (1988).

[38] Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1997 Annual Report*, DOE/EIA-0216(97) (Washington, DC, December 1998).

[39] H.D. Beggs, *Gas Production Operations* (Tulsa, OK: OGCI Publications, November 1995), pp. 219-222.

[40] Particularly those that handle volatile oil and condensates, which may be significant contributors to overall hazardous air pollutant emissions because of flash emissions.

regulations. In near-offshore areas such as the Mississippi River Delta, canals have to be dredged to permit movement of barge-mounted oil and gas drilling rigs and the laying of oil and gas gathering pipelines.

The environmental impacts of transmission pipeline construction and operation are considered by the Federal Energy Regulatory Commission prior to approval of construction. About 300,000 miles of high-pressure transmission pipelines are in place in the United States and its offshore areas. The construction ROW on land is commonly 75 to 100 feet wide along the length of the pipeline; this is the area disturbed by clearing and grading, trenching, soil storage, pipe storage, vehicle movement, pipe burial, trench in-filling, and surface restoration, which is between 9.1 and 12.1 acres per mile of pipe. In agricultural areas, it may take 1 to 3 years for cropland to return to its former productivity after pipeline installation. The permanent ROW on land is typically 50 to 75 feet wide times the length of the pipeline. This is the area needed by the operator for routine inspection and maintenance operations, occupying from 6.1 acres to 9.1 acres per mile of pipe.[41] For every mile of offshore pipeline constructed on non-rocky sea floors, about 6 acres of sea bottom are disturbed and 2,300 to 6,000 cubic yards of sediment displaced.[42]

Pipeline Operations

Valves are installed along the pipeline to allow isolation of leaking or failed segments of the line or complete shutdown should that become necessary. The pipe is generally brought to the surface so that the valve can be easily reached and observed; siting is commonly in areas accessible by road but away from residential areas. The EPA has identified leaking valves as a potential hazardous air pollutant emission point. It has also identified pipeline "pigging" operations and the storage of resulting wastes as potential hazardous air pollutant emission points. Pigging operations are performed to inspect and clean the interior of pipelines and entail safe disposal of the removed solid and liquid contaminants.

[41]Federal Energy Regulatory Commission, *Pony Express Pipeline Project Environmental Assessment*, Docket No. CP96-477-000 (April 1997), p. 2-20.

[42]Minerals Management Service, "Oil and Gas Program: Cumulative Effects," MMS 88-0005 (1988), pp. V-23 and V-20.

Compressor stations (about 1,900 of them in the United States)[43] are also located along the route of the pipeline to ensure efficient movement of the gas. Because the location of a compressor station need not be precise, it can usually be sited so as to reduce its impact on the human or natural environment. However, there are unavoidable emissions of nitrogen oxides (NO_x) and other gases during compressor operations. A transmission compressor station powered by natural gas has been estimated to produce 1.50 grams of NO_x per baseplate horsepower per hour (g/bhp-hr), 2.30 g/bhp-hr of carbon monoxide, and 1.50 g/bhp-hr of volatile organic compounds.[44] Methane leakage also occurs (Table 5). Significant reductions in methane leakage have occurred by converting wet (oil) shaft seals to dry (high-pressure gas) shaft seals, which reduces the leakage rate range from 40 to 200 standard cubic feet (scf) per minute to at most 6 scf per minute.[45]

Some transmission pipelines used polychlorinated biphenyls (PCBs) as lubricants in their compressors prior to 1976 when their manufacture was banned by the Toxic Substance Control Act. The PCBs are a group of aromatic organic compounds that have inherent thermal and chemical stability but are quite toxic. Unfortunately, they diffused out of the compressors into the pipelines of those systems that utilized them; their cleanup has been a significant problem. Research is continuing into methods for removal of the PCBs.

Underground Storage Operations

The construction and operations associated with underground natural gas storage also have environmental impacts. There are about 410 underground gas storage facilities in the United States, which have been variously developed in former oil or natural gas producing

[43]Environmental Protection Agency, Federal Register Notice, Part II, 40 CFR Part 63, *National Emissions Standards for Hazardous Air Pollutants: Oil and Natural Gas Production and Natural Gas Transmission and Storage; Proposed Rule* (February 6, 1998), p. 6292.

[44]Federal Energy Regulatory Commission, *Pony Express Pipeline Project Environmental Assessment*, Docket No. CP96-477-000, p. 3-33.

[45]Environmental Protection Agency, "Lessons Learned from Natural Gas STAR Partners, Replacing Wet Seals with Dry Seals in Centrifugal Compressors," Executive Summary, <http://www.epa.gov/gasstar/ sealsprn. htm>.

reservoirs, in aquifers,[46] and in man-made cavities in salt deposits.

Storage well drilling has a similar impact to that of drilling production wells with the exception that the geology is often better known and the drilling is therefore less risky. In developing storage facilities at an aquifer or abandoned oil or gas reservoir, horizontal wells have recently been utilized to increase the input/output capacity and minimize total drilling. If a salt deposit is being developed for storage, the salt water disposal can be into adjacent underground reservoirs or into the surface water environment under permitted conditions. The laying of storage field pipelines has a similar effect as that of gas gathering pipelines, but usually occurs in a much smaller area and away from populated areas and sensitive habitats. The establishment of underground storage facilities at depleted production field sites sometimes entails little in the way of additional disturbance.

The environmental impacts associated with storage compressor facilities are similar to those for gathering and mainline compressor installations. Dehydration units located in storage fields are noted by EPA as a potential source of hazardous air pollutants. It is common practice to "blow" down production wells (often annually) when a storage reservoir is developed in an aquifer or an abandoned oil or gas reservoir. This practice clears loose particles from the interstices of the storage reservoir rock adjacent to the well bore, thereby restoring the rock's permeability and the maximum flow rate. However, this practice produces a noise effect and the need to flare the rapidly delivered gas.

Natural Gas Distribution

The local natural gas distribution company (LDC) takes gas from the intra- or interstate pipeline company serving its area. Facilities operated by the LDC include pressure reduction facilities, odorant storage and insertion facilities, and the small-diameter local distribution pipeline network with its attendant valves and meters. Line losses are more apparent in the LDCs' pipelines than elsewhere, as the odorant has been added and leaks can be detected by the human nose. Line losses are also more dangerous in distribution networks since built-up areas have many enclosed spaces, and their infusion with leaked gas can produce an explosive mixture of natural gas and air ignitable by any flame, spark, or electrostatic discharge that comes in contact with it. Nevertheless, the local distribution of coal or fuel oil for commercial or residential use is significantly less energy efficient, and in the case of oil potentially more environmentally hazardous than is that of natural gas.

Outlook

According to EIA's *Annual Energy Outlook 1999* reference case, natural gas consumption for electricity generation nearly triples, from 3.3 trillion cubic feet (Tcf) in 1997 to 9.2 Tcf, by 2020. Gas-fired generation is the economical choice for construction of new power generation units through 2010, when capital, operating, and fuel costs are considered.[47] Natural gas consumption and emissions are projected to increase more rapidly than other fossil fuels, at average annual rates of 1.7 percent through 2020.[48] However, this represents reductions in total carbon emissions derived from the environmental advantages of natural gas.

Concern about global warming and further deterioration of the environment caused by escalating industrial expansion and other development is being addressed by worldwide initiatives (e.g., the Kyoto Protocol) that seek a decrease in emissions of greenhouse gases and other pollutants. Natural gas is expected to play a key role in strategies to lower carbon emissions, because it allows fuel users to consume the same Btu level while less carbon is emitted. If carbon-reduction measures are implemented, EIA projects in its Kyoto Protocol analysis that, by 2010, natural gas demand would increase by 2 to 12 percent over otherwise expected levels.[49] Emissions from natural gas consumption would also rise, but the natural gas share of total emissions would increase only slightly.

[46]A body of rock that is sufficiently permeable to conduct ground water and to yield economically significant quantities of water to wells and springs, although they do not do the latter in the vicinity of a storage site. Robert L. Bates and Julia A. Jackson, American Geological Institute, *Dictionary of Geological Terms*, 3rd ed. (New York: Doubleday, 1983), p. 26.

[47]Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998), p. 82.

[48]Energy Information Administration, *Annual Energy Outlook 1999*, p. 85.

[49]Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998), pp. xix and 95.

3. Future Supply Potential of Natural Gas Hydrates

Earth's vast deposits of natural gas hydrates hold the promise of meeting the world's natural gas needs far into the 21st century—if they can be tapped. Presently they are at best a sub-economic resource, but realization of even a small part of their potential would provide a very significant new source of natural gas to meet future energy and environmental requirements. Detailed knowledge of natural gas hydrate deposits is scant, and how they might be produced economically and safely has barely been considered. Still:

- Global estimates place the gas volume (primarily methane) resident in oceanic natural gas hydrate deposits in the range of 30,000 to 49,100,000 *trillion* cubic feet (Tcf), and in continental natural gas hydrate deposits in the range of 5,000 to 12,000,000 Tcf. Comparatively, current worldwide natural gas resources are about 13,000 Tcf and natural gas reserves are about 5,000 Tcf.

- The current mean (expected value) estimate of domestic natural gas hydrates in-place is 320,222 Tcf. In comparison, as of 1997 the mean estimate of all untapped technically recoverable U.S. natural gas resources was 1,301 Tcf, U.S. proved natural gas reserves were 167 Tcf, and annual U.S. natural gas consumption was about 22 Tcf.

- Large volumes of natural gas hydrates are known to exist in both onshore and offshore Alaska, offshore the States of Washington, Oregon, California, New Jersey, North Carolina, and South Carolina, and in the deep Gulf of Mexico. Most of the volume is expected to be in Federal jurisdiction offshore waters, although 519 Tcf of hydrated gas-in-place was assessed for onshore Alaska—more than three times the 1997 level of U.S. proved natural gas reserves.

Significant safety and environmental concerns are also associated with the presence of natural gas hydrates, ranging from their possible impact on the safety of conventional drilling operations to the influence on Earth's climate of periodic natural releases into the atmosphere of large volumes of hydrate-sourced methane or derivative carbon dioxide.

Considerable research is needed to characterize more completely and accurately the location, composition, and geology of Earth's natural gas hydrate deposits. This body of research is a necessary precursor to development of means to extract them, as well as to determination of their possible future climatic impacts.

Natural gas is widely expected to be the fastest-growing primary energy source in the world over the next 25 years. In the Energy Information Administration's *International Energy Outlook 1998* reference case,[1] worldwide gas consumption was projected to grow by 3.3 percent annually through 2020, as compared with 2.1-percent annual growth for oil and renewable energy sources and 2.2-percent annual growth for coal. The world's consumption of natural gas was projected to be 172 trillion cubic feet by 2020, more than double the 1995 level. Much of this growth was expected to fuel electricity generation worldwide, but resource availability, cost, and environmental considerations were also expected to contribute to growing use of natural gas in industrial, residential, and commercial sector applications.

Conventional world natural gas resources are estimated to be about 13,000 trillion cubic feet. The ability of this conventional resource base to meet the world's growing gas supply needs is limited by the fact that a substantial portion of it is not located close to major and developing gas markets and would therefore require enormous investments in pipelines and other facilities to move the gas to market. For that reason, much of the current conventional resource is uneconomic to produce.

Natural gas hydrates are a vast potential, though not presently commercial, source of additional natural gas. One of the most appealing aspects of this potential new gas source is that large deposits are located near the expected demand growth areas. Some countries, such as Japan, do

[1]Energy Information Administration, *International Energy Outlook 1998*, DOE/EIA-0484(98) (Washington, DC, April 1998).

not have indigenous oil or gas resources but do have nearby oceanic natural gas hydrate deposits. Even in those countries that have some conventional gas supplies, additional supplies from hydrate production would allow greater expansion of their use of natural gas. Such prospects, however, hinge on whether or not gas can ever be commercially produced from the world's natural gas hydrate deposits, and if so, to what extent.

Natural gas hydrates are solid, crystalline, ice-like substances composed of water, methane, and usually a small amount of other gases, with the gases being trapped in the interstices of a water-ice lattice. They form under moderately high pressure and at temperatures near the freezing point of water (see box, p. 75). The naturally occurring version is primarily found in permafrost regions onshore and in ocean-bottom sediments at water depths exceeding 450 meters (see box, p. 76 and Figure 25).[2] Although their natural existence has only been known since the mid-1960s, it is firmly established that in sum these deposits are volumetrically immense: their estimated carbon content dwarfs that of all other fossil hydrocarbons combined.

Huge volumes of natural gas hydrates are either known or expected to exist in a relatively concentrated form at numerous locations (Figure 26). Current estimates indicate that the mass of carbon trapped in natural gas hydrates is more than half of the world's total organic carbon and twice as much as all other fossil fuels combined (Table 7). It has been estimated that a maximum of 270 *million* trillion cubic feet of natural gas could theoretically exist in hydrate deposits. Although the actual maximum volume is probably at least an order of magnitude smaller, it is still a huge volume (see Table 8). The "central consensus" estimate independently obtained by different investigators using varied estimation methods is about 742,000 trillion cubic feet (Tcf), whereas worldwide natural gas resources exclusive of natural gas hydrates are only about 13,000 Tcf and worldwide natural gas reserves are about 5,000 Tcf. In the United States, very large methane hydrate deposits are located both on- and offshore northern Alaska, offshore the States of Washington, Oregon, California, New Jersey, North Carolina, and South Carolina, and in the deep Gulf of Mexico (Figure 27). The U.S. Geological Survey's 1995 mean (expected value) estimate is that in aggregate these deposits contain 320,222 Tcf of methane-in-place.[3] Almost all of it (99.8 percent) is expected to be located in Federal-jurisdiction offshore waters (Figure 27). Nonetheless, 519 Tcf of gas in place—a bit more than three times the 1997 level of U.S. proved dry gas reserves—was assessed for onshore Alaska.

To place these estimates in perspective, consider that the corresponding mean estimate of all untapped technically recoverable U.S. natural gas resources was 1,301 Tcf, proved U.S. natural gas reserves were 167 Tcf at the end of 1997, and in 1997 the United States consumed 22 Tcf, 13 percent of which was imported from Canada.

Irrespective of the large in-place volumes, natural gas hydrates are at present only a potential, as opposed to an assured, future energy source. Methods for intentionally producing gas from them for profit at commercial scale have yet to be developed. How much of the gas-in-place might be technically recoverable is presently unknown, and the economically recoverable volume would be smaller. But even if only a small percentage of the total in-place volume could be commercially produced, the impact would be dramatic. As noted by the Department of Energy's (DOE) Office of Fossil Energy, if 1 percent of the resource could be recovered, that would more than double the domestic gas resource base.[4]

How To Produce?

Means of economically and safely producing methane from gas hydrate deposits are not yet on the drawing board. Nevertheless, there is one place where commercial production of natural gas hydrate is possibly already happening, although not by design: the Messoyakha Gas

[2]Most knowledge of naturally occurring natural gas hydrates and their geocontext is of recent vintage. In consequence, a significant portion of the source material for this chapter consists of matter directly published on the Internet rather than in peer-reviewed journals and similar traditional sources. Owing to the extensive list of sources and their fragmented coverage, attribution footnotes appear only for the most important references. A complete bibliography is provided in conjunction with the electronic version of this chapter at the Energy Information Administration's Internet site at URL http://www.eia.doe.gov.

[3]The U.S. Geological Survey estimated that there is a 95-percent chance that they contain at least 112,765 trillion cubic feet and a 5-percent chance that they contain at least 676,110 trillion cubic feet. The estimates represent the statistical sum (not the arithmetic sum, excepting the mean) of individual estimates for 13 assessed gas hydrate plays.

[4]U.S. Department of Energy, Office of Fossil Energy, Statement of Robert S. Kripowicz, Principal Deputy Assistant Secretary for Fossil Energy, Before the Subcommittee on Energy, Research, Development, Production, and Regulation, Committee on Energy and Natural Resources, U.S. Senate (May 21, 1998).

What Are Natural Gas Hydrates?

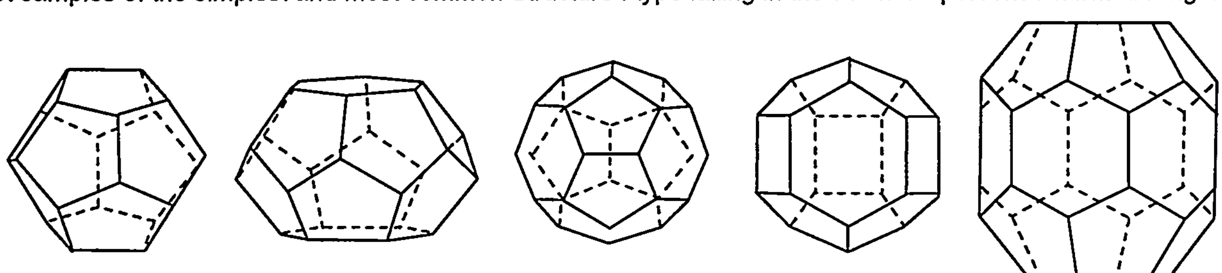
Natural gas hydrates are members of a highly varied class of substances called clathrates. These are solids formed by the inclusion of molecules of one kind (guest molecules) within the intermolecular cavities of a crystal lattice composed of molecules of another kind (host molecules). The guest molecules are necessary to support the cavities, and the association between host and guest molecules is principally physical because such bonding as exists is due to the weak attraction between adjacent molecules, rather than to the stronger chemical bonding responsible for most compounds as well as the hydrate water-ice lattice, which is hydrogen bonded.

Gas hydrates are ice-like substances composed of a host lattice of water molecules (H_2O) and one or more of a potential suite of guest molecules which at normal temperatures and pressures occur in the gaseous phase and are capable of physically fitting into the interstices of the water-ice lattice. This suite includes the noble gases (the elements helium, neon, krypton, argon, xenon, and radon), the halogens chlorine, bromine, iodine, and astatine, and hydrogen sulfide, sulfur trioxide, sulfur hexafluoride, and carbon dioxide (CO_2). Significantly, it also includes the low molecular-weight hydrocarbons methane (CH_4), ethane (C_2H_6), propane (C_3H_8), and the pentanes (C_5H_X). A particular natural gas hydrate can contain from one to all of these.

Depending on the size of the guest molecule, natural gas hydrates can consist of any combination of three crystal structures: Structure I, Structure II, and Structure H. When pure liquid water freezes it crystallizes with hexagonal symmetry, but when it "freezes" as a hydrocarbon hydrate it does so with cubic symmetry for structures I and II, reverting to hexagonal symmetry for Structure H.

- Structure I gas hydrates contain 46 water molecules per unit cell arranged in 2 dodecahedral voids and 6 tetrakaidecahedral voids (the water molecules occupy the apices in the stick diagrams of the void types shown below), which can accommodate at most 8 guest molecules up to 5.8 Angstroms in diameter. Structure I allows the inclusion of both methane and ethane but not propane.
- Structure II gas hydrates contain 136 water molecules per unit cell arranged in 16 dodecahedral voids and 8 hexakaidecahedral voids, which can also accommodate up to 24 guest molecules, but to a larger diameter of 6.9 Angstroms. This allows inclusion of propane and iso-butane in addition to methane and ethane.
- The rare Structure H gas hydrates, which contain 34 water molecules per unit cell arranged in 3 pentagonal dodecahedral voids, 2 irregular dodecahedral voids, and 1 icosahedral void, can accommodate even larger guest molecules such as iso-pentane.

The hydrocarbon hydrates are non-stoichiometric substances, i.e., their compositional proportions are not fixed. A variable number of guest molecules up to the maximums given above can be accommodated in the host lattice since not all of the available lattice positions need be filled. Typically the volume of gas included in a fixed volume of hydrate increases in response to either lower temperature or higher pressure. Thus, given the substantial density difference between water and free gas, one volume of water can accommodate from 70 to over 160 volumes of gas depending on how many of the available voids are filled (the degree of saturation). Natural gas hydrates are often undersaturated, with most samples of the simplest and most common Structure I type falling in the 70- to 90-percent saturated range.



Pentagonal Dodecahedron | Tetrakaidecahedron | Hexakaidecahedron | Irregular Dodecahedron | Icosahedron

Where Do Natural Gas Hydrates Occur ... and Why?

The first known natural gas hydrates were man-made, although not intentionally. The early natural gas industry found to its dismay that natural gas hydrate sometimes formed in pipelines as a wax-like, crystalline material which plugged the line. Worse yet, when the pipeline was depressured in order to remove the plug, the gas hydrate often stubbornly remained stable right up to ambient temperature and pressure. This occurred because natural gas hydrates that contain more than one kind of guest molecule are often physically stable over a wider range of temperature and pressure conditions than the range characteristic of pure methane hydrate. Hydrate clogging of pipelines has been simply if not inexpensively avoided ever since by drying the gas stream before injecting it into the pipeline, inasmuch as the removal of water eliminates the possibility of hydrate formation. Its formation is typically chemically inhibited when necessary in production operations.

Natural Occurrences

Naturally occurring natural gas hydrates were first discovered in 1964 in association with cold subsurface sediments located in Siberian permafrost terrains. The discovery of oceanic gas hydrates within the upper tens to hundreds of meters of continental margin sediments was reported in 1977. Natural gas hydrates also occur in sediments at the bottom of Russia's Lake Baikal, a very deep freshwater lake, but the volumes associated with such occurrences are very small as compared with the other two habitats. These are the only places on Earth in which natural gas hydrates can naturally occur, because they are the only ones where the thermodynamic (primarily temperature and pressure) conditions at which natural gas hydrates are physically stable prevail. Pure methane hydrate can neither form nor persist exposed to atmospheric temperatures and pressures; colder temperatures and higher, though still moderate, pressures are required for its formation and stability. Similarly, natural gas hydrates are stable only below an upper temperature bound and above a lower pressure bound.

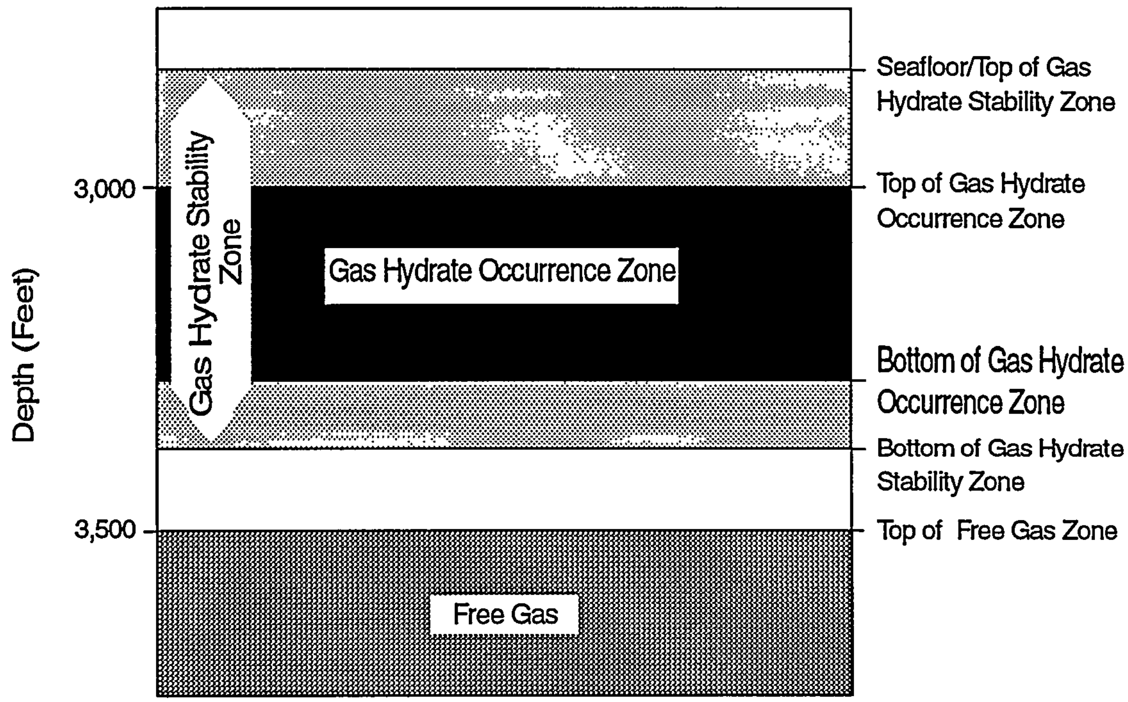
The Hydrate Stability Zone

The range of subsurface or subsea depths within which the prevailing temperature and pressure conditions allow a natural gas hydrate of the particular local gas composition to form and remain stable is called the hydrate stability zone (HSZ) (Figure 25). Because it is much colder at the surface in the Arctic, the top of the HSZ is in most instances much shallower in the onshore permafrost environment than in the oceanic environment. In the ocean, the HSZ starts at around 45 atmospheres of pressure (663 psi), which equates to a depth of 450 meters (1,476 feet). The temperature at that depth is typically in the range of 4 to 6 degrees Centigrade (39 to 43 degrees Fahrenheit). Because the oceanic temperature gradient not only begins at a much higher temperature but also ends at a higher one, a substantially greater hydrostatic pressure and therefore more depth is required for natural gas hydrates to form and remain stable than is the case onshore.

The range of depths over which natural gas hydrates are stable is in most instances much greater in the permafrost terrain environment. Because the Arctic atmosphere has been very cold for a long time, the permafrost, consisting of those sediments in which the resident pore water has remained frozen at zero degrees Centigrade or below for 2 or more consecutive years, extends from the surface (or a few inches below it in mid-summer) to more than 700 meters (2,297 feet) in the coldest areas; its maximum depth along the Alyeska Pipeline is, for example, 2,230 feet—almost a half-mile. Natural gas hydrates are stable anywhere within the permafrost zone and for a variable distance below it depending on the local subsurface heat flow rate. Permafrost terrains occupy about 20 percent of the Earth's surface.

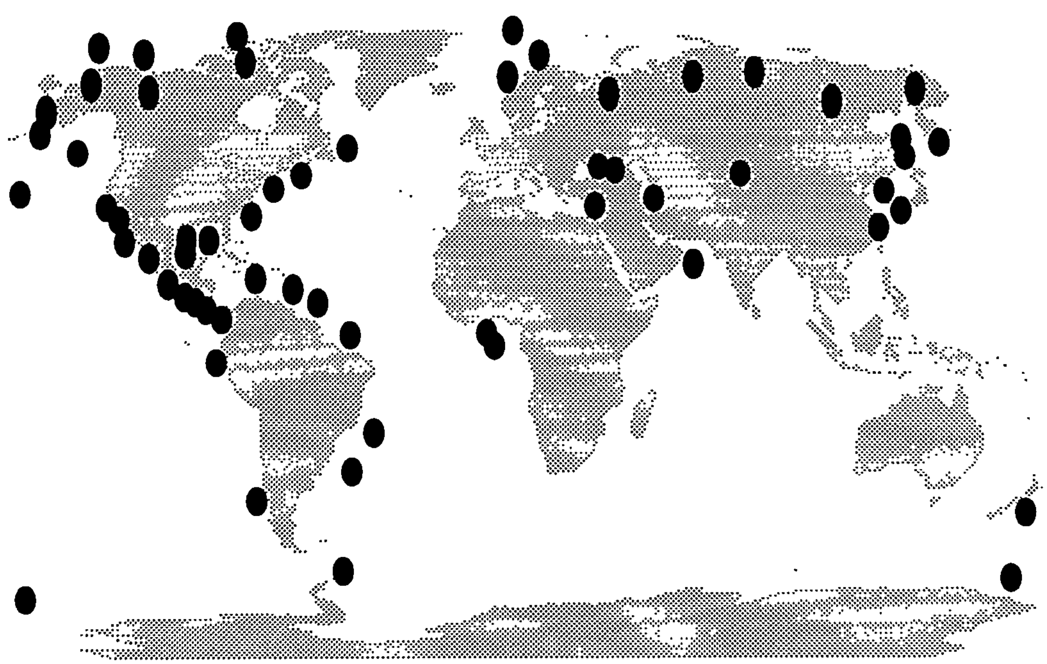
Natural gas hydrates are known to have at least four manifestations within the HSZ: as finely disseminated grains in the sediment (the most commonly observed form), as small nodules in the sediment, as small layers within the sediment, and as massive (blocky) occurrences. They need not and often do not occur throughout the entire HSZ. Beneath the HSZ, in what is called the free-gas zone (Figure 25), the sediment's pore spaces are filled with salty water that contains dissolved gas, or with bubbles of gas if the water is gas-saturated. For gas hydrates to form in sediments: (1) the thermodynamic conditions suited to gas hydrate formation must exist, i.e., there must in fact *be* an HSZ, (2) adequate gas must be generated in the subjacent sediments or by bacteria within the HSZ itself, (3) subjacently generated gas must be able to migrate upward to the HSZ, and (4) water must be present in the HSZ.

Figure 25. Gas Hydrate Occurrence Zone and Stability Zone



Source: Energy Information Administration, Office of Oil and Gas, based on W. Xu and C. Ruppel, "Predicting the Occurrence, Distribution, and Evolution of Methane Gas Hydrate in Porous Marine Sediments," draft submitted to *Journal of Geophysical Research* (April 1998).

Figure 26. Locations of Known and Expected Concentrated Methane Hydrate Deposits



Source: After U.S. Geological Survey, based on K.A. Kvenvolden, "Methane Hydrate—A Major Reservoir of Carbon in the Shallow Geosphere?" *Chemical Geology*, Vol. 71 (1988).

Table 7. The Earth's Organic Carbon Endowment by Location (Reservoir)

Reservoir	Organic Carbon	
	10^{13} Kilograms	Trillion Short Tons
Gas Hydrates (on- and offshore)	10,000	110,230
Fossil Fuels (coal, oil, natural gas)	5,000	55,116
Soil	1,400	15,432
Dissolved Organic Matter in Water	980	10,803
Land Biota	830	9,149
Peat	830	9,149
Detrital Organic Matter	60	661
Atmosphere	3.6	40
Marine Biota	3	33

Note: As a point of reference, the Great Lakes' 5,500 cubic miles of fresh water have a mass of about 25.2 trillion short tons.

Source: K.A. Kvenvolden, "Gas hydrates - geologic perspective and global change," *Review of Geophysics 31* (1993), pp. 173-187.

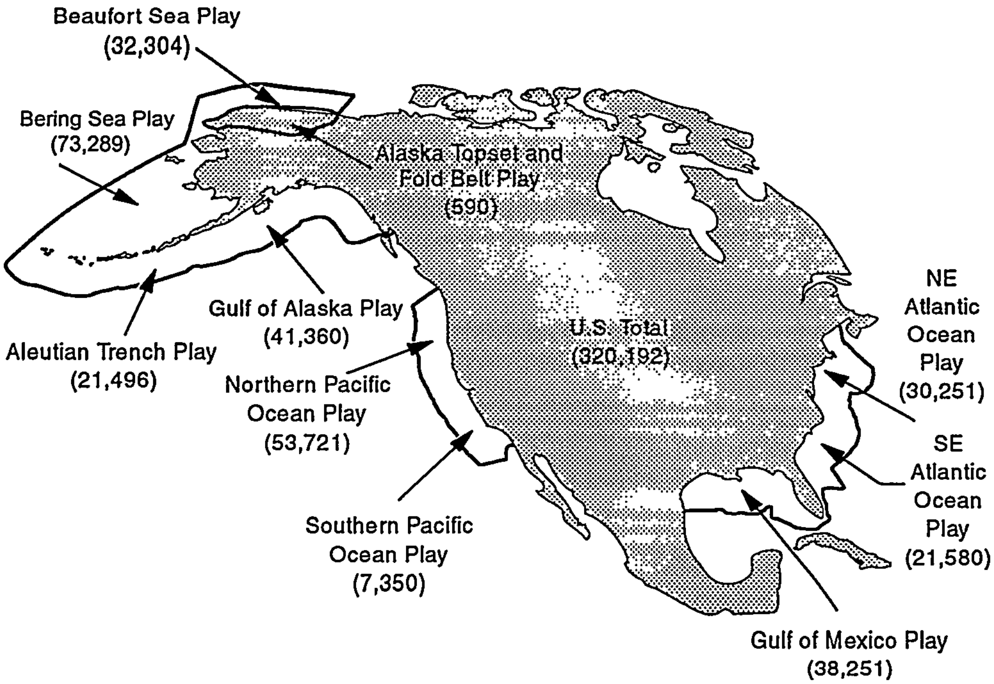
Table 8. Estimates of Methane in Natural Gas Hydrate Deposits
(100,000 Trillion Cubic Feet)

Date of Estimate/Source	Oceanic Deposits	Continental Deposits	All Deposits
1977/Trofimuk et al	1.8 to 8.8	0.02	--
1981/McIver	1.1	0.011	--
1981/Meyer	--	0.005	--
1988/Kvenvolden	6.2	--	--
1990/MacDonald	6.9	--	--
1994/Gornitz and Fung	9.3 - 49.1	--	--
1998/Kvenvolden	--	--	0.35 - 16.25
1998/Kvenvolden "Consensus"	--	--	7.42

Notes: The differences in the estimates are due to different assumptions and estimation approaches. Both McIver and Meyer based their estimates on thermodynamic considerations and assessments of the availability of methane. Gornitz and Fung used estimates of geothermal gradients, porosity, pore fill chemistry, and the two methane generation theories (biogenic and thermogenic) to calculate the potential range of volumes, noting that the actual amount is likely to be near the lower bound. The earlier Kvenvolden estimate represents extrapolation of an estimate of the hydrate present off northern Alaska to all continental margins. The latest Kvenvolden estimate takes into account the most recent work in the field, providing a constrained range and a "consensus" central estimate. Dobrynin, et al. (not tabulated here) estimated theoretical maximum volumes by assuming that methane hydrate would occur at all locations where conditions were favorable and that it would be fully saturated; the result, 2,700,000 trillion cubic feet in oceanic deposits and 12,000,000 trillion cubic feet in continental deposits, is unlikely to be the actual case.

Sources: •A.A. Trofimuk, N.V. Cherskii, and V.P. Tsaryov, "The Role of Continental Glaciation and Hydrate Formation on Petroleum Occurrence," R.F. Meyer, ed., *The Future Supply of Nature-Made Petroleum and Gas* (New York, 1977), pp. 919-926. •R.D. McIver, "Gas Hydrates," *Long-term Energy Resources* (1981), pp. 713-726. •R.F. Meyer, "Speculations on oil and gas resources in small fields and unconventional deposits," *Long-term Energy Resources* (1981), pp. 49-72. •K.A. Kvenvolden, "Methane Hydrate—A Major Reservoir of Carbon in the Shallow Geosphere?" *Chemical Geology*, Vol. 71 (1988), pp. 41-51. •G.J. MacDonald, "The Future of Methane as an Energy Resource," *Annual Review of Energy*, Vol. 15 (1990), pp. 53-83. •V. Gornitz and I. Fung, *Potential Distribution of Methane Hydrates in the World's Oceans: Global Biogeochemical Cycles*, Vol. 8, No. 3 (1994), pp. 335-347. •K.A. Kvenvolden, "Estimates of the Methane Content of Worldwide Gas-Hydrate Deposits," *Methane Hydrates: Resources in the Near Future?*, JNOC-TRC (Japan, October 20-22, 1988).

Figure 27. USGS Assessment of Gas Hydrate Plays and Provinces, 1995
(Trillion Cubic Feet)



USGS = U.S. Geological Survey.
Source: **Volumes:** T.S. Collett, *Gas Hydrate Resources of the United States*, Table 2. **Map:** U.S. Geological Survey, *Digital Map Data, Text, and Graphical Images in Support of the 1995 National Assessment of United States Oil and Gas Resources*, Digital Data Series (DDS) 35 (1996), Figure 5.

Field located in permafrost terrain on the eastern margin of Russia's West Siberian Basin. The Messoyakha Field was developed as a conventional gas field and has produced continuously from 1970 through 1978 and thereafter intermittently, primarily in the summer to accommodate regional industrial demand. As is normally the case, reservoir pressure declined as a consequence of production. However, the reservoir pressure remained substantially higher than normally expected. A 100-meter-thick methane hydrate zone is located 700 meters beneath the surface, and the apparent difference between the actual and predicted pressure decline behavior has been attributed to recharging of the reservoir with gas derived from pressure decline-induced decomposition of the natural gas hydrates in this overlying layer. In 1990, the gas evolved from it reportedly comprised nearly half of cumulative field production, although some investigators have expressed doubt that gas hydrate production actually occurred.

Possible Production Methods

There are at least three means by which commercial production of natural gas hydrates might eventually be achieved, all of which alter the thermodynamic conditions in the hydrate stability zone such that the gas hydrate decomposes.

- The first method is *depressurization*, akin to what may have happened at the Messoyakha Field. Its objective is to lower the pressure in the free-gas zone immediately beneath the hydrate stability zone, causing the hydrate at the base of the hydrate stability zone to decompose and the freed gas to move toward a wellbore.

- The second method is *thermal stimulation*, in which a source of heat provided directly in the form of injected steam or hot water or another heated liquid, or indirectly via electric or sonic means, is applied to the hydrate stability zone to raise its temperature, causing the hydrate to decompose. The direct approach could be accomplished in either of two modes: a frontal used to produce heavy oil, or by pumping hot liquid through a vertical fracture between an injection well and a production well.

- The third method is *chemical inhibition*, similar in concept to the chemical means presently used to inhibit the formation of water ice. This method seeks to displace the natural gas hydrate equilibrium condition beyond the hydrate stability zone's thermodynamic conditions through injection of a liquid inhibitor chemical adjacent to the hydrate.

A major disadvantage of the thermal stimulation method is that a considerable portion of the applied energy (up to 75 percent) could be lost to nonhydrate-bearing strata (thief zones). A second major disadvantage is that the producing horizon must have good porosity, on the order of 15 percent or more, for the heat flooding to be effective. These drawbacks make the thermal stimulation method quite expensive. The chemical inhibitor injection method is also expensive, although less so than the thermal stimulation method, owing to the cost of the chemicals and the fact that it also requires good porosity. Finally, the injection of either steam or inhibitor fluid tends to "flood out" the reservoir over time, which makes it ever more difficult for liberated gas to flow to the producing well bore. Depressurization will therefore likely be the first production method tested outside the laboratory. It may prove useful to apply more than onc production method in some cases.

Where Might Production First Be Attempted?

Substantial research will be necessary to determine which, if any, natural gas hydrate deposits are suited to production. In the United States, the onshore Alaskan permafrost deposits are likely to be the first ones tested for producibility, for at least two reasons.

- Site access is physically easier and probably cheaper than for the oceanic deposits.

- The hydrate stability zone occurs in rocks that have petrophysical characteristics similar to those in conventional oil and gas reservoirs, so initial production attempts will not require the degree of technological innovation that will be necessary to produce from oceanic deposits.

As regards the oceanic deposits where most natural gas hydrates are located, those in the Gulf of Mexico are likely to be the first domestic ones tested for production, albeit that they are not very well known at present. The most thoroughly studied domestic oceanic deposits are located on the continental slope and rise off the U.S. Atlantic Coast, proximate to a large and growing natural gas market. But recent sediment studies of the natural gas hydrate deposits at the Blake Ridge, located about 200 miles east of Charleston, South Carolina, have not been encouraging. Blake Ridge is a large hill-like sedimentary feature formed by drift currents in water depths ranging from 900 to 4,000 meters (3 to 13 thousand feet). The studies indicate that about 1,800 trillion cubic feet of hydrated gas plus underlying free methane exists within a 26,000 square kilometer area (10,038 square miles, approximately the combined size of the Commonwealth of Maryland and Chesapeake Bay). Assuming a 50-percent recovery factor, that is equivalent to a 40-year national supply of gas at the 1997 consumption rate.

Unfortunately from the standpoint of production potential, the sediments in the Blake Ridge area are very finely-grained, silty clays. Their bulk porosity, on the order of 55 percent, is not a constraint on producibility but their ability to conduct fluid flow (their *in-situ* permeability)[5] has not been investigated and is probably very limited. Clays characteristically have quite low permeabilities that vary a bit in accord with their water content, which in turn is dependent on pressure. At the depth of the Blake Ridge hydrate stability zone,[6] it is safe to assume that the clays are fully water-saturated and therefore have the lowest possible permeability, which is a potentially serious constraint on methane hydrate producibility. The permeabilities of most conventional reservoir rocks range between 5 and 1,000 millidarcies. A reservoir rock with a permeability of 5 millidarcies or less is considered a "tight formation." While commercial production has been obtained from rocks with laboratory-measured permeabilities as low as 0.1 millidarcy, this may have been due to fractures rather than matrix permeability. Not only do the sediments in the Blake Ridge area fall in the tight formation category, their permeability would also be

[5]A quantitative measure of the ability of a porous material to conduct fluid flow. That ability is governed by porosity, grain size of the sediment, the pores' interconnections, and physical characteristics of the involved fluid or fluids.

[6]The sea floor in the Blake Ridge area lies about 2,800 meters (9,186 feet) below the surface. The hydrate stability zone (HSZ) begins 190 to 200 meters below the sea floor (mbsf), the bottom of the HSZ is at 450 mbsf, and the underlying free-gas zone extends to at least 700 mbsf.

reduced in proportion to hydrate concentration. The implications for fluid flow and therefore production rates are not encouraging.

Other areas along the U.S. Atlantic Coast might be more suitable for production. The Blake Ridge study area comprises only 3.5 percent of the Atlantic Coast's mean estimated in-place hydrated gas volume, and not all sediments on the Atlantic shelf are identical to those at Blake Ridge. Some are coarser-grained and therefore likely more permeable.

The same is true for other oceanic gas hydrate deposits. The limited data available on the clastic sediments associated with natural gas hydrate deposits on the Cascadia margin off Oregon indicate that they have a larger grain size than those at Blake Ridge. Those located in the deep Gulf of Mexico predominantly occur in high-porosity clastic rocks, which is why the Gulf of Mexico, rather than the Atlantic or Pacific oceans, will likely be the site of the first U.S. attempt to produce oceanic gas hydrates.

Irrespective of when and where the first domestic attempts to produce methane commercially from natural gas hydrate deposits ultimately occur, it is clear that considerable research will be required to (1) ascertain the true extent of the United States' and the world's natural gas hydrate deposits, (2) determine what if any portion of these deposits may be suitable for production, and (3) develop means of economically and safely producing natural gas from those that are.

Possible Transportation Methods

If commercial production from oceanic natural gas hydrates is eventually established, there are at least three ways to transport the gas ashore: (1) by conventional pipeline; (2) by converting the gas hydrates to liquid middle distillates via the newly-improved Fischer-Tropsch process and loading it onto a conventional tanker or barge; or (3) by reconverting the gas into solid hydrate and shipping it ashore in a close-to-conventional ship or barge. The latter option was proposed in 1995 by a research team at the Norwegian Institute of Technology,[7] which determined that use of natural gas hydrate for the transportation and storage of natural gas was a serious alternative to gas liquefaction since the upfront capital costs are 25 percent lower. Yet another positive factor is that it is far safer to create, handle, transport, store, and regasify natural gas hydrate than liquefied natural gas.[8]

Safety and Environmental Concerns

Naturally occurring natural gas hydrates present both mechanical and chemical risks. Normal drilling can generate enough downhole heat to decompose surrounding hydrates, possibly resulting in loss of the well, or in loss of well control and conceivably—should the drilling be from a platform—an ensuing loss of foundation support.

While large volumes of oceanic natural gas hydrate deposits are known to have decomposed in the past absent human influence, information on their role in the global carbon cycle and global climate change is limited. It is clear that the release of large quantities of methane into the atmosphere, for whatever reason, would substantially increase its greenhouse capability since methane is 21 times more potent a greenhouse gas than is carbon dioxide. Very little is presently known about the stability of natural gas hydrate deposits, especially those located on the ocean floor, during a period of "normal" global warming, i.e., gradual and low amplitude.

Potential Hazard to Drilling Operations

Offshore operators have from time to time reported problems in drilling through gas hydrate zones. Drillers seeking conventional hydrocarbons have whenever possible purposely avoided drilling through natural gas hydrates because the process introduces two foreign sources of heat, friction and circulated drilling muds, that can cause dissociation of hydrates immediately adjacent to

[7]J.S. Gudmundsson, F. Hedvig, A. Børrehaug, Norwegian Institute of Technology, Department of Petroleum Engineering and Applied Geophysics, *Frozen Hydrate Compared to LNG* (Trondheim, Norway, January 1995); and J.S. Gudmundsson, A. Børrehaug, *Natural Gas Hydrate an Alternative to Liquefied Natural Gas*, at <http://www.ipt.unit.no/~sg/ forskning/hydrater/ paper1.html>.

[8]It has even been suggested that the produced gas be rehydrated at the sea floor and injected into large "bladders" that could then be towed to shore by a submersible "tug."

the borehole. When not avoidable, the hydrate stability zone is drilled and cased as fast as possible to minimize the risk of wall failure, perhaps leading to loss of the hole. Additionally, the free-gas zone beneath a hydrate cap can be overpressured, such that drilling into it without taking proper precautions can result in a blowout, just as is the case when conventional oil and gas drilling targets are involved. The Minerals Management Service has long maintained maps of the potential offshore natural gas hydrate occurrences to help ensure that this and the next category of risks are avoided or anticipated.

Potential Hazard to Sea Floor Structures

From 200 to 300 miles seaward of the shoreline, the continental shelves, slopes, and rises are replete with many types of man-made structures—drilling platforms, subsea well completions, pipelines, instrument housings, communication cables—and their numbers and distance from shore increase every year. Decomposition of natural gas hydrates, either gradual or rapid and either on-site or nearby, can place those structures located in sufficiently deep water at risk of damage or destruction. One such structural risk results from the fact that hydrate presence inhibits the normal compaction and cementation of sediments. If a hydrate deposit formed in the past has since decomposed, leaving behind poorly consolidated water-filled sediment, significant damage could occur if a heavy structure is placed at that location. If not recognized in a timely manner, compaction of the underlying sediment by the imposed mass, perhaps not uniformly distributed over the base area of the structure, could cause the structure to tilt or topple.

The other source of structural risk is submarine landslides. The sloping continental margins are the principal place of sedimentation and several mechanisms can trigger slope failures on them, such as earthquakes, faunal activity, and undercutting by bottom currents. At least one platform has been lost to a slide triggered by hurricane waves, and it is now known that natural gas hydrate decomposition is yet another cause of minor to major slides. Along the U.S. Atlantic seaboard, there is abundant evidence of such slope failure where, although the sea floor gently dips basinward at an average of less than 6 degrees, the slide locations are concentrated just seaward of the line at which the top of the hydrate stability zone intersects the sea floor (Figure 28). The relationship between hydrate decomposition and mass movement is also evidenced by thinning of the hydrate layer beneath slide scars. The size of these apparently Pleistocene Epoch slides is impressive. The Albermarle-Currituck Slide on the lower slope off North Carolina is 13.7 miles long, 4.3 to 7.5 miles wide, and 980 feet thick. The Cape Fear Slide, also on the lower slope, is 23 miles long, 6.2 to 7.5 miles wide, and up to 260 feet thick. The Cape Lookout Slide, which cut a shallow trough on the shelf and slope, is 174 miles long and associated with a 22-mile-wide failure on the upper rise. It was apparently triggered by a fairly small upslope failure.

Potential Hazard to Vessels and Other Floating Structures

Conceptually, the sudden release at the sea floor of large volumes of either methane or crystalline hydrate (which is buoyant in sea water) owing to the mechanical disruption of hydrated sediments (whether or not caused by rapid decomposition of the natural gas hydrate itself) could launch a mass of methane bubbles toward the surface—a methane plume. To the extent that the water column is occupied by bubbles, its bulk density is reduced and it follows that whatever is afloat above such a plume is at risk of quickly sinking.[9]

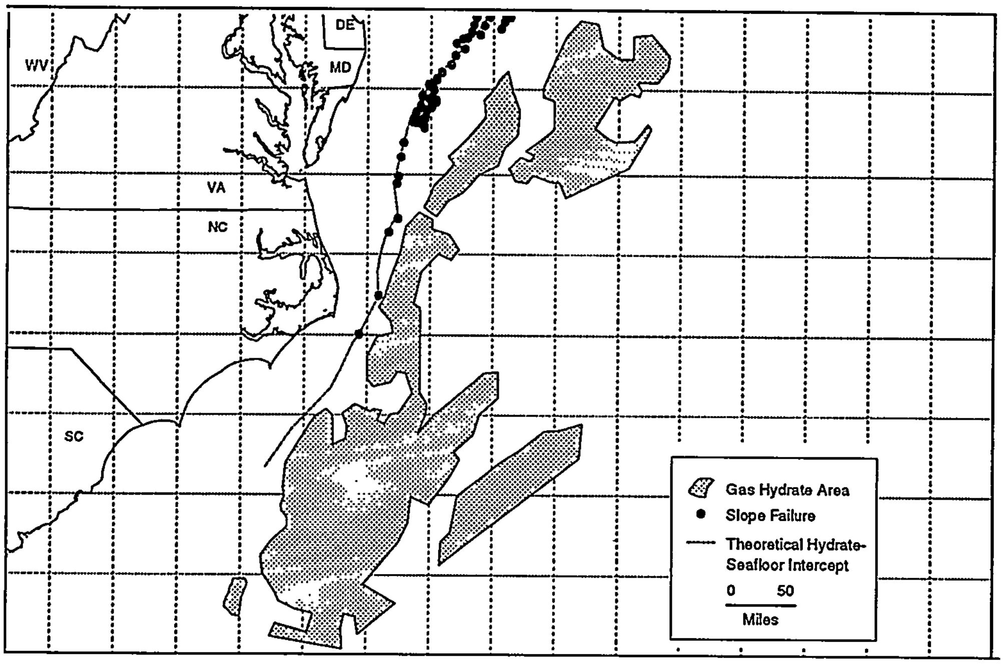
It is indisputable that massive submarine methane releases do naturally occur, although it is unclear just how sudden they are. The rate of decomposition of natural gas hydrate depends on how fast the ambient pressure and temperature conditions change. In particular, if pressure is reduced very quickly or temperature is increased very rapidly, the gas hydrate can powerfully liberate gas.

The Global Carbon Cycle Role of Natural Gas Hydrates

As stated earlier, little is known about the stability of natural gas hydrates during a period of gradual, low amplitude global warming. Various parts of the ocean floor ranging from shallow to deep water are replete with "pockmarks," roughly conical depressions up to 350 meters (1,148 feet) or more in diameter and 35 meters (115 feet) deep. The area of some pockmark fields exceeds

[9]For this reason, it has been proposed that hydrate-sourced methane plumes are responsible for what is popularly characterized as a high incidence of "mysterious disappearances without trace" in the so-called Bermuda Triangle. In actuality, such events are no more common in the Bermuda Triangle than anywhere else.

Figure 28. U.S. East Coast Locations of Marine Slides and Natural Gas Hydrate Deposits



Note: The mapped areas are those encompassing concentrated hydrates. Dispersed hydrates occur over a much larger area than mapped here.

Source: "Circumstantial evidence of gas hydrates and slope failure associations on the United States Atlantic continental margin," *International Conference on Natural Gas Hydrates*, Vol. 715 (New York: Plenum Press, 1994).

1,000 square kilometers (386 square miles). At Maine's Belfast Bay, the pockmark density is 160 per square kilometer, the pockmarks are fresh, and methane bubbles up from some of them. In the shallow Barents Sea (average depth a bit more than 1,000 feet) off Murmansk, Russia, the sea floor exhibits many pockmarks believed to have been triggered by the removal of several thousand feet of ice overburden at the end of the last glaciation. Offshore booms and mistpouffers are often heard in areas where pockmarks are common.[10] These physical and auditory signs lead to the prevailing interpretation that the pockmarks are formed by abrupt venting of gas associated with rapid methane hydrate decomposition, although no one has ever "seen" it happen.

More-or-less common and continuous releases of unknown total magnitude originate from ocean floor natural gas hydrate deposits and those associated with mud volcanoes. Gas hydrate can form as a tabular layer on the ocean floor at places where methane escapes from warm-to-hot seeps or vents into water having the necessary pressure and temperature conditions. Many examples of this occur in the Gulf of Mexico in association with small gas seeps. Since methane normally dissolves or oxidizes in free sea water, and chunks of gas hydrate can also break off into pieces that float away because they are less dense than seawater, this is possible only because the methane is constantly being replenished. In the quiescent state, a mud volcano[11] can emit thousands to tens of thousands of cubic feet of mostly methane gas per day, and in the active state, hundreds of millions of cubic feet per day. Mud diapirs are common in the Caspian and Black Seas and presumably there are many more elsewhere.

Clear indication of the delicacy of at least some natural gas hydrate deposits relative to even minor climate change has recently been provided. In 1987, gas hydrates were found on the ocean floor in 1,700 feet of water at a location in the Eel River Basin off northern California. Peter Brewer of

[10]"Boom" and "mistpouffer" are two of the many names given to strange, dull, distant, explosion-like sounds (like sonic booms) that are heard sporadically along the coasts of Europe and Atlantic Canada with no apparent cause.

[11]Mud volcanos are the vents of mud diapirs that occur in places where great thicknesses of sediments were deposited very rapidly leading to large pore fluid overpressures (pressures in excess of normal hydrostatic pressure).

the Monterey Bay Aquarium Research Institute and his colleagues, who in 1997 reinspected the site using a remotely operated vehicle, found no gas hydrates on the ocean floor although methane gas was actively seeping from the sediments. The disappearance of the ocean bottom hydrates at this location appears to have been caused by a mere 1 degree Centigrade increase of water temperature engendered by the northward encroachment of warm water associated with the recent El Niño event.

Apart from gradual, low amplitude global warming, over the past few years a growing body of evidence has been extracted from the geologic record which supports the hypothesis that very large volumes of methane arising from rapid decomposition of natural gas hydrates have from time to time been released into Earth's atmosphere, either unaltered or following natural oxidation to carbon dioxide. These episodes occurred in response to rare but similarly repeated major-scale geologic events and may have caused or significantly contributed to rapid, significant alterations of Earth's climate with attendant major consequences for the ecosystems and biota then in existence.[12]

That said, it should not be inferred that future commercial production of natural gas from natural gas hydrate deposits will necessarily either cause or contribute to their massive decomposition. The list of possible drilling and production problems is similar to that associated with conventional oil and gas wells, and production done with due care would progressively reduce the environmental risks these deposits pose.

[12]The emerging body of evidence is technically complex and scattered among many journals. The following are suggested starting points. Many other pertinent references are included in the bibliography that is provided in conjunction with the electronic version of this chapter at the Energy Information Administration's Internet site < http://www.eia.doe.gov. •Anon., "Wind of Change," *New Scientist* (May 2, 1998), pp. 35-37; •R. Monastersky, "Death Swept Earth at End of Permian," *Science News*, 153 (May 16, 1998), p. 308; •D. Harvey, *Potential Feedback Between Climate and Methane Hydrate*, <http://www.gcrio.org/ASPEN/science/eoc94/EOC2/EOC2-5.html>; •E. Nisbet, "Methane Hydrates Could Strongly Amplify Global Warming," in "Climate Change and Methane," *Nature*, 347 (September 1990), p. 23, <http://www.greenpeace.org/~climate/database/records/zgpz0687.html>; •D. Lal, "Global Effects of Meteorite Impacts and Volcanism," *Global Climate Change*, S.F. Singer, ed. (New York: Paragon House, 1989); •G.R. Dickens et al, "Dissociation of oceanic methane hydrate as a cause of the carbon isotope excursion at the end of the Paleocene," *Paleoceanography*, 10/6 (December 1995), pp. 965-971.

Natural Gas Hydrate Research

A very modest amount of natural gas hydrate research and development (R&D) has been performed to date. Most of it has been focused on gas industry operations, with the objective of finding better and/or cheaper means of ensuring that natural gas hydrates do not cause problems during the production, transportation, and distribution of conventionally-sourced natural gas.[13] The small portion directed to naturally occurring natural gas hydrates, mostly undertaken since 1980 and either U.S.-based or motivated, is summarized in the following section.

U.S. Efforts to Date

In response to recovery of a 3-foot-long oceanic natural gas hydrate-cemented core by the *R/V Glomar Challenger* in 1981, a 10-year, $8 million natural gas hydrate research program was established in 1982 by the Department of Energy's (DOE) Federal (formerly Morgantown) Energy Technology Center, with cooperation from the U.S. Geological Survey (USGS), the Naval Research Laboratory (NRL), and universities. This program:

- Established the existence of natural gas hydrates in the Kuparuk Field on the Alaskan North Slope.

- Performed studies of 15 offshore hydrate basins.

- Developed preliminary estimates of gas-in-place.

- Built the Gas Hydrate and Sediment Test Lab Instrument, operated by the USGS at the Woods Hole Oceanographic Institution, which allows generation, dissolution, and measurement of the properties of gas hydrates under controlled conditions.

- Developed production models for the depressurization and thermal modes of production.

The program was canceled in 1992 as government policy shifted to near-term conventional exploration- and production-oriented research and development. Since then, some work has continued on a small scale at the USGS, the NRL, and universities.

[13]It was not until 1946 that the U.S. Bureau of Mines produced the first definitive study.

In fiscal years 1997 and 1998, the DOE Natural Gas Supply Program provided a small amount of funding to support:

- Participation in the production testing and sample analysis of a 1,200-meter-deep well in the MacKenzie Delta of Canada that was drilled by the Japan National Oil Corporation and the Japan Petroleum Exploration Company in cooperation with the Canadian Geological Survey and the USGS[14]
- The processing and evaluation of seismic data acquired in the hydrate regions of the Gulf of Mexico
- Design of a global database on natural gas hydrates and related gas deposits
- Participation in the Colorado School of Mines industry/university gas hydrate research consortium.

In conjunction with its pursuit of a wealth of other scientific objectives, the multi-national Ocean Drilling Program (ODP), operating the *R/V JOIDES Resolution*, has drilled into or through and in part pressure-cored and logged the hydrate stability zone at several places around the globe since 1985. Other work, which until very recently consisted of small projects, was also performed during the post-1980 period in Russia, Japan, and Norway.

In late 1997, the Energy Research and Development Panel of the President's Committee of Advisors on Science and Technology recommended "a major initiative for DOE to work with the USGS, the Naval Research Lab, the Mineral [sic] Management Service, and industry to evaluate the production potential of methane hydrates in U.S. coastal waters and world wide." The President's Committee noted that these studies of methane hydrates could also lead to sequestering of carbon dioxide in hydrate form. An initial Department of Energy funding level of $44 million over 5 years was recommended, thereafter evolving to more or less per year as progress indicated. Subsequently, in May 1998, the Subcommittee on Energy, Research, Development, Production, and Regulation of the U.S. Senate Committee on Energy and Natural Resources reported out S. 1418, "The Methane Hydrate Research and Development Act of 1997." This proposed legislation would authorize DOE, in consultation with USGS and NRL, to conduct methane hydrate research for the identification, assessment, exploration, and development of methane hydrate resources. The measure is in essence just an expression of the intent of Congress; it provides no funds.

Efforts Elsewhere

Coastal nations that have few conventional oil and gas resources to draw upon are already initiating major natural gas hydrate R&D programs. Japan has mounted a program involving the government, academia, industry, hundreds of researchers, and a planned investment ranging from US$45 million to as much as $90 billion through 2005. The program initially aims to demonstrate the feasibility of commercial "harvesting" of natural gas hydrates from deposits in the Nankai Trough east of the main island, Honshu. A test well is scheduled to be drilled there by 2000. Natural gas satisfied 12 percent of Japan's energy requirements with 2.4 trillion cubic feet in 1996. Ninety-seven percent of it was imported as liquefied natural gas (LNG), making Japan the largest LNG importer in the world.

The Oil Industry Development Board of India devoted $56 million of its $420 million 1997-1998 budget to a natural gas hydrates exploitation program, the objective of which was to characterize the resource off India's coasts and develop the new technologies needed to produce it. The already approved and funded first phase will collect and interpret seismic data at water depths above 600 meters; the second phase will drill two or more test wells, probably off the west coast on the Arabian Basin margin. Natural gas use in India is primarily industrial: 44 percent for fertilizer manufacture, 40 percent for electric generation, and 5 percent for sponge iron production, with the bulk of the remaining 11 percent scattered among other industries since only a few cities have any residential/commercial gas service.

Future U.S. Research and Development

Plans for future U.S. natural gas hydrate R&D activities fall into four categories: resource characterization, production research, engineering research into safety and sea floor stability, and climate influence analysis. Many of the proposed R&D activities are itemized in *A Strategy for*

[14]The Mallik 2L-38 well was finished at a cost of $6 million in April 1998. Natural gas hydrate-cemented fluvial sands and pebble conglomerates were cored from 890 to 920 meters, the first fully confirmed natural gas hydrate retrieved from Arctic permafrost deposits since ARCO and EXXON recovered a hydrate-cemented core in 1972.

Methane Hydrates Research & Development, a 10-year "road map" of R&D activities (Figure 29) published by the Department of Energy's Office of Fossil Energy in August 1998. Quoting from the plan:[15]

> "The overall objective of the methane hydrate R&D program is to maximize the potential contribution of the huge methane hydrate resources to reliable supplies of a cleaner fuel with reduced impacts on global climate, while mitigating potential hydrates risks for marine safety and sea floor stability. This will be achieved through a four-pronged approach that will answer the questions:
>
> **How Much?**
> Determine the location, sedimentary relationships, and physical characteristics of methane hydrate resources to assess their potential as a domestic and global fuel resource.
>
> **How to Produce It?**
> Develop the knowledge and technology necessary for commercial production of methane from oceanic and permafrost hydrate systems by 2015.
>
> **How to Assess Impact?**
> Develop an understanding of the dynamics and distribution of oceanic and permafrost methane hydrate systems sufficient to quantify their role in the global carbon cycle and climate change.
>
> **How to Ensure Safety?**
> Develop an understanding of the hydrate system in near-seafloor sediments and sedimentary processes, including sediment mass movement and methane release so that safe, standardized procedures for hydrocarbon production and ocean engineering can be assured."

Resource Characterization

The uncertainty reflected by the wide range in the estimates of the Earth's total natural gas hydrate endowment underscores both the fact that a standardized assessment method does not exist and the fact that the detailed coverage is geographically spotty. Accurate identification and quantification of the Earth's natural gas hydrate deposits is a crucial precursor to all other gas hydrate R&D activities.

The principal investigative tool will continue to be seismic (acoustic) surveying, optimized to render the deposits in detail. These data can be augmented with other geophysical data, such as resistivity survey data, and with geochemical data, such as bottom water or shallow sediment methane concentration surveys (see box, p. 88). However, unlike seismic, these methods cannot alone sufficiently resolve the three-dimensional details of the deposits needed for accurate estimation of the natural gas hydrate equivalent of "gas-in-place," mapping of the distribution of gas hydrate within the hydrate stability zone, determination of its relationship to structural features, and quantification of the concentration and volume of gas in, or the permeability of, the free-gas zone.

Extensive petrophysical and field research is needed to provide the generalized models that will enable conversion of widespread seismic surveys to sufficiently accurate estimates. This work will also yield a significant body of information about the strength of hydrate-bearing sediments for use in safety and sea floor stability analysis. Efficient means of determining the composition of the hydrated gas will also have to be developed, since that has a major effect on the stability range of the hydrate, knowledge of which is prerequisite to assessment of the response of the world's gas hydrate deposits to climate change.

Production and Sea Floor Stability Research and Engineering

While the bulk of production-oriented research and engineering must await at least the early results of the resource characterization effort, a variety of site-specific geophysical and test borehole studies involving both permafrost and oceanic deposits can be undertaken now. Also, chemical, laboratory, and engineering feasibility studies can be conducted to study potential methods of production from both permafrost deposits and oceanic deposits developed in relatively low-permeability, high-clay content sediments.

As regards safety and sea floor stability, the construction of definitive hazard maps must await detailed mapping of the deposits. In the interim, engineering studies intended to optimize methods of drilling through the hydrate stability zone and to stabilize it in the vicinity of an operating well bore can be worked on. In both cases, investigations must be conducted both in the laboratory and in the field.

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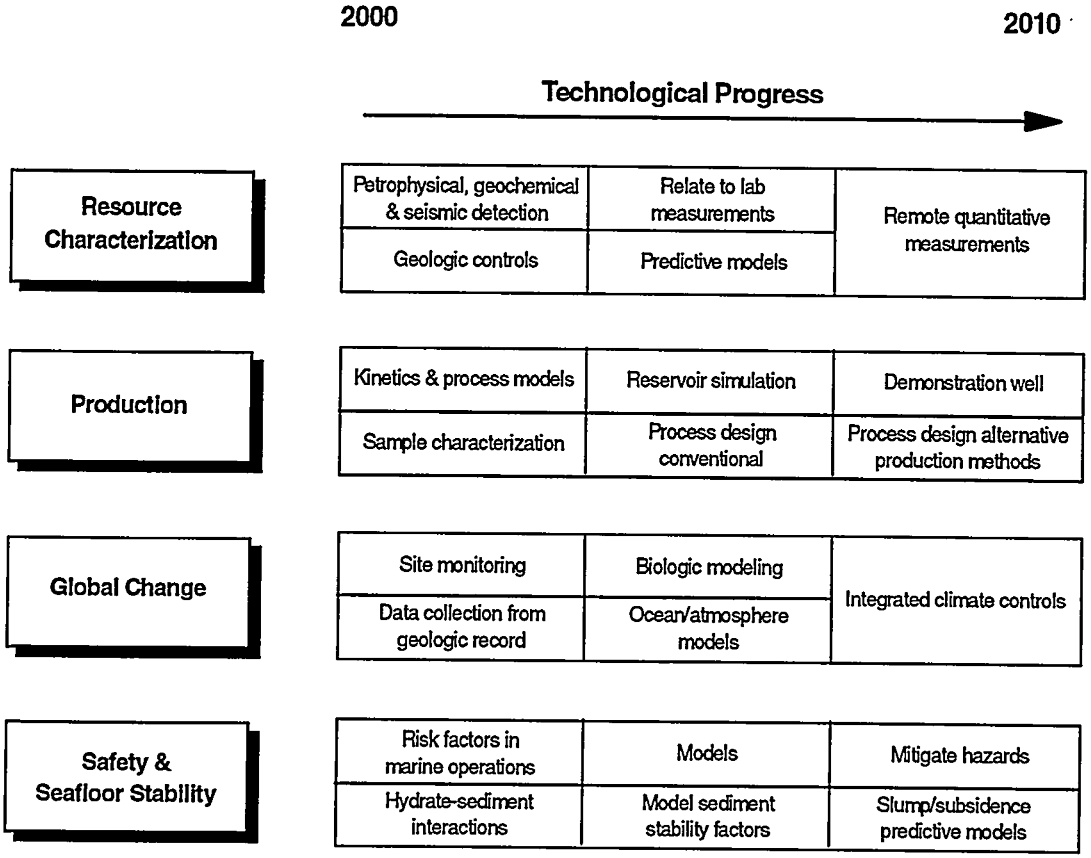
[15] U.S. Department of Energy, Office of Fossil Energy, *A Strategy for Methane Hydrates Research and Development* (Washington, DC, August 1998), p. 10.

Figure 29. The Department of Energy Proposed Technology Roadmap



Source: U.S. Department of Energy, Office of Fossil Energy, *A Strategy for Methane Hydrates Research and Development* (August 1998), p. 12.

Carbon Cycle Influence Analysis

Analysis of the role of natural gas hydrate deposits in Earth's carbon cycle involves four main activities:

- Assessment of the vulnerability of the deposits to decomposition relative to both gradual and abrupt climate change scenarios
- Assessment of the potential contribution of the evolved methane or derivative carbon dioxide (CO_2) to climate change
- Additional examination of the geologic record to detect as-yet unrecognized gas hydrate decomposition events and study their causes and consequences
- Integration of the results of the first three activities into improved, high-resolution global climate models.

In order to assess vulnerability to decomposition and the potential contribution of evolved methane and/or derivative CO_2 to global warming, it is first necessary to map the worldwide distribution of hydrate volume by depth below sea level and by gas composition, and then:

- Determine what volumes may become unstable in response to various degrees of sea level lowering
- Estimate the thermal effects of changes in water circulation in the vicinity of the deposits that may be induced by global warming and/or alteration of the oceans' thermohaline circulation
- Estimate time lags associated with the resulting explosive (due to gas overpressure) or slower in-situ decomposition process over a range of rates of sea level lowering or bottom water warming

How Are Natural Gas Hydrates Detected?

Onshore or offshore, seismic surveys are presently the only means of indirectly detecting and mapping natural gas hydrates in sediments. Unfortunately they are not perfect indicators. The vast majority of seismic surveys conducted in the search for conventional oil and gas deposits are shot at sound frequencies which are optimal for finding them, rather than at the higher frequencies needed to map gas-hydrated sediments. Thus, gas hydrate may be present in places where it does not "show" on existing seismic records. Second, most industry seismic surveys are also optimized to produce high-quality images at considerable subsurface depths rather than at the relatively shallow depths where hydrates occur. Third, substantial oceanic gas hydrates have been found in boreholes drilled in areas where no indicators appeared in coincident seismic data, even when appropriate frequencies were utilized. Fourth, the diminished reflection amplitude of the sediment layers located above the bottom simulating reflector that is characteristic of hydrate presence (similar to the ocean bottom reflection but caused by the impedance contrast between hydrated and unhydrated sediments) can result from either hydrate cementation of the sediments or in some cases from lithologic homogeneity, so it may not be entirely diagnostic as regards hydrate presence. Adjunct transient dipole electrical surveys may prove useful in interpreting the oceanic reflection seismic data, in that they can provide a measure of porosity, which correlates with the degree of hydrate cementation, as a function of the resistivity of the sediments.

Another indirect method, bathymetric mapping, can be used to infer the presence of oceanic hydrates on the basis of sea-floor features such as pockmarks and mud diapirs as indicated by the bottom relief, but whether these features reflect current or only past hydrate presence is unknowable from these data alone. Other potential means of indirect detection, such as instruments called "sniffers" towed near the sea floor that can detect the presence and measure the concentration of low molecular-weight hydrocarbons dissolved in the bottom water, have yet to be optimized for and tested in this application.

All of the presently available means of directly detecting gas-hydrated sediments require drilling. The most direct method is to retrieve cores (cylindrical samples that are at most a few inches in diameter) of the suspected gas hydrate zone, using a special drilling tool that can be sealed after coring is completed such that the core sample remains at the pressure at which it was cored during retrieval of the tool, and then retrieving the core barrel quickly enough that the temperature of the sample minimally changes. Examination of the core upon removal from the barrel quickly reveals the presence of gas hydrate based on visual detection of either its physical manifestation or voids in which it was present before it decomposed during retrieval owing to an unavoidable increase of temperature. If still present, the hydrate will immediately begin to decompose, fizzing and bubbling if in visible form or invisibly outgassing if in disseminated form. The core will be noticeably cold to the touch, since hydrate decomposition is an endothermic process. The presence of hydrocarbons as opposed to an alternative gas, such as carbon dioxide, can be ascertained by several means, ranging from lighting a match and touching it to the area of gas evolution to collection of the evolved gas for a variety of definitive chemical analyses.

Another fairly direct but less conclusive method for detection of gas-hydrated sediments involves downhole geophysical logging, which measures physical parameters of the sediments adjacent to the well bore. Resistivity is a measure of the resistance of the sediments to the flow of electric current, which is directly related to the composition of the sediments and their pore contents. Like water ice, natural gas hydrates are electrically insulating. Massive methane hydrate has a resistivity on the order of 150 to 175 ohm-meters, as opposed to methane-saturated water, which has a resistivity in the range of 1 to 3 ohm-meters. Also, one of the consequences of the formation of gas hydrate in the pores of a sediment is the exclusion of dissolved chloride salts from the hydrated volume. The remaining pore water in a hydrated zone is therefore "saltier" than that which is present in nonhydrated sediments, and its resistivity is consequently lower. Resistivity logging of the borehole can therefore be used to infer the presence of a hydrated interval, but whether the hydrate is still present or was only previously present in the interval is unknowable based on the resistivity log alone.

- Investigate the residence time of methane in the water column, its rate of conversion therein to CO_2, and the rate of transfer of both methane and CO_2 from the ocean surface to the atmosphere over a range of water and air temperatures and surface wind conditions.

As stated earlier, it appears likely that one to many significant prior global climate change events involved massive decomposition of methane hydrate deposits. Completing the record of such hydrate-associated events would yield greater insight about their frequency, causes, and effects, and that would in turn lead to a more certain projection of the likely base-line climatic future.

Considerable advancement in global climate modeling will be needed to take advantage of the new, evolving body of data on the world's natural gas hydrate deposits and their sensitivity to climate change. Today's global climate models are only capable of modeling regional-scale effects and do not model the effects of coupling between the atmosphere and the mid- and deep ocean layers. They are unable to examine interactions at the scale of concentrated methane hydrate deposits, which range from a kilometer to perhaps as much as 100 kilometers wide, are only a few hundred meters thick, and are located beneath the oceans' surface layer.

Advancements in global climate models are also necessary to improve their treatment of the effects of cloud cover and ocean-atmosphere coupling. The latter problem, which is central to assessment of the likely climate effects of methane hydrate decomposition, has two sources. The first is that knowledge of the oceans is far less than that of the atmosphere, for the most part because of the much more limited body of observations at depth. The second is that oceanic circulation is much slower than atmospheric circulation, with the thermohaline circulation taking several hundred years to a millennium to cover its full route. Coupled atmosphere/ocean climate change models must therefore be run ahead for hundreds of years to capture the oceanic changes, which imposes a tremendous computation burden.

Efforts to develop better global climate models that properly incorporate all of the major influencing factors and feedbacks and have finer geographic resolution are already underway. Some of this work is dependent upon development and proliferation of much larger and faster computers, such as the ones being built under the Department of Energy's Advanced Computing Initiative and their eventual "descendants."

Time, Talent, and Money

Future gas hydrate R&D efforts will not only vastly improve knowledge of natural gas hydrates, they will also lead to the development of new multiple-application technologies and a greatly improved understanding of the mid- and deep ocean and of the interaction of the oceans and the atmosphere. The United States proposes to begin its Department of Energy-coordinated efforts at a funding level of $0.5 million in fiscal year 1999 and $1.8 million in fiscal year 2000, far less than recommended by the panel of the President's Committee of Advisors on Science and Technology. Several other countries, including Japan India, Canada, United Kingdom, Germany, Brazil, Norway, and Russia, have active gas hydrate research and development programs and are expected to propose cooperative work as the U.S. program develops.

The large scale of the ultimately necessary R&D effort is dictated by the very widespread occurrence of these deposits, their huge size, and the magnitude and importance of their potential impacts on energy supply and the environment. While some of the required work will be relatively inexpensive, particularly some of the laboratory-based studies, most of the work will involve considerable expense owing to the necessity of extensive field operations in adverse environments and/or the necessity to invent or develop hardware that does not yet exist. The following examples are indicative of the involved cost scale:

- A research vessel suitable for extended high-seas operation charters for anything from $10,000 to $50,000 per day depending on how it is equipped. The charter rate does not include the cost of the scientific equipment and staff.

- A single square mile of 3-D marine seismic data presently costs up to $1 million to acquire, process, and interpret.

- A drilling vessel capable of operating under all conditions in the water depths of the continental slopes and rises costs between $250 and $500 million to build depending on the vessel type and its maximum depth capability, and then costs $130,000 to $150,000 per day to operate. Such a vessel will be required for some hydrate research studies. But, fortunately, a great deal of valuable natural gas hydrate field research can be done using less expensive vessels equipped with smaller drilling units (since most of the natural gas hydrate in the U.S. economic zone is less than

1.5 kilometers below the surface and periods of very inclement weather could in most cases be avoided).

It is quite clear that the requisite R&D programs are so large, lengthy, and costly that the commercial sector may not be able to undertake them even if the programs' scope were reduced to the matter of gas production alone.

Outlook

The Earth's natural gas hydrate deposits potentially offer a vast new source of low-polluting, carbon-based energy that could provide a comfortable and very much needed bridge to an eventual carbon-free energy future. Because so little is known about them and their producibility, they are not at present included as a source of methane in estimates of the technically recoverable natural gas resource base, nor are they included as a source of methane in existing energy models and forecasts. A modicum of increased knowledge of the deposits, coupled with a few breakthroughs regarding their production, could dramatically alter this situation.

These deposits may also be a periodic source of rapid, naturally-caused releases of large volumes of greenhouse gases into Earth's atmosphere. Much more needs to be learned about Earth's natural gas hydrate deposits before their role in the global carbon cycle will be sufficiently understood relative to both slow and abrupt climate change events.

4. Offshore Development and Production

Natural gas production in the Federal offshore has increased substantially in recent years, gaining more than 400 billion cubic feet between 1993 and 1997 to a level of 5.14 trillion cubic feet. Virtually all U.S. offshore production flows from the Outer Continental Shelf (OCS) of the Gulf of Mexico, which accounted for 27 percent of dry natural gas production from the Lower 48 States in 1997 and 18 percent of proved reserves. This trend is expected to continue, particularly as innovative technologies have improved the economics of offshore investment and opened up development in the deeper waters of the Gulf.

- Recoverable gas resources in the Gulf of Mexico (as of 1995) are estimated to be 96 trillion cubic feet (Tcf) in undiscovered fields with an additional 37 Tcf to be proven in already known fields. The ultimate volume and timing of recovery from these target volumes will depend on future economics and the evolving infrastructure.
- Industry success in the offshore, given the relatively low natural gas prices of the past 10 years, is due to achievements in cost management, reductions in project cycle time, and increases in well productivity.
- Fields in the deep water supplied only 3 percent of natural gas production from the Federal offshore in the Gulf of Mexico in 1997, but the average annual growth in deep-water gas production was 46 percent between 1990 and 1996.
- In 1989, the deep-water record for production was the Jolliet platform in 1,760 feet of water. This mark has been eclipsed by the Mensa project in more than 5,300 feet of water, which initiated production in July 1997. Mensa shattered the then-record for the Gulf of 3,214 feet held by the Ram-Powell tension leg platform.
- The Deep Water Royalty Relief Act (DWRRA), signed into law by President Clinton in November 1995, improved the economics of deep-water production. The fraction of blocks in water deeper than 800 meters (2,526 feet) receiving bids in 1994 was less than 10 percent of all bids for blocks in the Western and Central Gulf of Mexico, but by 1997, blocks at this water depth received more than half the bids. Bids for the deepest tracts offered in sale #169 for the Central Gulf of Mexico in 1998 remained stable, while bids for shallow-water tracts plummeted by more than 50 percent.
- Overall, offshore gas production from the Gulf of Mexico is expected to be between 3.7 and 7.2 trillion cubic feet by 2002. The key element in any outlook is the production trend for shallow-water fields, which is consistent with the relatively large volumes flowing from that region compared with the deep-water fields.

The near-term outlook for natural gas production from the offshore regions of the Lower 48 States depends on a number of factors, but primarily the prevailing economics. The relatively low oil and gas prices for much of 1998 have resulted in reduced drilling in the shallow waters of the Gulf. While this is of concern in the near term, gas supplies from the Gulf over the long term undoubtedly will be very large given the extremely large estimates of recoverable resource volumes.

The offshore regions of the Lower 48 States are an important source of domestic energy supplies. Production from Federal and State waters provided about 29 percent of total dry gas production in the Lower 48 States in 1997, with 95 percent of this total from the Outer Continental Shelf (OCS) of the Gulf of Mexico alone.[1] This situation stands in impressive contrast to expectations just two decades ago when the Gulf of Mexico was considered to be a mature oil and gas region with limited potential for

[1] Figures derived from *U.S. Crude Oil, Natural Gas, Natural Gas Liquids Reserves, 1997 Annual Report,* Energy Information Administration, DOE/EIA-0216(97) (Washington, DC, September 1998).

further discovery and development. In fact, the region was considered so lacking in promise that it was then called the "Dead Sea." A December 1973 report by the U.S. Department of the Interior stated that all potentially productive blocks in water depths up to 600 feet in the Federal Offshore Louisiana would be leased by 1978 and all exploration and development would be completed by 1985.[2] However, development of shallow prospects continued, and by the late 1980s and early 1990s improvement in existing technologies and the introduction of new technologies enabled the industry to access prospects in the deep-water areas[3] and the subsalt plays.[4]

The economics of deep-water activities has improved to the point that operators have continued with project development despite the recent downturn in prices for crude oil and natural gas, reflecting a very healthy and improving environment for oil and gas production and development. Deep-water fields require relatively long lead times for development and substantial capital investment even at an early stage, and they have relatively low operating costs. All of these factors encourage continued development and operation even though the prevailing economics may seem inadequate.

Although this chapter does not include an economic analysis of the impact of recent price declines, it appears the recent drop in oil and gas prices may have only a minimal impact on the long-term outlook for offshore production unless the low prices persist for an extended period. There has been some reduction in shallow-water drilling activity recently, but development of deep-water projects proceeds. The expected expansion of deep-water field production can help to offset declines in shallow-water operations, but shallow-water fields yield the vast portion of the gas total so some falloff may be expected.

[2]U.S. Department of the Interior, Bureau of Mines, *Offshore Petroleum Studies Estimated Availability of Hydrocarbons to a Water Depth of 600 Feet from the Federal Offshore Louisiana and Texas Through 1985* (December 1973).

[3]For this report, *deep waters* pertain to water depths of greater than 1,000 feet (approximately 305 meters), which establishes the effective economic barrier between the use of fixed platforms and the new technology of the deep-water production systems. There are different regulatory requirements by the Minerals Management Service (MMS) for deep-water projects in depths of 1,000 feet or more. For example, operators have to file Deep Water Operating Plans with MMS for projects beyond 1,000 feet of water depth and for all subsea completions.

[4]About 85 percent of the continental shelf in the Gulf of Mexico is covered by salt deposits, comprising an extensive area for potential hydrocarbon development. The salt layers pose great difficulty in geophysical analysis and drilling through and below salt columns presents unique challenges.

This chapter analyzes recent production trends in the offshore Gulf of Mexico to provide an indicator of expected production levels from the shallow-water regions and from known deep-water fields. The economics of offshore projects is examined by reviewing and assessing trends in costs and productivity. The chapter also discusses the effect of environmental laws and regulations on offshore activities, especially as they pertain to deep-water operations.

The oil and gas industry has been active in the offshore regions of the United States throughout much of this century (see box, p. 93). During that time, the industry often found itself as a critical element in the ongoing debate regarding the best policy for managing offshore resources. Sometimes the goals of supplying energy and preserving water and air resources have been perceived as conflicting. In fact, over time, certain laws and Congressional or Presidential actions have limited activities in offshore areas or explicitly blocked them at least temporarily. At present, oil and gas drilling is prohibited along the entire U.S. East Coast, the west coast of Florida, and the U.S. West Coast except for some areas off the coast of southern California. Thus, today virtually all offshore activity is confined to the Gulf of Mexico, and offshore development can be considered almost synonymous with that of the Gulf.

Production from the Gulf of Mexico

The Federal offshore region of the Gulf of Mexico has become an increasingly important source of natural gas, accounting for nearly 27 percent of dry natural gas production in 1997. This is in sharp contrast to earlier years. Gas production in the mid-1950s from the Federal waters of the Gulf of Mexico was relatively small, with only 81 billion cubic feet (Bcf) produced in 1955, or less than 2 percent of the volume produced in the mid-1990s. Production surged dramatically after the mid-1950s, exceeding 1 trillion cubic feet in 1966 and achieving a then-record 4.99 trillion cubic feet in 1981 (Figure 30). After the surge in the early 1980s, offshore gas production declined until 1986, after which it gradually has grown to a record level of 5.14 trillion cubic feet in 1997.

The success in offshore production is expected to continue, but the recent downturn in economic conditions may hinder realization of production. Overall, offshore gas

Offshore Milestones

The oil and gas industry in 1997 celebrated the golden anniversary of a major milestone for activities in offshore waters. In 1947, Kerr-Mcgee, Stanolind, and Phillips Petroleum Company drilled the Kermac 16 in 20 feet of water in the Ship Shoal Block 32 field. This field is located 43 miles southwest of Morgan City, Louisiana. Other wells were drilled in water as early as 1905 in Southern California, but the Kermac 16 was the first well drilled out of the sight of land. Sixteen 24-inch piles supported the platform, which produced 1.4 million barrels of oil and 37 million cubic feet of gas. This platform produced until 1984.

Another milestone event for the Gulf of Mexico took place in 1953 when the first movable offshore drilling rig, called "Mr. Charlie," was built, which was a major advancement. That was also the year the State and Federal boundaries were defined according to the U.S. Submerged Land Act. The first offshore sale of oil and gas leases also was held in 1953. Other notable events after 1953 are as follows.

- The first semi-submersible drilling rig was launched by Shell in 1962.
- The first subsea production system was installed for Shell in 1972 in Main Pass Block 290.
- The Cognac Platform was installed for Shell in a record 1,025 feet of water in Mississippi Canyon block in 1979.
- In 1988, Shell installed the Bullwinkle platform, the world's tallest standing structure, to produce in 1,353 feet of water, and Placid Oil first used a floating production system in Green Canyon Block 29.
- In 1989, Conoco and Texaco established production at their Jolliet tension leg platform (TLP), located in 1,760 feet of water.
- The Deep Water Royalty Relief Act (DWRRA) was passed in 1995, which mandates royalty relief for certain leases in the Gulf of Mexico (the DWRRA is described in more detail later in the chapter).
- Production began in June 1998 from Shell's Mensa field in 5,376 feet of water, which established the then water-depth record for production. This project included a world record 68-mile subsea tieback to transport production to an existing platform in shallower water.

production from the Gulf of Mexico is expected to range between 9 and 20 Bcf per day by the end of 2002, reflecting the considerable uncertainties involved. The near-term production outlook is affected greatly by recent development and the expected development of the inventory of waiting prospects. The expected volumes of recoverable natural gas resources are significant for the longer term. The Minerals Management Service published an estimate for total natural gas resources in the Federal waters of the Gulf of Mexico of 275 trillion cubic feet (Tcf), of which 95.7 Tcf remain as conventionally recoverable volumes in undiscovered fields as of January 1, 1995.[5] This bountiful endowment provides opportunities for sizeable gas supplies from this area in the longer term.

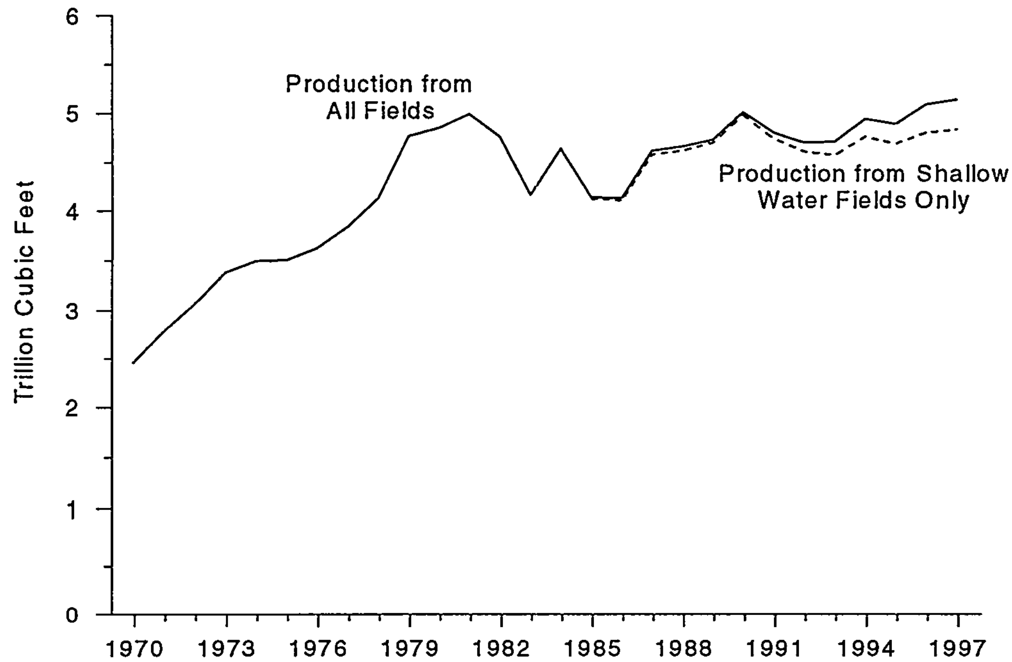
Factors Affecting Production

An important factor contributing to the recent production growth has been impressive technological advances, which over time have extended the industry's reach into areas previously inaccessible because of major technical and operational obstacles, such as deposits in waters greater than 1,000 feet in depth and subsalt deposits.[6] Despite these opportunities in more challenging locations, the major share of gas production to date has flowed from

[5]Minerals Management Service, *Summary of the 1995 Assessment of Conventionally Recoverable Hydrocarbon Resources of the Gulf of Mexico and the Atlantic Outer Continental Shelf*, OCS Report MMS 96-0047 (January 1997).

[6]Subsalt accumulations can be found in structural traps below salt sheets or sills, which comprise an impermeable barrier that entraps the hydrocarbons in potentially commercial prospects.

Figure 30. Total Gas Production from Federal Waters of the Gulf of Mexico, 1970-1997



Sources: **1970-1992:** Minerals Management Service. **1993-1997:** Energy Information Administration, Office of Oil and Gas.

those deposits in shallow waters. Thus, the most fruitful application of new technologies, in terms of gas production, has been in maintaining or increasing flow from areas that already were subjected to considerable exploration and developmental activity. Deep-water gas production, which was 143 Bcf in 1997, or 3 percent of Gulf of Mexico OCS production, remains a significant but limited fraction of the total. Subsalt prospects retain considerable promise for the future, but successes have been limited so far. While projects such as the Mahogany and Tanzanite fields are encouraging, the modest number of subsalt projects overall and the relatively slow pace of development are indicative of the obstacles that remain to be resolved.

The major factors affecting near-term offshore production include the availability and utilization of drilling rigs, trained personnel, and transportation capacity. The circumstances for these factors differ for the shallow- and deep-water areas.

Drilling Rigs

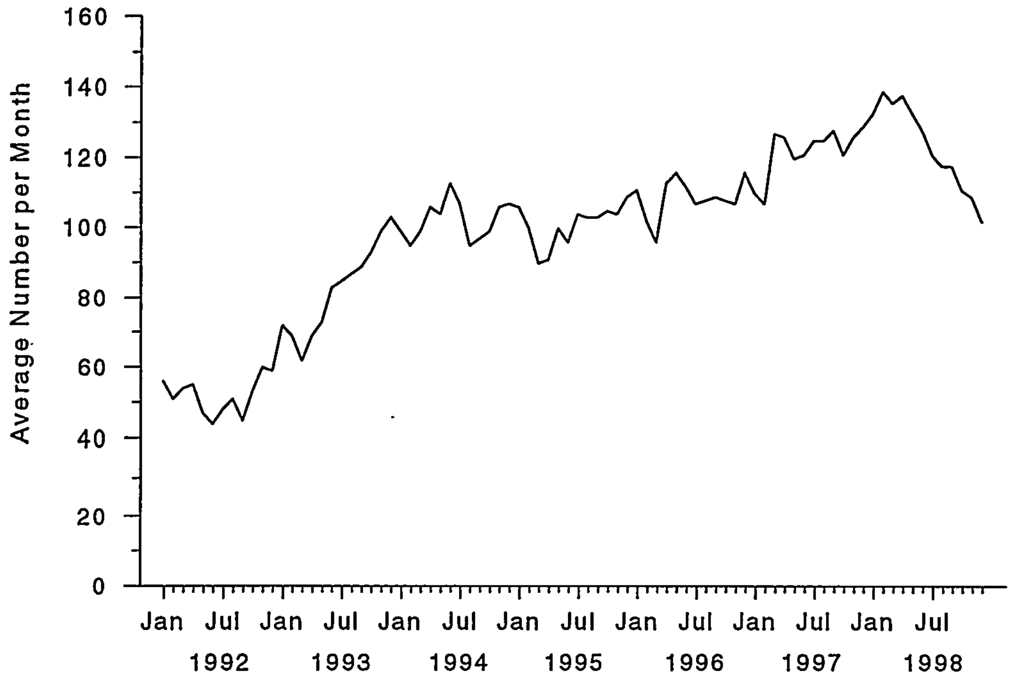
The number of drilling rigs employed in the offshore during the past few years has grown from an average of 52 in 1992 to 124 in 1998 (Figure 31). However, with the recent decline in prices for both natural gas and crude oil, the number of active rigs has declined 27 percent from the peak of 139 in February to 102 in December. The ratio of active to contracted rigs in the Gulf of Mexico (all depths) is at an all-time low.[7] One operator estimated that the cost for shallow-water rigs would decline by roughly 45 percent from mid year to the end of 1998.[8] Unfortunately these usually attractive costs are not expected to stimulate much additional industry activity given that they are being offered in an attempt to maintain activity levels. Utilization of deep-water rigs, however, remains at relatively high levels despite the decline in price for output.

Operators of deep-water projects appear to be proceeding with a longer-term planning horizon. Deep-water drilling rigs are generally under contract through 2001 or 2002, by which time prices may recover to levels comparable to those in recent years. These factors have contributed to continued development in deep waters, however, operators are not necessarily compelled to proceed aggressively. An operator with flexibility in project development may

[7]One reason for the idle contracted rigs is to avoid incurring the other variable costs associated with drilling.

[8]Karen Santos, "Less Jack for Rigs," *Houston Chronicle* (July 14, 1998).

Figure 31. Monthly Offshore Drilling Rigs, 1992-1998



Source: Energy Information Administration, *Monthly Energy Review* (various issues).

choose to extend a project's schedule, and planned projects that have not begun may be delayed until favorable economic conditions return or are expected to return. If such delays become common, the sequence of new production may not be timely enough to offset declines in regional production volumes. However, it appears likely at present that the industry is proceeding with deep-water development activity. The number of drilling rigs capable of operating in deep waters would be the constraining factor if interest in project development surged, because the inventory of available prospects is more than sufficient to utilize available equipment and personnel.

Before the recent falloff owing to low prices, the increase in drilling activities had created tight markets for rigs in the Gulf of Mexico, with signs of rig scarcity appearing regularly. Contracts for two Global Marine jack-up rigs in 1997 were secured within a week of the company announcement of their availability.[9] Deep-water rig rates had increased tremendously during the past year and rapid development of the set of pending deep-water prospects would tend to drive well drilling costs eventually to prohibitive levels. A number of new drilling rigs are being built, but unless the industry sees very high utilization rates or guaranteed contracts are offered to motivate new rig manufacture, a reluctance to build in the industry has lingered limiting the amount of new rig construction.[10]

Availability of Trained Personnel

Another important factor in production levels is the availability of personnel, with respect to both numbers and skill levels. The limited number of trained and experienced offshore workers also is likely to constrain rapid offshore development. Previous cuts in personnel have reduced the numbers of skilled workers, and also have discouraged growth in the size of the workforce. Even if higher wages were offered to entice new workers, new experts and workers require time to train. The scarcity of qualified personnel willing to take the risk in such a cyclic industry

[9]Sheila Popov, "The Tide Has Turned in the Gulf of Mexico," *Hart's Petroleum Engineer International* (October 1997), pp. 25-35.

[10]A major factor impeding the construction of new rigs is the very high cost. Upgrading an existing rig incurs costs exceeding $100 million, according to "Deepwater semi upgrade nearing completion," *Oil and Gas Journal* (November 10, 1997), p. 40.

seems to have more significance for the future than previously seen, according to anecdotal evidence.[11]

Transmission Capacity

An essential factor needed for supporting offshore gas supply operations is adequate transmission capacity to move supplies to onshore pipelines and then to market. Additional capacity of 2.6 billion cubic feet (Bcf) per day was completed in 1998 to increase flow to onshore Louisiana. This flow rate is the equivalent of 4 percent of total U.S. gas production. Although it is generally considered that the Gulf of Mexico transportation system is virtually full, claims of actual capacity constraints have not arisen to date. Further, new and expanded capacity in 1999 and 2000 is expected to total 2.0 Bcf per day at an estimated cost of more than $410 million.[12] While logistical difficulties may remain, no major bottlenecks appear likely in moving gas onshore in the near term, although requirements over the longer term are expected to be extensive. One study estimated the cost of new transportation pipelines in the offshore would exceed $7 billion during the next 15 years.[13]

Deep Water Royalty Relief Act

One sign favorable to near-term supply prospects is the resurgence in offshore blocks receiving bids in recent leasing sales. Lease bids received by the Minerals Management Service (MMS) for Gulf of Mexico tracts offered in Federal lease sales averaged about 959 per year from 1988 to 1990. From the relative high point of 1,079 tracts receiving bids in 1989, however, bidding declined to a level of 212 in 1992. Beyond 1992, bidding increased through 1997 when numbers reached their highest levels in the past 10 years. In fact, the 863 tracts receiving bids in 1995 were only slightly below the 943 bids received in the previous 2 years combined.

The upward trend in lease bidding was stimulated further by the passage of *The Outer Continental Shelf Deep Water Royalty Relief Act* (DWRRA) in November 1995. This legislation mandates royalty relief for certain oil and gas leases in at least 200 meters of water (656 feet) in the Gulf of Mexico.[14] The deep-water zone is further divided into three parts for different levels of royalty relief (Table 9). Production in excess of the stated levels is subject to standard royalty charges. An eligible lease is one that results from a sale held after November 28, 1995, of a tract 200 meters or deeper, lying wholly west of 87 degrees 30 minutes west Longitude, and is offered subject to royalty suspension volume authorized by statute. The DWRRA seems to have stimulated interest in deep-water prospects. Although the resurgence of offshore bidding began before the DWRRA took effect, even the 863 bids in 1995 were more than 20 percent below the 1,079 bids received 6 years earlier (Figure 32). There is a distinct upward shift in the trend for the number of bids received in 1996 when the DWRRA took effect.

Although progress in accelerating development schedules for deep-water projects has improved, they generally still require 2 to 4 years. New fields discovered in the next few years and developed according to a typical schedule likely would not initiate production until after 2002. Thus, future production from deep-water fields in the Gulf of Mexico over the near term depends heavily on discoveries to date.

Near-Term Production Outlook

A sense of optimism is a common element in the outlook for gas production from the Gulf of Mexico OCS, particularly in light of a number of large deep-water projects that are awaiting development. But the immediate outlook for gas production is more uncertain now than in recent years because of some decline in shallow-water activities. The gas production trends to date indicate that the bulk of production in the offshore will flow from shallow-water fields. Thus, if shallow-water fields do not maintain their level of production, the offshore Gulf of Mexico total likely will decline as reductions in the much larger shallow-water production rates would more than offset anticipated new deep-water gas production. Significantly larger volumes from the Gulf would depend heavily on new reserves from fields in both shallow and deep waters.

Overall, offshore gas production from the Gulf of Mexico is expected to range between 10 and 20 Bcf per day by

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[11]Limitations of personnel and equipment are not limited to the offshore. One company claims that it is unable to "utilize its full complement of drilling rigs...due to the lack of qualified labor and certain supporting equipment not only within the company but in the industry as a whole." Further, the company expects this to continue "throughout 1998 and into 1999." Unit Corporation, a contract drilling firm, as reported in their 10-Q report, June 30, 1998.

[12]Additional detail on transmission projects can be found in Chapter 5, "Natural Gas Pipeline Network: Changing and Growing."

[13]Estimate cited in "INGAA Foundation Releases Updated Study On Gulf Of Mexico Resources And Pipeline Infrastructure," *Foster Report*, No. 2185 (June 4, 1998).

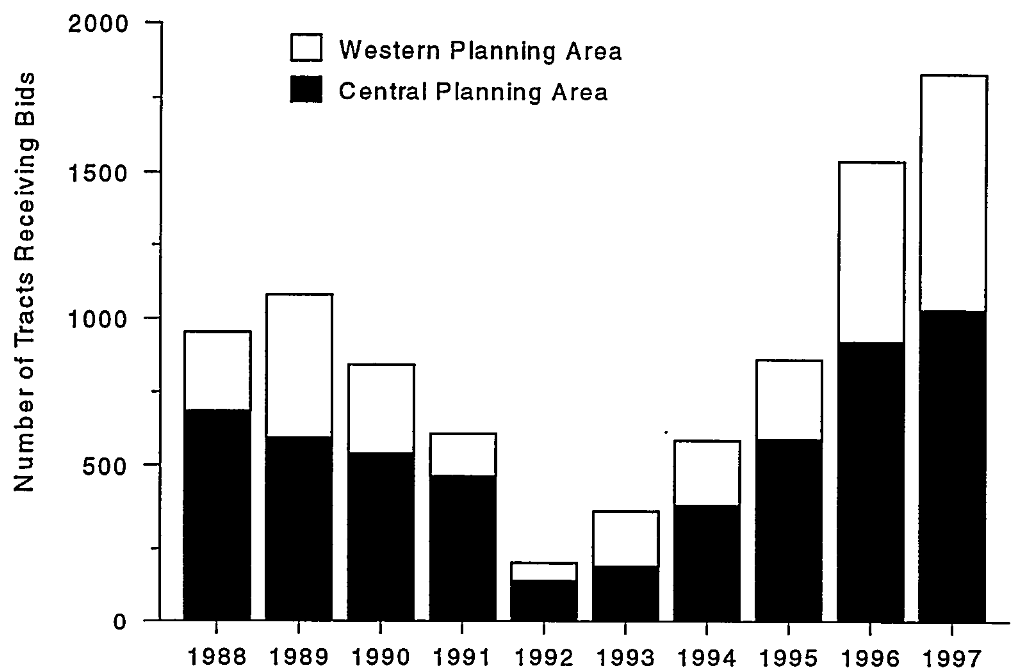
[14]The footage equivalents of metric measures throughout this report are determined on the basis of 1 meter equal to 39.37 inches. Source: *Webster's New Collegiate Dictionary*, G. & C. Merriam Company (1976).

Table 9. Offshore Oil and Gas Volumes Exempt from Royalty Charges Under the *Outer Continental Shelf Deep Water Royalty Relief Act*

	Exempt Volumes	
Depth	Barrel of Oil Equivalent (million barrels)	Equivalent Gas Volume (billion cubic feet)
200-400 meters (656-1,312 feet)	17.5	98.5
400 to 800 meters (1,312-2,625 feet)	52.5	295.6
>800 meters (2,526 feet)	87.5	492.6

Note: The barrel of oil equivalent volumes were converted into billion cubic feet based on assumed heat content of 5.8 million Btu per barrel of oil and 1,030 Btu per cubic foot of gas.
Source: Energy Information Administration, Office of Oil and Gas.

Figure 32. Gulf of Mexico Bidding Trends, 1988-1997



Note: See Appendix A for maps of the Western and Central Planning Areas of the Gulf of Mexico.
Source: Minerals Management Service, *Gulf of Mexico Projections 1998-2002*, Figure 5.

2002 (see box, p. 98). The possibility of large additional production volumes has important implications for markets in the Gulf Coast region. Realization of the high estimate (20 Bcf per day) means that roughly 2 trillion cubic feet of additional production would flow into onshore markets by 2002. Introduction of such large volumes in a relatively short period would have a significant impact on regional gas markets. This volume is equivalent to 10.6 percent of total gas produced in the United States during 1997. However, the optimistic production projections may not reflect a number of practical considerations. Any large incremental volumes from deep-water fields depend on development of both the projects themselves and the associated infrastructure, so these volumes are less certain than those from shallow-water fields.

The shorter lead times and relative availability of existing infrastructure in shallow-water areas facilitate quicker project development. Consequently, there is not a significant backlog of pending projects, and shallow-water development through 2002 will depend primarily on expected reserve additions. The pace of reserve additions is conditional on both the level of drilling and the size of expected discoveries. Annual reserve additions are unlikely

Outlook Methodology

The outlook for offshore production in this chapter was developed using a scenario approach, in which low and high cases were developed by altering selected technical assumptions to demonstrate the range in results under reasonably possible outcomes. Projections for gas and oil production were developed to account for both nonassociated (NA) gas and associated-dissolved (AD) gas. Most gas production in the deep-water regions has been as a coproduct of oil projects, so AD gas projections are particularly important for this area. The projections were determined from available data on recent production, proved reserves, and reserves additions, as well as a number of related parameters. The assumed technical parameters determine the projected production without explicitly incorporating current or expected prices into the analysis. Actual production likely will differ from the projections owing to unforeseen circumstances, such as variation in project timing, available transportation capacity, and fluctuations in market demands.

Projected production in each scenario consists of three elements: flows from currently producing fields in both shallow and deep waters, volumes from known deep-water fields undergoing or awaiting development, and production from new field discoveries, which were derived from available offshore reserves and production information.

Low-case production from currently producing fields was based on an analytical method using the proved reserves estimates, both initially and as they are expected to "grow" over time. The reserves available in each time period are produced according to the measured reserves-to-production (R/P) ratio, which is based on historical data. Reserve growth was fitted to historical data and estimated using Minerals Management Service (MMS) Gulf of Mexico ratios. The natural decline in production performance more than offsets the gains from reserves growth, resulting in a declining production profile. The high case for currently producing shallow- and deep-water fields was based on the assumption of stable production. Detailed parameter assumptions were not established for this case, but it is deemed reasonable as a continuation of the general trend for production from shallow waters during recent years.

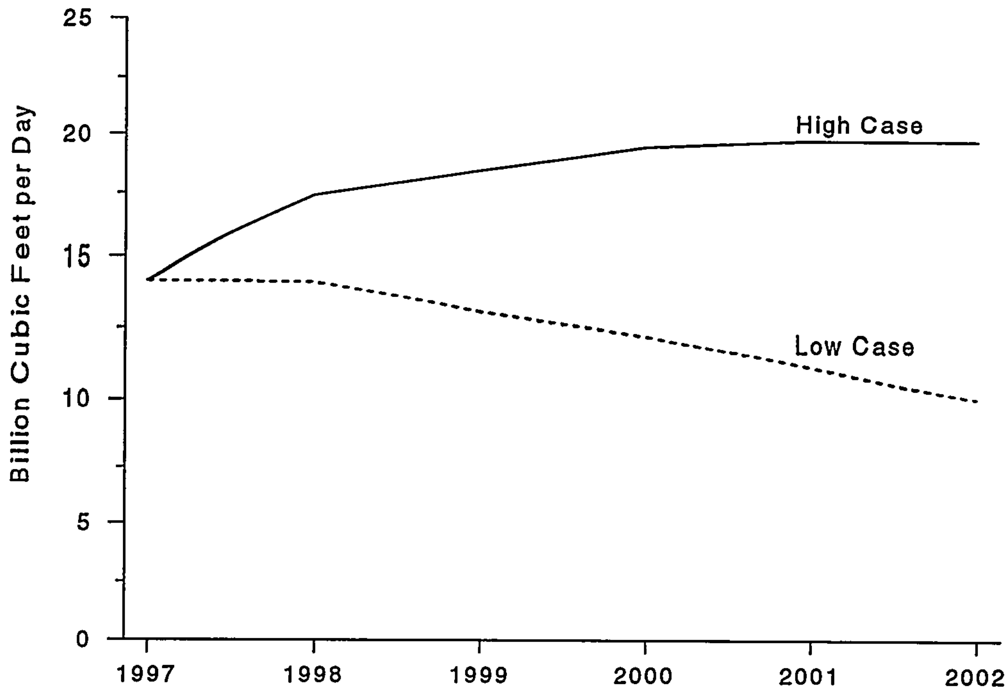
Volumes from known deep-water fields undergoing or awaiting development were incorporated into the projection according to the announced schedule. The third element, production from new field discoveries, was derived from available offshore reserves and production information. New field discovery volumes occur at the rate of 1.1 trillion cubic feet per year, which is estimated from recent trends in the data. These volumes were adjusted to account for additional recovery growth and then produced according to the decline rate indicated by recent R/P ratios.

The high-case scenario results in increased offshore natural gas production up to 20 billion cubic feet (Bcf) per day by 2002, although it also could decline significantly to 10 Bcf per day (Figure 33). The gas production outlook clearly depends upon expected shallow-water production to a great extent. This is due to the relative size of the volumes produced in shallow and deep fields. Reductions in the much larger shallow-water production rates can more than offset anticipated new deep-water gas production, as seen in the low case. Total production in the low case declines even though new deep-water projects may add more than 1.9 Bcf per day by 2002. The importance of shallow-water production is significant in light of the recent reduction of drilling efforts in these areas. The large incremental volumes from deep-water fields depend on development of both the projects themselves and the associated infrastructure, so these volumes are less certain than those from shallow-water fields.

to increase significantly from historical levels because of the expected declines in average field size and the reduced levels of drilling in shallow waters.

Development of pending deep-water projects will offset some portion of any decline in shallow-water production—deep-water projects scheduled for initial production by 2002 may add more than 1.9 billion cubic feet per day—but potential development in the deep waters cannot proceed unconstrained. The number of rigs capable of drilling in deep water is limited. In 1996 and 1997, 1,531 leases were granted in deep-water tracts with 10-year lease terms and 245 tracts with 8-year terms. As the industry has only approximately 39 semi-submersibles and ships, with a capacity to drill four wells per year for each drillship, it would require more than 11 years to drill just a single well in each lease. Given the uncertainties surrounding offshore development, any projections are subject to wide variation.

Figure 33. Projected Gas Production for the Federal Gulf of Mexico



Source: Energy Information Administration, Office of Oil and Gas.

Also, as noted earlier, factors contributing to uncertainty surrounding production outlooks for the Gulf of Mexico are not limited to geologic risk, but include the relative economics and available equipment and personnel. Perpetuation of the very high growth rates of the 1990s implies yearly increases in incremental production that would be a challenge in terms of available personnel and equipment and the required infrastructure.

The deep-water regions to date have yielded fields with very large recoverable gas volumes. Estimates for potential production have been quite optimistic regarding oil, with growth in natural gas lagging behind. As one example, the Minerals Management Service (MMS) projected, in a high case, crude oil production from the entire Gulf of Mexico in 2002 of 1,976 thousand barrels per day, which is a virtual doubling of its estimated December 1996 basis of 1,047 thousand barrels per day. Even in the low case, MMS still projected a gain of 59 percent by 2002 relative to the end-of-1996 volume.[15] MMS projected that gas production in the high case would rise by 24 percent, to 17.5 Bcf per day, during the same period. The conditions of the MMS low case would produce instead a decline to 12.4 Bcf per day by 2002.[16]

The low- and high-case scenario projections developed by the Energy Information Administration (EIA) for this report show a wider range of possible variation than the MMS low- and high-gas scenarios. These differences arise for a number of reasons. The MMS analysis was based on data through June 1997, while the EIA scenarios incorporate the latest information and data available for offshore activities. These data and a greater production decline rate in the EIA analysis result in lower projected gas production in the low-case scenario, with EIA's 10.1 Bcf per day in 2002 almost 20 percent below the MMS estimate. In contrast, the EIA high-case scenario shows an estimated 19.8 Bcf per day, which exceeds the MMS value by 12 percent. The EIA estimate reflects the impact of more optimistic assumptions regarding the impact of field development on expected reserves and the likelihood of new discoveries.

The low- and high-case scenarios provide a reference range of likely outcomes for offshore production, which

[15]All oil production figures in this chapter include lease condensate liquids.

[16]Minerals Management Service, *Gulf of Mexico Outer Continental Shelf Daily Oil and Gas Production Rate Projections From 1998 Through 2002*, OCS Report MMS 98-0013 (February 1998).

can be used to assess offshore outlooks. For example, the reference case in EIA's *Annual Energy Outlook 1999 (AEO99)* shows offshore Gulf of Mexico gas production initially declining by 13 percent from 1997 to 2000, then a reversal in trend leads to production recovering to the 1997 level by 2002. While the *AEO99* volumes in the later years are well within the expected range, production levels in 1998 and 1999 are below the low-case scenario. This discrepancy in the analyses is attributable mainly to a difference in the expected timing of changes driven by the recent severe drop in prices. The *AEO99* reference case and the low-case scenario are consistent after adjusting for this lag.

The 1998 price decline caused significant declines in certain industry activities, such as drilling and field development, however, the lag between these changes and production apparently is more extensive than previously thought. The latest information from operators indicates that, despite reductions in overall supply activities in the offshore Gulf of Mexico, industry endeavors have yielded sufficient new production volumes to offset any decline from 1997 to 1998. (Production from the offshore is expected to begin to show more dramatic declines in 1999.) The extent of the response lag was not known at the time of the AEO99, so this aspect of offshore supply was not incorporated into that analysis. The response lag between reduced industry activities in the offshore and the impact on gas supplies apparently has obscured important trends underlying present and future markets. As domestic gas supplies decrease, prices should rise, although gas supply increases expected elsewhere, including Canadian supplies,[17] should mitigate potential increases in wellhead gas prices.

The near-term outlook provides a number of insights regarding the interplay of the underlying attributes of the industry. The level of reserve additions assumed in each case serves as a limiting factor that cannot support continued production growth. Expanding production volumes require a corresponding growth in the sequence of reserve additions, otherwise reserves are not replenished and the reserve stock declines. Further gains in production might be achieved with higher extraction rates from the existing proved reserve stock, but production growth as a result of such attempts is not sustainable.

[17]A discussion of pending projects expected to increase U.S. imports of Canadian gas can be found in Chapter 1 of this report.

Economics of Offshore Investments

The success of offshore production activities has occurred despite the exceptionally large dollar amounts required for development. Deep-water projects in particular have associated investment costs that may exceed $1 billion,[18] thus requiring a favorable geology base to be successful. Initial recovery estimates for individual fields in deep waters have been in the range of hundreds of billions of cubic feet, with ultimate recovery possibly approaching 1 trillion cubic feet in some cases. Fields of such magnitude are exceptional but offshore fields in general dwarf those expected to be found elsewhere in the Lower 48 States and they are a clear enticement for operators to pursue additional offshore supplies.

The presence of hydrocarbons alone is not sufficient to promote production without both favorable economics and a means to operate in such extreme circumstances. Large volume fields allow relatively fixed costs, such as those for discovery wells or production platforms, to be spread over many more units, lowering the average fixed cost per unit. This tendency is apparent in the finding costs data for the large major U.S. energy companies.[19] The finding costs for oil and gas combined in all water depths of the offshore declined from $15 per barrel of oil equivalent (BOE) to $4 per BOE (1997 dollars) in the 10 years from 1986 to 1996. The differential in finding costs between the relatively low-cost onshore and the offshore was all but eliminated until a slight surge in offshore finding costs appeared. Despite the recent increase, offshore finding costs remain below levels in 1992 and earlier years (Figure 34).[20]

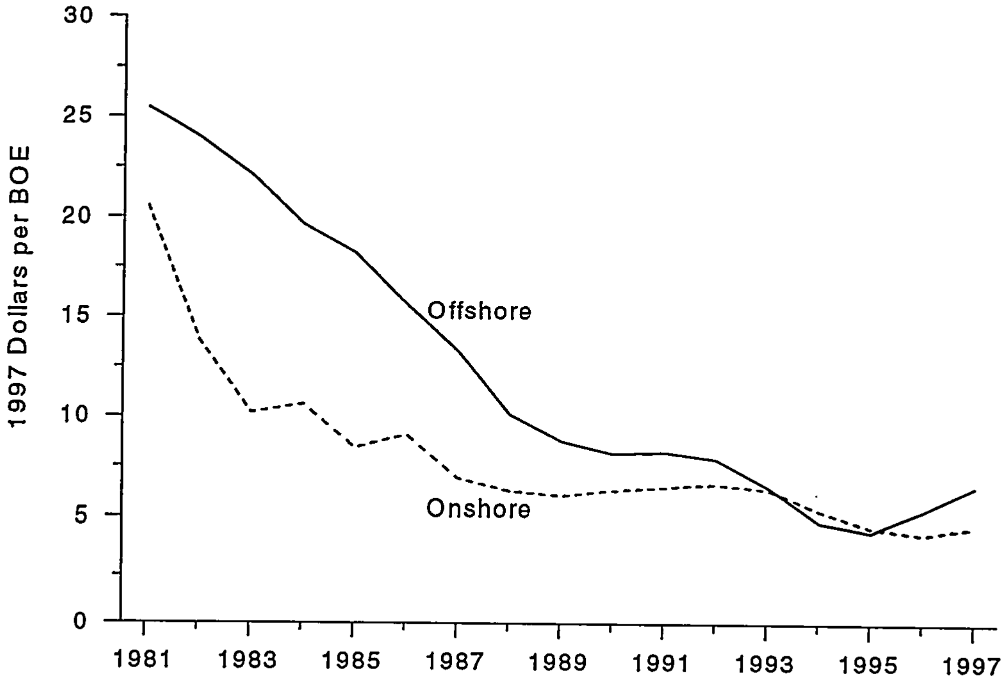
It is misleading, however, to attribute the success of the industry in offshore regions to the discovery of large fields alone. There have been tremendous strides in innovation and technology that have refined virtually all aspects of exploratory and developmental costs and productivity. Competition drives operators to push the limits of

[18]The initial development phase for Shell's Mars project is estimated to cost $1 billion, as reported in <http://www.offshore-technology.com/projects/mars>.

[19]These companies are those required to file Form EIA-28, "Financial Reporting System," pursuant to Section 205(h) of the Department of Energy Organization Act. In 1996, 24 companies filed Form EIA-28. These data are for the offshore, including both shallow- and deep-water operations. The data are used here as a representative sample for illustrative purposes.

[20]Energy Information Administration, *Performance Profiles of Major Energy Producers 1996*, DOE/EIA-0206(96) (Washington, DC, January 1998).

Figure 34. U.S. Onshore and Offshore Finding Costs for Major Energy Companies, 1981-1997



BOE = Barrel of crude oil equivalent.

Notes: Major energy companies are those required to file Energy Information Administration (EIA) Form EIA-28, "Financial Reporting System." Natural gas is converted to its oil equivalent using the conversion factor of 0.178 barrels of oil per thousand cubic feet of gas.

Source: Energy Information Administration, derived from Form EIA-28, as published in the *Performance Profiles of Major Energy Producers 1997.*

technology continually in their search for economic rewards. Within this framework, it is advantageous to seek improved technology as well as new and better ways to conduct business in order to gain possible competitive advantages. These efforts to create the necessary technologies that make offshore operations possible and manage costs have been as important as the geology base itself.

Key Factors in Economic Success

Three key elements that contribute to economic success in the offshore are cost management, reduction in project development time, and improved well performance.[21] The degree to which firms achieve gains in any or all of these areas will contribute heavily to their potential for success or failure.

Cost Management

Cost management includes both efforts to alter operations to offset increased costs and measures to reduce costs associated with given aspects of a project. An example of the first type of effort occurred when recent increased demand for offshore rigs drove drilling rates up. Companies had no control over the market-determined price but could search for ways to minimize drilling time and therefore drilling costs. The other type of cost management effort refers to the continual search for cost-reduction techniques. Technology often is a major influence on cost reduction. For example, the collection of 3-D seismic data has been enhanced through new processing techniques and new mechanical techniques, such as increasing the numbers of streamers, using longer streamers, and using remotely operated vehicles to set geophones or hydrophones on the sea floor.[22] Improved data and interpretation can lower drilling costs by reducing the number of required exploratory wells and better placement of a smaller number of developmental wells.

[21]These elements are adapted from "Three Main Factors Drive Deepwater Project Economics" by Sheila Popov, *Hart's Petroleum Engineer International* (December 1997).

[22]Additional detail on technology is available in Appendix B.

Cost reductions are achieved in a number of other ways. Outsourcing of certain services can allow for the sharing of resources to avoid the cost of being on site 24 hours per day. For example, inspection of operational equipment by qualified contractor personnel and equipment on a part-time basis allows those resources to be used for multiple projects. As costs are shared across a larger volume of service, the costs associated with any one project decline. Despite potential economic advantages, outsourcing is an area of concern for the Minerals Management Service (MMS). The MMS has issued a notice regarding possible waivers from daily inspection requirements, which may prove essential for marginally economic projects.[23] Used equipment is becoming another important factor even for deep-water operations. This approach allows for both direct cost savings and reduction in delivery time to the site. Another cost-saving option is subsea well completions and transportation tiebacks to nearby platforms for production processing. This has been a promising approach to offshore development in deep waters. This approach lowers overall project cost by avoiding the cost of a production platform at the water's surface dedicated solely to a single project.[24] The record to date for a tieback is the 68-mile transmission system connecting the Mensa subsea completions with the production platform at West Delta 143. This record is not expected to be broken anytime soon, owing to the substantial costs of the transmission system.

The Shasta and Mustique projects, in water depths between 830 and 1,040 feet of water,[25] are prime examples of the importance of cost management. These projects were released by major companies to Hardy Oil and Gas USA Inc. for development. Management of these projects focused on development of a project team with active vendor participation to allow the inclusion of their expertise in all phases of the project. The approach to develop both fields was to employ subsea completions with tiebacks to existing production platforms. Additional cost savings were achieved by the use of specialized equipment to complete the wells at Shasta, which is expected to reduce operating costs by 15 percent over the life of the wells. Successful project development can be seen in the Shasta wells, each of which can produce 30 million cubic feet (MMcf) per day, and the single Mustique well, which produces at 25 MMcf per day.

Accelerated Project Development

The success of the Shasta and Mustique projects underscores the importance of adequate planning to ensure both optimal resource recovery and a strong economic return on investment. However, as experience in offshore operations grows, companies' need for measured caution lessens and firms emphasize timely activity in their approaches to project development. The goal is to accelerate development, which increases the expected net financial return by yielding an earlier economic return and reducing the carrying costs of early expenditures on leases, geology and geophysical work, and exploratory drilling.

Design improvements between the Auger (initial production in 1994) and Mars (initial production in 1996) projects, both at water depths of approximately 2,900 feet, allowed Shell to cut the construction period to 9 months with a saving of $120 million.[26] Accelerated development enhances economic attractiveness by reducing project uncertainty because adverse changes in market price for the commodity or factor costs become more of a possibility as development time lengthens.

One approach to achieve revenues as soon as reasonable is the use of a subsea completion and transportation of production to an existing platform. A key advantage to this approach is that it provides an early contribution to project returns while additional engineering and design work for the full project proceeds. Another approach being developed especially for deep-water project development is in the overlapping of design phases and construction. Improvements in technology and project management allowed Shell Deepwater to develop the Ursa project in about the same calendar time as its Mars and Ram-Powell projects, even though Ursa is roughly twice their size. Development for offshore projects in general had ranged up to 5 years previously, with deep projects requiring up to 10 years. Recent field development has been accelerated with the period from discovery to first production in shallow water ranging between 6 and 18 months.[27] Experience with deep-water construction and operations has enabled development to proceed much faster, with time

[23]Gregg Falgout, "Outsourcing Lowers Costs," *Hart's Oil and Gas World* (April 1998), pp. 33-34.

[24]This option is quite attractive to the operator of the production platform, who charges for the processing service. Anecdotal evidence indicates that the platform operator in some cases may profit more from the project than the production operators.

[25]The Shasta project consists of two wells, separated by 1.5 miles, in 860 and 1,040 feet of water.

[26]Minerals Management Service, *Deepwater in the Gulf of Mexico: America's New Frontier*, OCS Report MMS 97-0004 (February 1997).

[27]"New Ideas, Companies Invigorate Gulf," *The American Oil & Gas Reporter* (June 1996), p. 68.

from discovery to production declining from 10 years to just over 2 years by 1996 (Figure 35).

Improved Well Performance

A third major factor behind favorable offshore economics for gas production is the rather astonishing production performance characteristics of large fields. This is seen clearly in deep-water fields, which tend to have high permeability and pressure that result in rapid flow to the wellbore. Individual well flows of 100 million cubic feet (MMcf) per day have been achieved at some fields, such as Mensa. Flows of this magnitude eclipse the average daily rate of 170 thousand cubic feet for wells in the entire Lower 48 States.

Well performance is important in terms of both ultimate recovery volumes and the speed at which those volumes are produced. Ultimate recovery determines the level of project revenues, and the flow rate affects the present value of expected revenues. If the improvement in early well flow rates occurs without sacrificing recovery volumes, the present value revenue is enhanced in both ways. Greater recovery per well is a key objective to the operator because, in addition to the contribution to higher revenues, it also reduces the number of required production wells and the associated drilling and completion expenditures.

Accelerated production improves present value profit in an indirect way. Within the income tax code, the advantage of cost deductions is delayed until project revenues generate tax liabilities for which the deductions are a useful offset. Increased flow in the initial years of a project generates larger early revenues and thus provides opportunities for the use of the accrued tax deductions from cost expenditures, enhancing the present value of cost recovery for tax purposes. This attribute is particularly advantageous for projects evaluated on a standalone basis.

The importance of well performance is underscored in a sensitivity test conducted on the expected profitability of a representative gas field.[28] The initial flow rate was identified as a major influence on the estimated present value profit (PVP) based on computation of rank correlations between PVP and the stochastic input variables. The rank correlation provides a useful quantitative approach to validate the importance of project elements to the expected returns. Drilling costs, on the other hand, did not show up as important to expected profitability, even though it may constitute many millions of dollars in total project cost.

Given that production performance variables such as the initial flow rate dominate over drilling costs as a major influence on profitability, a rational strategy is for the operator to pursue well drilling and completion technology with an emphasis on increased productivity despite increased costs. As long as the cost increments are managed properly, the productivity gains may be well justified. Analysis of a representative deep-water gas project shows that possible increases in drilling costs of 50 percent could be offset by flow rate increases of only 19 percent (assuming all other project parameters remain unchanged). These estimates show the economic incentive behind research and development in drilling and completion technologies that have resulted in very high flow rates.

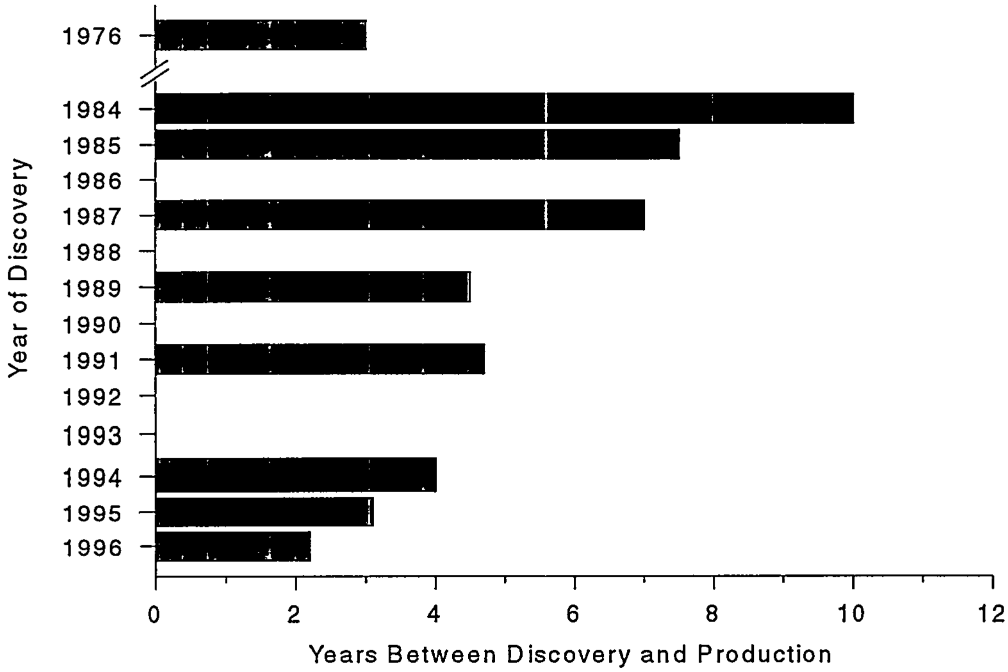
Other Factors

In addition to those items that are within the influence of the companies themselves, developments in the industry at large affect the economic environment for offshore operations. Growth of the industry drives infrastructure expansion, which in turn may enhance the economics of new offshore projects in a number of ways. Project costs are reduced as new projects can avoid full costs of assets dedicated to that single project, such as pipelines for transport to market. Pipeline construction and operation offer economies of scale that result in lower unit costs when output from multiple fields can be aggregated. Project costs also may be reduced by the use of subsea completions with output being "tied-back" to existing production platforms for gathering and processing. This practice will benefit from a more extensive infrastructure system, in which a larger number of platforms will offer greater numbers of opportunities to use this approach. Development of marginal fields will depend heavily on platforms in the area, not at any great distance. (The use of platforms for multiple projects also has the reciprocal advantage for the platform operator of increased overall return to those assets.)

Investors in incremental projects that rely on existing infrastructure also benefit from reduced risk in project timing, less cost uncertainty, and reliable performance of supporting assets. Reliance on existing assets avoids new construction endeavors, which could encounter delays or

[28]A description of the representative gas field and details of the economic analysis are provided in Appendix C.

Figure 35. Cycle Time for Deep-Water Projects



Note: Cycle times are for projects in production or under development. Prospects without a scheduled start date are excluded.
Source: Energy Information Administration, Office of Oil and Gas.

unforeseen events that cause the project to fail outright. In conducting project evaluation, such risk factors do not necessarily preclude construction, but they can raise unit costs for the associated service, thus reducing the net price or profit received by the producers. The net price received by producers is determined as the netback from the market price after accounting for transportation and other services, if any. While the markets may not yield a price sufficient to ensure a favorable return for the production project, the net price received by producers is subject to less risk if the needed infrastructure is in-place and available. Reduced risk enhances the expected profitability outlook for the project, which underscores the importance of new pipeline construction projects for improving the economic outlook for this region.[29] As economic returns for marginal fields improve, the minimum economic field size becomes smaller, resulting in ever-greater volumes of economically recoverable hydrocarbon volumes.

[29]Additional information on new pipeline construction and capacity expansion is available in Chapter 5 of this report.

Environmental Aspects of Offshore Operations

The oil and gas industry has conducted offshore activities for more than 5 decades. As a key contributor to the Nation's energy supplies, the industry has periodically found itself in the midst of a tense debate concerning the proper balance of sometimes conflicting interests in the offshore. Numerous people and companies are concerned with the offshore and its coastal regions as a resource to provide residential areas, wildlife habitat, recreation, fishing and agriculture, in addition to oil and gas operations. Government agencies have tried with various strategies and policies to reflect the will of the people in managing the offshore regions including the coastal areas. In 1953, Congress designated the Secretary of the Interior to administer mineral exploration and development of the OCS through the Outer Continental Shelf Lands Act (OCSLA). While the OCS is under Federal jurisdiction, federally approved activities must be as consistent as possible with approved State management programs.

After the OCSLA, the next major legislation affecting offshore operations was the National Environmental Policy

Act (NEPA) passed in 1969, the same year in which there was a major oil spill in the Santa Barbara channel. Additional environmental legislation was passed over the ensuing years. Targeted items under these laws included protection of the water and air, as well as the wildlife (Table 10). Most of the provisions under these laws imposed procedural steps or restrictions on operations, which generally caused higher costs for compliance, but oil and gas development itself could proceed. Over time, however, certain laws and Congressional actions either worked to block activities in offshore areas or explicitly blocked them at least temporarily. Since 1990, most portions of coastal waters have been subject to moratoria precluding any oil and gas activity.

Coastal Zone Issues

The Coastal Zone Management Act (CZMA), passed in 1972, has had far-reaching consequences and provoked extensive litigation and discussion. The CZMA aimed for the preservation, protection, and restoration of coastal areas to the extent possible,[30] and to resolve conflicts between various uses that were competing for coastal areas. The CZMA was intended to promote cooperation and coordination between the Federal government and State and local agencies in coastal States and States bordering the Great Lakes. An important element in achieving these goals is management of the offshore and coastal areas that is consistent with Federal and State plans and policies. Congress recognized that Federal decisions or actions in the OCS may have a severe impact that extends well into State waters. Thus, the CZMA requires that an applicant submitting a plan for exploration, development, or production from an OCS lease must include "a certification that each activity which is described in detail in such plan complies with such state's approved management program and will be carried out in a manner consistent with such program."[31] In effect, the CZMA provides for State review of Federal actions that affect a State's coastal zone.[32]

Prior to State review of Federal actions, the State must establish a management program that has been approved by the Secretary of Commerce. The key features in a State management plan would:

- Identify the relevant coastal area subject to management under the program
- Define permissible land and water uses
- Identify areas of particular concern
- Develop guidelines for use in particular areas
- Establish an organization and process for planning and implementation of the program.

The CZMA is rather unique in that participation by the States is on a voluntary basis. The CZMA provides mechanisms to encourage States to develop a management program, and in fact, it provides considerable incentive to do so. Advantages of participating in the program include technical assistance to local decisionmakers, funds for hiring State and local government employees to help implement the program, funds to develop special plans for areas of particular concern, funds for low-cost construction projects, such as boardwalks, to improve the public's ability to enjoy the coastal resources, and Federal consistency with the State's coastal management program. Not all qualifying States have become active participants, but all that have not, with the exception of Illinois and Indiana, currently are in the process of developing a program.

Although the intent of Congress in passing the CZMA was to promote cooperation and coordination between Federal and other agencies, disagreements arose over time that led to litigation. These cases initially led to a Supreme Court decision in 1984 that substantially weakened the act, but drove Congress to issue additional legislation that further refined its intent and actually gave the CZMA more strength. In 1990, the act was amended to clarify that all activities of Federal agencies are subject to the consistency requirements of the CZMA if the activities affect natural resources, water uses, or land uses in the coastal zone.

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[30] "The Congress finds and declares that it is the national policy...to preserve, protect, develop, and where possible, to restore or enhance, the resources of the Nation's coastal zone for this and succeeding generations." 16 USC Sec. 1452, Title 16 – Conservation, Chapter 33 – Coastal Zone Management, Sec. 1452. Congressional declaration of policy. Source: <gopher://hamilton1.house.gov70/00d%3A/uscode/title16/sect38/file.011>.

[31] Source: <http://wetland.usace.mil/regs/CZMA307.html>.

[32] The *coastal zone* is defined for purposes of the CZMA as "coastal waters (including the lands therein and thereunder) and the adjacent shorelands (including the waters therein and thereunder), strongly influenced by each other and in proximity to the shorelines of the several coastal states, and includes islands, transitional and intertidal areas, salt marshes, wetlands, and beaches. The zone extends, in Great Lakes waters, to the international boundary..." *Coastal Zone Management Act of 1972*, Section 304(1).

Table 10. Major Environmental Actions Affecting Federal Offshore Gas Recovery

Year	Action	Notes
1953	Outer Continental Shelf Lands Act passed.	Provides for Federal jurisdiction over submerged lands of the OCS and authorizes the Secretary of the Interior to lease those lands for mineral development.
1969	National Environmental Policy Act passed.	Requires a detailed environmental review before any major or controversial Federal action.
1970	Clean Air Act passed.	Regulates emission of air pollution from industrial activities.
1972	Coastal Zone Management Act passed.	Requires State review of Federal action that affects the land and water use of the coastal zone.
	Marine Mammal Protection Act passed.	Provides for the protection and conservation of all marine mammals and their habitats.
1973	Endangered Species Act passed.	Requires a permit for the taking of any protected species and requires that all Federal actions not significantly impair or jeopardize protected species or their habitats.
1977	Clean Water Act passed.	Regulates discharge of toxic and nontoxic pollutants into the surface waters of the United States.
1981	First OCS leasing moratorium enacted by Congress–FY 1982.	California.
1982	Federal Oil & Gas Royalty Management Act passed.	Among other requirements, requires that oil and gas facilities be built in a way that protects the environment and conserves Federal resources.
1983	First preleasing moratorium enacted–FY 1984.	North Atlantic.
1984	National Fishing Enhancement Act passed.	Encourages using offshore oil platforms as artificial reefs.
	Focused leasing concept introduced.	Allows deletion of low-interest, environmentally sensitive acreage from sale areas early in the lease sale process.
1988	Congress enacts first OCS drilling ban–FY 1989 DOI appropriations.	Covers leases in eastern GOM, south of 26° N.
1990	Amendments to Clean Air Act passed.	Gives Environmental Protection Agency jurisdiction for OCS facilities outside Central and Western GOM.
	Oil Pollution Act of 1990 (OPA-90) passed.	Among other provisions, OPA-90 addresses areas of oil-spill prevention, contingency planning, and financial responsibility for all offshore facilities in, on, or under navigable waterways.
	Outer Banks Protection Act passed.	Includes moratorium language for areas offshore North Carolina.
	Presidential decision withdrew areas offshore California, Washington, Oregon, North Atlantic, and Eastern GOM (south of 26° N) until after the year 2000.	
1995	Deep Water Royalty Relief Act passed.	Expands MMS' discretionary authority to grant royalty relief and mandates royalty relief (under certain conditions) for GOM leases in 200 meters or greater water depth.

OCS = Outer Continental Shelf. FY = Fiscal year. GOM = Gulf of Mexico. DOI = Department of the Interior. MMS = Minerals Management Service.
Source: Adapted from "U.S. Offshore Milestones," Minerals Management Service, <http://www.mms.gov>.

Florida and North Carolina are using the CZMA consistency provisions to block exploration and development of OCS prospects, which are thought to be largely gas prone. Critics of the CZMA have characterized this law as "the 'veto' law"[33] because of the powerful role delegated to the States, and States certainly have used its provisions to impede and obstruct Federal activities within their jurisdictions, such as oil and gas leasing. However, decisions regarding offshore activities under the provisions of the CZMA are based on the States' management program that has previously been approved at the Federal level by the Secretary of Commerce. Thus, the outcome reflects coordinated planning on a Federal and State basis, and it generally cannot be circumscribed by the program objectives of a single Federal or State agency.

Artificial Reefs

Although support for offshore oil and gas development varies among the States, it has a long history of acceptance in the Gulf of Mexico. Activities have been conducted for decades off Texas and Louisiana, with industry operations extending more recently into areas off the coasts of Mississippi, Alabama, and Florida.

While problems have occurred from time to time, a number of benefits have flowed from offshore operations. The more readily apparent ones include valuable supplies of oil and gas, government revenues, and employment. An additional benefit comes in the form of artificial reefs formed by the placement of obsolete operating platforms or rigs. An artificial reef refers to the placement of a man-made object on the sea bottom, which then becomes part of the ecosystem. This is particularly beneficial in the Gulf of Mexico given that the submerged terrain generally is flat and sandy, lacking hard structures on which invertebrates and plants can attach themselves.

The success of artificial structures in providing food and shelter for a host of fish species has led to the use of various materials for this purpose. Ships, airplanes, buses, bridge rubble, old tires and other items have been installed as artificial reefs with varying degrees of success. Train boxcars have been found to deteriorate greatly within a year or two of placement. Items also may shift and move when subjected to currents. Abandoned oil and gas platforms, however, were designed for a marine environment and so are quite durable and they tend to be secure. New rigs tend to become covered within 6 months to a year, which in turn attracts other creatures to eventually form a complex food chain.

The Minerals Management Service has encouraged the "rigs to reefs" option owing to its environmental and economic advantages. In 1983, MMS announced its support for the program, and in 1985 announced a formal policy on it. Under the rigs to reefs program, companies donate structures, install the reefs, and may make financial donations to the States from any realized savings related to avoided disposal costs. In cases with high relocation costs, such as moving a rig from the Gulf to the east coast of Florida, there may be no savings to allow for a donation to the State. However, the donation of the platform and absorption of transportation costs by the company provides the State the opportunity to gain the benefits while avoiding the costs otherwise associated with the installation of an artificial reef.

The first planned rigs to reef conversion occurred in 1979 with the relocation of an Exxon experimental subsea template from offshore Louisiana to a permitted site off Florida. To date, at least 120 structures have been used for the creation of artificial reefs, with 72 off Louisiana, 39 off Texas, 3 off Alabama, and 6 off Florida. Financial contributions to the States from the companies exceed $15 million.[34] The advantages to the State from the program include the environmental benefits and funds for the management of marine habitat, enhanced recreational areas, and the companies benefit from lower dismantling costs.

Outlook

Relatively low gas and oil prices during 1998 have made the outlook for offshore supply activities in the next year or two rather uncertain. However, a recovery in prices or further improvement in cost management, project cycle reduction, or well productivity can help to mitigate the impact of these price levels. Technology has contributed greatly to improved performance in the offshore. Much of the current attention is focused on technology enhancements that make the deep-water and subsalt fields increasingly attractive as investment options. However, the bulk of production historically has come from conventional fields in shallow-water regions of the Gulf of Mexico, and

[33] *Coastal Zone Management Act*, <http://moby.ucdavis.edu/GAWS/161/2metro/CZMA.html>.

[34] Figures provided by Villere Reggio of the Minerals Management Service, Gulf of Mexico OCS Region (October 5, 1998).

this trend is expected to persist for some time to come. Much of the technology that holds promise for great returns in the deep-water areas also has wide applicability in shallow depths.

Production in the longer term naturally depends on the trend in discoveries, which is itself conditional on geologic and economic factors. A key geologic factor is the field size distribution, which generally is expected to be highly skewed with few very large fields and increasing numbers as field size declines. The largest fields, being less challenging to find, tend to be discovered first, so exploration efforts yield diminishing volumes of reserve additions over time as smaller fields are discovered.[35] While even these smaller fields are likely to be large compared with those found in other regions in the Lower 48 States, this perspective on resources leads to declining returns to exploration. However, exceptions to the theoretical discovery model occur often. One recent example is the King discovery, about 70 miles southest of Louisiana in the Mars Basin, where development plans had not been completed when two additional "major" oil-bearing zones were discovered.[36] Given the Mars and Ursa fields already had been discovered in the Mars basin, this is a rather promising development. Elsewhere, after disappointments in the pursuit of subsalt prospects led to a relative lull in activity industry-wide, Anadarko announced a major subsalt discovery in shallow water that should contain at least 140 million barrels of crude oil equivalent (BOE), with reasonable potential of exceeding 200 million BOE.[37]

The frequency of these unexpected events indicates that declining offshore reserve additions with no relief is not an inevitable outcome. Additionally, annual reserve additions also relate to the number of wells drilled, which is influenced by economic factors. The timing of the exploitation of the resource base will depend on costs, productivity, and the evolving infrastructure. Production over a sustained period cannot expand unless reserve additions increase.

The optimistic consensus regarding the long-term supply potential of the offshore Gulf region is heavily influenced by the prodigious estimates of remaining recoverable natural gas resources. Recoverable gas resources in undiscovered fields in the Federal waters of the Gulf of Mexico are estimated by the Minerals Management Service (MMS) to be 96 trillion cubic feet (Tcf), with an additional 37 Tcf to be proven in already known fields. Combined with the 29 Tcf already in proved reserves for this area, this is equivalent to the 1997 estimate of 165 Tcf in proved reserves for the entire United States.

The estimated 96 Tcf in undiscovered fields represents the volumes of gas that are expected to be recoverable by conventional techniques, but without regard to the economic merit of recovery. As the economics for the offshore Gulf of Mexico improves, the portion of the technically recoverable resource base that is expected to be recovered expands considerably. Industry success in its efforts to manage costs, reduce cycle time, and increase productivity enhances the expected economic return for marginal fields, allowing the minimum economic field size at each water depth to become smaller. The apparent success of offshore operators in improving costs and productivity has increased the set of economically viable fields beyond the numbers previously anticipated for the offshore and, in particular, the deep-water regions. Because of the highly skewed distribution of field sizes, the inclusion of ever smaller fields multiplies the number of economically viable fields, which expands the economically recoverable portion of the total, although by less than a proportionate amount.

In conclusion, the supply outlook for the Gulf of Mexico shows considerable potential for growth. Although the relatively low oil and gas prices for much of 1998 have led to reduced drilling in the shallow waters of the Gulf, over the long term, gas supplies from the Gulf of Mexico undoubtedly are going to be very large in light of the estimated recoverable resource volumes. The timing of the resource development is subject to both market and technical influences. The expected flow volumes from both shallow- and deep-water regions potentially are so large that the supply outlook has important implications for both regional markets and the Lower 48 States as a whole.

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[35]Declining volumetric returns to exploratory drilling over time do not require that successive discovered fields are strictly smaller. The search process is not perfect and the outcome for any year represents the aggregation of fields of different sizes. The yearly average volume per discovery will decline as the set of yearly discoveries shifts from larger to smaller sizes.

[36]"Vastar hits deep zones at Gulf prospect," *Oilgram News* (July 23, 1998), p. 3.

[37]"Anadarko announces big subsalt discovery," *Oilgram News* (July 30, 1998), p. 1.

5. Natural Gas Pipeline Network: Changing and Growing

Natural gas consumption is expected to grow steadily into the next century, with demand forecasted to reach 32 trillion cubic feet by 2020. The likelihood of a substantial increase in demand has significant implications for the interstate natural gas pipeline system. A key issue is what kinds of infrastructure changes will be required to meet this demand and what the costs will be of expanding the pipeline network, both financial and environmental. Significant changes have already occurred on the pipeline grid. During the past decade, for example, interstate pipeline capacity has increased by more than 16 percent (on an interregional basis). Average daily use of the network was 72 percent in 1997, compared with 68 percent in 1990. More than 15 new interstate pipelines were constructed, as well as numerous expansion projects. From January 1996 through August 1998 alone, at least 78 projects were completed adding approximately 11.7 billion cubic feet per day of capacity. By the end of 1998, another 8.4 billion cubic feet of daily capacity is expected to be in service (Figure 36). Moreover:

- In the next 2 years (1999 and 2000), proposals for new pipelines or pipeline expansions call for the potential expenditure of nearly $9.5 billion and an increase of 16.0 billion cubic feet per day of capacity. The proposed capacity additions would be less than what was installed in 1997 and 1998 but represent a 122-percent increase in expenditures (Table 11).

- The Energy Information Administration projects that interregional pipeline capacity (including imports) will grow at an annual rate of only about 0.7 percent between 2001 and 2020, compared with 3.3 percent between 1990 and 2000. But natural gas consumption will grow at more than twice that rate, 1.8 percent per year, reaching an additional 25 billion cubic feet per day by 2020. The majority of the growth in consumption is expected to come from the electric generation sector, which will tend to level out overall system load during the year, i.e., greater utilization, and result in less need for capacity expansion

- While many of the current expansion plans are associated with growing demand for Canadian supplies (15 percent of proposed capacity through 2000), several recent proposals also reflect a growing demand for outlets for Rocky Mountain area (Wyoming/Montana) gas development, which is steadily expanding.

- Although the Henry Hub in Louisiana remains the major natural gas market center in North America, the Chicago Hub can be expected to grow significantly as new Canadian import capacity targets the area as a final destination or transshipment point.

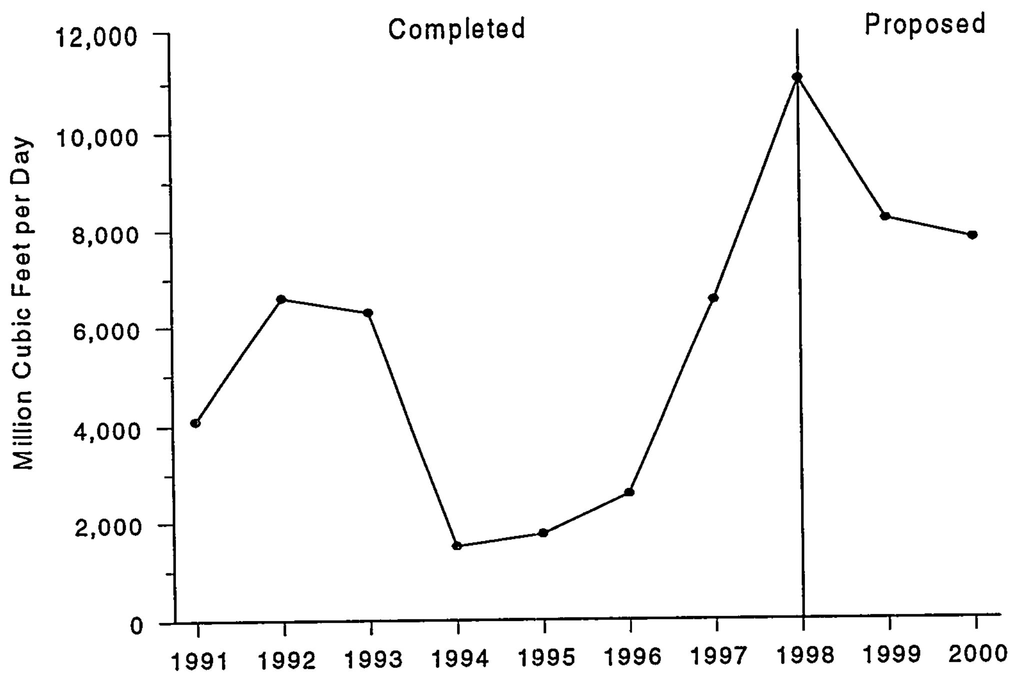
- Expanding development in the Gulf of Mexico (particularly deep water gas drilling) is competing heavily with Canadian imports to maintain markets in the Midwest and Northeast regions but is also finding a major market in its own neighborhood, that is, in the Southeast Region. Greater natural gas use for electric generation and to address environmental concerns is fueling a growing demand for natural gas in the region.

This chapter focuses upon the capabilities of the national natural gas pipeline network, examining how it has expanded during this decade and how it may expand further over the coming years. It also looks at some of the costs of this expansion, including the environmental costs which may be extensive. Changes in the network as a result of recent regional market shifts are also discussed.

Prior to the 1990s, nearly all natural gas flowing in the interstate market was owned by the major pipeline companies, which transported and sold the gas to their customers. The regulatory changes by the Federal Energy Regulatory Commission (FERC) in the 1980s, culminating in Order 636 in 1993, changed all that. These initiatives and emerging market forces created open access transportation on the interstate pipeline system and provided increasing flexibility in the way the industry operates. Now, almost all natural gas is purchased directly from producers in an open market with the pipeline companies principally providing transportation services for their customers.

The combination of wellhead price deregulation in the 1980s, greater access to transportation services, a growth

Figure 36. Major Additions to U.S. Interstate Natural Gas Pipeline Capacity, 1991-2000



Note: 1998 includes 10 projects completed through August.

Sources: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System: Natural Gas Pipeline Construction Database, as of August 1998; Natural Gas State Border Capacity Database.

Table 11. Summary Profile of Completed and Proposed Natural Gas Pipeline Projects, 1996-2000

Year	All Type Projects						New Pipelines[a]		Expansions	
	Number of Projects	System Mileage[b]	New Capacity (MMcf/d)	Project Costs (million $)	Average Cost per Mile ($1,000)[c]	Costs per Cubic Foot Capacity (cents)	Average Cost per Mile ($1,000)[c]	Costs per Cubic Foot Capacity (cents)	Average Cost per Mile ($1,000)[c]	Costs per Cubic Foot Capacity (cents)
1996	26	1,029	2,574	552	448	21	983	17	288	27
1997	42	3,124	6,542	1,397	415	21	554	22	360	21
1998	54	3,388	11,060	2,861	1,257	30	1,301	31	622	22
1999	36	3,753	8,205	3,135	727	37	805	46	527	31
2000	19	4,364	7,795	6,339	1,450	81	1,455	91	940	57
Total	**177**	**15,660**	**36,178**	**14,285**	**862**	**39**	**1,157**	**48**	**542**	**29**

[a]New pipelines include completely new systems and smaller system additions to existing pipelines, i.e., a lateral longer than 5 miles or an addition that extends an existing system substantially beyond its traditional terminus.

[b]Includes looped segments, replacement pipe, laterals, and overall mileage of new pipeline systems.

[c]Average cost per mile is based upon only those projects for which mileage was reported. For instance, a new compressor station addition would not involve added pipe mileage. In other cases final mileage for a project in its initial phases may not yet be final and not available. In the latter case, cost estimates may also not be available or be very tentative.

MMcf/d = Million cubic feet per day.

Source: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System, Natural Gas Pipeline Construction Database through August 1998.

in new services and pipeline routings, and greater participation in the market by end users, marketers, and others has resulted in a much more competitive pipeline transportation network than existed a decade ago.

Changes in Production and Market Links

The cumulative effect of market changes and regulatory reforms has, among other things, brought on shifts in North American production patterns and regional market demands. As producers and shippers alike have sought greater access to new and expanding production areas, pipeline companies have been quick to improve their receipt facilities to retain their position in the face of current or potential competition. Pipeline companies have also enhanced their regional facilities and increased capacity to maintain and expand their markets in the face of changes in customer demand profiles. Overall, this has resulted in some shifts in long-haul transport patterns, with gas flow decreasing along some traditional transportation corridors while increasing in others as new or modified production/market links have been established.

Between 1990 and the end of 1997, capacity additions on the long-haul corridors alone, which link production and market areas, totaled approximately 12.4 billion cubic feet per day, an increase of about 17 percent.[1] Capacity and deliverability additions during the period fall into several categories:

- New pipeline systems built either to transport gas from expanding production areas or to serve new market areas
- Expansion of existing systems to accommodate growing customer demand but accessing supplies already linked to the network
- Expansion of an existing system to accommodate shipper supplies transported via other pipeline systems
- Expansions of short-haul local delivery lines to link with new customers who bypass local natural gas distribution companies
- Expansions of pipeline systems in areas where productive capacity was greater than existing transportation capacity.

This pipeline network expansion activity was also augmented by the development of the natural gas market center, greater (open-) access to interstate underground storage capacity (see box, below), the development of a release market for pipeline capacity in which unused firm capacity can be sublet by others, and increased use of computer-based electronic trading. These changes have helped improve the operational flexibility of the interstate pipeline system.

Market Centers and Improved Storage Access

Since 1990, 39 natural gas market centers have been established in the United States and Canada. They have become a key factor in the growing competitiveness within the natural gas transportation market, providing locations where many natural gas shippers and marketers can transact trades and receive value-added services. Among other features, they provide numerous interconnections and routes to enhance transfers and movements of gas from production areas to markets. In addition, many provide short- term gas loans to shippers who have insufficient (receipt) volumes to meet the contractual balancing requirements of the transporting pipeline. Conversely, temporary gas parking is often available when shippers find they are delivering too much gas to the pipeline. Market centers also offer transportation (wheeling) services, balancing, title transfer, gas trading, electronic trading, and administrative services needed to complete transactions on behalf of the parties.

Many of the services offered by market centers are supported by access to underground storage facilities. More than 229 underground storage sites (out of 410 total) in the United States currently offer open-access services to shippers and others through market centers or interstate pipeline companies. These services are essential in today's transportation market—without them pipeline system operations would be much less flexible and seasonal demand would be more difficult to meet.

[1]Energy Information Administration, EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity.

The greatest increase in capacity since 1990 occurred on those routes between Canada and the U.S. Northeast, 1.9 billion cubic feet (Bcf) per day, or 412 percent (Table 12). This was brought about with the completion of several new pipelines and expansions to several import stations, almost exclusively in New York State. The largest increase in solely domestic capacity, however, was between the Southwestern and Southeastern States, 1.1 Bcf per day. This increase was driven primarily by the growth in electric power and industrial demand for natural gas in the Southeast, particularly in Florida.[2]

The magnitude of pipeline expansion since 1990 can best be illustrated in conjunction with the natural gas pipeline transportation patterns that have emerged in North America over the years (Figure 37). In the early 1990s, three geographic regions were the primary focus of capacity expansion: the Western, Midwest, and Northeast regions. All three regions shared one common element, greater access to Canadian supplies. In addition, the Western Region was the target of expansions out of the Southwest Region, as new production sources were developed in the San Juan Basin of New Mexico and demand for natural gas in California was expected to grow substantially during the decade.

Through the year 2000, U.S. access to Canadian production is expected to continue to expand but at a rate never before seen, while major service expansion to the Western Region appears to have ended (Figure 38). During the next several years, the emphasis will shift to expanding natural gas transportation capabilities from the Rocky Mountain, New Mexico, and West Texas areas eastward to link with pipeline systems reaching the Midwest and Northeast markets. With the completion of this effort, the interstate natural gas pipeline network will come closer to being a national grid where production from almost any part of the country can find a route to customers in almost any area. It will fill the gap in the national network that to some extent has left the Rocky Mountain and Western natural gas producers isolated from certain markets.

Environmental issues related to the emission reductions mandated by the Clean Air Act Amendments (CAAA) of 1990 are also providing opportunities for increasing the use of natural gas, particularly in the generation of electricity. For instance, regulatory agencies in several States have instituted initiatives that encourage reductions in consumption of residual fuel oil and coal as a utility boiler fuel, resulting in the increased use of natural gas in this area. Throughout the country, natural gas will figure as an option in the powering of utility boilers to meet the emission reduction requirements under Phases I and II of the CAAA. Natural gas will also figure prominently in any implementation of the Kyoto Protocol, which specifies a reduction in greenhouse gas emissions. One of the main ways to reduce these emissions is to replace coal- and oil-fired boilers with gas-fired or renewable facilities or to improve energy efficiency.

Interregional Growth

Since 1990, approximately 11.7 billion cubic feet per day of additional interregional capacity has been constructed, principally to expand service to the West and Northeast. While the current utilization rates into the Northeast remain high and, in fact, have grown since the expansions began (83 versus 79 percent), the average daily usage rate into the Western Region fell as an excess capacity situation developed with the completion of its expansion program (Table 12). Capacity into the Midwest and Southeast increased substantially as well, adding 2.3 and 1.6 billion cubic feet per day, respectively. The average pipeline usage rate into the Midwest increased by 10 percentage points, rising to 75 percent, between 1990 and 1997. This increase occurred primarily because of increased demand and utilization of pipeline capacity out of Canada.

On an average day during 1997, utilization of interregional pipeline capacity varied from 50 to 96 percent (Table 12). (This excludes capacity into the Southwest, which is principally an exporting region.) These figures indicate that a substantial amount of unused off-peak pipeline capacity still remains on some interregional pipeline routes, although the usage-rate range itself is up somewhat from the 45-to-90-percent range in 1990. This increased capacity usage, in part, reflects the demand growth in some markets and also the growth in the capacity release market, which has helped improve the use and viability of some previously underutilized pipeline systems.

These increases in the average pipeline usage rates and the steady growth in natural gas consumption have brought about the need for expanded capacity and service in some areas. More than 11,500 miles of pipeline (109 projects)[3]

[2]Only a small part of this additional capacity, 342 million cubic feet per day, represented capacity that continued on to the Northeast or Midwest regions.

[3]Excludes minor looping and minor extension projects.

Table 12. Interregional Pipeline Capacity, Average Daily Flows, and Usage Rates, 1990 and 1997

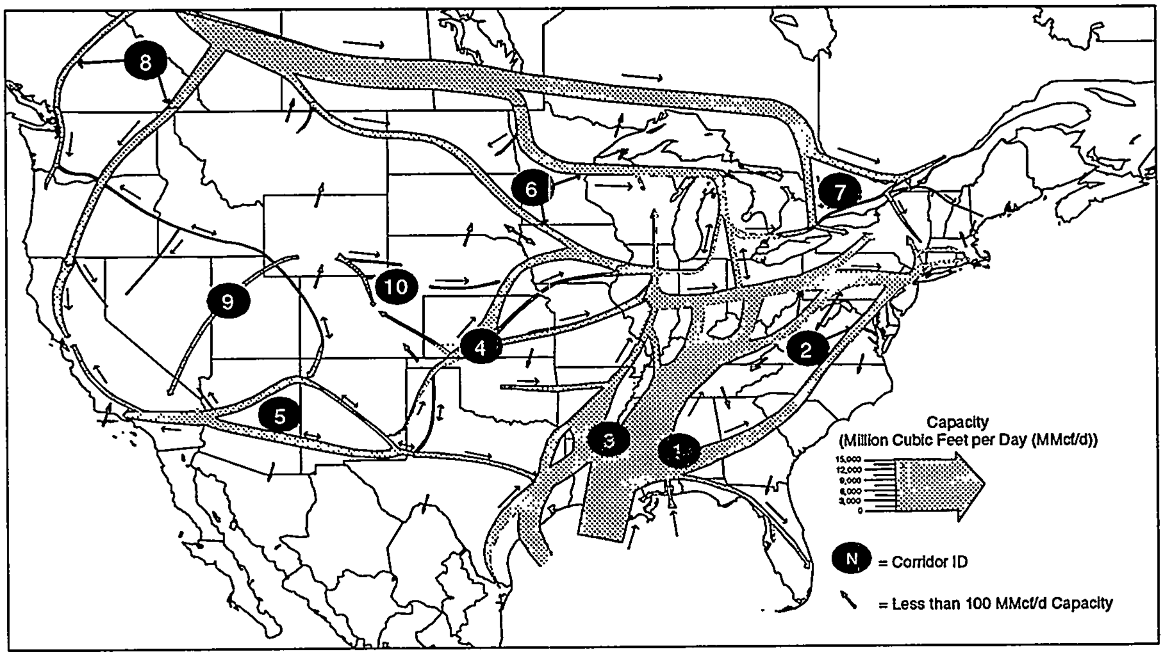
Regions		Capacity (MMcf per day)			Average Flow (MMcf per day)			Usage Rate[1] (percent)		
		1990	1997	Percent Change	1990	1997	Percent Change	1990	1997	Percentage Point Change
		To Market Areas								
Receiving	**Sending**									
Midwest	Canada	2,161	3,111	44	1,733	2,647	53	84	85	1
	Central	8,888	10,069	13	5,754	7,514	31	65	75	10
	Northeast	2,054	2,068	1	729	1,045	43	45	51	6
	Southeast	9,645	9,821	2	6,134	7,199	17	64	78	14
Total to Midwest		**22,748**	**25,070**	**10**	**14,350**	**18,405**	**28**	**65**	**75**	**10**
Northeast	Canada	467	2,393	412	309	2,007	549	66	84	18
	Midwest	4,584	4,887	7	3,474	4,072	17	76	84	8
	Southeast	4,971	5,173	4	4,091	4,232	3	82	83	1
Total to Northeast		**10,022**	**12,453**	**24**	**7,875**	**10,311**	**31**	**79**	**83**	**4**
Southeast	Northeast	100	521	417	63	15	-77	63	58	-5
	Southwest	19,801	20,946	6	14,613	15,508	6	74	74	0
Total to Southeast		**19,901**	**21,467**	**8**	**14,676**	**15,523**	**6**	**74**	**74**	**0**
Western	Canada	2,631	4,336	65	1,874	3,222	72	71	77	6
	Central	365	1,194	227	196	747	260	54	96	42
	Southwest	4,340	5,351	23	3,910	2,655	-32	90	50	-40
Total to Western		**7,336**	**10,881**	**48**	**5,784**	**6,624**	**15**	**83**	**64**	**-19**
Total to Central		**12,093**	**13,096**	**8**	**6,248**	**8,183**	**31**	**56**	**68**	**12**
Total to Southwest		**2,058**	**2,879**	**40**	**651**	**1,240**	**91**	**69**	**55**	**-14**
U.S. Interregional Total		**74,158**	**85,847**	**16**	**49,584**	**60,286**	**22**	**68**	**72**	**4**
		From Export Regions								
Sending	**Receiving**									
Canada	Central	1,254	1,566	25	941	1,592	69	75	99	24
	Midwest	2,161	3,111	44	1,733	2,647	53	84	85	1
	Northeast	467	2,393	412	309	2,007	549	66	84	18
	Western	2,631	4,336	65	1,874	3,222	72	71	77	6
Total from Canada		**6,514**	**11,406**	**75**	**4,857**	**9,468**	**95**	**76**	**84**	**8**
Central	Canada	66	66	0	44	44	0	67	66	-1
	Midwest	8,888	10,069	13	5,754	7,514	31	65	75	10
	Southwest	1,303	2,114	63	575	1,181	105	68	65	-3
	Western	365	1,194	227	196	747	260	54	96	42
Total from Central		**10,622**	**13,453**	**27**	**6,373**	**9,442**	**48**	**63**	**78**	**15**
Southwest	Central	8,824	8,878	1	4,137	4,950	20	48	58	10
	Mexico	354	1,056	198	38	140	265	11	13	3
	Southeast	19,801	20,946	6	14,613	15,508	6	74	74	0
	Western	4,340	5,351	23	3,910	2,656	-32	90	50	-40
Total from Southwest		**33,319**	**36,231**	**9**	**22,698**	**23,254**	**2**	**69**	**65**	**-4**

[1]Usage rate shown may not equal the average daily flows divided by capacity because in some cases no throughput volumes were reported for known border crossings. This capacity was not included in the computation of usage rate.

MMcf = Million cubic feet.

Sources: Energy Information Administration (EIA). **Pipeline Capacity:** EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity Database, as of December 1997. **Average Flow:** Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition." **Usage Rate:** Office of Oil and Gas, derived from Pipeline Capacity and Average Flow.

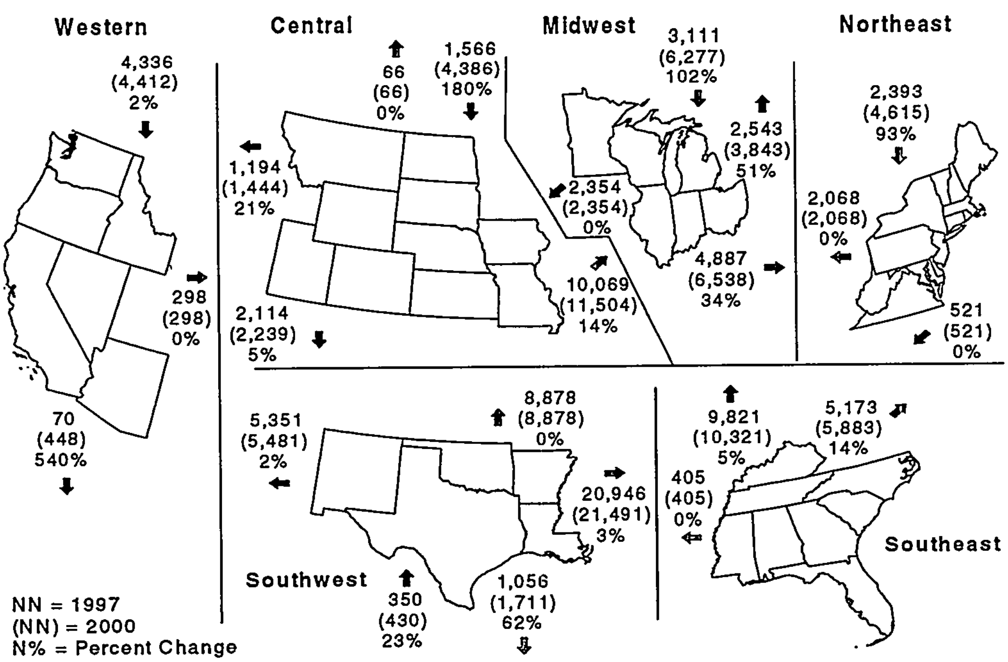
Figure 37. Major Natural Gas Transportation Corridors in the United States and Canada, 1997



Note: The 10 transportation corridors are: (1) Southwest-Southeast, (2) Southwest-Northeast, (3) Southwest-Midwest, (4) Southwest Panhandle-Midwest, (5) Southwest-Western, (6) Canada-Midwest, (7) Canada-Northeast, (8) Canada-Western, (9) Rocky Mountains-Western, and (10) Rocky Mountains-Midwest.

Source: Energy Information Administration, EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity Database, as of December 1997.

Figure 38. Region-to-Region Natural Gas Pipeline Capacity, 1997 and Proposed by 2000
(Volumes in Million Cubic Feet per Day)



Source: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System: Natural Gas Proposed Pipeline Construction Database, as of August 1998, and Natural Gas Pipeline State Border Capacity Database.

are scheduled to be added between 1998 and 2000 within the United States. Even if only half of these projects are eventually built, the level of proposed activity is a dramatic change from the slow growth in the mid-1980s when only 200 to 800 miles of pipeline were added each year,[4] and more recently in 1994 and 1995 when only 550 and 325 miles, respectively, were installed as part of 12 projects.

Regional Trends

The increased deliverability and utilization of the U.S. natural gas system reflect recent regional trends in supply access as well as in market demand. The natural gas transmission and delivery network within the different U.S. regional markets has evolved over time to meet particular requirements (Table 13). Each region differs in climate, underground storage capacity, number of pipeline companies, and availability of local production. Additionally, the varying demographics of each region dictate different patterns of gas use and potential for growth. Since 1990, some changes have occurred in each region and, thus, so has the level of natural gas deliverability within the respective regional markets. Further changes surely will occur during the next two decades as the demand for natural gas grows to a projected 32 trillion cubic feet annually by 2020 and a 28-percent share of the total U.S. energy market (Figure 39). The following section highlights some of the major regional trends that have affected deliverability during the past decade and are likely to affect the whole network over the next several years.

Increased Demand for Access to Canadian Supplies

Growing U.S. demand for Canadian natural gas has been a dominant factor underlying many of the pipeline expansion projects this decade. As a consequence, Canadian natural gas has become an increasingly important component of the total gas supply for the United States. In 1997, more than 2.9 trillion cubic feet of gas was imported from Canada, an increase of 100 percent from the level in 1990.[5] This trend is expected to continue as Canadian production expands rapidly in the western provinces of British Columbia and Alberta and is developed off the east coast of Nova Scotia. Consequently, more pipeline projects are expected to be built to gain greater access to these Canadian supplies.[6] Among these projects is a proposed expansion of the NOVA system in Alberta, Canada, by up to 2.3 billion cubic feet (Bcf) per day. This in turn will link with the TransCanada Pipeline system expansion and its connections with existing and new U.S. pipelines feeding into the expanding markets in the Midwest and Northeast regions. In addition, two totally new pipeline systems, the Alliance and the Maritime & Northeast, are scheduled to be in service by the end of 2000. The former will link British Columbia/Alberta, Canada production sources with U.S. Midwestern and Northeastern markets, while the latter will bring Sable Island gas supplies from off the east coast of Canada to the New England marketplace.

While pipeline capacity and U.S. access to Canadian supplies increased by 75 percent (11.4 versus 6.5 Bcf per day) between 1990 and 1997 (Table 12), an additional 6.0 Bcf per day capacity could be in place by the end of 2000 if the planned projects are completed (see Chapter 1). This would amount to a 168-percent increase in import capacity between 1990 and 2000. Put another way, in 1990, Canadian import capacity was only 20 percent as large as export capacity from the U.S. Southwest, the major-producing region in the United States. By 2000, Canadian import capacity could be as much as 53 percent of the Southwest's export capacity (Figure 38).

Southwest Producers Seek Greater Access to Eastern Markets

Natural gas pipeline export capacity from the Southwest Region has continued to grow, by 9 percent since 1990 (Table 12), but the rate has slowed as production and new reserve additions continued on a downward trend.[7] The Southwest Region now accounts for 68 percent of the natural gas reserves in the Lower 48 States, down from 72 percent in 1990. The bright spot in the region is the increased exploration and development activity in the Gulf of Mexico. Annual production levels in the Gulf remained relatively steady throughout much of the 1980s but have increased significantly since 1996. A number of deep-

[4]Federal Energy Regulatory Commission, Office of Pipeline Regulation, Staff Report, *Cost of Pipeline and Compressor Station Construction Under Natural Gas Act Section 7(c), for the Years 1984 Through 1987* (Washington, DC, June 1989) and subsequent issues.

[5]Energy Information Administration, "U.S. Natural Gas Imports and Exports—1997," *Natural Gas Monthly,* DOE/EIA-0130(98/09) (Washington, DC, September 1998).

[6]Energy Information Administration, EIAGIS-NG Geographic Information System, Natural Gas Pipeline Construction Database, as of September 1998.

[7]Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquid Reserves, 1997 Annual Report,* DOE/EIA-0216(97), Advance Summary (Washington, DC, September 1998) and *1990 Annual Report,* DOE/EIA-0216(90) (Washington, DC, September 1991)

Table 13. Principal Interstate Natural Gas Pipeline Companies Operating in the United States, 1997

Destination/ Pipeline Name	Major Supply Source(s)	Beginning Region	Beginning State	Intermediate States	Ending State(s)	System Capacity (MMcf/d)	Miles of Mainline Transmission[a]
Central Region							
Colorado Interstate Gas Co	WY,N TX/OK	Central	Wyoming	TX,OK,KS	Colorado	2,218[b]	4,199
KN Interstate Gas Co	WY,N TX/OK	Central	Wyoming	TX,OK,CO,NE,MT	Kansas	906	6,268
KN Wattenberg LL Co	WY,CO	Central	Wyoming	None	Colorado	171[b]	64
Mississippi River TransCorp	N TX/OK/AR	Southwest	Texas	OK,AR,LA,IL	Missouri	1,670[b]	1,976
Northern Border PL Co	Canada	Central	Montana	ND,SD,MN	Iowa	1,760	971
Northern NG Co	N TX,OK,KS	Southwest	Texas	NM,OK,KS,NE,IA,IL,WI,SD	Minnesota	3,800	16,424
Questar Pipeline Co	WY,CO	Central	Wyoming	CO	Utah	1,362[b]	1,712
Trailblazer Pipeline Co	WY	Central	Colorado	WY	Nebraska	508[b]	436
Williams NG Co	N TX,OK,KS,WY	Central	Wyoming	CO,NE,KS,OK,TX	Missouri	1,850[b]	5,837
Williston Basin Interstate PL Co	WY	Central	Montana	WY,SD	North Dakota	460[b]	3,067
Wyoming Interstate Gas Co	WY	Central	Wyoming	None	Colorado	732	269
Midwest Region							
ANR Pipeline Co (WL)	N TX,OK,KS	Southwest	Texas	OK,KS,NE,MO,IA,IL,IN,WI	Michigan	5,846[b]	9,565
ANR Pipeline Co (EL)	LA,MS	Southwest	Louisiana	AR,MS,TN,KY,IN,OH	Michigan	[c]	[c]
Bluewater PL Co	MI, Other Pipelines	Midwest	Michigan	None	Canada	225	95
Crossroads Pipeline Co	Other Pipelines	Midwest	Indiana	None	Ohio	250	205
Great Lakes Gas Trans Co	Canada	Midwest	Minnesota	WI	Michigan	2,483[b]	2,005
Midwestern Gas Trans Co	Tennessee Gas PL	Southeast	Tennessee	KY,IN	Illinois	785	350
Natural Gas PL Co of Am (WL)	N TX,OK,KS	Southwest	Texas	OK,KS,NE,IA,	Illinois	5,011[b]	9,856
Natural Gas PL Co of Am (EL)	S TX,LA,	Southwest	Texas	LA,AR,MO	Illinois	[c]	[c]
Panhandle Eastern PL Co	N TX,OK,KS	Southwest	Texas	OK,KS,MO,IL,IN,OH	Michigan	2,765[b]	6,334
Texas Gas Trans Corp	LA	Southwest	Louisiana	AR,MS,TN,KY,OH	Indiana	2,787[b]	5,736
Trunkline Gas Co	S TX,LA	Southwest	Texas	LA,AR,MS,TN,KY,IL	Indiana	1,884[b]	4,143
Viking Gas Trans Co	Canada	Midwest	Minnesota	ND	Wisconsin	513[b]	609
Northeast Region							
Algonquin Gas Trans Co	Other Pipelines	Northeast	New Jersey	NY,CT,RI	Massachusetts	1,586[b]	1,064
CNG Trans Corp	LA,WV,PA	Northeast	Pennsylvania	WV,MD,VA	New York/Ohio	6,275	3,851
Columbia Gas Trans Co	LA,WV/PA	Northeast	West Virginia	PA,MD,VA,NJ,DE,NC	New York/Ohio	7,276[b]	11,249
Eastern Shore NG Co	Other Pipelines	Northeast	Pennsylvania	DE	Maryland	58[b]	270
Empire PL Co	Canada	Northeast	New York	None	New York	503	155
Equitrans Inc	WV	Northeast	West Virginia	None	Pennsylvania	800[b]	492
Granite State Gas Trans Co	Canada	Northeast	Vermont	NH	Maine	49[b]	105
Iroquois Gas Trans Co	Canada	Northeast	New York	CT,MA	New York	829	378
National Fuel Gas Supply Co	OP, Canada	Northeast	New York	None	Pennsylvania	2,133[b]	1,613
Tennessee Gas PL Co	S TX,LA, Canada	Southwest	Texas	LA,AR,KY,TN,WV,OH,PA,NY,MA	Massachusetts	5,939	15,257
Texas Eastern Trans (WL)	S TX,LA	Southwest	Texas	LA,AR,MO,IL,IN,OH,WV,PA,NJ	New York	5,587[b]	9,270
Texas Eastern Trans (EL)	S TX,LA	Southwest	Texas	LA,MS,AL,TN,KY,OH	Pennsylvania	[c]	[c]
Transcontinental Gas PL Co	S TX,LA	Southwest	Texas	LA,MS,AL,GA,SC,NC,VA,MD	New York	6,556	10,245
Vermont Gas Systems Inc	Canada	Northeast	Vermont	None	Vermont	40	165
Southeast Region							
Chandeleur PL CO	Gulf of Mexico	Offshore	–	None	Mississipi	280	172
Columbia Gulf Trans Co	SE TX,LA	Southwest	Texas	LA,MS,TN	Kentucky	2,063	4,190
East Tennessee NG Co	Tennessee Gas PL	Southeast	Tennessee	None	Virginia	675	1,110
Florida Gas Trans Co	S TX,LA,MS	Southwest	Texas	LA,MS,AL	Florida	1,405[b]	4,843
Mobile Bay PL Co	Gulf of Mexico	Offshore	–	None	Alabama	600	29
Midcoast Pipeline Co	Other Pipelines	Southeast	Alabama	None	Tennessee	136[b]	288
South Georgia NG Co	Southern NG PL	Southeast	Georgia	AL	Florida	129	909
Southern NG Co	SE TX,LA,MS	Southwest	Texas	LA,MS,AL,GA,TN	South Carolina	2,536	7,394
Southwest Region							
Discovery PL Co	Gulf of Mexico	Offshore	–	None	Louisiana	600	147
High Island Offshore System	Gulf of Mexico	Offshore	–	None	Louisiana	1,800	203
Koch Gateway PL Co	SE TX,LA	Southwest	Texas	LA,MS,AL	Florida	3,476	7,781
Noram Gas Trans Co	AR,TX,KS,OK	Southwest	Texas	KS,AR,LA	Missouri	2,797[b]	6,222
Mid-Louisiana Gas Co	LA	Southwest	Louisiana	MS	Louisiana	193[b]	412
Nautilus Pl Co	Gulf of Mexico	Offshore	–	None	Louisiana	600	101
Ozark Gas Trans Co	OK	Southwest	Oklahoma	None	Arkansas	166[b]	436
Sabine Pipeline Co	TX	Southwest	LA	None	Louisiana	1,348[b]	190
Sea Robin PL Co	Gulf of Mexico	Offshore	–	None	Louisiana	1,241	470
Shell Gas PL Co	Gulf of Mexico	Offshore	–	None	Louisiana	600	45
Stingray PL System	Gulf of Mexico	Offshore	–	None	Louisiana	1,132[b]	318
Valero Interstate Trans Co	TX	Southwest	Texas	None	Texas	–	–
Western Region							
El Paso NG Co	S CO,NM	Southwest	New Mexico	AZ	California/TX	4,744	9,838
Kern River Trans Co	WY	Central	Wyoming	UT,NV	California	714	925
Mojave PL Co	Transwestern PL	Western	Arizona	None	California	407	362
Northwest PL Co	Canada	Western	Washington	ID,OR,WY,UT	Colorado	3,300	2,943
PG&E Trans Co - Northwest	Canada	Western	Idaho	OR	California	2,568[b]	1,336
TransColorado PL Co	CO	Central	Colorado	None	New Mexico	135	28
Transwestern Gas PL Co	CO,NM,W TX	Southwest	New Mexico	AZ	California/TX	2,640	2,487
Tuscarora Gas Trans Co	PG&E-Northwest	Western	Oregon	CA	Nevada	110[b]	229

[a]Includes miles of looped (parallel) pipeline.

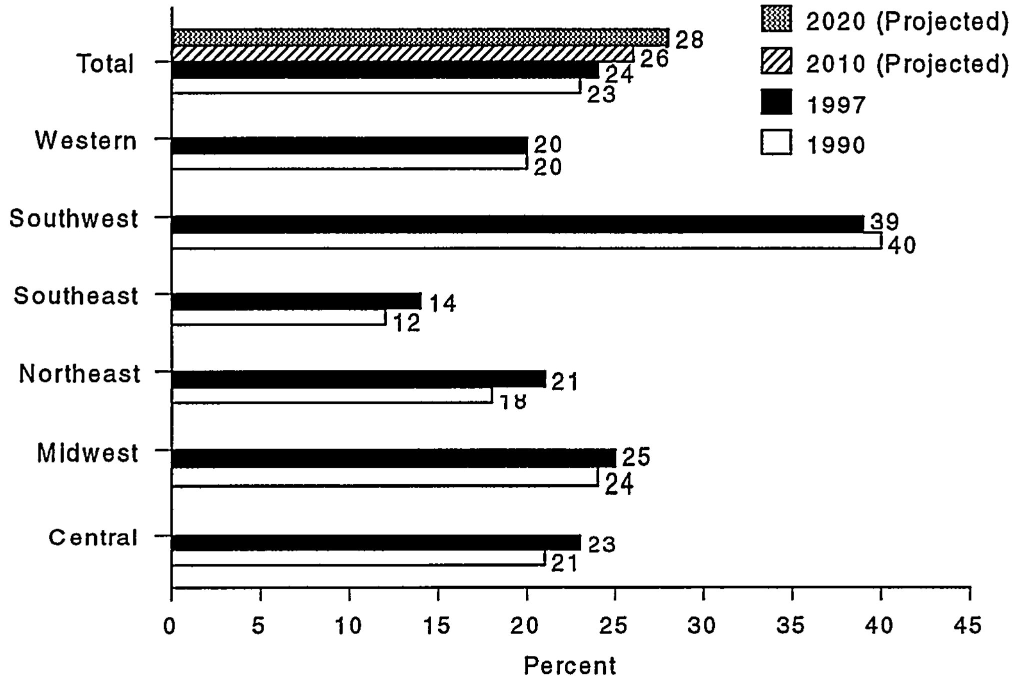
[b]Reported in thousand decatherms per day (Mdth/d). Converted to million cubic feet per day (MMcf/d) using 1.027 conversion factor, e.g., 113 Mdth/d / 1.027 = 110 MMcf/d.

[c]Included in above figure.

– = Not applicable; WL = West Leg; EL = East Leg, NG = Natural Gas; PL = Pipeline; Trans = Transmission. OP = Other Pipelines.

Sources: **Capacity:** Federal Energy Regulatory Commission, FERC 567 Capacity Report, "System Flow Diagram" and Annual Capacity Report (18 CFR §284.12); Energy Information Administration, EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity. **Transmission Line Mileage:** Federal Energy Regulatory Commission, FERC Form 2, "Annual Report of Major Natural Gas Companies" and FERC Form 2A, "Annual Report of Minor Natural Gas Companies."

Figure 39. Percent of Total Energy Fueled by Natural Gas in the United States



Source: **1990-1997:** Energy Information Administration (EIA), *State Energy Data Report, Consumption Estimates 1980-1996* (December 1996) and *Annual Energy Review 1997* (July 1998). **Projected:** EIA, *Annual Energy Outlook 1999* (December 1998).

water oil and gas development projects and corollary pipeline expansions are slated to become operational over the next several years. While much of this development in the Gulf replaces reduced production in older areas, some will also serve expanding customer demand in the Southeast Region for access to additional sources of supply.

Nevertheless, only a limited amount of new pipeline capacity onshore is being added to accommodate the new production. Currently, existing capacity within and exiting the region is not being fully utilized throughout the year. Thus until overall demand for space on those lines rises substantially, any major expansion possibilities will be held in abeyance. A sizeable portion of the new offshore capacity is supporting specific developmental project locations. The few onshore expansion proposals that have been announced (or are under study) will most likely support new interconnections and links to expanding offshore production.

A growing part of the production from the San Juan Basin (New Mexico) and pipeline capacity from the general area has been redirected eastward into the West Texas Waha trading area. This change in orientation was due primarily to greater price competition and sluggish growth in older markets. During 1998, however, the traditional California market has begun to demand a greater portion of San Juan production, and thus the growth in eastward gas flow from the basin has slowed somewhat. Nevertheless, since 1993, several projects have been completed and several more are planned that in total could increase pipeline capacity in this new direction by as much as 715 million cubic feet per day by 2000. This amounts to almost a 30-percent increase in available pipeline capacity flowing eastward to the West Texas trading points since 1990.

Supporting the increased flow of gas eastward has been the growing development of new pipeline capacity on the Texas intrastate system, as well as on several interstate pipelines that operate within Texas. These expansions support the movement of greater quantities of gas across the State from West to East Texas. These actions have given regional traders increased access to Eastern and Midwestern customers who traditionally trade in East Texas and Louisiana. Since 1990, at least 600 million cubic feet per day of new capacity has been added along this corridor.

Despite the increased capacity from the Southwest to the Southeast, customers in the Midwest and Northeast regions are currently opting for increased access to Canadian supplies rather than Southwestern supply. Only a limited amount of pipeline expansion from the Southwest Region (via the Central and Southeast regions) to the Midwest and Northeast regions (2- and 4-percent increases, respectively) occurred between 1990 and 1997 (Table 12). Nor has much been proposed for installation over the next several years. Customers in the Western Region have also come to rely less upon access to Southwestern supply sources and more on Canadian. Between 1993 and 1996, pipeline usage out of the Southwest production areas into the Western Region decreased significantly (more than 30 percent) while usage of those pipelines supplying Canadian gas increased significantly, despite a general economic downturn in the region during the period.

Increased Interest in Moving Rocky Mountain Supply Eastward

The Rocky Mountain area now accounts for 15 percent of gas reserves in the Lower 48 States, up from 10 percent in 1990. Yet, with the exception of the startup of the Kern River Pipeline system in 1993, little or no new pipeline capacity has been developed exiting the area. As a result, natural gas producers in the southern Montana, Wyoming, Utah, and Colorado area (which accounts for 9 percent of Lower 48 production) have sometimes encountered significant capacity bottlenecks, limiting their access to potential customers, especially to the east. This situation has been alleviated somewhat with the expansion of the Trailblazer, Pony Express and Colorado Interstate Gas Company systems in recent years. These systems carry gas out of the area to interconnections with regional pipeline systems and major interstate pipelines serving the Midwest Region.

With their traditional Western regional market growing at a slower rate than their production is expanding, Rocky Mountain producers are concentrating upon gaining greater access not only to Midwest markets but to growing metropolitan areas within the Central Region itself. As a result, the existing systems that exit the area eastward are operating at full capacity throughout most of the year.

Additional pipeline capacity out of this production area is scheduled to become available over the next several years, which will more than double 1997 levels. In addition, during 1998, several regional expansion proposals were announced or approved by regulatory authorities which would expand local market access out of the Powder River Basin with more than 750 million cubic feet per day of new capacity. Several proposals were also announced that would extend additional service to the Western Region, primarily to the northern Nevada area.

Chicago Area Becoming a Major Hub for Expanding Canadian Supplies

Because of its strategic position and extensive system infrastructure, the Chicago Market Center, which began operations in 1993, has become a major hub for the trading of natural gas in the Midwest Region. Among the regions, the Midwest is capable of receiving the highest level of supplies during peak periods, about 25.1 Bcf per day, up from 22.7 Bcf per day in 1990 (Table 12). Traders and shippers using the center can readily trade and gain access to gas from the Southwest Region, in particular at the Henry Hub (Louisiana), and arrange to transship the gas to any number of alternative points within the Midwest and Northeast.

This ability to accommodate shippers and traders has made the hub an attractive destination for several Canadian-proposed pipeline projects designed to bring western Canadian supplies into U.S. markets. Moreover, several other pipeline proposals, seeking to increase deliverability to the Northeast using potential excess capacity from these Canadian proposals, are targeting the Chicago hub as a receipt point for their systems. The flexibility of hub operations and the Chicago center's relationship to the Henry Hub also allow some of these expansion projects to the Northeast to offer shippers access to Southwestern supplies as an alternative to Canadian supplies.

The region has a relatively mature gas market but demand for natural gas continues to grow steadily. Between 1990 and 1997, regional natural gas use grew at an annual rate of 2.4 percent, while total energy use increased at only a 1.1-percent rate.[8] As a result, natural gas's share of the regional energy market increased by 1 percentage point during the period. Moreover, the average daily usage rates on all natural gas pipeline routes into the region, with the exception of some of the recently added Canadian import capacity, increased as well. Overall the usage rate into the region increased from 65 percent in 1990 to 75 percent in 1997. Much of this increase occurred on existing pipelines bringing supplies from the Southwest Region (via the Central and Southeast regions). In part, this increase can be attributed to greater trading activity owing to the links

[8]Energy Information Administration, *State Energy Data Report, Consumption Estimates, 1980-1996*, DOE/EIA-0214(96) (Washington, DC, December 1997); and *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998).

between the Chicago market center, the Henry Hub in Louisiana, and several East Texas market centers.

Greater Deliverability from Canada Expected for the U.S. Northeast

Natural gas still represents only about 21 percent of overall energy consumption in the Northeast (Figure 39), but it has made steady inroads into the region's total energy consumption picture (up 3 percentage points since 1990). This growth is expected to continue into the next century.

In 1997, the interstate pipeline system had the capability to move about 12.5 Bcf of gas per day into the region (Table 12), up 24 percent since 1990. The largest increase, 1.9 Bcf per day, occurred in import capacity from Canada, which grew by 412 percent over the period. By the end of 1998, capacity from Canada is estimated to have increased by 213 million cubic feet per day.

The Northeast Region displayed the most robust growth in natural gas usage with an average annual increase of 4.3 percent between 1990 and 1997 (Figure 40). So it is not surprising that the area has been targeted for the most development of new pipeline capacity of any region over the next several years, about 5 Bcf per day. A key factor in this growth has been the 4.1-percent average annual increase in gas-powered electric generating capacity placed in operation since 1990, which is reflected in an average annual growth in gas usage for electric generation of 3.7 percent during the same period. Future growth is also anticipated as several nuclear plants in the region are expected to be replaced over the next several years by gas-fired units.

Natural gas demand in the region is predicted to grow about 2.8 percent annually through 2010. To meet these added requirements, the trend that began in 1991, to expand access to Canadian imports, is expected to continue and grow. However, while almost all of the previous additional capacity came directly from Canada, about half (1.9 Bcf per day) of the current proposals (3.8 Bcf per day) to bring Canadian supplies into the Northeast Region have routes that will carry these supplies via the Midwest Region. Additional Canadian supplies, directed from the Sable Island area off Canada's east coast, will begin arriving in the region in late 1999, at the rate of up to 440 million cubic feet per day. Further growth along this route is expected after the turn of the century as Newfoundland/Nova Scotia coastal natural gas resources are scheduled to be developed to a greater degree.

Growing Electric Utility Demand for Natural Gas in the Southeast

Of all the regions, the Southeast uses natural gas the least in the overall energy mix: 14 percent versus the national average of 24 percent (Figure 39). However, several of its coastal States have been experiencing double-digit population growth, and as a result, growth in overall energy consumption in this portion of the region has risen at an annual rate of about 2 to 3 percent in recent years, while residential natural gas consumption has grown by 5.6 percent per year.[9]

The largest growth is expected in the electric utility sector. Indeed, between 1990 and 1997, natural gas use for electric power generation increased at an annual rate of 8.5 percent (Figure 40). During the same period, that sector's share of the region's natural gas market grew by 2 percentage points, accounting for 16 percent in 1997.[10] Since 1990, the region has also shown substantial growth in the industrial sector overall, with natural gas usage increasing at an annual rate of about 3.0 percent per year as the number of new industrial customers also grew.[11]

Increasing development of new natural gas reserves within the region and the Gulf of Mexico and expanding regional production are meeting the needs of the region's growing markets. For instance, regional production in 1997 satisfied 33 percent of regional natural gas needs compared with only 17 percent in 1990.[12] The outlook for additional regional production over the next decade is also bright. In particular, it is anticipated that production will be forthcoming from new platforms in Mobile Bay (Alabama) and planned offshore development of the Destin area south of the Florida Panhandle.

Natural Gas Has Lost Market Share in the Southwest and West

During the first half of the 1990s, population levels in the Southwest and Western regions grew at an estimated

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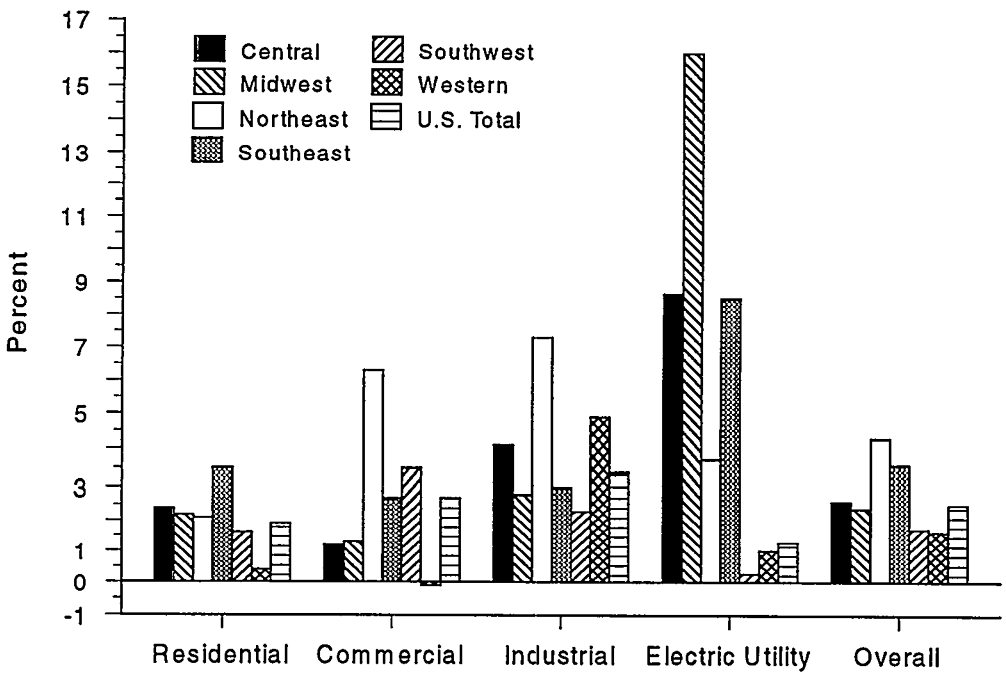
[9]Energy Information Administration, *State Energy Data Report, Consumption Estimates, 1980-1996*, DOE/EIA-0214(96) (Washington, DC, December 1997); and *Annual Energy Review* 1997, DOE/EIA-0384(97) (Washington, DC, July 1998).

[10]More than 90 percent of the expansion capacity on the Florida Gas Transmission system occurring in 1994 and 1995 was to satisfy demand by electric utilities.

[11]Energy Information Administration, *Deliverability on the Interstate Natural Gas Pipeline System*, DOE/EIA-0618(98) (Washington, DC, May 1998).

[12]Energy Information Administration, *Natural Gas Annual 1997*, DOE/EIA-0131(97) (Washington, DC, October 1998) and earlier issues.

Figure 40. Average Annual Rate of Change in Natural Gas Use by Sector, 1990-1997



Note: "Overall" excludes gas for vehicles, lease and plant fuel, and pipeline use.
Source: Energy Information Administration, *Natural Gas Annual 1997* and earlier issues.

average annual rate of 2.7 percent, while the total U.S. population grew at a rate of only 1.9 percent. Yet, since 1990, natural gas has lost market share in these regions. Both are non-weather-sensitive regions with comparatively low residential/commercial market shares. Industrial and electric utility customers constitute the largest users, and they are often able to switch to alternative fuels if the economics dictate. Nevertheless, in the case of the Southwest Region, which saw the largest regional drop in natural gas's share of the energy market, the use of natural gas for industrial purposes had the largest increase of any customer category on a volumetric basis (almost 500 Bcf since 1990), although at an annual rate of only 2.3 percent.

For both the interstate and intrastate pipeline companies in these two regions, this loss of market share has meant a drop in capacity utilization rates overall. However, there are signs that the situation was only temporary. Although the use of natural gas in California for power generation fell during the first half of the decade, primarily owing to a return of hydro power following a severe drought period, demand in other sectors appears to be picking up. During 1998, for instance, two projects were proposed that would increase natural gas supply to the southern California marketplace. One, Questar Pipeline Company's Four Corners project, would bring 130 million cubic feet per day to the Long Beach area from the northern Arizona/New Mexico area. Kern River Transmission Company has also proposed to expand its service to the California coast by building a lateral (300 million cubic feet per day) from its existing system, which now ends in Kern county.

Increased purchasing of Canadian gas by shippers in the West has returned the utilization rates of most of the regional pipelines to relatively high levels. Even the pipeline systems that transport supplies from the Southwest Region, Transwestern Pipeline and El Paso Natural Gas, who experienced a major drop in utilization rates as several major shippers turned backed capacity rights, are now attracting new customers eager to compete in the regional market.

In the Southwest Region, where a number of pipeline systems have experienced some falloff in pipeline usage in local markets, expansions in several major supply areas and increased demand for regional export capacity have somewhat compensated for the decline. Expansions on several intrastate systems in recent years, principally those that connect West Texas to East Texas markets, have also been a positive note.

Cost of Pipeline Development

All of this pipeline development requires significant capital investment.[13] In 1996, investment in pipeline developments amounted to about $0.6 billion (Table 11). From 1997 through August 1998, an estimated $2.1 billion was invested. And for the next several years at least, the amount of additional capital investment slated for natural gas pipeline expansion is expected to grow significantly, reflecting the anticipated development of several large (new) pipeline systems, mainly from Canada.

The cost of a pipeline construction project varies with the type of facilities being built and the distance involved (see box, p. 122, and Figure 41). Typically, a new pipeline, for which right-of-way land must be purchased and all new pipeline laid and operating facilities installed, will cost much more than an expansion of an existing route. For instance, a new pipeline, such as the proposed long-distance Alliance Pipeline system, is expected to cost as much as $1.81 per added cubic foot of daily capacity. In contrast, the relatively short-distance Texas Eastern Lebanon expansion project is expected to cost about $0.25 per added cubic foot of daily capacity. When recently completed and proposed projects are categorized by project type, new pipeline projects averaged about $0.48 per added cubic foot; a major expansion, about $0.33; and a small expansion, i.e., compression-only, about $0.15 (Figure 42).

During 1996 and 1997, the costs per added cubic foot of capacity averaged about $0.21 over 68 projects (Table 11). The majority of these projects (42) were expansions to existing pipelines systems. However, based on the projects currently scheduled for completion in 1998 and through 2000, average costs will increase as a number of new pipelines and large expansions projects are implemented. The high average cost per mile in 2000 reflects the magnitude of both expansion and new projects slated for development during that year.

The cost of a project also varies according to the region of the country in which it is located or traverses. For instance, projects that must go through major population areas, such as found in the Northeast or Midwest regions, on average cost more than those developed in the more sparsely populated and open Central and Southwest regions. Furthermore, while many of the projects completed in the Northeast and Midwest in recent years have tended to be expansions to existing systems, which are less expensive overall, future development in these regions will include many of the large new and expansion projects, which, on average, are much more expensive. For instance, in the Northeast Region, where 13 projects were completed during 1996 and 1997, the average cost per cubic foot of added daily capacity was about $0.22,[14] while over the next 3 years the average cost in the region is estimated to rise to about $0.37. On the other hand, in the Southwest Region, where much less long-haul pipeline development is slated to be installed, the average cost per project is estimated to fall into the range of $0.20 to $0.23 per cubic foot of capacity.

Although the least populated of the regions, the Central Region has relatively high average costs per planned project, reflecting the prevalence of new pipelines and large expansion projects scheduled for development over the next several years. For instance, of the 18 projects proposed for the region, average costs range between $0.35 and $0.43 per cubic foot of daily capacity, in the high range among the regions. Of the projects primarily located in the Central Region, a number are high-mileage trunkline expansions and new pipe laid to reach expanding supply areas, such as the Powder River area of Wyoming.

The differences between the estimates of project cost provided prior to construction and the actual costs are usually not large. Computer programs and extensive databases have improved estimation techniques substantially during the past several decades. According to one report that compared the actual cost of pipeline projects (filed with FERC between July 1, 1996, and June 30, 1997) with the original estimates,[15] the difference was only about 4 percent: the largest difference being in the estimated/actual cost of materials (7 percent) and the lowest being in labor costs (2 percent). Most of the differences between the two figures can usually be attributed to revisions in construction plans because of routing changes and/or pipeline-diameter changes on specific pipeline segments (often for environmental or safety reasons, see box, p. 124).

On average, construction/expansion projects completed in 1996 or 1997 took about 3 years from the time they were first announced until they were placed in service. Construction itself typically was completed within

[13] In 1997, according to filings with the Federal Energy Regulatory Commission, total capital (gas plant) investment in place by the major interstate pipeline companies amounted to close to $60 billion.

[14] One of the reasons for this was that almost all of the projects were low-mileage or compression additions rather than long-haul new pipelines.

[15] Warren R. True, "Construction Plans Jump: Operations Skid in 1996," Pipeline Economics OGJ Special, *Oil and Gas Journal* (Tulsa, OK: Pennwell Publishing Co., August 4, 1997).

Natural Gas Pipeline Development Options and Costs

Stages of Natural Gas Pipeline Development

The need for new or additional pipeline capacity to meet the growing demand for natural gas can be implemented in several ways. Pipeline designers have various options open to them, each with particular physical and/or financial advantages and disadvantages. The least expensive option, often the quickest and easiest, and usually the one with the least environmental impact is to upgrade facilities on an existing route. But that may not be feasible, especially if the market to be served is not currently accessible to the pipeline company. Some of the alternatives available, along with the various steps involved in completing the effort (besides the mandatory regulatory approval), include the following.

- **Build an Entirely New Pipeline**
  - — Survey potential routes and assess environmental/historical impact
  - — Acquire rights-of-way (new land or along routes of existing utility services)
  - — Build access roads and clear/grade/fence construction pathways
  - — Dig/explode pipe ditches (padding bottom and soil upgrades)
  - — Lay pipe (string, bending, hot pass, fill/cap weld, wrapping, inspection)
  - — Build compressor stations, pipeline interconnections, and receipt and delivery metering points
  - — Pad/backfill/testing and final survey
  - — Restore construction site(s).

- **Convert an Oil or Product Pipeline**
  - — Acquire pipeline and assess upgrade requirements
  - — Upgrade some pipe segments (for example, larger diameters to meet code standards in populated areas)
  - — Install compressor stations at 50- to 100-mile intervals
  - — Build laterals to reach natural gas customers and install metering points
  - — May have to build bypass routes (to avoid certain oil related areas such as tank farms).

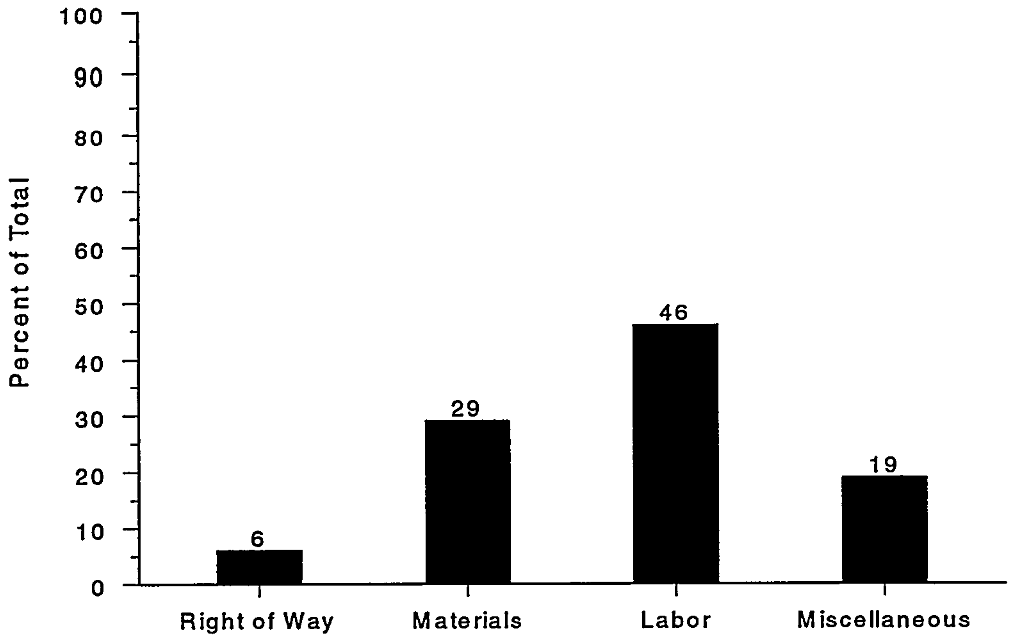
- **Expand an Existing Pipeline System**
  - — Add new laterals and metering points
  - — Install pipeline parallel to existing pipeline line (looping)
  - — Install new compressors
  - — Build interconnections with other pipeline systems.

Expanding an existing pipeline or converting an oil pipeline also include many of the same construction tasks as building a new pipeline but usually to a much lesser degree. When an expansion project includes building a lateral, then all the new-pipeline procedures apply to installing the new section. When pipeline looping is installed, digging/laying/testing and site restoration are necessary.

Component Costs of Pipeline Development

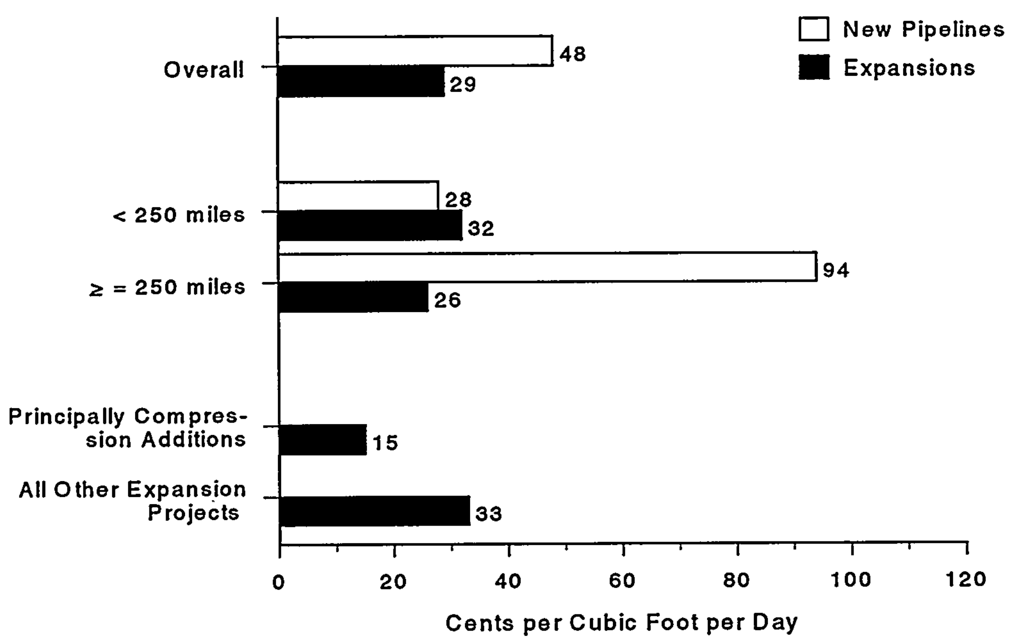
The major cost components associated with the building or expansion of a natural gas pipeline are usually placed under the following categories: labor (including survey and mapping), right-of-way acquisition, facilities (compressor stations, meter stations, etc.), materials (compressors, pipe, wrapping), and miscellaneous (administration, supervision, interest, Federal Energy Regulatory Commission fees, allowances for funds during construction, and contingencies). Generally, labor costs represent the largest component (Figure 41), although on new, long-distance pipeline projects, with pipe diameters greater than or equal to 36 inches, material costs approach labor costs. Right-of-way costs also represent a larger proportion of costs in the latter case.

Figure 41. Proportion of Costs by Category for Completed Natural Gas Pipeline Projects, 1991-1997



Note: Based on average cost per mile of onshore natural gas projects in the Lower 48 States of 16-inch or greater pipe diameter.
Source: Pennwell Publishing, *Oil and Gas Journal* (OGJ), Pipeline Economics OGJ Special (August 4, 1997).

Figure 42. Average Costs for New Capacity on Completed and Proposed Natural Gas Pipeline Projects, 1996-2000



Note: Data for each category were not available on all projects. For example, estimated/actual project cost or miles of pipeline were not announced or not available until filed with the Federal Energy Regulatory Commission. In some cases, where profiles of projects were similar but for which one cost was unavailable, an estimated cost was derived and assigned to the project based on known data.

Source: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System, Natural Gas Pipeline Construction Database, as of August 1998.

Environmental Impact of Natural Gas Pipeline Expansions

The extent of the environmental impact brought about by natural gas pipeline construction depends upon the size of the project, its length, and its design. A large new pipeline route, built from scratch, will necessitate a good deal of environmentally sensitive actions compared with a project that only involves the upgrading of existing facilities to expand capacity. For instance, planning of a new route has to include an evaluation of its need (perhaps to be economically viable) to cross wetlands, wildlife-sensitive areas, or potential archaeological sites, and its trespass minimized before being presented to regulatory authorities. Alternative routings must also be available, since the regulatory authorities may withhold approval even if passage through these lands has the potential to create only a minimal intrusion. Upgrades and expansion projects, since they usually involve less development of new rights-of-way (other than building relatively short laterals), generate much less of a potential impact in these types of environmentally sensitive areas. Some other types of impacts that must be evaluated include the effects of:

- Clearing construction routes and building access roads
- Possible redirection (oftentimes temporary) of waterways or other natural formations
- Possible oil-residue discharge (when converting an oil line)
- Hydrostatic test water discharge (when leaks are detected).

The proposed expansion also must be evaluated in regard to its potential environmental impact once it is completed and placed in operation. For instance, it must be examined for:

- Emissions from compressor station operations
- Noise from compressor stations.

Land-clearing affects indigenous vegetation to the extent that it must be removed; however, in most instances only a narrow layer of soil is usually scraped off (of the nonditch section of the construction right-of-way) leaving most root systems intact. Grading is required when the topography is not level enough to establish a stable work area or when conditions, such as steep slopes or side slopes, exist.

When natural gas is used for fuel, a sample compressor station unit will emit approximately 50 tons per year of nitrogen oxide, 75 tons of carbon monoxide, and 50 tons of volatile organic compounds. This estimate is based on continuous year-round operation (8,760 hours) of a unit with a 3,300 horsepower (HP) rating. The typical level of compressor station emissions will vary depending upon actual hours of annual operation, HP rating, number of individual units, and other factors. Some compressor stations use electric-powered units rather then natural-gas-fueled units. Their on-site direct emission levels are zero.

Environmental Review of Pipeline Construction

The National Environmental Policy Act (NEPA, 1969) requires that anyone proposing to undertake a major interstate-related project, such as construction of a pipeline, LNG import terminal, gas storage field, or other major project that may have a significant impact on the environment, first produce an environmental impact study (EIS) that examines the types of environment-sensitive features involved in their project. The EIS must also describe the actions that are to be taken to mitigate potential damage. The Federal Energy Regulatory Commission must evaluate and approve any EIS associated with a pipeline construction related activity within its jurisdiction.

Depending upon the project profile and its proposed route, the preparation of the EIS itself can be a major undertaking, the approval process lengthy, and the cost of implementing remedial actions significant. However, in many instances, approval delays occur because the initial study does not address the environmental aspects of the project thoroughly and is not complete enough to permit a proper evaluation. As a result, regulators often have to ask for additional data and more time is needed before environmental approval can be granted. In some instances, when only conditional environmental approval is granted, the project's economic viability may be affected because of unanticipated extra costs and schedule delays. Most proposed pipeline projects, however, encounter little or no delay as a result of environmental review.

18 months following FERC approval, sometimes in as little as 6 months. The remainder of the period was consumed with the initial open-season (2 months), plan development prior to filing (3 months), and FERC review and reaction to FERC revisions, if any. Generally FERC review takes from 5 to 18 months, with the average time being about 15 months.[16]

Future Development

From 1998 through 2000, more than 100 pipeline projects have been proposed for development in the Lower 48 States (Table 11). While a number of these projects are only in their initial planning stage with no firm cost estimates yet available, 70 projects have preliminary estimates associated with them.[17] Based upon these projects,[18] at least $12.3 billion could be spent on natural gas pipeline expansions from 1998 through 2000 (Figure 36). The largest expenditures, about $6.3 billion, would be for the several large projects scheduled for completion in 2000, such as the Alliance Pipeline ($2.9 billion), the Independence Pipeline ($680 million), and the Columbia Gas System's Millennium project ($678 million).

Between 2000 and 2020, EIA forecasts that the largest growth in demand,[19] 2.4 trillion cubic feet (Tcf), will occur in the Southeastern United States (the East South Central and South Atlantic Census regions)—an annual growth rate of 3.0 percent.[20] The next largest demand growth, 1.9 Tcf (2.3 percent annual growth rate), is expected in the Northeast (the New England and Middle Atlantic Census regions). The Southwestern area (West South Central) is also expected to have substantial growth, with demand increasing 1.2 Tcf (1.3 percent annual growth rate) between 2000 and 2020.

The projected demand growth in the Southeastern region is expected to be driven by greater electric utility demand and increased residential/commercial usage. A major portion of this growth will be supplied by increased natural gas production within the region (from coalbed methane sources in southern Appalachia and in the Black Warrior Basin in northern Alabama). The pipeline capacity additions to meet the transportation demands can be expected to be developed within the region itself. EIA forecasts that capacity into the region will increase at an annual rate of only about 0.1 percent between 2001 and 2020 and capacity exiting the region will increase at a 0.3 percent rate. A sizable portion of the additions is destined to meet demand in the Northeast, although some is also targeted for the Midwest market.

Overall, interregional pipeline capacity (including imports) is projected to grow at an annual rate of only about 0.7 percent between 2001 and 2020 (compared with 3.7 percent between 1997 and 2000 and 3.8 percent between 1990 and 2000). However, EIA also forecasts that consumption will grow at a rate of 27 Bcf per day (1.8 percent annually) during the same period. The difference between these two growth estimates is predicated upon the assumption that capacity additions to support increased demand will be local expansions of facilities within regions (through added compression and pipeline looping) rather than through new long-haul (interregional) systems or large-scale expansions.

It can be expected that additions to new capacity to the Midwest and Northeast from Canadian sources will slow after 2000. The EIA forecast projects that little new import capacity will be built between 2001 and 2006 (about 0.2 percent per year). From 2007 through 2020, import capacity is expected to grow only 0.7 Tcf, compared with the 1.8 Tcf (an estimated 4.8 Bcf per day) projected to be added between 1997 and 2000 alone. However, as demand continues to expand in the Midwest and Northeast during the period,[21] additional capacity on those pipelines extending from the Southeast Region (Texas, Louisiana, and especially out of the Gulf of Mexico) to these regions can be expected to grow. Several factors could influence this potential shift. First, as Canadian supplies expand their access to U.S. markets, growth in western Canadian production may slow. And, as a result, price competition between domestic and imported natural gas could

[16]Federal Energy Regulatory Commission, Office of Pipeline Regulation, Case Tracking System.

[17]Most projects that have yet to be filed with regulatory authorities do not provide cost estimates. Cost estimates given at the time of filing will certainly change by the time the project is completed. The Federal Energy Regulatory Commission requires that an actual cost figure must be filed within 6 months of the time a project is placed in service (CFR Section 157.20).

[18]Including derived estimates for an additional 15 projects without preliminary estimates. Estimates for these were developed based on proposed project profiles similar to completed or proposed projects for which estimates were given.

[19]Excluding lease, pipeline, or plant fuel usage, which varies per region but constitutes about 10 percent of total annual U.S. consumption.

[20]The geographic makeup of the Census regions discussed in this section differs slightly from the regions discussed elsewhere in this chapter and shown in Figure 38.

[21]Some Canadian expansion capacity into the Northeast (New England) will occur primarily to accommodate increased production from the Sable Island area off Canada's east coast.

narrow the price differential between them, and thus allow U.S. supply sources to attract new customers.

Investment Estimates

The amount of new pipeline capacity that is projected to be added to the national network between 2001 and 2020 represents a very large potential investment in new resources. After 2000 and the completion of several "new" systems, such as the Alliance, TriState, and Vector pipelines, it is likely that few, if any, new long-distance trunklines would be needed to improve the scope and reach of the national network.[22] By then, most potential sources of production and markets will be in relatively close proximity to some part of the grid, necessitating only short pipeline extensions or expansion of an existing route to meet new demand. As a result, it might be reasonable to assume that most of the expansion projects during the next 20 to 25 years will be additions to existing systems (through looping and added compression) and therefore in total should cost less (in real terms) to implement than the typical project built during the 1990s.

Based on the EIA-projected increase in natural gas consumption by 2020 of 24.9 Bcf per day (9.1 trillion cubic feet per year)[23] (half the rate projected to occur in the 1990s) and applying the current estimated average cost of $0.39 per cubic foot per day per unit of added capacity (Table 11), a minimum investment of $9.7 billion would be needed between 2001 and 2020 to match capacity, one for one, with growth in demand.[24] However, a greater amount of pipeline capacity must be placed in service over time to accommodate an anticipated increase in demand. Indeed, a comparison of the amount of completed and proposed capacity additions between 1996 and 2000 (36.2 Bcf per day) with projected demand growth during the same period (4.5 Bcf per day) shows an 8-to-1 ratio between the two.

Several factors account for this. First, pipeline capacity must be designed to meet peak-day demands, not simply average daily requirements. As a result, demands on a pipeline system during peak periods can be several times those occurring during offpeak periods. Second, while pipeline capacity, especially for a large project, becomes immediately available and accounted for upon completion of the project, the level of anticipated new demand may not immediately match the level of new capacity. Rather, for the first year or so after the project is completed, usage of the new capacity is expected to grow until the line is fully utilized (that is, peak-period demand nears capacity levels). As a consequence, and temporarily at least, the incremental increase in capacity will exceed demand needs.

Lastly, to move supplies to end-use markets from production areas, several discrete though complementary projects, each with its own capacity level and customer delivery requirements, are usually necessary. As a result, several units of new capacity may be tallied even though only one unit of gas flow (incremental demand) will be accommodated.[25] However, the need for multiple discrete, but related, projects will diminish if, as assumed, most new capacity beyond 2001 is from expansions to existing regional systems and short-haul lines rather than new pipelines and major interregional expansions. For instance, a review of projects completed or proposed within the 1996-through-2000 time frame indicates that the ratio between singular capacity additions and actual/projected demand might be closer to about 4 to 1 if related projects were consolidated and/or complementary ones eliminated.

Assuming then that the need for a certain level of new capacity relative to a specified level of demand-increase might range from 4-to-1 to 8-to-1, between $39 billion and $78 billion in capital investments (at $0.39 per added cubic foot)[26] could be required of the natural gas pipeline industry to meet the increase in demand (24.9 Bcf per day) projected to occur by 2020. The high investment estimate could also result if there is a need for one or more large, new pipeline systems during the period (2001 through 2020). More likely, much of the new capacity beyond 2000 will come from expansions to existing systems rather than new pipelines, in which case the total investment required will be at the lower end of the range, perhaps in the vicinity of about $45 billion.

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[22]Unless, perhaps, a source of supply in southern Mexico was tapped and a new pipeline system built in Texas to interconnect with the interstate system.

[23]Includes lease, pipeline, or plant usage of natural gas. Energy Information Administration (EIA), *Annual Energy Outlook 1999*, DOE/EIA-0383(98) (Washington, DC, December 1998).

[24]The investment figures are based on broad estimates of future pipeline expansion requirements and simplifying assumptions regarding how and where additional investments may be required. As such, they reflect, at best, rough estimates of future potential natural gas pipeline investment needs.

[25]For instance, the Alliance Pipeline project, starting from British Columbia, Canada, and ending in Chicago, Illinois, would deliver a portion of its flows to the TriState and/or Vector pipelines for eventual delivery to Ontario, Canada, and the Eastern United States. They, in turn, would redeliver to other new and expansion projects in the Northeast such as Columbia's Millennium and Tenneco's Eastern Express. Several other proposed new pipelines and expansions also anticipate redelivering some of Alliance's capacity to the eastern United States. These same projects would also be set up to accommodate shipments from other expansion pipelines bringing supplies to Chicago from other areas as well.

[26]And using a base of $9.7 billion for a 1-to-1 demand /capacity ratio.

Outlook

The natural gas pipeline network in Canada and the United States has grown substantially since 1990. Meanwhile, its numerous parts have become more interconnected, its routings more complex, and its business operations more fluid. New types of facilities, such as market centers, and established operations, such as underground storage facilities, have become further interwoven into the fabric of the network and have made the system operate in a much smoother manner.

While a major amount of new pipeline capacity is scheduled to be built over the next several years, just as important will be the types of complementary facilities and services that are installed or developed to support it. Although it is likely that only a few new market centers will become operational during the next few years, the services and flexibility offered at existing sites can be expected to be expanded and improved. The Chicago market center, for example, should grow as Canadian import and Southwest supplies (via the Henry Hub) expand into the area and some of this gas is redirected to the Northeast Region. The Leidy Hub in northcentral Pennsylvania is the transaction and transfer point for several major pipelines and market centers serving the Northeast and can be expected to become key to moving gas from the Midwest to New England markets and other parts of the region.

Underground storage operations, which facilitate both market center services and efficient pipeline operations, will also be expanding over the next several years in support of market center or pipeline expansions (Chapter 1).[27] For instance, the proposed Millennium (Columbia Gas Transmission Company) and Independence (ANR and Transcontinental Pipeline Company joint venture) pipeline systems to transport supplies from the Chicago, Illinois area[28] to the Northeast will require the expansion of several storage facilities in Ontario, Michigan, New York, and Pennsylvania to handle the additional load. Likewise, in the southern States of Texas, Louisiana, and Mississippi, where a number of market centers are located (including the Henry Hub), several high-deliverability salt cavern storage facilities are being expanded to handle growing production out of the Gulf of Mexico. They are also expected to handle increasing business among regional hubs, such as those located in the Midwest (Chicago) and the Northeast (Pennsylvania and New York). In these States alone, proposed increases in daily deliverability (through 2001) from storage sites that directly or indirectly support market or trading centers total 2,200 million cubic feet per day, or 5 percent more than current levels.

Given the forecasted growth in natural gas demand in the Midwest and Northeast, it seems certain that a good proportion of the proposed additional capacity will be built. However, a few of the projects might encounter later contract abandonments by customers because current estimates of near-term demand requirements could be overly optimistic. In some cases, where there is an obvious duplication of service, it is likely that some projects will be abandoned, downsized, or consolidated into a single effort.

EIA projects that natural gas consumption will move above the historical peak of 22 trillion cubic feet (Tcf) (reached in 1972) in 1999, increase by another 5 Tcf by 2010, and reach more than 32 Tcf by 2020. This growth is largely expected to come about as a result of increased use of natural gas for electricity generation in the electric utility sector and for cogeneration in the industrial sector.

The current extensive list of planned capacity additions and expansion projects indicates that substantial activity is underway to address these potential increases in demand. If all the projects currently proposed were built, interregional capacity would increase by as much as 12.8 billion cubic feet (Bcf) per day or about 15 percent from the level in 1997. Additional projects that are limited to providing service within a specific region comprise an additional 14.3 Bcf per day of capacity (see Chapter 1).

The current interregional and State-to-State capacity levels, in most instances, appear adequate to meet current customer demands, although in a few cases, the average daily pipeline utilization rates rose significantly between 1990 and 1997. This rise in usage is a good indicator that instances of peak-period capacity constraint could occur if demand for natural gas in some markets increases faster than expected. On the other hand, while the amount of new capacity proposed for the next several years is consistent with forecasted demand, there probably will be some local areas where available pipeline capacity may not always match demand.

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[27] Also see Energy Information Administration, "U.S. Underground Storage of Natural Gas in 1997: Existing and Proposed," *Natural Gas Monthly*, DOE/EIA-0130(97/09) (Washington, DC, September 1997).

[28] Much of it is Canadian gas shipped from Emerson, Manitoba, through Ontario, Canada, via the U.S. Midwest.

6. Contracting Shifts in the Pipeline Transportation Market

Natural gas must be competitively priced in order to be a viable energy choice for consumers. The cost of the natural gas commodity, set by market conditions, represented about half of total gas service costs paid by consumers in 1997. The remaining costs were associated with moving the gas from the field to the customer's point of consumption. These delivery costs are regulated under Federal (interstate transportation) and State (intrastate transportation and distribution) laws and regulations.

The terms and costs of transporting natural gas along the interstate pipeline grid are specified in contracts between pipeline companies and shippers. Many of the firm service contracts have been in place for several years and may no longer reflect current market conditions. Consequently, some shippers are choosing not to renew these contracts when they expire and instead are "turning back" some or all of the capacity to the pipeline companies. In fact, recent experience (based on a representative sample of 54 unique shipper-pipeline pairings) indicates that 19 percent (excluding a turnback of 1.2 trillion Btu per day to El Paso Natural Gas Company in 1997) of firm service capacity under expiring long-term contracts was turned back between April 1, 1996, and March 31, 1998. Some of this capacity has been remarketed to other shippers but generally at much lower rates.

Changes in capacity contracting are related to a larger transition in the natural gas transportation market. Shippers appear to be using capacity on different pipelines to access competing natural gas supply sources. Also, marketers, who are increasingly taking over LDC service functions, are writing more contracts for firm transportation service. Marketers increased their market share by 3 percentage points between April 1996 and July 1998, from 21 to 24 percent of total U.S. contracted capacity.

This analysis assesses the amount of capacity that may be turned back to pipeline companies, based on shippers' actions over the past several years and the profile of contracts in place as of July 1, 1998. It also examines changes in the characteristics of contracts between shippers and pipeline companies. The analysis does not factor in the projected growth in demand for natural gas, infrastructure growth, or other market changes; these factors would tend to mitigate the overall impact of capacity turnback.

- Between 1998 and 2003, about 8.0 trillion Btu per day, or 8 percent of currently committed capacity, is likely to be turned back to interstate pipeline companies. Some or all of this turned back capacity may be remarketed, but potentially at lower rates, which could lead to stranded facilities costs if the revenue does not cover the capital investment.

- Overall, the total amount of interstate capacity that is reserved under firm transportation contracts has remained fairly steady during the past 2 years (July 1996 through July 1998), at about 95 to 105 trillion Btu per day. This is due mainly to two factors: (1) the new contracts for recently completed pipeline capacity and (2) the remarketing of some turned back capacity.

The turnback of pipeline capacity appears to be a transitional issue for the natural gas industry—perhaps the last wave of fallout from the industry restructuring under Federal Energy Regulatory Commission (FERC) Order 636. There are parallels to take-or-pay costs in the 1980s, when wellhead contracts did not reflect market conditions and purchasers were unable to use the supplies they had under contract.

Restructuring within the natural gas industry, including unbundling at both the interstate pipeline and retail markets, has had a significant impact on contracting practices for interstate transportation services. Although Federal Energy Regulatory Commission (FERC) Order 636 required pipeline firm sales customers to convert to firm transportation, it did not permit these customers to reduce their level of service.[1] The firm sales customers were mainly local distribution companies (LDCs) who contracted for guaranteed service to meet the high-priority needs of customers. With the more competitive retail market of today, however, many of these LDCs no longer have the fixed customer base that the contracts were designed to serve, although they are locked into long-term transportation contracts.

When these contracts come up for renewal, shippers have the opportunity to reassess their service requirements and change the terms of their contract portfolio. In some cases, they are choosing to reserve less capacity and for shorter time periods.[2] From April 1996 to March 1998, in a sample of 54 shipper-pipeline pairs, 2.4 trillion Btu per day intransportation capacity under long-term contracts (in excess of 1 year) was turned back, or 37 percent of the total capacity covered by the expiring long-term contracts in the sample.[3] Much of this turnback was related to the nonrenewal of a 1.2-trillion-Btu-per-day contract with El Paso Natural Gas Company in 1997. If El Paso Natural Gas is excluded from the analysis, 19 percent of firm capacity under expiring long-term contracts was turned back during the period.

Over half of the total firm capacity reserved as of July 1, 1998, is under contracts that will expire by the end of 2003. While this provides shippers with the opportunity to adjust to changing market conditions, contract changes could result in stranded investment costs owing to underutilized pipeline and LDC assets.[4] This chapter quantifies the potential for capacity turnback based on shippers' current contracts and the amount of capacity traded via the release market.[5]

Estimates of turnback are developed by assuming that the current rate of capacity trading, via the release market, is representative of capacity that could be turned back. A key assumption of this analysis is that capacity that is released for an extended period of time is no longer needed by the shipper. Shippers generally release only that portion of capacity that they do not expect to use for their own service requirements. By combining this estimate with information on existing contracts, estimates can be made of the timing and amount of capacity that is likely to be turned back. This analysis builds on work published in the 1996 edition of *Natural Gas: Issues and Trends*.[6] The earlier work examined the contract expiration schedule and the maximum potential for capacity turnback. This chapter assesses the amount of capacity that may be turned back to pipeline companies, based on shippers' use of contracted capacity over the last several years and the profile of contracts in place as of July 1, 1998. The analysis does not factor in the projected growth in demand for natural gas, infrastructure growth, or other market changes that will affect the remarketing of capacity and tend to mitigate the overall impact of capacity turnback (see box, p. 131).

Background

Restructuring of the natural gas industry has resulted in the realignment of contracts in all facets of the industry as market participants adjust those contracts originally developed under a highly regulated environment to more market-oriented conditions. The costs associated with these adjustments have sometimes been significant and resulted in considerable time and negotiations to resolve who ultimately has to cover these costs. During the 1980s, pipeline companies and their customers were saddled with costs resulting from take-or-pay provisions in gas procurement contracts.[7] Take-or-pay liabilities grew to

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[1]Order 636 did not allow firm customers to reduce their reserved capacity levels unless another party was willing to contract for the capacity at maximum rates or the pipeline company was willing to assume responsibility for the cost of the capacity.

[2]Shippers having the option to rebundle or resell the capacity (for example in the "gray market") are exceptions to this generalization. See *Natural Gas 1996: Issues and Trends*, DOE/EIA-0560(96) (Washington, DC, December 1996).

[3]In this chapter, capacity and capacity trading are measured on a heat content or Btu basis to be consistent with the units generally used in natural gas contracts. Also, long-term contracts are defined as being longer than 366 days; short-term contracts are for 366 days or less.

[4]The LDC assets include capacity contracts for interstate pipeline transportation service.

[5]The analysis in this chapter is based on data from a sample of 64 major pipeline companies that accounted for approximately 92 percent of interstate natural gas transportation in 1997. The sample was selected to cover the period April 1996 through July 1998. A number of data sources were used in this analysis, including information provided by interstate pipeline companies on capacity release trading and on firm transportation contracts (see Appendix D).

[6]Energy Information Administration, *Natural Gas 1996: Issues and Trends*, DOE/EIA-0560(96) (Washington, DC, December 1996).

[7]Take-or-pay provisions require the pipeline companies to pay for specified gas quantities (typically a percentage of well deliverability) even if the gas is not delivered.

Methodology for Analysis

This chapter assesses the extent of the turnback of firm transportation capacity in recent years and the potential for capacity turnback in the future. Capacity turnback was analyzed by examining firm transportation contracts held by shippers on 64 interstate natural gas pipeline companies. The analysis consists of five separate, yet related components that focus on a distinct aspect of transportation contracts. Several of the component analyses focus on unique samples of either pipeline companies and/or contracts, so in some cases fewer than 64 interstate pipeline companies were examined.

Trends in Contracting Practices. The analysis addresses shipper contracting behavior relative to the amount of capacity held, the length of the contract (short- or long-term), and the average capacity per contract. The results are based on quarterly data for April 1, 1996, through July 1, 1998, in the Federal Energy Regulatory Commission's (FERC) Index of Customers. The availability of 10 quarters of data allows an examination of changes in shipper contracting behavior over time as well as separate analysis of contracting during two heating seasons. The shippers in the Index of Customers were assigned one of six classifications: electric utility, industrial, local distribution company, marketer, pipeline company, or other (including producers, gatherers, processors, storage operators, and shippers that could not be identified). Analysis of firm contracting volumes held by shipper type was performed with a particular focus on contract expirations and new contracts during the four quarters ended July 1, 1998.

Individual Shipper Contracting Practices and Regional Patterns. Capacity turnback was analyzed at the contract level by examining the behavior of shippers holding the largest contracts that expired in each region.This resulted in a sample of 54 unique shipper-pipeline pairings. For each large contract expiration during the period April 1, 1996, through March 31, 1998, shipper activity in the subsequent quarter was observed (e.g., a new contract may have been put in effect, but with different characteristics from the expired contract). Aggregate shipper activity upon contract expiration is presented in the analysis at the regional level.

Capacity Release. Capacity release information and contract expiration data as reported in the Index of Customers were used to assess the potential future turnback of capacity. Data on daily amounts of released capacity held by replacement shippers were obtained from Pasha Publications, Inc. and the Federal Energy Regulatory Commission. To obtain a consistent set of data on both capacity from the Index of Customers and on capacity release, the set of 64 pipeline companies was reduced to 27. These 27 companies accounted for 82 percent of the firm capacity held by the original set of 64 companies on July 1, 1998.

Estimates of Capacity Turnback. The minimum amount of released capacity held by replacement shippers in each region during the heating season (November through March) was used to estimate the percentage of capacity that can reasonably be expected to be turned back as shipper contracts expire. A "turnback ratio" was developed for each region using the region's capacity release and firm contracted capacity information for 27 interstate pipeline companies.These regional ratios were used to develop two estimates. The first was regional estimates of capacity turnback and the second a national profile of when capacity turnback will occur. The estimate of capacity turnback is the total that may be expected to be turned back over time as contracts expire. An estimate of the regional total and the timing of these turnbacks or a national turnback "profile" was developed by applying the regional turnback ratios to the long-term capacity under contract as of July 1, 1998. The ratios were applied to the amount of long-term firm capacity expiring each year in the region (for the full set of 64 pipeline companies). It may be likely that a greater proportion of early expirations will be turned back than later expirations, but without more specific data, applying the turnback ratio as a constant in each year provided a baseline national profile that can be used to assess the potential impact of capacity turnback on the natural gas industry.

high levels in the 1980s when many pipeline companies faced rapidly declining sales and realized that they would probably not be able to take (and resell) the gas for which they had contracted. The resulting recovery of these costs has stretched into the 1990s. Contract reformation costs resulting from take-or-pay settlements totaled about $10.2 billion as of May 1995, of which $6.6 billion is being recovered from consumers.[8]

[8]Settlement costs filed with the Federal Energy Regulatory Commission. Interstate pipeline companies, in general, absorbed the difference between the $10.2 billion settlement total and the $6.6 billion billed to consumers.

In the early 1990s, transition costs were incurred by interstate pipeline companies as a result of complying with FERC Order 636, which required them to become transporters rather than resellers of natural gas. These transition costs included charges for gas supply realignment, unrecovered gas costs, costs for new equipment, and stranded costs. As of early 1998, $3.3 billion in transition costs associated with Order 636 had been filed at FERC for recovery through increased transportation rates, with gas supply realignment accounting for more than half of that at $1.9 billion.[9]

The potential for incurring stranded costs because of reduced contracted capacity levels will continue for a number of years. In addition, the price impacts may be felt for many years after the contracts expire. Nevertheless, capacity turnback may also create opportunities for some shippers and pipeline companies, in that the unused capacity for firm service can be offered to other shippers who need the service. This, in turn, could reduce the need to build additional pipeline capacity, which is expected to be needed to meet the projected increased demand for natural gas during the next 20 years.

The Energy Information Administration (EIA) projects that annual consumption of natural gas will reach 32.3 trillion cubic feet by 2020, a 52-percent increase over the 1998 level. More than half of this growth results from rising demand for electricity generation, excluding industrial cogeneration. Market growth of this intensity will necessitate an expansion of the U.S. natural gas delivery system. The realignment of capacity contracts is another adjustment in the restructuring process. EIA projects a general decrease in transmission and distribution margins through 2020, as increased throughput combined with cost reductions result in a decrease in the price paid to deliver each unit of gas.[10] However, the market growth may not occur if the margins do not decrease as projected. In addition, the degree of this expansion will depend on the utilization of the transportation system currently in place. If transportation facilities can be utilized more efficiently and effectively, the overall cost to consumers for firm transportation service may be lowered.

[9]The McGraw-Hill Companies, *Inside F.E.R.C.* (September 2, 1996), pp. 1, 8 and 9. Order 636 estimates of transition costs were about $4.8 billion, according to the Government Accounting Office, *Costs, Benefits and Concerns Related to FERC's Order 636*, GAO/RCED-94-11 (November 1993), p. 62.

[10]Total transmission and distribution revenues for the natural gas industry are projected to remain fairly stable at 1997 levels through 2020. Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA–0383 (99) (Washington, DC, December 1998).

Trends in Contracting Practices

The amount of reserved pipeline capacity at the national level has remained relatively stable since April 1996 (Figure 43 and Table 14).[11] Although reserved firm capacity levels exhibit modest seasonal changes, reservation levels were relatively unchanged between heating seasons, increasing by about 2 percent between January 1997 and January 1998. The stable levels of contracted firm capacity are similar to the trend in pipeline utilization rates. Average pipeline utilization in the Lower 48 States did not change significantly between 1996 and 1997, decreasing from 75 percent to 72 percent, respectively.[12] In 1997, utilization rates were particularly high for pipeline companies bringing gas from Canada into the Midwest and for pipelines moving gas through the Southeast (Figure 44).

Despite differences in load characteristics between the peak winter heating season and summer when a shipper could more likely receive interruptible service, the relative share of firm capacity held by shippers is similar in winter and summer. For example, in January 1998, LDCs held 57 percent of total firm capacity and industrial users held 5 percent. In July 1998, the shares were essentially the same as in January: LDCs had 55 percent and industrial consumers had 5 percent (Figure 45). This may be due, in part, to the fact that only a few major pipeline companies have a rate structure for long-term firm service with different reservation levels during the heating and nonheating seasons (seasonal rates).

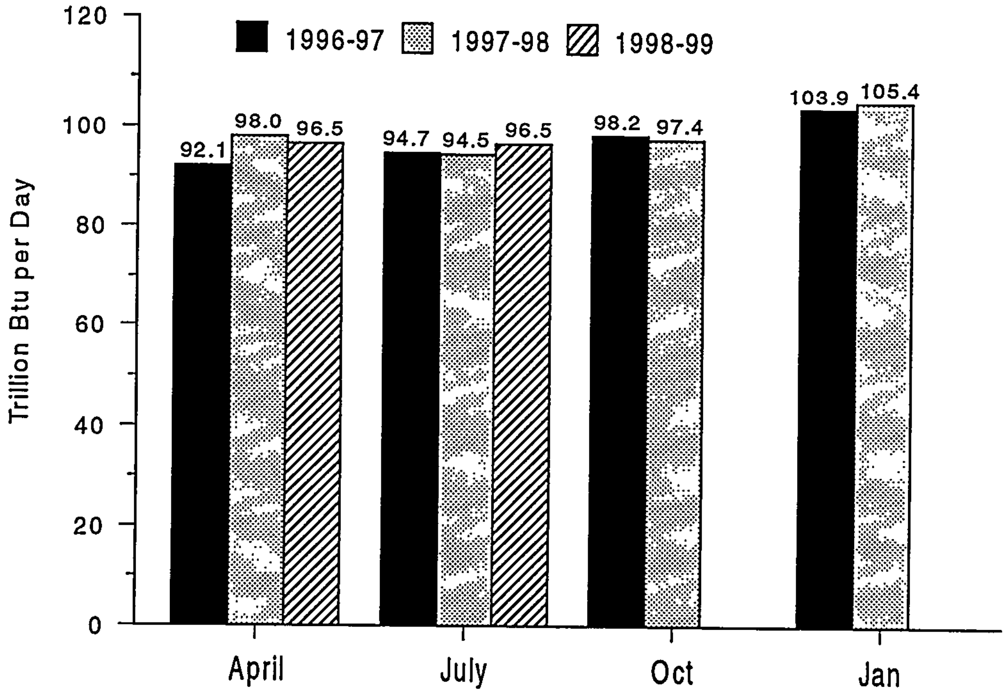
LDCs Reserve the Most Firm Capacity

Many different types of shippers contract for firm transportation services on the interstate natural gas pipeline

[11]In 1997, 46 interstate pipeline companies (accounting for 97 percent of interstate transportation deliveries in 1996) had a total maximum capability of 127 trillion Btu per day. Energy Information Administration, *Deliverability on the Interstate Natural Gas Pipeline System*, DOE/EIA-0618(98) (Washington, DC, May 1998), p. 81.

[12]For additional information, see the Energy Information Administration publication *Deliverability on the Interstate Natural Gas Pipeline System*, DOE/EIA-0618(98) (Washington, DC, May 1998). Utilization levels include only the pipeline capacity on which gas was actually transported from one State to another. If the calculation included pipeline capacity that had no reported flow, average utilization rates for 1996 and 1997 would be 65 and 62 percent, respectively.

Figure 43. Total Firm Transportation Capacity Under Contract at the Beginning of Each Quarter, April 1, 1996 - July 1, 1998



Note: Data are for 64 interstate pipeline companies.

Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers quarterly filings for April 1, 1996 through July 1, 1998, FERC Bulletin Board (August 14, 1998).

Table 14. Characteristics of Firm Transportation Capacity Under Contract at the Beginning of Each Quarter, April 1, 1996 - July 1, 1998

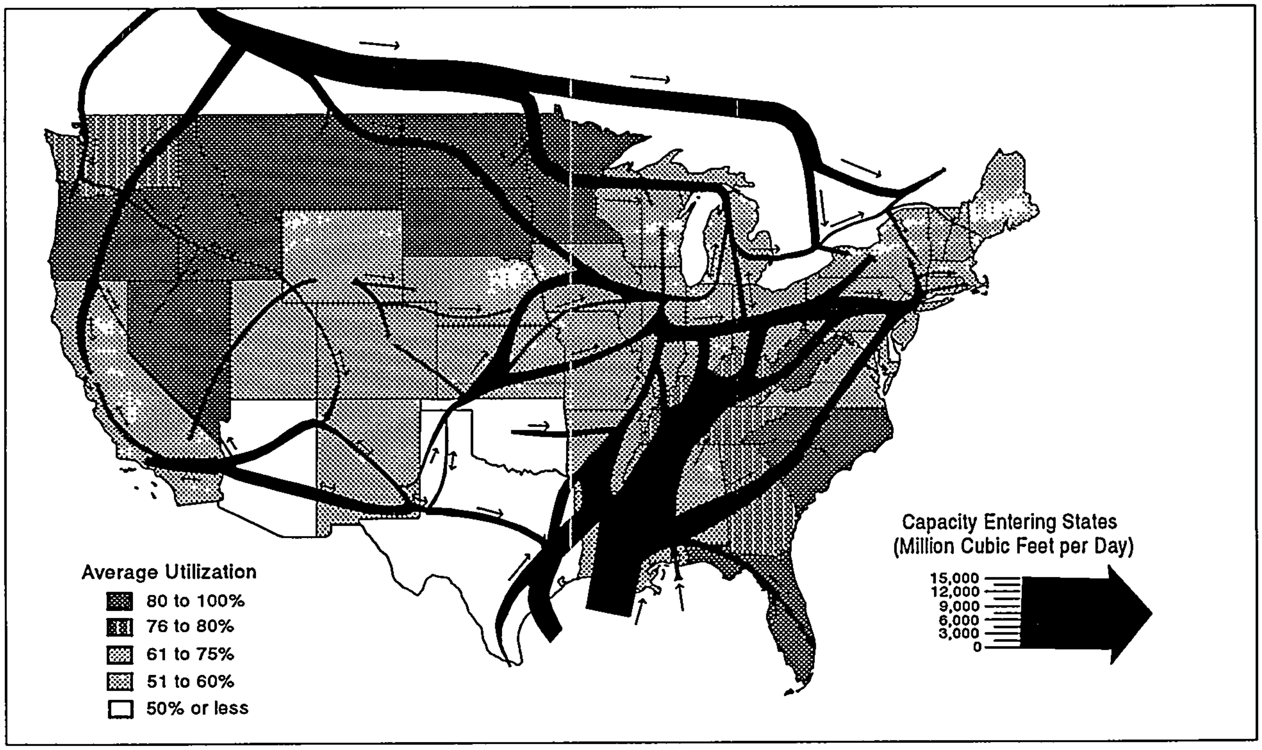
Quarter	All Contracts			Long-Term Contracts[a]			Short-Term Contracts[b]		
	Capacity (trillion Btu per day)	Number of Contracts	Average Term (years)	Capacity (trillion Btu per day)	Number of Contracts	Average Term (years)	Capacity (trillion Btu per day)	Number of Contracts	Average Term (months)
1996									
April	92.1	4,802	8.4	82.9	3,968	10.0	9.2	834	8.4
July	94.7	4,827	8.5	83.9	3,979	10.1	10.8	848	9.0
October	98.2	4,922	8.5	88.9	4,170	9.8	9.3	752	8.6
1997									
January	103.9	5,266	8.3	91.7	4,181	10.2	12.2	1,085	8.6
April	98.0	5,165	8.4	88.0	4,146	10.3	10.0	1,019	8.5
July	94.5	5,086	8.6	85.4	4,179	10.3	9.2	907	9.4
October	97.4	5,138	8.7	89.1	4,271	10.3	8.4	867	9.2
1998									
January	105.4	5,516	8.6	95.1	4,472	10.4	10.4	1,044	8.7
April	96.5	5,276	8.8	89.6	4,410	10.4	6.9	866	9.8
July	96.5	5,330	8.7	88.4	4,392	10.4	8.1	938	9.8

[a]Long-term contracts are longer than 366 days.
[b]Short-term contracts are for 366 days or less.

Note: Data are for 64 interstate pipeline companies.

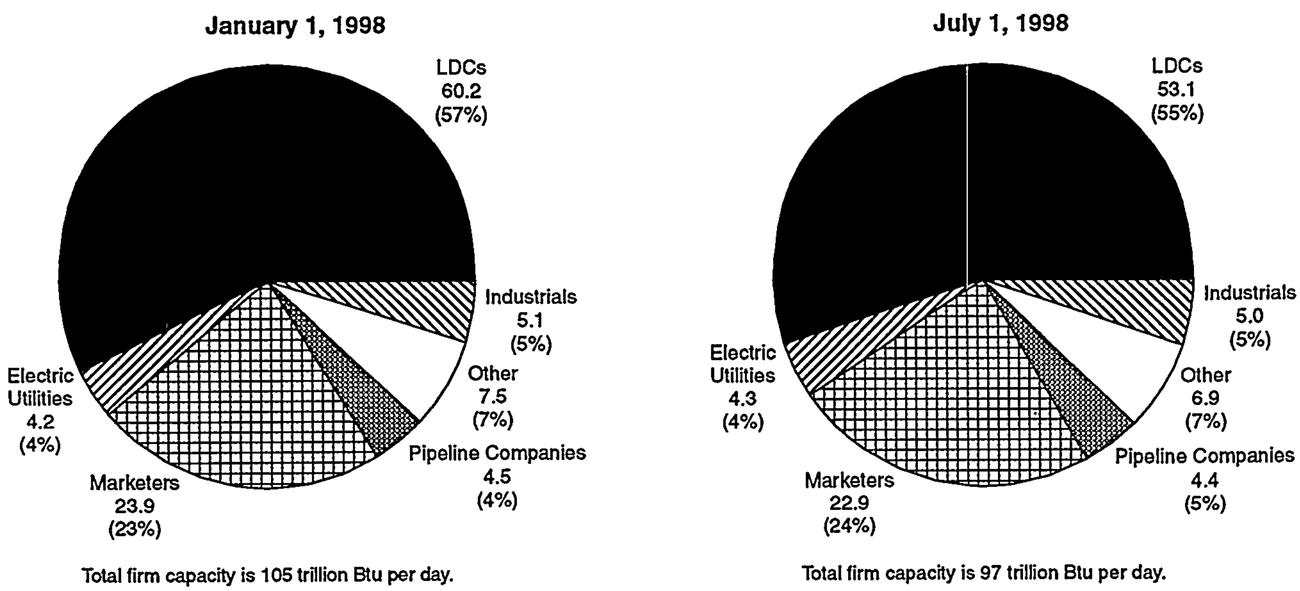
Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers quarterly filings for April 1, 1996 through July 1, 1998, FERC Bulletin Board (August 14, 1998).

Figure 44. Interstate Natural Gas Pipeline Capacity and Average Utilization, 1997



Source: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity Database, as of December 1998.

Figure 45. Share of Total Firm Capacity Held on January 1, 1998 and July 1, 1998, by Type of Shipper
(Capacity in Trillion Btu per Day)



LDC = Local distribution company.
Note: Data are for 64 interstate pipeline companies.
Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers quarterly filings for January 1, 1998 and July 1, 1998, FERC Bulletin Board (August 14, 1998).

system,[13] including local distribution companies (LDCs), electric utilities, industrial firms, marketers, interstate pipeline companies, producers, gatherers, and storage operators. As noted earlier, LDCs account for the largest share of contract capacity for firm service. They have traditionally served as "suppliers of last resort" for all customers in their service area and sole suppliers for the core residential and commercial customers. Thus, they must plan for peak-day demand to meet customers' needs and, because of seasonal variations, will have a lower average rate of utilization (also known as load factor) than other shippers. As a result of their customers' high-priority needs, LDCs are likely to hold a greater share of the firm capacity than shippers, such as industrial customers, who may have the ability to use interruptible service or easily switch to an alternative fuel. Many LDCs are mandated by their State public utility commissions (PUCs) to reserve a certain amount of capacity for reliability of service.

Although LDCs overwhelmingly hold the largest share of firm transportation capacity, they do not receive a proportionate share of natural gas deliveries. Industrial customers hold less than one-tenth of the firm capacity held by LDCs, although the volume of gas delivered to industrial customers was almost the same (82 percent) as that for LDCs.[14] It should be noted, however, that some of the LDCs' and marketers' firm contracted capacity may be used to provide interstate transportation to industrial customers and electric utilities. Therefore, not all of the industrial customers' use of firm transportation is accounted for by contracts with interstate pipeline companies. Traditionally, industrial customers, with well-defined and steady fuel requirements, also have contracted for longer periods than marketers who generally have opted for the flexibility of shorter term contracts. Marketers have mainly served customers with fuel-switching capability and, thus, have been able to focus more on cost minimization than supply reliability.

Now, these contracting approaches appear to be changing as the pace of retail restructuring increases. LDCs may no longer be required to act as the supplier of last resort. In many States, retail restructuring has given customers of LDCs the option of selecting their natural gas supplier. In most cases, the chosen service provider is responsible for securing the supply of natural gas and arranging transportation of the gas to the LDC's service area. The LDC then provides delivery service from the city gate to the customer's point of consumption (burner tip). However, since the LDC is no longer responsible for the interstate transportation of that natural gas, it can reduce its firm capacity commitments as the contracts expire.[15]

Although retail restructuring may allow an LDC to reduce its firm transportation capacity levels, another entity, whether it be the consumer or third-party service provider (e.g., marketer), must secure transportation capacity to move gas to the LDC's service area. However, these marketers may be more focused on cost efficiency than on service reliability. This partially accounts for some of the shifts in contracting practices as shippers adjust their contract portfolios. Shippers continue to prefer long-term contract arrangements for firm transportation capacity, but generally these new contracts are for shorter periods of time and for smaller amounts of capacity.

Shippers Prefer Long-Term Contracts

Although retail restructuring has allowed some LDCs to reduce their firm transportation capacity levels, at the national level LDCs had only minor reductions in their total long-term capacity commitments during the 12 months ended July 1, 1998. Contracts representing 8.9 trillion Btu (TBtu) per day of LDC capacity expired, representing 17 percent of the LDC average long-term capacity commitments of 53.8 TBtu per day.[16] Over the same period, LDCs maintained much of their reserved capacity levels by entering into new contracts for 8.6 TBtu per day (Figure 46 and Appendix D, Figure D3 and Table D13).

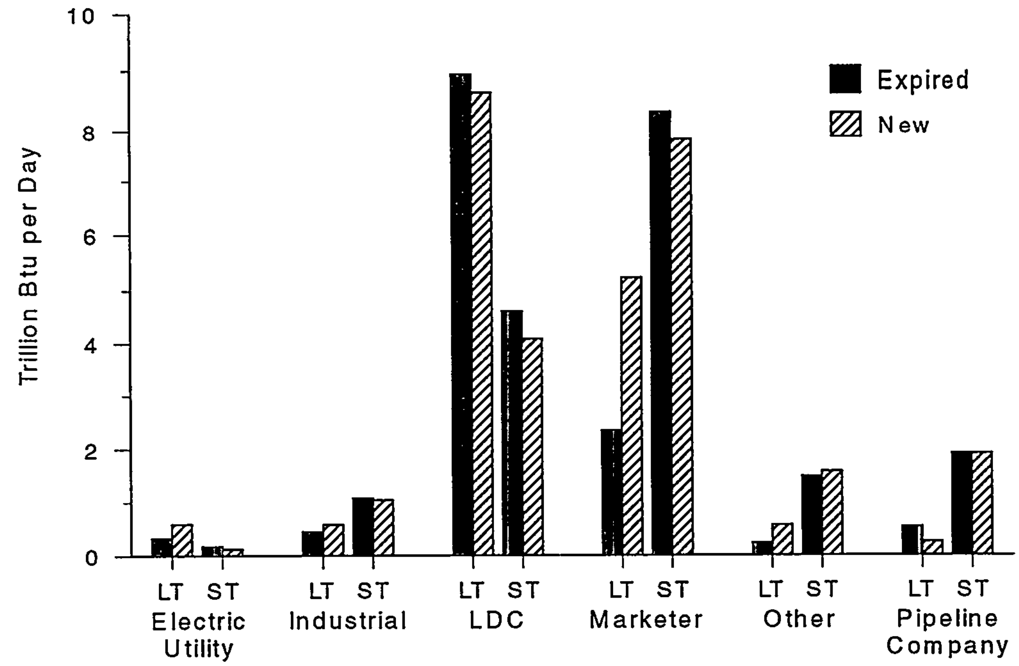
[13]As of July 1, 1998, there were approximately 73 interstate pipelines providing service to about 1,866 shippers under 5,700 firm transportation (FT) contracts. The typical FT contract in place as of July 1, 1998, was written 3.3 years ago and will continue in force for another 5.4 years. Short-term contracts average 9.6 months, whereas long-term contracts average 10.3 years. Source: Energy Information Administration, derived from Federal Energy Regulatory Commission, Index of Customers' data for July 1, 1998.

[14]Volumes are based on 1997 firm and interruptible deliveries to end users. Deliveries to LDCs include residential, onsystem commercial, and onsystem industrial deliveries. Deliveries to industrial customers include only offsystem deliveries. Source: Energy Information Administration, derived from *Natural Gas Annual 1997*, DOE/EIA-0131(97) (Washington, DC, October 1998).

[15]Most States have regulations that require local distribution companies to acquire and contract for interstate capacity assets necessary for gas to be made available on their system as well as the obligation to provide commodity sales service to retail customers. While at least one State has eliminated this requirement under complete retail restructuring, most States still have this obligation to serve in place.

[16]The expired capacity amounts include capacity for contracts that did not expire, but whose reservation levels were adjusted downward. Likewise, the new capacity amounts include capacity for contracts that did not expire, but whose reservation levels were adjusted upward. For example, changes in seasonal reservation levels would be accounted for through revisions.

Figure 46. Firm Capacity Under Expired and New Contracts During July 1, 1997 - July 1, 1998, by Shipper and Contract Length



LT = Long term (more than 366 days); ST = Short term (366 days or less); LDC = Local distribution company.

Notes: New capacity includes positive revisions and expired capacity includes negative revisions. The "Other" category includes producers, gatherers, processors, and storage operators as well as shippers that could not be classified. Data are for 64 interstate pipeline companies.

Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers quarterly filings for July 1, 1997 through July 1, 1998, FERC Bulletin Board (August 14, 1998).

There are several reasons why LDCs' aggregate firm capacity levels have not changed very much over the year. While retail restructuring is advancing, only five States have complete unbundling programs (see Chapter 1, "Retail Unbundling"). Therefore, LDCs must maintain firm capacity levels to serve customers who do not have a choice of service providers or who have chosen to stay with the LDC. Additionally, LDCs may be required to provide service to customers if marketers fail to deliver. LDCs may be retaining firm capacity to operate under this traditional role of "provider of last resort." Also, LDCs may be replacing capacity under expired contracts with capacity on other pipeline systems to access less expensive natural gas sources.

Several other shipper classes have increased the amount of firm transportation capacity held under long-term contracts. In particular, marketers increased their long-term capacity commitments by 18 percent during the 12 months ended July 1, 1998 (Appendix D, Table D12). They contracted for 5.2 TBtu per day of long-term capacity to replace the 2.4 TBtu per day which had been reserved under contracts that terminated during the period. The new contracts were for larger amounts (average capacity per contract increased) and there were more new contracts than expiring ones. Marketers held 96 more long-term contracts on July 1, 1998, than on July 1, 1997.

On the other hand, marketers showed less interest in short-term capacity. During the 12 months ended July 1, 1998, marketers reduced short-term capacity by 8.3 TBtu per day but entered new contracts for only 7.8 TBtu per day. The changes in the marketers' service selection resulted in long-term capacity representing 83 percent of their transportation portfolio as of July 1, 1998, up from 78 percent on July 1, 1997.

On the surface, it appears that marketers, on average, may have a growing preference for long-term versus short-term contracts. However, this may not be the full story, as marketers may, in fact, be simultaneously increasing their use of interruptible transportation while increasing the amount of firm capacity under long-term contracts and decreasing the amount under short-term contracts. Instead of using short-term firm contracts, marketers (as well as possibly other types of shippers) may be turning to less expensive interruptible service that has been available during warmer-than-normal weather.[17] The increase in long-term contracts may be a result of marketers increasing market share and not so much a switch from short-term contracts.

The contracting behavior of electric utilities is similar to that of marketers, in that they have also increased their long-term capacity commitments and reduced their short-term commitments. Long-term commitments represented virtually all (98 percent) of the transportation service portfolio for electric utilities for the 12 months ended July 1, 1998. During this period, electric utilities signed new, long-term contracts for 0.6 TBtu per day that more than replaced the 0.3 TBtu per day of capacity associated with expired contracts. The total number of contracts held reached 141 as of July 1, 1998, an 11-percent increase over the year-earlier level. On the other hand, short-term capacity commitments were reduced during the period, as electric utilities signed new contracts for 30 percent less capacity than the total under expired short-term contracts.

Industrial gas shippers that hold contracts for interstate transportation continue to favor long-term over short-term contracts. In fact, during the 12 months ended July 1, 1998, 90 percent of the capacity held by industrial shippers was under long-term contracts, a slight increase of 1 percentage point from the previous 12-month period. Total capacity under long-term contracts increased from 4.4 to 4.5 TBtu per day from July 1, 1997 to July 1, 1998. While the increase may be partially due to the strong U.S. economy, it also appears that more industrial customers are directly securing their own transportation service. The number of industrial shippers holding long-term transportation contracts increased by 33 percent from 210 to 280 unique industrial shippers.

Capacity held by industrial shippers under short-term contracts posted an average decrease of 8 percent during the 12 months ended July 1, 1998, compared with year-earlier levels. It appears that industrial customers have an increasing preference for long-term over short-term contracts, with long-term capacity under new contracts outpacing (by 30 percent) capacity under expired contracts for the 12-month period ended July 1, 1998. During this same period, industrial shippers continued to write new short-term contracts, although the contracted levels did not keep pace with expired short-term contracts.

[17]It is difficult to quantify this behavior because there are no information sources available on contracts for interruptible transportation.

Although the majority of firm transportation capacity is held under long-term contracts, a substantial amount of capacity is up for renewal on an annual basis. During the 12 months ended July 1, 1998, 30 trillion Btu (TBtu) per day of capacity was associated with contracts that expired (on average 8 percent of the total contracted capacity over the 12 months) and 32 TBtu was associated with new contracts (Appendix D, Table D13). Short-term firm transportation capacity accounted for 58 percent, or 17.6 TBtu per day, of expirations during the period.[18] Shippers replaced the expired capacity by entering into new short-term contracts totaling almost 16.6 TBtu per day. During the same 12-month period, shippers acquired 15.9 TBtu per day of long-term firm transportation capacity while long-term contracts accounting for 12.8 TBtu per day expired. Thus, new contracts for long-term transportation service exceeded expired contracts by 24 percent. From a shipper perspective, marketers accounted for the largest change in long-term contracted capacity (Figure 46).

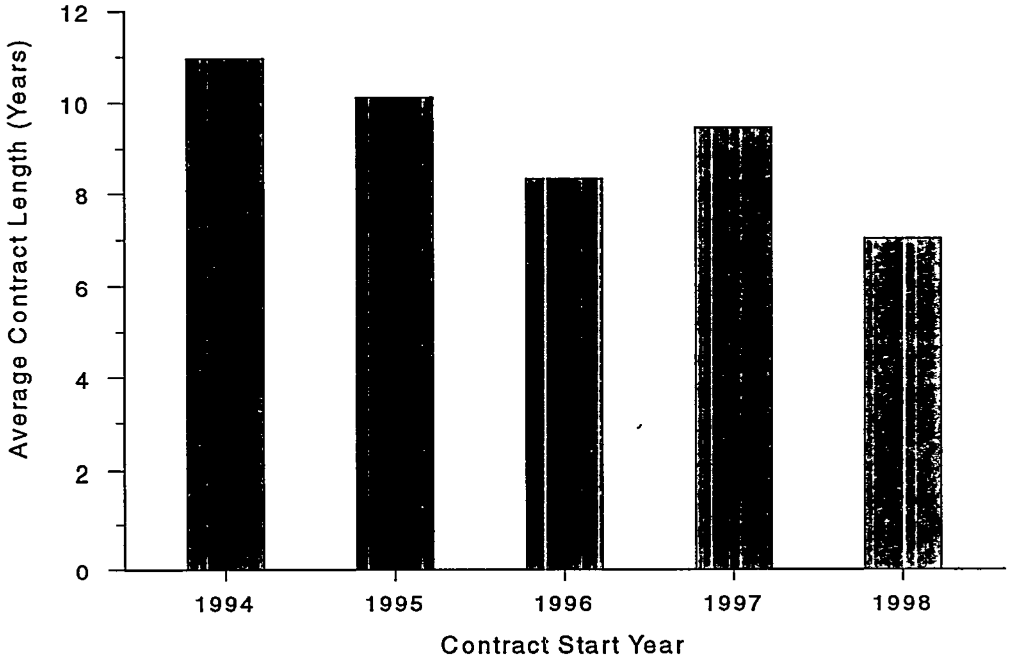
Total firm contracted capacity increased 2.0 TBtu per day between July 1, 1997, and July 1, 1998. This increase appears to be related to recent pipeline expansions, which provided an additional 3.3 TBtu per day of capacity during the 12 months ended July 1, 1998.[19] However, it cannot be determined whether the newly subscribed capacity will supplement or replace the shippers' other contracted capacity. If shippers have entered capacity contracts associated with new pipeline expansions to replace older contracts, a substantial amount of capacity may be turned back when old contracts expire.

Another change in the transportation market has been a reduction in the average duration of new long-term contracts. On average, long-term contracts written during the first 6 months of 1998 covered a period 16 percent shorter (measured in days) than those written in 1996. The trend toward shorter contracts is even more evident in those contracts of 3 years or more. The average length of those contracts declined by 36 percent, from 10.9 to 7.0 years, between 1994 and 1998 (Figure 47).

[18]The 17.6 trillion Btu per day of expired short-term capacity includes capacity that may be counted multiple times if the contract turns over several times during the year. For example, a 90-day contract for 100 million Btu per day that is always renewed would be counted as 400 million Btu per day of expired capacity over the year.

[19]Based on expansions on the 64 pipeline companies included in this analysis. Energy Information Administration, *Deliverability on the Interstate Natural Gas Pipeline System*, DOE/EIA-0618(98) (Washington, DC, May 1998), Appendix B, Table B1.

Figure 47. Average Contract Length for Contracts with Terms of 3 Years or More, by Year of Contract Start, 1994-1998



Note: Data are for 64 interstate pipeline companies.
Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers quarterly filings for April 1, 1996 through July 1, 1998, FERC Bulletin Board (August 14, 1998).

Individual Shipper Contracting Practices and Regional Patterns

The changes in capacity contracting exhibited by different types of shippers are also supported by studying the contracting behavior of individual shippers. Shippers who hold large long-term contracts are initiating fewer new contracts, for less capacity, and for shorter contract periods. From April 1996 through March 1998, based on a sample of 54 unique shipper-pipeline company contract pairings,[20] 37 percent, on average, of the capacity under expired contracts was turned back (19 percent if contracts with El Paso Natural Gas Company are excluded, see box, p. 139). The capacity associated with these expired contracts in the shipper-pipeline sample totaled 6.4 trillion Btu per day, or 67 percent of the 9.6 TBtu per day associated with expired contracts nationally during the same period.[21]

While results varied by region, the bulk of the turned-back capacity (58 percent) by the sample shippers was in the West Region, where 92 percent of the region's capacity under expired contracts was turned back, almost all of which was attributable to contracts on El Paso Natural Gas that expired in 1996 and 1997. The next largest regional turnback share, 42 percent, occurred in the Northeast (Table 15). It should be noted that at least some of the capacity that was turned back to interstate pipeline companies was subsequently remarketed. An assessment of these capacity amounts, such as how much of the turned-back capacity was remarketed, was beyond the scope of this analysis.

Individual shippers showed multilayered strategies and exercised a number of approaches when they had the

[20]To assess the actions of shippers holding large, long-term firm capacity contracts, a sample of shipper-pipeline pairings was derived by selecting the 10 largest contracts that expired in each region over the period April 1, 1996, through March 31, 1998 (see box, p. 131). The number of contracts was increased to 14 in the Midwest, because the 10 largest contracts accounted for less than 50 percent of the region's expiring capacity over the period. The largest contracts per region resulted in a sample of 54 unique shipper and pipeline company combinations. There are only 51 shippers in the sample because some had expired contracts with more than one pipeline company (see Appendix D).

[21]National information is based on the analysis of 64 pipeline companies discussed elsewhere in the chapter (see box, p. 131).

El Paso Natural Gas Company

One of the most significant cases of turnback since 1996 occurred on the El Paso Natural Gas Pipeline system. El Paso experienced a turnback of 1.2 trillion Btu per day of firm transportation capacity when Pacific Gas and Electric Company (PG&E) allowed a contract to expire on December 31, 1997. El Paso remarketed the turned back capacity to Dynegy (formerly NGC Corporation), but with several major differences from the original contract.

- PG&E held one contract with El Paso for its total reservations of 1.2 trillion Btu per day, while Dynegy contracted for a total of 1.3 trillion Btu per day spread over three contracts. The use of multiple contracts may provide Dynegy with more flexibility when the contracts come up for renewal. If Dynegy finds that it does not need all of the capacity reserved on El Paso, it can turn back one or more of the contracts and still maintain the same scheduling priority for the remaining contracts.

- Dynegy's contracts have shorter terms (lengths) than the PG&E's contract. PG&E's contract had a term of 6 years, while the Dynegy contracts are for 2 years each. The reduction in contract length increased El Paso's exposure to turnback in the near term.

- In addition, Dynegy received a significant discount on the contracted capacity. The PG&E contract with El Paso had been at the maximum tariff rate, but it appears that Dynegy received a 66-percent discount from this rate. The discounted rate reduces the cost of capacity to Dynegy, but it may not affect El Paso's total revenue if El Paso can recover the discounted amount through future rate adjustments to its other firm shippers. The discount is significant as an indication that supply of capacity may exceed demand on that portion of El Paso's system.

The details of the settlement that resulted in the new Dynegy contracts may be in question as the result of a decision by the U.S. Court of Appeals for the D.C. Circuit on December 11, 1998. The Federal Energy Regulatory Commission (FERC) had approved the settlement, but the Court remanded FERC's treatment of a contestant to the settlement, the Southern California Edison Company (Edison).

Table 15. Regional Capacity Under Long-Term Firm Contracts, April 1, 1996 - March 31, 1998

	Total Contracts		Sample Expired Contracts			
					Turnback[b]	
Region	Average Capacity[a] (TBtu/d)	Capacity Under Expired Contracts (TBtu/d)	Capacity (TBtu/d)	Percentage of Total Expired Capacity	Total Capacity (TBtu/d)	Percentage of Sample Capacity
Central	10.3	2.1	1.5	70.3	0.1	3.4
Midwest	19.3	2.7	1.4	51.4	0.5	37.2
Northeast	30.8	0.8	0.4	53.2	0.2	42.3
Southeast	9.2	1.3	0.9	68.6	0.1	11.7
Southwest	5.0	1.2	0.7	60.3	0.1	17.6
West	13.4	1.5	1.5	95.5	1.4	92.3
Total	**88.1**	**9.6**	**6.4**	**66.1**	**2.4**	**36.8**

[a]Average capacity is the sum of total capacity at the beginning of each quarter, April 1, 1996 through March 31, 1998, divided by the number of quarters (8).

[b]Turnback is the reduction or returning of capacity to the pipeline company at the expiration of the contract.

TBtu/d = Trillion Btu per day.

Notes: Total contracts are for 64 interstate pipeline companies. The sample contracts were selected from the expired contracts with these companies resulting in 54 unique shipper/pipeline pairs, see Appendix D. Totals may not equal sum of components because of independent rounding. Percentages were calculated using unrounded numbers. Long-term contracts are longer than 366 days.

Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers quarterly filings for April 1, 1996 through April 1, 1998, FERC Bulletin Board (August 14, 1998).

opportunity to adjust their contract portfolios. The types of adjustments in their new contracts, as compared with expired contracts, included changes in contract length, in the amount of contracted capacity, and in the quality of service (for instance, replacing a contract for no-notice service with one for firm service). New contracts may include one or several of the types of adjustments. What is noteworthy is that the shippers did not rely solely on a reduction (turnback) in contracted capacity amounts. Of the 54 shipper-pipeline pairs, 47 decreased the average length of their capacity contracts (Table 16). In over half of the cases (31), shippers decreased the total amount of capacity under long-term capacity contracts. Based on these actions, shippers are clearly positioning themselves for more flexibility in their firm transportation portfolios. The action shippers took depended on their motivation and perception of the capacity market within their region.

The analysis of the sample shippers indicated several distinct regional effects:

- Shippers in the Central Region had one of the largest amounts of expiring capacity (1.5 trillion Btu per day) but were one of the only ones that showed an increase in total capacity commitments (Appendix D, Table D8). The increase in committed capacity may indicate that shippers view the Central Region as somewhat capacity constrained. However, the most significant factor that led to this increase may have been the expansion of facilities and contracts to tap nearby natural gas supplies (coal seam gas) in the Powder River Basin. It also appears that shippers changed the quality and flexibility of their transportation portfolios by reducing capacity held under no-notice services and decreasing the average term of new contracts.

- Eight firm capacity contracts of the twenty-two contracts in the Midwest sample were completely turned back to the pipeline companies. The overall capacity reduction in the Midwest represented 37 percent of the region's capacity under expiring contracts. The turnback identified in the Midwest may be the result of two distinct but related factors. First, shippers may be terminating contracts for transportation from the South in anticipation of expansion tapping into Canadian supplies. Also, the underutilization of the pipeline systems transporting supply from the Southwest enables shippers to use interruptible transportation contracts.

- For the 64 pipeline companies, the Northeast had the highest average contracted capacity among the regions (30.8 trillion Btu (TBtu) per day), but a relatively small proportion (0.8 TBtu per day) of that capacity was associated with expiring contracts (Table 15). For the expired contracts in the sample (representing 0.4 TBtu per day), shippers either reduced the amount of contracted capacity, reduced the length of the contract, or both. The region's turnback represented 42 percent of the expiring capacity in the Northeast sample. Firm transportation contract changes in the region may be prompted by the shippers' needs for increased flexibility as a result of retail restructuring. All but one of the shippers in the Northeast sample are LDCs who serve areas that have some level of retail unbundling in place.

- The Southeast Region had one of the lowest rates (12 percent) of turnback in the sample, retaining about 88 percent of its expired capacity. However, shippers in the region did overwhelmingly reduce the lengths of their firm transportation contracts. The Southeast was unique in that 10 of the 11 contracts were held on one pipeline company, Columbia Gulf Transmission. The motivations behind contract changes in the Southeast are similar to those in the Northeast where shippers are focused on increasing the flexibility of their firm transportation portfolios.

- Contract length reductions dominated shipper actions in the Southwest Region. All shippers reduced the terms of their contracts. While some shippers did turn back capacity, it appears shippers were more interested in diversifying their capacity holding by entering into more contracts for smaller amounts and shorter terms, especially in light of the abundant capacity in the region.

- Similar to the Midwest, shippers in the West Region were interested in acquiring greater access to Canadian gas supply, thereby reducing their need for firm transportation capacity connected to the Southwest. Shippers in the West turned back 92 percent of their capacity under expiring contracts in the sample, including a single contract for 1.2 trillion Btu per day.[22] In fact, three Canadian shippers were the only contract holders in the sample that did not turn back all of their contracted capacity.

[22]Pacific Gas and Electric Company turned back one firm transportation contract of 1,166,220 million Btu per day to El Paso Natural Gas Company on January 1, 1998.

Table 16. Actions Upon Contract Expiration for Sample of the Largest Expired Long-Term Contracts in Each Region, April 1, 1996 - March 31, 1998

Region	Number of Contracts In Sample	Number of Shipper/Pipeline Pairs In Sample	Comparison of New Contracts with Expired Contracts (Number of Shipper/Pipeline Pairs In Each Category)								
			Number of Contracts Held			Total Capacity Held			Length of Contract		
			Increased	Same	Decreased	Increased	Same	Decreased	Increased	Same	Decreased
Central	14	7	2	3	2	2	3	2	3	0	4
Midwest	22	15	2	3	10	2	2	11	3	1	11
Northeast	10	8	2	1	5	1	1	6	0	0	8
Southeast	11	9	0	2	7	0	4	5	0	0	9
Southwest	13	7	2	3	2	2	3	2	0	0	7
West	10	8	0	3	5	0	3	5	0	0	8
Total	**80**	**54**	**8**	**15**	**31**	**7**	**16**	**31**	**6**	**1**	**47**

Notes: Long-term contracts are longer than 366 days. The sample was chosen from the expired contracts of 64 interstate pipeline companies. See Appendix D.

Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers quarterly filings for April 1, 1996 through April 1, 1998, FERC Bulletin Board (August 14, 1998).

Capacity Release Market

Shippers can also change their contract portfolios through the capacity release market, which was established under FERC Order 636. Shippers with excess capacity commitments can offer the capacity to other shippers as long as the reselling price does not exceed the maximum regulated rate. The amount of capacity released provides an indicator of unneeded capacity and where turnback might occur in the future.[23]

The capacity release market has grown steadily in terms of capacity traded, indicating that more shippers are using the release market as a source for transportation capacity. The release market's annual growth rate averaged 19 percent during the past 3 heating years (April through March) ended March 31, 1998, for the interstate pipeline companies included in this analysis. The growth in the market slowed somewhat during the 1998 heating year. The amount of capacity held by replacement shippers during the 12 months ended March 31, 1998, was 7.6 trillion cubic feet, or 10 percent more than the 6.9 trillion cubic feet held for the 12 months ended March 31, 1997.[24] The slowdown in growth may be weather related—the 1997-98 heating season was 5 percent warmer than the 1996-97 heating season, as measured by heating degree days.[25]

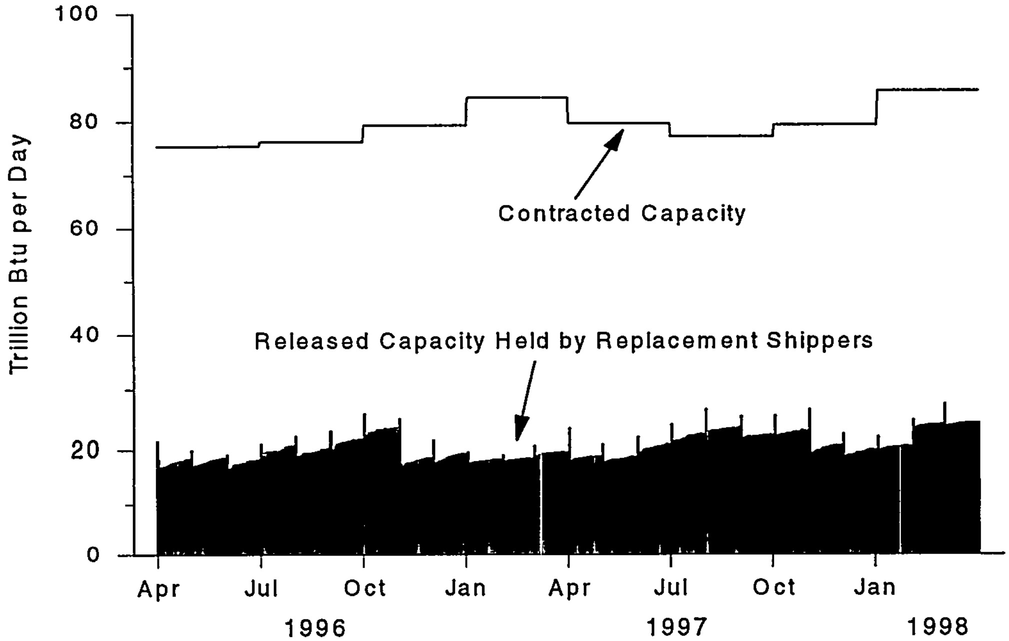
The level of capacity held by replacement shippers represents a significant amount of interstate pipeline capacity (Figure 47 and Appendix D, Figure D4). As much as 32 percent of the deliveries to end users could have moved using released capacity during the 1997–98 heating season. The fact that a large amount of capacity is available for release during the peak season also indicates that shippers are holding a substantial amount of unused capacity. The amount of capacity held by replacement shippers has historically represented about 20 percent of total reserved firm transportation capacity. The growth in the capacity release market suggests that some shippers have capacity under contract that they are not using and that the potential exists for a substantial capacity turnback in the future. However, the level and location of the turnback will in large part depend on the contracting practices and market conditions within specific regions, as well as the contract expiration dates.

[23]The amount of capacity *offered* to replacement shippers is a more accurate measurement of potential turnback compared with the amount of capacity actually *awarded*. However, only limited data are available on offered capacity. The capacity award dataset is used in this analysis because it is the most complete information available on capacity release.

[24]The total volume of released capacity held by replacement shippers during a season is the sum of the capacity effective on each day of the season. For example, if a 60-day contract for Z thousand cubic feet per day is effective within a season, then the sum of capacity held for the season would include Z thousand cubic feet 60 times for that contract. If that 60-day contract were only effective, for example, for the last 20 days of the season, then the sum for the season would include Z thousand cubic feet 20 times, and the sum for the next season would include Z thousand cubic feet 40 times for that contract.

[25]Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(98/04) (Washington, DC, April 1998), Table 26.

Figure 48. Daily Contracted and Released Firm Transportation Capacity, April 1, 1996 - March 31, 1998



Note: Data are for 27 interstate pipeline companies.
Source: Energy Information Administration, Office of Oil and Gas. **Contracted Capacity:** derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers filings for April 1, 1996 through January 1, 1998, FERC Bulletin Board (August 14, 1998). **Released Capacity:** derived from: April 1996-May 1997—FERC Electronic Data Interchange, May 1997-March 1998—FERC downloaded Internet data.

Outlook

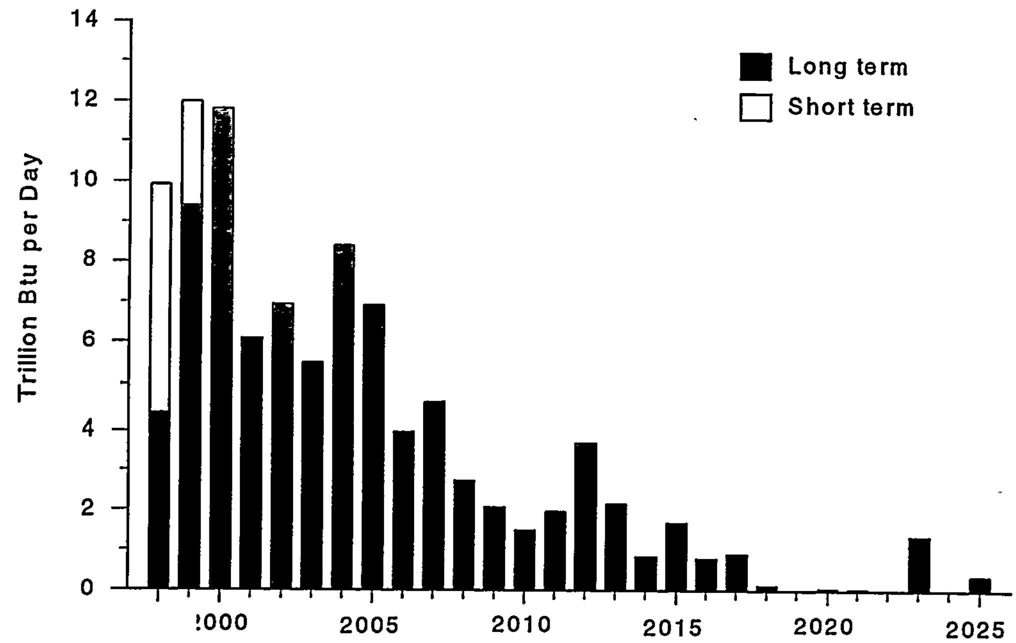
The expiration of firm transportation capacity under contract as of July 1, 1998, varies over time through 2025 (Figure 49). For most years, expirations account for 5 percent or less of total reserved capacity. However, the years 1999 and 2000 will be particularly active, when 12 percent of the contracted capacity will expire each year. Between 1998 and 2003, transportation contracts representing a total of 54 percent of the reserved firm transportation capacity will expire or come up for renegotiation.

The timing of the potential turnbacks is a major factor in assessing the impact of the capacity turnback on the transportation markets. As mentioned earlier, a considerable amount of capacity is up for renewal on an annual basis. Much of this capacity is associated with short-term contracts of a year or less that are used to address limited seasonal or market fluctuations. It is unlikely that expiration of short-term contracts will result in turnback of capacity for an extended period. Therefore, short-term contracts are not included in EIA's assessment of capacity turnback. In this analysis, only the expiration profiles of each region's long-term contracts were applied to the respective estimated turnback ratio and combined to provide a national turnback profile for firm transportation capacity (Figure 50).

On a regional basis, there is considerable variation in the quantity of cumulative capacity expirations in the near term (through 2003) (Figure 51), but the pattern of extensive contract turnovers or expirations through 2008 is similar and in the range of 71 to 97 percent of existing contracts. By 2003, shippers on pipelines that principally serve the Central, Midwest, and Southwest regions will have contracts expire that represent 71 to 86 percent of their currently reserved capacity. In contrast, pipeline companies in the Northeast and Southeast will have contracts covering only about 45 percent of their current reservations expire, while companies in the West expect about 29 percent of their capacity reservations to expire through 2003.

The existence of expiring contracts does not automatically equate to a turnback of capacity. The likelihood that contracts will be terminated upon reaching their expiration date can be estimated by comparing the capacity release

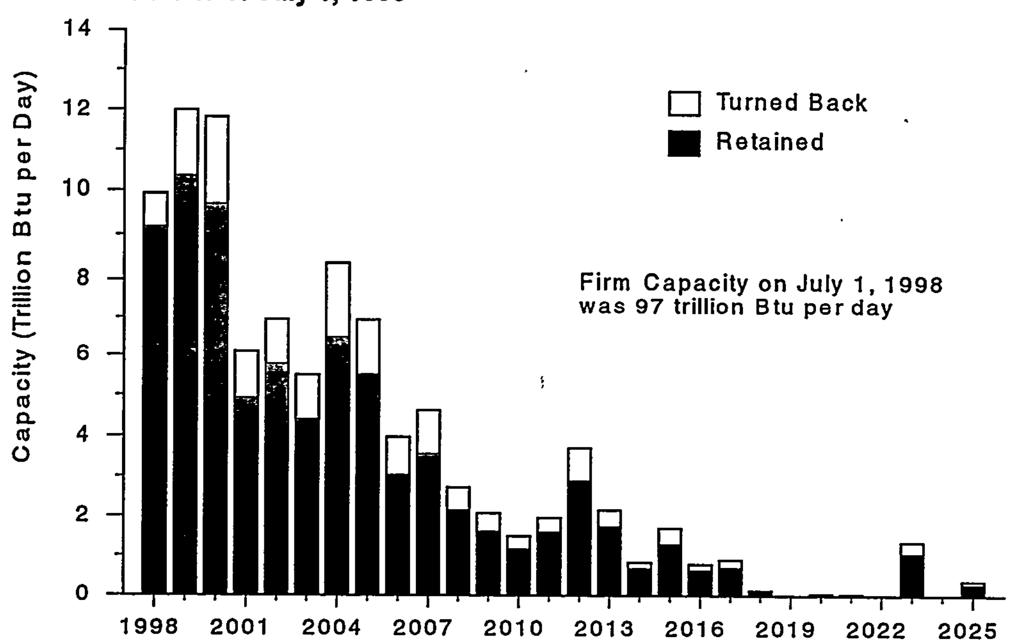
Figure 49. Firm Transportation Capacity by Year of Contract Expiration, 1998-2025, as Reported on July 1, 1998



Note: Long term is longer than 366 days, short term is 366 days or less. Data are for 64 interstate pipeline companies. Data for 1998 are for the last 6 months. Data for 2025 include 0.02 trillion Btu per day of capacity expirations in years beyond 2025.

Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers filing for July 1, 1998, FERC Bulletin Board (August 14, 1998).

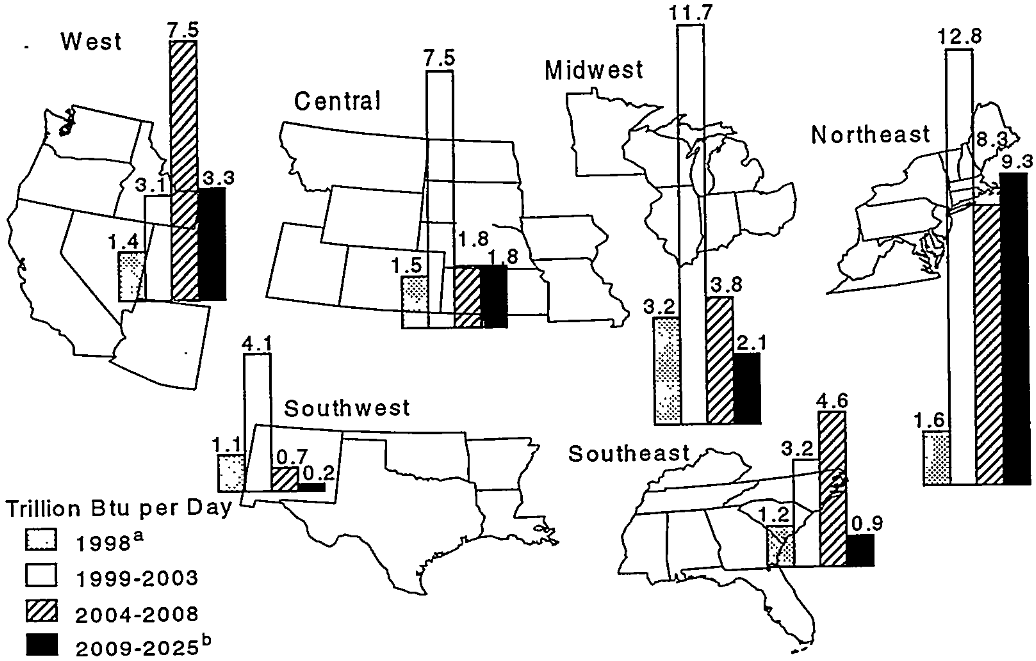
Figure 50. Estimated Amounts Turned Back and Retained of Firm Transportation Capacity Under Contract as of July 1, 1998



Note: Data are for 64 interstate pipeline companies. Data for 1998 are for the last 6 months. Data for 2025 include 0.02 trillion Btu per day of capacity expirations in years beyond 2025.

Source: Energy Information Administration, Office of Oil and Gas based on: **Total Expirations:** derived from Federal Energy Regulatory Commission (FERC) Index of Customers data for July 1, 1998, FERC Bulletin Board (August 14, 1998) and **Turned Back Capacity:** derived from various sources, see Appendix D.

Figure 51. Regional Exposure to Firm Capacity Contract Expirations, 1998-2025, as Reported on July 1, 1998



Total Firm Transportation Capacity and Percent of Regional Expirations by Period

Region	Total Capacity as of 07/01/98 (TBtu/d)	Percent of Total Expirations			
		1998[a]	1999-2003	2004-2008	2009-2025[b]
Central	12.6	12	60	14	15
Midwest	20.8	16	56	18	10
Northeast	32.0	5	40	26	29
Southeast	9.8	12	32	47	9
Southwest	6.0	18	68	11	3
West	15.3	9	20	49	22
Total	**96.5**	**10**	**44**	**28**	**18**

[a]Data are for the last 6 months of 1998.
[b]Data for 2025 include a total of 0.02 trillion Btu per day of capacity that expires in the Southwest beyond 2025.
TBtu/d = Trillion Btu per day.
Notes: Data are for 64 interstate pipeline companies. Sum of percents in a row may not equal 100 percent because of independent rounding.
Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers filing for July 1, 1998, FERC Bulletin Board (August 14, 1998).

and firm capacity market information.[26] A recurrent release of capacity during a heating season (peak season) generally implies that capacity is no longer needed by the shipper. Therefore, the smallest daily award of released capacity during the heating season may be used to estimate the share of a region's capacity that could be turned back (see box, p. 131 and Appendix D).

The regional turnbacks that may occur through 2025 vary from 6.7 TBtu per day in the Northeast (22 percent of the regional long-term capacity) to 0.2 TBtu per day in the Southwest (4 percent of the regional long-term capacity) (Table 17). The national turnback level is estimated to be 17.8 TBtu per day, or 20 percent of the long-term contracted capacity (18 percent of total contracted capacity) as of July 1, 1998. The most pronounced

[26]A sample of 27 pipeline companies was assembled for the comparison of released and firm contracted capacity. The sample was chosen to ensure a consistent and complete coverage of information between the two sets of data and across the time frame analyzed.

Table 17. Regional Estimated Turnback of Firm Transportation Capacity, 1998-2025, for Contracts Reported on July 1, 1998
(Billion Btu per Day)

Region	Total Turnback of Capacity Under Contract as of July 1, 1998	Estimated Regional Capacity Turnback by Period			
		1998[a]	1999-2003	2004-2008	2009-2025[b]
Central	2,176	129	1,373	330	344
Midwest	2,368	247	1,388	471	262
Northeast	6,744	75	2,718	1,856	2,095
Southeast	2,779	274	856	1,388	261
Southwest	206	17	152	29	7
West	3,492	20	721	1,908	843
Total	17,765	762	7,208	5,982	3,813

[a]Data are for the last 6 months of 1998.
[b]Data for 2025 include a total of 896 million Btu per day of capacity that is estimated to be turned back in the Southwest beyond 2025.
Notes: Data are for 64 interstate pipeline companies. Sum may not equal total because of independent rounding.
Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers filings for April 1, 1996 through July 1, 1998, FERC Bulletin Board (August 14, 1998), and Capacity Release Awards data: April 1996–May 1997, FERC Electronic Data Interchange, and May 1997–March 1998, FERC downloaded Internet data.

turnbacks within the next 10 years are expected to occur in 1999, 2000, and 2004. Through 2003, 8.0 TBtu per day, or 8 percent of contracted capacity (or 9 percent of long-term contracted capacity), is likely to be turned back to pipeline companies.

The estimated level of future turnback produced by this portion of the analysis appears to be consistent with the analysis of contracting practices of individual shippers (presented earlier in the chapter). Between April 1, 1996, and March 31, 1998, these shippers turned back 19 percent (excluding the large turnback on El Paso Natural Gas Company) of the capacity reserved under expired long-term contracts—nearly the same as the 20-percent turnback in the comparison of released to contracted capacity, based on capacity under long-term contracts as of July 1, 1998. Although the two analyses are significantly different in approach, the overall conclusions are similar.

Revenue Impact

Capacity turnback may signify a period of adjustment for the transportation market as it becomes more competitive. Pipeline revenues may be affected during this adjustment process. For example, in the fourth quarter 1998, revenue losses attributable largely to turnback of capacity totaled $11 million for El Paso Natural Gas Company and $39.8 million for William Gas Pipeline Central. The challenge for pipeline companies is to market this capacity to existing customers as well as to other shippers who possibly have expanding markets.

Some loss of revenue could occur even if the turned-back capacity is picked up by other shippers. Pipeline companies may have to offer significant rate discounts to the new shippers in order to sell the turned-back capacity. El Paso Natural Gas Company agreed to a 66-percent discount from its maximum transportation rates for Dynegy's (formerly Natural Gas Clearinghouse) purchase of turned-back capacity. Prices on the capacity release market indicate that turned-back capacity will not command maximum prices. Replacement shippers are paying, on average, only 57 percent of the maximum reservation rate on released capacity during the heating season throughout the United States (see Chapter 1, "Capacity Release").

Shippers may find themselves under increasing pressure to reduce transportation costs as retail restructuring provides more customers with supplier choices. As of August 1998, 32 percent of the Nation's residential consumers of natural gas, representing 26 percent of residential gas consumption, live in areas where there are residential choice programs (see Chapter 1, "Retail Unbundling"). Service providers will have to scrutinize each gas service cost component to compete for these consumers and gain market share. Transportation service pricing and characteristics may have to be more flexible in the future to supply customers' diverse requirements. Changes in firm transportation contracting will likely challenge the current rate design structure for firm transportation services.

Competition among foreign and domestic producers coupled with the increased integration of the interstate pipeline grid could result in underutilization of some supply-to-market pipeline corridors. Innovative measures may be required to make capacity marketable. The Federal Energy Regulatory Commission's recent Notice of Proposed Rulemaking[27] may help move the industry to a more competitive marketplace by introducing market factors in lieu of regulatory policies for some transactions. FERC's goals are to improve competition in short-term markets and provide greater flexibility in interstate pipeline contracting practices. FERC proposes to attain these goals by:

- Removing the maximum price cap on short-term transportation

- Creating more uniform nominating procedures for released capacity so that it can compete more easily with capacity offered by pipeline companies and "delivered gas" transactions (that is, bundled sales and transportation)

- Requesting comments on whether changes in regulatory policy are needed to maximize shippers' ability to segment their capacity to provide them with greater competitive alternatives

- Reforming penalty procedures to ensure that different penalty processes across pipeline companies do not limit shippers' flexibility in using capacity or otherwise distort shippers' decisions about how best to use capacity

- Using auctions to allocate all short-term capacity, including that which is now obtained through prearranged deals

- Establishing reporting requirements to provide capacity and pricing information to all shippers

- Conducting a generic review of the operation of the short-term market without a price cap after two heating seasons.

The removal of the price cap on released capacity transactions may have little impact in the short term given that most released capacity now sells well below the price cap. There might, however, be an impact over the long term as removing the price cap may attract other players to the market with more valuable capacity.

Final comments on FERC's proposals were due to FERC on April 22, 1999. However, some companies and organizations provided preliminary comments on January 22, 1999. Many of the public comments so far have focused on FERC's proposal to have all short-term capacity, including released capacity and short-term firm and interruptible capacity, assigned to shippers through an auction system. Some pipeline companies are concerned about the potential loss of minimum guaranteed revenues from such a system, while LDCs and others are concerned that the auction might preclude the possibility of pre-arranged deals for short-term capacity.[28]

The gas industry continues to adjust to the impacts of restructuring, including changes at the production (wellhead), transportation, and retail segments. In the transportation segment of the industry, traditional approaches to contracting practices appear to be changing as reflected by the emphasis on flexibility (in terms of service type, amount of capacity reserved, and time period) incorporated in new contracts written by shippers during the past several years. The reductions in contracted capacity that shippers are making in their contract portfolios have the potential to lead to revenue impacts for the industry. If, however, the pipeline capacity is remarketed to other shippers or demand for natural gas increases as projected, the potential revenue effects may be minimal. The wave of adjustments in the transportation segment of the gas industry will likely continue for the next several years in response to changes in market conditions as well as possible revisions to capacity trading mechanisms and regulatory policies.

[27]Federal Energy Regulatory Commission, *Regulation of Short-Term Natural Gas Transportation Services*, Docket No. RM98-10-000 (July 29, 1998).

[28]Damien Gaul, "A Hard Sell," *Gas Daily's NG* (Winter 1998/1999), pp. 21-29. Foster Associates, Inc., "Relatively Few Parties File Preliminary Comments on FERC's Pending Rulemakings on Short-Term and Long-Term Issues," *Foster Natural Gas Report*, No. 2219 (January 28, 1999), pp. 2-5.

7. Mergers and Other Corporate Combinations in the Natural Gas Industry

Corporate combinations in the natural gas industry are growing in number and size as companies adjust to restructuring and increased levels of competition in the regulated sectors of the energy industry. Although the number of proposed mergers has increased significantly in recent years, many of the more innovative corporate combinations have been in the form of joint ventures and strategic alliances. In part this reflects the fact that such ventures are subject to less stringent regulatory review than are mergers. But it also is a reflection of the as-yet experimental nature of many of the combinations, ventures, and even strategic plans. Some of the major findings of the chapter include the following:

- Totaling $39 billion in 1997, mergers and acquisitions among companies in the natural gas industry have increased nearly four-fold since 1990. The value of mergers throughout the energy sector has also increased more than four-fold since 1992. Nevertheless it should be noted that despite the increase in value, combinations in the energy sector remained a relatively small part of corporate combinations in general, representing only about 11 percent of the total value of all combinations in 1997.

- In 1995, just prior to FERC Order 888 which initiated restructuring in the electric power industry, utility combinations increased sharply, accounting for two-thirds of all corporate combinations in the energy sector compared with 42 percent in 1990. Since 1995, the value of utility combinations has increased by 143 percent.

- Convergence of the gas and electricity markets or of overall energy services is a much discussed topic. However, relatively few recent mergers have been undertaken primarily as the result of convergence in either sense.

- Joint ventures have become increasingly popular, particularly in areas of convergence. Joint ventures are less binding than mergers, and although subject to regulatory review, they avoid many of the complications that can encumber the merger process.

- Consumers will benefit from utility combinations if savings gained through economies of scale, elimination of redundancies, and increased efficiencies are passed on to them. To insure benefits to consumers, regulatory oversight of corporate combinations, particularly at the State level, often results in mandated savings, rate freezes, caps on the ability of the utilities to recover stranded costs, and other cost limitations and savings-sharing mechanisms.

Regulations in both the gas and electric power sectors are in the process of change. Although many States have begun to open retail gas and electric power markets to competition, the process is far from complete. Further, guidelines for combinations are still being worked out at the Federal level and no national policy exists; even the need for a policy is still being debated. Also, corporate combinations remain under close scrutiny by both Federal and State agencies, particularly as to whether the resulting entities would exert undue market power.

Companies throughout the natural gas and electric power sectors face an uncertain future as the energy industry undergoes restructuring and moves toward increased competition. The changes, in large part, stem from the efforts of the Federal Energy Regulatory Commission (FERC) to introduce a greater measure of competition into the natural gas (by Orders 436 and 636) and electric power (by Order 888) markets. Similar efforts underway or anticipated at the State level are already altering the fundamentals of the manner in which energy is bought and sold and moved to the customer.

Spurred by these rapidly changing conditions in traditional regulated markets, companies in the energy sector are under immense pressure to develop and implement successful strategies to survive and prosper. Mergers, acquisitions, joint ventures, and other forms of corporate combinations play a prominent role in such plans and strategies (see box, p. 149). They are important tools, bolstering the efforts of companies to take advantage of the opportunities and withstand the challenges presented by a changing industry.

Corporate combinations are typically classified as either horizontal or vertical. Although the terms are most often associated with mergers, they apply equally to asset acquisition, as well as to some forms of joint ventures and alliances so popular at present. Horizontal combinations take place between firms engaged in similar activities in the supply chain, for example, between gas producers, between marketers, between local distribution companies (LDCs), or between pipeline companies. Vertical combinations provide the advantage of additional capabilities at different levels of the supply chain, such as between marketers and producers. Vertical combinations extend the scope and reach of the company into other areas for short- or long-term profit potential or to gain strategic advantage. Horizontal combinations tend to attract more intense antitrust scrutiny than vertical combinations or conglomerate-type mergers in which participating firms are involved in the production or marketing of different energy forms.

The review and approval process of proposed corporate combinations can be costly and time-consuming. Numerous Federal, State, and sometimes local levels of government have oversight of proposed combinations. At the Federal level, the Federal Energy Regulatory Commission, the Department of Justice, and the Federal Trade Commission examine whether the proposed combination could exert undue market power. The Internal Revenue Service rules on the tax status of the proposed combination. If nuclear power plants are involved, the Nuclear Regulatory Commission rules on the ability of the proposed combination to operate any nuclear facilities. Last in the chain is approval by the Securities and Exchange Commission. State public utility commissions typically hold responsibility for oversight in combinations involving utilities.

The level of activity in all forms of corporate combinations in the energy sector has increased dramatically since 1995. Both the number and size of the various combinations have increased since the issuance of the FERC orders on electric industry restructuring. The transformation of the electric generation industry is having a profound impact on all forms of combinations in the natural gas sector. On the one hand, electric generation companies are to some extent both customers and competitors for gas producers, marketers, and even LDCs. On the other hand, similarities in marketing natural gas and electric power offer potential synergies for large marketers to handle more than a single fuel.

This chapter investigates corporate combinations from the perspective of companies involved in some aspect of the natural gas industry. Although mergers are prominently featured, the focus is broader, encompassing the notion of corporate combinations in general rather than a single approach to meeting rapidly changing conditions in the industry. The chapter first presents a brief overview of corporate combinations thus far in the 1990s and contrasts that with patterns prominent during the 1980s. The discussion then examines the reasons why companies combine and how corporate combinations fit into corporate strategy. In addition, the chapter examines the issues involved in regulatory review and assesses the impact of corporate combinations on consumers, on the structure of the industry, and on the market. An appendix to the chapter (see p. 229) lists most of the corporate combinations in the natural gas industry from 1996 through mid-November 1998.

Overview

Thus far during the 1990s, the growth of corporate combinations throughout the U.S. economy has been spectacular. In 1991, the value of all forms of combinations in all sectors amounted to about $165 billion. Since 1991, led by the financial and services sectors, the value of all corporate combinations grew by more than a factor of 5 to reach more than $900 billion in 1997 (Figure 52, upper left).

For the energy sector, the 1990s has also been a period of intense activity and sweeping corporate combinations. Unlike the general economy-wide restructuring common to the 1980s, changes in the energy industry since the early 1990s have intensified largely as a result of regulatory reforms. Order 636, which modified the merchant function of the interstate natural gas pipeline companies,[1] and particularly Order 888, which initiated restructuring in the electric power industry, directly and indirectly provided the

[1]Order 636 required unbundling of services and attempted to establish a level playing field for any related services. Federal Energy Regulatory Commission, Order 636-A, FR 36128 (August 12, 1992).

Types of Business Combinations

Merger (Full)—complete legal joining together of two (or occasionally more) separate companies into a single unit; in legal terms only one entity survives.

Merger (Partial)—only certain units of one or both companies are involved in the merger. (For example, Chevron's gas unit merges with NGC, Chevron ends up owning about 25 percent of NGC while NGC operates all of Chevron's gas business.)

Merger (Vertical)—may be achieved by combining two companies in different areas of the gas industry or through the combination of two or more entities in the same industry.

Merger (Horizontal)—two similar entities merge to extend geographic coverage or increase market share: examples include combinations of pipelines or especially local distribution companies.

Acquisition—the purchase of one company by another, or the purchase only of certain assets of one company by another. Unlike a hostile takeover, an acquisition is agreeable to both parties. (At times, the term may be used synonymously with merger.)

Hostile Takeover—acquisition of one company by another despite the opposition of the target company.

Divestiture—involve the sale or trading of assets. Planned divestitures may be undertaken as a part of corporate reorganization, to reduce debt, to re-deploy capital, or to eliminate underperforming or noncore lines of business. Divestitures may also be required as the result of new or changing regulatory circumstances. Divestitures may also be required as a condition in a pending merger or other combination (for example, to mitigate market power).

Active Salvage—a company with serious financial problems forced to seek a merger, find a buyer, or declare bankruptcy. Selling of assets (perhaps even the entire company) with the aim of salvaging some value for the troubled company.

Joint Ventures and Alliances—combinations of two or more corporations to cooperate for specific purposes but falling short of a merger. Such arrangements may be rather informal and general or very specific even limited to a single project or purpose. Joint ventures may involve the formation of a separate company that in turn acquires others and develops new products and services on its own. Joint ventures may be open to others by selling shares (after the initial combination). Joint ventures have been used for decades, particularly in situations where high capital costs or risk are prevalent, such as pipeline construction and exploration and development of difficult fields such as offshore. Joint ventures have become common among nonregulated subsidiaries and affiliates with the formation of marketing companies, in telecommunications, software, and energy management.

Foreign Investment—may be in the form of acquisition, merger, or joint venture. Domestic companies may invest outside the United States to get into nonregulated business as markets privatize. Foreign companies also invest in the United States to gain entry into the large U. S. market and into a stable economic environment.

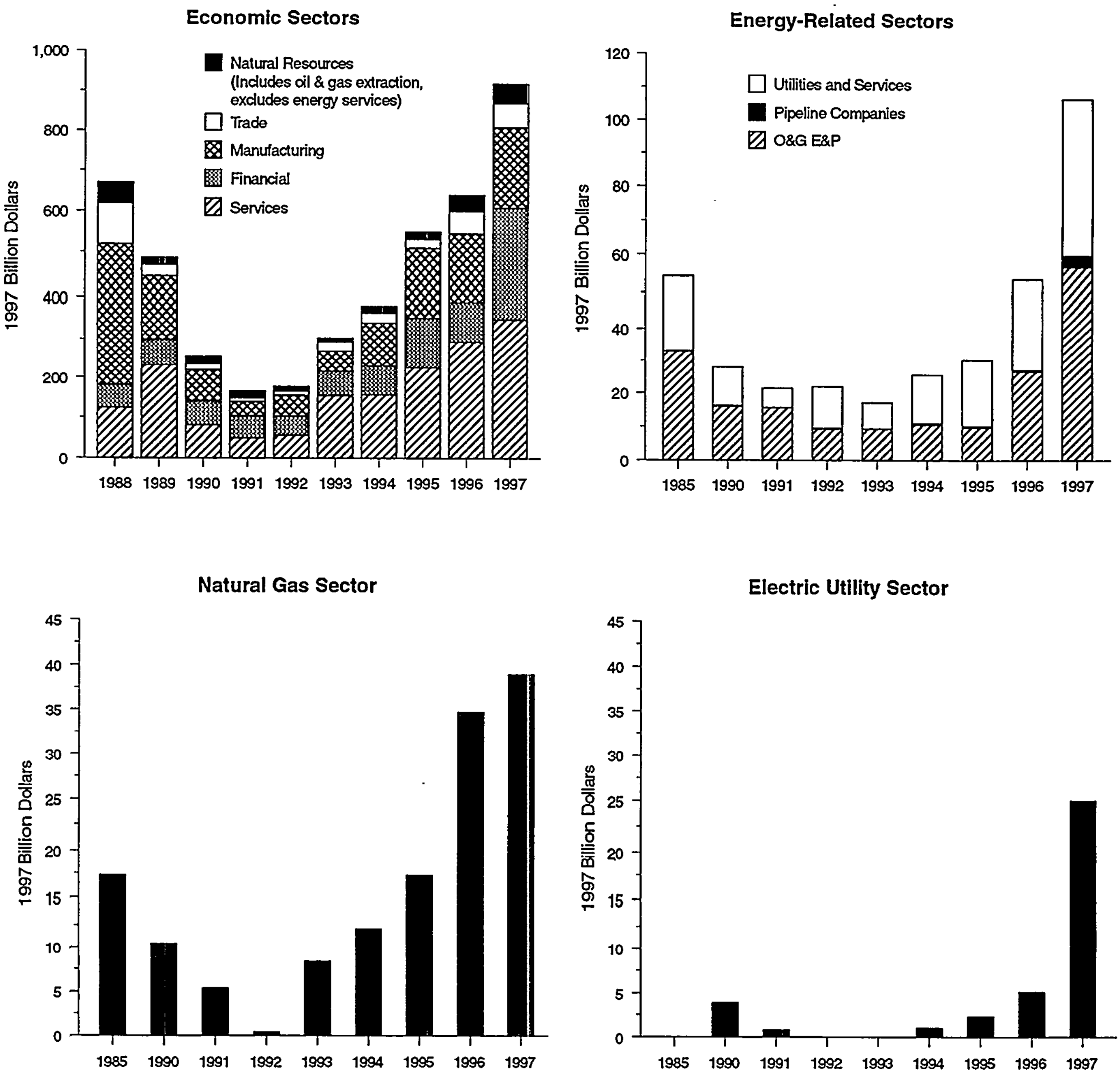
catalyst to stimulate the recent growth in both the number and value of corporate combinations.

In 1995, just prior to Order 888, utility combinations increased, accounting for two-thirds of all corporate combinations in the energy sector compared with 42 percent in 1990. Since 1995, the value of utility combinations has continued to rise, increasing by 143 percent. Following the implementation of Order 888, mergers in the electric utility sector more than doubled in value in 1996 and increased by a factor of 5 in 1997 (Figure 52, lower right).

Regulatory reform also provoked changes in other parts of the energy industry, not simply in the regulated and utility sectors. The increase in the number and value of corporate combinations has been general. For example, the growth in the value of mergers throughout the natural gas sector has been dramatic, surging from less than $1 billion in 1992 to more than $35 billion in 1997 (Figure 52, lower left). Similarly, the value of combinations in the energy sector as a whole has increased approximately fivefold since 1990 to more than $100 billion in 1997 (Figure 52, upper right).

As the importance of combinations involving gas and electric utilities grew, the value and number of those transactions in exploration, development, and production of the resource base and among equipment companies and suppliers of services to the oil and gas industry also grew, increasing by 270 percent during the period. Industry

Figure 52. Value of Corporate Combinations Has Increased



O&G E&P = Oil and gas exploration and production.

Notes: Value is measured in terms of stock purchase price and may also include debt and liability. Energy-related sectors exclude coal-related combinations. Graphs should not be directly compared because vertical scales differ.

Source: *The Merger Yearbook* (1985-1998).

restructuring not only sparked new flurries of activity in corporate combinations but also became a key factor behind fundamental changes throughout the energy industry.

However, despite a sharp increase in corporate combinations involving natural gas pipeline companies in 1997 (Figure 53), combinations involving the still-regulated pipeline companies represented only about 3 percent of all combinations in the energy sector (Figure 52, upper right). Also, it should be noted that corporate combinations in the energy sector continue to represent only a small fraction of the total for all sectors of the economy. In 1997, corporate combinations in the natural resource sector accounted for less than 5 percent of the value of all combinations.

The connection between the current surge of corporate combinations and regulatory change is not a new phenomenon. Major regulatory changes, such as the Public Utility Company Holding Act (PUCHA) in the 1930s, the Natural Gas Policy Act in 1978, and various FERC orders in the 1980s, also stimulated mergers, divestitures, joint ventures, and asset acquisition and influenced the structure of the gas industry (Figure 54).

During the 1980s, both the number and size of corporate combinations increased sharply as economic, regulatory, social, and technological conditions produced an environment promoting mergers and other forms of combinations. The value of all mergers, leveraged buyouts and other forms of combinations in 1981 nearly doubled from the level in 1980. At the same time, the number of large-scale "blockbuster" mergers also surged. In 1980 only one merger exceeded $1 billion in value; in 1981, the 10 largest mergers all exceeded $1 billion.[2] At the end of the 1980s, the collapse of the junk bond market, a general economic downturn, and changes in tax laws sharply reduced the number and value of corporate combinations.

Merger activity in the oil and gas sector followed a pattern of growth and decline through the 1980s similar to that in the overall economy. However, the level of activity reflected changes in the industry more intense than in many other sectors of the economy. In the early 1980s, oil prices were at historic highs and natural gas was seen to be in short supply. Both mergers and asset acquisitions became important strategies to build resources and to achieve the economies of scale seen as necessary to survive in the changed world of rising oil imports and diminishing domestic supplies. Record-setting mergers and acquisitions occurred with increasing frequency, growing not only in number but ballooning in value as well. When Shell Inc. acquired Belridge in 1980 for $3.7 billion, it set a record for the energy industry to that point. Yet just 4 years later, Chevron acquired Gulf Shell for a record $14.5 billion.

Although most mergers and acquisitions in the energy sector included oil and gas interests, the emphasis during most of the 1980s was clearly on the oil side. It was not until near the end of the decade, with the expansion of regulatory reform, that interest in natural gas combinations began to equal or even surpass the level of interest in oil-related combinations.

Why Energy Companies Combine

Corporate combinations, whether they entail the formality of a merger or a less structured joining-together, involve issues that are neither simple nor confined to the question of whether or not to merge. In addition to the opening up of the gas industry and more recently the electric power industry to competitive forces, there are a number of factors that influence and often determine corporate strategy. On the surface, the number of strategies in use appears to be as extensive as the number of combinations taking place. However, underlying most strategies are goals of cost management and growth to ensure corporate prosperity.

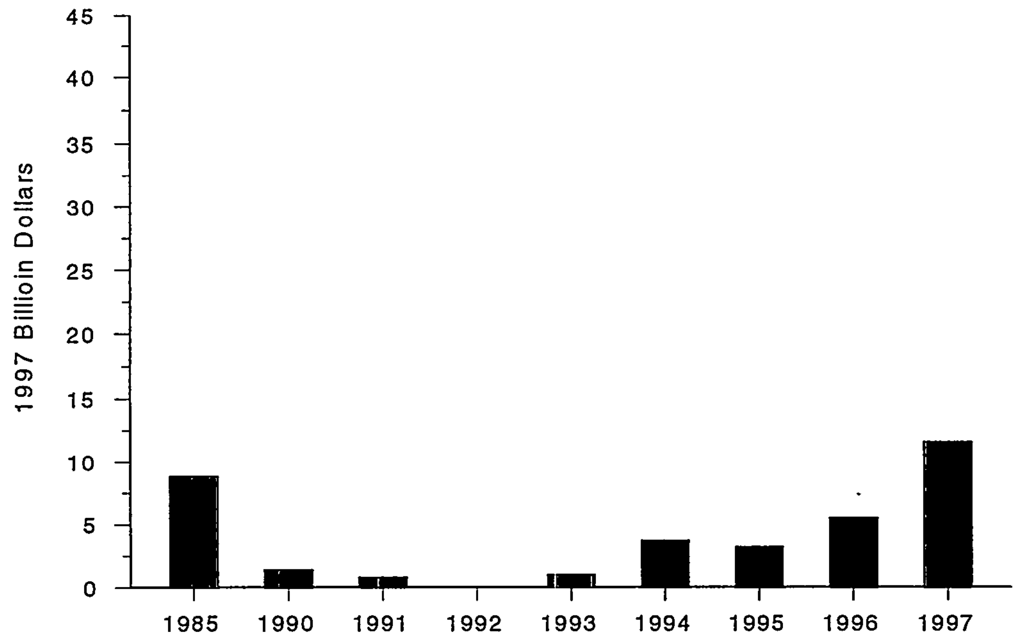
Corporate strategies involving natural gas companies also reflect certain characteristics of the gas industry. Although there are a few very large companies in each segment of the gas industry, a key feature of the industry is that most producing companies, marketers, and LDCs are relatively small. In the case of producers and marketers, this often means privately held companies. In the case of LDCs, many are small municipals or cooperatives. Natural gas production appears to be relatively unconcentrated, as demonstrated by findings that regional markets are unlikely to be dominated by one firm.[3]

The recent trend toward industry consolidation is changing this loose configuration of companies as producers,

[2]Securities Data Company, *Mergers Yearbook* (1982), p. 15.

[3]Energy Information Administration, *Oil and Gas Development in the United States in the Early 1990s: An Expanded Role for Independent Producers*, DOE/EIA-0600 (Washington, DC, October 1995).

Figure 53. Value of Mergers and Acquisitions Involving Natural Gas Pipeline Companies



Note: Value is measured in terms of stock purchase price and may also include debt and liability.
Source: *The Merger Yearbook* (1986 and 1991-1998).

gathering companies, marketers, and LDCs all jockey for position, while many seek to take advantage of structural changes in the industry, and some struggle simply to survive. Producers look for opportunities to enhance their return either by extending operations into other aspects of gas supply, such as storage or marketing, or by forming strategic alliances that combine dissimilar activities in the vertically differentiated gas supply process. Their objective is to enhance their market position or capture economies of scale.

Order 636 directly changed the way in which pipeline companies operated by requiring the unbundling of services and open access. The order stimulated the growth of independent gas-marketing companies as pipeline companies withdrew from or greatly reduced their merchant function. In addition, as a result of FERC's subsequent ruling that gathering systems were nonjurisdictional, many gathering systems were spun off by pipeline companies. Thus, by the middle of the 1990s, the operating environment for pipeline companies was very different from that just a few years earlier.

Strategies employed by some pipeline companies to deal with changed circumstances emphasized geographic expansion, such as El Paso Energy's acquisition of Tenneco Energy in 1996. Houston-based Tenneco Energy transported natural gas to customers in 20 States, primarily in the Midwest and Northeast, while El Paso Energy, based in El Paso, Texas, operates one of the largest mainline transmissions in the country. Others developed interests in other segments of the industry or in ventures outside of natural gas, such as Enron with its acquisition of the largest electric utility in Oregon (Portland General) or efforts by Williams Companies (an integrated gas firm) in telecommunications.

Significant changes have come about in the gas-marketing segment of the industry. The changes came about, in part, as the result of Order 636 as producers and others expanded their role into other market segments, and in part, as companies sought solutions to marketing problems. For example, under the terms of the partial merger between Chevron and NGC (now Dynegy), NGC became the marketer for Chevron's production in the United States. More recently, a number of similar mergers or joint ventures have been undertaken where marketing activities are taken over by an outside party. Despite such changes, gas marketing, like gas production, remains relatively unconcentrated. Between 1992 and 1997, the share of sales by the top four marketers declined by one-third to 21 percent, while sales volumes more than doubled. Sales by the top 20 slipped only from 69 to 66 percent but volume more than tripled to 40 trillion cubic feet (Figure 55).

Figure 54. Corporate Combinations: Timeline

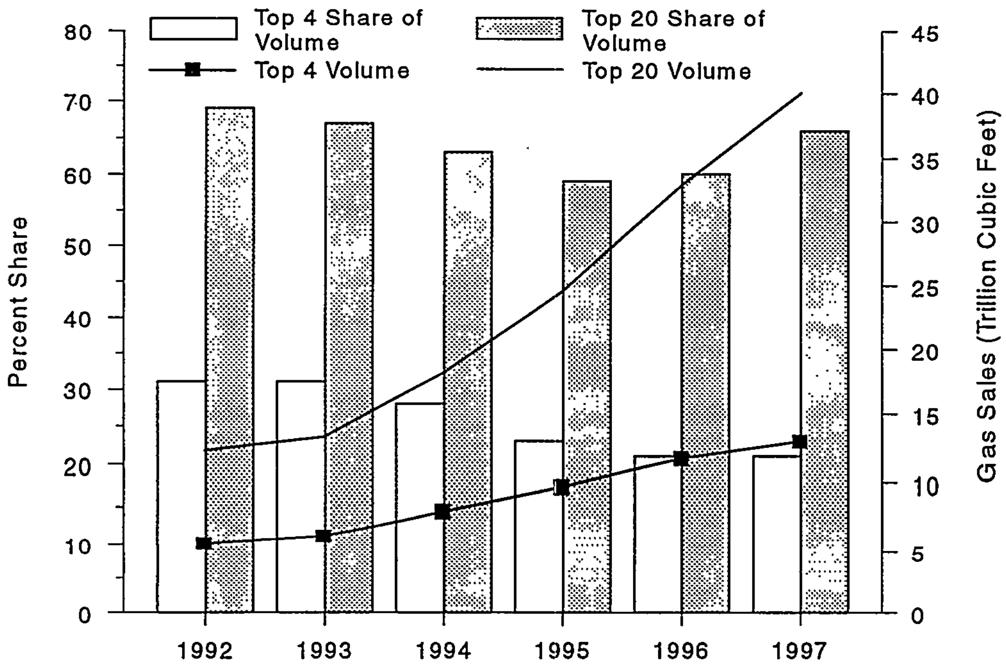
Institutional Changes Affecting Mergers Among Energy-Related Companies		Phases of Merger Activity
Federal Energy Regulatory Commision (FERC) Order 889 Establishes Open Access Same-Time Information System (formerly Real-Time Information networks) and Standards of Conduct.	1997	
FERC Order 888 Promotes wholesale competition through open access non-discriminatory transmission services by public utilities; recovery of stranded costs by public utilities and transmitting utilities.	1997	Alliances / Joint Ventures
FERC Order 636 Requires pipeline companies to provide open-access transportation and storage, and to separate sales from transportation services completely. Mandates capacity release, electronic bulletin boards, and straight fixed-variable (SFV) rate design.	1992	
Energy Policy Act Encourages development of clean-fuel vehicles; encourages energy conservation and integrated resource planning; gives alternative minimum tax relief to independent producers; and exempts "exempt wholesale generator" (EWGs) from regulation under the Public Utility Holding Company Act.	1992	Mega Mergers
Clean Air Act Amendments Required significant changes in gasoline composition for air-quality attainment and special programs for California vehicles; tightened restrictions on the release of hazardous pollutants; established tougher emission standards for most offshore drilling.	1990	
Natural Gas Wellhead Decontrol Act Phased decontrol of all gas wellhead prices.	1989	Acquisitions
FERC Order 500 Modified Order 436 to address pipeline companies' take-or-pay issues.	1987	
FERC Order 436 Authorized blanket certificates for interstate pipeline companies if they offered open access transportation on a first-come, first-served basis.	1985	
FERC Order 380 Invalidated contract requirements that a gas utility pay a pipeline company for a certain amount of gas even if it could not take the gas. This paved the way for utilities to buy gas directly from producers and marketing companies.	1984	Hostile Takeovers - Leveraged Buyouts
Natural Gas Policy Act Brought intrastate gas under Federal deregulation. Also provided for the phased deregulation of nearly all natural gas produced from wells spudded after January 1, 1975.	1978	

Earlier Legislation and Regulations Affecting Merger Policy and Practices

Natural Gas Act	1938	
Public Utility Holding Company Act (PUHCA)	1935	Divestiture
Sherman Anti-trust Act	1911	

Source: Energy Information Administration, Office of Oil and Gas.

Figure 55. Top 20 Natural Gas Marketers: Growth in Volume Outpaces Growth in Share



Note: Reported volumes include all sales, including sales for resale, so totals exceed actual consumption for the year.
Source: Ben Scheisinger & Associates, *Directory of Natural Gas Marketing Service Companies* (1997).

Major Goals of Combinations

The reasons for specific corporate combinations can be grouped into several broad categories, with the primary ones being cost management and growth. Often, issues that deal primarily with one approach are at least tinged with some aspect of another strategy. For example, the discussion of "economies of scale" has been grouped with cost management issues. However, it could also have been addressed in the discussion of growth.

Cost Management

Cost control issues are important in all corporate activities. As competition increases, cost avoidance and cost savings become even more critical and are drivers in virtually all corporate combinations. This is particularly true in combinations involving public utilities where cost factors play a special role. During the review process, projections of savings and the proposals for sharing the savings with ratepayers are scrutinized with care. Estimated savings are often substantial and typically projected over a period of 10 years or more. For example, in the case of the merger between Brooklyn Union Gas and Long Island Lighting Company, estimated savings over 10 years were $1 billion. Savings to consumers are most often presented (both by the parties involved and in the media) in terms of total savings to consumers or the savings to the individual residential consumer. For example, the pending acquisition of Orange and Rockland by Consolidated Edison projected that savings of $50 million per year would be passed on to ratepayers.

Stranded costs[4] are at the center of another cost issue. LDCs are often concerned about the potential loss of retail customers from the increased competition that may result from restructuring. The ability of the utilities to recover stranded costs may become a stumbling block in the merger process.[5]

[4]Stranded costs are costs arising from utility investments that are not supported by current market prices, especially long-term investments or contractual obligations the utility may not be able to recover from rate payers in a competitive environment.

[5]For example, in the attempted merger between Duquesne Light and Allegheny Energy, the State commission disallowed most of the stranded costs claimed by Allegheny. As a result, Duquesne withdrew from the merger citing as unacceptable the negative impact on its stakeholders. Subsequently, in October 1998, Allegheny sued Duquesne to block termination of the merger agreement. At present, the matter is pending.

Economies of Scale

A closely related argument to issues of size and cost-cutting centers on the need for increased size to produce the economies of scale also believed necessary to compete. A newly formed combination often trims costs by eliminating duplicate functions and underperforming units and by combining services. Economies of scale enable cost-cutting by reducing overall management costs.

It is also often argued that increased size will enable the new company or venture to compete more readily and, in the case of utilities, will enable the company to return savings to the rate payers or to freeze rates for some period of time. For example in the Chevron/ Dynegy merger, the increased scale spread fixed costs over a greater volume of gas. In the case of utilities, arguments may center on size or service. In the Brooklyn Union Gas and Long Island Lighting Company (LILCO) merger application, it was argued that the combined workforce would enable better response time to storm damage. In the failed merger attempt (December 1997) between Potomac Electric Power Company (PEPCO) and Baltimore Gas and Electric, the companies argued that if the merger were to fail, they would be too small to compete in the changing market, and that absent the projected savings from the proposed merger rate increases would result.

During the review process, government agencies and regulatory bodies closely examine these issues of size and cost savings. The review process differs from agency to agency; however, investigation of possible negative impacts of the proposed combination on competition is typically at the center of the review. Such factors as the ability to exert undue power in setting price, increased barriers to entry, or the ability to take unfair advantage of the size of the new entity are among the issues considered. (The regulatory review process is discussed in greater detail later in the chapter.)

Taxes

Another aspect of cost avoidance and cost reduction is the issue of taxes. Mergers are generally nontaxable. Judgments about tax liability are the responsibility of the Internal Revenue Service. For example, the acquisition of Enserch Corporation (an integrated natural gas company in Texas) by Texas Utilities was tax-free, as was the formation of Alliant (an unusual three-way merger between IES Utilities, Interstate Power Co., and Wisconsin Power & Light) and the KN Energy acquisition of American Oil and Gas. Corporate combinations are typically structured to avoid or at least minimize tax consequences. The result can be substantial growth through the addition of production, supply access, transportation or marketing assets, or other gains, without tax consequences.

Divestiture

Companies often downsize in order to be in a better position to compete. They may be motivated by a desire to shed various segments that either do not perform up to expectation or in order to concentrate effort and resources on "core" business. Companies may also be motivated by a desire to withdraw from high-risk businesses in order to move into or concentrate on areas with greater stability or those that offer a greater return for the amount of risk. Divestiture may be motivated by a current high market value of a particular class of assets.

Divestitures can be as much an integral part of an overall restructuring strategy as a merger or acquisition. Divestitures may be a significant part of the plan to build a cash pool in order to pursue other asset acquisitions or to fund entry into expanding or new markets. They may also be the result of regulatory decisions, as in the case of the merger between Texas Utilities Company and The Energy Group in June 1998—Texas Utilities spun off the Peabody Coal holdings in order to gain approval of the acquisition.

Growth

Corporate growth is an important factor, often the most important factor behind a merger or acquisition. Whether the aim is growth in size, geographic scope, or to prevent a takeover, nearly all corporate combinations have at least some aspect of growth as part of the reason for the combination. However, not all growth strategies imply an outward, aggressive focus and vision. Growth may also be inward-looking and defensive.

Some companies seek to secure their traditional market by expanding into a different line of endeavor in the same geographic area or by seeking an ally in an adjoining market, as in the case of Enova and Pacific Enterprises (PE). The marketing territory of Sempra Energy, the new company, encompasses the southern half of California, including the Los Angeles metropolitan region (home of PE) and San Diego (home of Enova). Such combinations reflect what is in essence a defensive strategy. Companies seek to create economies of scale either through internal growth or through combining with similar companies, often in adjacent territories, and attain a size that lessens the possibility of a takeover by outside interests.

Other companies, often among the largest, take advantage of their resource base to engage in a number of different strategies at the same time. For example, Enron Corporation has actively pursued acquisition of utilities, pipeline companies, and other assets in electric power and natural gas. At the same time, Enron has been a major participant in alternative energy projects involving both wind and solar power and in the development of energy marketing ventures as various States open their markets to competition. Enron has been heavily involved in projects outside the United States as well.

LDCs, backed by the reliable revenue stream from a large customer base, are often well positioned to pursue an aggressive course of diversification and expansion. Pacific Gas and Electric Company (PG&E), Houston Industries, Texas Utilities, and Duke Power have each undertaken a course of rapid diversification and expansion that embodies a philosophy that success depends on size, diversity, and rapid market entry. For example, Duke Power was a medium-sized electric LDC based in North Carolina until its rapid expansion propelled it into the top ranks of companies in natural gas production and gathering, transportation, electric power marketing, and international operations (see box, p. 157). Initially, Duke's plan was to grow from within and the company entered into a number of joint ventures, some of which are still in effect. However, the company subsequently decided that its approach was not keeping up with the rapid pace of events in the industry. As a result, Duke developed a strategy that sought to take advantage of the opportunities that regulatory reform presented. It initiated an aggressive campaign of acquisitions, including gas pipeline companies, gas production and gathering facilities, and electric power plants in States where restructuring is requiring a separation of generation from distribution. It also expanded overseas.

The two views of growth reflect an underlying dichotomy where on the one hand, growth is essential, economies of scale a must, bigger is better, and getting into the market first is important. On the other hand is the philosophy that emphasizes slow growth, and favors the smaller and more focused approach. In this approach, divestiture may play a role not so much to raise cash for other investments but to enable concentration on "core competencies," and where a local or regional strategy rather than a national or international strategy is employed.

Size Matters

The size of a company does matter. From a practical standpoint, size brings advantages of economies of scale, increased resources, more favorable financial terms, etc. Often both company press releases and the industry trade press note that, as the result of a recent combination, the new company or joint venture is now the largest of its kind. For example, the combination of Chevron and Natural Gas Clearinghouse in 1996 resulted in the largest marketer of natural gas in the United States and the second largest marketer of electric power. When El Paso Energy Corporation officially acquires DeepTech International (announced in March 1998), it will become the largest gatherer (in dollars) of natural gas in the offshore Gulf of Mexico.

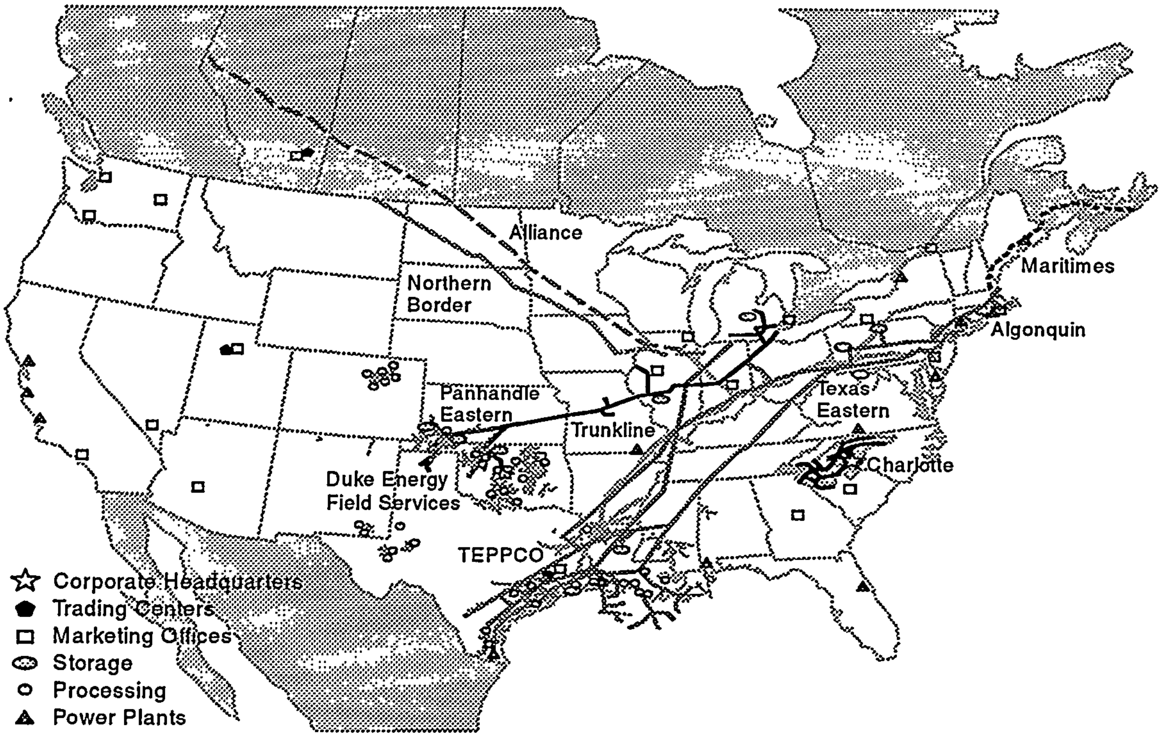
But size also matters, at least to some, in the less tangible sense of image. Being "number one" or being able to claim rank among the leading companies in a field holds interest for many combining companies. Rank provides a convenient measure or a shorthand code to place the new company in context. Size also is very much a part of corporate image; it reinforces name recognition and may even be a motivating factor in some combinations.

While being number one is not necessarily a goal, being among the largest companies by having x volume of production or y percentage of capacity, provides another measure of size and power. Following the acquisition of Tejas Gas Corporation (a natural gas pipeline and storage company) by Shell, the combination transports 8 billion cubic feet (Bcf) per day; the El Paso/Tenneco combination moves 9.3 Bcf per day; and the KN/MidCon combination transports 17 percent of all the gas in the United States (Appendix E, Table E1). Through such measures, companies attempt to demonstrate the utility of their acquisition, merger, or joint venture. In essence, they are saying bigger is better, and now that we are bigger, we are positioned to compete, and to serve our customers *better.*

An Outlet for Cash-Rich Companies

Cash-rich companies possess a strategic opportunity to acquire the choicest assets or seek out other investments and combinations. Companies with ready cash from restructuring efforts (usually the result of asset sales or other forms of divestitures) view mergers and acquisitions as a good way to spend that cash on investments with a potentially high return. For example, the sale by Dominion Energy of cogeneration assets in Texas provided capital to

Selected Milestones in Growth of Duke Energy Corporation



1900 Catawba Power Company (predecessor to Duke Power) formed to supply electricity to textile mills in South Carolina.

1904 Catawba Power began operation of its first plant. Considered the birthdate of Duke Power.

1988 Duke Energy Corporation formed to develop and finance projects outside traditional service territory.

1989 Duke/Fluor Daniel formed joint venture to provide services to coal-fired power plants.

1994 DukeNet Communications formed fiber optics communication services.

1995 Duke Energy Corporation and Louis Dreyfus Electric Power, Inc. formed joint venture.

1995 Duke Engineering & Services, Inc acquired ITERA multi-disciplinary environmental consulting firm.

1997 Duke Energy Corp. created by merger of Duke Power Co. in Charlotte, NC and PanEnergy Corp. of Houston, TX.

Duke Energy Trading and Marketing, LLC acquired Inland Pacific Energy Services Corp., a gas marketer in Spokane, WA.

Duke Energy Power Services (DEPS) & United American Energy Corp. (UAE) acquired 50 percent of American Ref-Fuel Co.

1998 Subsidiaries of Duke Energy Corp. acquired a 9.8 percent ownership in the Alliance Pipeline.

1998 Duke Energy Corp. and Williams announced Cross Bay Pipeline, a joint venture natural gas pipeline project into New York City.

Duke Energy Transport and Trading Co. purchased assets and related marketing business of Mesa Pipeline Co., a crude oil gathering & transportation company.

Duke Energy Transport and Trading letter of intent to acquire certain crude transportation and marketing operations from Dynegy Inc.

Duke Communication Services created (wireless communication in 33 States).

Duke Energy Field Services, Inc. & Koch Midstream Gathering and Processing Co., exchanged natural gas gathering and processing assets in several States.

DukeSolutions acquired Engineering Interface Limited of Toronto, Canada, to become the base for DukeSolutions Canada, Inc.

Duke Energy Corp. sold Duke Energy Transport and Trading Co. (DETTCO) to TEPPCO, L.P.; Duke Energy is the general partner of TEPPCO (increases Duke's interest in TEPPCO to approximately 20 percent).

Duke Energy announced it had signed a definitive agreement to sell Panhandle, Trunkline, and related assets to CMS Energy for $2.2 billion.

Duke Energy Field Services purchased gas gathering and processing facilities from ONEOK Inc. Also formed a joint venture with ONEOK.

*Excludes international ventures outside North America.

re-deploy into other ventures. Dominion Energy, Duke Power, PG&E,[6] and other sizable LDCs have expanded into energy projects across the United States and in other countries as well. Some companies are eager to make use of their present strong cash position to finance expansion before possible changes in regulatory structure eliminate or make such efforts more difficult.

Asset Acquisition

Growth strategy may also be focused on the acquisition of assets. Asset acquisition, a common practice employed to increase size in the late 1970s and 1980s,[7] has resurfaced recently and includes not only commodity resources and infrastructure, but less tangible assets such as access to transportation, management skills, technology, or information as well. The level of asset acquisition has surged in the past 2 years, reflecting increased activity throughout the industry to opportunities generated by utility restructuring. In 1995, asset acquisitions accounted for only 5 percent of all activity; in 1997, such purchases accounted for more than one-third of all combinations (Figure 56).

New Business Areas or Diversification

Activities to promote growth may be directed into new areas that are either outside of the traditional scope of activities of a company or the industry itself. For example, by the acquisition of Zond Wind Energy, a joint venture with Amoco in solar power, and a series of other ventures and acquisitions, Enron became a major participant in the renewable energy market. The Duke Power/PanEnergy merger brought gas transportation to the Duke portfolio. And by the acquisition of Zilkha Energy, Sonat entered into gas exploration.

Companies may also opt to respond to opportunities in other States or to changing circumstances overseas as restructuring opens markets around the world. For example, the Dominion acquisition of East Midland in the United Kingdom gave access to another market. Similarly, the TECO merger with Lykes gave TECO the opportunity to enter into natural gas distribution. Also, shrinking margins in gas marketing mean reduced profits, hence a shift by some companies (as with Enron) into capital ventures and international power projects.

A subset of the diversification strategy seeks to take advantage of new technology that enables companies to move into new areas, such as credit cards, banking systems, cable TV and other telecommunications, meter reading, and the like. Typical acquisitions in this area are small startup companies that have developed hardware, software, information systems, etc. The technology is acquired either through purchase (merger or acquisition) or in joint ventures or other marketing arrangements that then lease or market the technology. Some technologies such as electronic meter reading may also lead to bypass or allow competitors entry into the service territory of LDCs. As a result, they are suspect as startup companies or in the hands of competitors, yet sought after as important competitive tools.

Growth and Diversification in the Utility Sector

Much of the activity in the current wave of corporate combinations stems from the desire to expand into areas of services that were previously bundled and provided by regulated entities, or that appear likely to develop with the convergence of the gas and electric sectors. Corporate combinations in this area tend to be smaller; acquisitions over $100 million are more an exception than commonplace. Rather, many gas and electric utilities are joining in joint ventures to provide services ranging from telecommunications to banking. Initially, joint ventures such as NICOR Energy (formed by NGC and NICOR) and SouthStar Energy Services (formed by Dynegy, AGL Resources, and Piedmont Natural Gas Company) will target only the larger commercial and industrial customers but they plan to extend the service offering to the residential market as States unbundle gas and electric services.

Among the new services offered are credit cards, billing services (for others), network services, Internet, telephones, banking, data processing, energy management, and entertainment. Many combinations occur as the result of the desire to market energy or provide a menu of energy services. For example, the PG&E acquisition of Valero Energy in Texas included marketing assets in another region as well as the gas assets. Similarly, a more comprehensive energy services company emerged from the acquisition of Enserch by Texas Utilities. And with the addition of Lufkin-Conroe Communications, Texas Utilities expanded its ability to offer telecommunication services.

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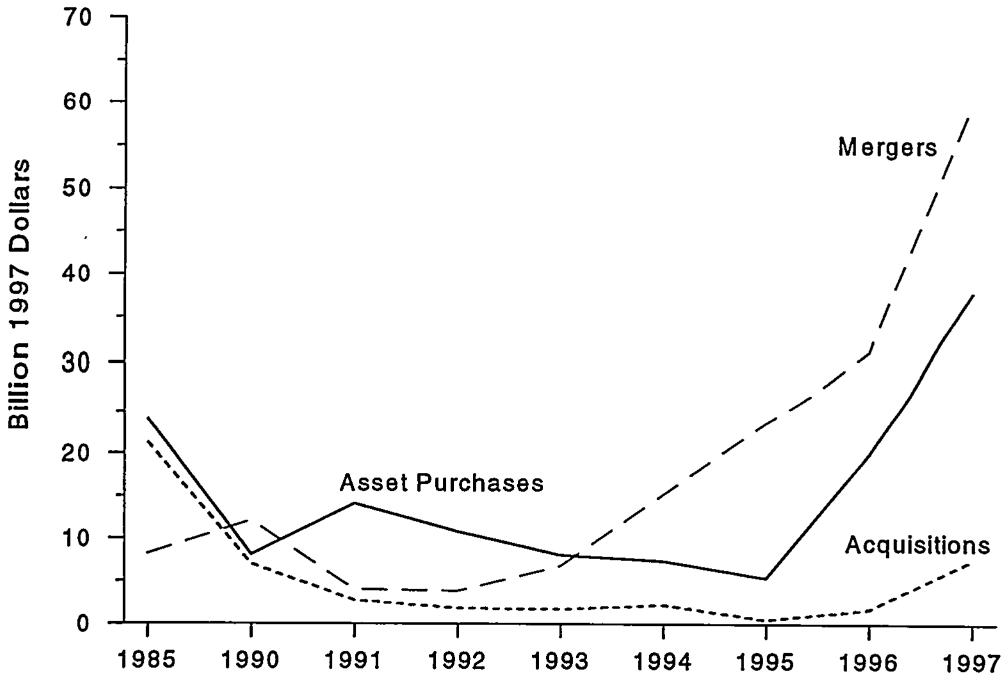
[6]Dominion is the parent of Virginia Power, a regulated LDC in the Middle Atlantic Region. Duke, an LDC in the Carolinas, acquired PanEnergy as well as significant gas-gathering facilities. California-based PG&E, through its subsidiary US Generating, has acquired electric power plants around the United States, principally in New England.

[7]Energy Information Administration, *Financial Aspects of the Consolidation of the U.S. Oil and Gas Industry in the 1980s*, DOE/EIA-0524 (Washington, DC, May 1989).

Figure 56. Mergers Continue To Grow in Value, Accounting for the Largest Share of Energy Combinations



Notes: Value is measured in terms of stock purchase price and may also include debt and liability. Acquisitions involve purchase of entire company; Asset Purchases involve only selected assets.

Source: *The Merger Yearbook* (1985, 1991-1998).

The concept of integrated one-stop shopping remains beyond the current scope of the service combinations. The packages vary and may include telephone, Internet access, satellite television, electronic shopping, radon testing, banking and insurance, and real estate services. The offerings tend to be flexible with customers having the ability to choose from a varied menu. The services also tend to go well beyond the scope of those services provided by the regulated LDC. For example, Boston Edison and RCN established a joint venture to develop a network for one-stop energy services and telecommunications. The Allied Utility Network, a joint venture initially consisting of four LDCs but open to other companies, offers energy services to the residential market.

As some utilities have lost much of their customer base in terms of large industrial and commercial customers, many joint ventures are undertaken with the specific purpose of developing a package or menu of services to market. Utilities are motivated by concerns that large marketers such as Enron and Southern, operating in many States will enter their territory and erode their remaining customer base. As a result, there are joint venture programs designed to hold existing customers and capture new ones, avoid bypass, pool customers, and rebundle services.

Other Reasons for Combinations

Brand Recognition

Sometimes an acquiring company buys or strikes an arrangement to lease or market a well-known product or acquires a company for the name recognition. Advertising becomes important to strategy whether merger, acquisition, or joint venture: Natural gas companies, which have not sold to the general public before, are budgeting for advertising campaigns and brand name logos. For example, Suncor in Canada offers customers at their gasoline outlets to sign up for natural gas service. Similarly, Shell launched a national campaign to market Shell "branded" natural gas and electricity in both the United States and Canada. Examples of joint ventures with some form of brand identification include: Simple Choice and En*able of KN Energy, Energy Marketplace of SoCal Gas, and Home Vantage of the Allied Utility Network. A few large companies such as Enron and Southern Company are conducting national advertising campaigns.[8]

Strategic Fit

Many companies have well-developed plans to develop the business in line with a vision of the future. Acquisitions may fit with core abilities. In the case of PG&E, the acquisition of Valero opened the Texas market and was compatible with other key acquisitions. The acquisition tied into several key issues: it assured PG&E of gas production, it augmented PG&E's pipeline network, and enabled PG&E to be in a better position to supply power plants as it expanded into New England (via its nonregulated subsidiary, U.S. Generating Company), and opened new markets. Similarly, Dominion's acquisition of Phoenix Energy Sales strengthened its position in the Appalachian Basin. Dominion's acquisition of Archer Resources in Canada and various acquisitions in Michigan furthered plans to concentrate assets in the Midwest and Northeast. Similarly, as a result of the Tenneco merger with El Paso, El Paso's pipeline network doubled in size. In the case of the Meridian Resource Corporation/Carin Energy merger, capitalization increased by a factor of 3 and the resource base doubled.

For some companies, strategic fit encompasses far more than natural gas or energy enterprises. For example, Western Resources developed a three-pronged response to changing market conditions. First, Western through a strategic alliance with ONEOK added 1 million gas customers. The second aspect of Western's approach was the acquisition of Westinghouse Security Systems that doubled its home security customer base to 2 million. Finally, Western added more than 1 million electric power customers by its merger with Kansas City Power and Light. Western Resources is not unique in developing a strategic plan that includes non-energy elements. Strategic fit for some includes real estate companies, thus providing residential customers with not only energy services through other affiliates but participation in the buying and selling of homes for customers and potential customers of the energy businesses. For others, generally the larger players, foreign ventures in the form of utilities, construction, or financing fit well with their plans, such as the Texas Utility acquisition of The Energy Group, an electric utility in the United Kingdom, in the spring of 1998.

Neither vision statements nor strategic plans are necessarily permanent and although most do not change radically from one year to the next, they do evolve. It is important to note that the key to strategic fit is the vision of the particular company, at a particular time. External factors, such as changing regulatory or economic factors, as well as internal changes in the composition or views of corporate management can result in changes to strategic plans and rethinking of acquisitions already undertaken (see box, p. 161).

Regulatory conditions in the United Kingdom played a role in the acquisition of East Midlands electric power utility by Dominion in 1996.[9] In the same way, changing regulatory conditions in the United Kingdom played a role in Dominion's decision to sell East Midlands in May 1998. In the case of Dominion, although the sale was profitable, corporate strategy changed to place greater emphasis on domestic projects.

Regulatory Concerns

To help insure fairness and to preserve open markets, agencies at the Federal, State, and sometimes local levels of government examine proposed combinations (Table 18). Among those most actively involved in the process of corporate combinations at the Federal level are the Federal Energy Regulatory Commission (FERC), the Department of Justice (DOJ), the Federal Trade Commission (FTC), the Internal Revenue Service (IRS), and the Nuclear Regulatory Commission (NRC). State public utility commissions, or their equivalent, typically hold responsibility for oversight in combinations involving utilities. The various agencies have the power to impose that conditions be met as a condition of approval or to withhold approval and prevent the combination from taking place.

Regulation at the State and Federal levels involves all aspects of the gas industry from production through supply to distribution and is divided into direct and indirect regulation. With the power to set rates and establish the rate of return, State commissions and the FERC exercise

[8]The power of brand recognition is clearly perceived by both utilities and regulators. As States begin opening the retail market to competition, State utility commissions in some cases have prohibited nonregulated affiliates of utilities from using the name of the regulated parent. In other instances, State commissions have required a disclaimer from the affiliate which clearly states that it is not the same entity as the parent.

[9]Electric power restructuring opening markets to competition was further advanced in the United Kingdom and played a major role in Dominion's decision to purchase East Midlands. Later changes in tax policies played a major role in Dominion's decision to sell East Midlands some 18 months later.

Why Some Deals Fail

The process of joining together two or more businesses is always complex, frequently time-consuming, and often costly. Most often, the process proceeds through to a successful conclusion. However, there are times when some situation or set of circumstances intervenes and the process is aborted.

A corporate combination may fail because it is directly prohibited during the review process. However, it is more likely that time delays resulting from the process or conditions imposed on the parties as the result of the review process will diminish the benefits or so add to the cost of the combination that the parties involved elect to abandon the combination. For example, the proposed merger between Potomac Electric Power Company (PEPCO) and Baltimore Gas and Electric fell through in large part because conditions imposed during the review process were unacceptable to the companies, but also because market conditions had changed rapidly and in unanticipated ways making the deal less desirable to the parties. Also affected by the passage of time and changing conditions, Western Resources in November 1997 sought to renegotiate or pull out of its arrangement to acquire Kansas City Power and Light (KCPL). Western had decided that the deal had become uneconomic. In addition, Western was less interested in the acquisition since it had begun to diversify away from utilities. In another example of the breakdown of a proposed combination, Maryland-based Duquesne Energy (DQE) formally notified Allegheny Energy (based in Pennsylvania) in October 1998 that it was terminating their proposed merger agreement. The decision of the Pennsylvania Public Utility Commission in its review of the proposed merger to disallow more than $1 billion of stranded costs claimed by Allegheny played a key role in DQE's attempt to terminate the merger despite subsequent approval by the Federal Energy Regulatory Commission. (Allegheny has filed suit in Federal District Court to block DQE from withdrawing from the merger.)

Corporate combinations may also fail because of the structure of the combination. Although joint ventures and alliances can be highly successful and profitable forms of corporate combinations, they are also somewhat fragile. In particular, joint ventures typically do not require the level of financial commitment necessary in mergers and acquisitions. As a result, failure may result from a lack of understanding the economic potential, failure to integrate or account for the skills and technological strengths of the participants, lack of clearly defined goals, or understanding of the market implications of the venture. Failure can also result because the participants are unfamiliar with the organizational process or the specifics of the joint venture approach to corporate combinations.

Timing can also be a crucial factor in the failure of corporate combinations. In their desire to be "first-to-market," companies may enter into combinations prematurely. For example, the joint venture between UtiliCorp and PECO collapsed in large measure because the market had not developed for the approach taken by the companies.

classical direct regulation. The FTC and the DOJ in the enforcement of antitrust laws constitute indirect regulation.

The oversight function for each agency is limited but often overlapping. When examining prospective corporate combinations, the regulators, the various agencies, and at times, the courts typically focus on those aspects of the combination where the possibility exists that the outcome might result in unfair advantage in pricing, barriers to entry and the like. The key issues include the ability of the combination to exercise undue market power or to bar entry into the field by others. In the case of utility combinations, agencies, particularly at the State level, also scrutinize the estimated savings and set the level for recovery of stranded costs.

In reviewing corporate combinations, State and Federal regulators and agencies have both different jurisdictions and are charged with different missions. The review process proceeds at both the State and Federal level simultaneously with the various agencies examining the proposed combination looking for certain trigger items. (Several lines of inquiry may proceed at the same time at the Federal level.) Although there is no single path that parties seeking to combine must follow, and while each proposed combination is unique at least to some extent, nonetheless the path followed by most proposed combinations embodies essentially the same elements.

Table 18. Agency Review of Corporate Combinations

Agency	Authority	Type of Review
Department of Justice	Hart-Scott-Rodino Antitrust Improvements Act	Antitrust, competition, market power
Federal Energy Regulatory Commission	Federal Power Act of 1935, Natural Gas Act, Department of Energy Reorganization Act of 1977, Energy Policy Act of 1992	Examines combinations to assure competitive markets, assures access to reliable service at reasonable prices
Federal Trade Commission	Interstate Commerce Act, Hart-Scott-Rodino Antitrust Improvements Act	Antitrust, competition, market power
Internal Revenue Service	16th Amendment to U.S. Constitution (1913)	Determines amount of tax liability for combination (if any)
Nuclear Regulatory Commission	Atomic Energy Act, Energy Reorganization Act of 1974, Energy Policy Act of 1992	Approval of transfer of control of nuclear facilities
Securities and Exchange Commission	Public Utility Holding Company Act (PUHCA)	Compliance with PUHCA provisions and protection of shareholders interests
State Public Utilities Commission (or equivalent)	Various State Laws	Full review may include: antitrust, market power, stranded costs, rates, DSM, has the authority to mandate how projected savings from merger will be split between rate payers and stakeholders

Source: Energy Information Administration, Office of Oil and Gas.

Typically, since review by the State regulatory commission is likely to be the most extensive and time-consuming, the public utility commission or its equivalent is notified first. (In cases where vertical market power is thought to be a potential problem of major concern, companies may notify FERC first.)

Central to the enforcement of antitrust law is the promotion of consumer welfare. Analysis of proposed corporate combinations for their potential to harm the consumer is principally under the shared jurisdiction of the FTC and the DOJ, where the concept of market power plays a central role in the antitrust review process. Specifically, provisions of the Hart-Scott-Rodino Act of 1976 trigger an "automatic report" to the FTC and the DOJ of proposed mergers or acquisitions of significant size.[10] The report includes revenues by type of business[11] as well as other financial data such as annual reports and 10k reports.

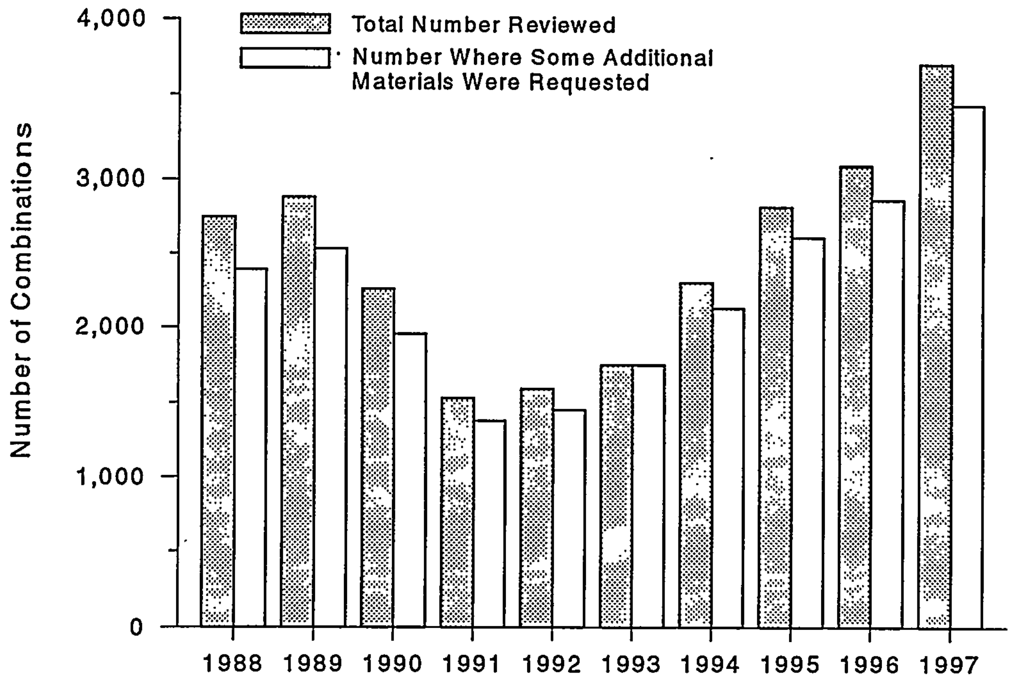
Since 1991, the number of cases reviewed by the FTC and the DOJ has increased by 140 percent. In the majority of cases some additional information is requested during the review process. In 1997, more than 3,700 cases were reviewed and additional information was requested in 93 percent (3,438) of the cases (Figure 57). Following the review, one or both of the agencies may then determine that further investigation is necessary. They would then issue a formal second request tailored to the specifics of the proposed combination and to the specific nature of the industry in which the combination will take place. While the number of second requests has also increased since 1991, the total remains small, representing only about 3 to 4 percent of the cases reviewed. Although the agencies can act to bar a combination, in most cases an agreement is reached that addresses any potential problem(s). For example when Phillips sought to acquire natural gas gathering assets from Enron, the FTC obtained a consent order wherein Phillips agreed to divest some of the properties.[12]

[10]Where the combined entity will have a value of $15 million and one of the parties has a value of $100 million and the other of at least $10 million. The limitations are less significant in the case of oil and gas interests that have been exempted unless their value exceeds $500 million.

[11]By Standard Industry Classification Code (SIC Codes) of the U.S. Department of Commerce.

[12]Such orders tend to be very specific, closely defining the market, specifying conditions as to contracts in force, properties to be divested, and the like.

Figure 57. Corporate Combinations Reviewed by the FTC and DOJ



FTC = Federal Trade Commission. DOJ = Department of Justice.
Source: Federal Trade Commission and Bureau of Competition, Department of Justice, Antitrust Division, *Annual Report to Congress, Fiscal Year 1997.*

It is not unusual for a consent order to be issued and for conditional approval to be granted. Conditional approval may require partial divestiture, continuation of contracts, rate freezes or other mitigating measures. FERC and the State commissions can and do also impose similar conditions. Conditional approval may be granted by one or more Federal agencies dependent on approval and mitigation measures imposed by the State regulators. It should also be noted that both DOJ and FTC may choose to revisit a completed merger or other combination at a later time. They may then determine that the combination is not in the public interest and negotiate a settlement (divestiture etc.) or institute proceedings seeking to break up the combination.[13]

Determination of Market Power

Fundamental to the investigation of proposed corporate combinations is a determination of market power. The analytical approach employed by DOJ, FTC, and FERC centers on a determination of market power in the proposed combination. Market power is defined by the Supreme Court as the ability to raise prices "above the levels that would be charged in the competitive market."[14] While virtually all firms have some degree of market power, the examination process looks for *excess market powerin* the ability to raise prices and increase profits (the "classical" definition of market power) by reducing output. The exercise of market power also occurs if a company is able to raise costs or reduce output of their competition (exclusionary market power). The Merger Guidelines adopted jointly by DOJ and FTC in 1992, and later adopted by FERC in 1996, use a modified definition that included "the ability to maintain prices above competitive levels for a significant period of time."[15]

Several specific questions arise during a market power investigation. First, could a company increase prices by reducing output? Second, does a company with the ability

[13]The DOJ and the FTC cooperate, each taking on only certain cases and passing on others based on available resources and expertise. A review committee determines which agency will pursue an investigation in those cases where both have an especially strong interest. DOJ reviews most electric utility cases, whereas FTC does more of the natural gas and gas utility cases.

[14]*Jefferson Parish Hospital, District No. 2 v. Hyde*, 466 U.S. 2, at 27 n.46. See also *National Collegiate Athletic Association v. Board of Regents of University of Oklahoma*, 468 U.S. at 109 n.38.

[15]*Merger Guidelines*, Section 0.1. See also: Federal Energy Regulatory Commission, *Order No. 592, Policy Statement* (Washington, DC, December 18, 1996).

to raise prices have the incentive to raise them above competitive levels? Next, how long must market power be exercised before a violation occurs? Finally, will savings from efficiencies gained be shared with consumers? The questions are not easily resolved. Agencies and courts must assess possible consequences that might or might not develop at some unknown time in the future.

Analytical tools such as the Lerner Index and the Herfindahl-Hirschman Index (HHI) are employed.[16] Both approaches attempt mathematically to define the extent of market power. The Lerner Index is derived by the direct subtraction of marginal costs of the firm from the price of the goods it sells. The index is based on the assumption that the higher the ratio between marginal cost and price, the more likely it is that the firm possesses market power. For a number of reasons, the Lerner Index is not the preferred measure of market power. It generally looks only at the potential for market power in the classical sense of the term and is further limited in that it does not take into account external factors, such as shifts in customer behavior.

The centerpiece of the market power analysis is the HHI. To utilize the HHI, analysts first determine the relevant market, then determine the shares of the market held by the major players. The values are squared and them summed to determine a statistical measure of market concentration. Analysts then factor in the shares of the market including the results of the proposed combination and compare the results. The contention is that a higher share reflects greater ability to set market price above marginal cost.

The Merger Guidelines address three ranges of post-merger market concentration:

- **Unconcentrated.** If the post-merger Herfindahl-Hirschman Index is below 1000, regardless of the change in HHI the merger is unlikely to have adverse competitive effects.

- **Moderately concentrated.** If the post-merger HHI ranges from 1000 to 1800 and the change in HHI is greater than 100, the merger potentially raises significant competitive concerns.

- **Highly concentrated.** If the post-merger HHI exceeds 1800 and the change in the HHI exceeds 50, the merger potentially raises significant competitive concerns. If the change in HHI exceeds 100, it is presumed that the merger is likely to create or enhance market power.[17]

The key to HHI analysis lies in the difference between the pre-combination and post-combination market index. If the calculations indicate that a combination is unlikely to create or enhance market power, then the Merger Guidelines set out certain safe harbors. If instead, the difference exceeds a certain range, there may be the presumption that a merger under the circumstances is "likely to create or enhance market power or facilitate its exercise." Nonetheless, neither a high HHI nor a high change in the relationship between the pre-merger HHI and the post-merger HHI automatically results in a denial of a proposed combination. By demonstrating that conditions giving rise to excessive market power are unlikely to arise, companies may be able to overcome the presumption of excessive market power arising from the HHI analysis. The HHI and similar tools provide indications, not absolute certainties.

Other Review

In addition to the approval of the FTC or DOJ on the antitrust issues and the FERC on regulatory matters, the IRS will issue a ruling regarding the tax status of the proposed combination. If nuclear power plants are involved, the Nuclear Regulatory Commission will pass on the ability of the proposed combination to operate any nuclear facilities. Following the review and approval of the other Federal agencies, the Securities and Exchange Commission (SEC) will review the proposed combination. The SEC operates under the concept of "watchful deference." That is, the Commission defers to the approval or conditional approval of the other agencies then examines the proposed combination with respect to the rights of the stakeholders. Notification of the SEC triggers final filings and the approval by the respective corporate boards and the like. The SEC review is always the last in the chain, and is usually completed within one to two months of notification.

Regulation of Joint Ventures

Concerns regarding joint ventures are in essence the same as those raised in the case of mergers and acquisitions. To

[16]The Federal Energy Regulatory Commission is also working to develop new approaches to measuring market power based on gaming theory.

[17]Federal Energy Regulatory Commission, *Policy Statement*, p. 27.

some extent, because of the more flexible and often more temporary nature of joint ventures, and in particular because of the ease of entry into the market, joint ventures in natural gas and energy services typically do not raise concerns on the part of either DOJ or FTC. Nonetheless, there are some questions raised by the current wave of joint ventures that have not been definitively answered. For example:

- Will certain types of joint ventures be more like mergers in their market impact?
- Between the same participants, is a collaboration less likely than a merger to restrict competition?
- To what extent are merger analysis techniques and approaches applicable to joint ventures?
- If the venture can exert sufficient market power to affect price, what is the relevant time frame to consider before taking action?

The additional questions that arise in the case of joint ventures make it unlikely that agencies or the courts will be able to rely to the same degree on quantitative analysis of market power as they do in reviewing a proposed merger. One approach to the analysis of a joint venture is to assume that if a merger between the entities is viewed to be lawful, that the joint venture should be presumed to meet the criteria for antitrust compliance.

At present, the criteria for answering the questions raised either by a particular merger or joint venture remain somewhat uncertain. Discussion and debate continue in and among the various agencies, the Congress, the Executive branch, and at the State level. Some of the policies will not be set until legislative action occurs. Even then, involvement by the courts is likely to result in changes and policy modification.

Implications for the Market and for Consumers

Corporate combinations in the natural gas industry are altering traditional ownership patterns and leading to greater diversification of the industry, particularly in terms of retail gas marketing and the proliferation of nontraditional service offerings. Consolidation in the gas and electric power industries is continuing at a rapid pace. Energy supplied to consumers will come increasingly from a single "one-stop" source. However, while consolidation is shrinking the number of players in the traditional regulated utility markets, both the natural gas and electric power sectors are becoming more open to competition. This trend opens the way for the expansion of the market to new players and to new approaches to energy delivery and energy services. The market will be fundamentally different, with fewer traditional utilities that are far larger than they have been in the past. On the other hand, there will be far more players in the market in terms of service providers. Often, the service providers will be nonregulated subsidiaries or joint ventures of utilities, producers, or pipeline companies located in other regions of the country that have expanded into areas where deregulation is advancing.

Events in the electric power deregulation are moving rapidly and in some respects have outstripped the pace of events in the natural gas sector. As a result, developments in the recently deregulated electric power markets in California and Massachusetts may be instructive as to what consumers may expect in the gas industry as States take up retail unbundling in earnest. Events suggest that consumers may not elect to switch suppliers. Of the 6 million customers eligible to choose a different electricity supplier in California, fewer than 100,000 did so. Surveys indicate that customers wanted savings on the order of double the 10 percent mandated by the legislature.

In addition, through referenda in California and Massachusetts, consumer groups have sought to overturn the existing structure and to mandate larger savings and cut the ability of the utilities to recover stranded costs.[18] These developments may be a precursor of similar conflicts to come in the natural gas sector. Additional support for the contention that consumers are unlikely to switch suppliers comes from the opening of gas markets to competition in Great Britain. Only about 20 percent of eligible consumers sought a new supplier when the gas industry opened to retail competition.[19]

The experiences in California and the United Kingdom also suggest that marketers may find it very difficult to win customers away from the local utilities despite efforts to introduce competition. Although it remains to be seen how consumers in other areas will react, it appears likely that

[18]Although the proposed legislation was defeated in both California and Massachusetts, opponents in California have indicated that they will continue their opposition by confronting utilities on questions of stranded costs as restructuring moves to other States.

[19]Randy Hobson, "Britain Starts Offering Choice of Electrical Supplier," *Daily Mail* (London, September 15, 1998).

the advantages enjoyed by LDCs and lack of distinct advantages offered by potential competitors will result in their ability to retain a sizeable share of the residential market.

Corporate combinations developed to take advantage of the opportunities offered by the opening up of the gas and electricity markets have become commonplace. In some cases, particularly those involving the acquisition of electric generation facilities, the assets have been sold at premium prices, at times for several times their book value. State agencies often preclude the new owner from simply passing on the cost to consumers. Rather, they require that rates be set in competitive markets, which means that acquiring companies are not assured of recovering costs. Nonetheless, the trend appears to be continuing, at least for the present.

Although consolidations among gas marketers have resulted in fewer participants, the share of sales accounted for by the top 20 marketers has declined. The joining together of NGC and Chevron, of Mobil and Duke, and others either through merger or joint ventures has resulted in a few companies capable of moving huge volumes of gas. Despite their apparent capacity, in reality many of their transactions involve transportation and resale and not sales to end users. Nonetheless, sales to end users by these large marketers have increased sharply in recent years. Yet sales by other marketers have increased even faster and the share of the largest companies has fallen as a result (Figure 55). It appears unlikely that this trend will reverse in the near future.

Many utility combinations develop in order to provide both gas and electric service. Utilities concerned about the loss of customer base are increasingly branching out through merger acquisition and especially through joint ventures into services. Energy service packages not only provide traditional service but also in many cases embrace such convergence items as one-stop energy shopping, billing, and telecommunications. Many of the service packages are in the development stage, and many as yet are available only to the larger industrial and commercial customers. Some will be extended in the future to residential customers and also expanded to encompass a larger regional or even national territory.

All of these changes have major implications for consumers. Some of the possible effects include:

- Lower prices, depending on the distribution and sharing of cost savings from the combination.
- New products and services and greater choice of service options.
- Increased need for information about the choices and options and the ability of the service provider to deliver the product.
- Shifting of risks: to stockholders in terms of financial returns, and potentially to customers in terms of reliability of the service provider.

Outlook

Corporate combinations ranging from mergers and acquisitions to joint ventures form an important part of the strategies employed by companies striving to respond to the rapidly changing conditions in the natural gas industry. The types of combinations employed in earlier periods of consolidation remain in common use in the current wave of corporate combinations. However, to a considerable extent, the emphasis has shifted away from mergers and asset acquisition to joint ventures and strategic alliances.

Despite substantial growth in the value of energy-related mergers and acquisitions, their combined value remains small in comparison with the total value of all combinations in the general economy. Although many large-scale mergers and asset purchases have taken place recently, a significant number of corporate combinations have been relatively small in value. These smaller transactions involve utilities, oil and gas companies, and others that seek entry into nontraditional areas, such as alternative energy, energy marketing, energy services, telecommunications, and niche markets of various types.

Some of the most innovative corporate combinations involve joint ventures or strategic alliances that have become popular in large measure because they are easier to set up, involve less commitment, and allow for greater flexibility. Joint ventures also often avoid lengthy regulatory reviews and costly tax consequences that lessen the attractiveness of the merger process. Joint ventures are particularly prevalent in the marketing of services.

At present, convergence, either in the sense of the coming together of gas and electric utilities or in the broad sense that includes one-stop energy shopping, Internet, media, and banking services, as yet plays a relatively minor role in mergers and asset acquisition. To some extent, convergence-driven corporate combinations have been impeded by the uncertainty regarding pending legislation that will do much to shape the nature of energy markets as they become more open to competition.[20] The long-term outlook for corporate combinations suggests that convergence will come to play a more significant role in mergers but that joint ventures will be the favored approach to incorporate convergence issues.

The primary objectives of corporate combinations often center on increased efficiency, economies of scale, and increased ability to compete in the changing environment. The stated objective of realized cost savings is to pass along savings to customers and to stakeholders. However, cost savings to consumers will vary by consuming sector and by region.

Despite such fundamental changes to the way of doing business, corporate combinations appear unlikely to result in significant changes in performance in terms of supply security of the natural gas sector. Infrastructure changes have added both capacity and flexibility to the system. However, indications from recent periods of peak demand in both the gas and electric power sectors are that increased price volatility during periods of strong demand is likely.

In the short term, the impact of such volatility likely will be exacerbated by such factors as: the ease of entry into marketing without qualifying standards, the lack of comprehensive operating procedures, and the underlying uncertainties associated with the changing energy market. Further, the collapse of some joint ventures, the failure of some mergers, coupled with the fallout from the electricity price spike in June,[21] suggest that the failure rate of companies could be high. As a result, the pace of corporate combinations may temporarily slow as companies take stock of the changes that are taking place.

Corporate combinations are resulting in new alignments of traditional elements in the energy sector. Two developments in corporate combinations, at first glance, appear to represent opposing trends. First, mergers, acquisitions, joint ventures, and strategic alliances are leading to greater diversification of the industry, particularly into retail gas marketing and other nontraditional activities. At the same time, other combinations result in reinforcing traditional segments in some markets as companies seek out partners in the same industry segment for acquisition or merger. However, rather than opposites, the two strategies may be complementary.

Recent experience shows a rich diversity of approaches characteristic of a new or developing market. Much of the recent activities in corporate combinations essentially have been the product of experimentation. This phase has developed largely in response to uncertainty regarding new retail energy markets. As a result, the ability to draw conclusions about the future course of the process and the implications for the market are limited. Nonetheless, it appears likely that in the short term, despite the changes sweeping through the industry, the residential consumer will not find that much difference between the old and new marketplace.

[20]For a discussion of retail unbundling, see Chapter 1, "Retail Unbundling."

[21]A combination of unseasonably hot weather, coupled with power plant outages, resulted in extreme price volatility. Prices surged by more than a factor of 200, reportedly reaching as much as $7,500 per megawatt hour.

Appendices

A. Maps of Gulf of Mexico OCS Planning Areas

B. Offshore Oil and Gas Recovery Technology

C. Economic Analysis of a Representative Deep-Water Gas Production Project

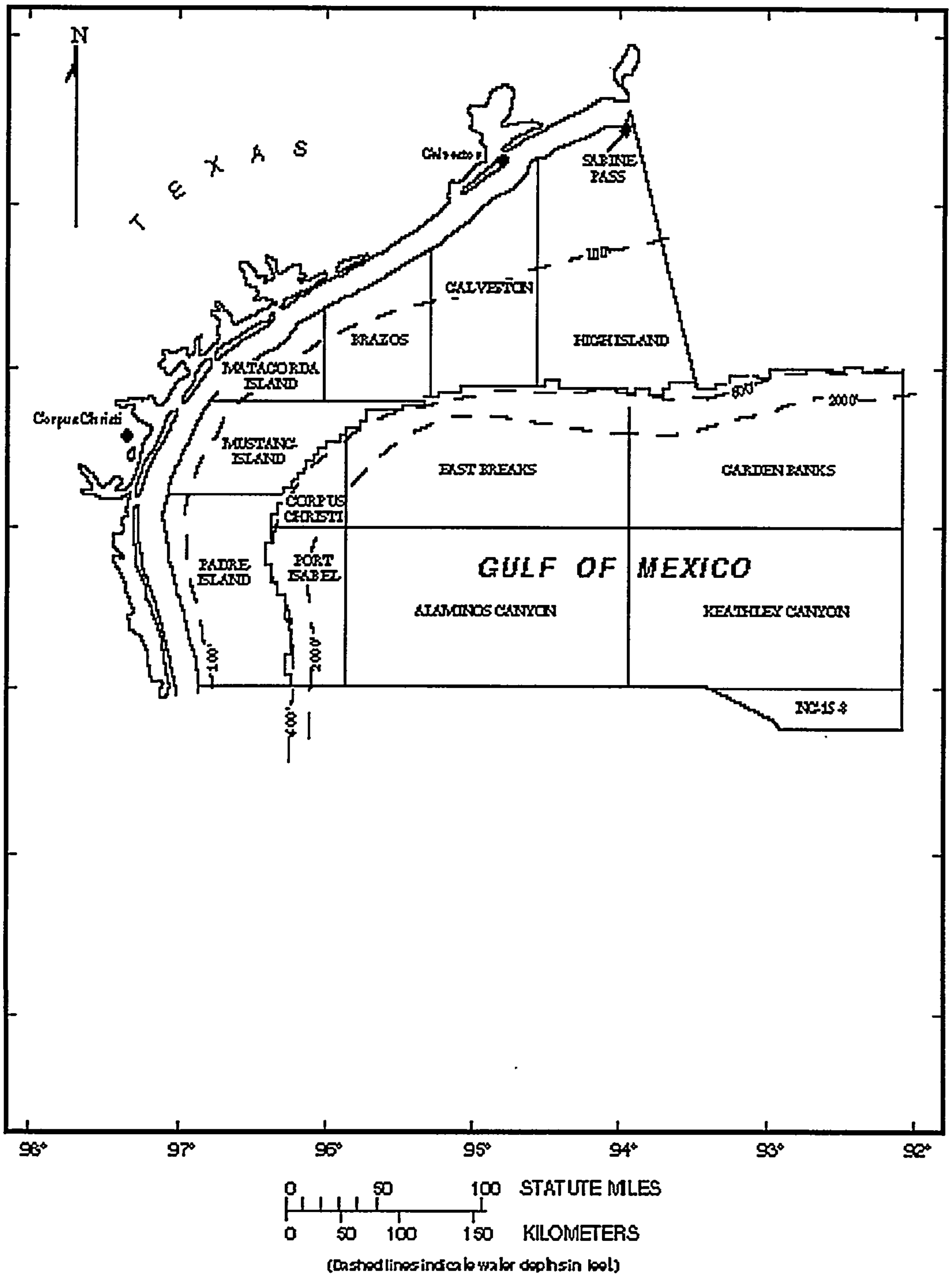
D. Data Sources and Methodology for Contracting and Capacity Turnback Analysis

E. Recent Corporate Combinations in the Natural Gas Industry

Appendix A

Maps of Gulf of Mexico OCS Planning Areas

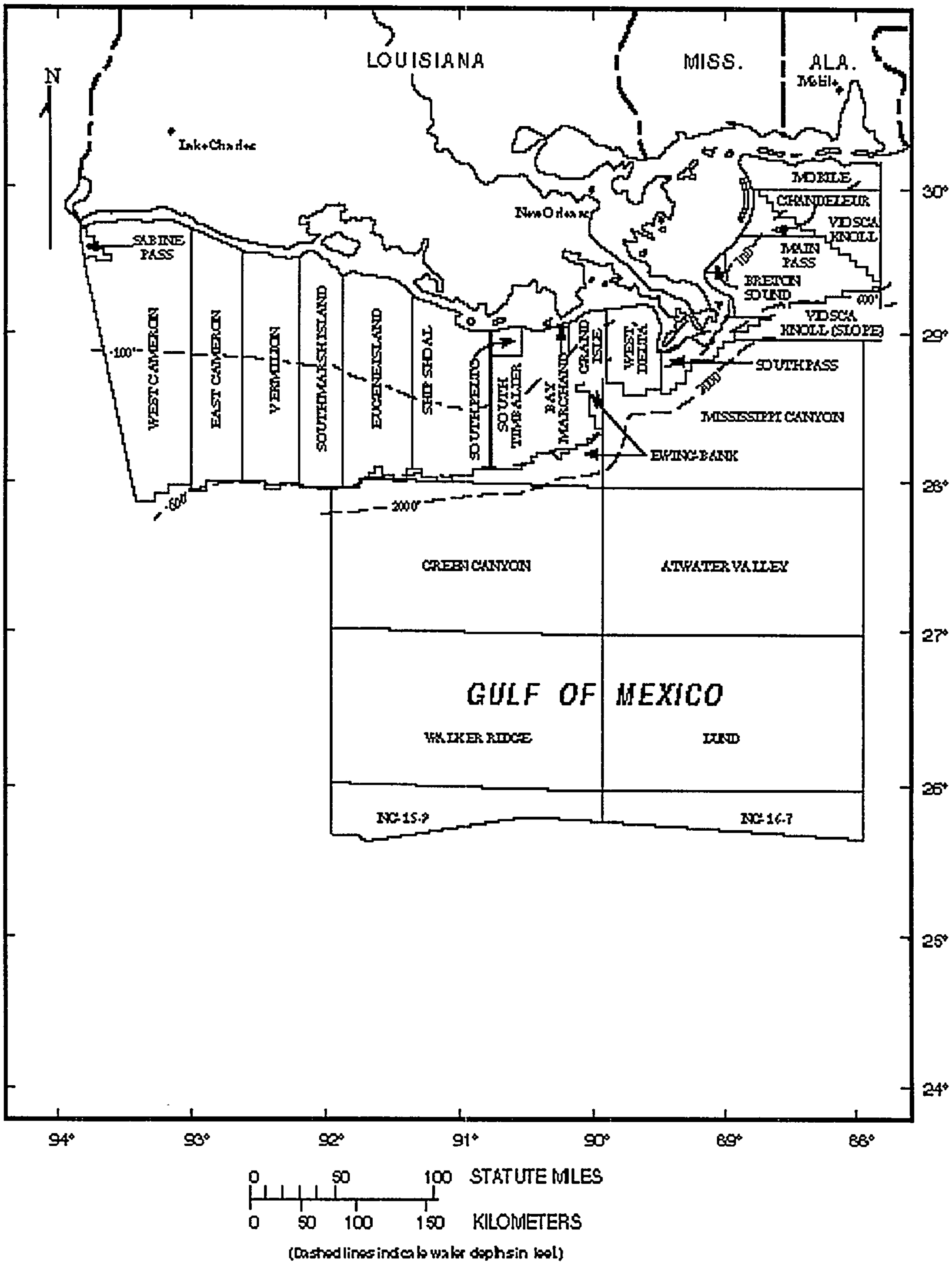
Figure A1. Western Planning Area, Gulf of Mexico Outer Continental Shelf Region



(Dashed lines indicate water depths in feet)

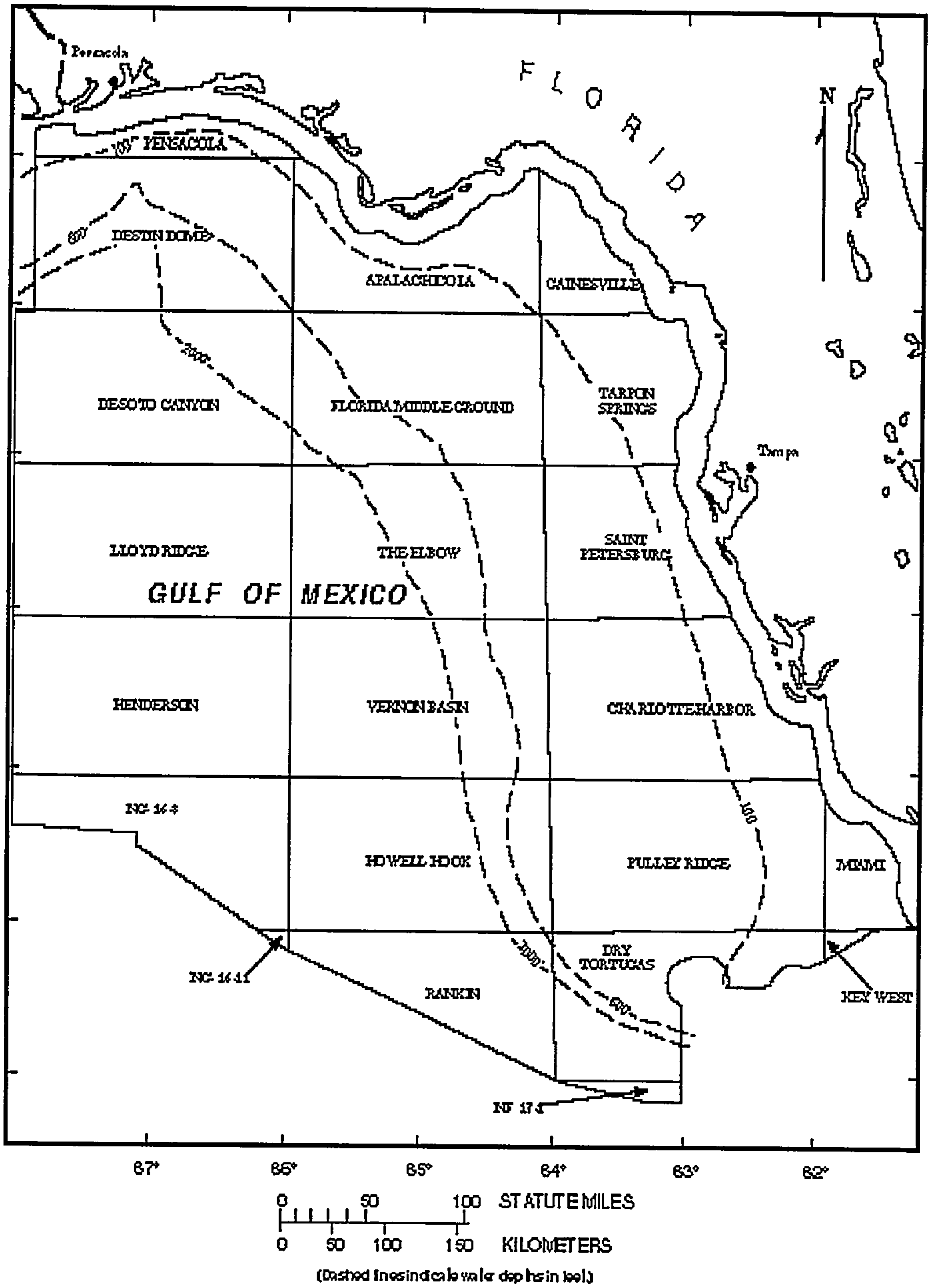
Source: U.S. Department of the Interior, after Minerals Management Service.

Figure A2. Central Planning Area, Gulf of Mexico Outer Continental Shelf Region



Source: U.S. Department Interior, after Minerals Management Service.

Figure A3. Eastern Planning Area, Gulf of Mexico Outer Continental Shelf Region



Source: U.S. Department of Interior, after Minerals Management Service.

Appendix B

Offshore Oil and Gas Recovery Technology

The success of offshore exploration and production during the past four decades can be attributed, in large part, to technological advances. Innovative technologies, such as new offshore production systems, three-dimensional (3-D) seismic surveys, and improved drilling and completion techniques, have improved the economics of offshore activities and enabled development to occur in deeper, more remote environments. This appendix describes the major developments in exploration, drilling, completion, and production technology. It also briefly discusses subsalt deposits, which comprise an additional area of promising application for the new technologies. Since 85 percent of the continental shelf in the Gulf of Mexico is covered by salt deposits, the potential for hydrocarbon development may be quite large.

Production Systems

Progress in offshore technology is exemplified by advances in production platforms, which provide a base for operations, drilling, and then production, if necessary.[1] For many years, the standard method for offshore development was to utilize a fixed structure based on the sea bottom, such as an artificial island or man-made platform. Use of this approach in ever-deeper waters is hindered by technical difficulties and economic disadvantages that grow dramatically with water depth.

The industry has advanced far beyond the 100-by-300-foot platform secured on a foundation of timber piles that served as the base of the first offshore discovery well drilled in the Gulf of Mexico in 1938.[2] At present, there are seven general types of offshore platforms, as described by the Minerals Management Service.[3]

- A *Fixed Platform* (FP) consists of a jacket (a tall vertical section made of tubular steel members supported by piles driven into the seabed) with a deck placed on top (Figure B1). The deck provides space for crew quarters, drilling rigs, and production facilities. The fixed platform is economically feasible for installation in water depths up to about 1,650 feet. An example of a fixed platform is the Shell's Bullwinkle in Green Canyon block 65 installed in mid 1988. This is the world's tallest platform. It became the largest production platform when its capacity was increased to handle production from the Troika prospect in Green Canyon Block 244, which began production in late 1997.

- A *Compliant Tower* (CT) consists of a narrow, flexible tower and a piled foundation that can support a conventional deck for drilling and production operations. Unlike the fixed platform, the compliant tower withstands large lateral forces by sustaining significant lateral deflections, and is usually used in water depths between 1,500 and 3,000 feet. An example of compliant tower use is the Lena field produced by Exxon in 1983.

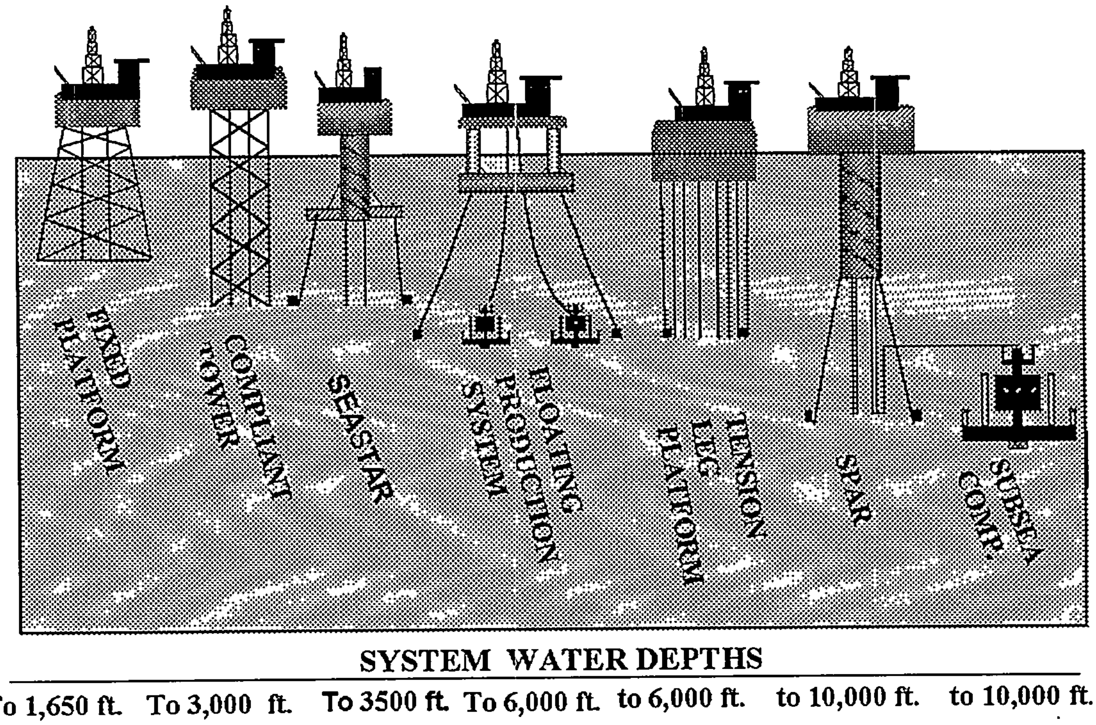
- A *Seastar* is a floating mini-tension leg platform of relatively low cost developed for production of smaller deep-water reserves that would be uneconomic to produce using more conventional deep-water production systems. It can also be used as a utility, satellite, or early production platform for larger deep-water discoveries. Seastar platforms can be used in water depths ranging from 600 to 3,500 feet. British Borneo is planning to install the world's first Seastar in the Gulf of Mexico in the Ewing Bank area at a water depth of 1,700 feet. British Borneo refers to this prospect as Morpeth.

[1] Recent projects in very deep water, such as Shell's Mensa have been developed with subsea completions that are "tied back" to an existing production platform in shallower water. This cost-reduction technique obviates the on-site production platform, the expense of which grows rapidly with water depth.

[2] This occurred at the Creole Field in 14 feet of water, located about 1.5 miles from the Louisiana coast. "U.S. Offshore Milestones," Minerals Management Service (December 1997), available on the MMS website, <http://www.mms.gov>.

[3] Energy Information Administration, Office of Oil and Gas, adapted from "Deepwater Development Systems in the Gulf of Mexico: Basic Options," Minerals Management Service, <www.gomr.mms.gov/homepg/offshore/deepwatr/options.html>.

Figure B1. Offshore Production Systems



Source: Energy Information Administration, Office of Oil and Gas. Adapted from Minerals Management Service, "Deepwater Development Systems in the Gulf of Mexico: Basic Options," <www.gomr.mms.gov/homepg/offishore/deepwater/options.html>.

- A *Floating Production System* (FPS) consists of a semi-submersible that has drilling and production equipment. It has wire rope and chain connections to an anchor, or it can be dynamically positioned using rotating thrusters. Wellheads are on the ocean floor and connected to the surface deck with production risers designed to accommodate platform motion. The FPS can be used in water depths from 600 to 6,000 feet.

- A *Tension Leg Platform* (TLP) consists of a floating structure held in place by vertical, tensioned tendons connected to the sea floor by pile-secured templates. Tensioned tendons provide for use of the TLP in a broad water depth range and for limited vertical motion. TLPs are available for use in water depths up to about 6,000 feet. An example of a TLP is Shell's Ursa platform, anticipated to begin production in 1999. Ursa is the second largest find in the Gulf of Mexico. This platform will be installed in 4,000 feet of water, will have the depth record for a drilling and production platform, and will be the largest structure in the Gulf of Mexico.

- A *Spar Platform* consists of a large-diameter single vertical cylinder supporting a deck. It has a typical fixed platform topside (surface deck with drilling and production equipment), three types of risers (production, drilling, and export), and a hull moored using a taut catenary system of 6 to 20 lines anchored into the sea floor. Spars are available in water depths up to 3,000 feet, although existing technology can extend this to about 10,000 feet. Spar is not an acronym but refers to the analogy of a spar on a ship. In September 1996, Oryx Energy installed the first Spar production platform in the Gulf in 1,930 feet of water in Viosca knoll Block 826. This is a 770-foot-long, 70-foot-diameter cylindrical structure anchored vertically to the sea floor.

- A *Subsea System* ranges from a single subsea well producing to a nearby platform to multiple wells producing through a manifold and pipeline system to a distant production facility. These systems are being applied in water depths of at least 7,000 feet or more. A prime example of a subsea system development is Shell's Mensa field located in Mississippi Canyon Blocks 686, 687, 730 and 731. This field started producing in July 1997 in 5,376 feet of water, shattering the then depth-record for production. Consisting of a subsea completion system, the field is tied back through a 12-inch flowline to the shallow water platform West Delta 143. The 68-mile tieback has the world record for the longest tieback distance to a platform.

Seismic Technology

The search for hydrocarbons relies heavily on the use of seismic technology, which is based on reading data initiated from energy sources, such as explosions, air guns (offshore use), vibrator trucks, or well sources. These sources produce waves that pass through the subsurface and are recorded at strategically placed geophones or hydrophones. In the offshore, these seismic responses are usually read from streamers towed behind modern seismic vessels, recorded, and processed later by computers that analyze the data.

The earliest seismic surveys, during the 1920s, were analog recorded and produced two-dimensional (2-D) analyses. Digital recording was introduced in the 1960s, and then, as computer technology burgeoned, so did geophysical signal processing. During the past 30 years, computer-intensive techniques have evolved.

Geophysicists began experimental three-dimensional (3-D) seismic survey work in the 1970s. Commercial 3-D seismology began in the early 1980s on a limited basis. Recent innovations that were essential to the development of 3-D seismology are satellite positioning, new processing algorithms, and the interpretative workstation.[4] The 3-D seismic technology has been a critical component in Gulf of Mexico activity. According to Texaco, in 1989 only 5 percent of the wells drilled in the Gulf of Mexico were based on 3-D seismic surveys. In 1996, nearly 80 percent of the wells drilled were based on 3-D seismic.[5]

New mechanical techniques being used today, and currently being considered for wider application, include increasing the numbers and lengths of streamers, using remotely operated vehicles (ROV) to set geophones or hydrophones on the sea floor, and running forward and backward passes over subsalt prospects.

[4] Energy Information Administration, "Three-Dimensional Seismology: A New Perspective," *Natural Gas Monthly*, DOE/EIA-0130(92/12) (Washington, DC, December 1992).

[5] "U.S. E&P Surge Hinges on Technology, Not Oil Prices," editorial in the *Oil and Gas Journal* (January 13, 1997), p. 42.

New processing techniques are prestacked 3-D depth migration, interpretation of multiple 3-D surveys in different times (4-D seismic), and reservoir characterization of horizons. These methods are allowed by the rapid increase of computer processing power. Before 1990, the processing of seismic survey data consumed the largest processors for weeks. With the introduction of massive parallel processors (MPP), the processing time has been reduced from weeks to only days. The increase in processing power has also allowed more sophistication in analysis and processing.

Because of developments in seismic data acquisition and development, the industry has realized that the presence of salt in an exploratory hole may indicate the presence of hydrocarbon deposits below the salt in sedimentary deposits. Progress in 3-D and 4-D seismic interpretation, along with the additional computer advancements to process these data, have opened possibilities in new subsalt structure development (more detail on subsalt activity is available in the last section of this appendix).

Advances in seismic technology have not only improved the industry's results in exploration, but also have increased productivity and lowered costs per unit output. The improved information provided by the new seismic techniques lead to improved well placement, which increases well flow and ultimate recovery. Further, the fewer dry holes incurred in project development enhance project profitability by avoiding additional costs and the time lost drilling dry holes.

Drilling Technology

Drilling is the most essential activity in oil and gas recovery. Once a prospect has been identified, it is only through the actual penetration of the formation by the drill bit that the presence of recoverable hydrocarbons is confirmed. The challenging conditions that confront drilling in deep water necessitate specialized equipment. The number of drilling rigs qualified for deep-water operations are limited. Five rigs capable of drilling in up to 2,500 feet of water were operating in 1995. By 1996, nine were in operation and additional rigs were being upgraded for operations in deep water. Because this set of equipment has expanded more slowly than the demand for drilling services, deep-water day rates are increasing rapidly and are at the highest levels in 20 years. According to C. Russell Luigs, Global Marine Inc. Chairman and CEO, "Compared to a year ago our rig fleet average day rate has increased about 50 percent."[6]

Drilling rigs that use such new technology as top-drive drilling and proposed dual derricks are reducing drilling and completion times. In light of the limited number of vessels available for drilling deep-water wells and the resulting increasing drilling rates for such equipment, shorter operating times are a key advantage expected from dual rig derricks.[7]

In addition to creating drilling rigs that can operate at great water depths, new drilling techniques have evolved, which increase productivity and lower unit costs. The evolution of directional and horizontal drilling to penetrate multiple diverse pay targets is a prime example of technological advancement applied in the offshore. The industry now has the ability to reduce costs by using fewer wells to penetrate producing reservoirs at their optimum locations. Horizontal completions within the formation also extend the reach of each well through hydrocarbon-bearing rock, thus increasing the flow rates compared with those from simple vertical completions. These advancements can be attributed to several developments. For example, the evolution of retrievable whipstocks allows the driller to exit the cased wells without losing potential production from the existing wellbores. Also, top drive systems allow the driller to keep the bit in the sidetracked hole, and mud motor enhancements permit drilling up to 60 degrees per 100-foot-radius holes without articulated systems. In addition, pay zone steering systems are capable of staying within pay zone boundaries.[8]

New innovations in drilling also include multilateral and multibranch wells. A multilateral well has more than one horizontal (or near horizontal) lateral drilled from a single site and connected to a single wellbore. A multibranch well has more then one branch drilled from a single site and connected to a single wellbore. Although not as pervasive in the offshore as in the onshore because of the necessity of pressure-sealed systems, multilateral and multibranch wells are expected to be more important factors in future offshore development.

[6] Sheila Popov, "The Tide Has Turned in the Gulf of Mexico," *Hart's Petroleum Engineer International* (October 1997), pp. 25-35.

[7] Michael J.K. Craig and Stephen T. Hyde, "Deepwater Gulf of Mexico more profitable than previously thought," *Oil and Gas Journal* (March 10, 1997), pp. 41-50.

[8] "Multilateral-Well Completion-System Advances," editorial in the *Journal of Petroleum Technology* (July 1997), pp. 693-699.

Completion Technology

The average rate of production from deep-water wells has increased as completion technology, tubing size, and production facility efficiencies have advanced. Less expensive and more productive wells can be achieved with extended reach, horizontal and multilateral wells. Higher rate completions are possible using larger tubing (5-inch or more) and high-rate gravel packs. Initial rates from Shell's Auger Platform were about 12,000 barrels of oil per day per well. These flow rates, while very impressive, have been eclipsed by a well at BP's Troika project on Green Canyon Block 244, which produced 31,000 barrels of oil on January 4, 1998.[9]

Another area of development for completion technology involves subsea well completions that are connected by pipeline to a platform that may be miles away. The use of previously installed platform infrastructure as central producing and processing centers for new fields allows oil and gas recovery from fields that would be uneconomic if their development required their own platform and facilities. Old platforms above and on the continental slope have extended their useful life by processing deep water fields. A prime example of this innovation is the Mensa field, which gathers gas at a local manifold and then ships the gas by pipeline to the West Delta 143 platform 68 miles up the continental shelf.

Other Technology

The exploitation of deep water deposits has benefitted from technological development directed at virtually all aspects of operation. Profitability is enhanced with any new equipment or innovation that either increases productivity, lowers costs, improves reliability, or accelerates project development (hence increasing the present value of expected returns). In addition to the major developments already discussed, other areas of interest for technological improvement include more reliable oil subsea systems (which include diverless remotely operated vehicle systems), bundled pipeline installations of 5 miles or more that can be towed to locations, improved pipeline connections to floating and subsea completions, composite materials used in valving, and other construction materials.

[9] Minerals Management Service, "Gulf of Mexico Deepwater Continues to Shine As America's New Frontier," <www.gomr.mms.gov/homepg/whatsnew/newsreal/980305.html>.

The advantages of adopting improved technology in deep water projects are seen in a number of ways. For example, well flow rates for the Ursa project are 150 percent more than those for the Auger project just a few years earlier. The economic advantages from these developments are substantial as the unit capital costs were almost halved between the two projects. The incidence of dry holes incurred in exploration also has declined with direct reduction in project costs. The number of successful wells as a fraction of total wells has increased dramatically, which reflects the benefits of improvements in 3-D seismic and other techniques. Lastly, aggressive innovation has improved project development by accelerating the process from initial stages to the point of first production. Rapid development requires not only improvements in project management, but also better processes to allow construction of new facilities designed for the particular location in a timely fashion. Project development time had ranged up to 5 years for all offshore projects previously. More recent field development has been conducted in much less time, with the period from discovery to first production ranging between 6 and 18 months.[10] Experience with deep-water construction and operations has enabled development to proceed much faster, with time from discovery to production declining from 10 years to just over 2 years by 1996 (Chapter 4, Figure 35). Accelerated development enhances project economics significantly by reducing the carrying cost of early capital investment, and by increasing the present value of the revenue stream. Design improvements between the Auger and Mars projects allowed Shell to cut the construction period to 9 months with a saving of $120 million.[11]

Subsalt Deposits

Technology has provided access to areas that were either technically or economically inaccessible owing to major challenges, such as deposits located in very deep water or located below salt formations. While the major additions to production and reserves in the Gulf of Mexico have occurred in deep waters, work in refining the discovery and recovery of oil and gas deposits in subsalt formations must be noted as another promising area of potential supplies.

[10]"New Ideas, Companies Invigorate Gulf," *The American Oil & Gas Reporter* (June 1996), p. 68.

[11]Minerals Management Service, *Deepwater in the Gulf of Mexico: America's New Frontier*, OCS Report MMS 97-0004 (February 1997).

Eighty-five percent of the continental shelf in the Gulf of Mexico, including both shallow- and deep-water areas, is covered by salt deposits, which comprises an extensive area for potential hydrocarbon development. Phillips Petroleum achieved the first subsalt commercial development in the Gulf of Mexico with its Mahogany platform. This platform, which was set in August 1996, showed that commercial prospects could be found below salt (in this case below a 4,000 foot salt sheet).

The subsalt accumulations can be found in structural traps below salt sheets or sills. The first fields under salt were found by directional wells drilling below salt overhangs extending out from salt domes. Experience in field development close to salt-covered areas indicated that not all salt features were simple dome-shaped features or solid sheets. Often the salt structure was the result of flows from salt deposits that extended horizontally over sedimentary rocks that could contain oil. The salt then acts as an impermeable barrier that entraps the hydrocarbons in accumulations that may be commercially viable prospects.

The identification of structures below salt sheets was the first problem to overcome in the development of subsalt prospects, as the salt layers pose great difficulty in geophysical analysis. The unclear results did not provide strong support for investing in expensive exploratory drilling. The advent of high-speed parallel processing, pre- and post-stack processing techniques and 3-D grid design helped potential reservoir resolution and identification of prospects.

Industry activity in subsalt prospect development has been encouraged also by improvements in drilling and casing techniques in salt formations. Drilling through and below salt columns presents unique challenges to the drilling and completion of wells. The drilling of these wells requires special planning and techniques. Special strings of casing strategically placed are paramount to successful drilling and producing wells.

The highly sophisticated technology available to firms for offshore operations does not necessarily assure success in their endeavors, and the subsalt prospects illustrate this point. The initial enthusiasm after the Mahogany project was followed by a string of disappointments in the pursuit of subsalt prospects. After a relative lull in activity industry-wide, Anadarko announced a major subsalt discovery in shallow water that should contain at least 140 million barrels of oil equivalent (BOE), with reasonable potential of exceeding 200 million BOE.[12] Successes of this magnitude should rekindle interest in meeting the challenge posed by salt formations.

Subsalt development has also been slowed because the majority of prospects have been leased or recovery from the subsalt is delayed by production activities elsewhere on a given lease. Subsalt operations apparently will be more a factor in the future as flows from leases presently dedicated to other production decline and the leases approach the end of their lease terms, which will promote additional development to assure continuation of lease rights.

[12]"Anadarko announces big subsalt discovery," *Oilgram News* (July 30, 1998), p. 1.

Appendix C

Economic Analysis of a Representative Deep-Water Gas Production Project

This appendix provides an analysis of the economic merit of a representative deep-water gas prospect. The two defining characteristics of deep-water operations are the extremely high costs and the high degree of uncertainty surrounding many physical and economic parameters that affect project returns. The economic merit of large-scale project investments in deep-water regions is evaluated using a discounted cash flow (DCF) model to determine the expected returns associated with a representative project. Expected returns are dependent on the assumptions regarding selling prices; the costs of drilling, operation, and all equipment; and the production performance of the wells.

The DCF model, which is based on expected values of key variables, is a common approach that provides measures of profitability conditioned on the values of the input data. This method can be employed to evaluate the project under different scenarios, in which the expected returns are determined as values of selected variables are altered. The measures from such analysis methods are useful, but limited because they provide an incomplete range of possible outcomes.

Project risk is caused by uncertainty from unforeseen or unknowable conditions or events that affect costs or performance. Adverse conditions may be present in the formation or at the seabed, affecting either the installation of subsea equipment or its operation. Events, such as mudslides in the subsurface, can increase costs or cause operations to cease altogether. Market events, such as lower prices than anticipated, are quite familiar to most operators, both onshore and offshore. In fact, the net price received for production is subject to variation not only because of market events, but also because of deviations in transportation costs from expected levels. When transportation costs are higher than expected, the net unit revenue remaining for the production operations is correspondingly lower. This uncertainty confronts producers whether they also own the transportation facilities or not.

The appendix describes the representative deep-water project that is used in the DCF model to calculate the return on investment based on a given set of input values. It then presents the results of a comparative analysis of economic returns using a sensitivity approach that alters the values for a variable or set of variables in a particular way.

The project evaluation is then extended to recognize explicitly the impact of uncertainty. The uncertainty analysis is conducted using the DCF model within an iterative sampling procedure. The results of multiple trials are compiled to produce a frequency distribution that describes the set of possible outcomes along with estimated probabilities of occurrence. The results of this analysis provide a richness of detail in characterizing the possible outcomes that substantially enhances subsequent decisionmaking whether from the point of view of the investment project manager or a policymaker considering programs to impose incentives or penalties on gas and oil activities. In addition to the more complete information regarding the project, the results show that the calculated returns based on the expected values of input variables do not necessarily equal the expected value of the returns based on the distribution of expected returns.

Characteristics of the Representative Deep-Water Project

The present examination uses a hypothetical deep-water project as the basis of its analysis. This project has significant characteristics that are consistent with those of known projects, either active or in development. It does not describe a particular project, but it serves as an illustrative model that reflects the relevant economics of deep-water investment. The characterization of the representative project is based primarily on information from three sources: the Minerals Management Service (MMS), background information used in the Energy Information Administration's (EIA) National Energy Modeling System (NEMS), and company information as reported in the professional literature.

The expected profitability of a project depends on the output price and a comprehensive set of costs, physical performance characteristics, and institutional parameters, such as tax rates (values for major input variables in the DCF analysis appear in Table C1). The proposed project produces natural gas as its primary product with petroleum liquids as a secondary output. The project produces from one discovery well and from 12 wells drilled during a 2-year development period. The success rate for developmental wells drilled is 75 percent. Wells produce at the initial flow rate for 18 months, then yearly flow declines geometrically at a constant rate. Project costs are consistent with those for a field in 2,000 feet of water. The project is evaluated on a standalone basis for tax purposes. All applicable Federal tax provisions apply, but the project is assumed to be outside State waters and thus not liable for State taxes. As a deep-water project, initial production is exempt from royalty payment obligations. The net price received for produced gas is $1.50 per thousand cubic feet and the discount rate is assumed to be 10 percent.

Project Evaluation with Certain Data

The initial project evaluation is based on the common approach in which expected values for all relevant variables are adopted as input variables, and measures of expected returns conditional on the set of input values are calculated. Under this approach, the expected returns, such as net profitability or rate of return, represent an average or "likely" outcome. The expected value measures then are compared with threshold values for acceptability or with similar valuations of other projects for ranking. This simple approach has the advantage of expediency and the results generally are considered to be well understood.

The DCF model with reference case values for the input estimates yields present value profit (PVP) and internal rate of return (IROR) for the representative gas project of $14.8 million and 11.1 percent, respectively. These results indicate that this project should be undertaken since it will be profitable at the assumed discount rate of 10 percent and price of $1.50 per thousand cubic feet. This evaluation was conducted on a standalone project basis, which affects the present value of tax deductions. The expensed items and amortized capital expenditures are used only to offset tax liabilities generated by revenues from this project. The pattern of sizeable expenditures early in project development followed by years of revenues ensures that the present value of the associated tax writeoffs is reduced. If the project is evaluated from the perspective of an ongoing firm that can use the deductions as incurred to offset tax liabilities generated elsewhere in the firm, the PVP and IROR rise to $32.5 million and 13.0 percent, respectively. The effectiveness of the firm's tax planning will determine how successfully the project might approach such returns. This case indicates that this project may return even higher value than reflected in the initial estimation.

Table C1. Values for Selected Variables of the Representative Deep-Water Natural Gas Project Under Three Scenarios

Variables	Scenarios: Pessimistic	Scenarios: Reference	Scenarios: Optimistic
Input			
Drilling costs (million dollars per well)	12.5	10.0	7.5
Operating costs (dollars per thousand cubic feet)	0.30	0.25	0.20
Upfront capital expenditure (million dollars)	387.5	350.0	312.5
Output Price (dollars per thousand cubic feet)	1.25	1.50	1.75
Initial well flow rate (million cubic feet per year)	4,000	5,000	6,000
Decline rate for well production (percent)	6.0	5.0	4.0
Water saturation point, measured as production relative to initial rate (percent)	78.75	75.0	71.2
Output			
Present Value Profit (million dollars)	-272.4	14.8	323.5
Internal Rate of Return (percent)	-14.1	11.1	33.4

Note: Output results from use of a simple discounted cash flow model. Dollar values are discounted to 1997 dollars.
Source: Energy Information Administration, Office of Oil and Gas.

These results, which favor the decision to pursue this project, are conditional on the specific values of the input data. The pervasive uncertainty associated with each of these variables suggests that the eventual project return is likely to vary from any particular estimate. The interest in characterizing the range of outcomes for a proposed project often is addressed by employing a scenario approach to assess the sensitivity of calculated profitability under alternative conditions. The resulting set of outcomes comprise a range of measures that are then used to evaluate the investment decision.

Many key variable values simply cannot be known in advance. Output prices, especially as markets have become more competitive, have become subject to dramatic shifts, which can be factored into the evaluation even if the occurrence is expected to be a low probability. Sensitivity analysis was conducted with output prices at $1.25 and $1.75 per thousand cubic feet, a 16.7-percent variation from the assumed value of $1.50. This limited fluctuation in price is well within observable market patterns. At the lower output price, the expected returns fall, becoming a loss of $58.4 million (discounted at 10 percent) and the IROR is 5.5 percent. The higher price results in a PVP of $86.4 million and an IROR of 16.6 percent.

There are numerous other changes that may greatly alter the expected return. Examples of positive events include higher output prices, lower costs, or substantially greater well performance than originally anticipated. The possibility of other outcomes as a result of changes in a set of variables can also be analyzed. Pessimistic and optimistic scenarios were established for the representative project by systematically varying selected variables, using shifts from 9 to 25 percent (Table C1).[1] The optimistic assumptions describe a project that yields more than $323.5 million, with an associated IROR of more than 33 percent. On the other hand, the conditions of the pessimistic scenario produce losses of more than $272 million and an IROR of -14.1 percent.[2]

The potential investor at this point has a set of possible outcomes, ranging from a "home run" to utterly disastrous without additional information or a clear framework within which the outcomes can be assessed. For example, the preceding results suggest that, on average, the project should provide a profitable return. However, the decision should account for the possibility of other outcomes. These shortcomings of the standard DCF approach can be alleviated to some degree with an explicit treatment of project risk.

Project Evaluation Under Uncertainty

The representative project is analyzed using the simple DCF model within an iterative sampling technique that randomly draws values for selected input variables from the specified distribution for each. The set of randomly sampled input values, along with the given values for all other variables, is used to determine the values for PVP and IROR. The results from each trial are compiled to form a frequency distribution of possible outcomes. The distribution shows the range of possible outcomes along with their frequency, which indicates the relative probability of occurrence. The probability weighted average of all occurrences is the mean of the distribution, or the expected outcome. The distribution has a number of attributes that provide useful insights into the economic merit of the investment.

As an illustrative exercise, selected input variables that describe the representative project are respecified as stochastic variables. The selected stochastic variables are the output price, drilling costs, operating costs, upfront capital expenditures, the initial flow rate per well, the decline rate for production (after the first 18 months), and the water saturation level at which gas production ceases. These variables were selected as major factors affecting profitability, and they have shown themselves in the available data to be subject to wide variation, because of either market fluctuations or unanticipated physical characteristics of the geologic structure or its contents. The variables are assumed to conform to a symmetric triangular distribution with expected values equal to the input data of the Reference Case (Table C2).[3] All other data and the basic DCF model itself are unchanged.

Allowing the selected seven input variables to be randomly perturbed yields a wide range of outcomes with a mean, or expected value, PVP of $1.4 million. The PVP ranges from a low of $158 in losses to a profit of $179 million

[1] The pessimistic and optimistic values are the mid-point values between the most likely and minimum or maximum values used in the stochastic analysis in the following sections.

[2] In practice, the massive losses in the pessimistic outcome may be contained somewhat if early actions such as well flow testing provide the firm with sufficient information to terminate the project without incurring the full project losses. However, this strategy is incapable of avoiding sizeable losses if the project is a failure.

[3] Testing with skewed distributions for the input variables was conducted and the results indicate that this was not a dominant influence.

Table C2. Representative Gas Project: Stochastic Values for Selected Input Variables and Output Values

Variables	Stochastic Variables		
	Minimum	Most Likely	Maximum
Input			
Drilling costs (million dollars per well)	5.0	10.0	15.0
Operating costs (dollars per thousand cubic feet)	0.20	0.25	0.30
Upfront capital expenditure (million dollars)	275.0	350.0	425.0
Output Price (dollars per thousand cubic feet)	1.00	1.50	2.00
Initial well flow rate (million cubic feet per year)	3,000	5,000	7,000
Decline rate for well production (percent)	3.0	5.0	7.0
Water saturation point, measured as production relative to initial rate (percent)	67.5	75.0	82.5
Output	95th Percentile	Mean Value	5th Percentile
Present Value Profit (million dollars)	-158	1.4	179
Internal Rate of Return (percent)	-3.3	9.8	23.4

Note: Stochastic variables are assumed to conform to a triangular distribution. All other variables are set at expected values.
Source: Energy Information Administration, Office of Oil and Gas.

(Figure C1).[4] Similarly, the expected value IROR is 9.8 percent, from a low of -3.3 percent to a high of 23.4 percent. The foremost difference between the simple DCF analysis and the explicit treatment of uncertainty is that the comparable measures of profitability differ. The calculated profitability from the assumed input values was a PVP of $14.8 million with an associated IROR of 11.1 percent. The profitability values based on the assumed distributions for the input variables are returns of $1.4 million and 9.8 percent.

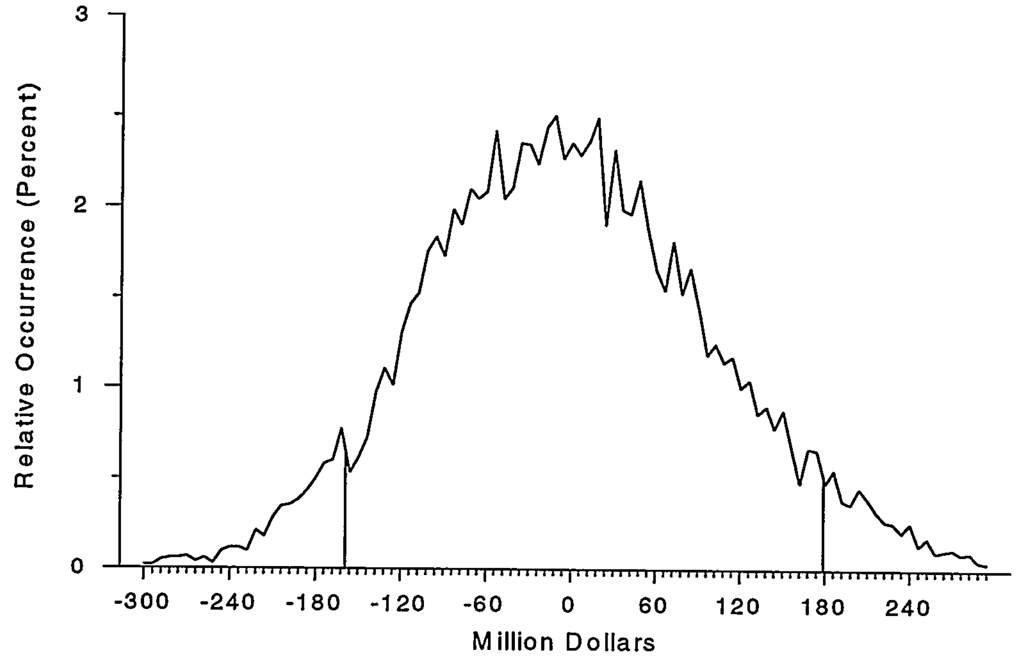
The frequency results showing the relative probability of occurrence can be transformed into a cumulative frequency distribution (CFD) that shows the probability that the results will be at least as great as the corresponding values for the PVP. Despite the positive expected value PVP, the median of -$4.4 million indicates that the odds of a positive PVP are less than 50 percent. The IROR shows a close to adequate return at the mean level, with a value of 9.8 percent, and the median at 9.6 percent, both below the acceptable threshold (Figure C2). The representative project that seemed economically viable based on the simple DCF now shows expected returns that are closer to a marginal decision level.

The CFD provides insight into the results of the scenario analysis. For example, the hypothesized shift in any one input variable for the pessimistic and optimistic scenarios is not extreme and well within the range of the observed data. This might lead to the conclusion that the combined shifts in all seven variables might be anticipated as at least somewhat likely, thus having a significant probability of occurrence. This conclusion is not validated by the uncertainty analysis results. Estimates of expected probability from a comparison of the scenario results with the distribution show that the pessimistic and optimistic scenario results are in fact so extreme that they are well outside the range given by the 95th and 5th percentiles of the distributions. In fact, these outcomes have less than a 0.5 percent chance of occurrence. Reliance on analysts' judgment to estimate the likelihood without benefit of a formal analysis is a dubious practice given the complexity inherent in the determination of joint probabilities.

The results of the uncertainty analysis show that even though the change to each variable is slight, the likelihood that all variables would shift in such a systematic fashion is remote. Since the variables are determined independently, it is more likely that variables will shift to varying degrees and often in opposing directions. The countervailing influence of these changes tends to produce results with higher probabilities around the mean. A scenario that may seem comparable to the Reference case, might be interesting but highly unlikely to occur, especially if the the shifts in the variables are all in the same direction.

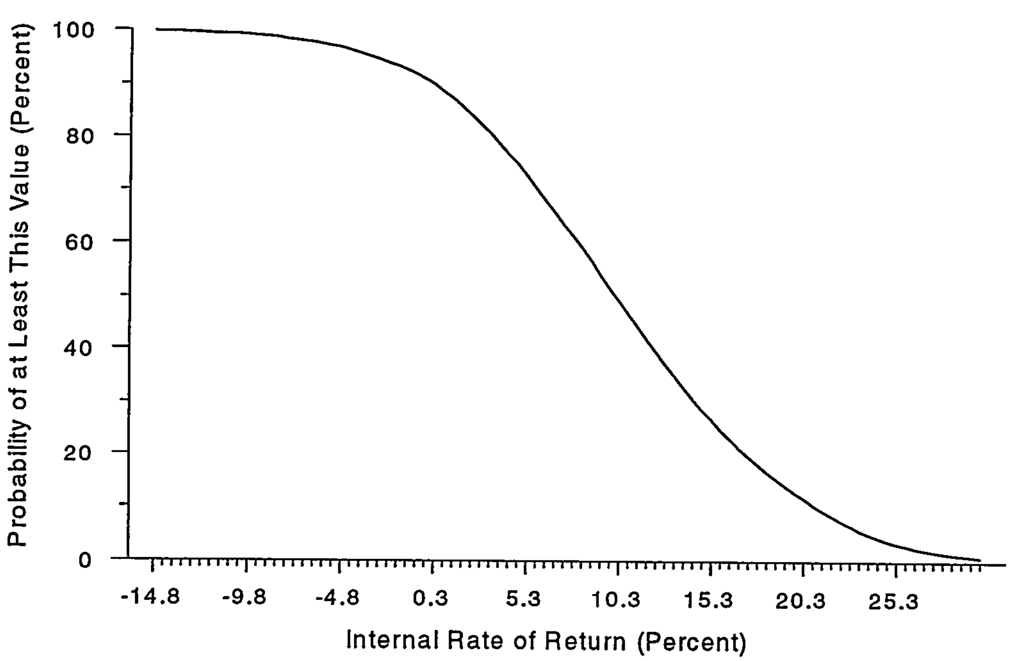
[4]The low and high values are presented at the 95th and 5th percentiles because the reported extreme low and high values from the simulation, while available in the run results, tend to be outliers that are not necessarily reliable measures of expected returns.

Figure C1. Frequency Distribution of Present Value Profit for the Representative Gas Project



Note: The areas in either 'tail' of the distribution represent the 5th and 95th percentiles, which outcomes are low probability events.
Source: Energy Information Administration, Office of Oil and Gas.

Figure C2. Internal Rate of Return - Representative Gas Project (Cumulative Frequency Distribution)



Source: Energy Information Administration, Office of Oil and Gas.

Key Project Variables

Analysis based on the explicit treatment of uncertainty also provides an opportunity to assess the influence of the different variables on the estimated returns. Any change that increases revenues or productivity, or reduces costs or taxes will enhance the project returns. Operators have a keen interest in identifying those factors with the largest impact in order to focus their efforts most productively. The multiple outcomes inherent in the uncertainty analysis allows for the computation of rank correlations between the output and input variables on a pairwise basis. The correlation coefficients are a measure of the degree to which any stochastic input variable and the output variable change together, which is presumed to measure the relative influence of the input variable to the output value. The correlation factor is a guideline for further analysis, but conclusions may be conditional, as can be seen in the following examples.

The major influences on the PVP estimate for the representative project are the initial flow rate and the output price (Figure C3). The initial flow rate dominates due to its pivotal role in the project characterization as a major determinant of total field recovery and the positive relation between its value and the present value of project cost recovery for tax purposes. The price variable determines the total revenue for any given production schedule for the field, which has a direct impact on profitability. The decline rate is a key influence on the length of the productive life of the well, as well as the ultimate recovery per well. Drilling cost per well and the upfront capital costs correlate with PVP, but they seem to have less influence on the PVP based on the rank correlation. This additional information regarding project profitability can be quite useful to the operator.

Given that drilling costs are a lesser influence on profitability, while the initial flow and well decline rate are strong factors, it is a prudent strategy for the operator to address well drilling and completion technology even when this raises costs. As long as the cost increments are managed properly, the productivity gains may be well justified. For example, the representative project would be at a break-even level with initial well flows of 4,797 million cubic feet per year, given drilling costs of $10 million per well. Application of enhanced drilling and completion technology that might raise the flow to 5,700 million cubic feet, less than 19 percent, is worthwhile as long as the cost per well was no greater than $15 million (assuming all other well productive parameters remain unchanged.) Conversely, actions that could lower drilling costs by as much as 50 percent are uneconomic if they reduce initial flow by as little as 19 percent. Changes in the upfront capital costs require a larger offset in initial flow rate than is the case for drilling costs, despite the lower rank correlation coefficient. A rise or fall in upfront capital costs of 50 percent would require a corresponding 33-percent shift in initial flow rate, which is consistent with the relatively large capital expenditure (Table C3).

The explicit treatment of uncertainty in project analysis provides a richness of information that has a number of strong advantages in considering issues related to investment decisionmaking by offshore investors and operators. The significant and pervasive uncertainty surrounding many of the key attributes of any potential deep-water operation has considerable impact on the economic merit of projects proposed in this frontier. Applications of this approach are not limited to investment decisions. Explicit treatment of uncertainty can be quite useful to policymakers in evaluating the merits of possible changes in legislation or regulation. The consideration of the impact of the royalty relief program for deep-water projects is a good example of policy analysis applications.

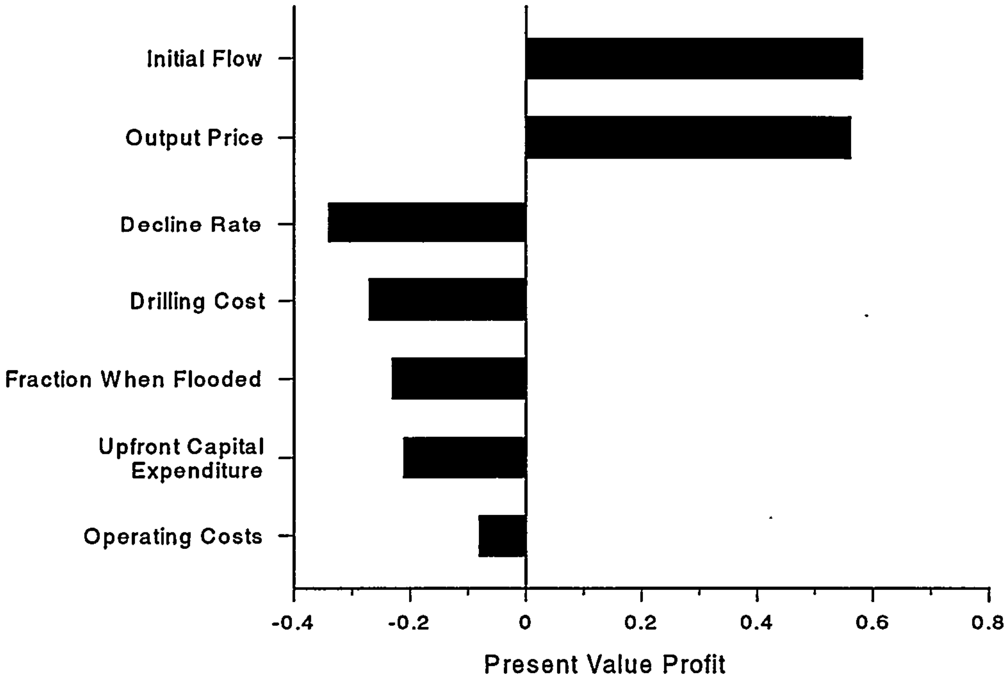
Analysis of Investment Incentives Under Royalty Relief

The Outer Continental Shelf Deep Water Royalty Relief Act (DWRRA) was passed in 1995 and mandates royalty relief for certain oil and gas leases in at least 200 meters of water in the Gulf of Mexico.[5] This legislation has been one of the most controversial national policies affecting gas and oil activities in the deep water. Opponents have charged that the program is an unnecessary financial reward. Proponents have claimed that the combination of royalty relief and recent technological advancements in the deep water are the prime reasons for record lease sales by the Minerals Management Service (MMS) in 1997. The implications of the DWRRA are assessed by use of the DCF model. Results of the economic evaluation under conditions of uncertainty show that the major stimulus of the DWRRA may be more from its impact on the relative chance of success and failure, than from the simple gains in expected returns.

The DWRRA defines the deep-water area as that in water depths greater than 200 meters (656 feet). The deep-water

[5]Title III of S.395, *The Alaska Power Administration Sale Act*, signed into law by President Clinton on November 28, 1995.

Figure C3. Rank Correlations for Present Value Profit and Input Variables



Source: Energy Information Administration, Office of Oil and Gas.

Table C3. Required Initial Production Rates Based on Alternative Cost Assumptions

Test A. Drilling Costs per Well			
Drilling costs (million dollars)	5	10	15
Required initial production rate (million cubic feet per year)	3,905	4,797	5,700
Test B. Upfront Capital Costs			
Capital costs (million dollars)	275	350	425
Required initial production rate (million cubic feet per year)	3,231	4,797	6,382

Note: The *required initial production rate* is that rate at which present value profit is zero.
Source: Energy Information Administration, Office of Oil and Gas.

zone is further divided into three parts for different levels of royalty relief. The zones are 200-to-400 meters (656-1,312 feet), 400-to-800 meters (1,312-2,625 feet), and greater than 800 meters (2,526 feet). The DWRRA provides for volumes of new production that will not be subject to royalty payments. Production in excess of the stated levels is subject to standard royalty charges (Table C4). An eligible lease is one that results from a sale held after November 28, 1995, 200 meters or deeper, lying wholly west of 87 degrees 30 minutes west Longitude.

A sensitivity analysis was conducted to show the impact of the DWRRA on a new field project evaluation. The previous analysis of the representative project was based on the assumption that the project qualified for royalty relief under the DWRRA. Removal of the royalty relief benefits from the project assessment shows a clear shift in the investment incentives for this project. Substantial profits remain a distinct possibility, with a 25-percent chance of profits of $38.3 million at the 10-percent discount rate, compared with a 35-percent chance in the base case results. However, the expected return from the

Table C4. Offshore Oil and Gas Volumes Exempt from Royalty Charges Under the *Outer Continental Shelf Deep Water Royalty Relief Act*

Depth	Minimum Volumes	
	Barrel of Oil Equivalent (million barrels)	Equivalent Gas Volume (billion cubic feet)
200-400 meters (656-1,312 feet)	17.5	98.5
400 to 800 meters (1,312-2,625 feet)	52.5	295.6
>800 meters (2,526 feet)	87.5	492.6

Note: The barrel of oil equivalent volumes were converted into billion cubic feet based on assumed heat content of 5.8 million Btu per barrel of oil and 1,030 Btu per cubic foot of gas.
Source: Energy Information Administration, Office of Oil and Gas.

PVP distribution shows an economic loss of $14.6 million, compared to the previous expected value of $1.4 million. The chance of at least breaking even decreased from 49 percent to 37 percent. Further, the IROR shifted downwards to 7.5 percent, a significant reduction from the earlier 9.8-percent return. The chance of achieving a 10-percent or greater return on this project is 37 percent without the royalty relief program (Figure C4). In fact, the program may be strongest in reducing the likelihood of losses as an important element in promoting additional investment in deep-water projects.

The royalty relief program increases the expected value return from the deep-water offshore projects. However, it also enhances the perceived returns in a fundamental way that is more readily apparent when such a project is assessed under conditions of uncertainty. In light of the substantial investment volumes involved, corporate managers would have to be risk neutral in order to be unaffected by the shift in the relative occurrence of success and failure. Risk aversion on the part of the firms active in this region likely would result in avoiding such marginal investments without the additional relief.

Evidence supporting this assessment of the impact of the DWRRA can be found in the lease sales conducted since the effective period for royalty relief began. Federal lease sales during 1991-92 resulted in the MMS accepting only 878 bids from companies. The 1993-94 Outer Continental Shelf sales resulted in only 943 accepted bids. In 1995-96, the number of accepted bids increased to 2,204. In the last four sales during 1996-97, each sale broke the previous record for submitted bids. The stimulus from the royalty relief provisions seems readily apparent when the bids are broken down by water depth levels. The fraction of blocks in water deeper than 200 meters (656 feet) receiving bids in 1994 was less than 10 percent of all bids for blocks in the Western and Central Gulf of Mexico. By 1997, blocks in water deeper than 800 meters (2,526 feet) received more than half the bids (Figure C5). This is particularly impressive given that the water depth record for production was less than 1,800 feet a mere 10 years earlier. In 1995 there were only 5,000 active leases in the Gulf of Mexico region. By January 1997, this had reached 6,177 leases. Estimates from the MMS indicate that by 1998 there should be more than 8,300 leases.

The explicit treatment of risk and uncertainty is a useful tool for consideration of the royalty relief provisions as a stimulus for deep-water development. The analysis shows that the program strengthens the positive incentives to invest, while lessening the negative aspects of deep-water opportunities. It does not directly address the effectiveness of the policy in achieving the goal of motivating the intended behavior. Nor does this analysis show whether the royalty relief program is the best alternative to promote such behavior.

Figure C4. Cumulative Frequency Distributions for Internal Rate of Return for the Representative Gas Project With and Without Royalty Relief

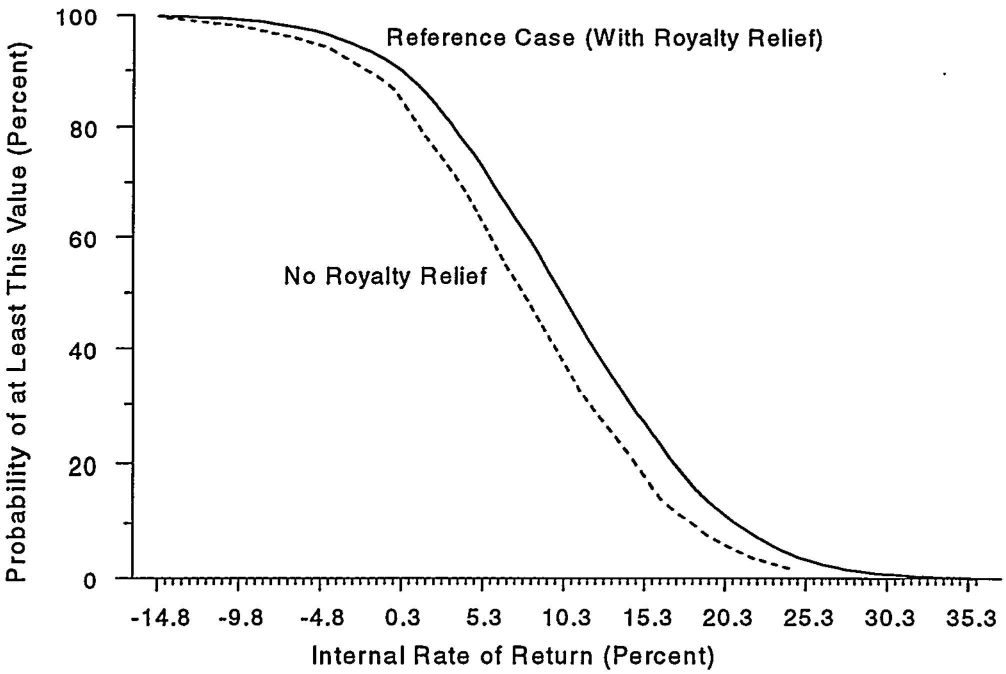
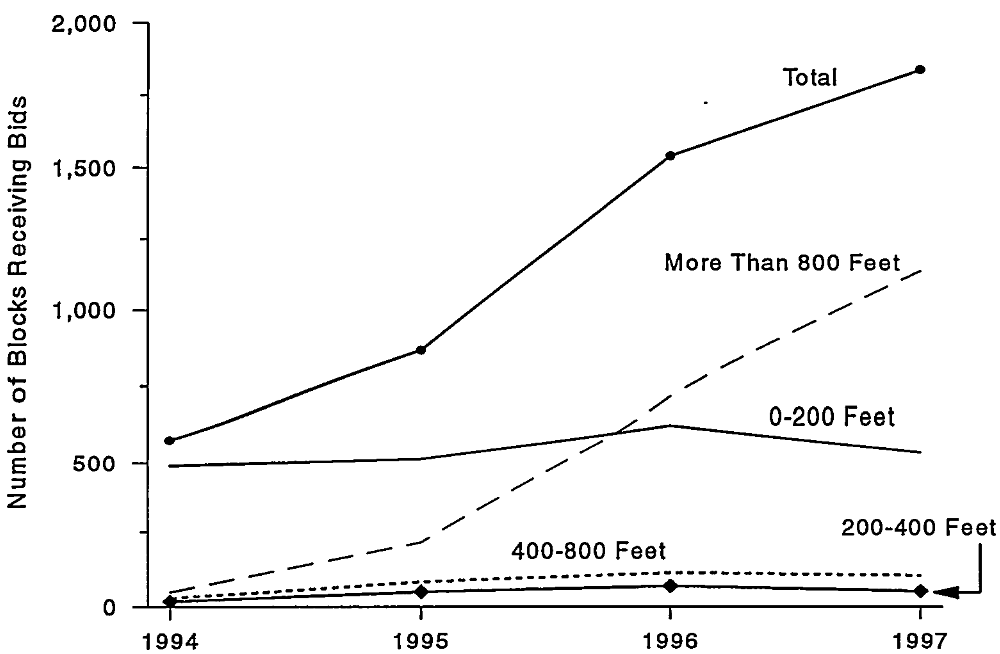


Figure C5. Gulf of Mexico Blocks Receiving Bids by Depth Class, 1994-1997



Source: Energy Information Administration, Office of Oil and Gas.

Appendix D

Data Sources and Methodology for Contracting and Capacity Turnback Analysis

This appendix describes how original data sources were edited for use in the analysis presented in Chapter 6, "Contracting Shifts in the Pipeline Transportation Market." It also presents some further analysis and more detailed information on firm capacity contracts and released capacity than was possible in the chapter. In addition, it describes the various analytical methods used in development of the chapter.

The appendix has four sections.

- The first section describes the editing of the original capacity release and contracted firm capacity data. In some cases the editing required was extensive. The analysis presented in this report would not be easy to derive by simply using the original data sources cited.

- The second section describes the analysis employed to examine shippers' contracting behavior and identify examples of turnback.

- The third section presents the derivation of the sample of individual shippers whose contracts are analyzed in the chapter. Specific contract-level information is included for the sampled shipper-pipeline combinations.

- The final section presents further details on firm capacity and capacity release in both graphic and tabular form.

Data Editing

Capacity Release Data

Prior to the implementation of the Federal Energy Regulatory Commission's (FERC) Order 636 on November 1, 1993, capacity held under a contract between a shipper and a pipeline company could not be assigned or sold to any other shipper. Under Order 636, shippers have the right to sell all or part of the capacity under a firm transportation contract for any portion of the term of the contract. This is known as "capacity release." FERC required each pipeline company to set up an electronic bulletin board (EBB) to post offers to release capacity made by their shippers and to post capacity release awards. In the beginning, individual pipeline companies had created unique formats and programs for their EBBs, which resulted in a burdensome system that prompted the industry to seek standardization. The Gas Industry Standards Board (GISB) was assigned the task of standardizing capacity release and other natural gas industry business practices. In Order 587, issued in July 1996, FERC agreed to the GISB proposal that transaction information should be available on the Internet's World Wide Web site for each interstate pipeline company.

The capacity release data used in this report were obtained from Pasha Publications, Inc. (PASHA) and the FERC Office of Pipeline Regulation. For the period November 1, 1993, through July 19, 1994 (date of capacity release award), data were obtained from PASHA, who had compiled a database of the information posted on various pipeline companies' EBBs. For the period July 20, 1994, through approximately May 1997, data were obtained from the FERC Office of Pipeline Regulation (OPR), who in turn had downloaded the data from each pipeline company's EBB. The FERC data was in electronic data interchange (EDI) format. In those instances where the EDI-downloaded data did not include rate information and PASHA data included the same capacity release award, the rate information was taken from PASHA. If no rate was available for a given award and other awards existed for that day, then the average rate of all the other awards for that award date was used.

Capacity release data from May 1997 through June 1998 were also obtained from the FERC OPR. These data were also downloaded from the Internet but were put in GISB capacity release documentation format (see capacity release implementation guide on <http://www.gisb.org>).

The PASHA and EDI data were merged using the calendar date of July 20, 1994. Because there was an overlap of several months when both the EDI data and the Internet data were obtained and in some cases data existed in one data format and not the other, the EDI and Internet data series were merged using a different scheme. The pipeline company name, offer number, and beginning and ending dates of the award were used as keys to identify unique capacity release awards. This required reformatting of the offer numbers for several of the pipeline companies.

The final file contained 82,456 capacity release award records. In order to perform certain specific analyses for this report, this file was expanded by converting a single award record for a time period into a record for each day the award was effective. This expanded file contained 3,773,075 records. By simple summation of this expanded file for any time period, the amount of released capacity awarded and revenue could be calculated.

Table D1 lists each pipeline company, the earliest and latest dates of capacity release awards recorded in the three data sets, the number of awards, the average length of all awards, and the average volume of all awards. For 46 Internet-based awards, the award date was after the end of the release period, so the transaction posting date was used instead. It is also interesting to note that there are over 100 instances of the capacity release beginning date being several years after the date of the award. In one case, a pipeline company has capacity on three other pipeline companies beginning on December 31, 1999, for 1 day and also beginning on January 1, 2000, for 1 day, apparently as "Year 2000" insurance. Other instances exist of monthly and seasonal volumes being reserved for many years.

In the analysis of capacity release activities in Chapter 6, data were used only for those pipeline companies that had data across the entire 1994-through-1998 period. Thus, the pipeline companies Canyon Creek, Equitrans, Great Lakes, Iroquois, K N Interstate, Kern River, Koch Gateway, Midcoast Interstate, Mobile Bay, Mojave, National Fuel, Questar, Stingray, Viking, and Williston Basin were excluded. For reasons explained in the following section, Northern Natural was also excluded. (In the capacity release material in Chapter 1, data from all 43 pipeline companies shown in Table D1 were used.)

Index of Customers Data

The FERC Index of Customers filings were the principal source of information for the analysis of firm capacity contracts in Chapter 6. Each pipeline company regulated by FERC that provides firm transportation or storage service is required to file contract and customer information quarterly. For all firm transportation contracts in effect on the first day of each calendar quarter, the pipeline companies must provide customer name, rate schedule, beginning and ending dates of the contract, rollover days (if any), maximum daily transportation volume, and unit of measure. FERC then posts this information on the FERC Bulletin Board Network as Index of Customers (IOC) information.

The quarterly FERC Index of Customers filings for April 1, 1996, through July 1, 1998, were used as the basis for the analysis. All storage contracts were deleted, leaving files of firm transportation contracts only. The quarterly files were edited to convert all volumes to a heat content (million Btu per day) basis. Additional editing was performed. If a contract end date was before the date of the quarterly filing, the contract was assumed to be operating in its rollover period, and the rollover period was added to the original end date to produce a new end date.

Shipper names were respelled as necessary to have a common spelling for each customer across the 10 quarterly filings. Originally, there were 3,642 unique shipper names across all 10 quarters. This was reduced to 2,228 unique names as a result of the respellings. The respelling affected approximately 23,000 records across the quarters, or 43 percent of all Index of Customers records. The vast majority of these were simple, such as "Corp" versus "Corp.", but in several cases a company's name changed completely when it was purchased by another company (for example, Washington Natural Gas is now Puget Sound Energy, Inc.).

Once common names were arrived at, longitudinal analyses of the data were performed. In some cases, a customer had a contract in quarters x and x+2 but not x+1, and these gaps were filled where appropriate by copying the record from the previous quarter's database. This was required for 2 contracts in July 1996, 1 in October 1996, 11 in January 1997, 9 in April 1997, 2 in July 1997, 1 in October 1997, 4 in January 1998, 2 in April 1998, and 47 in July 1998.

In its July 1998 filing, Northern Natural split what had been single, firm transportation contracts into multiple segments (for example, separate rate schedules covered transportation in the production and market areas rather than the single rate schedule used in previous quarters). This greatly increased the number of entries in the filing compared with previous quarters. The April 1998 filing for Northern Natural contained 268 records totaling 4,662,053 million Btu per day of capacity, while the July 1998 filing had 495 records representing a total of 12,832,673 million

Table D1. Capacity Release Activity by Pipeline Company

Pipeline Company	Date of Capacity Award		November 1993 - June 1998		
	Earliest Award	Latest Award	Number of Awards	Average Length of Award (days)	Average Capacity of Award (MMBtu/d)
Algonquin Gas Transmission Co.	Dec. 1993	Apr. 1998	1,348	534	2,704
ANR Pipeline Co.	Nov. 1993	Apr. 1998	2,617	62	8,290
Canyon Creek Gas Co.	Jan. 1995	Mar. 1996	28	100	14,143
Colorado Interstate Gas Co.	Oct. 1993	Apr. 1998	1,237	41	5,641
CNG Transmission Co.	Oct. 1993	Apr. 1998	4,610	61	6,374
Columbia Gas Transmission Co.	Nov. 1993	May 1998	8,885	53	3,856
Columbia Gulf Transmission Co.	Jun. 1994	May 1998	4,818	55	4,093
East Tennessee Gas Co.	Nov. 1993	Feb. 1998	606	148	2,764
El Paso Natural Gas Co.	Jul. 1993	Apr. 1998	4,992	35	14,428
Equitrans, Inc.	Sep. 1993	Jan. 1996	57	27	11,335
Florida Gas Transmission Co.	Dec. 1993	Apr. 1998	929	83	2,412
Great Lakes Transmission Co.	Dec. 1995	Apr. 1996	120	184	11,967
Iroquois Gas	Nov. 1993	Apr. 1998	22	2,406	6,638
KN Interstate	Oct. 1993	Apr. 1996	877	25	3,856
Kern River	May 1994	Apr. 1998	32	48	15,659
Koch Gateway Pipeline Co.	Dec. 1994	Dec. 1994	3	605	11,013
Midcoast Interstate Transmission, Inc.[1]	Jan. 1996	Apr. 1996	9	252	1,993
Midwestern Gas Transmission Co.	Mar. 1994	Mar. 1998	252	27	13,718
Mississippi River Transmission Co.	Nov. 1993	Apr. 1998	958	91	3,508
Mobile Bay Transmission System	Dec. 1997	Apr. 1998	28	229	3,652
Mojave Pipeline Co.	Jun. 1994	Jan. 1998	72	34	26,785
National Fuel Gas Supply Corp.	Jul. 1994	Apr. 1996	615	28	2,266
Natural Gas Pipeline Co. of America	Dec. 1993	Feb. 1998	2,910	45	11,681
NORAM Gas Transmission	Nov. 1993	May 1998	283	229	1,780
Northern Border Pipeline Co.	Dec. 1993	Apr. 1998	169	395	14,913
Northern Natural Gas Co.	Nov. 1993	Apr. 1998	2,413	53	7,467
Northwest Pipeline Corp.	Nov. 1993	May 1998	2,197	359	6,316
Pacific Gas Transmission Co.	Nov. 1993	Jan. 1998	2,040	200	11,785
Paiute Pipeline Co.	Dec. 1993	Oct. 1997	524	30	571
Panhandle Eastern Pipe Line Co.	Jul. 1993	Apr. 1998	2,158	36	4,981
Questar Pipeline Co.	Sep. 1993	Sep. 1993	1	30	1,000
Southern Natural Gas Co.	Dec. 1993	Mar. 1998	3,368	35	8,164
Stingray Pipeline Co.	Sep. 1995	Aug. 1997	177	63	1,564
Tennessee Gas Pipeline Co.	Oct. 1993	May 1998	7,258	230	4,738
Texas Eastern Transmission Corp.	Jul. 1993	Apr. 1998	5,809	326	8,717
Texas Gas Transmission Corp.	Nov. 1993	Feb. 1998	6,127	67	5,502
Trailblazer Pipeline Co.	Feb. 1994	Nov. 1997	399	98	11,705
Transcontinental Gas Pipe Line Corp.	Nov. 1993	Apr. 1998	8,891	100	4,836
Transwestern Pipeline Co.	Jul. 1993	Apr. 1998	973	44	11,500
Trunkline Gas Co.	Sep. 1993	Apr. 1998	673	47	7,446
Viking Gas Transmission Co.	Apr. 1994	Aug. 1994	7	57	12,990
Williams Natural Gas Co.	Dec. 1993	Apr. 1998	2,931	83	4,800
Williston Basin Interstate Pipeline Co.	Oct. 1997	May 1998	24	657	2,052

[1]Formerly known as Alabama-Tennessee Gas Co.

MMBtu/d = Million Btu per day.

Source: Energy Information Administration, Office of Oil and Gas, derived from: **November 1993-July 1994:** Pasha Publications, Inc.; **July 1994-May 1997:** Federal Energy Regulatory Commission (FERC) Electronic Data Interchange; **May 1997-June 1998:** FERC downloaded Internet data.

Btu per day. In several instances, one contract in the April filing appeared multiple times in the July filing, with the total term of the contract split into pieces with differing volumes. In those cases, the volume appearing in the earliest time period was used across the entire time period and the extra pieces were deleted. After this editing step, the file contained 301 records totaling 5,323,507 million Btu per day. The large volume in July 1998 remained a concern, however, so Northern Natural was excluded from the analysis. This resulted in sample of 64 pipeline companies for the analysis.

Contract Length

To study the trends in long-term and short-term contracting, the contracts in the Index of Customers were designated as long-term or short-term based on the contract's effective term (the number of days between its start and end date). Long-term contracts are defined as those contracts with terms longer than 366 days. The analysis assumes that shippers do not use contracts with annual (including leap year) or shorter terms to satisfy long-term transportation portfolio planning. The separation of capacity between long-term (more than 366 days) and short-term (366 days or less) is also necessary since it is unlikely that the expiration of short-term contracts will result in a permanent or long-term turnback of a significant amount of capacity.

Shipper Type Classification

Another aspect of preparing the Index of Customers' data for analysis was the assignment of a shipper type to each shipper name. The Index of Customers provides the name of each company that contracted for firm transportation, but it does not provide any other information to identify what segment of the industry the shipper represented. Thus, Energy Information Administration (EIA) staff compared shipper names with lists of companies from other sources to classify each shipper. Five sources were used for comparison: (1) Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition"; (2) Benjamin Schlesinger and Associates, Inc., *Directory of Natural Gas Marketing Service Companies*, Eleventh Edition (May 1997) (a proprietary source); (3) Energy Planning, Inc., *Directory of Natural Gas Consumers*, 5th Edition (1996) (a proprietary source); (4) Form EIA-860, "Annual Electric Generator Report"; and (5) Form EIA-759, "Monthly Power Plant Report."

The list of electric utilities from Form EIA-860 included combination electric and gas utilities. Shippers that appeared in this list and that used more than 50 percent of their 1997 gas deliveries for fuel to generate electricity were classified as electric utilities. Combination companies that used 50 percent or less of their 1997 gas deliveries for fuel to generate electricity were classified as local distribution companies. For example, Baltimore Gas and Electric Company was classified as a local distribution company while Consolidated Edison Company was classified as an electric utility.

The final set of shipper categories is as follows:

1. Electric utilities (including combination electric and natural gas utilities who used more than 50 percent of their 1997 gas deliveries for fuel to generate electricity)

2. Industrial companies (including independent power producers, cogenerators, and commercial firms)

3. Local distribution companies (including intrastate pipeline companies and combination electric and natural gas utilities who used 50 percent or less of their 1997 gas deliveries for fuel to generate electricity)

4. Marketers

5. Pipeline companies

6. Others (including producers, gatherers, processors, storage operators, and all other shippers not classified).

After shipper categories were assigned using the procedure just described (which required some respellings of shipper names), some shippers still were not assigned a category. Internet searches were performed on the shippers with the largest contracted volumes in an attempt to determine the appropriate category, yet some still remained unclassified. Those shippers that could not be categorized using a direct source were subsequently classified as "other." Across all 10 quarters, 2.0 percent of the contracts were not identified as to shipper type, accounting for 0.4 percent of the total contract volume. One-quarter of this classified volume is accounted for by two shippers on Transwestern. Table D2 lists the top 25 shippers by volume in each shipper category according to the July 1998 Index of Customers.

Further Editing

Further editing was done to prepare the data for analysis. All zero-volume contracts were deleted, so that average volume calculations would not be biased. With one exception, pipeline companies that did not have data for all

Table D2. Top 25 Shippers by Shipper Type and Amount of Firm Transportation Capacity on All Pipeline Companies, July 1, 1998

Shipper Type / Name	Capacity (million Btu per day)
Electric Utility	
CONSOLIDATED EDISON COMPANY OF NEW YORK, INC	678,892
FLORIDA POWER & LIGHT	630,000
NEW ENGLAND POWER CO	559,445
SIERRA PACIFIC POWER COMPANY	350,010
DELMARVA POWER & LIGHT CO	246,746
CONNECTICUT LIGHT & POWER COMPANY	220,620
PORTLAND GENERAL ELECTRIC COMPANY	196,925
CITY OF LOS ANGELES DEPARTMENT OF WATER & POWER	174,893
VIRGINIA ELECTRIC & POWER CO	161,288
SOUTHERN CALIFORNIA EDISON COMPANY	132,990
FLORIDA POWER CORPORATION	111,036
TALLAHASSEE, CITY OF	78,936
CENTRAL LOUISIANA ELECTRIC COMPANY, INC.	75,000
SAN DIEGO GAS & ELECTRIC COMPANY	62,738
BOSTON EDISON CO	60,300
EMPIRE DISTRICT ELECTRIC COMPANY	58,101
WISCONSIN POWER & LIGHT CO	57,288
KANSAS POWER & LIGHT COMPANY	48,668
ORLANDO UTILITIES COMMISSION	32,423
POWER AUTHORITY OF THE STATE OF NEW YORK	31,765
KANSAS CITY POWER & LIGHT COMPANY	31,455
CITY OF HAMILTON, OHIO	30,000
LAKELAND, CITY OF	28,529
GULF STATES UTILITIES CO.	27,000
TAUNTON MUNICIPAL LIGHTING PLANT	27,000
Industrial	
SITHE/INDEPENDENCE POWER PARTNERS, L.P.	279,382
GENERAL MOTORS CORPORATION	182,990
BETHLEHEM STEEL CORP.	181,909
SELKIRK COGEN PARTNERS, L. P.	154,280
DOSWELL LIMITED PARTNERSHIP	125,000
ALLIED SIGNAL, INC.	117,198
PCS NITROGEN FERTILIZER, L.P.	115,110
U.S. STEEL GROUP	112,040
EAGLE POINT COGENERATION	112,000
ARCHER-DANIELS-MIDLAND CO.	106,050
NATIONAL STEEL CORPORATION - GREAT LAKES STEEL DIV.	100,000
INTERNATIONAL PAPER CO.	95,136
ENTERGY POWER, INC.	90,000
SUN COMPANY, INC. (R&M)	82,423
CANAL ELECTRIC COMPANY	75,000
PCS NITROGEN OHIO, L.P.	70,000
ALUMINUM COMPANY OF AMERICA	69,803
LTV STEEL CORPORATION	63,000
GRANITE CITY STEEL DIVISION OF NATIONAL STEEL CORP.	59,939
PROCTER & GAMBLE PAPER PRODUCTS	59,790
U S GYPSUM CO	59,617
INDECK-OLEAN LIMITED PARTNERSHIP	55,500
INDECK-CORINTH LIMITED PARTNERSHIP	53,700
KN PROCESSING, INC.	50,000
OCEAN STATE POWER	50,000

Table D2. Top 25 Shippers by Shipper Type and Amount of Firm Transportation Capacity on All Pipeline Companies, July 1, 1998 (Continued)

Shipper Type / Name	Capacity (million Btu per day)
Local Distribution Company	
PUBLIC SERVICE ELECTRIC & GAS	2,351,539
COLUMBIA GAS OF OHIO, INC.	2,343,647
SOUTHERN CALIFORNIA GAS COMPANY	1,907,450
NATIONAL FUEL GAS DISTRIBUTION CO	1,706,397
EAST OHIO GAS CO	1,673,004
NICOR GAS COMPANY	1,614,411
ARKANSAS LOUISIANA GAS COMPANY	1,239,638
PUBLIC SERVICE COMPANY OF COLORADO	1,184,598
MISSOURI GAS ENERGY	1,181,805
LACLEDE GAS COMPANY	1,155,418
NIAGARA MOHAWK POWER CORP	1,089,510
ATLANTA GAS LIGHT CO.	1,086,395
NORTHERN INDIANA PUBLIC SERVICE COMPANY	1,081,856
PACIFIC GAS & ELECTRIC CO	1,080,850
WASHINGTON GAS LIGHT CO	1,068,151
MICHIGAN CONSOLIDATED GAS CO	941,353
BOSTON GAS COMPANY	905,093
BROOKLYN UNION GAS COMPANY	835,624
ROCHESTER GAS & ELECTRIC CORPORATION	804,949
MOUNTAIN FUEL SUPPLY COMPANY	798,902
PIEDMONT NATURAL GAS COMPANY, INC.	767,392
BALTIMORE GAS & ELECTRIC CO	689,297
WISCONSIN GAS COMPANY	577,800
CINCINNATI GAS & ELECTRIC COMPANY	573,082
UGI UTILITIES INC	573,065
Marketer	
NATURAL GAS CLEARINGHOUSE, INC.	1,694,411
BURLINGTON RESOURCES	1,016,694
ENGAGE ENERGY U.S., L.P.	826,163
KANSAS GAS SERVICE	810,202
MIDCON GAS SERVICES CORP	800,618
DUKE ENERGY TRADING & MARKETING	789,709
PUGET SOUND ENERGY, INC	763,179
NORAM ENERGY SERVICES, INC.	746,245
TEXACO NATURAL GAS INC.	728,688
AMOCO ENERGY TRADING CORP.	673,986
CONSUMERS ENERGY COMPANY	668,231
CHEVRON USA, INC.	629,584
NORTHWEST NATURAL GAS COMPANY	550,814
UNION PACIFIC FUELS, INC.	503,207
ENRON CAPITAL & TRADE RESOURCES	482,941
K N MARKETING	461,984
COLUMBIA ENERGY SERVICES CORPORATION	448,476
WILLIAMS ENERGY SERVICES	423,495
NUI CORP	391,806
TRANSCO ENERGY MARKETING COMPANY	383,892
PROLIANCE ENERGY LLC	354,278
KIMBALL TRADING CO., L.L.C.	341,400
CORAL ENERGY RESOURCES	337,744
EXXON	325,569
COLORADO INTERSTATE GAS CO.	313,730

Table D2. Top 25 Shippers by Shipper Type and Amount of Firm Transportation Capacity on All Pipeline Companies, July 1, 1998 (Continued)

Shipper Type / Name	Capacity (million Btu per day)
Other	
PAN-ALBERTA GAS (U.S.) INC.	843,859
KOCH ENERGY TRADING, INC.	312,000
BARRETT RESOURCES CORP.	199,591
MICHCON GATHERING COMPANY	165,000
SHELL OFFSHORE INC	152,488
VASTAR RESOURCES, INC.	120,000
EQUITABLE RESOURCES ENERGY CO	107,770
AERA ENERGY LLC	103,000
AGAVE ENERGY CO.	100,000
CIG RESOURCES COMPANY	98,152
ENRON OIL & GAS COMPANY	95,000
PEMEX GAS Y PETROQUIMICA BASICA	95,000
RENAISSANCE ENERGY (U.S.) INC.	86,121
MURPHY EXPLORATION & PRODUCTION COMPANY	85,120
ENRON INDUSTRIAL NATURAL GAS COMPANY	75,000
SOCO WATTENBERG CORPORATION	74,198
SHELL WESTERN E & P, INC.	70,000
CHEVRON U.S.A. PRODUCTION COMPANY	60,600
AMERICAN CENTRAL GAS COS INC	60,000
OXY USA, INC.	56,000
SHELL DEEPWATER PRODUCTION, INC.	55,000
PENNZOIL EXPLORATION AND PRODUCTION CO.	53,560
ORCHARD GAS, INC.	50,750
CNG PRODUCING CO	47,597
NORCEN EXPLORER, INC.	45,000
Pipeline Company	
TRANSCANADA PIPELINES LTD.	1,531,556
ANR PIPELINE COMPANY	856,366
CNG TRANSMISSION CORP	716,675
TRUNKLINE GAS CO	635,000
NATURAL GAS PIPELINE COMPANY OF AMERICA	517,954
PACIFIC INTERSTATE TRANSMISSION COMPANY	488,267
TEXAS EASTERN TRANSMISSION CORPORATION	438,528
SOUTHERN NATURAL GAS CO.	274,612
TRANSCONTINENTAL GAS PIPE LINE CORP	240,070
SOUTHERN CONNECTICUT GAS CO	234,148
TENNESSEE GAS PIPELINE COMPANY	183,800
FLORIDA GAS TRANSMISSION COMPANY	145,642
COLUMBIA GAS TRANSMISSION CORPORATION	131,682
KOCH GATEWAY PIPELINE CO	106,831
HOPE NATURAL GAS COMPANY	103,809
NORTHERN NATURAL GAS CO.	90,005
NATIONAL FUEL GAS SUPPLY CORP	70,213
IROQUOIS GAS TRANSMISSION SYSTEM	50,000
NATURAL GAS TRANSMISSION SERVICES, INC.	14,000
K N INTERSTATE GAS TRANSMISSION COMPANY	12,413
ALGONQUIN GAS TRANS CO	11,137
GAS TRANSPORT, INC.	9,832
CARNEGIE INTERSTATE PIPELINE COMPANY	9,722
RATON GAS TRANSMISSION COMPANY	8,239
QUESTAR P/L CO.	6,324

Notes: Shippers were selected from data for 64 interstate pipeline companies. "Other" includes producers, gatherers, processors, and storage operators as well as shippers that could not be classified.

Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers quarterly filing for July 1, 1998, FERC Bulletin Board (August 14, 1998).

10 quarters were also deleted. KO Transmission Company was kept because it was missing data only for the first quarter and had a steady volume in every quarter thereafter. The final edit was to assign a region code to each pipeline company, using the region where most of the pipeline end-use deliveries were made. The total firm capacity for all pipeline companies across the 10 quarters from April 1996 through July 1998 is listed in Table D3 by region. Table D4 shows the number of firm capacity contracts held on each pipeline company.

How Capacity Turnback Was Identified

Only long-term (longer that 366 days) firm contracts were considered in the analysis of capacity turnback in Chapter 6. As a preliminary step in determining whether any turnback has occurred on the interstate pipeline system, total long-term firm capacity levels over the eight-quarter period, April 1, 1996 through January 1, 1998, in the Index of Customers were examined at both the regional and the pipeline company level. For pipeline companies that showed consistent declines in capacity, the behavior of shippers was also examined, but at the level of total long-term capacity held, not at the contract level.

While this preliminary examination of the data looked for net declines in capacity as an indicator of turnback, a constant or increasing amount of capacity does not necessarily mean that no turnback has occurred. If shippers turned back capacity, yet the pipeline company was able to remarket that capacity to other shippers, there may be little change in total capacity commitments on the system. Thus, further analysis of shipper behavior and individual contracts between shippers and pipeline companies was also included in Chapter 6 (with detailed results presented in the next section of this appendix).

Capacity Changes Over 12 Months

A means of identifying significant cases of capacity turnback was to calculate the 12-month changes in long-term firm transportation capacity, that is, the change from April 1, 1996, to April 1, 1997, from July 1, 1996 to July 1, 1997, etc. The first eight quarters of data from the Index of Customers were used to provide four sets of comparisons: April, July, October, and January.

Using these 12-month comparisons helped to mitigate the effects of seasonal demand that some pipeline companies may experience. Comparing the quarters sequentially would probably have produced numerous examples of declines in capacity from the January quarter to the April quarter, which in many cases may just reflect seasonal demand on the part of shippers (the heating season runs from November through March). However, declines in capacity between January of one year and January of the next year would indicate that a pipeline company may be experiencing the turnback of capacity and that the data for that company should be examined further.

At a regional level, the 12-month comparisons showed very little evidence of net declines in capacity. In fact, this measure indicates that long-term firm capacity commitments generally increased during the period examined—the biggest exception being in the Southwest Region (Table D5). The Southwest had the lowest amount of long-term firm capacity on April 1, 1996 of all the regions, and capacity seems to have been reduced throughout the period. The Southwest experienced declines in each of the four 12-month comparisons, the largest being 14 and 16 percent, respectively, in the July and October comparisons. The Northeast and the West also had some declines in capacity according to this measure, but all the declines were 2 percent or less.

The regional results show only the net impact of changes that occurred on individual pipeline systems. So, the 12-month comparisons were also applied to all 64 interstate pipeline companies in this study. Many companies showed increases in long-term firm capacity in each quarterly comparison, while others showed a mixture of increases and declines. Several pipeline companies showed declines in three or more of the 12-month comparisons. The most significant of these, in terms of the change in volume and the number of quarters that showed a decline, occurred on: Algonquin Gas Transmission Company in the Northeast; Koch Gateway Pipeline Company and Noram Gas Transmission Company, both in the Southwest; and Northwest Pipeline Corporation and Pacific Gas Transmission Company, both in the West (Table D6).[1] Taken together, these five companies accounted for 15 percent of the total long-term firm capacity that was effective on April 1, 1996. Koch Gateway and Northwest

[1]Besides the companies discussed here, two other pipeline companies had declines in each of the four quarters, but the long-term firm capacity on their systems as of April 1, 1996 was less than 500 billion Btu per day. These companies were Canyon Creek Compression Company and Williston Basin Interstate Pipeline Company, both in the Central Region.

Table D3. Firm Transportation Capacity by Region and Pipeline Company, April 1, 1996 - July 1, 1998
(Million Btu per Day)

Region / Pipeline Company	April 1, 1996	July 1, 1996	October 1, 1996	January 1, 1997	April 1, 1997	July 1, 1997	October 1, 1997	January 1, 1998	April 1, 1998	July 1, 1998
Central										
Canyon Creek Compression Co.	225,764	224,291	219,548	215,859	213,013	210,168	205,214	202,263	200,260	200,260
Colorado Interstate Gas Co.[a]	2,096,216	1,697,972	2,132,011	2,161,156	2,167,465	2,216,199	2,378,401	2,474,467	2,472,012	2,441,588
K N Interstate Gas Transmission Co.	612,454	520,595	527,208	463,665	440,867	444,506	735,071	936,065	859,152	741,437
MIGC, Inc.	12,000	12,000	12,000	45,000	45,000	45,000	45,000	90,000	90,000	90,000
Mississippi River Transmission Corp.[a]	1,600,841	1,569,591	1,572,341	1,661,737	1,656,550	1,592,800	1,595,800	1,727,706	1,627,687	1,622,687
Northern Border Pipeline Co.[a]	1,684,194	1,680,015	1,677,974	1,671,840	1,691,019	1,697,170	1,647,301	1,694,494	1,695,686	1,695,686[b]
Questar Pipeline Co.	1,093,946	1,091,087	1,075,644	1,045,494	1,062,269	1,035,590	1,079,088	1,146,861	1,121,027	1,122,904
Trailblazer Pipeline Co.[a]	284,271	540,351	553,351	555,462	555,462	555,462	605,017	605,017	605,017	605,017
Westgas Interstate Inc	10,572	10,572	13,372	13,372	13,372	13,372	13,372	13,372	13,372	13,372
Williams Natural Gas Co.[a]	2,697,941	2,698,791	2,737,300	2,870,893	2,911,948	2,900,039	2,787,988	2,861,286	2,762,068	2,845,768
Williston Basin Interstate Pipeline Co.	440,217	440,217	439,960	507,233	467,717	423,126	436,001	464,913	442,768	438,185
Wyoming Interstate Co, Ltd.	500,000	515,000	542,488	542,484	542,494	542,494	753,779	784,679	784,679	784,679
Total Central	**11,258,416**	**11,000,482**	**11,503,197**	**11,754,195**	**11,767,176**	**11,675,926**	**12,282,032**	**13,001,123**	**12,673,728**	**12,601,583**
Release Sample Central	8,363,463	8,186,720	8,672,977	8,921,088	8,982,444	8,961,670	9,014,507	9,362,970	9,162,470	9,210,746
Release Sample as a Percent of Total	74%	74%	75%	76%	76%	77%	73%	72%	72%	73%
Midwest										
ANR Pipeline Co.[a]	4,295,471	4,907,838	5,118,103	7,442,094	4,976,316	5,043,139	5,232,978	7,423,021	5,149,463	5,157,798
Crossroads Pipeline Co.	91,769	61,019	91,064	127,000	131,130	132,100	132,000	148,466	153,466	153,466
Great Lakes Gas Transmission, L.P.	3,895,797	5,180,176	5,319,225	4,903,204	4,575,852	4,369,826	4,340,100	4,249,214	3,509,519	3,884,669
Michigan Gas Storage Co.	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000
Midwestern Gas Transmission Co.[a]	762,090	742,347	724,540	909,446	742,897	744,397	754,055	899,176	755,255	745,597
Natural Gas Pipeline Co. of America[a]	5,821,173	5,756,254	5,756,254	6,241,854	6,109,313	6,061,653	5,975,549	5,789,238	5,657,238	5,450,813
Panhandle Eastern Pipe Line Co.[a]	2,540,173	2,495,729	2,603,294	3,240,222	2,692,940	2,529,538	2,662,717	3,226,964	2,725,278	2,580,112
Trunkline Gas Co.[a]	2,059,353	2,033,043	2,050,362	2,172,524	2,020,556	1,968,610	2,192,426	2,513,750	2,052,074	2,027,489
Viking Gas Transmission Co.	472,401	462,336	478,378	535,006	569,508	574,508	562,858	596,256	481,858	500,336
Total Midwest	**20,238,227**	**21,938,742**	**22,441,220**	**25,871,350**	**22,118,512**	**21,723,771**	**22,152,683**	**25,146,085**	**20,784,151**	**20,800,280**
Release Sample Midwest	15,478,260	15,935,211	16,252,553	20,006,140	16,542,022	16,347,337	16,817,725	19,852,149	16,339,308	15,961,809
Release Sample as a Percent of Total	76%	73%	72%	77%	75%	75%	76%	79%	79%	77%
Northeast										
Algonquin Gas Transmission Co.[a]	1,812,309	1,810,493	1,810,439	1,877,351	1,880,091	1,962,591	1,962,591	2,001,394	1,981,656	1,981,655
Carnegie Interstate Pipeline Co.	85,000	85,000	85,000	85,000	88,300	88,300	88,300	38,000	38,000	38,000
CNG Transmission Corp.[a]	4,750,112	4,755,669	4,753,072	4,818,972	4,779,172	4,748,926	4,748,926	4,865,578	4,859,909	4,849,918
Columbia Gas Transmission Corp.[a]	4,847,885	4,942,941	6,774,126	7,170,793	7,027,913	4,904,448	6,837,765	7,654,259	5,472,517	5,271,781
Equitrans, L.P.	358,798	366,798	372,914	738,879	383,319	381,344	387,094	738,510	373,169	374,771
Granite State Gas Transmission, Inc.	177,367	177,367	177,367	177,367	177,367	177,367	177,367	177,367	177,367	177,367
Iroquois Gas Transmission System, L.P.	827,470	878,045	852,556	971,756	1,001,350	1,001,350	972,182	935,067	966,997	1,115,482
Kentucky West Virginia Gas Co.	138,442	138,442	138,442	138,442	138,442	138,442	138,442	103,235	71,414	103,442
National Fuel Gas Supply Corp.	1,853,613	1,769,181	1,792,405	1,880,051	1,812,476	1,814,476	1,814,476	1,840,432	1,874,323	1,888,276
NORA Transmission Co.	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000
Tennessee Gas Pipeline Co.[a]	5,655,492	5,348,525	5,247,581	5,372,776	5,359,628	5,325,983	5,243,812	5,424,504	5,393,603	5,242,068
Texas Eastern Transmission Corp.[a]	4,098,907	4,499,641	4,502,947	4,743,049	4,607,968	4,598,686	4,598,936	4,856,062	4,794,486	4,793,156
Transcontinental Gas Pipe Line Corp.[a]	5,518,592	5,658,409	5,854,482	5,912,461	5,830,988	5,830,988	5,830,988	6,022,325	6,022,327	6,117,602
Total Northeast	**30,158,987**	**30,465,511**	**32,396,331**	**33,921,897**	**33,122,014**	**31,007,901**	**32,835,879**	**34,691,733**	**32,060,768**	**31,988,518**
Release Sample Northeast	26,683,297	27,015,678	28,942,647	29,895,402	29,485,760	27,371,622	29,223,018	30,824,122	28,524,498	28,256,180
Release Sample as a Percent of Total	88%	89%	89%	88%	89%	88%	89%	89%	89%	88%
Southeast										
Chandeleur Pipe Line Co.	280,000	280,000	280,000	280,000	280,000	280,000	280,000	280,000	280,000	280,000
Columbia Gulf Transmission Co.[a]	3,345,481	3,378,889	3,298,911	3,672,394	3,297,278	3,366,545	3,309,980	3,581,090	3,265,529	3,197,179
East Tennessee Natural Gas Co.[a]	598,106	602,706	489,273	640,667	639,911	526,316	526,316	675,601	645,264	645,264
Florida Gas Transmission Co.[a]	1,532,921	1,529,790	1,530,335	1,555,495	1,543,451	1,548,358	1,505,867	1,568,445	1,541,451	1,533,594
KO Transmission Co.	0	221,000	221,000	221,000	221,000	221,000	221,000	221,000	221,000	221,000
Midcoast Interstate Transmission Inc. (aka Ala-Tenn)	132,502	133,774	132,502	132,502	132,502	132,502	132,502	157,844	157,844	157,844
Mobile Bay Pipeline Co.	27,885	27,885	30,085	27,885	27,885	27,885	27,885	27,885	27,885	27,885
South Georgia Natural Gas Co.	114,341	117,775	121,246	121,246	121,246	128,456	122,276	120,834	122,276	122,276
Southern Natural Gas Co.[a]	2,557,874	2,664,132	2,376,091	2,355,491	2,349,826	2,395,746	2,393,950	2,433,292	2,433,292	2,433,343
Texas Gas Transmission Corp.[a]	1,042,048	1,050,249	1,077,658	1,317,318	1,130,581	1,136,381	1,136,381	1,428,009	1,215,903	1,229,907
Total Southeast	**9,631,158**	**10,006,200**	**9,557,101**	**10,323,998**	**9,743,680**	**9,763,189**	**9,656,157**	**10,494,000**	**9,910,444**	**9,848,292**
Release Sample Southeast	9,076,430	9,225,766	8,772,268	9,541,365	8,961,047	8,973,346	8,872,494	9,686,437	9,101,439	9,039,287
Release Sample as a Percent of Total	94%	92%	92%	92%	92%	92%	92%	92%	92%	92%

Table D3. Firm Transportation Capacity by Region and Pipeline Company, April 1, 1996 - July 1, 1998 (Continued)

(Million Btu per Day)

Region / Pipeline Company	April 1, 1996	July 1, 1996	October 1, 1996	January 1, 1997	April 1, 1997	July 1, 1997	October 1, 1997	January 1, 1998	April 1, 1998	July 1, 1998
Southwest										
Black Marlin Pipeline Co.	250,383	238,588	236,841	239,500	273,000	254,678	257,500	247,750	114,806	83,288
High Island Offshore System	215,460	215,460	215,460	215,460	215,460	215,460	215,460	215,460	215,460	21,280
Koch Gateway Pipeline Co.	2,370,751	2,802,208	2,869,350	2,958,159	2,761,641	2,142,847	2,252,362	2,913,579	2,399,711	2,261,610
Mid Louisiana Gas Co.	120,655	91,489	120,479	306,936	121,187	95,415	134,353	235,047	146,476	127,563
Noram Gas Transmission Co.[a]	2,729,150	2,603,982	2,369,066	2,699,430	2,706,241	2,730,790	2,644,103	2,561,322	2,498,360	2,632,318
Oktex Pipeline Co.	33,600	33,600	33,600	33,600	33,600	33,600	33,600	33,600	33,600	33,600
Ozark Gas Transmission System	124,333	133,198	135,141	114,353	64,808	55,433	55,455	143,261	50,698	38,249
Sabine Pipe Line Co.	185,000	185,000	185,000	185,000	185,000	185,000	185,000	215,000	195,000	215,000
Sea Robin Pipeline Co.	159,275	157,608	157,608	144,218	144,218	70,058	124,648	321,981	315,565	411,829
Stingray Pipeline Co.	167,181	187,181	187,181	265,931	192,259	192,259	197,259	154,043	154,043	154,043
Total Southwest	**6,355,788**	**6,648,314**	**6,509,726**	**7,162,587**	**6,697,414**	**5,975,540**	**6,099,740**	**7,041,043**	**6,123,719**	**5,978,780**
Release Sample Southwest	2,729,150	2,603,982	2,369,066	2,699,430	2,706,241	2,730,790	2,644,103	2,561,322	2,498,360	2,632,318
Release Sample as a Percent of Total	43%	39%	36%	38%	40%	46%	43%	36%	41%	44%
West										
El Paso Natural Gas Co.[a]	3,978,504	4,133,498	4,387,216	4,252,412	4,747,618	4,352,880	4,402,341	4,583,904	4,603,819	4,738,219
Kern River Gas Transmission Co.	730,000	751,900	751,900	726,150	751,900	751,900	751,900	793,306	782,800	762,200
Mojave Pipeline Co.	392,600	395,500	395,500	395,500	395,500	395,500	395,500	395,500	395,500	392,600
Northwest Pipeline Corp.[a]	3,533,131	3,590,848	3,842,248	3,653,740	3,300,087	3,293,221	3,304,681	3,524,791	3,324,971	3,342,393
Pacific Gas Transmission Co.[a]	2,847,102	2,827,102	2,827,102	2,783,205	2,728,227	2,928,714	2,868,710	2,870,839	2,970,320	2,956,278
Pacific Interstate Offshore Co.	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000
Paiute Pipeline Co.[a]	138,780	138,780	138,780	229,584	138,780	138,780	138,780	229,807	138,780	75,075
Riverside Pipeline Co., L.P.	130,000	130,000	130,000	130,000	130,000	130,000	130,000	130,000	130,000	130,000
Transwestern Pipeline Co.[a]	2,536,948	2,546,444	3,155,475	2,529,600	2,187,063	2,182,660	2,178,710	2,340,930	2,413,745	2,724,795
Tuscarora Gas Transmission Co.	106,250	106,250	106,250	107,710	117,210	168,010	168,110	168,210	168,210	169,760
Total West	**14,428,315**	**14,655,322**	**15,769,471**	**14,842,901**	**14,531,385**	**14,376,665**	**14,373,732**	**15,072,287**	**14,963,145**	**15,326,320**
Release Sample West	13,034,465	13,236,672	14,350,821	13,448,541	13,101,775	12,896,255	12,893,222	13,550,271	13,451,635	13,836,760
Release Sample as a Percent of Total	90%	90%	91%	91%	90%	90%	90%	90%	90%	90%
Total United States	**92,070,891**	**94,714,571**	**98,177,046**	**103,876,928**	**97,980,181**	**94,522,992**	**97,400,223**	**105,446,271**	**96,515,955**	**96,543,773**
Release Sample United States	**75,365,065**	**76,204,029**	**79,360,332**	**84,511,966**	**79,779,289**	**77,281,020**	**79,465,069**	**85,837,271**	**79,077,710**	**78,937,100**
Release Sample as a Percent of Total	**82%**	**80%**	**81%**	**81%**	**81%**	**82%**	**82%**	**81%**	**82%**	**82%**
Pipeline Companies Excluded from Sample										
Caprock Pipeline Co.	-	-	-	-	-	-	300,000	300,000	300,000	300,000
Cove Point LNG	-	-	-	-	-	-	-	-	-	-
Discovery Gas	-	-	-	-	-	-	-	-	179,452	179,452
Eastern Shore Natural Gas Co.	-	-	-	-	-	-	-	-	69,112	59,112
Garden Banks Gas Co.	-	-	-	-	-	304,000	346,080	485,130	485,130	488,220
Natilus Pipeline Co.	-	-	-	-	-	-	-	185,367	265,696	276,769
Northern Natural Gas Co.	4,813,245	5,020,287	5,267,012	6,671,617	4,776,740	4,974,657	6,404,875	6,765,573	4,662,053	5,323,507[c]
Nova Gas Transmission Ltd.	-	-	-	-	-	-	-	-	-	-
Overthrust Pipeline Co.	-	-	-	91,183,584	84,556,030	82,559,678	86,516,025	93,573,342	85,039,154	80,240,654
PG&E Gas Transmission	-	-	-	-	-	-	-	-	-	-
Shell Gas Pipeline	-	-	-	5,150	5,150	5,150	92,700	97,850	149,350	149,350
Transcolorado	-	-	-	90,000	92,139	90,000	90,000	90,000	90,000	133,000
U-T Offshore System	-	-	-	-	-	-	-	-	-	-
Venice Gathering	-	-	-	-	-	-	-	591,530	601,714	631,260
Westcoast Energy Inc.	-	-	-	-	-	-	-	-	-	-
Western Gas Interstate	-	-	-	-	-	31,250	32,050	31,250	31,250	-

[a]Only these companies were used in the analysis of capacity release data.

[b]Northern Border April 1, 1998 data used as an estimate for July 1, 1998.

[c]In the July 1, 1998 filing, Northern Natural segmented its capacity. Thus, the total capacity should not be compared to that of other quarters.

Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers quarterly filings for April 1, 1996 through July 1, 1998, FERC Bulletin Board (August 14, 1998).

Table D4. Number of Firm Transportation Contracts by Region and Pipeline Company, April 1, 1996 - July 1, 1998

Region / Pipeline Company	April 1, 1996	July 1, 1996	October 1, 1996	January 1, 1997	April 1, 1997	July 1, 1997	October 1, 1997	January 1, 1998	April 1, 1998	July 1, 1998
Central										
Canyon Creek Compression Co.	6	5	5	5	5	5	5	5	5	5
Colorado Interstate Gas Co.	84	91	107	112	112	120	128	132	137	142
K N Interstate Gas Transmission Co.	51	49	55	42	40	41	42	39	38	35
MIGC, Inc.	1	1	1	2	2	2	2	3	3	3
Mississippi River Transmission Corp.[a]	106	109	107	109	110	106	110	109	105	104
Northern Border Pipeline Co.[a]	40	40	40	40	41	41	40	42	43	432[b]
Questar Pipeline Co.	25	24	23	25	24	24	27	33	30	30
Trailblazer Pipeline Co.[a]	18	23	23	27	30	30	25	25	25	25
Westgas Interstate Inc	4	4	4	4	4	4	4	4	4	4
Williams Natural Gas Co.[a]	181	184	194	201	219	216	221	242	227	243
Williston Basin Interstate Pipeline Co.	17	17	16	28	21	12	16	23	14	14
Wyoming Interstate Co, Ltd.	9	9	9	30	11	11	20	23	23	23
Total Central	**542**	**556**	**584**	**625**	**619**	**612**	**640**	**680**	**654**	**1,060**
Release Sample Central	429	447	471	489	512	513	524	550	537	946
Release Sample as a Percent of Total	79%	80%	81%	78%	83%	84%	82%	81%	82%	89%
Midwest										
ANR Pipeline Co.[a]	196	211	230	284	233	255	259	317	258	266
Crossroads Pipeline Co.	6	5	6	5	7	7	7	8	8	8
Great Lakes Gas Transmission, L.P.	68	74	77	86	86	74	83	69	58	66
Michigan Gas Storage Co.	2	2	2	2	2	2	2	2	2	2
Midwestern Gas Transmission Co.[a]	19	20	19	32	18	19	20	26	20	19
Natural Gas Pipeline Co. of America[a]	214	210	210	210	208	211	211	230	219	212
Panhandle Eastern Pipe Line Co.[a]	203	202	211	225	219	212	216	226	216	207
Trunkline Gas Co.[a]	114	109	114	120	115	111	114	119	104	102
Viking Gas Transmission Co.	34	37	35	45	46	47	41	50	39	42
Total Midwest	**856**	**870**	**904**	**1,009**	**934**	**938**	**953**	**1,047**	**924**	**924**
Release Sample Midwest	746	752	784	871	793	808	820	918	817	806
Release Sample as a Percent of Total	87%	86%	87%	86%	85%	86%	86%	88%	88%	87%
Northeast										
Algonquin Gas Transmission Co.[a]	144	143	143	152	147	148	148	135	126	126
Carnegie Interstate Pipeline Co.	5	5	5	5	6	6	6	3	3	3
CNG Transmission Corp.[a]	113	117	121	127	125	123	123	134	131	130
Columbia Gas Transmission Corp.[a]	212	218	211	263	217	209	205	301	275	278
Equitrans, L.P.	25	26	29	30	26	28	29	33	27	28
Granite State Gas Transmission,inc.	6	6	6	6	6	6	6	6	6	6
Iroquois Gas Transmission System, L.P.	36	37	34	43	44	44	44	41	43	49
Kentucky West Virginia Gas Co.	15	15	15	15	15	15	15	16	15	14
National Fuel Gas Supply Corp.	51	52	54	77	58	60	60	62	68	70
NORA Transmission Co.	1	1	1	1	1	1	1	1	1	1
Tennessee Gas Pipeline Co.[a]	483	452	441	450	448	448	450	460	456	455
Texas Eastern Transmission Corp.[a]	321	324	325	347	339	341	342	354	350	347
Transcontinental Gas Pipe Line Corp.[a]	324	323	323	324	324	324	324	347	348	350
Total Northeast	**1,736**	**1,719**	**1,708**	**1,840**	**1,756**	**1,753**	**1,753**	**1,893**	**1,849**	**1,857**
Release Sample Northeast	1,597	1,577	1,564	1,663	1,600	1,593	1,592	1,731	1,686	1,686
Release Sample as a Percent of Total	92%	92%	92%	90%	91%	91%	91%	91%	91%	91%
Southeast										
Chandeleur Pipe Line Co.	4	4	4	4	4	4	4	6	6	6
Columbia Gulf Transmission Co.[a]	136	134	133	135	126	129	128	134	133	131
East Tennessee Natural Gas Co.[a]	79	79	82	94	94	93	93	109	99	99
Florida Gas Transmission Co.[a]	89	88	87	90	90	90	90	103	110	105
KO Transmission Co.	89	2	2	2	2	2	2	2	2	2
Midcoast Interstate Transmission Inc. (aka Ala-Tenn)	31	33	32	32	32	32	32	42	42	42
Mobile Bay Pipeline Co.	1	1	1	1	1	1	1	1	1	1
South Georgia Natural Gas Co.	48	48	49	49	49	50	50	50	50	50
Southern Natural Gas Co.[a]	335	342	334	350	348	348	346	354	354	353
Texas Gas Transmission Corp.[a]	78	81	88	98	93	94	94	108	94	97
Total Southeast	**890**	**812**	**812**	**855**	**839**	**843**	**840**	**909**	**891**	**886**
Release Sample Southeast	717	724	724	767	751	754	751	808	790	785
Release Sample as a Percent of Total	81%	89%	89%	90%	90%	89%	89%	89%	89%	89%

Table D4. Number of Firm Transportation Contracts by Region and Pipeline Company, April 1, 1996 - July 1, 1998 (Continued)

Region / Pipeline Company	April 1, 1996	July 1, 1996	October 1, 1996	January 1, 1997	April 1, 1997	July 1, 1997	October 1, 1997	January 1, 1998	April 1, 1998	July 1, 1998
Southwest										
Black Marlin Pipeline Co.	4	4	4	5	5	5	5	4	4	2
High Island Offshore System	2	2	2	2	2	2	2	2	2	1
Koch Gateway Pi peline Co.	184	191	189	195	187	188	201	210	201	205
Mid Louisiana Gas Co.	35	35	60	60	60	61	61	62	62	61
Noram Gas Transmission Co.[a]	247	231	230	245	256	253	253	259	234	241
Oktex Pipeline Co.	2	2	2	2	2	2	2	2	2	2
Ozark Gas Transmission System	7	7	7	7	5	5	5	6	4	4
Sabine Pipe Line Co.	4	5	5	6	6	6	6	7	6	7
Sea Robin Pipeline Co.	8	7	7	7	7	6	9	8	9	16
Stingray Pipeline Co.	6	6	6	9	9	9	10	9	9	9
Total Southwest	499	490	512	538	539	537	554	569	533	548
Release Sample Southwest	247	231	230	245	256	253	253	259	234	241
Release Sample as a Percent of Total	49%	47%	45%	46%	47%	47%	46%	46%	44%	44%
West										
El Paso Natural Gas Co.[a]	36	44	49	47	150	45	48	49	48	56
Kern River Gas Transmission Co.	17	18	16	15	16	16	16	21	21	17
Mojave Pipeline Co.	7	8	8	8	8	8	8	8	8	8
Northwest Pipeline Corp.[a]	130	135	140	141	131	133	136	134	143	149
Pacific Gas Transmission Co.[a]	60	59	59	69	60	89	76	88	84	84
Pacific Interstate Offshore Co.	1	1	1	1	1	1	1	1	1	1
Paiute Pipeline Co.	13	13	13	13	13	13	13	13	13	9
Riverside Pipeline Co., L.P.	3	3	3	3	3	3	3	3	3	3
Transwestern Pipeline Co.[a]	94	92	106	92	86	83	84	87	92	104
Tuscarora Gas Transmission Co.	7	7	7	10	10	12	13	14	12	13
Total West	368	380	402	399	478	403	398	418	425	444
Release Sample West	333	343	367	362	440	363	357	371	380	402
Release Sample as a Percent of Total	90%	90%	91%	91%	92%	90%	90%	89%	89%	91%
Total United States	4,891	4,827	4,922	5,266	5,165	5,086	5,138	5,516	5,276	5,719
Release Sample United States	4,069	4,074	4,140	4,397	4,352	4,284	4,297	4,637	4,444	4,866
Release Sample as a Percent of Total	83%	84%	84%	83%	84%	84%	84%	84%	84%	85%
Pipeline Companies Excluded from Sample										
Caprock Pipeline Co.	-	-	-	-	-	-	1	1	1	1
Cove Point LNG	-	-	-	-	-	-	-	-	-	-
Discovery Gas	-	-	-	-	-	-	-	-	4	4
Eastern Shore Natural Gas Co.	-	-	-	-	-	-	-	-	36	35
Garden Banks Gas Co.	-	-	-	-	-	2	2	2	2	3
Natilus Pipeline Co.	-	-	-	-	-	-	-	3	3	3
Northern Natural Gas Co.	239	258	284	304	248	264	279	311	268	301[c]
Nova Gas Transmission Ltd.	-	-	-	-	-	-	-	-	-	-
Overthrust Pipeline Co.	-	-	-	-	-	-	-	-	-	-
PG&E Gas Transmission	-	-	-	-	-	-	-	-	-	-
Shell Gas Pipeline	-	-	-	1	1	1	5	6	7	7
Transcolorado	-	-	-	2	3	2	2	2	2	4
U-T Offshore System	-	-	-	-	-	-	-	-	-	-
Venice Gathering	-	-	-	-	-	-	-	12	12	12
Westcoast Energy Inc.	-	-	-	-	-	-	-	-	-	-
Western Gas Interstate	-	-	-	-	-	3	3	3	3	-

[a]Only these companies were used in the analysis of capacity release data.

[b]Northern Border April 1, 1998 data used as an estimate for July 1, 1998.

[c]In the July 1, 1998 filing, Northern Natural segmented its capacity. Thus, the number of contracts should not be compared to that of other quarters.

Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers quarterly filings for April 1, 1996 through July 1, 1998, FERC Bulletin Board (August 14, 1998).

Table D5. Long-Term Firm Capacity on April 1, 1996, and 12-Month Changes by Region
(Billion Btu per Day)

		12-Month Change in Capacity							
		4/1/96 - 4/1/97		7/1/96 - 7/1/97		10/96 - 10/97		1/1/97 - 1/1/98	
Region	Long-Term Firm Capacity on 4/1/96	Amount	Percent	Amount	Percent	Amount	Percent	Amount	Percent
Central	9,493	642	7	954	10	675	6	1,723	17
Midwest	17,426	1,528	9	605	3	849	5	222	1
Northeast	28,738	2,845	10	362	1	-515	-2	644	2
Southeast	8,854	312	4	264	3	139	2	435	5
Southwest	5,181	-142	-3	-718	-14	-869	-16	-97	-2
West	13,223	-90	-1	-31	0	-140	-1	441	3
Total	82,915	5,096	6	1,436	2	139	0	3,368	4

Notes: Long-term contracts are longer than 366 days. Data are for 64 interstate pipeline companies. Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers quarterly filings for April 1, 1996 through January 1, 1998, FERC Bulletin Board (August 14, 1998).

Table D6. Long-Term Firm Capacity on April 1, 1996, and Significant 12-Month Changes by Pipeline Company
(Billion Btu per Day)

		Long-Term Firm Capacity on 4/1/96		12-Month Change in Capacity							
				4/1/96 - 4/1/97		7/1/96 - 7/1/97		10/96 - 10/97		1/1/97 - 1/1/98	
Pipeline Company	Region	Amount	Percent of Region	Amount	Percent	Amount	Percent	Amount	Percent	Amount	Percent
Algonquin	Northeast	1,738	6	-164	-9	-82	-5	-111	-6	185	12
Koch Gateway	Southwest	2,361	46	-78	-3	-672	-29	-674	-28	-79	-3
Noram Gas	Southwest	2,064	40	-83	-4	-87	-4	-63	-3	96	5
Northwest	West	3,382	26	-426	-13	-387	-12	-161	-5	-129	-4
Pacific Gas	West	2,847	22	-129	-5	-72	-3	-72	-3	37	1

Note: Long-term contracts are longer than 366 days.

Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers quarterly filings for April 1, 1996 through January 1, 1998, FERC Bulletin Board (August 14, 1998).

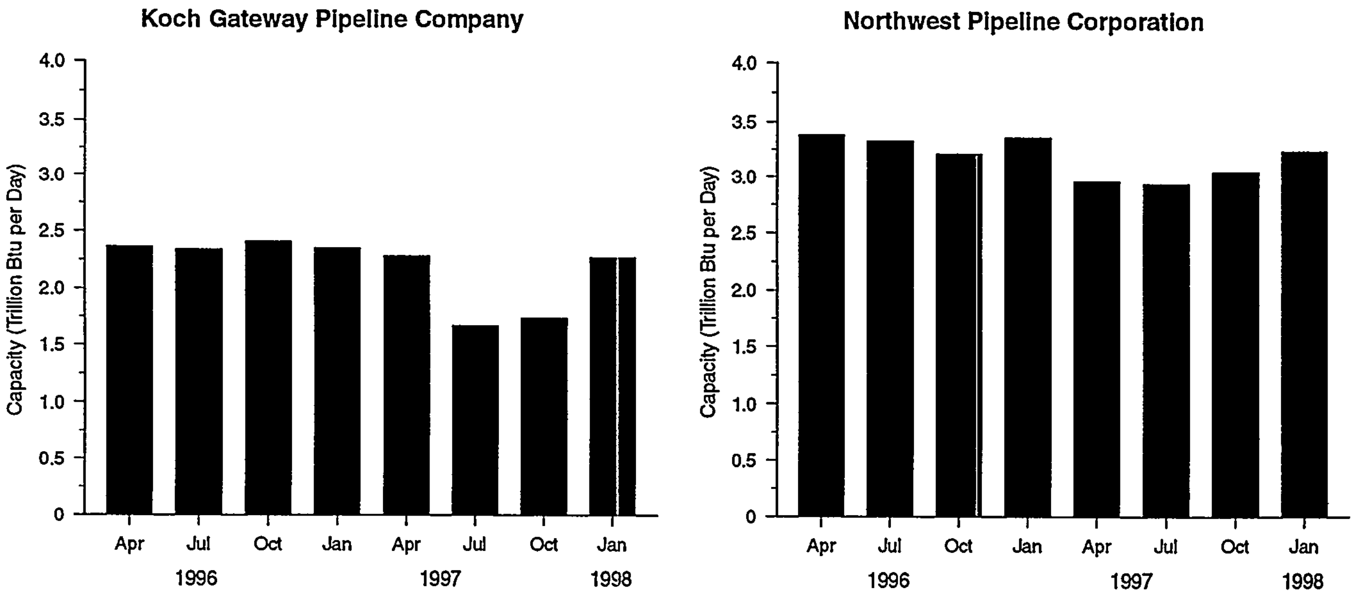
had the largest declines in capacity, so the shippers on these systems were examined for evidence of turnback.

Koch Gateway Pipeline Company

Koch Gateway had the largest 12-month declines in capacity held on its system, in both absolute and percentage terms, of any pipeline company in the study. The long-term firm capacity on Koch ranged from 2,300 to 2,400 billion Btu per day in most quarters. But it fell to about 1,700 billion Btu per day in the July 1997 and October 1997 quarters, causing the large declines seen in the 12-month comparisons (Figure D1). These declines on Koch accounted for the majority of the declines seen in the Southwest Region as a whole. Koch accounted for 46 percent of the long-term firm capacity held in the Southwest Region on April 1, 1996.

Koch provided long-term firm transportation capacity to 130 different shippers during the eight-quarter period, however, most of the decline in capacity seen in the July and October comparisons was caused by four shippers: an intrastate pipeline company and three local distribution companies (LDCs). The largest decline came from the intrastate pipeline company, Entex. Entex had fairly steady capacity levels of roughly 550 billion Btu per day during the first five quarters, but capacity was significantly lower in the July 1997 and October 1997 quarters. This resulted

Figure D1. Long-Term Firm Transportation Capacity on Two Pipeline Companies at the Beginning of Each Quarter, April 1, 1996 - July 1, 1998



Note: Long-term contracts are longer than 366 days.
Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers quarterly filings for April 1, 1996 through January 1, 1998, FERC Bulletin Board (August 14, 1998).

in declines of 234 and 212 billion Btu per day, respectively, in the July and October comparisons. However, in the January 1998 quarter, Entex increased its long-term capacity on Koch back to the levels held previously.

One LDC, New Orleans Public Service, held 100 billion Btu per day of long-term firm capacity on Koch for the first three quarters, but then turned it all back, having zero long-term capacity on Koch in the remaining quarters of the period. Thus, New Orleans Public Service turned back capacity on Koch and contributed 100 billion Btu per day in capacity declines in the April, July, and October comparisons.

The two other LDCs had a pattern similar to that of Entex—their capacity dropped in the July 1997 and October 1997 quarters, but increased to earlier levels in the January 1998 quarter. Louisiana Gas Service and Mississippi Valley Gas contributed 106 and 81 billion Btu per day, respectively, to the decline in capacity shown in the July comparisons and 82 and 62 billion Btu per day, respectively, in the October comparisons.

Of these four shippers, New Orleans Public Service was clearly a case of turnback on Koch. The other three shippers may have also been examples of turnback if the drops in capacity were the result of contracts ending prior to July 1, 1997. Together, these four shippers had declines in capacity totaling 521 and 456 billion Btu per day in the 12-month comparisons for July and October, respectively. This is equivalent to 78 and 68 percent, respectively, of the net decline on Koch's system for those quarters.

Northwest Pipeline Corporation

Northwest Pipeline is second only to Koch Gateway in terms of the amount and percentage declines in capacity shown in the 12-month comparisons, indicating the strong possibility that turnback has occurred on the Northwest system. Northwest Pipeline had 3,382 billion Btu per day of long-term firm capacity on April 1, 1996, accounting for 26 percent of the capacity held in the West Region. The quarterly capacity on Northwest did not decline as dramatically as it did on Koch, but capacity was lower during the April 1997 and July 1997 quarters than during the other quarters (Figure D1).

Northwest had 74 different shippers during the eight-quarter period, but much of the decline seen in the 12-month comparisons for April and July was caused by capacity turnback on the part of only four shippers. Enron

Capital & Trade Resources and Williams Energy Services, both marketers, had 114 and 100 billion Btu per day of long-term firm capacity, respectively, on Northwest in the first two quarters, then had no capacity on Northwest in the remaining quarters.[2] Intermountain Gas Co., an LDC, had 102 billion Btu per day of capacity on Northwest in the first five quarters, but this changed to zero in July 1997 and subsequent quarters. And finally, Engage Energy, U.S. (the shipper type could not be determined) had 70 billion Btu per day of long-term firm capacity on Northwest during the first three quarters, but turned this capacity back, having no long-term capacity beginning with the January 1997 quarter. These four shippers turned back a total of 284 billion Btu per day of capacity on Northwest as of the October 1996 quarter and a total of 386 billion Btu per day as of the January 1997 quarter. Thus, they account for a significant proportion of the net decline in long-term capacity on Northwest shown in the 12-month comparisons for April and July.

As these examples on Koch Gateway and Northwest indicate, some turnback of capacity did take place during the eight quarters examined. While on Northwest, long-term capacity was reduced to zero on the part of some shippers, on Koch, capacity was turned back for several quarters, then resubscribed by those same shippers in later quarters.

Individual Shipper Analysis

The analysis of the contracting behavior of individual shippers in Chapter 6 is based on a sample of 54 unique shipper-pipeline pairs representing those shippers who held the largest long-term contracts that expired during the period April 1, 1996, through March 31, 1998, in each of six U.S. regions.[3] The sample of shippers for this analysis was selected by identifying the 10 largest long-term firm transportation capacity contracts that expired between April 1, 1996, and March 31, 1998, in each region.

The number of expired contracts analyzed in the Midwest Region was increased to ensure that the analysis included at least 50 percent of the capacity that expired between April 1, 1996, and March 31, 1998, in each region (Figure D2). In the Midwest Region, the top 10 expired contracts represent only 30 percent of the expired capacity for the region. The next 10 largest expired long-term contracts were added to the regional analysis to arrive at 51 percent of the expired capacity. The analysis of shippers in the Central Region included 14 expired contracts, which represents 70 percent of the total expired long-term capacity in that region.[4]

The contracts with the largest amount of expired capacity provided the shipper name, pipeline name, and the quarter during which the capacity expired. The analysis then identified any other contracts needed to assemble the complete picture of the shipper's total capacity contracts with the pipeline company that expired during the selected quarter. This step only changed the total number of expired contracts for the Southeast and Southwest regions. The inclusion of additional expired contracts increased the number of contracts analyzed in the Southeast and Southwest from the original 10 to 11 and 13, respectively.

Once the sample of shippers and their expired long-term capacity contracts were assembled, the analysis identified the shipper reactions to contract expiration. Using the next quarterly index of customer filing, all of the shippers new capacity contracts with the pipeline company were identified and compared with the capacity, term, and service under the expired contracts (Tables D7 and D8).

Changes in a shipper's number of contracts and amount of capacity reserved were easy to determine. However, determining whether a shipper changed the length (term) of a contract was more difficult to assess. In some cases, shippers may have increased the length of some contracts while reducing the length of others during the same quarter. Thus, this analysis weighted the length by the amount of the capacity for each contract to arrive at a weighted average contract length for the shipper's transportation portfolio before and after the contract expiration.

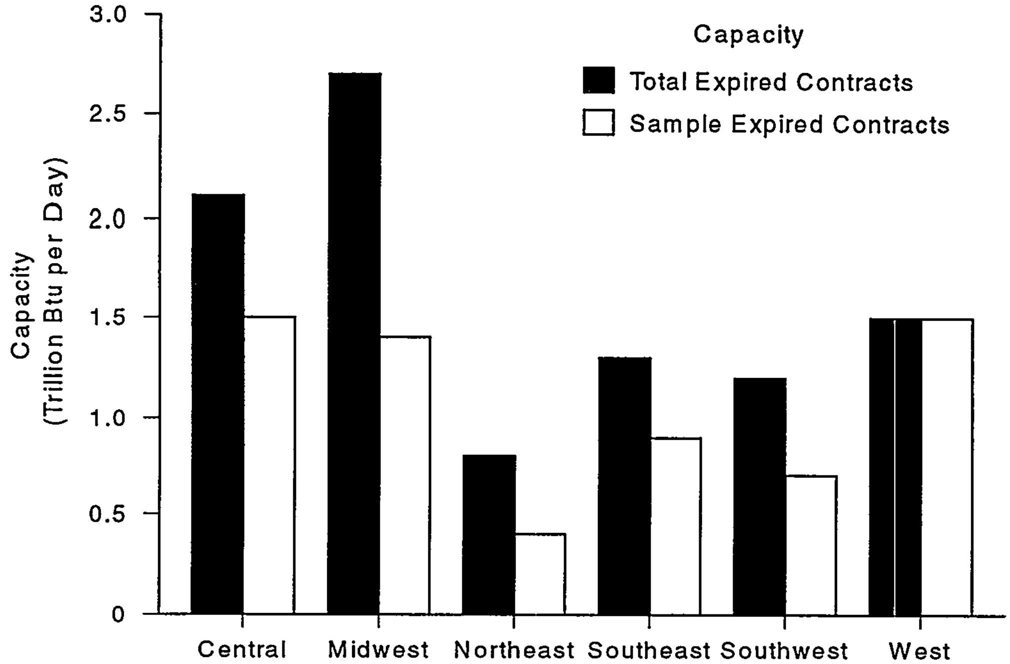
In some cases, the beginning date of a new contract was difficult to determine as several companies reported the same beginning date for both the expired and the new contracts. In such cases, the effective start date for the new

[2]Both companies switched their long-term capacity to the same volume of short-term capacity for the October 1, 1997, quarter. After this, Enron had no capacity on Northwest and Williams had either 0 or 27 billion Btu per day of short-term capacity.

[3]This analysis uses the FERC Index of Customers data for each quarter from April 1996 through July 1998. Each quarterly filing provides the contracts due to expire during the 3 months following the first day of the quarter and all new contracts since the first day of the previous quarter.

[4]Because of a change in its filing method, Northern Natural Pipeline Company was excluded from the Index of Customer data for the analysis. The sample of the 10 largest contracts was determined from the remaining contracts. This resulted in seven shipper-pipeline pairs with 14 contracts.

Figure D2. Regional Capacity Associated With Long-Term Contract Expirations, April 1, 1996 - March 31, 1998, Total and Sample



Notes: Total expired contracts are for 64 interstate pipeline companies. The sample contracts were selected from the expired contracts with these companies resulting in 54 unique shipper/pipeline pairs. Long-term contracts are longer than 366 days.

Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers quarterly filings for April 1, 1996 through January 1, 1998, FERC Bulletin Board (August 14, 1998).

contract was assumed to be the day following the end date of the expired contract. The revisions to the start dates were necessary to avoid the false increases in contract length that otherwise would have occurred.

Assessment of Potential Turnback

To assess potential future capacity turnback, capacity release information was combined with contracted firm capacity data as reported during the period April 1, 1996, through July 1, 1998. To obtain a consistent set of data on both capacity from the Index of Customers and on capacity release, the set of 64 pipeline companies was reduced to 27. These 27 companies accounted for 82 percent of the firm capacity held by the original set of 64 companies as of July 1, 1998 (Table D3).

The smallest amount of daily capacity held by replacement shippers in each region during the heating seasons 1996-97 and 1997-98 was used to estimate the percentage of that region's firm contracted capacity that can reasonably be expected to be turned back as shipper contracts expire. The regional share was calculated by dividing the smallest daily capacity release amount by the total contracted firm transportation capacity held under contract during the same day for the sample of 27 pipeline companies. Two turnback ratios were developed for each region since the released and firm contracted capacity data spanned two heating seasons. The smaller of the two was selected as the regional ratio in order to provide the more conservative estimate.

These regional turnback ratios from the sample of 27 pipeline companies were then multiplied by the amount of long-term firm transportation capacity under contract in each region as of July 1, 1998, for all 64 pipeline companies in the analysis in order to estimate the regional capacity turnback. It is unlikely that expiration of short-term contracts will result in a long-term turnback of transportation capacity. Therefore, all significant turnbacks were assumed to result from the expiration of long-term contracts. The regional capacity turnback estimates were summed to arrive at an estimate of the total amount of capacity that may be turned back to pipeline companies in the future.

An estimate of the timing of these turnbacks was also determined to assess the impact of the capacity turnback on the transportation markets. Because the specific firm transportation contracts associated with the released capacity cannot be identified, the respective turnback ratio was multiplied by each region's amount of long-term capacity expiring each year to calculate the regional turnback profiles. The six regional turnback profiles were combined to arrive at a national capacity turnback profile. It may be likely that a greater proportion of early expirations will be turned back than later expirations, but without more specific data, applying the turnback ratio as a constant provides a baseline national profile that can be used to assess the potential impact of capacity turnback on the natural gas industry.

Table D7. Characteristics of Expired and New Contracts for 54 Sampled Shipper/Pipeline Pairs

Central Region

Shipper/ Pipeline Co.	Sample Contracts due to Expire April 1, 1996 - March 31,1998					New Contracts Following Expiration					Change in Capacity	Change in Length of Contract (years)
	Quarter	Contracted Capacity (MMBtu/d)	Begin Date	End Date	Rate Schedule	Quarter	Contracted Capacity (MMBtu/d)	Begin Date	End Date	Rate Schedule		
Public Service of Colorado/ Colorado Interstate Gas Company												
	Jul 96	543,066	10/01/93	09/30/96	NNT-1	Oct 96	420,200	10/01/96	04/30/02	NNT-1	(122,866)	2.58
	Jul 96	149,880	10/01/93	09/30/96	TF-2	Oct 96	114,480	10/01/96	05/31/25	TF-2	(35,400)	25.68
						Oct 96	35,000	10/01/96	09/30/06	TF-2	35,000	10.00
						Oct 96	277,092	10/01/96	09/30/01	TF-1	277,092	5.00
						Oct 96	49,371	10/01/96	08/31/97	TF-1	49,371	0.92
						Oct 96	8,387	10/01/96	12/31/06	TF-1	8,387	10.25
						Oct 96	156,000	10/01/96	04/30/02	TF-3	156,000	5.58
Montana-Dakota Utilities Co./ Williston Basin P L Co.												
	Apr 97	239,159	11/01/93	06/30/97	FT-1	Jul 97	291,673	07/01/97	06/30/02	FT-1	52,514	1.34
	Apr 97	52,515	07/01/88	06/30/97	FT-1						(52,515)	(9.00)
	Apr 97	119,135	11/01/93	06/30/97	FTN-1	Jul 97	119,135	07/01/97	06/30/02	FTN-1	0	1.34
KN Energy, Inc./ KN Interstate Gas Transmission Co.												
	Jul 97	136,313	10/01/93	09/30/97	FT	Oct 97	136,313	10/01/93	09/30/98	FT	0	(3.00)
Anthem Energy/KN Interstate Gas Transmission Co.												
	Jul 96	50,000	10/01/93	08/31/96	FT	Oct 96	0				(50,000)*	(2.92)
Colorado Springs Utilities/Colorado Interstate Gas Company												
	Jul 96	40,747	10/01/93	09/30/96	TF-2	Oct 96	14,045	10/01/96	4/30/02	TF-2	(26,702)	2.58
	Jul 96	29,550	10/01/93	09/30/96	TF-2	Oct 96	12,854	10/01/96	4/30/02	TF-2	(16,696)	2.58
	Jul 96	20,780	10/01/93	09/30/96	NNT-1	Oct 96	62,495	10/01/96	4/30/02	NNT-1	41,715	2.58
	Jul 96	23,135	10/01/93	09/30/96	TF-1	Oct 96	23,135	10/01/96	4/30/02	TF-1	0	2.58
	Jul 96	20,000	11/01/93	09/30/96	TF-1	Oct 96	20,000	10/01/96	9/30/11	TF-1	0	12.09
						Oct 96	19,700	10/01/96	8/31/97	TF-1	19,700	0.92
Granite City Steel/Mississippi River Corp.												
	April 96	34,142	11/01/93	04/30/96	FTS	Jul 97	34,142	5/01/96	4/30/97	FTS	0	(1.50)
Questar Energy Trading/Trailblazer Pipeline Co.												
	Oct 97	31,800	11/01/95	10/31/97	FTS	Jan 98	31,800	11/01/95	10/31/98	FTS	0	(1.00)

See note at end of table.

Table D7. Characteristics of Expired and New Contracts for 54 Sampled Shipper/Pipeline Pairs (Continued)

Midwest Region

Shipper/ Pipeline Co.	Sample Contracts due to Expire April 1, 1996 - March 31,1998					New Contracts Following Expiration					Change in Capacity	Change in Length of Contract (years)
	Quarter	Contracted Capacity (MMBtu/d)	Begin Date	End Date	Rate Schedule	Quarter	Contracted Capacity (MMBtu/d)	Begin Date	End Date	Rate Schedule		
Texas Eastern Transmission Corp./Trunkline Gas Co.												
	Oct 97	150,000	09/01/93	10/31/97	FT	Jan 98	150,000	01/01/98	10/31/99	FT	0	(2.34)
Midcon Gas Services Corp./Natural Gas P L Co. of America												
	Jan 98	97,500	02/01/97	03/31/98	FTS	Apr 98	37,500	02/01/97	03/31/99	FTS	(60,000)	(0.16)
Peoples Gas Light & Coke/Natural Gas P L Co. of America												
	Apr 97	65,000	03/01/96	04/30/97	FTS	Jul 97	30,000	05/01/97	04/30/99	FTS	(35,000)	0.83
	Apr 97	20,000	03/01/96	04/30/97	FTS	Jul 97	0				(20,000)*	(1.16)
	Jan 98	90,000	12/01/95	03/31/98	FTS	Apr 98	90,000	04/01/98	03/31/00	FTS	0	(0.33)
Illinois Power Company/Natural Gas P L Co. of America												
	Oct 96	89,454	11/13/93	11/30/96	FTS	Jan 97	68,545	11/13/93	11/30/98	FTS	(20,909)	(1.05)
						Jan 97	40,000	10/22/96	11/30/02	FTS	40,000	6.11
						Jan 97	40,000	11/05/96	11/30/02	FTS	40,000	6.07
Indiana Gas Company/Panhandle Eastern Pipe Line Co.												
	Jan 97	77,144	05/01/93	03/31/97	FFT	Apr 97	0				(77,144)*	(3.92)
	Jan 97	51,431	05/01/93	02/28/97	EFT	Apr 97	51,431	05/01/93	03/31/99	EFT	0	(1.75)
Illinois Power Company/Panhandle Eastern Pipe Line Co.												
	Apr 96	75,900	05/01/93	04/30/96	EFT	Apr 97	75,900	04/01/96	03/31/99	EFT	0	0.00
Texaco Natural Gas, Inc./Natural Gas P L Co. of America												
	Oct 96	75,000	11/01/94	10/31/96	FTS	Jan 97	75,000	11/01/94	10/31/97	FTS	0	(1.00)
	Oct 97	75,000	11/01/94	10/31/97	FTS	Jan 98	0				(75,000)*	(3.00)
Energy Source, Inc./Panhandle Eastern Pipe Line Co.												
	Oct 96	61,050	09/01/94	10/31/96	FT	Jan 97	0				(61,050)*	(2.17)
	Oct 96	60,000	09/01/94	10/31/96	EFT	Jan 97	25,000	11/01/96	10/31/97	EFT	(35,000)	(1.17)
	Oct 96	10,000	10/01/95	10/31/96	EFT	Jan 97	0				(10,000)*	(1.08)
General Motors Corp./ANR Pipeline Co.												
	Oct 97	60,000	11/01/93	12/31/97	FTS-1	Jan 98	60,000	11/01/93	03/31/01	FTS-1	0	(0.92)
Archer-Daniels-Midland Co./Natural Gas P L Co. of America												
	Oct 96	55,050	11/01/91	11/30/96	FTS	Jan 97	38,525	11/01/96	10/31/99	FTS	(16,525)	(2.09)
						Jan 97	31,525	11/01/96	10/31/99	FTS	31,525	3.00
Shell Offshore, Inc./ANR Pipeline Co.												
	Oct 96	55,000	11/01/93	10/31/96	FTS-1	Jan 97	0				(55,000)*	(3.00)
Proliance Energy, LLC/Panhandle Eastern Pipe Line Co.												
	Jan 97	50,000	05/01/93	03/31/97	EFT	Apr 97	77,144	05/01/93	03/31/00	EFT	27,144	(0.92)
	Jan 97	50,000	05/01/93	03/31/97	FT	Apr 97	51,431	05/01/93	02/29/00	EFT	1,431	(1.00)
						Apr 97	30,113	05/01/93	03/31/98	FT	30,113	4.92
Utilicorp United, Inc./Natural Gas P L Co. of America												
	Jan 98	50,000	11/01/96	03/31/98	FTS	Apr 98	0				(50,000)*	(1.41)
Norcen Explorer, Inc./Trunkline Gas Co.												
	Oct 97	45,000	02/01/96	12/31/97	FT	Jan 98	0				(45,000)*	(1.92)
East Ohio Gas Co./ANR Pipeline Co.												
	Oct 97	43,500	11/01/93	10/31/97	FTS-1	Jan 98	43,000	11/01/93	10/31/00	FTS-1	(500)	(1.00)

See note at end of table.

Table D7. Characteristics of Expired and New Contracts for 54 Sampled Shipper/Pipeline Pairs (Continued)

Northeast Region

Shipper/ Pipeline Co.	Sample Contracts due to Expire April 1, 1996 - March 31,1998					New Contracts Following Expiration					Change in Capacity	Change in Length of Contract (years)
	Quarter	Contracted Capacity (MMBtu/d)	Begin Date	End Date	Rate Schedule	Quarter	Contracted Capacity (MMBtu/d)	Begin Date	End Date	Rate Schedule		
Boston Gas Company/Algonquin Gas Transmission Co.												
	Oct 96	97,059	09/01/94	10/31/96	AFT-1	Jan 97	97,059	11/01/96	11/01/97	AFT-1	0	(1.17)
	Oct 96	48,234	09/01/94	10/31/96	AFT-1	Jan 97	48,234	11/01/96	11/01/97	AFT-1	0	(1.17)
	Oct 96	30,000	09/01/94	10/31/96	AFT-E	Jan 97	30,000	11/01/96	11/01/97	AFT-E	0	(1.17)
Equitable Gas Co./Kentucky West Virginia Gas Co.												
	Oct 96	72,270	12/01/77	11/30/97	FTS	Jan 97	31,821	12/01/97	03/31/98	FTS	(40,449)	(19.68)
						Jan 97	5,242	12/01/97	11/30/98	FTS	5,242	1.00
National Fuel Gas Distribution Co./Tennessee Natural Gas Pipeline Co.												
	Jul 96	30,750	09/01/93	08/01/96	FT-A	Oct 96	0				(30,750)*	(2.92)
Bethlehem Steel Corp./Columbia Gas Transmission Corp.												
	Jan 98	30,707	11/01/93	03/31/98	FTS	Apr 98	30,707	04/01/98	03/31/99	FTS	0	(3.42)
UGI Utilities, Inc./Tennessee Natural Gas Pipeline Co.												
	Apr 96	30,000	09/01/93	06/22/96	FT-A	Jul 96	0				(30,000)*	(2.81)
Bethlehem Steel Corp./Tennessee Natural Gas Pipeline Co.												
	Jan 98	30,000	04/01/94	03/31/98	FT-A	Apr 98	0				(30,000)*	(4.00)
New Jersey Natural Gas/Carnegie Interstate Gas Co.												
	Oct 97	27,000	10/11/95	10/31/97	FTS	Jan 98	0				(27,000)*	(2.06)
PSC of North Carolina/CNG Transmission Corp.												
	Jan 98	25,000	12/01/96	02/28/98	FT	Apr 98	0				(25,000)*	(1.24)

Southeast Region

Shipper/ Pipeline Co.	Sample Contracts due to Expire April 1, 1996 - March 31,1998					New Contracts Following Expiration					Change in Capacity	Change in Length of Contract (years)
	Quarter	Contracted Capacity (MMBtu/d)	Begin Date	End Date	Rate Schedule	Quarter	Contracted Capacity (MMBtu/d)	Begin Date	End Date	Rate Schedule		
Columbia Gas of Ohio/Columbia Gulf Transmission Co.												
	Oct 96	451,536	11/01/94	10/31/96	FTS2	Jan 97	457,693	11/01/94	10/31/98	FTS2	6,157	0.00
Exxon/Columbia Gulf Transmission Co.												
	Jan 98	110,000	11/01/93	3/31/98	FTS2	Apr 98	110,000	11/01/93	3/31/99	FTS2	0	(3.42)
Dayton Power & Light/Columbia Gulf Transmission Co.												
	Oct 96	51,351	11/01/93	10/31/96	FTS1	Jan 97	51,351	11/01/93	10/31/97	FTS1	0	(2.00)
Commonwealth Gas/Columbia Gulf Transmission Co.												
	Oct 96	49,312	11/01/94	10/31/97	FTS2	Jan 97	52,883	11/01/94	10/31/98	FTS2	3,571	(2.00)
Columbia Gas of PA/Columbia Gulf Transmission Co.												
	Oct 96	47,686	11/01/93	10/31/96	FTS2	Jan 97	44,600	10/31/93	10/31/98	FTS2	(3,086)	(1.00)
Texaco Natural Gas, Inc./Columbia Gulf Transmission Co.												
	Jul 97	35,000	11/01/95	8/31/97	FTS2	Oct 97	0				(35,000)*	(1.83)
	Jan 98	28,000	03/01/96	2/28/98	FTS2	Apr 98	0				(28,000)*	(2.00)
Louisville Gas & Electric/Texas Gas Transmission Corp.												
	Oct 96	30,000	11/01/91	10/31/96	FT	Jan 97	0				(30,000)*	(5.00)
Columbia Energy Services/Columbia Gulf Transmission Co.												
	Oct 97	30,000	11/01/94	10/31/97	FTS2	Jan 97	30,000	11/01/97	10/31/98	FTS2	0	(2.00)
	Oct 97	5,000	11/01/95	10/31/97	FTS2	Jan 97	0				(5,000)*	(2.00)
Columbia Gas of Kentucky/Columbia Gulf Transmission Co.												
	Oct 96	26,899	11/01/94	10/31/96	FTS2	Jan 97	27,500	11/01/94	10/31/98		601	0.00

See note at end of table.

Table D7. Characteristics of Expired and New Contracts for 54 Sampled Shipper/Pipeline Pairs (Continued)

Southwest Region

Shipper/ Pipeline Co.	Sample Contracts due to Expire April 1, 1996 - March 31,1998					New Contracts Following Expiration					Change in Capacity	Change in Length of Contract (years)
	Quarter	Contracted Capacity (MMBtu/d)	Begin Date	End Date	Rate Schedule	Quarter	Contracted Capacity (MMBtu/d)	Begin Date	End Date	Rate Schedule		
Texas Gas Transmission Corp./High Island Offshore System												
	Apr 96	194,180	12/01/77	05/29/96	Rate Sch	Jul 96	194,180	05/30/96	05/29/97	Rate Sch	0	(17.51)
FINA Natural Gas Co./Koch Gateway Pipeline Co.												
	Jul 97	150,000	04/01/95	9/30/97	FTS	Oct 97	36,024	10/01/97	12/31/00	FTS	(113,976)	0.75
						Oct 97	29,482	10/01/97	03/31/98	FTS	29,482	0.50
						Oct 97	6,308	10/01/97	03/30/00	FTS	6,308	2.50
						Oct 97	4,808	10/01/97	03/31/98	FTS	4,808	0.50
						Oct 97	2,000	10/01/97	03/30/00	FTS	2,000	2.50
						Oct 97	589	10/01/97	03/31/98	FTS	589	0.50
						Oct 97	40	10/01/97	03/31/98	FTS	40	0.50
Pennunion Energy Services (Columbia Energy Services)/Sea Robin Pipeline Co.												
	Apr 97	74,160	04/01/94	04/01/97	FT	Jan 98	151,471	11/01/97	03/31/98	FT	77,311	(2.59)
Natural Gas Clearinghouse/NorAm Gas Transmission Co.												
	Jan 97	55,000	02/01/95	03/31/97	FT	Apr 97	0				(55,000)*	(2.16)
	Jan 97	20,000	04/01/95	03/31/97	FT	Apr 97	30,000	04/01/97	03/31/98		10,000	(1.00)
NorAm Energy Services/NorAm Gas Transmission Co.												
	Jul 96	30,000	11/01/91	08/31/96	FT	Oct 96	30,000	11/01/91	10/31/96	FT	0	(4.59)
	Jul 96	8,000	06/01/94	07/31/96	FT	Oct 96	0				(8,000)*	(2.17)
	Jul 96	1,300	08/01/94	07/31/96	FT	Oct 96	1,300	08/01/94	07/31/97	FT	0	(1.00)
	Oct 96	50,000	11/01/92	10/31/96	FT	Jan 97	50,000	11/01/96	03/31/97	FT	0	(3.59)
	Oct 96	30,000	11/01/91	10/31/96	FT	Jan 97	30,000	11/01/96	03/31/97	FT	0	(4.59)
	Oct 96	30,000	11/01/94	10/31/96	FT	Jan 97	20,000	11/01/96	10/31/97	FT	(10,000)	(1.00)
	Oct 96	75	11/01/94	10/31/96	FT	Jan 97	56,000	12/01/96	02/28/97	FT	55,925	(1.76)
International Paper Co./NorAm Gas Transmission Co.												
	Oct 96	30,000	05/01/89	12/31/96	FT	Jan 97	30,000	01/01/97	01/01/98	FT	0	(6.67)
Duke Energy Trading & Mktlng/NorAm Gas Transmission Co.												
	Jan 97	30,000	12/01/92	3/31/97	FT	Apr 97	20,000	04/01/97	3/31/98	FT	(10,000)	(3.33)
						Apr 97	10,000	04/01/97	3/31/98	FT	10,000	1.00

West Region

Shipper/ Pipeline Co.	Sample Contracts due to Expire April 1, 1996 - March 31,1998					New Contracts Following Expiration					Change in Capacity	Change in Length of Contract (years)
	Quarter	Contracted Capacity (MMBtu/d)	Begin Date	End Date	Rate Schedule	Quarter	Contracted Capacity (MMBtu/d)	Begin Date	End Date	Rate Schedule		
PG & E/ El Paso Natural Gas Co.												
	Jan 97	1,166,220	09/01/91	12/31/97	FT1	Apr 98	0				(1,166,220)*	(6.34)
Southern Co. Energy Mktlng/Tranwestern Pipeline Co.												
	Oct 97	79,000	12/1/96	12/31/97	FTS-1	Jan 98	0				(79,000)*	(1.08)
BC Gas Utility/Northwest Pipeline Corp.												
	Apr 96	63,000	04/01/94	04/30/96	TF-2	Jul 96	63,000	05/01/96	05/01/97	TF-2	0	(1.08)
	Apr 97	11,934	12/15/95	04/30/97	TF-2	Jul 97	11,934	05/01/97	04/30/01	TF-2	0	2.62
Coastal Gas Marketing/Northwest Pipeline Corp.												
	Oct 96	50,000	11/01/94	10/31/96	TF-1	Jan 97	0				(50,000)*	(2.00)
	Oct 96	20,000	11/01/94	10/31/96	TF-1	Jan 97	0				(20,000)*	(2.00)
Petro-Canada Hydro Carbons, Inc./Northwest Pipeline Corp.												
	Oct 97	30,772	03/31/93	11/01/97	TF-1	Jan 98	30,772	11/02/97	11/01/98	TF-1	0	(3.59)
Chevron USA, Inc./EL Paso Natural Gas Co.												
	Jul 96	24,830	10/01/94	09/30/96	FT1	Oct 96	0				(24,830)*	(2.00)
Conoco, Inc./Tranwestern Pipeline Co.												
	Oct 96	20,000	03/01/94	11/02/96	FTS-1	Jan 97	0				(40,000)*	(2.68)
James River Corp./Northwest Pipeline Corp.												
	Oct 97	7,000	09/01/90	10/31/97	TF-1	Jan 98	7000	10/06/97	10/06/98	TF-1	0	(6.17)

*All capacity associated with the contract was turned back.

MMBtu/d = Million Btu per day.

Note: The sample of expired contracts consists of contracts with the largest amount of capacity in each region that expire from April 1, 1996 through March 31, 1998.

Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers quarterly filing for July 1, 1998, FERC Bulletin Board (August 14, 1998).

Table D8. Characteristics of All Contracts from 54 Sampled Shipper/Pipeline Pairs

Region	Shipper Type	Shipper	Pipeline Company	Number of Contracts: Before Expiration	Number of Contracts: After Expiration	Number of Contracts: Change	Capacity (MMBtu/day): Before Expiration	Capacity (MMBtu/day): After Expiration	Capacity (MMBtu/day): Change	Change[1] in Length
Central										
	LDC	Public Service of Colorado	Colorado Interstate Gas Co.	4	9	5	703,296	1,070,880	367,584	+
	LDC	Montana-Dakota	Williston Basin P L Co.	4	3	-1	411,265	411,264	(1)	+
	LDC	KN Energy	KN Interstate Gas Transmission	3	3	0	143,313	143,313	0	-
	MARK	Anthem Energy	KN Interstate Gas Transmission	1	0	-1	50,000	0	(50,000)	-
	LDC	Colorado Springs Utilities	Colorado Interstate Gas Co.	5	6	1	134,212	152,229	18,017	+
	INDU	Granite City Steel	Mississippi River Transmission	3	3	0	55,347	55,347	0	-
	MARK	Questar Energy Trading	Trailblazer Pipeline Co.	2	2	0	50,880	50,880	0	-
				Total Change		4			335,600	
Midwest										
	PIPE	Texas Eastern Trans	Trunkline Gas Co.	1	1	0	150,000	150,000	0	-
	MARK	Midcon Gas	Natural Gas P L Co. of America	17	17	0	853,450	820,950	(32,500)	-
	LDC[2]	People's Gas Light & Coke	Natural Gas P L Co. of America	5	3	-2	721,000	330,000	(391,000)	+
	LDC	Illinois Power	Natural Gas P L Co. of America	1	3	2	89,454	149,454	60,000	+
	LDC	Indiana Gas	Panhandle Eastern Pipe Line Co.	4	1	-3	218,578	51,431	(167,147)	+
	LDC[3]	Illinois Power	Panhandle Eastern Pipe Line Co.	3	2	-1	176,140	100,240	(75,900)	
	MARK	Texaco Natural Gas, Inc.	Natural Gas P L Co. of America	4	2	-2	113,500	28,500	(85,000)	-
	MARK	Energy Source, Inc.	Panhandle Eastern Pipe Line Co.	3	1	-2	131,050	25,000	(106,050)	-
	INDU	General Motors Corp.	ANR Pipeline Co.	7	4	-3	86,120	81,700	(4,420)	-
	INDU	Archer Daniels-Midland	Natural Gas P L Co. of America	4	4	0	86,050	86,050	0	-
	OTHR	Shell Offshore, Inc.	ANR Pipeline Co.	1	0	-1	55,000	0	(55,000)	-
	MARK	Proliance Energy, LLC	Panhandle Eastern Pipe Line Co.	5	11	6	155,192	269,257	114,065	-
	LDC	Utilicorp	Natural Gas P L Co. of America	1	0	-1	50,000	0	(50,000)	-
	OTHR	Norcean Explorer	Trunkline Gas Co.	1	0	-1	45,000	0	(45,000)	-
	LDC	East Ohio Gas	ANR Pipeline Co.	3	2	-1	100,000	56,000	(44,000)	-
				Total Change		-9			(881,861)	
Northeast										
	LDC	Boston Gas	Agonquin Gas Transmission Co.	9	11	2	279,534	285,814	6,280	-
	LDC	Equitable Gas	Kentucky-West Virginia Gas Co.	2	3	1	85,948	50,741	(35,207)	-
	LDC	National Fuel Gas Dist.	Tennessee Natural Gas Pipeline	4	3	-1	279,534	248,708	(30,826)	-
	INDU	Bethlehem Steel Corp.	Columbia Gas Transmission Corp.	3	3	0	35,139	35,139	0	-
	LDC	UGI Utilities	Tennessee Natural Gas Pipeline	1	0	-1	30,000	0	(30,000)	-
	INDU	Bethlehem Steel Corp.	Tennessee Natural Gas Pipeline	1	0	-1	30,000	0	(30,000)	-
	LDC	NJ Natural Gas	Carnegie Interstate Gas Co.	1	0	-1	27,000	0	(27,000)	-
	LDC	PSC of North Carolina	CNG Transmission Corp.	6	0	-6	90,035	65,035	(25,000)	-
				Total Change		-7			(171,677)	
Southeast										
	LDC	Columbia Gas of Ohio	Columbia Gulf Transmission Co.	3	2	-1	933,126	933,126	0	-
	MARK	Exxon	Columbia Gulf Transmission Co.	2	2	0	155,000	155,000	0	-
	LDC	Dayton Power & Light	Columbia Gulf Transmission Co.	1	1	0	51,351	51,351	0	-
	LDC	Commonwealth Gas	Columbia Gulf Transmission Co.	4	2	-2	108,713	108,713	0	-
	LDC	Columbia Gas of PA	Columbia Gulf Transmission Co.	3	2	-1	93,286	88,232	(5,054)	-
	MARK	Texaco Natural Gas, Inc.	Columbia Gulf Transmission Co.	3	1	-2	86,000	23,000	(63,000)	-
	LDC	Louisville Gas & Electric	Texas Gulf Transmission Corp.	2	0	-2	54,000	0	(54,000)	-
	MARK	Columbia Energy Services	Columbia Gulf Transmission Co.	5	4	-1	100,000	95,000	(5,000)	-
	LDC	Columbia Gas of Kentucky	Columbia Gulf Transmission Co.	3	2	-1	56,491	56,491	0	
				Total Change		-10	1,637,985	1,510,913	(127,054)	
Southwest										
	LDC	Texas Gas Trans. Corp.	High Island Offshore System	2	2	0	215,460	215,460	0	-
	MARK	FINA Natural Gas	Koch Gateway Pipeline Co.	1	7	6	150,000	79,521	(70,479)	-
	MARK	Pennunion Energy Service	Sea Robin Pipeline Co.	1	1	0	74,160	151,471	77,311	-
	MARK	Natural Gas Clearinghouse	Noram Gas Transmission	3	2	-1	95,000	60,000	(35,000)	-
	MARK	Noram Energy	Noram Gas Transmission	20	19	-1	199,325	237,050	37,725	-
	INDU	International Paper	Noram Gas Transmission	1	1	0	30,000	30,000	0	-
	MARK	Duke Energy	Noram Gas Transmission	1	2	1	30,000	30,000	0	-
				Total Change		5			9,557	

See note at end of table.

Table D8. Characteristics of All Contracts from 54 Sampled Shipper/Pipeline Pairs (Continued)

Region	Shipper Type	Shipper	Pipeline Company	Number of Contracts			Capacity (MMBtu/day)			Change[1] in Length
				Before Expiration	After Expiration	Change	Before Expiration	After Expiration	Change	
West										
	LDC	PG & E	El Paso Natural Gas Co.	1	0	-1	1,166,220	0	(1,166,220)	-
	MARK	Southern Co., Energy Mkting	Transwestern Pipeline Co.	2	1	-1	109,000	30,000	(79,000)	-
	LDC	BC Gas	Northwestern Pipeline Corp.	2	2	0	74,934	74,934	0	-
	MARK	Coastal Gas Marketing	Northwestern Pipeline Corp.	4	0	-4	94,562	0	(94,562)	-
	MARK	Petro-Canada Hydro Carbons	Northwestern Pipeline Corp.	2	2	0	61,543	61,543	0	-
	INDU	Chevron USA	El Paso Natural Gas Co.	1	0	-1	24,830	0	(24,830)	-
	MARK	Conoco, Inc.	Transwestern Pipeline Co.	4	3	-1	50,000	40,000	(10,000)	-
	INDU	James River Corp.	Northwest Pipeline Corp.	3	3	0	17,431	17,431	0	-
				Total Change		-8			(1,374,702)	

[1]For definition of Change in Length, see "Individual Shipper Analysis," p. 205.

[2]People's Gas Light & Coke and Natural Gas Pipe Line Co. of America had three contracts in the sample, but they expired during 2 separate quarters. By taking the weighted average, People's Gas Light & Coke experiences an increase in overall length of the terms, even though two contracts decreased in length.

[3]Weighted average appears to be a decrease by 1 day. The original contract expired in 1996 which was a leap year, so it was recorded as no change.

MMBtu = Million Btu; LDC = Local distribution company; MARK = Marketer; PIPE = Pipeline company; INDU = Industrial.

Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers quarterly filings for April 1, 1996 through April 1, 1998, FERC Bulletin Board (August 14, 1998).

Additional Tables and Graphs

Table D9. Characteristics of Firm Transportation Capacity Under New Contracts Effective During Each Quarter, April 1, 1996 - July 1, 1998

Quarter	All Contracts: Capacity (MMBtu per day)	All Contracts: Number of Contracts	All Contracts: Average Term (years)	Long-Term Contracts[a]: Capacity (MMBtu per day)	Long-Term Contracts[a]: Number of Contracts	Long-Term Contracts[a]: Average Term (years)	Short-Term Contracts[b]: Capacity (MMBtu per day)	Short-Term Contracts[b]: Number of Contracts	Short-Term Contracts[b]: Average Term (months)
1996									
April	7,456,872	566	5.7	2,107,363	121	7.0	5,349,509	445	5.3
July	5,428,360	422	5.2	1,325,567	81	5.8	4,102,793	341	5.1
October	8,076,494	492	4.6	4,485,545	206	5.1	3,590,949	286	4.3
1997									
January	10,755,664	981	7.4	3,652,088	246	7.8	7,103,576	735	7.3
April	5,150,956	491	4.5	710,904	52	5.2	4,440,052	439	4.4
July	4,841,854	392	5.6	1,710,542	72	7.4	3,131,312	320	5.2
October	3,450,632	361	5.3	1,263,502	78	7.1	2,187,130	283	4.8
1998									
January	10,941,370	1,004	7.9	3,993,608	266	9.1	6,947,762	738	7.4
April	5,017,717	391	6.1	1,816,463	85	5.7	3,201,254	306	6.2
July	4,064,427	357	5.9	652,105	61	5.4	3,412,322	296	6.0

[a]Long-term contracts are longer than 366 days.
[b]Short-term contracts are 366 days or less.
MMBtu per day = Million Btu per day.
Note: Data are for 64 interstate pipeline companies.
Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers quarterly filings for April 1, 1996 through July 1, 1998, FERC Bulletin Board (August 14, 1998).

Table D10. Capacity Associated with Expiring Firm Transportation Contracts by Region, 1998 - 2025, as Reported on July 1, 1998
(Million Btu per Day)

Region	Total Capacity as of 07/01/98	Expirations: 1998[a]	Expirations: 1999-2003	Expirations: 2004-2008	Expirations: 2009-2025[b]
Central	12,601,583	1,459,755	7,524,633	1,771,280	1,845,915
Midwest	20,800,280	3,233,811	11,728,323	3,752,100	2,086,046
Northeast	31,988,518	1,628,529	12,753,152	8,269,840	9,336,997
Southeast	9,848,292	1,158,194	3,168,093	4,647,104	874,901
Southwest	5,978,780	1,071,192	4,071,970	675,268	160,350
West	15,326,320	1,377,043	3,076,346	7,539,540	3,333,391
Total	**96,543,773**	**9,928,524**	**42,322,517**	**26,655,132**	**17,637,600**

[a]Data are for the last 6 months of 1998.
[b]Data for 2025 include a total of 20,600 million Btu per day of capacity that expires in the Southwest beyond 2025.
Note: Data are for 64 interstate pipeline companies.
Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers filing for July 1, 1998, FERC Bulletin Board (August 14, 1998).

Table D11. Expiration of Firm Transportation Capacity Under Contract as of July 1, 1998
(Million Btu per Day)

Pipeline Company	FERC ID	Total Capacity Under Contract As of July 1, 1998	Rollover and Short-term CapacityExpiring 1998[a]	Long-term Capacity Expiring 1998[a]	Total Capacity Expiring 1998[a]	Total Capacity Expiring 1999
Central						
Canyon Creek Compression Co.	67	200,260	0	0	0	24,242
Colorado Interstate Gas Co.	32	2,441,588	167,310	83,671	250,981	39,753
K N Interstate Gas Transmission Co.	53	741,437	0	173,622	173,622	23,293
MIGC, Inc.	47	90,000	33,000	0	33,000	0
Mississippi River Transmission Corp.	25	1,622,687	135,292	46,500	181,792	1,024,237
Northern Border Pipeline Co.	9	1,695,686	0	0	0	0
Questar Pipeline Co.	55	1,122,904	37,072	123,733	160,805	837,152
Trailblazer Pipeline Co.	68	605,017	0	31,800	31,800	51,940
Westgas Interstate Inc.	121	13,372	0	0	0	13,372
Williams Natural Gas Co.	43	2,845,768	421,911	175,398	597,309	201,544
Williston Basin Interstate Pipeline Co.	49	438,185	8,653	647	9,300	824
Wyoming Interstate Co., Ltd.	76	784,679	0	21,146	21,146	0
Total Central		12,601,583	803,238	656,517	1,459,755	2,216,357
Midwest						
ANR Pipeline Co.	48	5,157,798	292,536	98,425	390,961	602,099
Crossroads Pipeline Co.	123	153,466	57,000	50,000	107,000	10,000
Great Lakes Gas Transmission, L.P.	51	3,884,669	324,450	89,771	414,221	483,429
Michigan Gas Storage Co.	124	300,000	90,000	0	90,000	0
Midwestern Gas Transmission Co.	5	745,597	2,000	1,500	3,500	0
Natural Gas Pipeline Co. of America	26	5,450,813	184,448	1,326,577	1,511,025	950,221
Panhandle Eastern Pipe Line Co.	28	2,580,112	103,822	126,770	230,592	577,904
Trunkline Gas Co.	30	2,027,489	182,441	222,704	405,145	409,346
Viking Gas Transmission Co.	82	500,336	31,017	50,350	81,367	0
Total Midwest		20,800,280	1,267,714	1,966,097	3,233,811	3,032,999
Northeast						
Algonquin Gas Transmission Co.	20	1,981,655	193,205	0	193,205	105,427
Carnegie Interstate Pipeline Co.	120	38,000	15,000	10,000	25,000	13,000
CNG Transmission Corp.	22	4,849,918	120,000	0	120,000	33,502
Columbia Gas Transmission Corp.	21	5,271,781	452,415	92,891	545,306	177,619
Equitrans, L.P.	24	374,771	26,026	0	26,026	10,964
Granite State Gas Transmission, Inc.	4	177,367	0	0	0	0
Iroquois Gas Transmission System, L.P.	110	1,115,482	78,538	10,115	88,653	0
Kentucky West Virginia Gas Co.	46	103,442	31,172	0	31,172	72,270
National Fuel Gas Supply Corp.	16	1,888,276	11,469	0	11,469	92,589
NORA Transmission Co.	100	35,000	0	0	0	35,000
Tennessee Gas Pipeline Co.	9	5,242,068	36,172	93,362	129,534	160,221
Texas Eastern Transmission Corp.	17	4,793,156	105,309	63,614	168,923	682,021
Transcontinental Gas Pipe Line Corp.	29	6,117,602	235,938	53,303	289,241	485,398
Total Northeast		31,988,518	1,305,244	323,285	1,628,529	1,868,011
Southeast						
Chandeleur Pipe Line Co.	97	280,000	0	0	0	190,000
Columbia Gulf Transmission Co.	70	3,197,179	132,085	684,961	817,046	230,976
East Tennessee Natural Gas Co.	2	645,264	0	0	0	0
Florida Gas Transmission Co.	34	1,533,594	40,000	1,800	41,800	24,601
KO Transmission Co.	131	221,000	0	0	0	0
Midcoast Interstate Transmission Inc. (aka Ala-Tenn)	1	157,844	205	0	205	1,272
Mobile Bay Pipeline Co.	114	27,885	0	27,885	27,885	0
South Georgia Natural Gas Co.	8	122,276	3,265	0	3,265	23,306
Southern Natural Gas Co.	7	2,433,343	66,591	97,184	163,775	112,333
Texas Gas Transmission Corp.	18	1,229,907	30,872	73,346	104,218	308,120
Total Southeast		9,848,292	273,018	885,176	1,158,194	890,608
Southwest						
Black Marlin Pipeline Co.	88	83,288	8,288	75,000	83,288	0
High Island Offshore System	77	21,280	0	0	0	0
Koch Gateway Pipeline Co.	11	2,261,610	117,100	77,854	194,954	1,528,441
Mid Louisiana Gas Co.	15	127,563	21,430	44,133	65,563	47,000
Noram Gas Transmission Co.	31	2,632,318	368,383	164,358	532,741	244,449
Oktex Pipeline Co.	116	33,600	0	0	0	17,600
Ozark Gas Transmission System	73	38,249	1,219	23,259	24,478	0
Sabine Pipe Line Co.	79	215,000	25,000	0	25,000	0
Sea Robin Pipeline Co.	6	411,829	104,515	0	104,515	89,105
Stingray Pipeline Co.	69	154,043	23,153	17,500	40,653	0
Total Southwest		5,978,780	669,088	402,104	1,071,192	1,926,595
West						
El Paso Natural Gas Co.	33	4,738,219	322,449	0	322,449	1,548,042
Kern River Gas Transmission Co.	99	762,200	25,750	0	25,750	0
Mojave Pipeline Co.	92	392,600	0	0	0	0
Northwest Pipeline Corp.	37	3,342,393	310,814	24,097	334,911	161,450
Pacific Gas Transmission Co.	86	2,956,278	182,973	0	182,973	18,470
Pacific Interstate Offshore Co.	64	35,000	0	35,000	35,000	0
Paiute Pipeline Co.	41	75,075	0	0	0	0
Riverside Pipeline Co., L.P.	8	130,000	0	0	0	0
Transwestern Pipeline Co.	42	2,724,795	454,710	21,250	475,960	327,300
Tuscarora Gas Transmission Co.	126	169,760	0	0	0	0
Total West		15,326,320	1,296,696	80,347	1,377,043	2,055,262
Total United States		96,543,773	5,614,998	4,313,526	9,928,524	11,989,832

See note at end of table.

Table D11. Expiration of Firm Transportation Capacity Under Contract as of July 1, 1998 (Continued)
(Million Btu per Day)

Pipeline Company	Total Capacity Expiring 2000	Total Capacity Expiring 2001	Total Capacity Expiring 2002	Total Capacity Expiring 2003	Total Capacity Expiring 2004	Total Capacity Expiring 2005
Central						
Canyon Creek Compression Co.	0	0	176,018	0	0	0
Colorado Interstate Gas Co.	108,688	451,565	940,798	58,720	48,170	77,488
K N Interstate Gas Transmission Co.	2,850	122,031	6,600	2,500	0	7,000
MIGC, Inc.	12,000	0	0	0	0	0
Mississippi River Transmission Corp.	28,457	72,792	185,409	0	0	130,000
Northern Border Pipeline Co.	0	794,896	0	225,769	134,517	117,762
Questar Pipeline Co.	5,000	18,450	22,698	15,000	12,859	20,000
Trailblazer Pipeline Co.	0	42,951	203,780	62,946	39,080	20,000
Westgas Interstate Inc.	0	0	0	0	0	0
Williams Natural Gas Co.	16,833	465,919	384,384	79,826	0	39,268
Williston Basin Interstate Pipeline Co.	285	0	418,605	0	0	456
Wyoming Interstate Co., Ltd.	0	6,160	20,600	355,746	96,529	0
Total Central	174,113	1,974,764	2,358,892	800,507	331,155	411,974
Midwest						
ANR Pipeline Co.	592,136	329,717	186,543	1,398,898	36,151	67,329
Crossroads Pipeline Co.	30,000	0	0	0	0	6,466
Great Lakes Gas Transmission, L.P.	508,469	13,294	112,688	179,463	87,645	1,464,986
Michigan Gas Storage Co.	0	0	0	0	0	0
Midwestern Gas Transmission Co.	332,097	0	40,000	0	260,000	110,000
Natural Gas Pipeline Co. of America	2,020,730	451,085	137,950	41,000	0	23,408
Panhandle Eastern Pipe Line Co.	573,497	209,251	218,216	87,268	76,509	170,480
Trunkline Gas Co.	213,292	71,200	636,115	8,073	115,649	0
Viking Gas Transmission Co.	256,798	15,000	32,544	0	0	0
Total Midwest	4,527,019	1,089,547	1,364,056	1,714,702	575,954	1,842,669
Northeast						
Algonquin Gas Transmission Co.	91,794	0	77,500	0	43,712	0
Carnegie Interstate Pipeline Co.	0	0	0	0	0	0
CNG Transmission Corp.	600	1,894,878	769,331	148,116	7,500	87,215
Columbia Gas Transmission Corp.	13,331	17,350	47,730	52,425	3,317,117	1,400
Equitrans, L.P.	18,288	276,000	42,485	1,008	0	0
Granite State Gas Transmission, Inc.	170,247	0	0	0	0	0
Iroquois Gas Transmission System, L.P.	10,300	0	0	0	0	61,800
Kentucky West Virginia Gas Co.	0	0	0	0	0	0
National Fuel Gas Supply Corp.	32,128	13,056	82,924	1,290,522	30,262	132,530
NORA Transmission Co.	0	0	0	0	0	0
Tennessee Gas Pipeline Co.	3,581,988	72,020	170,772	76,810	291,616	15,120
Texas Eastern Transmission Corp.	484,992	133,201	423,955	200,611	79,014	35,886
Transcontinental Gas Pipe Line Corp.	366,642	87,828	216,463	19,846	358,523	1,236,490
Total Northeast	4,770,310	2,494,333	1,831,160	1,789,338	4,127,744	1,570,441
Southeast						
Chandeleur Pipe Line Co.	75,000	0	0	15,000	0	0
Columbia Gulf Transmission Co.	1,302	83,000	0	11,088	1,896,867	0
East Tennessee Natural Gas Co.	393,511	4,696	11,683	8,889	0	1,000
Florida Gas Transmission Co.	337,478	10,000	0	12,156	8,787	551,297
KO Transmission Co.	0	0	0	0	0	0
Midcoast Interstate Transmission Inc. (aka Ala-Tenn)	26,647	15,556	44,795	65,111	0	0
Mobile Bay Pipeline Co.	0	0	0	0	0	0
South Georgia Natural Gas Co.	384	0	12,978	258	36,050	26,592
Southern Natural Gas Co.	120,468	22,346	127,996	704,376	36,776	173,366
Texas Gas Transmission Corp.	96,476	20,240	0	56,051	21,450	261,527
Total Southeast	1,051,266	155,838	197,452	872,929	1,999,930	1,013,782
Southwest						
Black Marlin Pipeline Co.	0	0	0	0	0	0
High Island Offshore System	21,280	0	0	0	0	0
Koch Gateway Pipeline Co.	96,476	17,808	74,081	42,000	200,000	32,600
Mid Louisiana Gas Co.	0	15,000	0	0	0	0
Noram Gas Transmission Co.	710,523	89,330	825,675	44,700	7,900	157,500
Oktex Pipeline Co.	0	16,000	0	0	0	0
Ozark Gas Transmission System	0	13,771	0	0	0	0
Sabine Pipe Line Co.	20,000	0	60,000	0	60,000	0
Sea Robin Pipeline Co.	41,200	0	53,560	0	0	95,275
Stingray Pipeline Co.	0	3,971	0	0	79,419	0
Total Southwest	889,479	155,880	1,013,316	86,700	347,319	285,375
West						
El Paso Natural Gas Co.	163,335	27,065	88,105	46,035	0	327,769
Kern River Gas Transmission Co.	0	0	0	0	0	0
Mojave Pipeline Co.	0	0	0	0	0	0
Northwest Pipeline Corp.	0	13,434	0	0	878,626	22,000
Pacific Gas Transmission Co.	0	0	20,000	0	0	941,745
Pacific Interstate Offshore Co.	0	0	0	0	0	0
Paiute Pipeline Co.	0	0	0	75,075	0	0
Riverside Pipeline Co., L.P.	0	0	0	0	0	0
Transwestern Pipeline Co.	241,375	171,000	65,714	109,946	125,000	506,000
Tuscarora Gas Transmission Co.	0	0	0	0	0	0
Total West	404,710	211,499	173,819	231,056	1,003,626	1,797,514
Total United States	11,816,897	6,081,861	6,938,695	5,495,232	8,385,728	6,921,755

See note at end of table.

Table D11. Expiration of Firm Transportation Capacity Under Contract as of July 1, 1998 (Continued)
(Million Btu per Day)

Pipeline Company	Total Capacity Expiring 2006	Total Capacity Expiring 2007	Total Capacity Expiring 2008	Total Capacity Expiring 2009	Total Capacity Expiring 20010	Total Capacity Expiring 2011
Central						
Canyon Creek Compression Co.	0	0	0	0	0	0
Colorado Interstate Gas Co.	67,017	86,500	21,779	35,145	6,000	51,204
K N Interstate Gas Transmission Co.	30,600	146,674	37,000	100,000	54,267	0
MIGC, Inc.	0	45,000	0	0	0	0
Mississippi River Transmission Corp.	0	0	0	0	0	0
Northern Border Pipeline Co.	29,441	58,882	111,896	47,105	135,298	0
Questar Pipeline Co.	0	30,177	0	0	0	763
Trailblazer Pipeline Co.	0	121,320	10,000	0	0	0
Westgas Interstate Inc	0	0	0	0	0	0
Williams Natural Gas Co.	0	0	10,280	827	1,308	66,801
Williston Basin Interstate Pipeline Co.	0	0	0	0	0	0
Wyoming Interstate Co., Ltd.	0	221,585	0	0	0	0
Total Central	**127,058**	**710,138**	**190,955**	**183,077**	**196,873**	**118,768**
Midwest						
ANR Pipeline Co.	104,563	57,957	439,291	33,126	33,115	550,760
Crossroads Pipeline Co.	0	0	0	0	0	0
Great Lakes Gas Transmission, L.P.	52,829	0	227,915	0	15,651	88,689
Michigan Gas Storage Co.	0	0	0	0	0	0
Midwestern Gas Transmission Co.	0	0	0	0	0	0
Natural Gas Pipeline Co. of America	1,400	272,500	10,236	31,258	0	0
Panhandle Eastern Pipe Line Co.	75,400	5,336	7,600	5,800	0	0
Trunkline Gas Co.	0	31,050	0	0	0	0
Viking Gas Transmission Co.	0	0	47,400	0	0	25,627
Total Midwest	**234,192**	**366,843**	**732,442**	**70,184**	**48,766**	**665,076**
Northeast						
Algonquin Gas Transmission Co.	23,886	27,000	40,000	57,929	125,000	221,400
Carnegie Interstate Pipeline Co.	0	0	0	0	0	0
CNG Transmission Corp.	433,641	102,813	301,213	103,100	51,395	192,438
Columbia Gas Transmission Corp.	32,500	3,000	20,386	565,075	92,097	47,500
Equitrans, L.P.	0	0	0	0	0	0
Granite State Gas Transmission, Inc.	0	0	0	0	0	0
Iroquois Gas Transmission System, L.P.	15,406	0	31,065	16,995	0	193,743
Kentucky West Virginia Gas Co.	0	0	0	0	0	0
National Fuel Gas Supply Corp.	37,290	130,581	18,088	0	0	0
NORA Transmission Co.	0	0	0	0	0	0
Tennessee Gas Pipeline Co.	0	50,160	0	3,477	79,336	134,150
Texas Eastern Transmission Corp.	184,665	18,000	260,000	83,809	110,250	29,000
Transcontinental Gas Pipe Line Corp.	670,322	114,448	57,191	492,130	619,432	32,036
Total Northeast	**1,397,710**	**446,002**	**727,943**	**1,322,515**	**1,077,510**	**850,267**
Southeast						
Chandeleur Pipe Line Co.	0	0	0	0	0	0
Columbia Gulf Transmission Co.	30,000	23,000	15,627	62,089	4,601	21,583
East Tennessee Natural Gas Co.	7,500	18,657	0	0	113,416	0
Florida Gas Transmission Co.	216	8,611	0	5,211	0	10,706
KO Transmission Co.	221,000	0	0	0	0	0
Midcoast Interstate Transmission Inc. (aka Ala-Tenn)	0	0	0	0	0	0
Mobile Bay Pipeline Co.	0	0	0	0	0	0
South Georgia Natural Gas Co.	6,180	13,263	0	0	0	0
Southern Natural Gas Co.	202,167	327,621	405,925	13,390	0	0
Texas Gas Transmission Corp.	201,092	62,533	90,000	8,200	0	0
Total Southeast	**668,155**	**453,685**	**511,552**	**88,890**	**118,017**	**32,289**
Southwest						
Black Marlin Pipeline Co.	0	0	0	0	0	0
High Island Offshore System	0	0	0	0	0	0
Koch Gateway Pipeline Co.	0	0	0	0	0	0
Mid Louisiana Gas Co.	0	0	0	0	0	0
Noram Gas Transmission Co.	0	5,000	0	0	0	0
Oktex Pipeline Co.	0	0	0	0	0	0
Ozark Gas Transmission System	0	0	0	0	0	0
Sabine Pipe Line Co.	0	0	0	0	0	50,000
Sea Robin Pipeline Co.	0	7,574	0	0	0	0
Stingray Pipeline Co.	0	30,000	0	0	0	0
Total Southwest	**0**	**42,574**	**0**	**0**	**0**	**50,000**
West						
El Paso Natural Gas Co.	1,176,450	885,519	0	0	0	153,450
Kern River Gas Transmission Co.	0	726,150	0	0	0	0
Mojave Pipeline Co.	0	392,500	0	0	100	0
Northwest Pipeline Corp.	0	109,078	474,493	263,761	61,175	102,000
Pacific Gas Transmission Co	259,800	0	0	15,708	0	0
Pacific Interstate Offshore Co	0	0	0	0	0	0
Paiute Pipeline Co.	0	0	0	0	0	0
Riverside Pipeline Co., L.P.	0	0	0	130,000	0	0
Transwestern Pipeline Co.	112,500	500,000	90,000	0	0	0
Tuscarora Gas Transmission Co.	11,110	800	0	0	0	0
Total West	**1,559,860**	**2,614,047**	**564,493**	**409,469**	**61,275**	**255,450**
Total United States	**3,986,975**	**4,633,289**	**2,727,385**	**2,074,135**	**1,502,441**	**1,971,850**

See note at end of table.

Table D11. Expiration of Firm Transportation Capacity Under Contract as of July 1, 1998 (Continued)
(Million Btu per Day)

Pipeline Company	Total Capacity Expiring 2012	Total Capacity Expiring 2013	Total Capacity Expiring 2014	Total Capacity Expiring 2015	Total Capacity Expiring 20016	Total Capacity Expiring 2017
Central						
Canyon Creek Compression Co.	0	0	0	0	0	0
Colorado Interstate Gas Co.	17,600	18,000	0	0	0	0
K N Interstate Gas Transmission Co.	35,000	0	0	0	0	0
MIGC, Inc.	0	0	0	0	0	0
Mississippi River Transmission Corp.	0	0	0	0	0	0
Northern Border Pipeline Co.	40,120	0	0	0	0	0
Questar Pipeline Co.	0	0	0	0	0	0
Trailblazer Pipeline Co.	0	0	0	0	0	0
Westgas Interstate Inc.	0	0	0	0	0	0
Williams Natural Gas Co.	30,255	896,231	0	28,849	0	16,134
Williston Basin Interstate Pipeline Co.	8,240	475	0	0	0	0
Wyoming Interstate Co., Ltd.	0	0	0	0	21,699	0
Total Central	**131,215**	**914,706**	**0**	**28,849**	**21,699**	**16,134**
Midwest						
ANR Pipeline Co.	0	106,252	207,900	0	0	0
Crossroads Pipeline Co.	0	0	0	0	0	0
Great Lakes Gas Transmission, L.P.	0	59,888	0	175,502	0	0
Michigan Gas Storage Co.	0	0	0	0	0	0
Midwestern Gas Transmission Co.	0	0	0	0	0	0
Natural Gas Pipeline Co. of America	0	0	0	0	0	0
Panhandle Eastern Pipe Line Co.	0	10,450	32,069	50,093	249,647	0
Trunkline Gas Co.	0	99,814	27,303	0	10,502	0
Viking Gas Transmission Co.	41,600	0	0	0	0	0
Total Midwest	**41,600**	**276,404**	**267,272**	**225,595**	**260,149**	**0**
Northeast						
Algonquin Gas Transmission Co.	585,134	37,455	29,758	95,455	62,000	165,000
Carnegie Interstate Pipeline Co.	0	0	0	0	0	0
CNG Transmission Corp.	130,500	98,233	17,200	26,200	30,000	302,043
Columbia Gas Transmission Corp.	198,279	0	113,790	0	0	2,636
Equitrans, L.P.	0	0	0	0	0	0
Granite State Gas Transmission, Inc.	7,120	0	0	0	0	0
Iroquois Gas Transmission System, L.P.	404,739	61,800	112,270	0	26,011	0
Kentucky West Virginia Gas Co.	0	0	0	0	0	0
National Fuel Gas Supply Corp.	0	16,837	0	0	0	0
NORA Transmission Co.	0	0	0	0	0	0
Tennessee Gas Pipeline Co.	280,634	100,421	61,500	10,868	0	20,500
Texas Eastern Transmission Corp.	1,169,520	124,036	98,181	132,905	233,712	125,475
Transcontinental Gas Pipe Line Corp.	443,581	171,982	65,226	196,178	853	189,795
Total Northeast	**3,219,507**	**610,764**	**497,925**	**461,606**	**352,576**	**805,449**
Southeast						
Chandeleur Pipe Line Co.	0	0	0	0	0	0
Columbia Gulf Transmission Co.	0	0	0	0	0	0
East Tennessee Natural Gas Co.	51,113	15,079	0	17,145	0	0
Florida Gas Transmission Co.	797	0	0	425,802	66,108	26,900
KO Transmission Co.	0	0	0	0	0	0
Midcoast Interstate Transmission Inc. (aka Ala-Tenn)	2,500	0	0	0	0	1,758
Mobile Bay Pipeline Co.	0	0	0	0	0	0
South Georgia Natural Gas Co.	0	0	0	0	0	0
Southern Natural Gas Co.	20,600	0	0	0	0	0
Texas Gas Transmission Corp.	0	0	0	0	0	0
Total Southeast	**75,010**	**15,079**	**0**	**442,947**	**66,108**	**28,658**
Southwest						
Black Marlin Pipeline Co.	0	0	0	0	0	0
High Island Offshore System	0	0	0	0	0	0
Koch Gateway Pipeline Co.	0	74,000	0	0	0	0
Mid Louisiana Gas Co.	0	0	0	0	0	0
Noram Gas Transmission Co.	14,500	0	0	0	0	0
Oktex Pipeline Co.	0	0	0	0	0	0
Ozark Gas Transmission System	0	0	0	0	0	0
Sabine Pipe Line Co.	0	0	0	0	0	0
Sea Robin Pipeline Co.	0	0	0	0	0	0
Stingray Pipeline Co.	0	0	0	0	0	0
Total Southwest	**14,500**	**74,000**	**0**	**0**	**0**	**0**
West						
El Paso Natural Gas Co.	0	0	0	0	0	0
Kern River Gas Transmission Co.	0	10,300	0	0	0	0
Mojave Pipeline Co.	0	0	0	0	0	0
Northwest Pipeline Corp.	250,467	259,044	77,595	206,123	46,112	7,000
Pacific Gas Transmission Co.	0	7,158	0	234,795	44,700	0
Pacific Interstate Offshore Co.	0	0	0	0	0	0
Paiute Pipeline Co.	0	0	0	0	0	0
Riverside Pipeline Co., L.P.	0	0	0	0	0	0
Transwestern Pipeline Co.	0	0	0	0	0	0
Tuscarora Gas Transmission Co.	0	0	0	106,100	0	50,200
Total West	**250,467**	**276,502**	**77,595**	**547,018**	**90,812**	**57,200**
Total United States	**3,732,299**	**2,167,455**	**842,792**	**1,706,015**	**791,344**	**907,441**

See note at end of table.

Table D11. Expiration of Firm Transportation Capacity Under Contract as of July 1, 1998 (Continued)
(Million Btu per Day)

Pipeline Company	Total Capacity Expiring 2018	Total Capacity Expiring 2019	Total Capacity Expiring 2020	Total Capacity Expiring 2021	Total Capacity Expiring 20022	Total Capacity Expiring 2023
Central						
Canyon Creek Compression Co.	0	0	0	0	0	0
Colorado Interstate Gas Co.	0	0	0	0	0	0
K N Interstate Gas Transmission Co.	0	0	0	0	0	0
MIGC, Inc.	0	0	0	0	0	0
Mississippi River Transmission Corp.	0	0	0	0	0	0
Northern Border Pipeline Co.	0	0	0	0	0	0
Questar Pipeline Co.	0	0	0	0	0	0
Trailblazer Pipeline Co.	21,200	0	0	0	0	0
Westgas Interstate Inc.	0	0	0	0	0	0
Williams Natural Gas Co.	10,000	0	0	0	0	0
Williston Basin Interstate Pipeline Co.	0	0	0	0	0	0
Wyoming Interstate Co., Ltd.	0	0	41,214	0	0	0
Total Central	31,200	0	41,214	0	0	0
Midwest						
ANR Pipeline Co.	0	0	0	0	0	0
Crossroads Pipeline Co.	0	0	0	0	0	0
Great Lakes Gas Transmission, L.P.	0	0	0	0	0	0
Michigan Gas Storage Co.	0	0	0	0	0	210,000
Midwestern Gas Transmission Co.	0	0	0	0	0	0
Natural Gas Pipeline Co. of America	0	0	0	0	0	0
Panhandle Eastern Pipe Line Co.	0	0	0	0	0	0
Trunkline Gas Co.	0	0	0	0	0	0
Viking Gas Transmission Co.	0	0	0	0	0	0
Total Midwest	0	0	0	0	0	210,000
Northeast						
Algonquin Gas Transmission Co.	0	0	0	0	0	0
Carnegie Interstate Pipeline Co.	0	0	0	0	0	0
CNG Transmission Corp.	0	0	0	0	0	0
Columbia Gas Transmission Corp.	0	0	0	24,240	0	0
Equitrans, L.P.	0	0	0	0	0	0
Granite State Gas Transmission, Inc.	0	0	0	0	0	0
Iroquois Gas Transmission System, L.P.	92,700	0	0	0	0	0
Kentucky West Virginia Gas Co.	0	0	0	0	0	0
National Fuel Gas Supply Corp.	0	0	0	0	0	0
NORA Transmission Co.	0	0	0	0	0	0
Tennessee Gas Pipeline Co.	0	0	2,937	0	0	0
Texas Eastern Transmission Corp.	0	0	0	15,000	0	0
Transcontinental Gas Pipe Line Corp.	0	0	0	0	0	3,997
Total Northeast	92,700	0	2,937	39,240	0	3,997
Southeast						
Chandeleur Pipe Line Co.	0	0	0	0	0	0
Columbia Gulf Transmission Co.	0	0	0	0	0	0
East Tennessee Natural Gas Co.	0	0	2,575	0	0	0
Florida Gas Transmission Co.	0	0	3,124	0	0	0
KO Transmission Co.	0	0	0	0	0	0
Midcoast Interstate Transmission Inc. (aka Ala-Tenn)	0	0	0	0	0	0
Mobile Bay Pipeline Co.	0	0	0	0	0	0
South Georgia Natural Gas Co.	0	0	0	0	0	0
Southern Natural Gas Co.	0	0	0	0	0	2,204
Texas Gas Transmission Corp.	0	0	0	0	0	0
Total Southeast	0	0	5,699	0	0	2,204
Southwest						
Black Marlin Pipeline Co.	0	0	0	0	0	0
High Island Offshore System	0	0	0	0	0	0
Koch Gateway Pipeline Co.	1,250	0	0	0	0	0
Mid Louisiana Gas Co.	0	0	0	0	0	0
Noram Gas Transmission Co.	0	0	0	0	0	0
Oktex Pipeline Co.	0	0	0	0	0	0
Ozark Gas Transmission System	0	0	0	0	0	0
Sabine Pipe Line Co.	0	0	0	0	0	0
Sea Robin Pipeline Co.	0	0	0	0	0	0
Stingray Pipeline Co.	0	0	0	0	0	0
Total Southwest	1,250	0	0	0	0	0
West						
El Paso Natural Gas Co.	0	0	0	0	0	0
Kern River Gas Transmission Co.	0	0	0	0	0	0
Mojave Pipeline Co.	0	0	0	0	0	0
Northwest Pipeline Corp.	0	0	0	0	0	0
Pacific Gas Transmission Co.	0	0	0	0	0	1,146,029
Pacific Interstate Offshore Co.	0	0	0	0	0	0
Paiute Pipeline Co.	0	0	0	0	0	0
Riverside Pipeline Co., L.P.	0	0	0	0	0	0
Transwestern Pipeline Co.	0	0	0	0	0	0
Tuscarora Gas Transmission Co.	1,550	0	0	0	0	0
Total West	1,550	0	0	0	0	1,146,029
Total United States	126,700	0	49,850	39,240	0	1,362,230

See note at end of table.

Table D11. Expiration of Firm Transportation Capacity Under Contract as of July 1, 1998 (Continued)
(Million Btu per Day)

Pipeline Company	Total Capacity Expiring 2024	Total Capacity Expiring 2025[b]
Central		
Canyon Creek Compression Co.	0	0
Colorado Interstate Gas Co.	0	162,180
K N Interstate Gas Transmission Co.	0	0
MIGC, Inc.	0	0
Mississippi River Transmission Corp.	0	0
Northern Border Pipeline Co.	0	0
Questar Pipeline Co.	0	0
Trailblazer Pipeline Co.	0	0
Westgas Interstate Inc.	0	0
Williams Natural Gas Co.	0	0
Williston Basin Interstate Pipeline Co.	0	0
Wyoming Interstate Co., Ltd.	0	0
Total Central	0	162,180
Midwest		
ANR Pipeline Co.	0	21,000
Crossroads Pipeline Co.	0	0
Great Lakes Gas Transmission, L.P.	0	0
Michigan Gas Storage Co.	0	0
Midwestern Gas Transmission Co.	0	0
Natural Gas Pipeline Co. of America	0	0
Panhandle Eastern Pipe Line Co.	0	0
Trunkline Gas Co.	0	0
Viking Gas Transmission Co.	0	0
Total Midwest	0	21,000
Northeast		
Algonquin Gas Transmission Co.	0	0
Carnegie Interstate Pipeline Co.	0	0
CNG Transmission Corp.	0	0
Columbia Gas Transmission Corp.	0	0
Equitrans, L.P.	0	0
Granite State Gas Transmission, Inc.	0	0
Iroquois Gas Transmission System, L.P.	0	0
Kentucky West Virginia Gas Co.	0	0
National Fuel Gas Supply Corp.	0	0
NORA Transmission Co.	0	0
Tennessee Gas Pipeline Co.	0	4
Texas Eastern Transmission Corp.	0	0
Transcontinental Gas Pipe Line Corp..	0	0
Total Northeast	0	4
Southeast		
Chandeleur Pipe Line Co.	0	0
Columbia Gulf Transmission Co.	0	0
East Tennessee Natural Gas Co.	0	0
Florida Gas Transmission Co.	0	0
KO Transmission Co.	0	0
Midcoast Interstate Transmission Inc. (aka Ala-Tenn)	0	0
Mobile Bay Pipeline Co.	0	0
South Georgia Natural Gas Co.	0	0
Southern Natural Gas Co.	0	0
Texas Gas Transmission Corp.	0	0
Total Southeast	0	0
Southwest		
Black Marlin Pipeline Co.	0	0
High Island Offshore System	0	0
Koch Gateway Pipeline Co.	0	0
Mid Louisiana Gas Co.	0	0
Noram Gas Transmission Co.	0	0
Oktex Pipeline Co.	0	0
Ozark Gas Transmission System	0	0
Sabine Pipe Line Co.	0	0
Sea Robin Pipeline Co.	0	20,600
Stingray Pipeline Co.	0	0
Total Southwest	0	20,600
West		
El Paso Natural Gas Co.	0	0
Kern River Gas Transmission Co.	0	0
Mojave Pipeline Co.	0	0
Northwest Pipeline Corp.	0	75,124
Pacific Gas Transmission Co.	0	84,900
Pacific Interstate Offshore Co.	0	0
Paiute Pipeline Co.	0	0
Riverside Pipeline Co., L.P.	0	0
Transwestern Pipeline Co.	0	0
Tuscarora Gas Transmission Co.	0	0
Total West	0	160,024
Total United States	0	363,808

[a]Data are for the last 6 months of 1998.

[b]Expirations shown in 2025 in the Southwest actually occur in years beyond 2025.

Notes: Long-term contracts are longer than 366 days. Short-term contracts are 366 days or less.

Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers quarterly filing for July 1, 1998, FERC Bulletin Board (August 14, 1998).

Table D12. Firm Transportation Capacity by Region and Shipper Type, April 1, 1996 - July 1, 1998
(Million Btu per Day)

Region / Pipeline Company	Contract Length	April 1, 1996	July 1, 1996	October 1, 1996	January 1, 1997	April 1, 1997	July 1, 1997	October 1, 1997	January 1, 1998	April 1, 1998	July 1, 1998
Central											
Electric Utility	LT	21,097	21,095	21,094	94,031	94,034	94,037	124,291	124,291	142,927	144,127
	ST	0	0	0	0	403	403	403	807	0	0
	Total	21,097	21,095	21,094	94,031	94,437	94,440	124,694	125,098	142,927	144,127
Industrial	LT	208,451	158,839	228,240	154,437	140,651	136,154	172,376	237,043	242,279	234,921
	ST	28,618	83,980	25,950	112,435	113,616	118,100	94,909	47,563	49,946	53,901
	Total	237,069	242,819	254,190	266,872	254,267	254,254	267,285	284,606	292,225	288,822
LDC	LT	4,863,792	4,408,077	5,192,579	4,774,987	4,780,396	4,941,184	5,182,241	5,454,140	5,502,001	5,422,955
	ST	831,770	741,309	311,068	795,840	766,411	600,778	417,296	514,221	337,679	338,750
	Total	5,695,562	5,149,386	5,503,647	5,570,827	5,546,807	5,541,962	5,599,537	5,968,361	5,839,680	5,761,705
Marketer	LT	2,151,824	2,196,604	2,515,143	2,475,651	2,592,963	2,578,111	3,209,757	3,485,897	3,499,413	3,449,625
	ST	777,385	762,581	459,303	694,641	692,630	673,472	578,941	608,645	444,255	520,460
	Total	2,929,209	2,959,185	2,974,446	3,170,292	3,285,593	3,251,583	3,788,698	4,094,542	3,943,668	3,970,085
Other	LT	1,497,949	1,495,405	1,534,502	1,543,716	1,523,247	1,474,765	1,623,236	1,607,677	1,591,455	1,586,955
	ST	127,353	126,022	210,485	103,470	58,419	54,027	18,642	59,021	34,332	20,999
	Total	1,625,302	1,621,427	1,744,987	1,647,186	1,581,666	1,528,792	1,641,878	1,666,698	1,625,787	1,607,954
Pipeline Company	LT	750,177	994,920	1,004,833	1,004,987	1,004,406	1,004,895	859,940	861,818	829,441	828,890
	ST	0	11,650	0	0	0	0	0	0	0	0
	Total	750,177	1,006,570	1,004,833	1,004,987	1,004,406	1,004,895	859,940	861,818	829,441	828,890
Total Central	LT	9,493,290	9,274,940	10,496,391	10,047,809	10,135,697	10,229,146	11,171,841	11,770,866	11,807,516	11,667,473
	ST	1,765,126	1,725,542	1,006,806	1,706,386	1,631,479	1,446,780	1,110,191	1,230,257	866,212	934,110
	Total	11,258,416	11,000,482	11,503,197	11,754,195	11,767,176	11,675,926	12,282,032	13,001,123	12,673,728	12,601,583
Midwest											
Electric Utility	LT	214,848	214,848	214,848	321,842	254,033	294,033	244,033	293,659	236,960	261,913
	ST	0	0	0	16,759	16,759	16,759	16,759	34,533	14,191	4,191
	Total	214,848	214,848	214,848	338,601	270,792	310,792	260,792	328,192	251,151	266,104
Industrial	LT	1,595,942	1,481,619	1,471,504	1,536,273	1,483,697	1,506,830	1,560,063	1,582,130	1,526,085	1,511,640
	ST	198,041	205,363	181,640	159,255	129,780	128,172	132,068	128,384	122,800	156,224
	Total	1,793,983	1,686,982	1,653,144	1,695,528	1,613,477	1,635,002	1,692,131	1,710,514	1,648,885	1,667,864
LDC	LT	9,991,942	9,681,436	10,080,499	12,101,837	9,971,034	9,782,043	10,162,705	11,969,289	9,802,748	9,616,003
	ST	91,534	415,631	266,258	937,988	781,586	688,786	695,870	809,776	433,451	393,443
	Total	10,083,476	10,097,067	10,346,757	13,039,825	10,752,620	10,470,829	10,858,575	12,779,065	10,236,199	10,009,446
Marketer	LT	3,157,117	3,797,913	3,862,761	4,167,639	3,986,517	3,975,960	4,052,580	4,645,204	4,529,869	4,282,963
	ST	1,965,365	1,993,142	2,200,965	2,499,252	1,901,102	1,731,434	1,733,961	1,569,598	607,649	1,028,999
	Total	5,122,482	5,791,055	6,063,726	6,666,891	5,887,619	5,707,394	5,786,541	6,214,802	5,137,518	5,311,962
Other	LT	427,760	421,879	445,879	526,879	647,027	718,970	667,049	602,051	605,767	636,098
	ST	57,150	101,360	91,990	184,750	25,961	28,818	35,629	242,575	43,625	47,800
	Total	484,910	523,239	537,869	711,629	672,988	747,788	702,678	844,626	649,392	683,898
Pipeline Company	LT	2,038,528	2,614,090	2,613,416	2,613,415	2,612,015	2,538,948	2,851,965	2,397,989	2,547,989	2,547,989
	ST	500,000	1,011,461	1,011,460	805,461	309,001	313,018	1	870,897	313,017	313,017
	Total	2,538,528	3,625,551	3,624,876	3,418,876	2,921,016	2,851,966	2,851,966	3,268,886	2,861,006	2,861,006
Total Midwest	LT	17,426,137	18,211,785	18,688,907	21,267,885	18,954,323	18,816,784	19,538,395	21,490,322	19,249,418	18,856,606
	ST	2,812,090	3,726,957	3,752,313	4,603,465	3,164,189	2,906,987	2,614,288	3,655,763	1,534,733	1,943,674
	Total	20,238,227	21,938,742	22,441,220	25,871,350	22,118,512	21,723,771	22,152,683	25,146,085	20,784,151	20,800,280
Northeast											
Electric Utility	LT	1,457,449	1,525,479	1,546,259	1,615,492	1,543,740	1,676,240	1,676,975	1,811,973	1,819,776	1,819,776
	ST	8,951	0	0	10,000	0	0	0	30,750	25,000	25,000
	Total	1,466,400	1,525,479	1,546,259	1,625,492	1,543,740	1,676,240	1,676,975	1,842,723	1,844,776	1,844,776
Industrial	LT	1,573,425	1,571,917	1,622,448	1,665,992	1,651,092	1,664,518	1,609,381	1,646,075	1,567,089	1,606,626
	ST	122,946	105,631	43,674	138,100	106,617	81,527	81,127	189,014	151,278	119,546
	Total	1,696,371	1,677,548	1,666,122	1,804,092	1,757,709	1,746,045	1,690,508	1,835,089	1,718,367	1,726,172
LDC	LT	22,250,880	22,383,013	24,535,257	24,916,952	24,666,800	22,443,457	24,280,333	25,318,279	23,101,279	22,725,835
	ST	428,659	389,183	279,998	686,258	582,482	600,200	579,938	748,792	701,317	734,030
	Total	22,679,539	22,772,196	24,815,255	25,603,210	25,249,282	23,043,657	24,860,271	26,067,071	23,802,596	23,459,865
Marketer	LT	1,799,256	1,844,793	1,917,060	2,084,088	2,091,012	2,091,580	2,070,155	2,194,557	2,216,603	2,283,276
	ST	365,283	245,582	201,565	535,994	352,741	322,910	372,693	614,588	365,358	509,982
	Total	2,164,539	2,090,375	2,118,625	2,620,082	2,443,753	2,414,490	2,442,848	2,809,145	2,581,961	2,793,258
Other	LT	52,085	57,509	201,719	90,876	57,614	57,543	85,738	87,642	95,354	99,101
	ST	189,071	187,446	37,571	191,815	99,084	99,094	104,259	105,318	100,844	148,476
	Total	241,156	244,955	239,290	282,691	156,698	156,637	189,997	192,960	196,198	247,577
Pipeline Company	LT	1,604,982	1,761,869	1,991,591	1,578,290	1,572,792	1,572,792	1,577,240	1,536,705	1,518,830	1,518,830
	ST	306,000	393,089	19,189	408,040	398,040	398,040	398,040	408,040	398,040	398,040
	Total	1,910,982	2,154,958	2,010,780	1,986,330	1,970,832	1,970,832	1,975,280	1,944,745	1,916,870	1,916,870
Total Northeast	LT	28,738,077	29,144,580	31,814,334	31,951,690	31,583,050	29,506,130	31,299,822	32,595,231	30,318,931	30,053,444
	ST	1,420,910	1,320,931	581,997	1,970,207	1,538,964	1,501,771	1,536,057	2,096,502	1,741,837	1,935,074
	Total	30,158,987	30,465,511	32,396,331	33,921,897	33,122,014	31,007,901	32,835,879	34,691,733	32,060,768	31,988,518

Table D12. Firm Transportation Capacity by Region and Shipper Type, April 1, 1996 - July 1, 1998 (Continued)
(Million Btu per Day)

Region / Pipeline Company	Contract Length	April 1, 1996	July 1, 1996	October 1, 1996	January 1, 1997	April 1, 1997	July 1, 1997	October 1, 1997	January 1, 1998	April 1, 1998	July 1, 1998
Southeast											
Electric Utility	LT	685,724	872,330	718,362	660,717	680,430	837,007	769,365	725,720	758,626	948,648
	ST	10,215	0	5,037	2,142	2,142	2,142	2,142	17,142	17,142	2,142
	Total	695,939	872,330	723,399	662,859	682,572	839,149	771,507	742,862	775,768	950,790
Industrial	LT	412,312	408,364	456,988	489,800	492,043	472,979	444,206	501,355	522,573	534,005
	ST	66,086	74,261	55,770	58,950	49,860	24,860	24,060	22,845	22,845	22,845
	Total	478,398	482,625	512,758	548,750	541,903	497,839	468,266	524,200	545,418	556,850
LDC	LT	6,253,173	6,390,791	6,578,563	7,146,532	6,706,026	6,434,140	6,533,577	7,219,607	6,731,724	6,542,729
	ST	179,602	188,754	162,494	276,466	234,645	234,645	226,093	216,183	180,974	176,386
	Total	6,432,775	6,579,545	6,741,057	7,422,998	6,940,671	6,668,785	6,759,670	7,435,790	6,912,698	6,719,115
Marketer	LT	704,138	427,971	788,037	802,120	845,755	936,944	912,601	1,013,906	812,811	796,367
	ST	387,671	678,889	270,821	407,475	230,116	291,710	219,917	235,171	306,884	317,085
	Total	1,091,809	1,106,860	1,058,858	1,209,595	1,075,871	1,228,654	1,132,518	1,249,077	1,119,695	1,113,452
Other	LT	142,501	146,918	147,352	115,201	128,201	179,918	180,352	200,039	214,841	215,061
	ST	30,772	47,772	47,772	50,772	60,772	35,154	30,154	39,772	39,772	25,772
	Total	173,273	194,690	195,124	165,973	188,973	215,072	210,506	239,811	254,613	240,833
Pipeline Company	LT	656,114	664,214	325,905	313,823	313,690	313,690	313,690	302,260	302,252	267,252
	ST	102,850	105,936	0	0	0	0	0	0	0	0
	Total	758,964	770,150	325,905	313,823	313,690	313,690	313,690	302,260	302,252	267,252
Total Southeast	LT	8,853,962	8,910,588	9,015,207	9,528,193	9,166,145	9,174,678	9,153,791	9,962,887	9,342,827	9,304,062
	ST	777,196	1,095,612	541,894	795,805	577,535	588,511	502,366	531,113	567,617	544,230
	Total	9,631,158	10,006,200	9,557,101	10,323,998	9,743,680	9,763,189	9,656,157	10,494,000	9,910,444	9,848,292
Southwest											
Electric Utility	LT	36,997	24,676	54,355	122,477	54,355	26,922	54,117	122,477	52,239	39,167
	ST	0	0	0	0	0	0	0	0	0	0
	Total	36,997	24,676	54,355	122,477	54,355	26,922	54,117	122,477	52,239	39,167
Industrial	LT	292,734	306,784	322,175	314,512	331,897	359,286	359,490	358,327	362,459	327,554
	ST	100,572	183,884	92,254	123,536	89,027	113,097	58,177	57,930	63,197	141,156
	Total	393,306	490,668	414,429	438,048	420,924	472,383	417,667	416,257	425,656	468,710
LDC	LT	2,979,588	2,812,602	3,054,977	3,003,485	2,928,880	2,250,868	2,413,358	2,954,122	2,574,700	2,240,104
	ST	75,558	277,165	88,806	401,051	297,861	303,778	271,704	275,107	70,098	132,631
	Total	3,055,146	3,089,767	3,143,783	3,404,536	3,226,741	2,554,646	2,685,062	3,229,229	2,644,798	2,372,735
Marketer	LT	1,098,364	1,155,130	1,175,806	1,180,054	1,011,551	1,017,069	936,529	1,067,611	1,365,997	1,309,080
	ST	969,947	693,341	549,292	712,306	811,340	742,286	824,144	956,466	460,470	573,652
	Total	2,068,311	1,848,471	1,725,098	1,892,360	1,822,891	1,759,355	1,760,673	2,024,077	1,826,467	1,882,732
Other	LT	193,593	241,636	188,375	246,870	178,879	174,010	168,217	279,426	297,867	289,022
	ST	24,400	410,200	440,790	516,900	455,900	450,500	476,280	439,400	351,346	401,068
	Total	217,993	651,836	629,165	763,770	634,779	624,510	644,497	718,826	649,213	690,090
Pipeline Company	LT	579,345	538,065	538,065	536,565	532,893	532,893	532,893	525,346	525,346	525,346
	ST	4,690	4,831	4,831	4,831	4,831	4,831	4,831	4,831	0	0
	Total	584,035	542,896	542,896	541,396	537,724	537,724	537,724	530,177	525,346	525,346
Total Southwest	LT	5,180,621	5,078,893	5,333,753	5,403,963	5,038,455	4,361,048	4,464,604	5,307,309	5,178,608	4,730,273
	ST	1,175,167	1,569,421	1,175,973	1,758,624	1,658,959	1,614,492	1,635,136	1,733,734	945,111	1,248,507
	Total	6,355,788	6,648,314	6,509,726	7,162,587	6,697,414	5,975,540	6,099,740	7,041,043	6,123,719	5,978,780
West											
Electric Utility	LT	1,206,312	1,208,877	1,208,877	1,252,107	1,218,877	1,032,168	1,045,168	1,058,460	1,013,730	1,013,730
	ST	50,000	0	1,298	0	47,761	75,386	70,000	9,038	24,284	12,920
	Total	1,256,312	1,208,877	1,210,175	1,252,107	1,266,638	1,107,554	1,115,168	1,067,498	1,038,014	1,026,650
Industrial	LT	251,048	251,828	247,794	263,495	265,803	259,161	268,361	261,076	265,765	317,757
	ST	9,600	9,600	9,600	13,100	75,349	66,204	57,204	66,404	59,800	9,800
	Total	260,648	261,428	257,394	276,595	341,152	325,365	325,565	327,480	325,565	327,557
LDC	LT	6,010,581	5,975,901	6,326,751	5,733,274	5,602,121	5,528,220	5,571,217	4,659,429	4,593,936	4,540,379
	ST	9,100	95,360	95,560	10,353	138,696	97,386	9,000	51,670	37,944	225,591
	Total	6,019,681	6,071,261	6,422,311	5,743,627	5,740,817	5,625,606	5,580,217	4,711,099	4,631,880	4,765,970
Marketer	LT	4,763,805	4,777,964	4,682,734	4,962,870	4,927,429	5,449,210	5,399,188	6,692,410	6,742,015	6,797,781
	ST	1,027,666	1,091,854	1,704,315	901,737	1,029,416	695,060	676,174	788,782	894,211	999,065
	Total	5,791,471	5,869,818	6,387,049	5,864,607	5,956,845	6,144,270	6,075,362	7,481,192	7,636,226	7,796,846
Other	LT	503,336	607,071	609,105	661,628	631,114	522,203	650,953	642,903	640,903	645,000
	ST	108,600	123,600	133,360	164,320	106,552	148,400	138,200	203,848	202,290	266,030
	Total	611,936	730,671	742,465	825,948	737,666	670,603	789,153	846,751	843,193	911,030
Pipeline Company	LT	488,267	488,267	488,267	638,267	488,267	488,267	488,267	638,267	488,267	488,267
	ST	0	25,000	261,810	241,750	0	15,000	0	0	0	10,000
	Total	488,267	513,267	750,077	880,017	488,267	503,267	488,267	638,267	488,267	498,267
Total West	LT	13,223,349	13,309,908	13,563,528	13,511,641	13,133,611	13,279,229	13,423,154	13,952,545	13,744,616	13,802,914
	ST	1,204,966	1,345,414	2,205,943	1,331,260	1,397,774	1,097,436	950,578	1,119,742	1,218,529	1,523,406
	Total	14,428,315	14,655,322	15,769,471	14,842,901	14,531,385	14,376,665	14,373,732	15,072,287	14,963,145	15,326,320

Table D12. Firm Transportation Capacity by Region and Shipper Type, April 1, 1996 - July 1, 1998 (Continued)

(Million Btu per Day)

Region / Pipeline Company	Contract Length	April 1, 1996	July 1, 1996	October 1, 1996	January 1, 1997	April 1, 1997	July 1, 1997	October 1, 1997	January 1, 1998	April 1, 1998	July 1, 1998
Total United States											
Electric Utility	LT	3,622,427	3,867,305	3,763,795	4,066,666	3,845,469	3,960,407	3,913,949	4,136,580	4,024,258	4,227,361
	ST	69,166	0	6,335	28,901	67,065	94,690	89,304	92,270	80,617	44,253
	Total	3,691,593	3,867,305	3,770,130	4,095,567	3,912,534	4,055,097	4,003,253	4,228,850	4,104,875	4,271,614
Industrial	LT	4,333,912	4,179,351	4,349,149	4,424,509	4,365,183	4,398,928	4,413,877	4,586,006	4,486,250	4,532,503
	ST	525,863	662,719	408,888	605,376	564,249	531,960	447,545	512,140	469,866	503,472
	Total	4,859,775	4,842,070	4,758,037	5,029,885	4,929,432	4,930,888	4,861,422	5,098,146	4,956,116	5,035,975
LDC	LT	52,349,956	51,651,820	55,768,626	57,677,067	54,655,257	51,379,912	54,143,431	57,574,866	52,306,388	51,088,005
	ST	1,616,223	2,107,402	1,204,184	3,107,956	2,801,681	2,525,573	2,199,901	2,615,749	1,761,463	2,000,831
	Total	53,966,179	53,759,222	56,972,810	60,785,023	57,456,938	53,905,485	56,343,332	60,190,615	54,067,851	53,088,836
Marketer	LT	13,674,504	14,200,375	14,941,541	15,672,422	15,455,227	16,048,874	16,580,810	19,099,585	19,166,708	18,919,092
	ST	5,493,317	5,465,389	5,386,261	5,751,405	5,017,345	4,456,872	4,405,830	4,773,250	3,078,827	3,949,243
	Total	19,167,821	19,665,764	20,327,802	21,423,827	20,472,572	20,505,746	20,986,640	23,872,835	22,245,535	22,868,335
Other	LT	2,817,224	2,970,418	3,126,932	3,185,170	3,166,082	3,127,409	3,375,545	3,419,738	3,446,187	3,471,237
	ST	537,346	996,400	961,968	1,212,027	806,688	815,993	803,164	1,089,934	772,209	910,145
	Total	3,354,570	3,966,818	4,088,900	4,397,197	3,972,770	3,943,402	4,178,709	4,509,672	4,218,396	4,381,382
Pipeline Company	LT	6,117,413	7,061,425	6,962,077	6,685,347	6,524,063	6,451,485	6,623,995	6,262,385	6,212,125	6,176,574
	ST	913,540	1,551,967	1,297,290	1,460,082	711,872	730,889	402,872	1,283,768	711,057	721,057
	Total	7,030,953	8,613,392	8,259,367	8,145,429	7,235,935	7,182,374	7,026,867	7,546,153	6,923,182	6,897,631
All Shippers	LT	82,915,436	83,930,694	88,912,120	91,711,181	88,011,281	85,367,015	89,051,607	95,079,160	89,641,916	88,414,772
	ST	9,155,455	10,783,877	9,264,926	12,165,747	9,968,900	9,155,977	8,348,616	10,367,111	6,874,039	8,129,001
	Total	92,070,891	94,714,571	98,177,046	103,876,928	97,980,181	94,522,992	97,400,223	105,446,271	96,515,955	96,543,773

LT = Long term (longer than 366 days); ST = Short term (366 days or less); LDC = local distribution company.

Note: Data are for 64 interstate pipeline companies.

Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers quarterly filings for April 1, 1996 through July 1, 1998, FERC Bulletin Board (August 14, 1998).

Table D13. Firm Capacity Under Expired and New Contracts During July 1, 1997 - July 1, 1998, by Shipper Type and Contract Length

(Million Btu per Day)

Shipper/Length/Quarter Ending	Expired[1] Capacity	New[2] Capacity	Total Capacity Under Contract
Electric Utility			
Long-Term			
October 1, 1997	124,213	77,755	3,913,949
January 1, 1998	24,526	247,157	4,136,580
April 1, 1998	177,969	65,647	4,024,258
July 1, 1998	0	203,103	4,227,361
Total	326,708	593,662	
Short-Term			
October 1, 1997	7,528	2,142	89,304
January 1, 1998	87,162	90,128	92,270
April 1, 1998	39,321	27,668	80,617
July 1, 1998	36,364	0	44,253
Total	170,375	119,938	
Industrial			
Long-Term			
October 1, 1997	58,108	73,057	4,413,877
January 1, 1998	167,174	339,303	4,586,006
April 1, 1998	145,699	45,943	4,486,250
July 1, 1998	77,427	123,680	4,532,503
Total	448,408	581,983	
Short-Term			
October 1, 1997	231,717	147,302	447,545
January 1, 1998	273,707	338,302	512,140
April 1, 1998	292,462	250,188	469,866
July 1, 1998	284,153	317,759	503,472
Total	1,082,039	1,053,551	
Local Distribution Company			
Long-Term			
October 1, 1997	220,318	2,983,837	54,143,431
January 1, 1998	1,501,956	4,933,391	57,574,866
April 1, 1998	5,776,537	508,059	52,306,388
July 1, 1998	1,441,773	223,390	51,088,005
Total	8,940,584	8,648,677	
Short-Term			
October 1, 1997	876,923	551,251	2,199,901
January 1, 1998	1,602,585	2,018,433	2,615,749
April 1, 1998	1,530,353	676,067	1,761,463
July 1, 1998	600,525	839,893	2,000,831
Total	4,610,386	4,085,644	
Marketer			
Long-Term			
October 1, 1997	289,570	821,506	16,580,810
January 1, 1998	427,243	2,946,018	19,099,585
April 1, 1998	1,108,259	1,175,382	19,166,708
July 1, 1998	528,115	280,499	18,919,092
Total	2,353,187	5,223,405	
Short-Term			
October 1, 1997	1,232,495	1,181,453	4,405,830
January 1, 1998	2,833,575	3,200,995	4,773,250
April 1, 1998	3,449,191	1,754,768	3,078,827
July 1, 1998	829,425	1,699,841	3,949,243
Total	8,344,686	7,837,057	

Table D13. Firm Capacity Under Expired and New Contracts During July 1, 1997 - July 1, 1998, by Shipper Type and Contract Length (Continued)
(Million Btu per Day)

Shipper/Length/Quarter Ending	Expired[1] Capacity	New[2] Capacity	Total Capacity Under Contract
Other			
Long-Term			
October 1, 1997	14,894	263,030	3,375,545
January 1, 1998	158,587	202,780	3,419,738
April 1, 1998	11,550	37,999	3,446,187
July 1, 1998	40,688	65,738	3,471,237
Total	225,719	569,547	
Short-Term			
October 1, 1997	179,292	166,463	803,164
January 1, 1998	268,234	555,004	1,089,934
April 1, 1998	806,354	488,629	772,209
July 1, 1998	231,744	369,680	910,145
Total	1,485,624	1,579,776	
Pipeline Company			
Long-Term			
October 1, 1997	10,661	183,171	6,623,995
January 1, 1998	430,597	68,987	6,262,385
April 1, 1998	50,260	0	6,212,125
July 1, 1998	41,030	5,479	6,176,574
Total	532,548	257,637	
Short-Term			
October 1, 1997	472,336	144,319	402,872
January 1, 1998	15,493	896,389	1,283,768
April 1, 1998	889,425	316,714	711,057
July 1, 1998	547,549	557,549	721,057
Total	1,924,803	1,914,971	
All Shippers			
Long-Term			
October 1, 1997	717,764	4,402,356	89,051,607
January 1, 1998	2,710,083	8,737,636	95,079,160
April 1, 1998	7,270,274	1,833,030	89,641,916
July 1, 1998	2,129,033	901,889	88,414,772
Total	12,827,154	15,874,911	
Short-Term			
October 1, 1997	3,000,291	2,192,930	8,348,616
January 1, 1998	5,080,756	7,099,251	10,367,111
April 1, 1998	7,007,106	3,514,034	6,874,039
July 1, 1998	2,529,760	3,784,722	8,129,001
Total	17,617,913	16,590,937	
Total Contracts			
October 1, 1997	3,718,055	6,595,286	97,400,223
January 1, 1998	7,790,839	15,836,887	105,446,271
April 1, 1998	14,277,380	5,347,064	96,515,955
July 1, 1998	4,658,793	4,686,611	96,543,773
Total	30,445,067	32,465,848	
Average Oct. 1, 1997 - July 1, 1998	7,611,267	8,116,462	98,976,556
Percent of Total	7.7	8.2	

[1]Expired contracts from previous quarterly filing. Includes downward capacity revisions.
[2]New contracts include upward capacity revisions.

Notes: Long-term contracts are longer than 366 days, short-term contracts are 366 days or less. The "Other" category includes producers, gatherers, processors, and storage operators as well as shippers that could not be classified. Data are for 64 interstate pipeline companies.

Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers quarterly filings for July 1, 1997 through July 1, 1998, FERC Bulletin Board (August 14, 1998).

Table D14. Regional Characteristics of Released Capacity Used to Estimate Turnback, November 1993 - March 1998

Nonheating Season (April - October)

Region	1994 Average Rate ($/Mcf-Mo.)	1994 Capacity Held (Bcf)	1994 Percent Capacity Subject to Recall	1995 Average Rate ($/Mcf-Mo.)	1995 Capacity Held (Bcf)	1995 Percent Capacity Subject to Recall	1996 Average Rate ($/Mcf-Mo.)	1996 Capacity Held (Bcf)	1996 Percent Capacity Subject to Recall	1997 Average Rate ($/Mcf-Mo.)	1997 Capacity Held (Bcf)	1997 Percent Capacity Subject to Recall
Central	2.78	171	92	2.80	323	65	2.47	338	55	3.29	399	57
Midwest	6.20	325	88	5.69	472	82	8.66	589	73	6.92	472	72
Northeast	2.61	633	84	2.28	1,084	64	4.30	1,683	70	5.62	1,984	73
Southeast	2.64	247	79	1.45	469	67	3.57	526	67	3.63	686	68
Southwest	3.32	10	94	3.14	21	19	2.55	21	0	2.64	23	6
West	2.22	538	83	3.30	721	38	2.91	972	38	2.94	870	24
Total	3.13	1,922	85	2.97	3,090	61	4.34	4,129	61	4.70	4,434	60

Heating Season (November - March)

Region	1993-94 Average Rate ($/Mcf-Mo.)	1993-94 Capacity Held (Bcf)	1993-94 Percent Capacity Subject to Recall	1994-95 Average Rate ($/Mcf-Mo.)	1994-95 Capacity Held (Bcf)	1994-95 Percent Capacity Subject to Recall	1995-96 Average Rate ($/Mcf-Mo.)	1995-96 Capacity Held (Bcf)	1995-96 Percent Capacity Subject to Recall	1996-97 Average Rate ($/Mcf-Mo.)	1996-97 Capacity Held (Bcf)	1996-97 Percent Capacity Subject to Recall	1997-98 Average Rate ($/Mcf-Mo.)	1997-98 Capacity Held (Bcf)	1997-98 Percent Capacity Subject to Recall
Central	3.31	42	--	2.94	142	71	2.60	203	64	2.99	246	58	3.80	288	51
Midwest	4.78	72	--	6.73	172	79	8.06	341	84	9.14	401	69	6.84	372	71
Northeast	4.30	197	--	3.48	524	76	5.79	750	69	7.25	1,091	76	7.23	1,303	72
Southeast	3.60	52	--	2.11	283	79	2.70	343	76	4.16	463	79	5.15	475	67
Southwest	2.16	5	--	5.74	6	91	2.70	16	3	2.50	16	4	2.85	17	9
West	4.61	164	--	1.50	350	51	2.97	625	37	3.01	541	31	3.14	723	27
Total	4.30	532	--	3.08	1,477	71	4.59	2,278	63	5.77	2,758	65	5.61	3,177	59
Total for Heating Year	--	--	--	3.11	3,399	79	3.66	5,368	62	4.91	6,887	62	5.08	7,611	60

$/Mcf-Mo. = Dollars per thousand cubic feet per month. Bcf = Billion cubic feet. -- = Not applicable. Heating Year = April - March.

Note: These data are for the 27 interstate natural gas pipeline companies used to estimate capacity turnback. The company names are noted in Table D3.

Sources: Energy Information Administration, Office of Oil and Gas, derived from: **November 1993 - July 1994:** Pasha Publications, Inc. **July 1994 - March 1998:** Federal Energy Regulatory Commission, Electronic Data Interchange (EDI) data.

Table D15. Regional Characteristics of Released Capacity for All Pipeline Companies, November 1993 - March 1998

Nonheating Season (April - October)

Region	1994			1995			1996			1997		
	Average Rate ($/Mcf-Mo.)	Capacity Held (Bcf)	Percent Capacity Subject to Recall	Average Rate ($/Mcf-Mo.)	Capacity Held (Bcf)	Percent Capacity Subject to Recall	Average Rate ($/Mcf-Mo.)	Capacity Held (Bcf)	Percent Capacity Subject to Recall	Average Rate ($/Mcf-Mo.)	Capacity Held (Bcf)	Percent Capacity Subject to Recall
Central	2.49	274	94	2.11	563	78	2.50	440	62	2.70	551	56
Midwest	6.12	331	88	5.69	472	82	8.49	623	69	6.86	502	67
Northeast	2.61	638	85	2.27	1,103	64	4.30	1,683	70	5.62	1,984	73
Southeast	2.64	247	79	1.45	469	67	3.55	529	67	3.63	686	68
Southwest	3.32	10	94	5.27	35	26	5.24	29	1	2.65	24	6
West	2.21	541	83	3.26	731	38	2.87	984	38	2.89	885	24
Total	3.07	2,041	85	2.85	3,372	63	4.31	4,289	61	4.53	4,632	60

Heating Season (November - March)

Region	1993-94			1994-95			1995-96			1996-97			1997-98		
	Average Rate ($/Mcf-Mo.)	Capacity Held (Bcf)	Percent Capacity Subject to Recall	Average Rate ($/Mcf-Mo.)	Capacity Held (Bcf)	Percent Capacity Subject to Recall	Average Rate ($/Mcf-Mo.)	Capacity Held (Bcf)	Percent Capacity Subject to Recall	Average Rate ($/Mcf-Mo.)	Capacity Held (Bcf)	Percent Capacity Subject to Recall	Average Rate ($/Mcf-Mo.)	Capacity Held (Bcf)	Percent Capacity Subject to Recall
Central	3.14	75	--	2.41	236	80	2.33	349	75	2.90	283	60	3.47	391	55
Midwest	4.78	72	--	6.73	172	79	7.83	389	79	9.02	419	66	6.81	390	68
Northeast	4.28	199	--	3.47	535	76	5.75	764	69	7.25	1,091	76	7.24	1,305	73
Southeast	3.60	52	--	2.11	283	79	2.69	344	76	4.16	463	79	5.13	477	67
Southwest	2.16	5	--	9.18	10	51	5.18	23	10	5.14	21	3	2.84	17	9
West	4.61	164	--	1.49	353	50	2.95	629	37	2.97	548	32	3.16	742	26
Total	4.21	567	--	3.02	1,589	72	4.46	2,499	64	5.73	2,825	64	5.51	3,322	58
Total for Heating Year	--	--	--	3.05	3,630	79	3.54	5,872	63	4.87	7,113	62	4.97	7,954	59

$/Mcf-Mo. = Dollars per thousand cubic feet per month. Bcf = Billion cubic feet. -- = Not applicable. Heating Year = April - March.

Note: These data are for all (43) interstate natural gas pipeline companies for which capacity release information was available and were used in Chapter 1. The companies are listed in Table D1.

Sources: Energy Information Administration, Office of Oil and Gas, derived from: **November 1993 - July 1994:** Pasha Publications, Inc. **July 1994 - March 1998:** Federal Energy Regulatory Commission, Electronic Data Interchange (EDI) data.

Table D16. Expiration and Turnback of Capacity Under Contract as of July 1, 1998

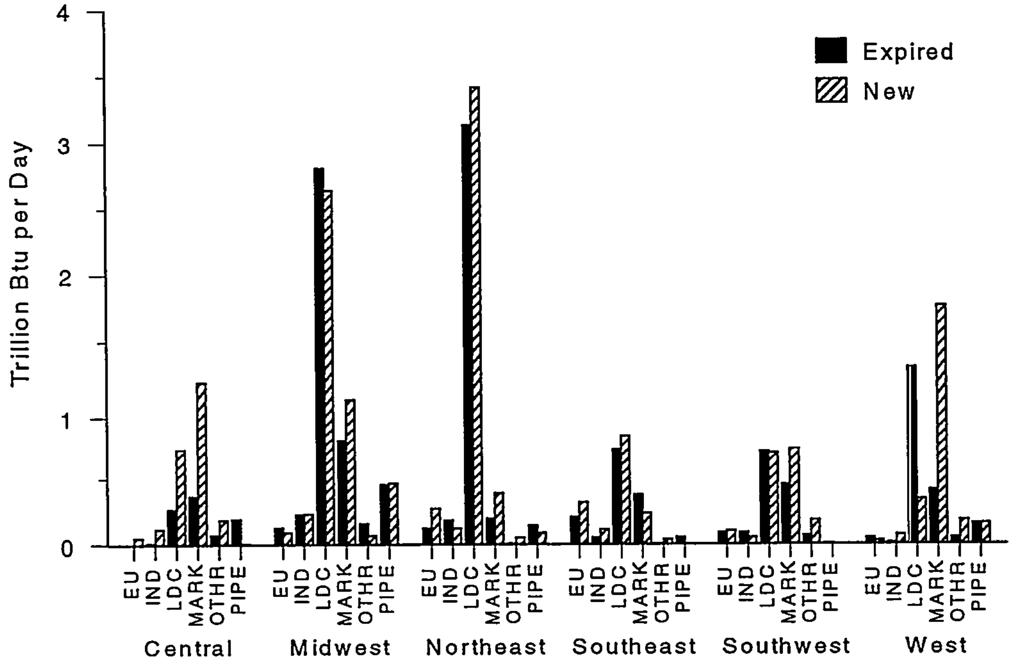
Year	Expiration of Firm Transportation Capacity			Estimated Turned Back Capacity (million Btu)	Cumulative Turned Back Capacity (million Btu)	Cumulative Turned Back Capacity as a Percent of Total Capacity	Cumulative Turned Back Capacity as a Percent of Long-Term Capacity
	Under Contract as of July 1, 1998		Total (million Btu)				
	Long-Term (million Btu)	Short-Term (million Btu)					
Total	**87,044,183**	**8,129,001**	**95,173,184**	**17,765,394**			
1998	4,313,526	5,540,465	9,853,991	761,917	761,917	0.8	0.9
1999	9,136,521	2,588,536	11,725,057	1,651,306	2,413,223	2.5	2.8
2000	11,517,498	0	11,517,498	2,126,620	4,539,843	4.8	5.2
2001	6,060,564	0	6,060,564	1,171,708	5,711,551	6.0	6.6
2002	6,938,695	0	6,938,695	1,169,205	6,880,757	7.2	7.9
2003	5,124,486	0	5,124,486	1,089,161	7,969,918	8.4	9.2
2004	8,193,511	0	8,193,511	1,926,771	9,896,688	10.4	11.4
2005	6,899,755	0	6,899,755	1,430,681	11,327,369	11.9	13.0
2006	3,986,975	0	3,986,975	960,979	12,288,349	12.9	14.1
2007	4,588,289	0	4,588,289	1,077,321	13,365,669	14.0	15.4
2008	2,680,689	0	2,680,689	586,576	13,952,245	14.7	16.0
2009	2,072,385	0	2,072,385	469,878	14,422,123	15.2	16.6
2010	1,492,441	0	1,492,441	335,389	14,757,513	15.5	17.0
2011	1,971,850	0	1,971,850	372,932	15,130,445	15.9	17.4
2012	3,725,179	0	3,725,179	838,558	15,969,003	16.8	18.3
2013	2,167,455	0	2,167,455	420,043	16,389,046	17.2	18.8
2014	842,792	0	842,792	164,935	16,553,981	17.4	19.0
2015	1,706,015	0	1,706,015	408,003	16,961,984	17.8	19.5
2016	783,288	0	783,288	158,562	17,120,546	18.0	19.7
2017	900,441	0	900,441	206,783	17,327,329	18.2	19.9
2018	126,700	0	126,700	27,067	17,354,397	18.2	19.9
2019	0	0	0	0	17,354,397	18.2	19.9
2020	49,850	0	49,850	10,048	17,364,444	18.2	19.9
2021	39,240	0	39,240	8,805	17,373,250	18.3	20.0
2022	0	0	0	0	17,373,250	18.3	20.0
2023	1,362,230	0	1,362,230	317,877	17,691,126	18.6	20.3
2024	0	0	0	0	17,691,126	18.6	20.3
2025[a]	363,808	0	363,808	74,267	17,765,394	18.7	20.4

[a]Data for 2025 include 0.02 trillion Btu per day of capacity expirations in years beyond 2025.

Notes: Data are for 64 interstate pipeline companies. Data for 1998 are for the last 6 months.

Sources: Energy Information Administration, Office of Oil and Gas based on: **Expiring Capacity:** derived from Federal Energy Regulatory Commission (FERC) Index of Custmers data for July 1, 1998, FERC Bulletin Board (August 14, 1998), and **Turnback Capacity:** derived from various sources, see "Assessment of Potential Turnback," pp. 206-207.

Figure D3. Long-term Firm Capacity Under Expired and New Contracts, by Region and Shipper Type, July 1, 1997 - July 1, 1998

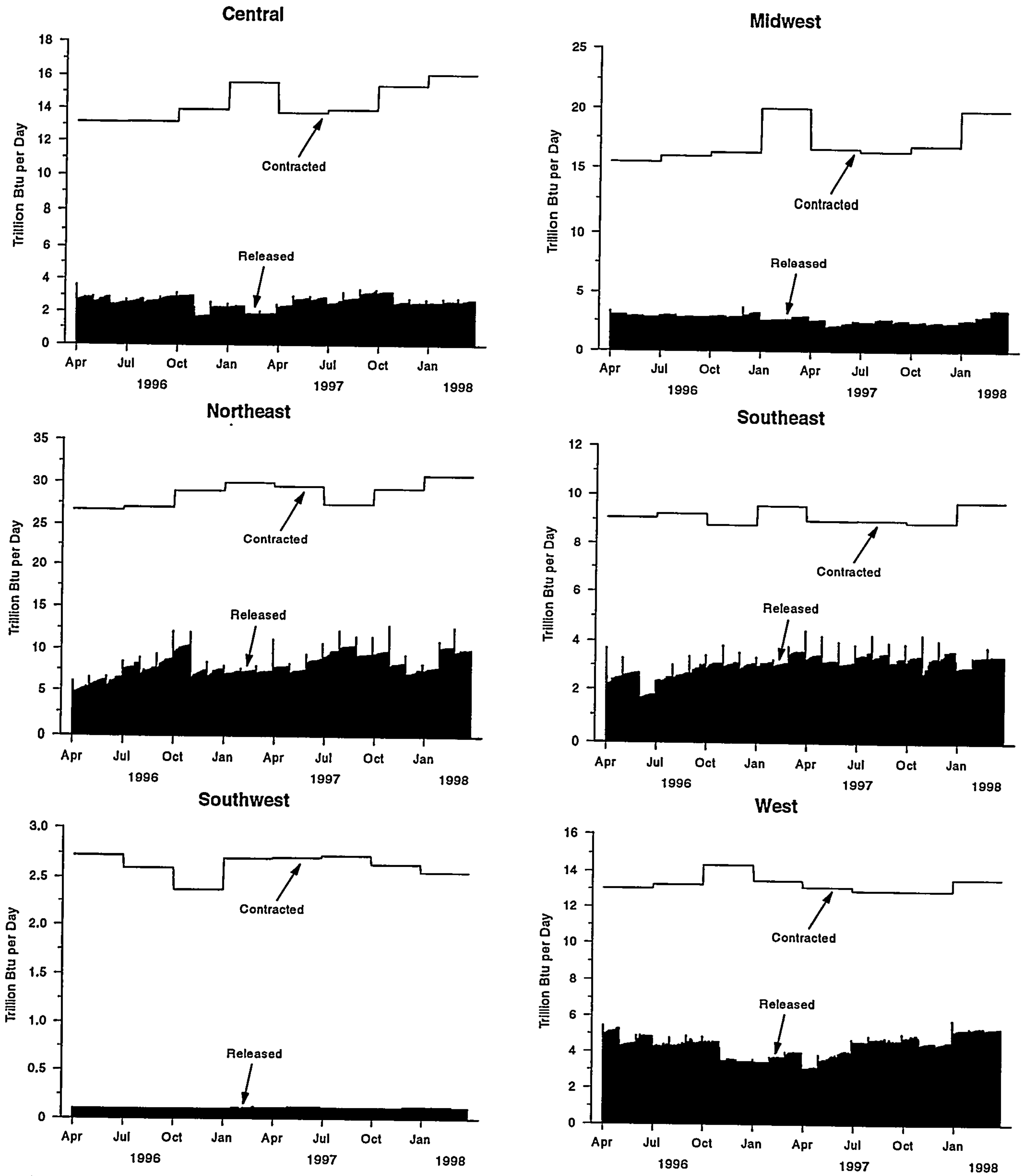


EU = Electric utility, IND = Industrial, LDC = Local distribution company, MARK = Marketer, OTHR = Other, PIPE = Pipeline company.

Notes: New capacity includes positive revisions and expired capacity includes negative revisions. Data are for 64 interstate pipeline companies.

Source: Energy Information Administration, Office of Oil and Gas, derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers quarterly filings for July 1, 1997 through July 1, 1998, FERC Bulletin Board (August 14, 1998).

Figure D4. Daily Contracted and Released Firm Transportation Capacity, April 1996-March 1998, by Region



Note: Released capacity is that held by replacement shippers. The scales on each graph are different. Data are for 27 interstate pipeline companies.

Source: Energy Information Administration, Office of Oil and Gas. **Contracted Capacity:** derived from Federal Energy Regulatory Commission (FERC) data from Index of Customers filings for April 1, 1996 through January 1, 1998, FERC Bulletin Board (August 14, 1998). **Released Capacity:** derived from: April 1996-May 1997—FERC Electronic Data Interchange, May 1997-March 1998—FERC downloaded Internet data.

Appendix E

Recent Corporate Combinations in the Natural Gas Industry

Table E1. Recent Corporate Combinations in the Natural Gas Industry

Acquiring Company or Partners	Acquired Company (all or part)	Brand Name or New Company Name	Type of Combination	Date Announced	Date Completed	Business Areas	Notes	Value (million dollars)
AEP Resources	Equitable Resources		Divestiture	Sep-98	Pending	Mid-stream gas assets	Properties in Louisiana and Texas including intrastate pipeline, processing, and storage facilities.	320
AES Corporation	Destec Energy		Acquisition	Dec-97	Feb-97	Elect	Destec to merge into Dynegy; AES gains international assets, Dynegy gains domestic assets.	(see NGC - Destec)
AGL Resources, Dynegy, Piedmont Natural Gas		SouthStar Energy Services LLC	Joint Venture	Jul-98		Energy products and services	Products and services include gas, electricity, fuel oil, and propane. Positioned to take advantage of deregulation in Georgia. Strategic fit in unregulated markets.	
Allegheny Energy	Duquesne Light		Merger	Apr-97	Pending	Gas, elect	Has regulatory approval with numerous restrictions and conditions. In Jul-98, DQE withdrew. In Oct-98, Allegheny sued DQE to block termination of the merger.	4,300
American Resources	TECO Oil & Gas, Inc.		Acquisition	Mar-98	Mar-98	O&G, E&P, offshore Gulf	Acquisition of all offshore assets of TECO (see TECO).	58
Amway Corp.; Columbia Energy Group			Alliance	Nov-98		Door-to-door marketing of gas & electricity	Amway distributors will market Columbia gas & electricity to residential and small commercial customers. Program begins in Georgia, will expand with restructuring to all States.	
Atmos Energy Corp.	United Cities Gas Co.	Atmos	Acquisition	Sep-96	Jul-97	Gas	Atmos becomes 12th largest gas LDC in U.S.; gas and some propane in 13 States.	
Aurora Natural Gas	GED Gas Services	Aurora	Acquisition	Mar-98	Mar-98	Gas marketing		
Baker Hughes	Western Atlas		Merger	May-98	Aug-98	Field service	Baker Hughes to buy all shares of Western Atlas.	5,500
Baytex Energy Ltd.	Dorset Exploration Ltd.	Baytex	Merger	Oct-97	Oct-97	Oil & gas	Canadian companies.	716
Boston Edison; RCN			Joint Venture	Sep-96		Energy services	To develop broadband network for 1-stop energy/telecommunication services. RCN owns 51 percent.	
Boston Gas	Essex County Gas		Merger	Dec-97	Pending	Gas	Eastern Enterprises is the parent of Boston Gas. State approved subject to a 10-year freeze on rates and 5 percent reduction in the cost of gas.	85
Boston Edison	Williams Energy Services Company	Energy Vision	Joint Venture			Energy marketing and services	Joint venture markets electricity, natural gas and energy services to retail customers in New England; Williams and Boston each own 50 percent	

Table E1. Recent Corporate Combinations in the Natural Gas Industry (Continued)

Acquiring Company or Partners	Acquired Company (all or part)	Brand Name or New Company Name	Type of Combination	Date Announced	Date Completed	Business Areas	Notes	Value (million dollars)
Brooklyn Union Gas	Long Island Lighting Company	KeySpan	Merger	Dec-96	May-98	Gas & electric utilities	Combined company serves parts of New York City and Long Island. Opportunity to expand Long Island gas market.	4,000
British Petroleum PLC	Amoco Corp.		Merger	Aug-98	Pending	Oil, gas, chemicals, renewables	Amoco is largest gas producer in U.S. Largest industrial merger in history.	48,000
Burlington Resources	Louisiana Land & Exploration		Acquisition	Jul-97	Oct-97	O&G, E&P	Creates "super independent."	3,200
CalEnergy Company	MidAmerican Energy Holdings Company	Mid American in U.S. - CalEnergy outside U.S.	Merger	Aug-98	Pending	Gas, electric, services	Mid American to become wholly owned subsidiary of CalEnergy; for name recognition, Cal will change name to MidAmerican; 3.3 million customers -- goal 11 million.	4,000
Calpine Corporation	Dominion Energy		Divestiture	Apr-98		Cogeneration	Two plants near Houston sold to raise capital for expansion elsewhere.	110
Calpine Corp.	Brooklyn Union Gas	Gas Energy, Inc	Divestiture	Dec-97	Dec-97	Gas power plants and cogeneration	With sale of Gas Energy and Gas Energy Cogeneration, BUG sought to maximize shareholder value and pursue other investment opportunities.	100
Canadian Occidental Petroleum Ltd.	Wascana Energy Inc.		Merger	1997	Jun-97	Oil & some gas	Wascana privatized by Saskatchewan govt - rich in heavy oil reserves. Wascana to manage Occidental properties in Canada.	1,700
Canadian Occidental Petroleum Ltd.	Compton Petroleum Corporation		Divestiture	1997	Jul-97	Gas wells, production, processing	Compton acquired working interests.	
Cargill, WPL Holdings		Cargill-IEC	Joint Venture	Jun-97		Energy trading & marketing	Energy trading, marketing, and risk management to wholesale electricity customers. The venture attempts to link Cargill's expertise in commodity trading to the electric power market.	
Carolina Light & Power Co.	North Carolina Natural Gas Corp.		Merger	Nov-98	Pending	Gas distribution; propane	Expands portfolio of products and services by adding gas and propane. Provides fuel supply for existing and planned gas-fired power plants.	
Carolina Light & Power Co.	Knowledge Builders	Strategic Resource Solutions Corporation	Acquisition	1996	Spring-97	Energy & facility management; building control systems	Software applications, energy performance, conservation; began joint venture with Avista in Oct-97. Acquired building automation & control systems companies and cogeneration facilities in '97 & '98.	
Carolina Light & Power Co.	Capital Information Services Inc.	Interpath Communications	Acquisition	Dec-97	Dec-97	Internet, telecommunications	Provides Internet and telecommunication services to residential and business customers.	
CMS Energy; WestCoast Energy, Inc.		TriState Pipeline	Joint Venture	Sep-97	Pending	Gas pipeline	Planned gas pipeline from Ontario, Canada to Chicago area. Two-thirds owned by CMS, one-third by WestCoast.	
CMS Energy	Continental Natural Gas	CMS Gas Transmission & Storage	Merger	Aug-98	Oct-98	Gathering, marketing	Provides financial base for expansion of Continental; provides additional supply source for CMS.	155
CMS Energy	Heritage Gas Service	CMS Gas Transmission & Storage	Acquisition	Oct-98	Oct-98	Gas gathering, processing, marketing	Expands CMS in Texas, Oklahoma area.	

Table E1. Recent Corporate Combinations in the Natural Gas Industry (Continued)

Acquiring Company or Partners	Acquired Company (all or part)	Brand Name or New Company Name	Type of Combination	Date Announced	Date Completed	Business Areas	Notes	Value (million dollars)
CMS Energy	Duke Power		Acquisition	Nov-98	Pending	Gas pipelines	CMS to purchase PanHandle and Trunkline from Duke. Duke will realize after-tax gain of $700 million; also reinvestment opportunities in high growth activities.	2,200
Chevron	Dynegy (NGC)	NGC	Merger	Jan-96	Aug-96	Gas, electric	Partial Merger -- Chevron to own 25 percent of Dynegy (formerly NGC): Dynegy to market Chevron's North American production of natural gas, NGLs, and electricity; Dynegy also to supply energy to Chevron refineries, chemical plants, and corporate facilities in North America.	
Cinergy Corp, Apache Corporation, Oryx Energy Company		ProEnergy	Strategic Alliance	Jun-98		Gas marketing	Cinergy acquired ProEnergy; the alliance will have exclusive rights to market all of the N. Amer gas production of Oryx and Apache for 10 years, also to market gas for others.	
Cinergy Corp, Florida Progress, New Century Energies		Cadence	Joint Venture	Sep-97		Energy services	Purchases and manages energy supply, develops energy plans, billing services, interactive software, auditing, metering and load profiles.	
Cinergy Corp.	Producers Energy Marketing, LLC		Acquisition	Jun-98		Gas marketing	Acquired as part of joint venture with Apache and Oryx. Markets all N. American gas production of Apache & Oryx.	
Coastal Corp.; Westcoast Energy Inc.		Engage Energy LLP	Joint Venture	Sep-96	First Quarter 1997	Gas marketing, gas services	Combined similar unregulated gas marketing subsidiaries to form energy and energy services company. (Also viewed as merger.)	
Cobb Energy Management Corp.; Colorado Springs Utilities; Idaho Power; Omaha Public Power District		Allied Utility Network	Joint Venture	May-98		Residential services	Joint venture of 4 utilities to provide home security, residential energy management, telecommunications, bill paying -- brand "Home Vantage."	
Columbia Natural Resources	Alamco Inc.		Acquisition	1997	Aug-97	Gas E&P	E&P subsidiary of Columbia Gas - focus on opportunities in Appalachian Basin.	
Consolidated Edison (NY)	Orange & Rockland		Acquisition	May-98	Pending	Electric, some gas	O&R to become wholly owned subsidiary of ConEd.	790
Constellation Energy Source; Goldman Sachs Power	Orion Power Holdings		Joint Venture	Mar-98		Merchant plant investment	Constellation is a wholely owned subsidary of BG&E. Orion plans to grow power marketing business by investing in and acquiring power plants in North America. May seek other investors.	310
Costilla Energy, Inc.	Pioneer Natural Resources Co.		Divestiture	Sep-98	Oct-98	O&G properties	Allows streamlining of operations by reduction of properties; proceeds to reduce overall cost structure.	410
Delmarva Power & Light	Atlantic Energy, Inc.	Conectiv	Merger	Aug-96	Feb-98	Electric, some gas	1 million electric customers; 100,000 gas customers.	

Table E1. Recent Corporate Combinations in the Natural Gas Industry (Continued)

Acquiring Company or Partners	Acquired Company (all or part)	Brand Name or New Company Name	Type of Combination	Date Announced	Date Completed	Business Areas	Notes	Value (million dollars)
Delmarva Power & Light; Connecticut Energy Corp.			Joint Venture		Sep-97	Gas & elecric, energy services	To sell energy and energy services in New York and New England. Initially to market to commercial and industrial customers, eventually to expand into residential.	
Dominion Energy	Phoenix Energy Sales	Carthage Energy Services	Acquisition	Jan-98	Jan-98	Gas production	Adds to Dominion's Appalachian Basin strategy. Becomes a division of Dominion's existing gas marketing company Carthage.	
Dominion Energy	Archer Resources Ltd.		Acquisition	Mar-98		Gas E&P	Increased Dominion's production by 50 percent; Based in Alberta, Canadian regulatory approval granted.	128
Dominion Energy	Peoples Energy Corporation		Joint Venture	May-98		Develop power plant	To develop and operate a 300MW peaking plant near Chicago -- close to several interstate gas pipelines.	90
Duke Energy Corporation; Mobil Corporation		Duke Energy Trading and Marketing, LLC	Joint Venture			Natural gas	Provide supply, storage, transportation and other services to companies and utilities. (Duke 40 percent, Mobil 60 percent.)	
Duke Energy Field Services; Louis Dreyfus Natural Gas		Duke/Louis Dreyfus	Joint Venture	Mar-95	Jun-97	Market gas/ electric & energy services	Initially set up as 50/50 joint venture. Duke acquired remaining 50 percent interest from Louis Dreyfus concluding the joint venture.	
Duke Energy Trading and Marketing, LLC; Puget Sound Energy		DETM	Joint Venture	Apr-98		Market electric & gas	Links Puget's surplus capacity with Duke Energy Corp's purchase of power plants from PG&E in California.	
Duke Energy Trading and Marketing; United Gas Management			Strategic Alliance	Jul 98		Energy management & marketing	DETM to support United in aggregating residential gas customers.	
Duke Energy	Oneok Inc.		Acquisition	Nov-98	Nov-98	Gas processing and gathering assets	Acquisition includes several Midcontinent assets including production, gathering, processing, and ½ of Oneok's interest in the Sycamore assets.	
Duke Energy Field Services	Brooks-Hidalgo Pipeline System	Duke Energy	Acquisition	Apr-98	Apr-98	Gathering	90-mile system. Continuing expansion of gathering and processing in south Texas.	
Duke Power	Pan Energy	Duke Energy	Merger	Nov-96	Jun-97	Elect/gas pipe	Becomes an all energy provider. In Nov-98, Duke announced sale of PanHandle and Trunkline to CMS of Michigan (see CMS).	7,500
Duke Power; Providence Gas Co.			Joint Venture	Fall 1997		Gas supply	Duke to purchase gas for Providence RI LDC. Duke can hedge, LDC can't.	
DukeSolutions	Engineering Interface Limited	DukeSolutions Canada, Inc	Acquisition	Sep-98	Sep-98	Energy services	Forms Canadian base of operations for DukeSolutions.	
Dynegy Inc.; AGL Resources; Piedmont Natural Gas Company, Inc.		SouthStar Energy Services	Joint Venture	Jul-98		Energy products and services	Initially to target commercial & industrial sectors; with deregulation plan to expand to include residential beginning in Georgia late in 1998.	

Table E1. Recent Corporate Combinations in the Natural Gas Industry (Continued)

Acquiring Company or Partners	Acquired Company (all or part)	Brand Name or New Company Name	Type of Combination	Date Announced	Date Completed	Business Areas	Notes	Value (million dollars)
Dynegy Inc.; Texaco		Versado Gas Processors LLC	Joint Venture	Jul-98		Gas gathering and processing	Dynegy (formerly NGC) and Texaco combined facilities in West Texas and New Mexico with combined daily volume of 341 mcf. Dynegy 63 percent, Texaco 37 percent.	
Dynegy; NICOR Inc.		NICOR Energy	Joint Venture	Jun-97		Energy services	Initially to market gas to commercial & industrial sectors, with deregulation plan to expand services & include residential. Formed a second venture in Jul-98 to develop gas-fired generation & cogeneration in 6 Midwest States.	
Dynegy; Chevron, Koch Industries; Shell	Venice Energy Services Company	VESCO	Joint Venture	Sep-97		Gas gathering & processing	VESCO expanded to include Shell participation; onshore Louisiana and offshore Gulf facilities.	
Dynegy (NGC Corp.)	Destec Energy		Acquisition	1996	Feb-97	Gas, elect	Joint acquisition with AES, Dynegy gained all domestic assets of Destec. (See AES/Destec.)	1,200
Dynegy	Trident NGL	NGL	Merger	1996	Apr-97	NGLs	Combined largest independent gas marketer with largest independent gas liquid operation in N. America.	95
Dynegy	Western Gas Resources		Acquisition	Oct-98	Oct-98	Production & gathering	Two separate transactions involving non-strategic assets of Western.	56
Eastern Group (see Statoil Energy)		Statoil Energy					Not the same as the Eastern Group Plc based in the UK & formed by Texas Utilities following its 1998 purachase of The Energy Group.	
Eastern Group	Blazer Energy (sub of Ashland, Inc.)		Acquisition	May-97	Jul-97	O&G, E&P	Blazer (domestic assets spun off from Ashland in Jan-97) assets in Appalachia & Gulf Coast.	
Edison International, New Energy Ventures			Joint Venture	Oct-98		Distributed generation		
El Paso Energy Corp.	Tenneco Energy	El Paso Energy Corp.	Merger	Jun-96	Dec-96	Gas	Creates one of largest U.S. natural gas transportation & marketing firms.	
El Paso Energy Corp.	Deep Tech International		Merger	Mar-98	Aug-98	Offshore Gulf	Includes Leviathon the largest gas gathering system in the Gulf ($ value is for Leviathon only).	450
El Paso Energy Corp.	PacifiCorp		Acquisition	Oct-97	Nov-97	Offshore assets	Offshore assets acquired by PacifiCorp's acquisition of TPC, resold to El Paseo: includes pipeline, gathering, and processing facilities.	195
Energetix	Griffith Energy		Acquisition	Apr-98	Sep-98	Heating oil, propane	Energetix is a nonregulated subsidiary of Rochester Gas & Electric; markets natural gas, electricity and energy services.	
Energy Pacific	CES/Way International		Acquisition	Dec-97	Jan-97	Energy services	Energy Pacific is a joint venture of Enova and Pacific Enterprises. Company is the largest independent energy services provider in U.S.	
Enova Corp., Pacific Enterprises		Sempra Energy	Merger	Oct-96	Jul-98	Gas, elec	FERC raised vertical market power concerns, but conditionally approved deal while deferring to California Public Utility Commission (PUC).	5,200

Table E1. Recent Corporate Combinations in the Natural Gas Industry (Continued)

Acquiring Company or Partners	Acquired Company (all or part)	Brand Name or New Company Name	Type of Combination	Date Announced	Date Completed	Business Areas	Notes	Value (million dollars)
Enova Corp.; Pacific Enterprises (Sempra Energy)		Sempra Energy Trading	Joint Venture	Dec-97		Gas & elect trading & marketing	Initially formed from acquisition of AIG Trading as a joint venture of PE / Enova. With completion of merger, became a wholly owned subsidiary of Sempra.	
Enron; Amoco		Amoco/Enron Solar	Joint Venture			Alternative energy	Largest U.S. photovoltaic producer; 50/50 Amoco and Enron Renewable Energy.	
Enron	Zond Corporation	Enron Renewable	Acquisition	Jan-97	Jan-97	Wind/solar	With Zond acquisition, Enron formed Enron Renewable (Includes all forms of renewable energy.)	
Enron	Portland General		Merger	Nov-96	Jul-97	Gas, elec	Combines a major marketer of gas and electricity with largest provider of electricity in Oregon. Provides a base for access into California market.	
Enron	Vastar		Joint Venture	Jan-97		Exploration	Onshore oil & gas exploration.	
Enron Capital & Trade Resources	Cogen Technologies		Acquisition	Nov-98		Gas-fired power plants	Enron to acquire 3 gas-fired power plants in New Jersey to take advantage of opportunities arising from restructuring in the State.	1,450
Enron; KeySpan Energy			Strategic Alliance	Feb-98		Gas supply	Enron provides management services for interstate pipeline transportation, gas supply, and storage.	
Enron; KeySpan Energy			Strategic Alliance	May-98		Gas supply services	Markets gas supply management services to gas distribution companies in Northeast. (Separate from interstate pipeline & supply venture of Feb-98.)	
Enron Energy Services; CB Richard Ellis; Insignia/ESG			Strategic Alliance	May-98		Energy management	Two separate alliances to provide energy management to residential and commercial properties. Extends Enron's efforts beyond core gas and electricity to commercial and industrial customers.	
Equitable Resources	NORESCO	ERI Services	Merger	Jan-97	May-97	Energy services	Expands geographic coverage of services business throughout Western Hemisphere; markets to commercial & industrial sectors.	
Entergy	London Electricity		Acquisition	Dec-96	Feb-97	Electric	Purpose in part to gain from operational experience in competitive market. In Nov-98, Entergy sold London Electircity to French national power company for $3.18 billion.	2,100
Investor Group	Union Drilling Division of Equitable Resources	Union Drilling Inc.	Divestiture	Oct-97	Oct-97	Contract drilling	Equitable also divested various o&g properties in the western U.S. and Canada for $175 million. Objective to focus development in Gulf Coast and Appalachian Basin.	
Exxon Corporation	Mobil Corporation	Exxon Mobil Corporation	Merger	Dec-98	pending	O&G, E&P	Creates world's largest o&g company; approximately 59 Tcf of gas and 11 billion bbls of oil reserves; gas production approximately 11 Bcf/day and sales of 14 Bcf/day.	79,300
FirstEnergy Corp.	Marbel Energy Corporation		Acquisition	Jun-98	Jun-98	O&G, E&P	Expands FirstEnergy capability by including o&g e&p in the portfolio.	
Halliburton Co.	Dresser Industries	Halliburton Co.	Merger	Feb-98	Sep-98	Field service	Becomes largest field service company.	7,700

Table E1. Recent Corporate Combinations in the Natural Gas Industry (Continued)

Acquiring Company or Partners	Acquired Company (all or part)	Brand Name or New Company Name	Type of Combination	Date Announced	Date Completed	Business Areas	Notes	Value (million dollars)
Houston Industries	NorAm Energy	NorAm Energy	Merger	Aug-96	Aug-97	Elect/gas pipe	Combines gas and electric operations.	3,800
IES Utilities Inc.	Wisconsin Power & Light; Interstate Power Co.	Alliant	Merger	Nov-95	Apr-98	Gas & elect	Three-way merger; of WPL Holdings, IES Industries and Interstate Power Co.	
KCS Energy, Inc.	MidAmerican Energy Company		Divestiture	Nov-96	Jan-97	O&G, E&P	MidAmerican sold InterCoast Oil and Gas Company, GED Energy Services Inc. and InterCoast Gas Services Company to KCS.	230
Kerr-McGee Corp.	Devon Energy Corp.		Merger	Oct-96	Dec-96	O&G	Merged onshore N. American properties into Devon, for 31 percent equity interest. Increases Devon's proved reserves 50 percent; Devon to manage o&g e&p and sales.	
Kerr-McGee Corp.	Oryx Energy Company	Kerr Mc-Gee Corporation	Merger	Oct-98	Pending	O&G, E&P	Forms 4th largest independent o&g e&p company in U.S.	4,000
KN Energy	MidCon Corp.		Acquisition	Dec-96	Jan-98	Gas	Acquired from Occidental - will increase KN thruput to 17 percent of total U.S. supply; pipelines, storage, sales, energy services, commodity.	3,500
KN Energy; PacifiCorp		Simple Choice; en*able	Joint Venture	Feb-97		Gas/elect util; Internet, satellite TV, electronic shopping	Formed "En*able" to market "Simple Choice" (energy/telecom 1-stop shopping; home & 24 hr road security) to other utilities & to PacifiCorp's retail customers.	
KN Energy	Interenergy		Acquisition	Aug-97	Dec-97	Gas gathering, processing, marketing	Exchanged 544,604 shares KN Energy common and assume debt. Gains access to Williston Basin, Montana Power, etc.	
KN Energy	Red Cedar Gathering Co. (From Stephens Group)		Acquisition		Dec-97	Gas gathering	Gathering system in San Juan Basin. Jointly owned with the Southern Ute Indian Tribe. Facitates KN marketing at Blanco Hub, includes plants and facilities.	
KN Energy International	Igasamex		Acquisition	Sep-98	Sep-98	Converts equipment to gas use	KN acquired partial interest (based in Mexico).	
KN Energy, El Paso Natural Gas, Questar Corporation	TransColorado Gas Transmission Company	TransColorado Pipeline	Joint Venture	Dec-96 (Phase I in service)	Pending	Gas pipeline	Natural gas pipeline under construction in Colorado.	200
LG&E Energy Corp.	KU Energy	LG&E Energy Corp.	Merger	May-97	May-98	Gas/elect util		3,000
LG&E Energy Marketing; New Energy Ventures			Joint Venture			Energy services	LG&E to do metering, billing, & systems coordination. (Unaffected by LG&E decision (third quarter 98) to withdraw from merchant trading and sales.)	
Lomak Petroleum	Cabot Oil & Gas		Acquisition		Oct-97	O&G, E&P	Lomak acquired only Appalachia properties; goal asset concentration & expanded size.	93
Louis Dreyfus Natural Gas	American Exploration Company		Merger	Jun-97	Oct-97	Gas, some oil	Independent e&p company with 1.2 tcf in gas equivalent (80 percent gas).	1,100
MCNIC Pipeline & Processing	American Central Gas	American Central Eastern Texas Gas	Joint Venture	Mar-98		Gathering	MCMIC sub of MCN Energy Group to operate the alliance; also acquire 40 percent of system.	

Table E1. Recent Corporate Combinations in the Natural Gas Industry (Continued)

Acquiring Company or Partners	Acquired Company (all or part)	Brand Name or New Company Name	Type of Combination	Date Announced	Date Completed	Business Areas	Notes	Value (million dollars)
Meridian Resource Corp.	Carin Energy USA	Meridian Resource Corp.	Merger	Jan-97		Drilling, O&G E&P	Shell subsequently acquired 40 percent interest in Meridian (see Shell).	234
MidAmerican Energy Company	AmerUS Home Services Inc.		Acquisition	Apr-98	Pending	Gas, elect util/real estate	Seen as opportunity to further expand home services.	
Midcoast Energy Resources Inc.	Texana Pipeline Company		Acquisition	Apr-98		Gathering	Acquired 50 percent interest in the Texana joint venture in south Texas.	
Mobil Corporation, Duke Energy, Westcoast Energy	Maritimes & Northeast Pipeline		Joint Venture		Nov-99	Gas pipeline	Line to bring gas into New England from Sable Island, Canada. Mobil (25 percent), Duke (37.5 percent), Westcoast (37.5 percent).	
NIPSCO Industries Inc (IN)	Bay State Gas Co (MA)		Acquisition	Dec-97	Pending	Gas, elec	Combined co will be among 10 largest gas distribution companies with >1 million customers. Merger expected to close fall 1998.	780
NorAm; Sprint		NorAm Energy Management	Joint Venture	Jun-97	Oct-97	Energy/telecommunications	A NorAm branded package with Sprint as "bonus." It also does "comarketing" directly to business customers in OH & MA & to resid & comm customers in MA.	
Northern States Power Co.	Wisconsin Electric Power Co	Primenergy	Merger	May-95	canceled May-97	Gas, elec	Adverse regulatory climate cited as reason for ending merger process.	
NOVA Corporation; British Gas plc		NGC Corporation ("Dynegy" in '98)	Joint Venture	1984		Gas	NOVA & British Gas each own approximately 26 percent. Chevron acquired 25 percent interest in partial merger (see Chevron - Dynegy).	
Ocean Energy	Untied Meridian Corp.	Ocean Energy	Merger	Dec-97	Mar-98	Deepwater O&G in Gulf	Formed 9th largest o&g e&p company in N. America. Provides capital to develop new discoveries.	
Ocean Energy; Shell			Joint Venture	Mar-98		Offshore E&P	Covers leases in water to 1,300 ft, project inventories and 3-D data; facilitates coordinates use of rigs.	
ONEOK Resources Company	PSEC (Potts Stephenson Exploration Company)		Acquisition	Jan-98	Feb-98	O&G, E&P	Acquisition of PSEC also includes 42 percent of Sycamore Gas Gathering System. (Sold ½ of Sycamore to Duke Nov-98.)	25
PacifiCorp	TPC Corp.		Acquisition	1996	Mar-97	Gas, elec	TPC had interests in gas gathering systems, salt dome storage projects and marketing. Sold offshore assets to El Paso (see El Paso). In Oct-98 PacifiCorp announced plans to sell TPC and selected other assets as part of restructuring.	288
PacifiCorp; Northwest Natural Gas		Energy Partners Program	Joint Venture	Jul-97		Market gas and energy services	PacifiCorp plans to take venture national by teaming up with other companies.	
PacifiCorp, DPL, Inc, NIPSCO Industries, Public Service Enterprise Group		Market Hub Partners, L.P.	Limited Partnership			Gas storage	Develops, owns, and operates underground gas storage facilities. In Oct-98, PacifiCorp announced it would sell gas storage unit as part of restructuring effort.	

Table E1. Recent Corporate Combinations in the Natural Gas Industry (Continued)

Acquiring Company or Partners	Acquired Company (all or part)	Brand Name or New Company Name	Type of Combination	Date Announced	Date Completed	Business Areas	Notes	Value (million dollars)
PanEnergy; Mobil Natural Gas Inc.		Duke Energy Trading and Marketing	Joint Venture	Jan-96		Natural gas	Markets 7 Bcf/d, 160 MWh/year, one of top 5 energy marketers in US. PanEnergy 60 percent Mobil 40 percent; Exclusive marketer for N. America gas production of Mobil.	
PanEnergy	Mobil Corporation		Divestiture	Mar-96	Aug-96	Natural gas	Mobil sold 2,600 milies of gathering and seven processing facilities and Mobil's interest in other properties.	300
Parker & Parsley	Mesa Inc.	Pioneer Natural Resources Co.	Merger	Apr-97	Aug-97	O&G, E&P	Combines oil-rich P&P with gas-rich Mesa to form 3rd largest independent producer in U.S.	3,000
PECO Energy, British Energy	Amergen		Joint Venture	Sep-97		Nuclear power plants	Formed to acquire nuclear generation assets in North America. Oct-98, first acquisition Three Mile Island, pending regulatory review.	
PEPCO	BG&E	Constellation Energy	Merger	Sep-95	canceled Dec-97	Gas, elec	Maryland PSC required $56 million cut in rates.	
PG&E; Atlantic Richfield Company			Strategic Alliance	Apr-98		Electricity, energy management	Long-term power purchasing agreement; also, energy management services, billing and information systems.	
PG&E	Teco Pipeline		Acquisition	Nov-96	Jan-97	Gas pipeline, gas gathering	Opportunity to expand midstream into Texas market. Included pipeline, gathering, and marketing.	380
PG&E	Valero Energy		Acquisition	Feb-97	Aug-97	Gas assets	Complements other acquisitions; good position in TX and coast-to-coast marketing.	1,500
PG&E; Ultramar Diamond Shamrock			Joint Venture	Mar-98		Complete energy systems management	Complete outsourcing by UDS of all energy services; expect to save $356 million over life of contract; largest value deal between non-affiliated companies; 70 percent of any savings to UDS, 30 percent to PG&E.	
Pioneer Natural Resources Co.	Chauvco Resources Ltd.		Merger	Sep-97	Dec-97	Gas/oil	Consolidation of assets outside U.S.; becomes 2nd largest U.S. independent in O&G E&P.	1,200
PP&L	Penn Fuel Gas, Inc.		Merger	Jun-97	Aug-98	Gas distribution & storage; propane	Expands gas trading function; part of on-going strategy to expand portfolio of energy products and services.	121
Public Service Co. of Colorado (PSCO)	Southwestern Public Service (SPS)	New Century Energies	Merger	Aug-95	Aug-97	Gas, elec	Creates holding company with each partner a subsidiary.	
Public Service Enterprise Group; Energis Resource			Joint Venture			Energy marketing	Marketing firm launched by PSEG of Newark, NJ.	
Puget Sound Power	Washington Energy		Merger	May-95	Feb-97	Gas, elec	Would create largest combined elec/gas utility in Washington State.	
Ranger Oil Ltd.	Elan Energy Inc.		Merger	Sep-97	Sep-97	Oil & gas	Elan brings oil (especially heavy) & gas - result seen to be balanced portfolio of gas, light & heavy oil. (Canada.)	
Scottish Power	PacifiCorp	Scottish Power	Merger	Dec-98	Pending	Gas & electric utilities	Becomes one of ten largest utiliities in world; 7 million customers in US, UK, & Austrialia	12,800

Table E1. Recent Corporate Combinations in the Natural Gas Industry (Continued)

Acquiring Company or Partners	Acquired Company (all or part)	Brand Name or New Company Name	Type of Combination	Date Announced	Date Completed	Business Areas	Notes	Value (million dollars)
Seren Innovations; CellNet Data Systems			Joint Venture			Energy services	Joint venture to market bundled services on meter reading, billing, and credit collections.	
Shell Oil; Tejas Gas		Coral Energy Resources	Joint Venture	Jul-95		Gas	Has access to Tejas' pipelines and storage facilities; Shell dedicates over 2 Bcf/d of gas production to Coral Energy.	
Shell	Tejas Gas Corp.	Tejas Energy, LLC	Merger	Sep-97	Jan-98	Gas	Midstream gas company; Tejas 8 Bcf/d of pipeline capacity in TX, LA, OK; storage, processing. Name changed in May-98 to reflect broader scope.	2,350
Shell	Meridian Resource Corp.		Merger	Dec-96	Mar-98	O&G	Shell acquired 39.9 percent of Meridian; Meridian acquired Shell's South Louisiana onshore properties.	
Sierra Pacific Resources	Nevada Power Co.	Sierra Pacific Resources	Merger	Apr-98	Pending	Elect, gas, water	Sierra Pacific will be the holding company.	3,772
Sonat	Zilkha Energy Co.		Merger	Nov-97	Jan-98	Gas, some oil	Successful E&P in Gulf; becomes 6th largest U.S. independent; goal is to be in top 3. In following reorganization sold other properties and consolidated units.	1,300
Sonat; AlliedSignal Inc			Joint Venture	Sep-97		Distributed power	Strategic Alliance - Sonat Power Systems Inc. to market small generators. Both members of DPCA.	
Sonat, Amoco Corporation, Tejas Energy	Destin Pipeline Company		Joint Venture	Dec-97	Jul-98	Offshore pipeline in Gulf	Construction began in Dec-97, initial opening Jul-98; plans for 2 extensions added in May-98.	512
Southern Company; Vastar		Southern Company Energy Marketing	Joint Venture	Sep-97		Markets gas, electricity, energy products and services	Provides energy trading, marketing, and financial services; other energy related commodities. Sold 5.1 bcf/d of gas in 1st quarter 1998. (Vastar is majority owned by ARCO.)	
Statoil	Eastern Group		Acquisition	1994	1998	E&P, gas marketing, energy management & services	Initial investment by Statoil began in 1994 and increased over the years. Eastern became a subsidiary of Statoil; name changed to Statoil Energy in May-98.	
Statoil Energy	Blazer Energy		Acquisition	May-97	Jul-97	O&G, E&P	Blazer (domestic E&P assets spun off Ashland in Jan-97) - assets in Appalachia & Gulf.	556
Statoil Energy	General Motors (certain assets)		Acquisition	1996	Jun-96	Developed and undeveloped gas reserves	Also included ten year supply agreement with Statoil Energy providing 28 bcf annually to GM Lordstown plant.	
Statoil Energy	Noble Corporation		Acquisition	1996	Jun-96	Gas properties	Included wells, pipeline in Ohio. (One of a number of similar acquisitions involving properties in the Ohio & West Virginia area.)	
Statoil Energy	EOF, Inc		Acquisition	1996	Dec-96	Energy services	First of several similar acquisitions in energy services. Provides services in New England as part of "Total Energy Solutions" strategy of Statoil.	
TECO Energy	Lykes Energy	Peoples Gas	Merger	Nov-96	Jun-97	Retail gas distribution, propane	TECO parent of Tampa Electric, Lykes parent of Peoples Gas, largest gas distribution in FL.	300
Texaco	Monterey Resources		Acquisition	1997	Aug-97	Oil, some gas	Reserves of 385 million BOE in California.	1,400

Table E1. Recent Corporate Combinations in the Natural Gas Industry (Continued)

Acquiring Company or Partners	Acquired Company (all or part)	Brand Name or New Company Name	Type of Combination	Date Announced	Date Completed	Business Areas	Notes	Value (million dollars)
Texas Pacific Group	Belden & Blake Corp.		Acquisition	1997	Jun-97	Various	TPG $1.8 billion equity fund (wineries, cinemas, airlines, waste mgmt) - leverage - goal to resell.	437
Texas Utilities	Enserch Corp.		Merger	Nov-96	Aug-97	Integrated gas company; electric power generation	ENSERCH parent of Lone Star Gas; Lone Star Pipeline; E&P to be spun off.	1,700
Texas Utilities	Lufkin-Conroe		Acquisition	Aug-97	Pending	Tele-communi-cations	Adds 100k telephone customers; also Internet, cellular, business long distance, and PBX services.	328
Texas Utilities Co.	The Energy Group		Merger	May-98	Jun-98	Electric power	The Energy Group is 2nd largest electric utility in the UK; To ensure approval - TU divested Energy Group's Peabody Coal to Lehman Brothers for $2.3 billion.	7,400
Trans Canada Pipeline	NOVA Corporation		Merger	Jan-98	Jul-98	Gas pipeline	TransCanada spun off Nova Chemical upon completion of merger.	9,200
Transco (unit of Williams), AGL Resources (Atlanta Gas Light)	Cumberland Pipeline Company		Joint Venture	Dec-96		Gas pipeline	Joint venture formed initially from existing facilities, also planned expansions and new line (Cumberland).	
Tucson Electric Power	New Energy Ventures		Acquisition	1995	Sep-97	Energy marketing	TEP exercised option to acquire 50 percent New Energy Ventures; transaction in exchange for start-up capital provided in 1995 by TEP.	
Unicom Corp.; Sonat		Unicom Gas Services	Joint Venture	Aug-97		Gas marketing & services to commercial & industrial customers	Joint venture of unregulated subs: Sonat Marketing Company L.P. & Unicom Energy Services. Sonat sought Midwest marketer with desire to expand beyond area. Also seek to expand distributed power.	
Union Electric Company	CIPSCO	Ameren Corporation	Merger	Aug-95	Dec-97	Electric & gas utilities	1.5 million electric customers and 300,000 gas customers.	1,400
Union Pacific Resources	Norcen Energy Resources Ltd.		Acquisition	Jan-98	Mar-98	Gas and oil	Canadian acquisition, creates "well balanced" North American company. Increases reserves by 80 percent.	3,500
United States Exploration, Koch Industries, Enron Oil and Gas, Collins & Ware.	Union Pacific Resources		Divestiture	Apr-98	Oct-98	Various gas and oil assets of UPR	Planned "deleverging" strategy to divest $600 million of assets following acquisition of Norcen. Sales of properties (a property trade in the case of Koch) to reduce costs and maximize assets. (Value was announced target for entire campaign.)	600
UtiliCorp	Aquila Gas Pipeline		Acquisition	Nov-98		Gas pipeline	Parent UtiliCorp announced that it will acquire the remaining 18 percent of Aquila. (In Mar-98, UtiliCorp sought to divest Aquila.)	
UtiliCorp; PECO Energy Co.		Energy One	Joint Venture		Suspended May-98	AT&T residential commercial services	"Energy One" brand; plan to expand by signing other utilities as equity partners or franchisees; work with gas & electricity	
Weatherford Enterra Inc.	EVI Inc.	EVI Weatherford	Merger	Mar-98	Mar-98	Services	Becomes fourth largest services co.	2,600
Western Atlas Inc.	Wedge Dia-Log Inc.		Merger	Mar-98	Mar-98	Services	Downhole services.	250

Table E1. Recent Corporate Combinations in the Natural Gas Industry (Continued)

Acquiring Company or Partners	Acquired Company (all or part)	Brand Name or New Company Name	Type of Combination	Date Announced	Date Completed	Business Areas	Notes	Value (million dollars)
Western Atlas Inc.	3-D Geophysical Inc.		Merger	Mar-98	Mar-98	Services	Seismic, logging, reservoir information.	115
Western Resources	Kansas City Power & Light	Westar Energy	Merger	Feb-97	Pending	Electric power		3,240
Western Resources	ONEOK		Merger		Dec-96	Gas, elec	ONEOK to receive all gas assets, Western to get 3 mil new shares of ONEOK common stock (45 percent).	660
Western Resources	Westinghouse (security division)		Acquisition		Dec-96	Security	Becomes 3rd largest in U.S. of monitored security systems; also holds 27 percent of ADT the #1 company.	425
Williams, Tenneco	Kern River Gas Transmission	Kern River Pipeline	Joint Venture		Apr-92	Gas pipeline	Initially held 50 percent by Tenneco, 50 percent by Williams. Williams acquired the Tenneco portion at the beginning of 1996.	
Williams Companies;	Energy Vision (Boston Edison)		Acquisition	Aug-98	Sep-98	Energy marketing and services	Originally announced in Oct-96 as a 50/50 joint venture with Boston Edison to market natural gas, electricity and energy services; began operation in Jun-97. Williams acquired remaining 50 percent in Sep-98.	
Williams Energy Services	Volunteer Energy Corporation		Acquisition	Nov-98	Nov-98	Energy services	Gas & electricity services in U.S. & UK. Part of Williams strategy to service retail markets; acquired remaining interest (Williams owned 50 percent prior to latest purchase).	
Williams Companies	Transco Energy Company		Merger		May-95	Gas pipeline	The acquisition of Transcontinental Gas Pipeline and Texas Gas Transmission gave Williams access to markets in the East and established Williams as the largest transporter of gas in the U.S.	
Williams Companies	Mapco		Merger	Nov-97	Mar-98	Natural gas, NGLs, NGL pipeline	Williams sees revenue from energy services to eventually exceed that of gas pipeline business. Viewed by Williams as a bridge until communications business matures. Mapco's Thermogas is 4th largest propane retailer in the U.S.	3,100
Wisconsin Energy Corp.	ESELCO (Edison Sault Electric Co.)	ESELCO	Merger	Mar-97	May-98	Electric/gas	ESELCO became wholly owned subsidiary of WEC.	71
Wisconsin Public Service Corporation	Upper Peninsula Energy Corporation	WPS	Merger	Jan-97	Sep-98	Gas/electric	UPEC became wholly owned subsidiary of WPSC.	

O&G = Oil & gas; E&P = Exploration & production.
Source: Energy Information Administration, Office of Oil and Gas, compiled from industry press releases and industry trade press.

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