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U.S. Natural Gas Markets: Recent Trends and Prospects for the Future

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Preface

The analysis in this report was undertaken at the request of the Secretary of Energy, Spencer Abraham. The principal purpose of this study is to examine recent trends and prospects for the future of the U.S. natural gas market. Natural gas prices rose dramatically in 2000 and have remained high through the first part of 2001, raising concerns about the future of natural gas prices and the potential for natural gas to fuel the growth of the U.S. economy. Exacerbating those concerns are the current low levels of natural gas supply stocks in storage and the prospect that a higher than normal rate of injection will be needed in the off-peak (non-heating) season to restore storage to normal levels—which could lead to a continuation of elevated prices in 2001 and 2002. The central questions addressed in this report are "Why have natural gas prices risen so high and so quickly?" and "What is the outlook for the U.S. natural gas market in the short and mid-term?"

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Executive Summary

Natural gas prices rose dramatically in 2000 and have remained high through the first part of 2001. High prices have raised concerns about the longer term prospects for natural gas prices and their potential impact on consumers and on economic growth. Exacerbating those concerns are the current low levels of natural gas supply in storage. The central questions addressed in this report are “Why have natural gas prices risen so high and so quickly?” and “What is the outlook for the U.S. natural gas market in the short and mid-term?”

Natural gas represented 24 percent of the energy consumed and 27 percent[1] of the energy produced in the United States in 2000. The industrial sector was the largest user of natural gas—for cogeneration of electric power and as an industrial feedstock. In addition, natural gas is the largest energy source consumed in the residential sector and the fastest growing energy source for electricity generation.

In recent months, the high prices of natural gas used in the industrial, residential and commercial, and electricity generation sectors have caused exceptional public concern about the present and future operations of the natural gas industry and markets. The recent high prices have also prompted some policymakers to question whether natural gas can play a dominant role in fueling U.S. economic growth in the next 20 years. These concerns led Secretary Spencer Abraham to request that the Energy Information Administration (EIA) assess the recent trends in the U.S. natural gas market that led to high natural gas prices and evaluate the implications of those trends for the short- and mid-term outlook.

Why Have Natural Gas Prices Risen So High and So Quickly?

High natural gas prices, experienced in 2000 and expected to persist at least through 2001 and 2002, were caused by constrained domestic productive capacity[2] that resulted from a sustained period of relatively low oil and natural gas prices, followed by unusually high demand—the result of strong economic growth and an unusually warm summer and cold winter—and a poor storage position heading into the winter season (November 2000 through February 2001).

Low oil and natural gas prices for most of the decade before 2000 contributed to the limited natural gas productive capacity going into 2000. Annual average wellhead natural gas prices (in 1999 dollars) hovered between $1.61 per million Btu ($1.65 per thousand cubic feet) and $2.32 per million Btu ($2.38 per thousand cubic feet)[3] through all of the 1990s, while crude oil prices (the composite refiners’ acquisition cost) ranged from $12.69 to $22.37 per barrel (excluding 1990). Oil and gas investments in exploration and production from 1990 through 1996 annually averaged $15 billion in real 1999 dollars, as compared with investments in excess of $30 billion annually (in 1999 dollars) before 1986. From 1986 to 1995, the average return on investment for major oil and gas companies[4] ranged from 5.5 percent to 7.3 percent, except for 1990 when the return jumped to 9.5 percent as oil prices rose during the Persian Gulf war.[5] These returns to investment were well under the range of 10.4 to 19.2 percent received between 1977 and 1985.

In 1996 and 1997, rising natural gas prices increased investment returns to over 10 percent, but in 1998, when natural gas prices fell below $2 per million Btu and oil prices were the lowest they had been in 25 years (in real terms), returns fell to 3.9 percent. Profits and returns on investments were considerably higher in 2000 as a result of the high oil and gas prices, and some of those revenues have been used to increase exploratory and developmental drilling. With the decline in industry investment and drilling during the 1990s, proved natural gas reserves declined from 169 trillion cubic feet at the end of 1990 to 164 trillion cubic feet at the start of 1999. More importantly, drilling levels were not sufficient to develop these reserves into increased productive capacity.

[1]Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2001/03) (Washington, DC, March 2001).

[2]Productive capacity is the quantity of natural gas that can be produced from existing completed wells.

[3]Natural gas prices are often reported in terms of dollars per million Btu—not in the more natural physical units of dollars per thousand cubic feet. Billing for natural gas customers by utilities and producers is usually done on an energy basis (dekatherms)—not by physical units. The energy content of natural gas can vary from about 1.005 to 1.035 million British thermal units (Btu) per thousand cubic feet. As an approximation, we assume that the energy content of natural gas is 1.027 million Btu per thousand cubic feet. In this report, natural gas consumption and production are reported in trillion cubic feet and prices in 1999 dollars per million Btu.

[4]Major U.S. energy companies are the top publicly owned U.S.-based crude oil and natural gas producers and petroleum refiners included in EIA’s Financial Reporting System (FRS).

[5]Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000).

Except for 1994, when domestic production increased by 0.72 trillion cubic feet, annual U.S. production increased by less than 0.3 trillion cubic feet in every year during the 1990s. This was short of the average annual growth in demand during that period (Table ES1). In 2000, domestic gas production increased by 0.7 trillion cubic feet in response to the higher demand and higher wellhead prices.[6] While this increase was sufficient to meet the major portion of demand growth seen in 2000, a large net drawdown of gas in storage and an increase in imports were also required to meet the remaining demand.

Sustained prices of about $2.25 per million Btu from 1994 to 1999 may have stimulated additional drilling and somewhat mitigated the tightened supply response that led to the jump in spot prices in 2000. For example, in 1996 natural gas prices rose by $0.60 to $2.21 per million Btu and the number of wells drilled increased by more than 10 percent over their 1995 level, and in 1997 prices rose by an additional $0.11 to $2.32 per million Btu and the number of wells increased by 26 percent above 1996.[7] Gas drilling declined precipitously in 1991 and 1992, in 1994 and 1995, and again in 1999 as a result of relatively low prices, setting the stage for the tight supply situation that developed in 2000.

The prospects for adding significant amounts of new gas supplies from 2002 to 2005 look promising in view of expected natural gas prices. *Natural Gas Week* reports that U.S. contractors and service companies, pumped up by profits from current natural gas sales, "are flinging themselves into a headlong rush for rigs as the boom is beginning to take on fabled proportions." First-quarter 2001 profits reported by Baker and Hughes rose by 600 percent over first-quarter 2000 profits, and Senior Vice President Andrew Sczescila predicted that 2001 would be the best year for service companies since 1981.[8]

Natural gas consumption increased by about 1 trillion cubic feet in 2000 because of strong economic growth and higher heating and cooling loads served by natural gas. As compared with 1.7-percent average annual growth in demand for natural gas from 1990 to 1999, demand jumped by 4.8 percent in 2000.[9] More importantly, there was virtually no growth in gas consumption between 1996 and 1999, due in part to mild weather. Stronger demand was already evident in the spring, when natural gas demand would normally be expected to abate and prices to moderate significantly. Because natural gas prices began to rise in the spring of 2000, the refill of gas storage was slowed considerably as the industry waited for a possible return to lower prices.

Table ES1. Natural Gas Prices, Production, and Consumption, 1990-2000, and Projections for 2001-2002

Year	Wellhead Price (1999 Dollars per Million Btu)	Wellhead Price (Nominal Dollars per Million Btu)	Domestic Production (Trillion Cubic Feet)	Domestic Consumption (Trillion Cubic Feet)
History				
1990	2.02	1.67	17.81	18.72
1991	1.68	1.60	17.70	19.04
1992	1.93	1.69	17.84	19.54
1993	2.21	1.99	18.10	20.28
1994	1.97	1.80	18.82	20.71
1995	1.61	1.51	18.60	21.58
1996	2.21	2.11	18.85	21.97
1997	2.32	2.26	18.90	21.96
1998	1.93	1.89	18.71	21.26
1999	2.11	2.11	18.62	21.70
2000	3.45	3.51	19.32	22.76
Projections				
2001	4.85	5.04	19.85	23.17
2002	4.43	4.69	20.34	23.96

Note: Nominal dollars were converted to real 1999 dollars for 2000-2002 using the chained gross domestic product deflator, rebased to 1999 dollars.

Sources: **History:** Wellhead natural gas prices, domestic production and consumption: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2001/03) (Washington, DC, March 2001), and associated databases. **Projections:** EIA, April 2001 *Short-Term Energy Outlook*, web site www.eia.doe.gov/steo/. **GDP Deflator (1990-2000):** Bureau of Economic Analysis, U.S. Department of Commerce.

[6] Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0103(2001/03) (Washington, DC, March 2001).

[7] Source of drilling data: Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0394(99) (Washington, DC, July 2000), Table 4.4, p. 95.

[8] "Land Rig Drilling, Dayrate Boom, Produce Huge Profits for Industry," *Natural Gas Week* (April 30, 2001), pp. 3-4.

[9] EIA, *Natural Gas Monthly*, March 2001.

Gas storage injections were minimized as demand growth accelerated during the summer and gas acquisition costs escalated.

In the 6 weeks ending October 31, 2000, natural gas storage was aggressively filled to 2.7 trillion cubic feet. However, the additional demand for filling storage in the 6 weeks before winter only served to keep natural gas prices high, and the total amount of gas in storage at the start of the 2000-2001 heating season began at a 5-year low for that time of year. The storage situation was even worse for Southern California gas utilities served by El Paso Pipeline Company because of the rupture on the El Paso pipeline in New Mexico.[10] Although interstate natural gas transmission capacity probably was adequate to meet normal peak demand with that pipeline in service, the pipeline rupture constrained California's gas supply capacity. California's environmental regulations on electricity generators also added to natural gas demand, because environmental emission allotments for other fuels were exhausted earlier in the year.

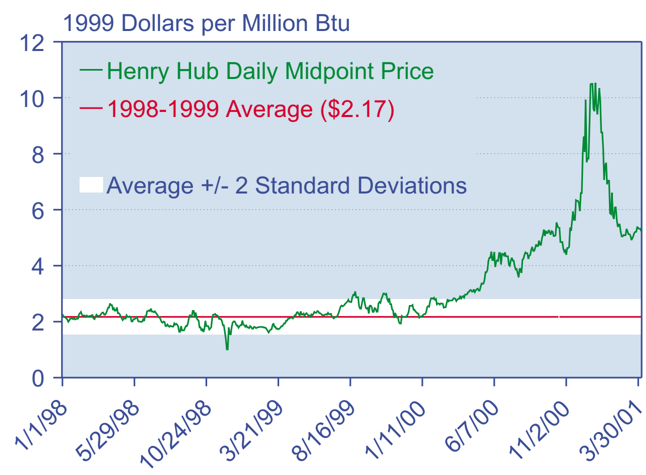
Thus, the U.S. natural gas market began the winter of 2000-2001 with high prices and a relatively weak storage position. Much colder than normal winter weather in November and December 2000 reduced gas stocks to such low levels that it raised concerns about possible supply shortfalls during peak periods for the remainder of the winter. The high natural gas demand and rapid gas stock drawdown strained U.S. productive capacity and drove up natural gas prices at the wellhead.

Although gas well completions have increased steadily since April 1999, production has not responded sufficiently to satisfy expanding market demand. The industry initially had to overcome the prior drilling slump associated with low natural gas prices. Despite this handicap, domestic production increased by about 0.7 trillion cubic feet in 2000, equivalent to about two-thirds of the increase in consumption from 1999 to 2000. Given an industry apparently pressing at the limits of its productive capacity, the higher demand did not bring about increased production, so prices rose higher.

Spot prices at Louisiana's Henry Hub[11] (Figure ES1) were below $3 per million Btu until mid-April 2000, then broke the $4 barrier in late May as strong demand continued in the electricity generation sector. They remained above $5 per million Btu from September 2000 to February 2001 in response to aggressive filling of storage in the fall and later in response to high heating demand. The average wellhead price for the winter months, November 2000 through February 2001, was roughly 2.7 times higher than during the previous heating season, and the length of time for which spot gas prices have remained elevated is historically unprecedented.

At regional trading centers, average quarterly spot prices displayed unexpected price differentials from the average at the Henry Hub. The Henry Hub average rose from the third to the fourth quarter of 2000 and then changed little in the first quarter of 2001 (Table ES2). Although the pattern was similar for the regional trading centers, price differentials from the Henry Hub price varied significantly after the third quarter, especially for the California market. Because natural gas transmission rates are regulated, it appears that the significant variation in spot price differentials among the trading centers originated in the costs of unregulated bundled services (transmission plus fuel) provided by marketers.

Figure ES1. Natural Gas Spot Market Prices at Henry Hub, 1998-2001



Source: *Gas Daily, Financial Times Energy*.

Gas Pipeline and Distribution

Gas Distribution Systems and Intrastate Capacity

As the interstate and intrastate natural gas pipeline systems expand, LDCs may have to expand correspondingly. A substantial portion of the new pipeline capacity will provide additional delivery capacity to LDCs, which either are expanding their own capabilities to

[10]The incident occurred at the El Paso Natural Gas Company's Pecos River crossing in the southeast corner of New Mexico where three lines (two 30-inch and one 26-inch pipeline) cross the river. While only one 30-inch line ruptured, the other two lines were also shut down. As a result, 1.2 billion cubic feet per day, out of a normal 2.0 billion cubic feet per day, of natural gas flowing along El Paso's southern route to its Arizona and California markets was affected for several months. The ruptured line has remained off line through April 2001.

[11]The Henry Hub is a key upstream market in Louisiana, based on the relatively large volumes traded there and its strategic position relative to producing and consuming markets—in the Southwest and on the Gulf Coast for production and in the Midwest and the East for consumption. The Henry Hub is often used as a benchmark for upstream spot prices in the United States.

Table ES2. Average Quarterly Spot Prices and Price Differentials for Selected Trading Centers
(Dollars per Million Btu)

Quarter and Year	Henry Hub, LA	Chicago Citygates	Florida Citygates	Katy, TX	New York Citygates	SoCal Citygate[a]
3rd quarter 2000	4.47	4.56	5.00	4.48	4.81	5.28
4th quarter 2000	6.41	6.82	6.73	6.38	8.07	13.59
1st quarter 2001	6.44	6.61	6.85	6.41	7.83	15.19
Price Differentials from Henry Hub Spot Price						
3rd quarter 2000	—	0.09	0.53	0.01	0.34	0.81
4th quarter 2000	—	0.41	0.32	-0.03	1.66	7.18
1st quarter 2001	—	0.17	0.41	-0.03	1.39	8.75

[a]SoCal is a large Southern California utility and is used as an indicator for typical spot prices to that region.

Source: Energy Information Administration, Natural Gas Division, adapted from prices reported in *Gas Daily, Financial Times Energy* (various issues).

serve their existing service territories or are building new pipe segments to extend their systems into new neighborhoods or to serve new industrial or electric power customers.

LDCs continue to invest in new and replacement main and service lines and local compression facilities in order to satisfy the firm service requirements of their sales and transportation customers. According to the American Gas Association, construction projects by distribution companies totaled $9.7 billion (nominal) in 1998 and 1999, a 16-percent increase from $8.4 billion in 1996 and 1997.

An example of the market complications that can occur is provided by the recent developments in California. California is the Nation's second-largest State market for natural gas and the tenth-largest producing State. In 1999, California's natural gas demand (Table 2, Chapter 2) was met by 372 billion cubic feet from domestic production, 137 from storage and 1,800 billion cubic feet from interstate pipeline supplies, compared to an annual interstate delivery pipeline capacity of about 2.5 trillion cubic feet. On a peak-day basis, interstate pipeline delivery capability into California is about 7 billion cubic feet per day while California's ability to absorb natural gas within the intrastate pipeline and distribution system ("take-away" capability) appears to be less, as low pressures and the inability to meet some interruptible gas load during peak periods indicate. Rapid gas demand and economic growth has evidently outstripped the rate of local infrastructure expansion and reinforcement required in some parts of California. Firm estimates await a more thorough investigation. However, various sources have indicated the magnitude of the capacity shortfall likely is measured in hundreds of millions of cubic feet per day (MMcf/d). One estimate for the total imbalance is about 300 MMcf/d.[12] However, estimates for specific border crossings suggest a larger figure.

The two interstate crossings from Arizona into California are at a southern corridor crossing between Blythe, CA, and Ehrenberg, AZ, and at a more northern crossing between Needles, CA, and Topock, AZ. Although the physical capability of the delivery point at Ehrenberg, AZ, could permit an estimated 1,410 MMcf/d to be delivered, the intrastate system can receive only 1,210 MMcf/d.[13] The California Energy Commission estimated that the imbalance at the northern corridor crossing (Needles/Topock) is about 350 MMcf/d.[14] These two estimates for the separate State border crossings combined indicate a potential shortfall in receipt capacity of 550 MMcf/d along the Arizona border.

Pipelines

The natural gas pipeline network has grown substantially since 1990, with more than 20 billion cubic feet per day of interregional capacity (a 27-percent increase) added through the end of 2000. The network has also become more interconnected, its routes more complex, and business operations more efficient. New types of facilities, such as market centers, and established operations, such as underground storage facilities, have become further integrated into the national pipeline grid, allowing the system to operate with greater flexibility and reliability. Except during periods of extreme weather conditions or disruptions caused by isolated pipeline outages, there has been no sustained disruption of the network since the mid-1970s.

Over the past 2 years, more than 60 natural gas pipeline construction projects (35 in 1999 and 28 in 2000) have

[12]"Power Plant Plans Hinge on Strained Gas Network," Christine Hanley, L.A. Times, February 20, 2001; available at www.latimes.com/business/reports/power/lat_gas010220.htm.

[13]Energy Information Administration, "A Look at Western Natural Gas Infrastructure During the Recent El Paso Pipeline Disruption," Jim Tobin, November 2000; available at www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2000/elpaso_disruption/elpaso.pdf.

[14]California Energy Commission, "California Energy Commission Workshop: Natural Gas Issues That May Affect Siting New Power Plants in California," Staff White Paper, January 25, 2001.

been completed and placed in service in the United States. These account for more than 12.3 billion cubic feet per day of new pipeline capacity, an increase of 15 percent over the capacity level in 1998.[15] Since 1996, natural gas pipeline capacity has grown by more than 5 billion cubic feet per day annually in most years, totaling almost 30 billion cubic feet per day. Annual expenditures on pipeline development have exceeded $1.4 billion in most years.[16]

A major growth area in pipeline expansion during the past several years has been the import/export market for natural gas. Much of the pipeline construction of the past several years has been focused on expanding import capacity for Canadian gas into the U.S. Midwest and Northeast. The completion of the Maritimes and Northeast, Portland Gas Transmission, and Alliance Pipeline systems represented a 15-percent increase in overall natural gas import capacity since 1998: a 58-percent increase into the Central region (most destined for the Midwest) and a 23-percent increase into the Northeast. In addition, natural gas export capacity to Mexico has more than doubled since 1996. Export capacity to Mexico totaled 2.1 billion cubic feet per day at the end of 2000, compared with only 0.9 billion cubic feet per day in 1996.

Current pipeline capacity levels into the Midwest region were sufficient to meet 2000-2001 winter demand, even though the first 2 months of the heating season were colder than anticipated. Demand in the Midwest is still growing, however,[17] and some of the capacity currently serving the region is expected to serve the Northeast in 2002. As a result, additional capacity to the Midwest region will be needed.

In most other parts of the country, immediate pipeline capacity limitations have not become apparent, although recent proposals to develop new pipeline capacity reflect a recognition that steady growth in natural gas demand is occurring. Florida, North Carolina, and South Carolina, for instance, have experienced significant growth in natural gas demand over the past decade, with sufficient additional pipeline capacity being installed to match the increase in demand.

What is the Outlook for the U.S. Natural Gas Market in the Short and Mid-Term?

Short-Term Outlook[18]

A major issue confronting the gas industry in 2001 will be the replenishment of gas storage to normal levels and the price implications of large net injections required during the April through October refill season. Given the low level of stocks at the end of the 2000-2001 heating season, net storage injections of about 2.0 trillion cubic feet will be required just to return to the level of 2.7 trillion cubic feet recorded for November 1, 2000. Total net storage injections during the 214-day fill period would need to be over 9 billion cubic feet per day or nearly 20 percent of daily gas deliveries to all consumers from April through October 2000, up from an average of 16 percent. The increased demand will continue to place upward pressure on natural gas prices in 2001.

Another issue will be the need to increase natural gas drilling and production. The cash flow from the sale of natural gas is an important determinant of drilling investments and has been a major factor in limiting increases in natural gas productive capacity, particularly from 1997 to 1999. Oil and gas investors do not initiate projects with long payback periods based on temporary price increases unless those prices are thought to be representative of a long-term market condition. Periodic downturns in the gas industry, such as in the 1984-89 and 1998-99 periods, trigger significant downsizing and cutbacks in spending for exploration and development of new gas sources. Reduced spending in these periods slows the construction of drilling rigs and other infrastructure needed to support future drilling, and results in downsizing and layoffs that reduce the industry's ability to attract qualified new employees. In 2000, when the number of new gas well completions increased by almost 45 percent,[19] gas production increased by an estimated 3.8 percent. The discrepancy reflects, in part, the lag in production following a shift in drilling (usually about 6 to 18 months) due to the time required to acquire necessary investment funds, install production equipment, and construct gathering lines in the field and pipelines needed for transportation.

[15]Total added capacity as measured on an individual project basis rather than interregional additions.

[16]Expenditures on new pipeline development and major extensions and laterals to existing systems have accounted for more than 70 percent of total expenditures, with expansions to existing systems accounting for the rest. In 1999 the largest share of expenditures, totaling $1.1 billion, was for projects terminating in the Northeast. In 2000, projects terminating in the Midwest accounted for the largest share of expenditures, at $1.8 billion.

[17]Proposals to build new and expanded natural gas pipelines into the Midwest over the next several years suggest that as much as 2.7 billion cubic feet per day of additional capacity into the region may be needed.

[18]Projections through 2002 are taken from EIA's April 2001 *Short-Term Energy Outlook* (and associated databases), web site www.eia.doe.gov/steo/.

[19]EIA, *Monthly Energy Review,* March 2001, Table 5.2.

Demand

The average growth rate for gas demand in the 2000-2002 time period is expected to be 3.4 percent per year, as compared with just 0.9 percent per year from 1994 to 1999. The next few years promise to provide an extraordinary boom in natural-gas-fired generating capacity additions, marked by the introduction into commercial service of about 22 gigawatts of new gas-fired capacity in 2000.[20] These additions contribute to expectations that natural gas will be the key fuel behind economic growth over the next few years.

Industrial Demand.[21] Although natural gas prices remain high, industrial natural gas consumption is expected to increase by about 0.5 percent in 2001. In 2002, a strengthening recovery in natural-gas-intensive output (4.4 percent) and the prospect of lower average gas prices yields the expectation that industrial natural gas consumption will climb by about 2.5 percent.

Residential Demand. The year-2000 growth rate for residential natural gas consumption was 4.3 percent, due partly to increased heating demand, particularly in the fourth quarter. Growth in 2001 is expected to be even higher at 4.9 percent over year-2000 levels—partly because the strong increases in gas consumption that resulted from the cold weather in December 2000 will actually be reported as demand in January 2001, but also because heating demand in the first quarter of 2001 was much higher than in the first quarter of 2000. Assuming normal weather for the rest of 2001 and 2002, residential natural gas demand in 2002 is expected to decline by about 0.8 percent. The rate of consumption growth for 2001 is uncertain, because sharp cost increases for natural-gas-heated households this past winter may have forced additional conservation. Average heating bills for the October-March period probably rose by an average of about 70 percent nationally,[22] possibly enough to encourage further reductions in gas consumption by many end users.

Commercial Sector: Natural gas demand growth in the commercial sector in 2000[23] was more than 7 percent above the average annual rate observed during the 1986 to 1999 period and was generated by the combination of strong domestic economic growth and colder than normal weather. With normal weather assumed for the remainder of 2001 and 2002 and the growth rate for U.S. GDP expected to fall, gas consumption growth in 2001 is expected to slow to 3.5 percent. The combination of slower growth in commercial employment and output plus lower heating degree-days is expected to yield growth in natural gas for the commercial sector of about 1.1 percent in 2002.

Electricity Generation: The continuation of relatively high natural gas prices in 2001 points toward slower growth in demand for gas in the electricity generation sector. A rebound in economic growth and modestly declining gas prices result in renewed strength in expected growth in gas demand for electricity generation (12.4 percent) in 2002.

Prices

Given the outlook for robust growth in gas consumption over the next 2 years, prices at the wellhead will not soon be returning to the low $2 per million Btu experienced just a year ago. Although gas production and imports are expected to increase in the short term, gains in supply probably will not be enough to bring the wellhead price down significantly in the next 2 years.

Beyond the end of the 2000-2001 heating season, average wellhead prices are expected to decline somewhat, averaging near $4.38 per million Btu for the spring and summer. However, if the summer weather is unusually hot in regions that consume large quantities of gas-fired electricity (California and Texas, for example), injections into underground storage for the next winter could be strained, and prices could start rising more sharply and sooner than expected. For 2001, the annual average wellhead price is projected to be about $5.18 per thousand cubic feet ($4.85 per million Btu in 1999 dollars). In 2002 the storage situation is expected to improve modestly, and the average annual wellhead price is expected to decline to about $4.82 per thousand cubic feet ($4.43 per million Btu in 1999 dollars).

Mid-Term Outlook[24]

The mid-term outlook for the U.S. natural gas market summarized in this report was developed from the *Annual Energy Outlook 2001* (*AEO2001*), a mid-term annual energy-economy projection of U.S. energy markets developed using EIA's National Energy Modeling System. The *AEO2001* reference case assumes no change in current laws, regulations, or policies.

[20]Capacity additions by location and fuel type are listed in EIA's *Electric Power Monthly*, DOE/EIA-0226(2001/03) (Washington, DC, March 2001).

[21]Here, industrial demand excludes natural gas used by independent power producers but includes use by industrial cogenerators.

[22]The estimate is developed by using average delivered natural gas prices to residential customers and applying consumption per heating degree-day for gas-heated homes and the average number of heating degree-days to obtain an estimate of the incremental cost for gas space heating.

[23]Because the data are still preliminary, a final assessment will not be feasible until later in 2001.

[24]Projections through 2020 are taken from EIA's Annual Energy Outlook 2001, DOE/EIA-0383(2001) (Washington, DC, December 2000), web site www.eia.doe.gov/oiaf/aeo/.

Because natural gas resources are expected to be adequate to meet future demand through 2020 and technological progress for exploration and development is expected to be sustained, natural gas prices are projected to return to a lower price path around 2005 and gradually increase to about $3.05 per million Btu in 2020. Advancing technologies are expected to offset some of the cost increases associated with harder-to-find natural gas pockets and smaller pools.

In the near term, however, natural gas prices are likely to be higher than projected in *AEO2001*. The higher near-term natural gas prices are expected to stimulate more non-gas-fired generation capacity between 2004 and 2010 than was anticipated in *AEO2001*. The expected surge in natural gas drilling activities, prompted by relatively high natural gas prices between 2000 and 2005, should add considerable natural gas productive capacity and increase proven reserves, making natural-gas-fired generating technology the preferred choice in the 2010-2020 time period.

Demand: In 2000, U.S. natural gas consumption of 22.8 trillion cubic feet accounted for almost 24 percent of domestic energy consumption. Natural gas consumption is expected to grow by 2.3 percent annually after 1999—faster than any other major fuel source—and is expected to reach 34.7 trillion cubic feet by 2020, mainly because of growth in natural-gas-fired electricity generation. More than half of the projected increase in consumption, which totals 13 trillion cubic feet, is expected in the electricity generation sector.

Supply and Prices: Domestic natural gas production is expected to increase more slowly than consumption over the forecast, from 19.3 trillion cubic feet in 2000 to 29.0 trillion cubic feet in 2020. Production over the forecast period is expected to total about 500 trillion cubic feet, or roughly 40 percent of the 1,281 trillion cubic feet of estimated recoverable resources as of the beginning of 1999. *AEO2001* projects that the average wellhead price of natural gas produced between 1999 and 2020 will be less than $3.05 per million Btu (in 1999 dollars) over most of the forecast period. Like any commodity price, however, actual natural gas prices are likely to oscillate significantly around the trend line projected in *AEO2001* as a result of business cycles in the industry, unusual seasonal temperature variations, or other special circumstances like pipeline ruptures—the kinds of events that have been experienced in the past 24 months.

Imports: Net natural gas imports are expected to grow in the forecast from 16 percent of total natural gas consumption in 1999 to 17 percent (5.8 trillion cubic feet), primarily from western Canada. Some new natural gas is also expected from Sable Island in the offshore Atlantic. Imports of liquefied natural gas (LNG) are expected to supply just 2 percent of U.S. natural gas consumption in the forecast, up from 0.6 percent percent in 2000.

Challenges Facing The Natural Gas Industry

Moderating the recurrence and severity of "boom and bust" cycles while meeting increasing demand at reasonable prices is one of the major challenges facing the U.S. natural gas industry today. The most serious short-term challenge is to increase production rapidly enough to satisfy natural gas demand at reasonable prices. This short-term challenge is inextricably woven into the investment cycles of the gas industry. Sustained high short-term natural gas prices can prompt significant new drilling investments and bring on new supply, but they can also prompt consumers to make potentially irreversible equipment investments and switch to lower cost fuel options. Both factors tend to put downward pressure on natural gas prices.

Attracting qualified personnel and natural gas drilling rig investments to meet expected demand growth is another challenge that may be difficult unless less risky but adequate long-term returns on investment can be achieved. Recent events in the oil and gas industry have led some to question the industry's ability to meet a projected 41-percent increase in domestic gas production by 2015. Periodic downturns in the gas industry, such as in the 1984-89 and 1998-99 periods, triggered significant downsizing and cutbacks in spending for exploration and development of new gas sources. Reduced spending slowed the construction of drilling rigs and other infrastructure needed to support future drilling, and continued downsizing and layoffs reduced the industry's ability to attract qualified new employees.

Also, overcoming low production growth despite a large increase in well completions because of smaller finds per well may be difficult to accomplish even with technological progress. While the number of new gas well completions increased by almost 45 percent in 2000,[25] gas production increased by only 3.7 percent. The discrepancy reflects, in part, the lag in production following a shift in drilling (usually about 6 to 18 months).

Avoiding natural gas delivery system bottlenecks resulting from increased growth in natural gas demand over the past several years has increased utilization of pipelines and resulted in pressure for pipeline

[25] Computed from Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(2001/03) (Washington, DC, March 2001), Table 5.2.

expansion in several areas of the country.[26] For instance, pipeline utilization levels in parts of the West (notably, pipelines delivering gas to the California market) have recently been well above 95 percent on a continuing basis. Further increases in demand could cause capacity bottlenecks to develop.[27] Growing gas service needs in the southern Nevada area also suggest the need for system expansion there.[28]

[26] Annual utilization of pipelines serving State markets varies considerably, and pipeline utilization rates during peak demand periods are significantly higher than the average annual rate.

[27] The recent problems with gas deliveries into California were also financial in nature. Some natural gas suppliers have been reluctant to sell on credit to two LDCs, PG&E and SoCal, due to their dire financial situation brought on by their need to purchase large amounts of out-of-state electricity in recent months. See "California Seeks Emergency Measures for PG&E," Gas Daily (January 17,2001), p. 1.

[28] In fact, because a significant portion of the flow on the Kern River Transmission system is currently reserved by shippers moving natural gas into the Las Vegas electric power generation market, only about 60 percent of Kern's 800 million cubic feet per day of capacity into California is currently flowing gas. To address this situation, and to respond to calls for rapid expansion of pipeline capacity to California, Kern River Transmission Company has been granted approval from the FERC to proceed with an expansion of its system (through installation of additional compression) by June 2001.

1. Introduction and Background

Statement of Purpose

In his memorandum of April 25, 2001, to the Energy Information Administration (EIA),[1] Secretary of Energy Spencer Abraham requested both a long-term and a short-term study of North American natural gas markets. This report presents the results of EIA's short-term study.

Natural gas prices rose dramatically in 2000 and have remained high through the first part of 2001, raising concerns about the potential for natural gas to fuel the growth of the U.S. economy. Exacerbating those concerns are the current low levels of natural gas in storage and the prospect that a higher than normal rate of injection will be needed in the summer of 2001 during the off-peak (non-heating) season to restore storage to normal levels—which could lead to further price increases in 2001 and 2002. The central questions addressed in this report are "Why have natural gas prices risen so high and so quickly?" and "What is the outlook for the U.S. natural gas market in the short and mid-term?"

Organization of the Report

Chapter 1 of this report provides a brief description of the U.S. natural gas market, its participants, and their relationships. Chapter 2 describes recent market trends in natural gas consumption, supply, storage, prices, and pipeline infrastructure and discusses the challenges facing the natural gas industry, including an examination of the challenges presented by the current situation in California. Chapter 3 completes the report with discussions of the short-term and mid-term outlook for natural gas.

Background

The Natural Gas Market in the United States

Natural gas represented 24 percent of the energy consumed and 27 percent of the energy produced in the United States in 2000. The industrial sector was the largest user of natural gas—for plant operations, cogeneration of electric power, and as an industrial feedstock. In addition, natural gas is the largest energy source consumed in the residential sector and the fastest growing energy source for electricity generation. In recent months, the high prices of natural gas used in the industrial, residential and commercial, and electricity generation sectors have caused exceptional public concern about the present and future operations of the natural gas industry and markets.[2]

Consumption of natural gas in 2000 is estimated to have surpassed the previous peak for natural gas consumption in 1972. Curtailments of natural gas supplies during the winter of 1976-77, as well as regulations governing the market during the 1970s, constrained interest in natural gas use for many years. The process of price deregulation began with the Natural Gas Policy Act of 1978 (NGPA), which provided for phased decontrol of natural gas wellhead prices. The deregulation of wellhead prices was completed with the Wellhead Decontrol Act of 1989. In addition, beginning in 1985, the Federal Energy Regulatory Commission (FERC) developed new regulations for interstate pipelines, which changed their role in the delivery of natural gas. At the same time, many State public utility commissions (PUCs) began to accommodate new competition for local distribution companies (LDCs) in supplying end users in local markets.

During the 1980s and most of the 1990s, when natural gas demand was low and end-use prices were regulated, natural gas prices were low relative to other energy sources,[3] except for coal. In 1997, for example, natural gas accounted for about one-half of the energy consumed in the residential sector but less than one-quarter of household energy expenditures for space heating, air conditioning, water heating, and appliances. Similarly, throughout most of the 1980s and 1990s, electricity generators paid less for natural gas than for residual oil, and the relative prices of natural gas and coal remained about 2 to 1. This price relationship, together with higher efficiencies, low capital costs, short construction lead times, and the fact that natural gas is a cleaner burning fuel than coal with respect to emissions of sulfur dioxide, nitrogen oxides, and particulate matter, led to a strong increase in use and planned use for natural gas in the industrial and electricity sectors.

[1] See Appendix A for the complete text of the Secretary's request.

[2] Energy Information Administration, *Monthly Energy Review*, DOE / EIA-0035(2001 / 03) (Washington, DC, March 2001).

[3] On a common energy content basis.

In the 1990s, however, demand for natural gas grew at a pace faster than the rate of growth in domestic natural gas production. Imports from Canada and elsewhere increased to meet the demand, but the overall supply-demand balance tightened significantly, and seasonal consumption patterns changed. Circumstances related to supply, consumption, and infrastructure capacity have become increasingly important to price and reliability in regional markets. Large and small decisions made in the gas supply industry, natural gas user community, and State and Federal regulatory bodies are all important when supply and demand are tightly balanced. Consequently, it has become increasingly important to prices and reliability that all portions of the supply and demand infrastructure operate smoothly, with clear market signals.

Natural Gas Market Participants and Their Relationships

The U.S. natural gas market is composed primarily of producers, pipeline companies, storage companies, LDCs, marketers (sometimes also referred to as "aggregaters"), and consumers. These are functional distinctions that are oversimplified in the current gas market, because some companies in the industry combine various segments, with ownership of production wells, pipelines, storage facilities, and even LDCs. For purposes of explanation, however, it is useful to think of the participants as distinct.

Producers include firms that explore for new gas resources and expand production from known reserves. The market for wellhead natural gas purchases is unregulated; that is, producers may negotiate prices and delivery terms with consumers or with other firms, such as marketers and LDCs, for the sale of their products.

After production, gathering lines deliver the gas to processing plants and/or to transmission pipelines. The vast majority of gathering pipelines are under State jurisdiction. They can be owned by producers, pipeline transmission companies, marketers, LDCs, or independent operators. During the restructuring of the 1990s, most pipeline gathering facilities were sold or spun off into separate companies. The gas processing plants remove noxious gases, such as hydrogen sulfide, separate out useful hydrogen and other light hydrocarbon liquids (natural gas liquids) for resale to refineries and other industries. They can be owned by firms in virtually any other market segment.

Pipeline companies connect to the production field or after-treatment points (often via gathering lines) and deliver the gas under either short term or longer term firm or interruptible contracts to their customers. The pipeline delivers gas to specified delivery points, which may be a storage facility to which the owner of the gas has rights, a "citygate" of an LDC, an end-use customer, or another point on the pipeline system. Rates (tariffs) and terms and conditions of services charged by interstate pipeline companies are based on rate proceedings approved by the FERC. The FERC also approves construction of interstate pipelines. State PUCs are responsible for approving the construction of and rates charged by pipelines entirely within the borders of their States. Pipeline safety is regulated by the U.S. Department of Transportation's Office of Pipeline Safety.

Storage firms are firms that have developed the facilities to store natural gas for later delivery. They may be federally regulated if their facilities are used to ensure pipeline reliability as part of FERC rate proceedings; otherwise, they are not federally regulated. State PUCs have regulatory authority over storage facilities that are used to serve LDC customers.

Underground storage is a vital part of the natural gas infrastructure. The ability to store gas ensures supply reliability during periods of heavy or peak demand by supplementing pipeline supplies and providing an alternative source of gas in case of supply interruption. Storage also allows load balancing of daily throughput levels on pipelines. More recently, storage is also being used to take advantage of expected price movements and to support futures market trading.

Natural gas can be stored in a variety of ways. The most common method of natural gas storage is in underground geologic formations, largely former producing reservoirs for which further production is uneconomical—hence the term "depleted fields." Two other types of underground facilities are aquifer reservoirs and salt caverns.[4] Storage injection and withdrawal rates can vary dramatically for different geologic formations. Salt domes or beds usually can be emptied in 2 to 4 weeks and refilled in 4 to 8 weeks, depending on compressor capacity. Depleted oil and gas formations usually have much greater capacity than salt deposits, but their injection and delivery periods usually are much longer. Most depleted field storage facilities are designed to provide for withdrawals over the 151-day heating season and refilling over the 214-day non-heating season.

LDCs are companies that control local gas distribution facilities. They may be transporters of natural gas owned by their LDC customers, or they may be both suppliers and transporters. LDC customers may also choose the LDC to provide all scheduling, fuel acquisition, and delivery functions (the "merchant function") for them. LDCs are regulated by State PUCs.

[4]Additional detail on storage is provided in Chapter 2 of this report.

Marketers are unregulated firms that typically perform the "merchant" function for natural gas customers, usually packaging supply, storage, and pipeline delivery capacity on either a firm or interruptible basis. The number of marketers offering natural gas services increased dramatically with implementation of FERC Order 636, which restructured the interstate pipeline companies by separating their merchant and transportation functions. Many marketers are affiliated with pipeline companies, LDCs, or producers.

The complexity of the deregulated natural gas market[5] and its growing interrelationship with electricity markets that also are moving toward deregulation have increased the need for coordination among market participants. For example, in addition to production challenges, timely additions of natural gas pipeline capacity and other infrastructure present challenges that will require coordination among pipeline companies, consumers, the FERC, and State regulatory bodies.

[5]The commodity (fuel) portion of the natural gas market is deregulated. However, transmission and distribution rates remain regulated by the FERC in the case of interstate transmission and by State authority in the case of intrastate distribution systems, including LDCs. Numerous programs are also underway to give small end users the opportunity to select suppliers.

2. Recent Trends and Current Situation

Trends in Natural Gas Consumption

Total Consumption

From the high levels of the early 1970s, U.S. natural gas consumption declined to a low of 16.2 trillion cubic feet in 1986.[6] Since then it has increased at an average annual rate of about 2.4 percent. In 2000, total natural gas consumption in the United States reached an all-time high of 22.8 trillion cubic feet, 4.8 percent higher than in 1999. The previous record was 22.1 trillion cubic feet in 1972. Total end-use consumption of natural gas increased by 0.8 trillion cubic feet from 1999 to 2000.[7] While industrial consumption declined, the increase in other sectors was about evenly split between electricity generation and the residential and commercial sectors combined.

Much of the variation from the general year-to-year trend of U.S. natural gas use can be attributed to variations in average winter temperatures.[8] The larger than average increase in gas use from 1999 to 2000 was primarily the result of a change from the particularly warm winter weather of 1999-2000 (3,351 heating degree-days or 457 fewer heating degree-days than normal) to the particularly cold winter of 2000-2001 (4,048 heating degree-days or 270 more heating degree-days than normal). Average national temperatures in November and December 2000 were near record cold levels (20 percent below normal) for those months. Other factors that can contribute to short-term increases in natural gas consumption are changes in natural gas prices relative to other fuel prices and changes in the availability of other fuels.

Consumption by Sector

In 2000, the residential, commercial, industrial, and electricity generation sectors accounted for about 24 percent, 16 percent, 39 percent, and 21 percent of the end-use natural gas market on an annual basis, respectively.[9] A small amount was consumed by natural gas vehicles. Consumption levels in the residential and commercial sectors are the most sensitive to temperature, those in the industrial sector the least. In these three sectors, natural gas use peaks in the winter period when heating loads are high. The electricity generation sector has a marked peak in the summer months when air conditioning demand is high and a second, smaller peak in the winter.

Industrial

The industrial sector consumes the greatest quantity of natural gas[10] and shows the least monthly variation in gas consumption throughout the year, with the peak month in the winter period averaging about 12 percent higher than the monthly average in recent years. Industrial consumption rose steadily from 1986 to 1996, at an average annual rate of 4.6 percent. From 1996 to 2000, industrial gas consumption fell by an average of about 1.9 percent per year, despite increases in manufacturing output that have averaged 2.9 percent annually since 1996.

In 1996 the U.S. industrial sector consumed 8.7 trillion cubic feet of natural gas. With a shift toward less energy-intensive industries and an overall increase in industrial energy efficiency resulting from the introduction of new capital equipment, however, industrial gas consumption dropped to 8.3 trillion cubic feet in 1999 and 8.1 trillion cubic feet in 2000. From September through December 2000, natural gas consumption in the industrial sector was down by 8 percent from 1999 levels. Manufacturing output growth began to slow during the third quarter of 2000, followed by a more significant slowdown during the fourth quarter of 2000, in part because of higher energy costs.

Many industrial consumers of natural gas do not have the option of switching to other fuels when natural gas prices rise. Others have some limited fuel switching

[6]Energy consumption data cited in this section are taken from Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(01/03) (Washington, DC, March 2001), unless otherwise noted.

[7]Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0103(2001/03) (Washington, DC, March 2001).

[8]Winter is defined as November 1 through March 31.

[9]Only about 91 percent of all natural gas production reaches ultimate end users. The rest is consumed or lost in its production, processing, or transmission.

[10]In data collected and published by EIA, industrial sector fuel consumption currently includes fuel consumed by cogenerators, independent power producers (IPPs), and nonutility generators (NUGs). In this section, using data from Form EIA-860B, "Annual Electric Generator Report - Non-Utility" (1999), estimated consumption by IPPs and NUGs was accounted for in the electricity generation sector.

capability.[11] An option that has been exercised by some industrial users recently as natural gas prices have risen dramatically is to reduce operations and sell contracted gas to the highest bidder. Examples include Terra Nitrogen, which shut down its Arkansas fertilizer plant in 2000 and cut back operations at its Oklahoma plant, and Mississippi Chemical, which halted fertilizer production. Both companies sold their natural gas futures contracts.[12]

Residential

From 1986 to 2000, residential natural gas use grew by an average of 1.0 percent per year. Several factors contributed to the increase. Newly constructed single-family homes increased in average size from 1,825 square feet in 1996 to 2,225 square feet in 1999 (22 percent), and in 1999 70 percent of those new homes used natural gas for space heating, compared with 47 percent in 1986.[13] Natural gas fireplaces have also become more popular in newly constructed homes. Over the same period, however, increases in both furnace and building shell efficiencies have tempered the growth in residential natural gas use.

Residential natural gas consumption in 2000 was 4.3 percent higher than in 1999, largely due to the colder winter. About 70 percent of annual residential gas consumption occurs during the winter months (November through March), which represents just 41 percent of the calendar year. In the peak consumption month (typically January), residential consumption typically has reached or exceeded industrial consumption. Colder than normal temperatures during peak months can further increase the peak demand.

With record low temperatures in the last 2 months of 2000, it is estimated that residential natural gas consumption in December 2000 and January 2001 was at record levels. Residential gas use in December 2000 is estimated at 893 billion cubic feet, which would be 13 percent above the previous record of 791 billion cubic feet in December 1989, as well as the largest-ever increase from the previous year and from the previous month in absolute terms. Residential gas consumption in January 2001 is estimated to have been even higher, at 1,006 billion cubic feet, 6 percent above the previous record of 953 billion cubic feet in January 1994 and 14 percent above the January 2000 level. During the 2000-2001 winter heating season, natural gas consumption in the residential sector is estimated to have been 20 percent greater than in the previous winter season.

Residential customers typically are the least responsive to natural gas prices, particularly in the short term. There are few short-term options for decreasing residential gas use other than lowering thermostats and sealing leaky doors and windows. Some households may be able to resort to backup heat, such as electric room heaters or woodstoves and fireplaces, but most are truly captive customers. In addition, residential customers often are not as informed about natural gas prices as they are about the prices of other, more widely advertised products such as gasoline, and frequently they do not receive price signals (monthly bills) in a timely manner. Some opt for levelized payment plans, which are beneficial for household budgeting but can delay price signals.

Commercial

The commercial natural gas market is only about two-thirds the size of the residential market, with only about half the January peak. Although consumption in the commercial sector is affected by winter temperatures, only 62 percent of its total annual consumption occurs during the winter months (as compared with 70 percent for the residential sector). Commercial consumption has grown much faster than residential consumption since 1986, by about 2.7 percent per year on average, and the annual total in 2000 was about 7 percent higher than the average, due mainly to the colder winter.

Like the residential sector, the commercial sector is estimated to have had record levels of natural gas consumption in December 2000 and January 2001. Total natural gas use in the commercial sector during the 2000-2001 winter heating season is estimated to have been about 16 percent higher than during the 1999-2000 heating season.

Electricity Generation

Natural gas consumption by electricity generators was relatively stable in the 1980s and early 1990s, averaging around 2.9 trillion cubic feet per year.[14] From 1996 to 2000, however, the use of natural gas for electricity production grew by an average of nearly 11 percent per year, to 3.9 trillion cubic feet in 1999 and 4.4 trillion cubic feet in 2000. The natural gas share of U.S. electricity

[11]According to EIA's 1994 Manufacturing Energy Consumption Survey (MECS), 39 percent of industrial natural gas consumption in 1994 could have been switched to other fuels. See Energy Information Administration, *Manufacturing Consumption of Energy 1994*, DOE/EIA-0512(94) (Washington, DC, December 1997), web site www.eia.doe.gov/emeu/mecs/mecs94/consumption/mecs4a.html.

[12]"California Haunted by Neglect of Infrastructure," *Natural Gas Week* (December 18, 2000), p. 10.

[13]U.S. Census Bureau, *Current Construction Reports—Characteristics of New Housing* Series C25, 1989 and 1999 (Washington, DC: U.S. Department of Commerce, 1990 and 2000).

[14]Includes consumption of natural gas by all electric power generators for grid-connected power except cogenerators, which produce electricity and other useful thermal energy. Gas use by IPPs and NUGs is included.

generation, including cogeneration, rose from 13.2 percent in 1996 to about 16 percent in 2000.[15]

The sharp increase in natural gas consumption for electricity generation since 1996 has resulted from increasing demand for electricity and from the growing use of gas in new generating plants. Recent increases in electricity sales have contributed significantly to recent increases in natural gas consumption. Electric utility retail sales have increased by 2.4 percent per year on average since 1995. The most rapid growth in electricity sales has been in the commercial sector (30 percent of the total market), at an average annual rate of about 3.6 percent. Between 1998 and 1999 total retail sales increased by 2.2 percent, from 3.24 to 3.31 trillion kilowatthours, and the increase from 1999 to 2000 was 2.5 percent.[16]

Annual variations in natural gas demand in the electricity generation sector are attributable to weather variations (particularly during the summer months), the availability of alternative energy supplies (e.g., hydropower), and fuel prices. In terms of weather, 1998 had a particularly warm summer, but the 1999 and 2000 summers were close to average on a national basis. In terms of alternative supplies, low water levels at hydroelectric dams in the Northwest over the past 2 years have resulted in relatively low levels of generation from hydroelectric sources, leading to a significant (12 percent) increase in natural-gas-fired electricity generation. Estimates for 2001 are for even lower levels of hydropower generation in the Northwest.

Even with the high prices for natural gas in 2000, natural gas use by electric generators increased to assist in satisfying higher demand for electricity and to supplement low levels of generation from hydropower. With the exception of hydroelectric power, petroleum, and some renewable energy sources, net generation of electricity, including cogenerators, from all sources increased from 1999 to 2000. While total net generation increased by 96 billion kilowatthours, conventional hydroelectric generation decreased by 44 billion kilowatthours, requiring a net increase from other sources of 140 billion kilowatthours. About half the increase came from coal, a third from natural gas, and about 17 percent from nuclear power. With relatively high prices of oil and still relatively low prices of natural gas at the beginning of 2000, generation from petroleum was down from 1999 levels (when petroleum prices were low). By the end of the year, as natural gas price increases far exceeded those of petroleum products, generation from petroleum increased more dramatically, so that by December net generation from petroleum was nearly triple 1999 levels. Although generation from natural gas slowed somewhat toward the end of 2000, estimates for December 2000 still exceeded 1999 levels.

While most areas of the country entered the 1990s with sufficient generating capacity, the need for new capacity started to grow in the mid-1990s. Natural gas turbine and combined-cycle plants were the units of choice for new plant construction because of their relatively low costs, high efficiencies, and short construction lead times. From 1995 through 1999, natural-gas-fired capacity in the United States increased by 21.4 gigawatts. The largest increase, 6.7 gigawatts, was in 1999. Twenty-two gigawatts of gas-fired generating capacity was added in 2000.[17] Estimates for additional planned gas-fired capacity for 2001 generally are in the range of 25 gigawatts.[18]

Natural Gas Supply

Domestic Production

Natural gas prices affect both short- and long-term domestic gas production. In the short term, price surges determine the degree of utilization for present productive capacity. Costs rise at an increasing rate as capacity limits are approached. In the longer term, higher gas prices provide both the primary means (cash flow) and incentive to invest in additional projects to either maintain or expand productive capacity.[19]

Recent gas production patterns show the impact of a lengthy period of low gas and oil prices, which had turned around by mid-1999.[20] In response to the relatively low gas and oil prices, gas production in 1999 hit a recent low of 18.6 trillion cubic feet. Incremental gas consumption requirements that year were satisfied by

[15]When cogeneration is excluded, the shares were 8.8 percent in 1996 and about 11 percent in 2000.

[16]Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2001/03) (Washington, DC, March 2001).

[17]Capacity additions by location and fuel type are listed in EIA's *Electric Power Monthly*, DOE/EIA-0226(2001/03) (Washington, DC, March 2001).

[18]Energy Information Administration, Form EIA-860A, "Annual Electric Generator Report - Utility," and Form EIA-860B, "Annual Electric Generator Report - Nonutility" (1999).

[19]Because industry revenues come from both gas and oil production, cash flow for gas investments also is related to oil prices. Low oil prices can limit gas investments.

[20]Official prices for natural gas at the New York Mercantile Exchange (NYMEX) are provided in dollars per million British thermal unit (Btu). This report follows the convention of stating prices in dollars per million Btu and consumption and production in trillion cubic feet. Monthly average wellhead prices for natural gas fell to $1.64 per million Btu ($1.68 per thousand cubic feet) in March 1999, the lowest level since November 1995, because of declining seasonal demand and growing imports from Canada. The domestic first purchase price for crude oil hit $10.87 per barrel in 1998, the lowest level for crude oil prices (after inflation adjustment) during the entire second half of the 20th century.

increased imports and a drawdown from storage during the year. Gas consumption in 1998 fell from the 1997 level of 22.0 trillion cubic feet [21] as a result of warm winters. With the decline in demand, production decreased in 1998 (by 0.2 trillion cubic feet) and 1999 (by less than 0.1 trillion cubic feet). As demand for gas diminished, prices also weakened, leading to a falloff in gas rig activity from a relative peak of 657 rigs drilling gas wells as of December 19, 1997, to 362 as of April 23, 1999 (Figure 1). Rig activity picked up in May of 1999 and accelerated in the fall of that year. By December 1999, active gas rigs averaged 636 units for the month. Gas rig activity continued to strengthen in 2000, yielding a count of 854 by December.

The reduced gas drilling activity through April 1999 did not affect production immediately. Changes in drilling generally affect the system over a 6- to 18-month period because of the time required to acquire investment funds, install production equipment, and construct gathering lines and pipelines for transportation. Extraction of natural gas resources occurs at a declining rate as gas deposits are depleted and pressures decline. Consequently, the development of new wells is important. More than 30 percent of U.S. gas production in recent years has flowed from wells that are no more than 2 years old (Figure 2).[22] When drilling falls, the natural decline in production from existing wells is not offset with new well capacity. If there is under- or unutilized productive capacity, production can be maintained by increased utilization of existing wells. Absent spare capacity, however, decreased drilling leads to an aggregate decline in production as producing wells are depleted. Subsequently, accelerated drilling must be undertaken to return to the previous production level or achieve higher production rates.

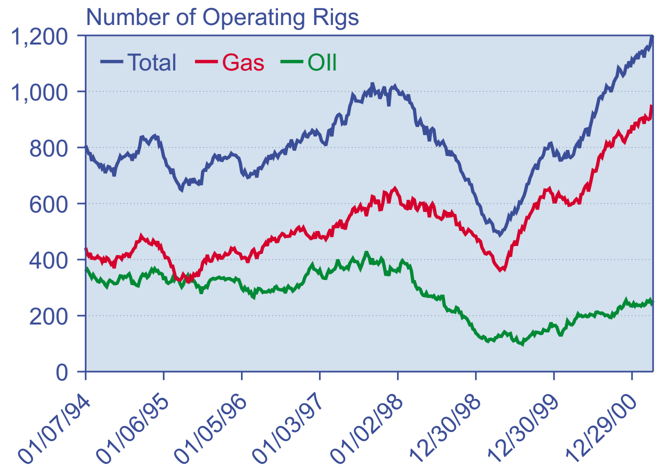
Although gas well completions have increased steadily since April 1999, production did not respond robustly enough to satisfy the expanding market demand, because the industry initially had to overcome the prior drilling slump. Despite this handicap, domestic production increased by about 0.7 trillion cubic feet in 2000, equivalent to about 66 percent of the increase in consumption from 1999 to 2000.[23] Given an industry apparently pressing the limits of its productive capacity, production could not increase sufficiently to meet rising demand, so prices were driven higher.

Drilling Activity and Reserve Additions

Natural gas well completions have outpaced oil well completions since 1993.[24] Gas completions as a share of all successful oil and gas wells increased from 63 percent in 1998 to 72 percent in 1999. Overall, however, gas drilling levels dropped by 13 percent between 1998 and 1999, in part because of low levels of cash available for investment in exploration and development.

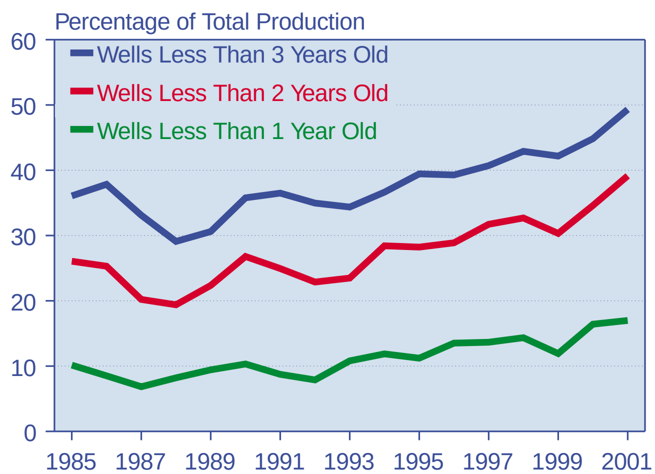
Despite a lower number of gas wells, natural gas reserve additions were higher in 1999 than in 1998, replacing 118

Figure 1. Weekly Counts of Rotary Rigs in Operation, 1994-April 2001



Source: Baker-Hughes Inc. (April 11, 2001) web site www.bakerhughes.com/investor/rig/rig_na.htm.

Figure 2. Shares of Lower 48 Natural Gas Production from New Wells by Age, 1985-2001



Note: The data shown for 1999 and 2000 are EIA estimates, and the data shown for 2001 are projections. Estimated production for wells no more than 1 year old is about half the flow recorded in the first 12 months, because on average wells completed in any calendar year produce for only 6 months.

Source: Energy Information Administration, Reserves and Production Division.

[21]Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0103(2001/03) (Washington, DC, March 2001).

[22]On a calendar year basis, the percentage of total production contributed by wells that are no more than 1 year old represents an average of 6 months production. This understates the relative contribution of new wells during the first 12 months of production.

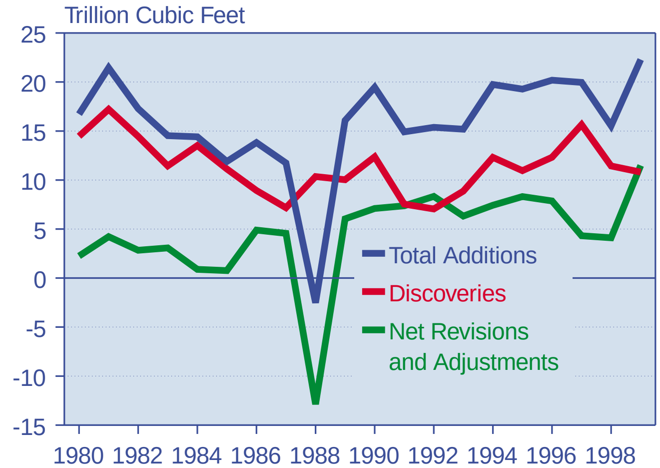
[23]Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0103(2001/03) (Washington, DC, March 2001).

[24]A well is completed when it has been prepared and is ready to produce or already producing.

percent of dry gas production with new reserves (Figure 3). Although total reserve additions were larger, total dry natural gas discoveries[25] in 1999 were 5 percent lower than in 1998 and 31 percent lower than in 1997. The decline in gas discoveries was not just a result of fewer exploratory wells. Average discoveries per exploratory well (the finding rate) also declined, and this level of reduced productivity is expected to have continued through 2000.

However, with average wellhead prices averaging roughly $2.50 per million Btu in mid-1999, net revisions and adjustments to proved reserves almost tripled, from 4.1 trillion cubic feet to 11.5 trillion cubic feet.[26] With continued high prices in 2000, reserve additions through revisions and adjustments are expected to remain well above the post-1976 average of 3.8 trillion cubic feet per year.

Figure 3. Additions to U.S. Dry Natural Gas Reserves, 1980-1999



Source: Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1999 Annual Report*, DOE/EIA-0216(99) (Washington, DC, December 2000).

Drilling Investment Trends

Analysis of available data suggests that the natural gas industry behavior in 2000 was consistent with its practices of the past decade. In response to the natural gas price increases in 2000 there were an average of 720 rotary gas rigs in operation, a 45-percent increase from 1999.[27] Gas rigs accounted for almost 80 percent of the total operating rigs. Between 1999 and 2000, both exploratory and developmental gas drilling increased significantly, by 31 percent and 45 percent, respectively.[28]

Drilling behavior (exploratory and developmental drilling) is correlated with natural gas wellhead prices (Figure 4). Exploratory wells are wells drilled with the goal of finding new reserves. Developmental wells are wells drilled with the aim of producing from existing proved reserves. The two types of wells are vastly different in terms of their riskiness. In 2000, fewer than one-third of all exploratory wells were successful. In contrast, more than 85 percent of development wells in 2000 were successful.[29]

From the mid-1970s to 1980 the gas industry and most forecasters expected gas prices to rise as supplies remained constrained and price ceilings were increased. This situation continued into the early 1980s after the passage of the Natural Gas Policy Act. Consequently, exploratory drilling reached very high levels with more than 8,500 exploratory wells, including dry holes (Figure 5); however, prices (measured in constant 1999 dollars) began to decline after 1983 and then fluctuated around $2.00 per million Btu. As natural gas prices declined and later moderated, so did exploratory drilling. When prices are low, the industry typically focuses more on producing from existing proved reserves, based on their expected profitability, rather than aggressively trying to add to reserves.

In 1998, capital expenditures for the major companies in the natural gas industry substantially exceeded cash flow,[30] leading to increases in borrowing, decreases in payouts to investors, and drawdowns of cash balances. Repairing balance sheets and boosting investor confidence became the focus in 1999, leading to reductions in capital expenditures, increased payments to reduce debt, and decreased payouts to investors.

As prices rose in 2000, the increases to expected profitability and industry cash flow motivated increased investment spending. The *Oil and Gas Journal* noted that 154 independent U.S. producers had increased capital spending by 48 percent in 2000 and that the top independent U.S. producers announced budget plans to increase spending in 2001 by about another 35 percent.[31]

[25]Total discoveries are those reserves attributable to field extensions, new field discoveries, and new reservoir discoveries in old fields.

[26]Revisions are changes to estimates of proved reserves at the end of the prior year, resulting from new information other than an increase in proved acreage (extensions).

[27]Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2001/03) (Washington, DC, March 2001), Table 5.2.

[28]Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2001/03) (Washington, DC, March 2001), Table 9.11.

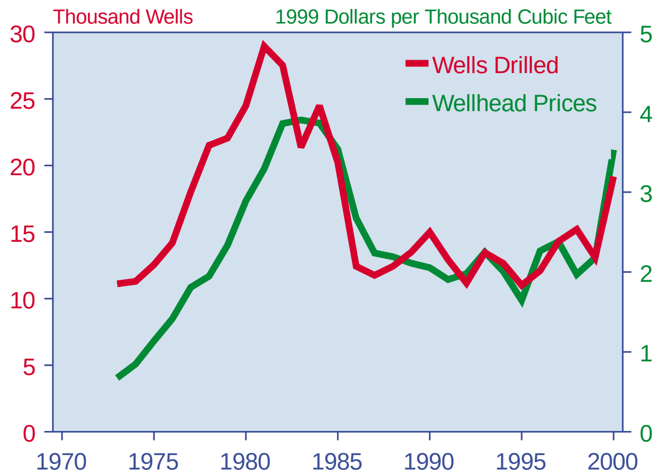
[29]Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2001/03) (Washington, DC, March 2001), Table 5.2.

[30]Energy Information Administration, *Performance Profiles of Major Energy Producers 1999*, DOE/EIA-0206(99) (Washington, DC, January 2001).

[31]P. Meroli, "Independents Up Spending, But Not Gas Output," *Oil Daily*, Vol. 51, No. 46 (March 8, 2001), pp. 1-2.

The prospects for adding significant amounts of new gas supplies from 2002 to 2005 look promising in view of expected natural gas prices. *Natural Gas Week* reports that U.S. contractors and service companies, pumped up by profits from current natural gas sales, "are flinging themselves into a headlong rush for rigs as the boom is beginning to take on fabled proportions." First-quarter 2001 profits reported by Baker and Hughes rose by 600 percent over first-quarter 2000 profits, and Senior Vice President Andrew Sczescila predicted that 2001 would be the best year for service companies since 1981.[32]

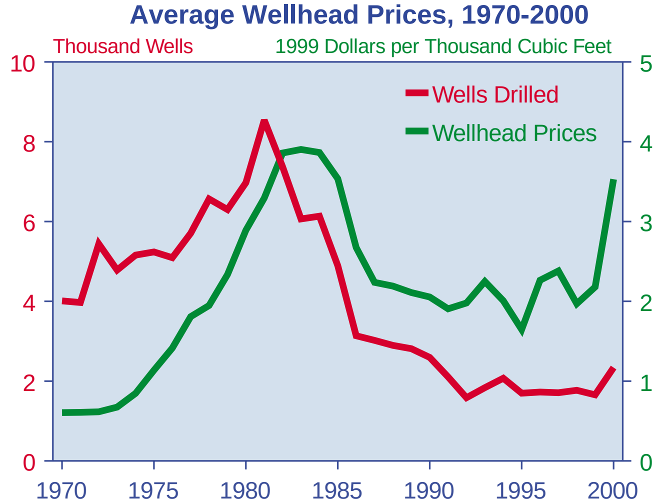
Figure 4. U.S. Natural Gas Exploratory and Developmental Wells and Average Wellhead Prices, 1974-2000



Notes: Well counts shown are for lower 48 exploratory and developmental wells, including dry holes. Prices are average lower 48 wellhead prices.

Source: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2001/02) (Washington, DC, February 2001).

Figure 5. U.S. Natural Gas Exploratory Wells and Average Wellhead Prices, 1970-2000



Notes: Well counts shown are for exploratory wells. Prices are average lower 48 wellhead prices.

Source: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2001/02) (Washington, DC, February 2001).

Factors Limiting Rapid Expansion of Domestic Gas Supply

Investor uncertainty about the duration of high prices moderates the rate of drilling investment. Investors do not initiate projects with long payback periods in any industry based on temporary price increases unless those prices are thought to be representative of a long-term market condition. Investments are based on expected prices over the project lifetime, and price expectations are not adjusted automatically and completely on the basis of a sudden shift in price trends. Thus, the impact of recent high prices on drilling investment may have been muted by uncertainty about their duration.

Natural gas prices at the Henry Hub in most of 2000 were well above the average range of the 1990s, including 1998 and 1999. In 2001, temperatures since the first of the year have been warmer than normal across the Lower 48 states, reducing gas demand and the natural gas spot prices at the Henry Hub by more than 50 percent from the winter peak—down to a level slightly above $5 per million Btu by late February 2001, which continued through April 23. Earlier episodes of severe price runups (such as in February 1996) were not as sustained as they have been in 2001.

The NYMEX prices for future delivery are a helpful barometer for identifying the consensus view of managers in the gas industry as well as outside investors regarding price expectations related to gas investment decisionmaking. Although NYMEX prices in mid-December 2000 approached roughly $10 per million Btu, prices were expected to return to a level slightly exceeding $4 per million Btu by summer 2002 and were expected to fall into the $3 range by March 2003.[33] In mid-January 2001, NYMEX prices had become more stable through 2003, with futures prices lower in the near-term months of 2001 and remaining above $4 per million Btu into 2003.[34]

An industry survey of independent operators in November 2000, when gas spot prices ranged from $4.38 to $6.34 per million Btu and oil prices were between $34 and $35 per barrel, indicated that gas prices averaging $3.58 per million Btu and oil prices averaging $25.35 per barrel were anticipated in their 2001 investment plans.[35]

[32]"Land Rig Drilling, Dayrate Boom, Produce Huge Profits for Industry," *Natural Gas Week* (April 30, 2001), pp. 3-4.

[33]"Futures NYMEX @ Henry Hub," *Gas Daily, Financial Times* (December 15, 2000), p. 4.

[34]"Futures NYMEX @ Henry Hub," *Gas Daily, Financial Times* (March 23, 2001), p. 4.

[35]B. Campbell, "Hard at Work: Independents Plan To Go the Extra Mile," *The American Oil & Gas Reporter* (January 2001), pp. 43-46.

Coincidentally, the average wellhead gas price for 2000 is estimated to have been $3.51 per million Btu.[36]

Unexpected rapid price surges do not allow the industry to carry out the preparatory planning and other activities necessary to build productive capacity efficiently. Virtually all industry participants attempt to respond in a short time frame, which leads to heightened competition for investment funding, personnel, and equipment. Heated competition for labor and equipment drives up associated costs, limiting the actual supply activities that can be accomplished under any given exploration and development budget and reducing the net benefit of higher prices for producers. For example, rates for a jackup rig in the Gulf of Mexico rose from an average of roughly $23,000 per day in January 2000 to an average of $45,000 in November—an increase of 95 percent in less than a year.[37]

As a result of the relatively low gas prices that prevailed through most of the 1980s and 1990s and the associated industry consolidations and downsizing, trained personnel have become quite scarce. Even at elevated salaries, the availability of trained crews for drilling and other operations often are limited. Further, although investment has been higher, the period of very high prices has been relatively short—not long enough to alter price expectations strongly. Natural gas prices in 1981-1983 averaged over $3.75 per million Btu.[38] If relatively high natural gas prices are sustained, additional supplies will be stimulated and the short-term difficulties will be resolved over time.

U.S. imports of natural gas have also increased in response to higher prices, but import volumes generally are limited by available transportation capacity, which is fixed in the short term. Imports from Canada have increased as new cross-border capacity has come on line. Shipments of liquefied natural gas (LNG) received in Massachusetts and Louisiana have also increased in response to higher U.S. gas prices.[39]

Imports and Exports

For the United States, international gas trade consists primarily of trade with Canada and Mexico and trade in LNG (Figure 6). Net imports accounted for 16 percent of U.S. natural gas consumption in 2000. With tight domestic supplies and growing demand for natural gas, imports are an important source of supplemental supply.

U.S. Trade with Canada

The United States is a net importer of natural gas from Canada, which provided approximately 94 percent of total U.S. imports in 2000.[40] Net imports from Canada in 2000 totaled 3.5 trillion cubic feet, 5 percent more than in 1999. The weighted average price of gas imports from Canada in 2000 was approximately $3.90 per million Btu,[41] almost 20 percent lower than the average citygate price in the United States.

The 5-percent increase in net imports from Canada in 2000 followed increases of 10 percent in 1999, 5 percent in 1998, 1 percent in 1997, and 2 percent in 1996. The extraordinary growth during 1999 was the result of increased utilization of transportation capacity from three pipeline projects that were completed in 1998 and operational in 1999. New pipeline capacity added in 2000 (see "Pipelines") contributed to the continued growth in imports.

U.S. Trade with Mexico

The United States is a net exporter of natural gas to Mexico. Pipeline exports to Mexico totaled 110 billion cubic feet in 2000,[42] representing an increase of almost 80 percent from the 1999 total. The United States also imported approximately 6 billion cubic feet of natural gas from Mexico in 2000, a decrease of 90 percent from the 1999 level. Both the decline in imports and the increase in exports probably are attributable to increased domestic demand and relatively flat production levels for natural gas in Mexico. Natural gas demand in Mexico has shown considerable growth over the past several years primarily because of new additions of natural-gas-fired electricity generation capacity. To meet the increasing demand, investments in infrastructure for export from Texas, California, and Arizona have grown rapidly. The majority of new cross-border pipeline projects have been designed to supply natural gas to Mexico's power producers.[43]

[36] Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0103(2001/03) (Washington, DC, March 2001).

[37] J. Greenberg, "Cautious Optimism Characterizes Gulf of Mexico Activity," *World Oil* (January 2001), p. 112.

[38] Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000), Table 6.8.

[39] Liquefied natural gas (LNG) is natural gas that has been liquefied by reducing its temperature to minus 260 degrees Fahrenheit at atmospheric pressure.

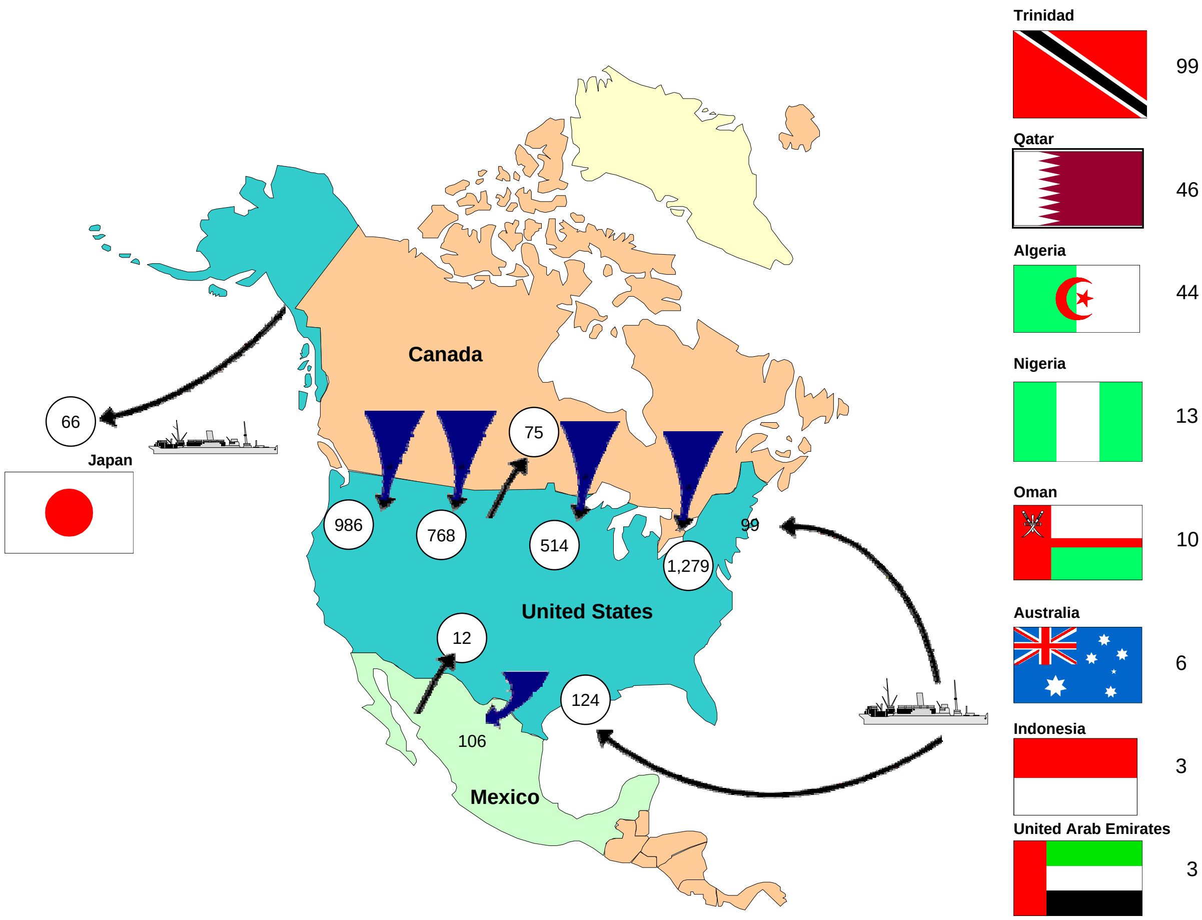
[40] Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0103(2001/03) (Washington, DC, March 2001).

[41] U.S. Department of Energy, Office of Fossil Energy, *Natural Gas Imports and Exports Fourth Quarter Report 2000*, DOE/FE-0428 (Washington, DC), based on Energy Information Administration, *Natural Gas Annual 1999*, DOE/EIA-0131(99) (Washington, DC, October 2000), Table B2. The thermal content of Canadian imports is assumed to be 1.019 million Btu per thousand cubic feet.

[42] The United States also exported approximately 271 million cubic feet of LNG to Mexico by truck, crossing the border at Nogales, Arizona, and San Diego, California. LNG deliveries to Mexico began in 1998, when 33 million cubic feet were shipped through Nogales.

[43] For a comprehensive analysis of the new pipeline projects, see U.S. Department of Energy, Office of Fossil Energy, *Natural Gas Imports and Exports Fourth Quarter Report 2000*, DOE/FE-0428 (Washington, DC).

Figure 6. U.S. Natural Gas Imports and Exports, 2000



Note: Numbers shown are billion cubic feet.
Source: U.S. Department of Energy, Office of Fossil Energy, *Natural Gas Imports and Exports Fourth Quarter Report 2000*, DOE/FE-0428 (Washington, DC).

LNG Trade

After nearly doubling in 1999, LNG imports continued their robust growth in 2000 to a total of 220 billion cubic feet, a 35-percent increase over 1999. Trinidad and Tobago and Qatar surpassed Algeria for the first time in 2000 as suppliers of LNG to the United States. Trinidad supplied 96 billion cubic feet of LNG, or 44 percent of total LNG imports in 2000, and Qatar supplied 46 billion cubic feet of LNG or 21 percent. Algeria continued to be a major supplier of LNG among the eight nations that export LNG to the United States (see Figure 6), with exports totaling 44 billion cubic feet or 20 percent of all LNG imports.

In 2000 the continental United States had two operational LNG receiving terminals, at Everett, Massachusetts, and Lake Charles, Louisiana. Imports into Everett totaled 99 billion cubic feet in 2000, an increase of 3 percent over 1999. Almost 81 percent of the imports received in Everett came from Trinidad, primarily under long-term arrangements. The Lake Charles facility received 124 billion cubic feet, an increase of almost 85 percent over 1999. Many of the shipments to Lake Charles were spot purchases. Algeria delivered to both facilities, primarily under long-term arrangements.

Expansion of LNG imports is expected in the near future as two other mothballed U.S. LNG receiving facilities are reopened for imports. Although the Cove Point LNG facility in Maryland has not received any shipments since 1980, it is filing an application with the FERC to resume importing LNG in 2002. The Elba Island terminal near Savannah, Georgia, has received clearance from the FERC to resume its LNG import activities and is expected to begin receiving shipments in 2002.

Storage

The ability to store natural gas is essential to the operation of the natural gas market. Withdrawals from storage provide additional gas supply during seasonal and short-term gas demand peaks, help keep pipelines and distribution systems in physical balance, and play an important role in commodity trading and management. In general storage is filled during low utilization periods (April-October) and withdrawn during high utilization periods (winter); however, increased demand for natural gas in the electricity generation sector during the traditional off-peak period in recent years has increased competition for gas to refill storage and put upward pressure on natural gas prices. In order for the storage of gas to be economical in competitive markets, the cost of storing generally should be less than the differential between the cost of natural gas in the withdrawal period and in the refill period.[44] With relatively high gas prices in mid-2000 (during the off-peak period), incentives to rebuild inventories to levels closer to the average were diminished.

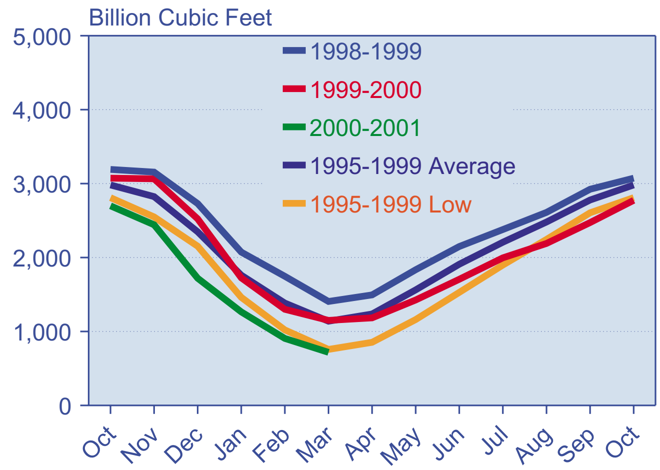
During the refill season of 2000, with relatively high natural gas prices, net injections into storage were down by almost 10 percent from 1999 levels, leading to low storage levels and increased pressure on natural gas prices going into the winter of 2000-2001. Many LDCs can recover the costs of higher gas prices under cost-of-service regulation, but restructuring has placed other storage operators and marketers at greater risk of not recovering their costs. When gas demand suddenly increased in the winter of 2000-2001 and gas storage levels were well below average, gas prices reached their recent peak levels.

Up until the latest heating season (November 2000-March 2001), working gas inventories[45] at the beginning and end of the heating season had reached their "modern era" lows in 1996.[46] In March 1996, the heating season ended with 758 billion cubic feet in storage. In November 1996, the heating season began with 2,810 billion cubic feet in storage, a record low partly because of the industry's record low starting point from which to refill inventories. The 1996-97 heating season began with a colder than normal November. Although temperatures moderated significantly in December 1996, temperatures for the entire heating season were slightly lower than average. In the three heating seasons that followed (1997-98 through 1999-2000) the weather was warmer than normal. At the national level, beginning with December 1996, 17 of the next 19 heating-season months over the ensuing 4 heating seasons were warmer than normal (using weighted heating degree-days[47] as the measure). Figure 7 shows recent storage performance with respect to both the 5-year average and lowest end-of-month inventory levels over the period 1995-1999.[48]

Monthly natural gas stock levels from October 1998 through December 1999 were significantly above average, but a large net stock draw in January 2000 (780 billion cubic feet—the largest for the month of January in the modern era) brought inventory levels below the average. In March 2000, during which weather nationally was 19 percent warmer than normal, light net withdrawals allowed working gas levels to return to above average.

Although the industry ended the 1999-2000 heating season with natural gas stocks slightly above average in March 2000, rising spot prices over the next 5 months

Figure 7. End-of-Month U.S. Natural Gas Stocks, 1998-2000



Sources: **U.S. monthly natural gas inventories, October 1998-December 2000:** Energy Information Administration (EIA), *Natural Gas Monthly*, various issues. **5-year (1995-1999) average and lowest levels by month:** EIA, *Natural Gas Monthly*, various issues. **U.S. monthly natural gas inventories, January-March 2001:** Projected from EIA inventory data for December 2000, using weekly inventory change estimates published by the American Gas Association in *Weekly American Gas Storage Survey*.

[44]Under regulation, supply security tends to receive greater emphasis than does the avoidance of unnecessary costs. Even under competition, high-cost storage injections may be economically justifiable as insurance against severe financial penalties for nonperformance.

[45]Underground storage facilities contain *working gas* and *base gas*. Base gas is the volume of gas intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates throughout the withdrawal season. Working gas is the volume of gas in the reservoir above the designed level of the base gas. Working gas is that which is available to the marketplace.

[46]The "modern era" is defined here as 1980 to the present.

[47]To calculate weighted heating degree-days by Census Division, State-level data on heating degree-days from the National Weather Service are multiplied by the number of residential gas customers in each State, and the products are summed for the States in each of the nine Census Divisions and then divided by the total number of residential gas customers in each Division. A similar calculation is performed at the national level to calculate national weighted heating degree-days.

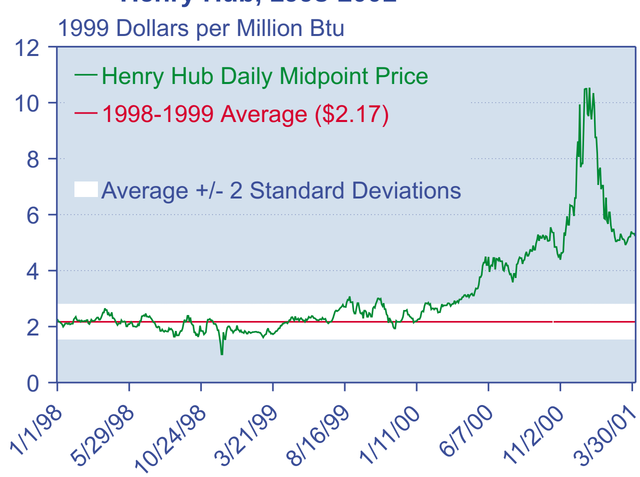
[48]This 5-year period was selected because it is believed that any major operational changes brought on by regulatory reform would have been in place for the 1995-96 heating season. Note that October is shown twice to illustrate that it is both the end of one heating year (a heating year runs from November 1 through October 31) and the beginning of the next.

due to continued strong demand, particularly for electricity generation, inhibited gas storage refill activity. Industry experience with previous storage refill periods suggested that gas prices might fall. For example, spot prices during 1998 and 1999 averaged only $2.17 per million Btu,[49] with almost all daily prices within a fairly limited range of $1.53 per million Btu to $2.81 per million Btu (Figure 8).

As the refill season began in April 2000, spot prices exceeded $3 per million Btu—levels seen only briefly in the fall of 1999. Gas demand continued to strengthen, and prices jumped to over $4 per million Btu by the end of May 2000, then declined slightly in July and took off again in August. Although supply adjusted to the increasing prices, the adjustment occurred at a slower pace, and additional supplies were readily absorbed by a growing market. By the middle of September, spot prices had crossed the $5 per million Btu threshold.

Undoubtedly, the high prices contributed to 5 consecutive months of lower than average storage injections. By the end of August, storage levels were not only well below the 5-year average but also below the record 5-year low. In the last 6 weeks of the refill season, injections accelerated to above average rates for that point in the year as the industry now had its final opportunity to put gas in storage for the coming heating season. As of the end of October 2000, stocks stood at 2,699 billion cubic feet—a new low for the beginning of the heating season in the modern era.

Figure 8. Natural Gas Spot Market Prices at Henry Hub, 1998-2001



Source: *Gas Daily, Financial Times Energy.*

The 2000-2001 heating season began with two very cold months. November and December were colder than normal and 43 and 32 percent colder (measured in heating degree days) than the previous year. By the end of December, natural gas stock levels stood at 1,720 billion cubic feet—nearly 27 percent below the 5-year average for that point in the heating season. The situation was worse in the West. In the late summer of 2000, underground storage facilities in California and New Mexico were called upon to supplement regional supplies lost because of the El Paso pipeline disruption in New Mexico in August 2000.[50] The high level of withdrawals drew down storage inventories in the region just as unseasonable weather and difficulties in the region's electricity market developed. By the end of February 2001, inventories in the West stood at an estimated 99 billion cubic feet—less than half the average level. Nationally, working gas inventories ended the season at an estimated 718 billion cubic feet, about 5 percent below the previous end-of-season low of 758 billion cubic feet in March 1996.

A major issue facing the industry in 2001 will be the replenishment of storage to normal levels and the price implications of large net injections during the April-October refill season. More than 1.6 trillion cubic feet of gas was injected into storage during each of the past 2 years. Given the low level of stocks at the end of the 2000-2001 heating season, however, net storage injections of about 2.0 trillion cubic feet will be required just to return to the level of 2.7 trillion cubic feet recorded for November 1, 2000. The more than 400 billion cubic feet of additional gas needed for storage will be an incremental requirement of almost 2 billion cubic feet per day during the 214-day refill season, which is the equivalent of nearly 20 percent of daily net injections from April through October 2000, compared with the historical average of about 16 percent. The increased demand will continue to place upward pressure on natural gas prices in 2001.

Prices

Some price volatility in a freely traded commodity with seasonal variations in demand is normal and expected. For example, average wellhead prices for natural gas have fluctuated around $2 per million Btu for almost a decade, but for most years (excluding the winter of 1996-97), peak-month and off-peak prices have not varied by much more than 35 percent above or below the

[49]The thermal content of U.S. production is 1.027 million Btu per thousand cubic feet. Based on Energy Information Administration, *Natural Gas Annual 1999,* DOE / EIA-0131(99) (Washington, DC, October 2000), Table B2.

[50]The incident occurred at the El Paso Natural Gas Company's Pecos River crossing in the southeast corner of New Mexico where three lines (two 30-inch and one 26-inch pipeline) cross the river. While only one 30-inch line ruptured, the other two lines were also shut down. As a result, 1.2 billion cubic feet per day, out of a normal 2.0 billion cubic feet per day, of natural gas flowing along El Paso's southern route to its Arizona and California markets was affected for several months. In fact, as of April 27, 2001, the blown pipeline segment, although repaired, has yet to be placed back in service. The company reports, however, that with adjustments to pressure in the other two lines, flows through the repaired portion at the site approximate 90 percent of previous levels for all three lines and customer service has not been impaired.

yearly average. In 2000, however, wellhead prices have varied by 100 percent or more, and the volatility of delivered end-use prices has also been severe in some cases, particularly for large industrial customers and electricity generators.

Anything that disrupts the normal cycle of supply and demand can exaggerate the volatility of natural gas prices. Such short-term disruptions can include supply disruptions—such as pipeline ruptures or closings, line freeze-ups, and storage operation failures, as well as demand surges due to cold weather or fuel switching by customers. If the growth in regional infrastructure has been constrained relative to growth in demand, the conditions for regional price differentials or price volatility are present.

Constrained pipeline capacity and infrastructure in a competitive market can result in price volatility during peak periods. Rapidly growing regions of the country are susceptible to such growing pains when the growth is not adequately anticipated. Further, unusually cold weather in the South and North, as was experienced in December 1989, can cause well freeze-ups and storage operation failures at some facilities. If demand is high and supply is curtailed for an extended period, gas prices may become quite volatile, as they did in the Northeast in 1989.

U.S. natural gas spot prices in 2000 reached levels that were unprecedented on a sustained basis.[51] Spot prices in major trading centers across the country have been at higher levels than those prevailing in recent years; however, prices have shown interesting variations in some locations.

Influences on regional price patterns differ, depending on whether the markets are upstream (close to major producing areas) or downstream (close to major consuming markets). Prices rise in upstream markets generally when there is widespread expansion in demand or a supply disruption. Higher prices in upstream markets affect prices downstream as the greater commodity costs are passed along in the supply process. Prices in downstream markets may also rise with a surge in local demand or a disruption in supply to the area, both of which can result in relative scarcity of the commodity. Price increases under those conditions tend to be localized within the downstream markets.

Quarterly average prices for the most recent three quarters (third quarter 2000 through first quarter 2001) show a general increase. The Henry Hub is a key upstream market in Louisiana, based on the relatively large volumes traded there and its strategic position relative to producing and consuming markets—in the Southwest and on the Gulf Coast for production and in the Midwest and the East for consumption. The Henry Hub is often used as a benchmark for upstream spot prices in the United States. Prices at the Henry Hub rose from the third quarter and then changed little when averaged on a quarterly basis (Table 1).

This price pattern is evident also at the Chicago, Florida, and Katy markets.[52] Average quarterly price movements in these markets are similar, subject to slight differentials reflecting local conditions and transportation costs. The differential between the Chicago and Henry Hub markets rose slightly in the fourth quarter of 2000, as brief episodes of price spikes occurred in Chicago in December. The largest differential was $5.22 per million Btu, which occurred when the industry was preparing for the Christmas holiday weekend. In each case, markets adjusted rapidly and the periods of elevated prices above the Henry Hub price were brief.

The similarity in price patterns between the Florida and Katy markets and the Henry Hub suggests that, although prices rose because of generally higher U.S. demand, there were no significant impediments hindering competitive adjustments between those markets. Price differentials for the Florida market ranged up to

Table 1. Average Quarterly Spot Prices for Selected Trading Centers
(Dollars per Million Btu)

Quarter and Year	Henry Hub, LA	Chicago Citygates	Florida Citygates	Katy, TX	New York Citygates	SoCal Citygate
3rd Quarter 2000 . . .	4.47	4.56	5.00	4.48	4.81	5.28
4th Quarter 2000 . . .	6.41	6.82	6.73	6.38	8.07	13.59
1st Quarter 2001 . . .	6.44	6.61	6.85	6.41	7.83	15.19

Source: Energy Information Administration, Natural Gas Division, adapted from prices reported in *Gas Daily, Financial Times Energy* (various issues).

[51]Spot prices spiked periodically during the 1990s, but those episodes were of relatively short duration. For example, an unexpected cold snap in February 1996 led to a spot price at the Henry Hub of $14.00 per million Btu on February 2, exceeding the recent peak of $10.53 recorded on December 29, 2000. However, the price a week earlier in 1996 was $2.73, and a week later it had fallen by almost 60 percent to $5.75. In less than 3 weeks, the price returned to below $3 per million Btu.

[52]For ease of presentation, the trading centers other than that at the Henry Hub in Louisiana are identified by their more commonly known names. The specific transactions or locations for each are as follows: Chicago—Chicago LDCs, large end-users; Florida—Florida citygates via Florida Gas Transmission; Katy—Katy plant tailgate; New York citygate—Transco Zone 6 for New York delivery; and Southern California (SoCa)l—SoCal gas, large packages.

$1.83 per million Btu.[53] At the Katy market, prices varied above and below the Henry Hub price within a fairly narrow range of $0.59 and -$0.38 per million Btu. Price levels in Chicago, Florida, and at the Katy market, although high this winter relative to previous seasons, reflected the general tight gas markets prevailing across the country.

Prices at two major downstream markets, New York City and SoCal, showed significant differences from the Henry Hub price on a persistent basis. The New York City price in the third quarter of 2000 was $0.34 per million Btu above the Henry Hub price. During the fourth quarter, however, New York prices showed the influence of demand pressures. Although the average differential in October and November was only about 10 cents more than the third quarter average of $0.34 per million Btu, the maximum difference for each month grew from $0.77 to $1.18. During December, New York prices spiked at $39.02 per million Btu at the end of the month, which was $28.49 above the Henry Hub price. As elsewhere, the largest price spikes were of relatively short duration as markets adjusted both demand and supply.

The largest regional price discrepancies for any market occurred on the SoCal system, where there were extremely large differentials from the Henry Hub benchmark price. The average differential of $0.81 per million Btu in the third quarter of 2000 was eclipsed by price differentials of $7.18 and $8.75 recorded in the fourth quarter of 2000 and first quarter of 2001. The average for December at SoCal was $16.92, with a maximum differential of $49.49. Although prices settled down somewhat in January, extreme price shocks were experienced again in February, when the average differential exceeded $13 per million Btu and the maximum fell just short of $31. Although prices in March 2001 improved slightly on average, the minimum differential remained in excess of $4, suggesting that markets have not yet been able to adjust, and that difficult conditions in southern California may continue for some time to come.

Natural Gas Transmission and Distribution

Overview

The U.S. has a complex and extensive pipeline infrastructure for transporting natural gas from production areas to ultimate consumers. More than 165 U.S. intra- and interstate natural gas pipeline companies operate about 278,000 miles of transmission lines, hundreds of compressor stations and numerous storage facilities, allowing gas delivery throughout the lower 48 States. In addition, more than 1,300 LDCs provide local delivery services through another 700,000+ miles of pipeline infrastructure. In 2000, these lines transported an estimated 22.8 trillion cubic feet of natural gas from supply sources to end-use markets. As sources of new supply have developed, new pipelines have been built and a large number of existing pipelines have been expanded to increase the level of service to a growing customer base.

Regional markets in the United States have widely varying patterns of energy use and natural gas requirements. The numerous natural gas pipeline systems that have evolved over time provide transportation services to and within these end-use markets and are designed to accommodate variations. For instance, in the colder seasonal markets, regional natural gas distribution systems are designed to meet space-heating demands by residential and commercial customers and are supported by underground storage and peaking facilities. In less weather-sensitive markets, where natural gas demand is mainly for electric power generation and/or industrial usage, storage is needed less for backup and more to support short-term fluctuations in demand and pipeline transportation system balancing.

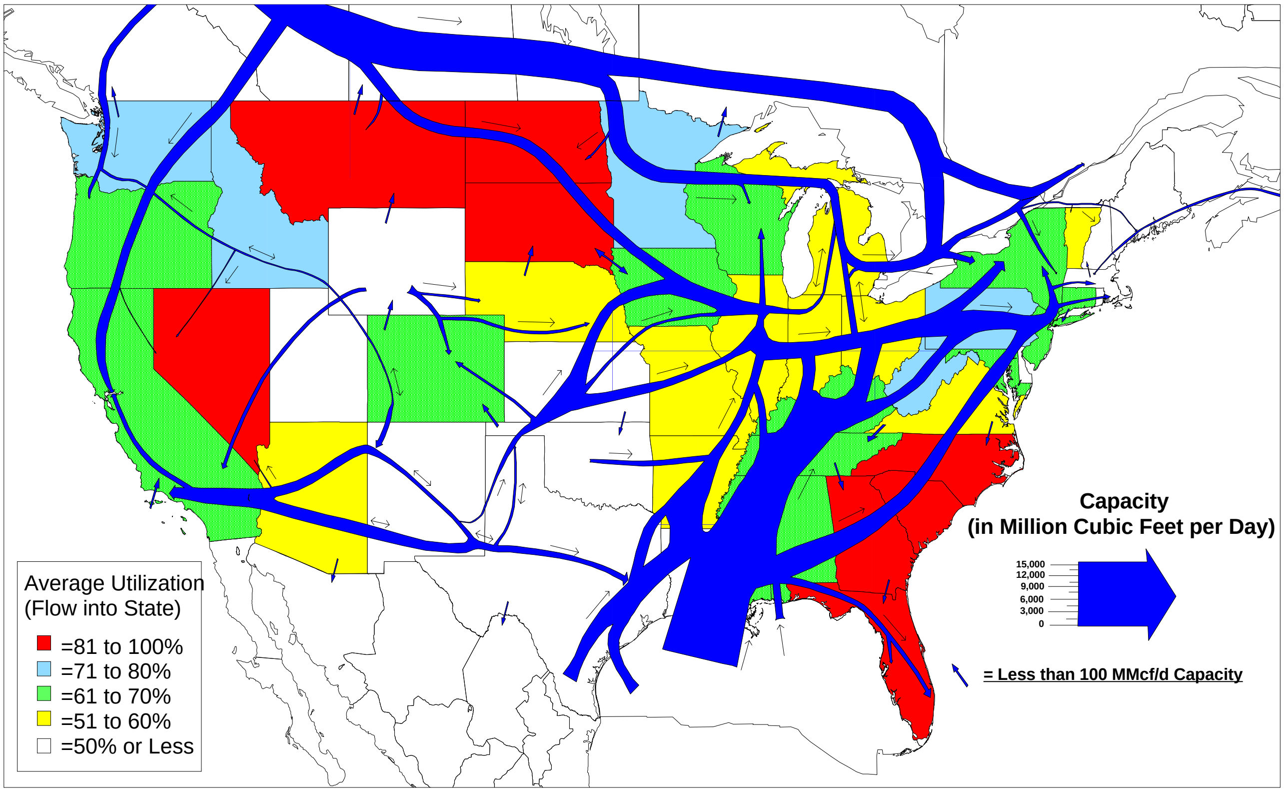
Pipelines

The natural gas pipeline network has grown substantially since 1990, with more than 20 billion cubic feet per day of interregional capacity (a 27-percent increase) added through the end of 2000. The network has also become more interconnected, its routings more complex, and business operations more efficient. New types of facilities, such as market centers, and established operations, such as underground storage facilities, have become further integrated into the national pipeline grid, allowing the system to operate with greater flexibility. The restructuring of the industry has changed the way in which network resources are used and has caused some shift in transportation routes and trading and shipping arrangements, but system reliability has continued to improve. Except during periods of extreme weather conditions or disruptions caused by isolated pipeline outages, there has been no sustained disruption of the network since the mid-1970s.

Nonetheless, the increasing growth in natural gas demand over the past several years has led to an increase in the utilization of pipelines (Figure 9) and has resulted in some pressure for expansion in several areas

[53]Florida prices were below the Henry Hub price on two separate days during the 9-month period. On December 11, the Henry Hub price rose by $1.87 per million Btu in a single day. Consequently, the Florida price, which had roughly matched the Henry Hub price the day before, was $1.83 below the Henry Hub price for that one day.

Figure 9. U.S. Natural Gas Pipeline Transportation Corridors and Average Interstate Pipeline Utilization Rates by State, 1999



Note: The average utilization rate does not reflect seasonal load variations, which could be significant for some pipelines and States, especially in the northern tier of the country.

Source: Energy Information Administration, EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity (as of December 2000).

of the country.[54] For instance, pipeline utilization levels in parts of the West (notably, pipelines delivering gas to the California market) have recently been well above 95 percent on a continuing basis. Further increases in demand could cause capacity bottlenecks to develop.[55] Growing gas service needs in the southern Nevada area also suggest the need for system expansion there.[56]

Over the past 2 years, more than 60 natural gas pipeline construction projects (35 in 1999 and 28 in 2000) have been completed and placed in service in the United States, accounting for more than 12.3 billion cubic feet per day of new pipeline capacity, an increase of 15 percent over the capacity level in 1998.[57] Since 1996, natural gas pipeline capacity has grown by more than 5 billion cubic feet per day annually in most years, totaling almost 30 billion cubic feet per day (Figure 10). Annual expenditures on pipeline development have exceeded $1.4 billion in most years (Figure 11). Expenditures on new pipeline development and major extensions and laterals to existing systems have accounted for more than 70 percent of total expenditures, with expansions to existing systems accounting for the rest. In 1999 the largest share of expenditures, totaling $1.1 billion, was for projects terminating in the Northeast. In 2000, projects terminating in the Midwest accounted for the largest share of expenditures, at $1.8 billion.

A major growth area in pipeline expansion during the past several years has been the import/export market

[54] Annual utilization of pipelines serving State markets varies considerably, and pipeline utilization rates during peak demand periods are significantly higher than the average annual rate.

[55] The recent problems with gas deliveries into California were also financial in nature. Some natural gas suppliers have been reluctant to sell on credit to two LDCs, PG&E and SoCal, due to their dire financial situation brought on by their need to purchase large amounts of out-of-state electricity in recent months. See "California Seeks Emergency Measures for PG&E," *Gas Daily* (January 17,2001), p. 1.

[56] In fact, because a significant portion of the flow on the Kern River Transmission system is currently reserved by shippers moving natural gas into the Las Vegas electric power generation market, only about 60 percent of Kern's 800 million cubic feet per day of capacity into California is currently flowing gas. To address this situation, and to respond to calls for rapid expansion of pipeline capacity to California, Kern River Transmission Company has been granted approval from the FERC to proceed with an expansion of its system (by installation of additional compression) by June 2001.

[57] Total added capacity as measured on an individual project basis rather than interregional additions.

for natural gas. Much of the pipeline construction of the past several years has been focused on expanding import capacity for Canadian gas into the U.S. Midwest and Northeast. The completion of the Maritimes and Northeast, Portland Gas Transmission, and Alliance Pipeline systems represented a 15-percent increase in overall natural gas import capacity since 1998: a 58-percent increase into the Central region (most destined for the Midwest) and a 23-percent increase into the Northeast. In addition, natural gas export capacity to Mexico has more than doubled since 1996. Export capacity to Mexico totaled 2.1 billion cubic feet per day at the end of 2000, compared with only 0.9 billion cubic feet per day in 1996.

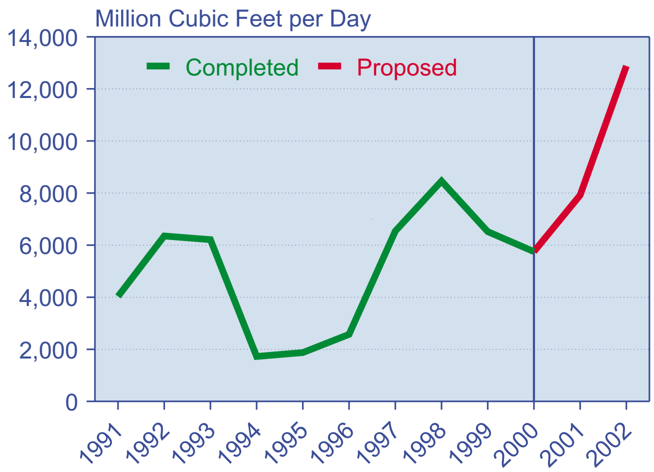
On the supply side, expanding coalbed methane production in the Rocky Mountains area of Wyoming and Montana has increased the need for additional long-haul capacity to carry the gas to end-use markets. Although several new gathering and header systems have been built over the past 2 years to move the gas from the production field to transmission lines, not enough matching interstate pipeline capacity has been installed so far. Only in the past 6 months have proposals been made for significant expansions of the area's interstate systems.

Current pipeline capacity levels into the Midwest region were sufficient to meet 2000-2001 winter demand, even though the first 2 months of the heating season were colder than anticipated. Because of the cold weather, the Alliance Pipeline began operation at close to full capacity shortly after service was inaugurated in December 2000. Demand in the Midwest is still growing, however,[58] and some of the capacity currently serving the region will be needed to serve the Northeast in 2002. As a result, additional capacity to the Midwest region will be needed.

In most other parts of the country, immediate pipeline capacity limitations have not surfaced, although recent proposals to develop new pipeline capacity reflect a recognition that steady growth in natural gas demand is occurring. Florida, North Carolina, and South Carolina, for instance, have experienced significant growth in natural gas demand over the past decade, but with sufficient additional pipeline capacity being installed to match the increase in demand.

While overall natural gas production dropped somewhat in the Gulf of Mexico, after several consecutive years of extensive pipeline development, installation of additional offshore Gulf of Mexico pipeline capacity has slowed. In 1997 and 1998, for instance, 14 natural gas pipeline projects were completed that added a total of 6.4 billion cubic feet per day of new pipeline capacity in the Gulf, most of which represented large-capacity pipelines connecting onshore facilities with developing

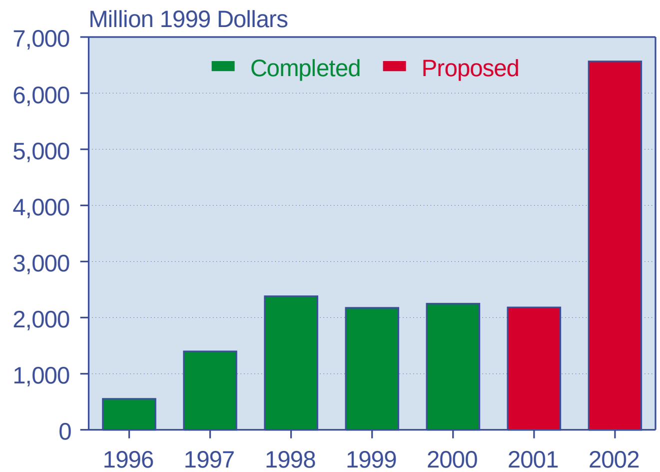
Figure 10. Additions to U.S. Natural Gas Pipeline Capacity, 1991-2000, and Estimated Additions, 2001-2002



Note: 2001-2002 estimated capacity additions include new pipelines or expansions to existing natural gas pipeline systems that have either been announced, filed with regulatory authorities, or approved for completion during the time frame.

Source: Energy Information Administration, EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity (as of December 2000), and Natural Gas Proposed Pipeline Construction Database (as of March 2001).

Figure 11. Natural Gas Pipeline Construction Expenditures, 1996-2000, and Estimated Expenditures, 2001-2002



Note: 2001-2002 expenditures include estimated costs for proposed new pipelines or proposed expansions to existing natural gas pipeline systems that have either been announced, filed with regulatory authorities, or approved for completion during the time frame.

Source: Energy Information Administration, EIAGIS-NG Geographic Information System, Natural Gas Proposed Pipeline Construction Database (as of March 2001).

[58] Proposals to build new and expanded natural gas pipelines into the Midwest over the next several years suggest that as much as 2.7 billion cubic feet per day of additional capacity into the region may be needed.

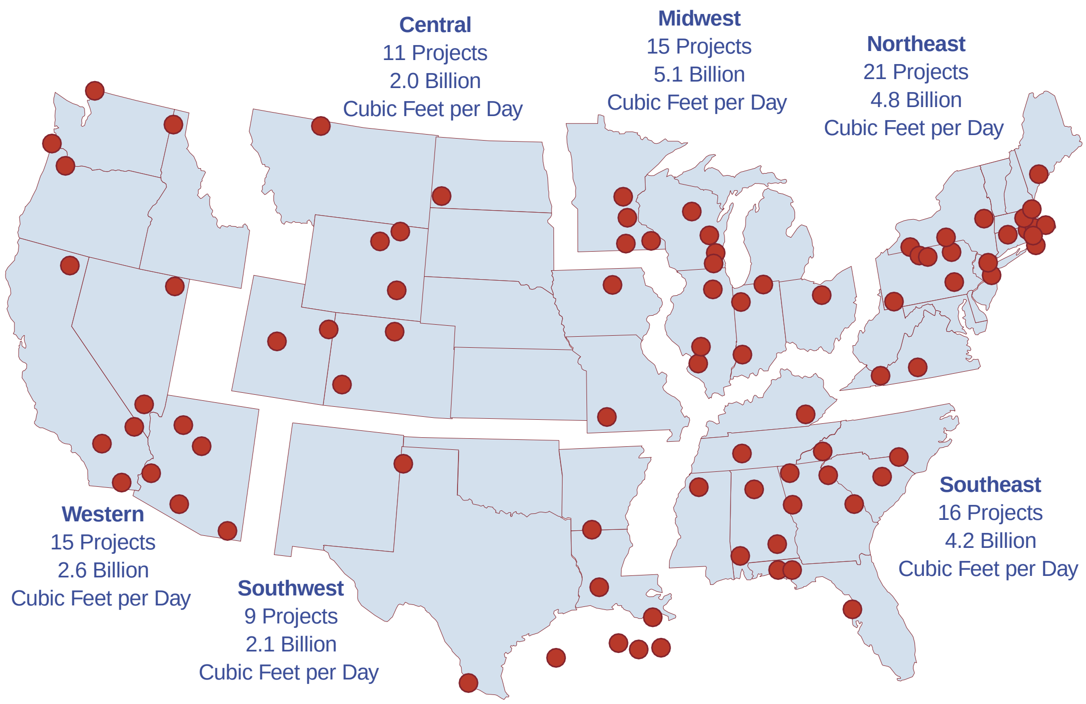
offshore sites, particularly in the deepwater areas of the Gulf. During 1999-2000, 8 significant projects were completed, adding 1.8 billion cubic feet per day to the area's pipeline capacity. The majority of these projects were built primarily to improve gathering operations and to link new and expanding producing platforms in the Gulf with recently completed offshore mainlines directed to onshore facilities.

A major factor in much of the recent installation of new natural gas pipelines and expansion of existing systems has been the construction of many new gas-fired electric power plants and cogeneration of electricity by industrial and other large users of natural gas. Moreover, since a large number of gas-fired electric power plants are currently planned for development throughout the country over the next several years, many new laterals will be needed to link the new plants to local pipeline systems. In many instances an existing local natural gas pipeline or LDC will provide the link, but some of those systems may have to be expanded to accommodate the new plants.

The quickest and least expensive way of providing additional gas transportation capacity is to increase compression on the system, if feasible. Looping (integrating a parallel pipeline with all or a portion of the system) or a combination of looping and compression would be the next least expensive capacity expansion alternative. The number of proposals over the past several years to develop new laterals or to expand capacity by increasing compression reflects growth in this trend. To date, the U.S. natural gas pipeline industry has been able to finance and install the additional infrastructure needed to accommodate the decade-long growth of the network. Barring any major disruption of financial markets, it should be able to continue doing so.

Based on 88 announced pipeline projects covering the next several years, U.S. natural gas pipeline companies have proposed to install an additional 20.8 billion cubic feet per day of capacity within the national network (Figure 12). Of the projects announced, 21 would terminate in the Northeast region. The largest amount of new capacity (5 billion cubic feet per day) would be added in the Midwest region. Several of the projects terminating in the Northeast region in 2002 represent projects that originally were proposed for 2000 but were delayed due to public opposition and/or failure on the part of the sponsors to meet regulatory filing requirements. In other areas of the country, a number of projects are planned for areas where new supply sources are being tapped, such as deepwater development in the Gulf of Mexico and expanding growth in coalbed methane production in the Rocky Mountains area. The large amount of capacity and expenditures estimated for 2002 (see Figures 10 and 11) partly reflect this situation; however, the large increase in capacity expected in 2002 also reflects a number of large new projects scheduled to be completed that year. In fact, 9 of the 37 projects that may be constructed in 2002 have capacity levels of 500 million cubic feet per day or more. Many, if not most, of those major projects have been premised on the need to serve growing electric power generation markets.

Figure 12. Proposed Natural Gas Pipeline Expansion Projects for 2001 and 2002



Source: Energy Information Administration, EIAGIS-NG Geographic Information System, Natural Gas Proposed Pipeline Construction Database (as of March 2001).

Another near-term trend that is reflected in the proposed 2001-2002 pipeline projects is the increased number and incremental capacity represented by compression-only or looping and compression expansion projects.[59] The increase use of looping and compression expansion reflects the maturity of many of the systems that make up the national network. Using these methods, pipelines can more quickly add capacity to meet increasing demand while minimizing the potential opposition, especially in heavily populated areas. Additionally, with the growth in new gas-fired electric power plants, the miles of "lateral" projects and the average capacity increases they represent have increased over the past several years.[60]

Distribution System

The institutional and pipeline infrastructures associated with the local delivery of gas have been undergoing substantial adjustment and ongoing investment. Increasingly, as individual States restructure their natural gas markets, LDCs are becoming primarily transporters of natural gas. Currently, about two-thirds of the States have taken at least some steps toward increasing retail competition for residential and small commercial customers by providing a choice of fuel supplier. Large commercial and industrial consumers have had the option to purchase gas from different providers for years, whereas choice for residential and small commercial customers has only recently been made available. State regulators and lawmakers, who are responsible for designing and implementing the retail restructuring programs, have in some cases delayed implementing customer choice until they could ensure reliable service and protect the interests of captive residential and commercial customers.

The degree to which core customers are eligible to participate in choice programs varies from State to State. Some customers and State regulators have raised questions about the benefits of retail unbundling. In addition, several instances of marketer nonperformance or bankruptcy have occurred, leaving it up to LDCs, which are obligated to provide service if marketers (or third-party service providers) fail to deliver gas, to provide local delivery service. Another variation in retail choice programs is the number of marketers offering service in local markets. In some States, such as New York, more than 100 marketers are operating; in others only 2 to 5 marketers are active. Some marketers have withdrawn from certain markets because of lack of customer participation or because of eroding profitability. In Georgia, there are currently 9 marketers offering services, down from 24 marketers 16 months ago.

LDCs continue to invest in new and replacement main and service lines and local compression facilities in order to satisfy the firm service requirements of their sales and transportation customers. According to the American Gas Association, construction projects by distribution companies totaled $9.7 billion (nominal) in 1998 and 1999, a 16-percent increase from $8.4 billion in 1996 and 1997.

As the interstate and intrastate natural gas pipeline systems expand, LDCs may have to expand correspondingly. A substantial portion of the new pipeline capacity will provide additional delivery capacity to LDCs, which either are expanding their own capabilities to serve their existing service territories or are building new pipe segments to extend their systems into new neighborhoods or to serve new industrial or electric power customers. Indeed, in almost all instances, except when a pipeline developer plans to bear the full cost and risk of a new or expansion project and its recovery, interested shippers (including LDCs in the potential market area), are given an opportunity to sign up for future service on the proposed expansion in a process called an "open season." A successful open season is a good indicator that demand is increasing or is expected to develop in the downstream market by the time the project is completed and placed in service. Any LDC that commits to the project will have plans in place to expand its system to accommodate increased supply commitments when the expanded service begins.

Challenges Facing the Natural Gas Industry

Moderating the recurrence and severity of "boom and bust" cycles while meeting increasing demand at reasonable prices is one of the major challenges facing the U.S. natural gas industry today. The most serious short-term challenge will be to increase production rapidly enough to satisfy natural gas demand at reasonable prices. The short-term challenge is inextricably woven into the investment cycles of the gas industry. Sustained high short-term natural gas prices can prompt significant new drilling investments and bring on new supply, but they can also prompt consumers to make potentially irreversible equipment investments and switch to lower cost fuel options. Both factors tend to put downward pressure on natural gas prices.

[59]As compared with 1996 through 2000, when only an average of 0.75 billion cubic feet per day per year was added by completion of these types of projects, the amount of new capacity to be added in 2001 and 2002 could be as much as 2.3 and 2.6 billion cubic feet per day, respectively.

[60]The average capacity of new laterals installed between 1996 and 2000 was 100 million cubic feet per day. By comparison, 261 million cubic feet per day could be added in 2001and 238 million cubic feet per day in 2002. In 2001 and 2002, 120 and 189 miles, respectively, of new laterals have been proposed, compared with an average of 98 miles per year for the previous 5 years.

Recent events in the oil and gas industry have led some to question the industry's ability to meet a projected 41-percent increase in domestic gas production by 2015. Periodic downturns in the gas industry, such as in the 1984-89 and 1998-99 periods, triggered significant downsizing and cutbacks in spending for exploration and development of new gas sources. Reduced spending slowed the construction of drilling rigs and other infrastructure needed to support future drilling, and continued downsizing and layoffs reduced the industry's ability to attract qualified new employees.

The availability of capital for new natural gas production is dependent on cash flow from the industry's sales of crude oil and natural gas. During the 1998-99 downturn, new supply development in the United States slowed considerably, and production exceeded reserve additions for the first time in 6 years. More recently, while the number of new gas well completions increased by almost 45 percent in 2000,[61] gas production increased by only 3.7 percent. The discrepancy reflects, in part, the lag in production following a shift in drilling (usually about 6 to 18 months).

An example of the market complications that can occur is provided by the recent developments in California. California is the Nation's second-largest State market for natural gas and the tenth-largest producing State. With natural gas accounting for more than 45 percent of the power generated in California,[62] the State's recent electricity problems have prompted greater scrutiny of natural gas markets.

Recent Challenges for Natural Gas and Electricity Markets in California

Residential and commercial demand for natural gas in California grew by an average of 1.8 percent per year from 1995 to 1999. In 1999, California's residential and commercial sectors consumed 813 billion cubic feet of natural gas (Table 2), more than in any other State. Although 60 percent of the State's population resides in its nine southernmost counties, more natural gas is consumed in the north, where demand for space heating is higher.

In combination, the State's industrial and electric utility sectors consumed 1,254 billion cubic feet of natural gas in 1999, following 3.7-percent average annual growth from 1995 to 1999. In addition to manufacturers, the industrial sector includes cogeneration facilities.[63] For cogeneration facilities the primary product is usually heat or steam and the secondary product is electricity, usually for own use. Electricity production from these facilities is periodically sold to the power grid and is on the rise. Tremendous economic growth has been the impetus for the increase in power generation in both the industrial and electric utility sectors. The only State using more natural gas for electricity generation is Texas.

Steady increases in natural gas demand have been met by increasing gas production in California, which rose by 104 billion cubic feet between 1995 and 1999, to 372 billion cubic feet in 1999. Production, which accounted for just under 20 percent of consumption in 1999, is located solely in the southern part of the State. Much of

Table 2. Natural Gas Supply and Disposition in California, 1999

Market Segment	Billion Cubic Feet	Million Cubic Feet per Day
Supply		
Dry Production	372	1,019
Interstate Receipts	1,795	4,918
Withdrawals from Storage	137	375
Balancing Item	-26	-71
Total Supply	**2,278**	**6,241**
Disposition		
Natural Gas Operations	75	206
Additions to Storage	129	352
Exports	4	10
Consumption		
Residential	569	1,558
Commercial	245	670
Industrial[a]	610	1,671
Vehicular Fuel	3	9
Electricity Generation[a]	644	1,764
Total Consumption	**2,071**	**5,673**
Total Disposition	**2,278**	**6,241**

[a] EIA natural gas consumption data for the industrial sector currently include fuels consumed by cogenerators, independent power producers (IPPs), and nonutility generators (NUGs). Using data from Form EIA-860B, it is estimated that 499 billion cubic feet of "industrial" gas consumption in California was consumed by IPPs and NUGs.

Source: Energy Information Administration, *Natural Gas Annual 1999,* DOE/EIA-0131(99) (Washington, DC, October 1999), Table 45.

[61]Computed from Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2001/03) (Washington, DC, March 2001), Table 5.2.

[62]Based on Energy Information Administration surveys EIA-759, "Monthly Power Plant Report," and EIA-860B, "Annual Electric Generator Report - Non-utility," for 1999.

[63]The definition of the industrial and power sectors may be a source of confusion, because the restructuring of the electricity and natural gas industries has changed reporting requirements. EIA is currently redesigning its electricity data collection forms to correct the problem. EIA natural gas consumption data for the industrial sector currently include fuels consumed by cogenerators, independent power producers (IPPs), and nonutility generators (NUGs). Using data from Form EIA-860B, it is estimated that 499 billion cubic feet of "industrial" gas consumption in California was consumed by IPPs and NUGs. In this section, that quantity has been moved from the industrial sector to the electricity generation sector, to be consistent with the rest of the report.

the gas consumed in California comes from interstate pipelines delivering gas from other States and from Canada (Figure 13). The expansion of Pacific Gas Transmission Company's Northwest pipeline in the early 1990s allowed California's use of Canadian gas to jump by 300 billion cubic feet per year to 1,200 billion cubic feet per year in 1999.

According to the California Energy Commission (CEC), the interstate natural gas pipelines serving California (PG&E Northwest, Tuscarora, El Paso Natural, Transwestern, Kern River, and Mojave) have adequate capacity to meet current State demand, although all but Kern River and Mojave have been operating at full capacity much of the time during the past several months.[64] These interstate pipelines have the capability to deliver more than 7.5 billion cubic feet per day of summer capacity[65] to the State if needed. The current load on the State's major internal transmission and distribution networks, however, is near 100 percent of certified capacity and periodically exceeds it.[66]

A significant portion of the natural gas in storage in California is dedicated to core or high-priority customers, leaving other customers vulnerable to disruption before stocks are completely drained. Another issue, not unique to California, is that deliverability from underground storage reservoirs declines as the amount of gas remaining in storage is reduced.

California started off the 2000-2001 heating season with 152 billion cubic feet of natural gas in storage, 34 billion cubic feet below the 5-year (1995-99) average (Figure 14). During the summer of 2000, natural gas demand for electricity generation was strong due to unusually high cooling requirements. In November 2000, nuclear power outages contributed to a notable draw of 27 billion cubic feet from storage during a month when a small net

Figure 13. Major Natural Gas Pipelines Serving the Western United States

Source: Energy Information Administration, EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity Database (as of December 2000).

[64]California Energy Commission, "Natural Gas Price Increases—Frequently Asked Questions" (December 10, 2000), web site www.energy.ca.gov/naturalgas/natural_gas_faq.html.

[65]Gas flows generally are lower in the summer due to ambient temperatures. Therefore, summer capacities represent a conservative estimate of pipeline capacity in winter. See Energy Information Administration, "A Snapshot of California Natural Gas Supply and Demand" (March 23, 2001), web site www.eia.doe.gov/pub/oil_gas/natural_gas/presentations/2001/snapshot_of_california/camapcap.pdf.

[66]California Energy Commission, "Natural Gas Price Increases—Frequently Asked Questions" (December 10, 2000), web site www.energy.ca.gov/naturalgas/natural_gas_faq.html.

addition to stocks typically occurs. Low rainfall for 1999 and 2000 in the Northwest significantly reduced hydroelectric generation and led to a sustained increase in demand for gas-fired generation. December's call on stocks was attributed to cold weather and electricity outages caused by environmental concerns and equipment failure. Continued cold weather, electricity generation outages, and then nondelivery of supplies due to financial uncertainties caused stocks to dwindle further. By mid-February, California's working gas inventories were estimated at less than 70 billion cubic feet, well below the 1995-1999 average of 100 billion cubic feet for the end of March, the traditional end of the heating season.

When warm weather finally returned and the financial security of the utilities improved, reports of injections to storage surfaced by the week ending March 15, 2001. As of March 23, however, stocks in the West region, which includes California, remained at half the 5-year average. If natural gas is required to meet a heavy cooling demand this summer, stocks may not be replenished at the same rate as in previous years, and the 2001-2002 heating season may open with an even smaller volume in storage than at the beginning of the past heating season.

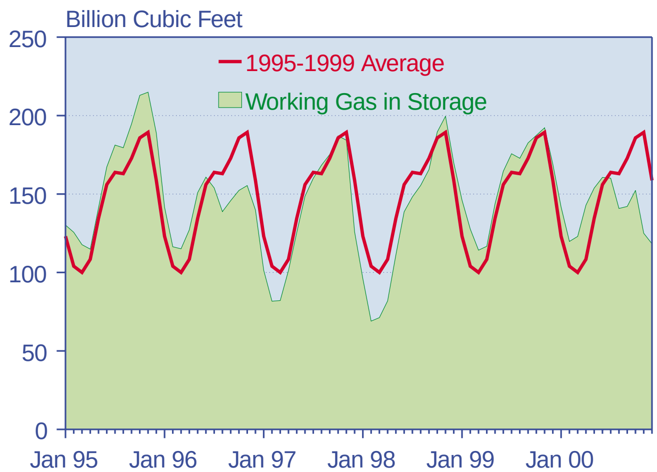
Tightness in the balance between supply and demand is reflected in prices. Last summer, spot prices for natural gas in California moved higher as more gas was required to generate electricity. The pipeline explosion on the El Paso pipeline system in southern New Mexico in August 2000 also caused price trends in California to break from the national pattern. The next price shock took place in mid-November, when cool weather in combination with unplanned outages in the power sector caused a spike in the demand for natural gas. As a result, stocks declined rather than being supplemented.

Environmental regulations also played a role in keeping prices elevated through the end of year, as other forms of generation were idled after using their annual emissions allotments. Prices have been bid higher recently in order for financially strapped utilities to attract supplies. A Federal order requiring suppliers to provide natural gas to California's utilities was implemented on January 19, 2001, extending through February 7, 2001.

Throughout 1998-99, spot prices for natural gas at the Henry Hub, on SoCal for large packages, and at the PG&E citygate tracked fairly closely. Beginning in June 2000, however, California prices began to diverge from Henry Hub prices (Figure 15). Thus far in 2001, the average differentials have spiked to as much as to $30.92 per million Btu[67] on SoCal (February 14) and $8.55 per million Btu on PG&E (February 15). The peak 2000-2001 heating season prices on PG&E occurred on December 9, 2000, spiking to about $50.80 per million Btu. SoCal prices peaked at a midpoint of $59.40 per million Btu 3 days later. While prices at the Henry Hub generally began to decline around the second week of January 2001, prices on the two California LDCs have persisted at high levels, with much volatility, particularly on the SoCal system.

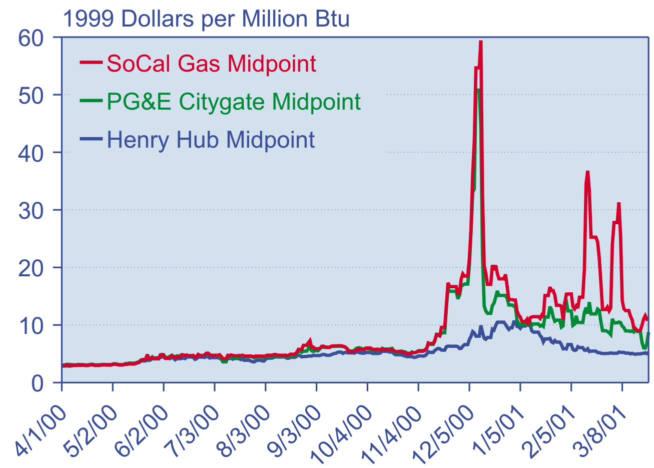
Aside from weather and equipment failure, a key determinant of prices in the short term is how much additional planned pipeline capacity is built and placed in service. With less than 20 percent of California's current gas demand being met from the State's own production, the rest of its supplies must come via interstate pipelines. Currently, only 90 million cubic feet per day of new interstate natural gas pipeline capacity (only a 1-percent increase) is slated for installation in California in 2001. Intrastate receipt points will also be enlarged to

Figure 14. Natural Gas in Underground Storage in California, 1995-2000



Source: Energy Information Administration, Form EIA-191, "Monthly Underground Gas Storage Report" (January 1995 to December 2000).

Figure 15. Natural Gas Spot Market Prices, April 2000-March 2001



Source: *Gas Daily, Financial Times Energy* (various issues).

[67]Assuming 1.027 million Btu per thousand cubic feet. See Energy Information Administration, *Natural Gas Annual 1999*, DOE/EIA-0131(99) (Washington, DC, October 2000), Table B2.

receive expanded deliveries. Several projects have been proposed for the next several years, but only one has been filed with the FERC to date, and the others are only in the planning stage. If all these projects are completed, the increase in capacity will represent an 11-percent increase (about 800 million cubic feet per day) over today's levels. Natural gas demand is projected to increase by 550 million cubic feet per day, or about 7 percent, between 2000 and 2003 according to the CEC.[68]

[68]California Energy Commission Workshop, "Natural Gas Issues That May Affect Siting New Power Plants in California" (January 25, 2001), and California Energy Commission, "Natural Gas Price Increases—Frequently Asked Questions" (December 10, 2000), web site www.energy.ca.gov/naturalgas/natural_gas_faq.html.

3. Outlook for the U.S. Natural Gas Market

Short-Term Outlook

Demand

The next few years[69] promise to provide an extraordinary boom in natural-gas-fired generating capacity additions, marked by the introduction into commercial service of about 22 gigawatts of new gas-fired capacity in 2000.[70] These additions contribute to expectations that natural gas will be the key fuel behind economic growth over the next few years. In the Energy Information Administration's (EIA's) *Short-Term Energy Outlook* for April 2001, the average growth rate for gas consumption in the 2000-2002 time period is expected to be 3.6 percent per year, as compared with just 0.9 percent per year from 1994 to 1999.

Factors that could limit the upward momentum in natural gas demand are lagging production increases (with concomitant sharp rises in wellhead and delivered natural gas prices), a slowdown in U.S. economic growth, or a return to successive seasons of below-normal heating (and cooling) demand. However, natural gas demand requirements are likely to absorb expected supply increases and maintain market prices well above what was common in the 1990s for at least the next 2 years.

Industrial Sector

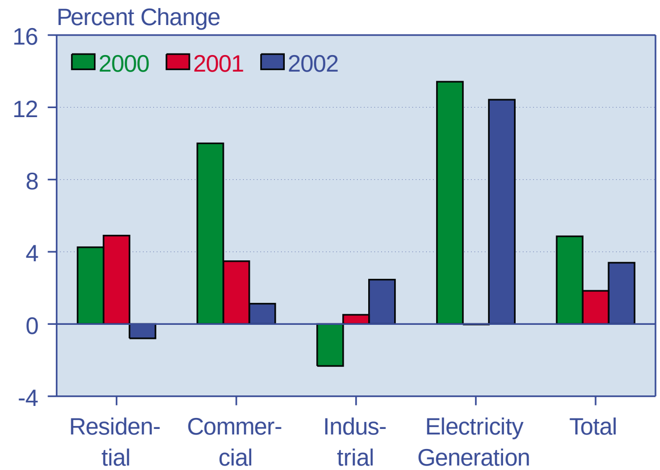
Industrial natural gas demand is tied to the level of output in industries that typically use natural gas as fuel for process heat or as feedstock. Weak output growth in natural-gas-intensive industries (up only 0.9 percent) combined with rapidly rising natural gas prices (up approximately 44 percent to the industrial sector) apparently drove total industrial gas demand down in 2000 by about 2.3 percent. Despite overall slowing in the U.S. economy in 2001, a composite index of natural-gas-intensive industries looks likely to recover somewhat in 2001. Although natural gas prices remain high, industrial natural gas demand is expected to increase by about 0.9 percent in 2001. In 2002, a strengthening recovery in natural-gas-intensive output (4.4 percent) and the prospect of lower average gas prices yields the expectation that industrial natural gas demand will climb by about 4 percent.

Residential Sector

The preliminary year-2000 growth rate for residential natural gas consumption was 4.3 percent, due mostly to increased heating demand, particularly in the fourth quarter. Growth in gas consumption in 2001 is expected to be even higher, at 4.9 percent over year-2000 levels (Figure 16). These are robust growth rates; residential natural gas demand would normally be expected to grow at about the rate of household formation, or about 1 percent per year.

In 2001, the impetus for above-normal natural gas demand growth stems from the higher level of heating degree-days measured in the first quarter compared to year-ago levels.[71] Given normal weather for the rest of 2001 and 2002, along with the other assumptions used in EIA's latest base case projections, residential natural gas demand is expected to decline by about 0.8 percent in 2002.

Figure 16. Projected Annual Percentage Changes in Natural Gas Demand by Sector, 2000-2002



Source: Energy Information Administration, *Short-Term Energy Outlook* (April 2001).

[69]Projections through 2002 are taken from EIA's April 2001 *Short-Term Energy Outlook* (and associated databases), web site www.eia.doe.gov/steo/.

[70]Capacity additions by location and fuel type are listed in EIA's *Electric Power Monthly*, DOE/EIA-0226(2001/03) (Washington, DC, March 2001).

[71]Because natural gas utilities typically stagger their meter readings over a 20-day period to minimize their costs, some of the demand reported in the current month will actually have occurred in the previous month. For example, a portion of November's gas consumption may be reported in December.

The rate of demand growth that is likely to be measured for 2001 is uncertain beyond the question of whether degree-days remain normal from here on in. Generally, the consumption response of consumers to changes in natural gas prices is quite low in the short run. However, the sharp increases in residential delivered prices estimated for average natural-gas-heated households this past winter may have forced additional conservation. Average heating bills for the October-March period probably rose by an average of about 70 percent nationally, possibly enough to bring budget constraints into play for many end users. Precise data on the net offset to estimated residential demand increases this winter as a result of conservation efforts are not available.

Commercial Sector

Natural gas demand growth in the commercial sector averaged 10 percent in 2000. This rate of growth was nearly 7 percentage points above the average annual rate observed during the 1986 to 1997 period and was generated by the combination of strong domestic economic growth, colder than normal weather, and growth in commercial cogeneration. Gas consumption growth in 2001 is expected to slow to 3.5 percent as the U.S. GDP growth rate falls to less than one-half the torrid 5-percent rate of 2000. The combination of slower growth in commercial employment and output plus lower heating degree-days is expected to yield commercial gas consumption growth of about 1.3 percent in 2002.

Electricity Generation

The change in relative energy prices and a slowing down in the growth of electricity demand in 2001 point toward low growth in the demand for gas in the power sector this year. A rebound in economic growth and modestly declining gas prices are expected to result in robust growth in gas demand for electricity generation (12.4 percent) in 2002.

In general, U.S. gas-fired generating capacity is growing rapidly. EIA reported that about 22 gigawatts of new gas-fired generating capacity was added in 2000 (an 18-percent increase from the 1999 level).[72] Various surveys by private organizations indicate that a much greater increment (30 to 50 gigawatts[73]) of gas-fired generating capacity in 2001 is implied by the announced additions around the country. A similarly large increase for 2002 is possible given public announcements compiled to date.

While the likelihood that all the announced additions will actually enter commercial service as scheduled is low, it does appear likely that the additions will be at least as high as observed in 2000. The potential for net increases in gas demand associated with these new generating plants reinforces the conclusion that significant new natural gas supply, which may accrue from the very high rate of gas well completions currently estimated for North America, would probably be quickly absorbed. This would suggest that a relatively high floor for spot gas prices should be expected for at least the next few years.

Supply

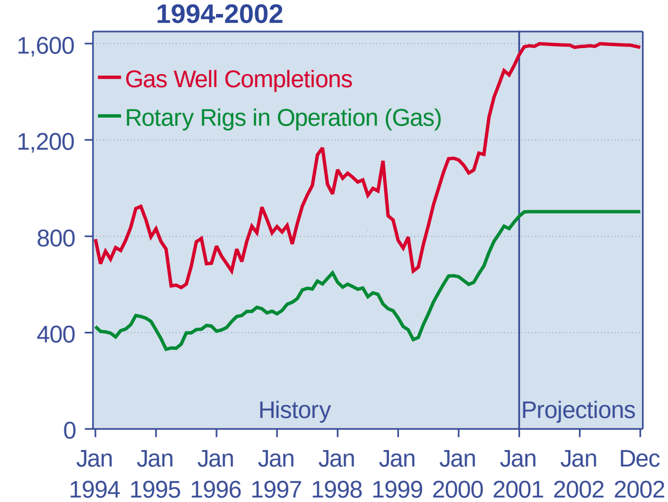
Production

Preliminary data indicate that dry gas production increased by about 3.7 percent in 2000. These figures are consistent with the available well completion data. It is expected that an additional 2.7-percent production increase will occur in 2001, followed by a 2.5-percent increase in 2002, to 20.3 trillion cubic feet. Similar production increases and higher exports to the United States are expected from Canada.

Drilling

In March 2001, the gas rig count stood at about 900 units (Figure 17).[74] EIA estimates that the number of new (i.e., excluding recompletions) gas well completions in 2000 was 15,200, 45 percent above the (depressed) 1999 total.[75] Assuming that rig activity continues to increase

Figure 17. U.S. Natural Gas Drilling Activity, 1994-2002



Sources: **History:** Well Completions: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2001/02) (Washington, DC, February 2001), Table 5.2, and associated historical databases. Rigs: Baker Hughes, Inc., *Rotary Rigs Running—by State* (Houston, TX). **Projections:** Energy Information Administration, *Short-Term Energy Outlook* (April 2001).

[72]Capacity additions by location and fuel type are listed in EIA's *Electric Power Monthly*, DOE/EIA-0226(2001/03) (Washington, DC, March 2001).

[73]These are more recent estimates than the values provided in Chapter 2, which are based on data from EIA surveys.

[74]Drilling rig data are published by Baker-Hughes, web site www.bakerhughes.com/investor/rig/index.htm.

[75]Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2001/03) (Washington, DC, March 2001), Table 5.2.

at about the current rate, one would expect an additional 25-percent increase in gas well completions in 2001. Given the underlying strength in gas demand expected through 2002, it is reasonable to expect price incentives for continued high completion rates next year.

Imports

Total net imports increased by about 4 percent in 2000 following a strong 14-percent growth spurt in 1999 due to significant increases in cross-border capacity from two projects completed in late 1998 (Great Lakes Transmission expansion and Northern Borders expansion). In 2000 new gas from Sable Island (Nova Scotia) was shipped to the Northeast via the Maritimes and Northeast pipeline, which opened in late 1999, and gas from the Alliance pipeline was available late in 2000.

One sign that net foreign supply to the United States will contribute measurably to the U.S. market in 2001 comes from preliminary data for December 2000, which indicate that total net imports of natural gas to the United States for the month were 16 percent higher than the December 1999 level. With strong natural gas prices expected to persist in 2001 and 2002, net natural gas imports are expected to increase by another 13 percent in 2001 and an additional 4 percent in 2002, rising to 4.18 trillion cubic feet, as gas prices abate somewhat.

Storage

Despite improvements in domestic gas supply, it is unlikely that spot gas prices will move to levels much lower than current levels (about $5 per million Btu) for the rest of the year. This is because of the large amount of new gas supply that will have to go into storage to replenish the very low levels that developed over the past winter (Figure 18). Assuming that a return to near normal levels is required before the beginning of the next heating season, net injections that are about 20 to 25 percent above the average for recent years (1996-2000) would be needed. Thus, the probability that storage will not reach average levels at the end of the summer is relatively high. Monitoring storage this summer will be useful for anticipating the strength of gas prices going into the next heating season.

Prices

The average wellhead price of natural gas in the 2000-2001 heating season (October 2000-March 2001) is estimated to have been 144 percent higher than the average recorded for the 1999-2000 heating season. The length of time that nominal gas prices have remained this high is unprecedented. Moreover, the current dynamics of the natural gas market suggest that prices at the wellhead will not soon be returning to the low $2.00 per million Btu experienced just one year ago. The chief basis for this view is an outlook for robust levels of gas demand growth over the next two years, particularly in the electric power sector. About 90 percent of the planned additions to electric generating capacity over the next few years are designed to use natural gas as the primary fuel. Although gas production and imports are expected to increase in the forecast period, the gains in supply may not be enough to bring the wellhead price below $3.00 per million Btu in the short term.

It is estimated that winter (October 2000-March 2001) natural gas prices at the wellhead averaged about $5.60 per million Btu. Current estimates suggest that residential prices for natural gas were about 42 percent higher for the October 2000-March 2001 period compared to the previous winter. Beyond the end of the heating season it is projected that average wellhead prices will decline somewhat, averaging near $4.40 per million Btu for the spring and summer. However, if the summer weather is exceedingly hot in regions that consume large quantities of gas-fired electricity (California and Texas for example), then injections into underground storage for the next winter would be strained and prices could start rising more sharply and sooner than expected. For 2001, the annual average wellhead price is projected to be about $4.85 per million Btu. The storage situation is expected to improve modestly in 2002, with an expected decrease in the average annual wellhead price to about $4.43 per million Btu.[76]

Economic Impacts

The full extent of the macroeconomic impacts of the rapid natural gas price increases that developed over the past winter in terms of reduced output, increased

Figure 18. Working Gas in Storage: Percent Change from Previous Year, January 2000-November 2002

Source: Energy Information Administration, *Short-Term Energy Outlook* (April 2001).

[76] Annual average prices have been converted to constant 1999 dollars. See Table ES1 for the relation between current-year dollars and constant 1999 dollars.

unemployment, and lower real income are not completely understood at this point. However, some indicators of the significance of the increase in natural gas costs can be estimated. Large increases in aggregate national expenditures for natural gas used by consumers, businesses, and power plants have been seen since April 1999. Households that use natural gas, particularly those that heat with natural gas, have seen winter fuel bills rise dramatically between the 1999-2000 and 2000-2001 heating seasons.

On balance, it is estimated that the rapid increase in natural gas prices that occurred between 1999 and 2001 has reduced near-term economic growth in the United States by between 0.5 and 1.0 percent from what would have been the case with constant natural gas prices. One result of high natural gas prices that is obvious, but is nevertheless worth some detailed discussion, is that natural gas producers' income increased dramatically. Large infusions of net cash flow to natural gas producers would, among other things, be expected to support strong increases in spending for natural gas resource development. Financial data for domestic oil and natural gas companies that report such information publicly show strong increases in profits for the fourth quarter 2000. Equally strong or stronger financial results are expected for the first quarter of 2001 when those data are available.

Consumer Prices

Natural gas price increases seen in 2000 (including an approximate increase at the residential level of 15 percent) probably contributed an average of 0.3 percentage point to consumer prices last year. Based on the track for natural gas commodity costs so far in 2001 and the base case projections through the end of the year, it is expected that natural gas price increases will result in a consumer price index (CPI) for 2001 that is about 1.0 percent above the level that would have resulted from natural gas prices remaining constant at 1999 levels.

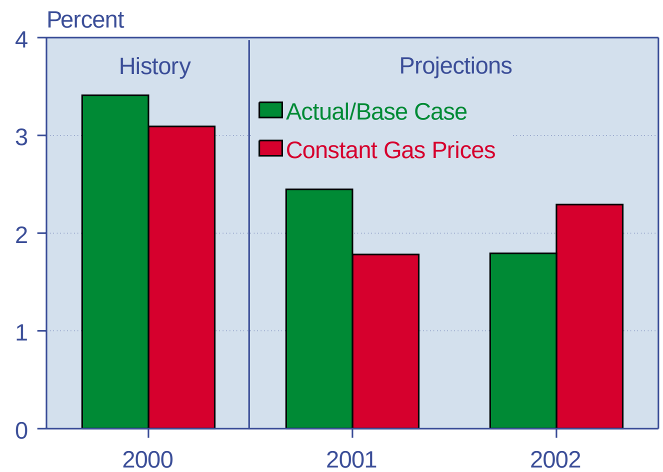
In terms of the rate of consumer inflation, the analysis indicates that the rate of increase in the CPI would have been about 0.3 percent lower than it actually was in 2000 except for the runup in natural gas prices. Also, the expected rate of growth in the CPI this year (2.4 percent) is about 0.7 percentage point greater than would have been the case if natural gas prices had remained constant. Because of lags in the effects of natural gas price increases on consumer prices of other energy and non-energy goods, it is likely that some (rapidly diminishing) impacts on consumer prices would remain even after natural gas prices returned to baseline levels. Overall, consumer price inflation during the 1999-2001 will probably prove to be about 0.5 percentage point above the average rate that would have resulted if new natural gas supply could have been obtained without significant price changes from the 1999 levels (Figure 19).

Expenditures

The extent to which domestic end-use expenditures for natural gas increased in 2000 and so far in 2001 relative to levels that were generally prevailing in 1998 and 1999 is rather startling in nominal terms.[77] In inflation-adjusted terms the level of natural gas expenditures seems slightly less remarkable but still noteworthy. Total expenditures for natural gas in the United States (calculated as the estimated sum paid for natural gas delivered to residences, commercial establishments, industrial plants, and electric power plants) rose from $105 billion in 1999 to $134 billion in 2000, an increase of 28 percent (Figure 20). In real (inflation-adjusted) terms the increase amounted to 25 percent.[78] Total natural gas expenditures as a percent of GDP, which averaged 1.33 percent between 1995 and 1999 but moved up to 1.44 percent in 2000, are expected to average 1.80 percent in 2001 and 1.69 percent in 2002 (Figure 21).

To put the higher natural gas costs to households in some perspective, it is useful to calculate the dollar

Figure 19. Projected Consumer Price Inflation in Two Cases, 2000-2002



Source: Energy Information Administration, *Short-Term Energy Outlook* (April 2001).

[77]End-use prices and consumption levels used to derive estimates of aggregate end-use expenditures for natural gas for historical periods are taken from EIA's *Natural Gas Monthly*. Projections and estimates for some recent values are from the April 2001 version of EIA's Short-Term Integrated Forecasting System database, which contains model results used to produce the April 2001 *Short-Term Energy Outlook*.

[78]The deflator used to convert nominal expenditures to real dollars is the chained GDP price deflator.

increase in costs of home heating for a typical natural-gas-heated home.[79] Due to successive warm winters and low natural gas prices in the years prior to the 2000-2001 heating season, winter household natural gas costs averaged about $540 for the three previous winters. It is estimated that for the 2000-2001 heating season, winter household natural gas costs were about $920, 70 percent above the year-ago level. Looking ahead to next winter, slightly warmer temperatures (assuming normal weather) and somewhat lower residential natural gas prices suggest a decline in expenditures of perhaps 8 percent (Figure 22).[80]

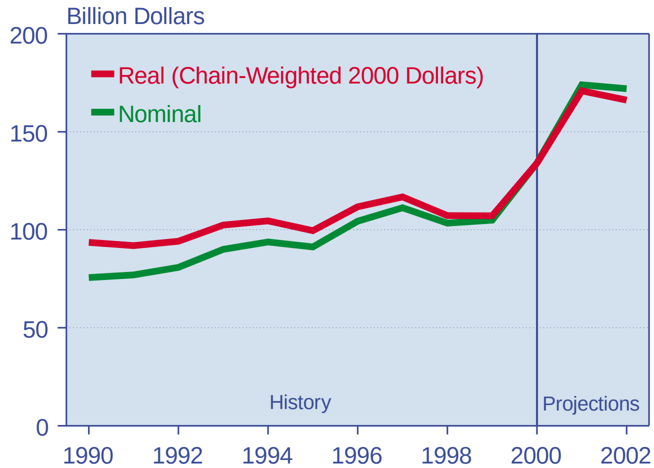
Macroeconomic Impacts

Since 1999, dramatic increases in natural gas prices have meant increasing consumer expenditures for energy and have been indicative of strong demand and constrained natural gas supply. Rapid increases in costs have impacts on inflation and output. EIA has performed some preliminary analysis on the impacts of increases in natural gas costs on the U.S. economy by reconstructing the pattern of gas price increases seen between 1999 and 2001 as an alternative scenario for the baseline macroeconomic forecast used in the April 2001 *Short-Term Energy Outlook*. The alternative macroeconomic simulation was created by using the McGraw-Hill/DRI quarterly model of the U.S. economy.[81] Comparing the results from this alternative scenario and the reference case forecast may yield some insight into the aggregate effects of the recent rapid increase in natural gas prices on inflation and economic output. Of course, any attempt to simulate an alternative history cannot fully account for the dynamic events that shaped the past.

High costs of natural gas have reduced real incomes of consumers and reduced the profitability of gas-consuming industries. Because short-run substitution possibilities between gas and other fuels are limited, one would expect substantial increases in gas prices to result in declining output. Production and profits are higher for gas producers, but natural gas consumers have seen their expenditures rise.

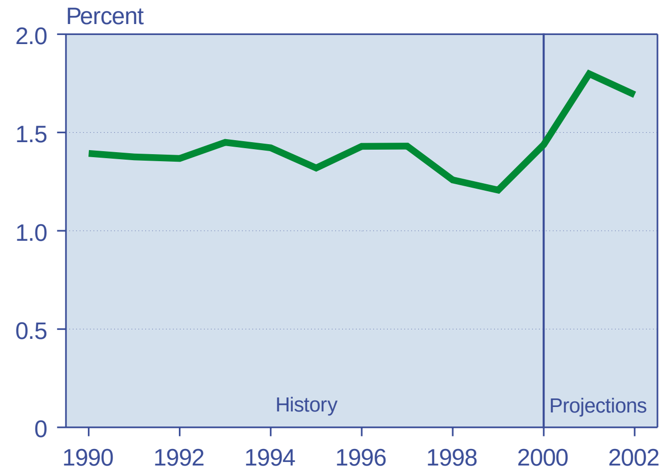
Real GDP would have been about 0.2 percent higher in 2000 except for the tightening supply conditions for natural gas. Furthermore, expectations for GDP growth in 2001 would be about 0.7 percentage point higher if

Figure 20. Domestic Natural Gas Expenditures, 1990-2002



Sources: **History:** Nominal Expenditures: Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(2001/03) (Washington, DC, March 2001), Tables 10, 21, 22, 23, and 24, and associated historical databases. Real Expenditures: Nominal expenditures divided by the chained gross domestic product deflator, rebased to the year 2000 (available from the Bureau of Economic Analysis, U.S. Department of Commerce. **Projections:** Energy Information Administration, *Short-Term Energy Outlook* (April 2001).

Figure 21. Natural Gas Expenditure Share of Gross Domestic Product, 1990-2002



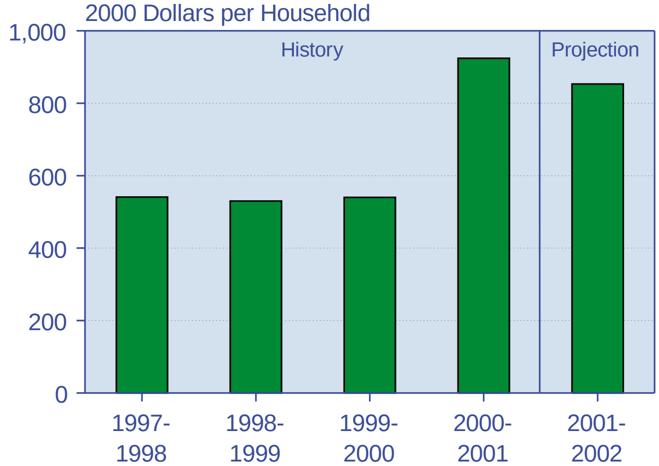
Sources: **History:** Expenditures: Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(2001/03) (Washington, DC, March 2001), Tables 10, 21, 22, 23, and 24, and associated historical databases. Real GDP: Bureau of Economic Analysis, U.S. Department of Commerce. **Projections:** Energy Information Administration, *Short-Term Energy Outlook* (April 2001).

[79]Typical household winter gas expenditures are calculated as the product of estimated per-household winter gas usage and reported average residential prices form EIA's *Natural Gas Monthly* and *Short-Term Energy Outlook*. Per-household usage is based on EIA's 1997 Residential Energy Consumption Survey (RECS), except that per-household consumption is converted to consumption per heating degree-day and then reconstructed for the winter period (October-March) instead of the as-reported calendar year basis.

[80]The source of recent and projected values for household winter gas costs is EIA's April 2001 *Short-Term Energy Outlook*.

[81]The methodology used to derive the alternative macroeconomic scenario was as follows: (1) start with the base case macroeconomic simulation for the April 2001 *Short-Term Energy Outlook* (DRI CONTROL0301); (2) resimulate the macro model for the 2001-2002 period with natural gas prices changed so as to replicate (relative to the base case) the gas price changes seen or expected for the 1999-2001 period; and (3) use the differences from the baseline for the 2001-2002 period as an indicator of the approximate impacts of higher gas prices on economic aggregates (output, income, inflation) for 2000 and 2001.

Figure 22. Winter Heating Costs for Natural-Gas-Heated Homes, 1997-2002



Sources: **History:** Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(2001/03) (Washington, DC, March 2001), Tables 10 and 21 (residential expenditures), and Residential Energy Consumption Survey 1997 (per-household consumption). **Projections:** Energy Information Administration, *Short-Term Energy Outlook* (April 2001).

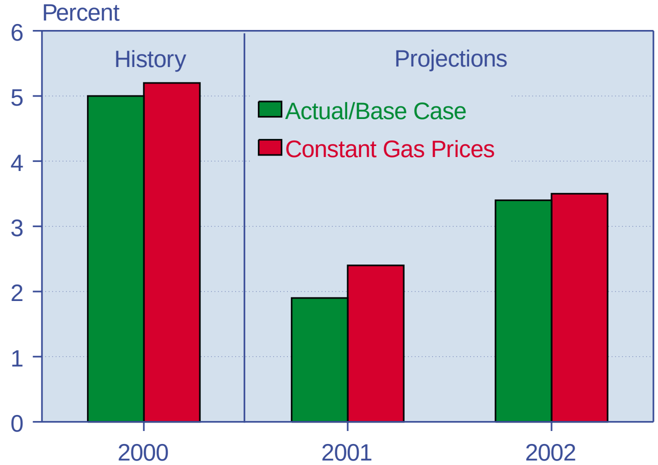
natural gas prices had remained at average 1999 levels through 2001 (Figure 23). Real disposable personal income, which grew by 2.8 percent in 2000 and is projected to post a 2.5-percent increase in 2001, would have likely grown by an average 3.1 percent for both years without the natural gas price increases (Figure 24).

Natural Gas Industry Finances

Major Energy Companies.[82] Major energy companies with domestic oil and gas operations reported that earnings rose due to much higher crude oil and natural gas prices. Although the results were strongly influenced by the operations of BP Amoco and Exxon Mobil, which together accounted for 44 percent of the net income total for this category, almost all the companies reported higher net income from domestic oil and gas production in the fourth quarter of 2000 than in the fourth quarter of 1999. The benefits of higher oil and domestic natural gas prices were somewhat magnified by higher domestic oil and gas production relative to the fourth quarter of 1999, both of which increased by 11 percent. However, much of the higher production was due to major asset acquisitions (mergers). Omitting the data for companies with significant acquisitions results in a 6-percent decline in domestic production of crude oil and a 5-percent increase in natural gas production for the fourth quarter of 2000 relative to the fourth quarter of 1999.

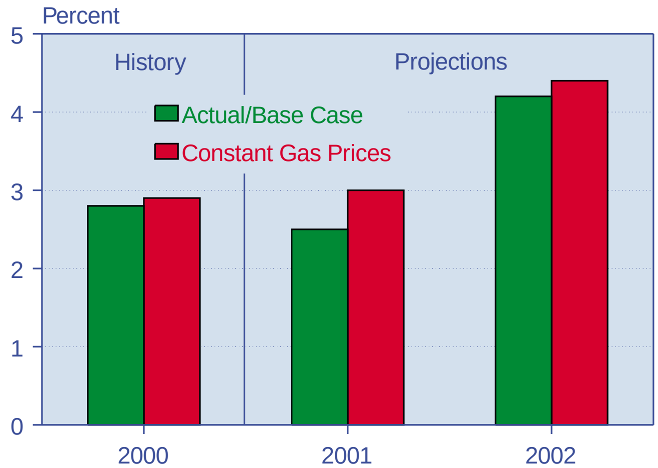
On the negative side, the majors reported an 86-percent decline in net income from chemical operations. The reason given for the decline in chemical net income in the fourth quarter of 2000 relative to the fourth quarter of 1999 was reduced margins due to higher raw materials costs as both crude oil and natural gas prices increased relative to the fourth quarter of 1999.

Figure 23. Projected Growth in Real Gross Domestic Product in Two Cases, 2000-2002



Source: Energy Information Administration, *Short-Term Energy Outlook* (April 2001).

Figure 24. Projected Growth in Real Disposable Personal Income in Two Cases, 2000-2002



Source: Energy Information Administration, *Short-Term Energy Outlook* (April 2001).

Independent Companies.[83] Independent oil and gas producers, oil field companies, and refiner/marketers all reported big gains in net income in the fourth quarter of 2000 compared with the fourth quarter of 1999. Oil and gas producers led the group with a 312-percent increase. In total, net income for independents was up 271 percent

[82]Information taken from EIA's quarterly analysis of major energy companies' financial performance, web site www.eia.doe.gov/emeu/perfpro/news_m/index.html.

[83]Information taken from EIA's quarterly analysis of independent energy companies' financial performance, web site www.eia.doe.gov/emeu/perfpro/news_i/index.html.

in the fourth quarter of 2000 over the fourth quarter of 1999. Price increases for oil and, especially, natural gas led to large increases in net income for independent oil and gas producers over the past year. Oil prices increased by 23 percent and natural gas wellhead prices by 131 percent. EIA reported in its February 2001 *Monthly Energy Review* that domestic oil production declined by 1.9 percent while natural gas production grew by 4.4 percent between the fourth quarter of 1999 and the fourth quarter of 2000.

Mid-Term Outlook

The mid-term outlook for the U.S. natural gas market summarized in this report was developed from the *Annual Energy Outlook 2001* (*AEO2001*),[84] a mid-term annual energy-economy projection of U.S. energy markets developed using EIA's National Energy Modeling System (NEMS). The *AEO2001* reference case assumes no change in current laws, regulations, or policies and no change in the basis for consumer choices.

Because gas resources are expected to be adequate to meet future natural gas demand through 2020, and technological progress for exploration and development is expected to be sustained, natural gas prices in the *AEO2001* forecast are expected to return to a lower price path after 2005 and gradually increase to $3.05 per million Btu in 2020. Advances in drilling technologies are expected to offset some of the cost increases associated with harder-to-find natural gas pockets and smaller pools.

In the near term, natural gas prices are likely to be higher than projected in *AEO2001*. The higher near-term natural gas prices are expected to stimulate more non-gas-fired generation capacity between 2004 and 2010 than was anticipated in *AEO2001*. However, the expected surge in natural gas drilling activities, prompted by relatively high natural gas prices between 2000 and 2005, should add considerable natural gas productive capacity and increase proven reserves, lowering natural gas prices and making natural gas generating technologies the preferred choice in the post-2010 time period.

The United States consumed about 22.8 trillion cubic feet of natural gas in 2000.[85] The previous record for U.S. annual consumption of natural gas, 22.1 trillion cubic feet, was set in 1972. In the *AEO2001* forecast, natural gas consumption is projected to reach 31.6 trillion cubic feet in 2015 and continue to rise to 34.7 trillion cubic feet in 2020. As demand increases, pressure on natural gas supply and the transportation infrastructure are expected to grow. These demand-side pressures will raise such questions as "Is there enough gas to meet demand?" "Can we produce the gas fast enough?" "Can we build pipelines fast enough?" and, ultimately, "How high will prices go?"

Demand

The macroeconomic projection for *AEO2001* was derived from DRI's baseline,[86] adjusted for world oil prices and other energy prices projected in NEMS.[87] In the reference case, between 1999 and 2020, the economy is projected to grow at an annual average rate of 3.0 percent. Economic growth leads to growth in housing starts, commercial floorspace, disposable income, and industrial output, all of which tend to lead to growth in energy consumption.

In 2000, U.S. natural gas consumption was more than 22 trillion cubic feet and accounted for almost 24 percent of domestic energy consumption.[88] Natural gas consumption is expected to grow by 2.3 percent annually from 1999 to 2020 (to 34.7 trillion cubic feet)—faster than any other major fuel source—mainly because of growth in natural-gas-fired electricity generation. The increase is expected to occur with a relatively moderate mid-term impact on natural gas wellhead prices in real terms (1999 dollars), which are expected to rise slowly along a "fundamental path,"[89] reaching about $3.05 per million Btu in 2020. Natural gas consumption in 2015 is expected to be more than 10 trillion cubic feet higher than in 1999. More than half the increase, 5.5 trillion cubic feet, is expected in the electricity generation sector (Figure 25).

[84]Energy Information Administration, *Annual Energy Outlook 2001*, DOE/EIA-0383(2001) (Washington, DC, December 2000), web site www.eia.doe.gov/oiaf/aeo/. All information describing the mid-term outlook after 2005 is taken from *AEO2001*. The *AEO2001* projections are not meant to be exact predictions of the future but represent a likely future, assuming known trends in demographics and technology improvements, and also assuming no change in current law, regulation, and policy. Important assumptions include: (a) current laws and regulations (as of August 2000); (b) continuation of current trends in research and development (R&D) and technological progress; (c) current estimates of resource availability; and (d) consistent with consumer values and choices.

[85]Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2001/03) (Washington, DC, March 2001).

[86]Standard and Poor's DRI, Simulation T250200 (February 2000).

[87]For a general description of NEMS, see Energy Information Administration, *National Energy Modeling System: An Overview 2000*, DOE/EIA-0581(2000) (Washington, DC, March 2000), web site www.eia.doe.gov/oiaf/aeo/overview/.

[88]Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2001/03) (Washington, DC, March 2001).

[89]An expected fundamental price path assumes that the industry gears up without efficiency losses imposed by too rapid a rate of investment in rigs and crews and the absence of factors causing price volatility (e.g., weather, pipeline or infrastructure accidents, or supply bottlenecks). See Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2001/03) (Washington, DC, March 2001).

Although industrial output is projected to grow at an average annual rate of 2.6 percent from 1999 through 2020, the most rapid growth is for the non-energy-intensive manufacturing sectors, particularly electronics and industrial machinery. The greater growth in non-energy-intensive industries results in energy consumption increases that are less than proportional to the increase in industrial output.

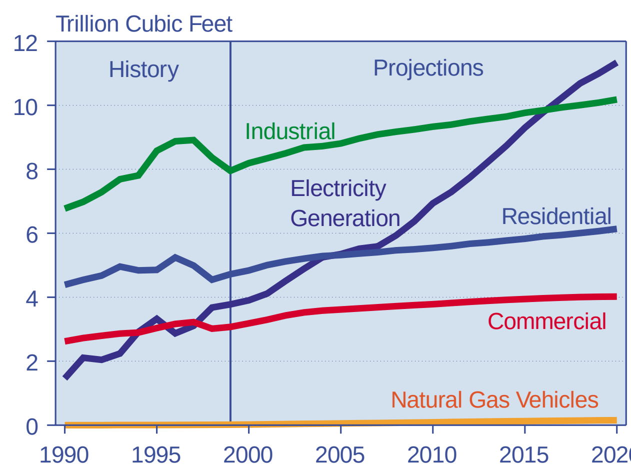
The industrial sector (including cogeneration) is the largest natural-gas-consuming sector, with significant amounts of natural gas used in the bulk chemical, refining, and metal durables sectors. Industrial natural gas consumption is projected to increase by 2.2 trillion cubic feet over the forecast—about 1.2 percent per year—particularly in the metal durables and bulk chemical sectors, because of relatively low and stable natural gas prices in the long run.

Combined, the residential and commercial sectors are expected to add 2.4 trillion cubic feet to 1999 annual gas use by 2020. Natural gas demand in the residential and commercial sectors is driven by housing and building stock, increasing housing size (i.e., larger homes being built), and steady consumer prices. In the forecast, the relatively stable prices paid by residential consumers reflect increased natural gas distribution efficiencies in an increasingly competitive market. Because residential natural gas prices are generally lower than the prices of other fuels, the increase in the number of homes heated by natural gas is projected to be more than three times the increase in those heated by electricity. Residential and commercial natural gas consumption is expected to grow by 1.3 percent annually from 1999 through 2020.

Coal is projected to remain the dominant fuel for electricity generation throughout the forecast period; however, its share of total electricity generation is expected to decline from 51 percent in 1999 to 44 percent in 2020. The natural gas share of total generation is expected to increase from 16 percent in 2000 to 36 percent in 2020.[90] Natural gas consumption by electricity generators, not including industrial cogenerators, increases threefold in the forecast, from 3.8 trillion cubic feet in 1999 to 11.3 trillion cubic feet in 2020. Significant growth in natural-gas-fired generation is reinforced by electric industry restructuring and other related factors, including lower capital costs, shorter construction lead times, and higher efficiencies for natural gas turbines and combined-cycle units than for coal, renewables, and nuclear alternatives.

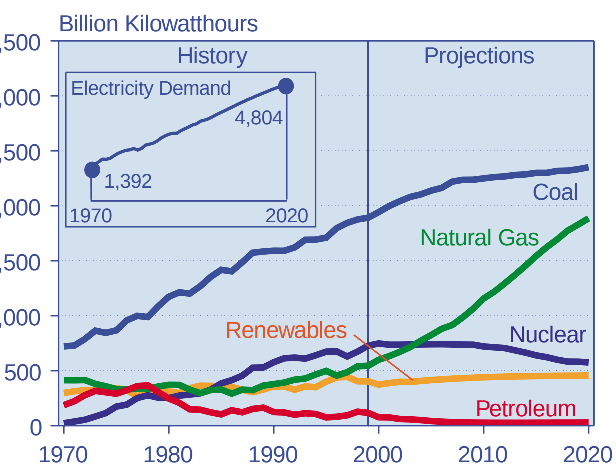
Natural-gas-fired electricity generation (including industrial cogeneration) is projected to grow rapidly, from a 15-percent share of generation in 1999 and a 16-percent share in 2000[91] to a 36-percent share in 2020 (Figure 26). Throughout the forecast, natural gas technologies are projected to capture the majority of capacity additions for electricity generation, excluding cogeneration. Of this new capacity, it is projected that 92 percent will be combined-cycle plants or combustion turbines, including distributed technologies, fueled by natural gas. Only 6 percent is projected to be coal-fired plants and 2 percent renewable technologies. Renewable technologies for electricity generation are projected to

Figure 25. Natural Gas Consumption by Sector, 1990-2020



Sources: **History:** Electric Utilities: Energy Information Administration (EIA), *Electric Power Annual 1999*, Vol. 1, DOE/EIA-0348(99)/1 (Washington, DC, August 2000). Nonutilities: EIA, Form EIA-867, "Annual Nonutility Power Producer Report, 1998." Other: EIA, *State Energy Data Report 1997*, DOE/EIA-0214(97) (Washington, DC, September 2000). **Projections:** EIA, *Annual Energy Outlook 2001*.

Figure 26. Electricity Generation by Fuel, 1970-2020



Sources: **History:** Energy Information Administration (EIA), Form EIA-860B, "Annual Electric Generator Report - Nonutility;" EIA, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000); and Edison Electric Institute. **Projections:** EIA, *Annual Energy Outlook 2001*.

[90]Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2001/03) (Washington, DC, March 2001).
[91]Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2001/03) (Washington, DC, March 2001).

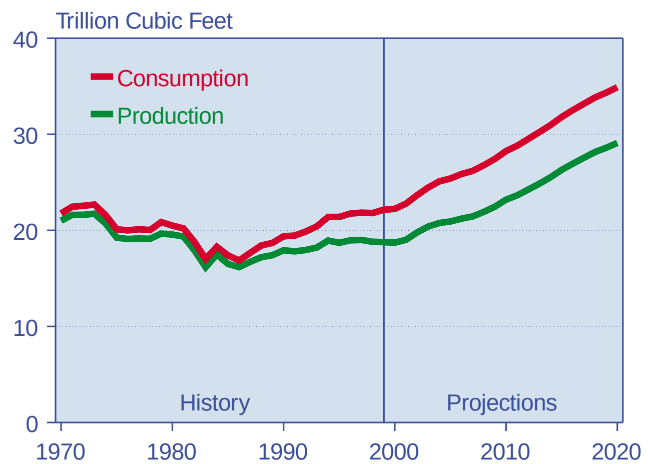
grow slowly because of the relatively low cost of fossil-fuel-fired generation technologies, and because electricity industry restructuring is expected to favor less capital-intensive natural gas technologies.

Supply

Domestic Production

Domestic natural gas production is expected to increase more slowly than consumption over the forecast, from 19.3 trillion cubic feet in 2000 to 29.0 trillion cubic feet in 2020 (Figure 27). To satisfy demand of 31.6 trillion cubic feet in 2015, annual domestic natural gas production will need to increase by 7 trillion cubic feet. Thus, over the next 15 years, production increases must average over 460 billion cubic feet per year. To produce 29.0 trillion cubic feet of gas in 2020, lower 48 natural gas wells drilled will have to increase from about 10,500 in 1999 to about 24,000 in 2020 (Figure 28).

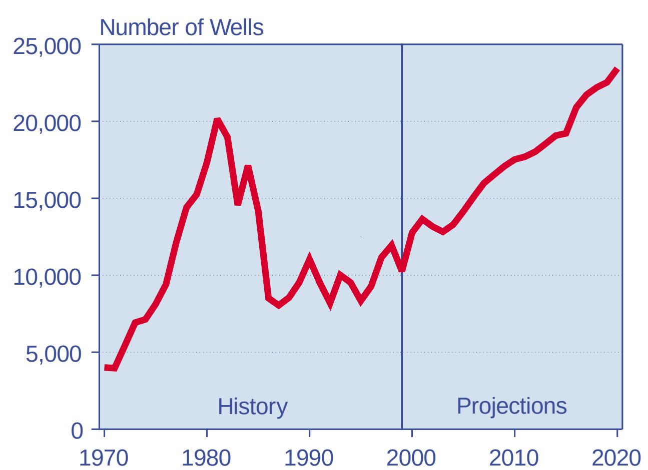
Figure 27. U.S. Natural Gas Consumption and Production, 1970-2020



Note: Production includes supplemental supplies; consumption includes discrepancies and net storage additions.

Sources: **History:** Energy Information Administration (EIA), *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** EIA, *Annual Energy Outlook 2001*.

Figure 28. Lower 48 Natural Gas Wells Drilled, 1970-2020

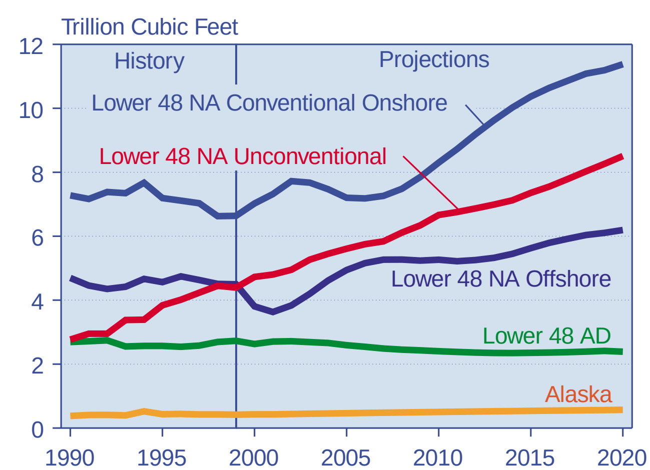


Sources: **History**: Consumption and Production: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2001/03) (Washington, DC, March 2000), Table 2. Successful Lower 48 Wells Drilled, EIA, *Monthly Energy Review*, DOE/EIA-0035(2001/03) (Washington, DC, March 2001), Table 5.2. **Projections:** EIA, *Annual Energy Outlook 2001*, DOE/EIA-0383(2001) (Washington, DC, December 2000).

From 1955 to 1972 the industry increased production at more than 140 percent[92] of the projected rate required from 1999 to 2015. Of course, conditions are different from those earlier years. Undiscovered field sizes in mature producing areas are smaller, and larger prospects are located in more remote areas. On the other hand, the real price (in 1999 dollars) of natural gas was more than three times higher in 1999 ($2.11 per million Btu) than it was in 1955 ($0.52 per million Btu), real exploration and production costs are lower, technology is better, and the regulatory environment is more favorable to natural gas production. Figure 29 shows the expected domestic sources of natural gas.

In the past, producers were constrained by price controls and the market was unable to send clear signals about consumers' interest in purchasing and suppliers' willingness to sell. As a result, during some periods curtailments in supply were of great concern. In today's competitive market, improved price signals are sent to

Figure 29. Projected Natural Gas Production by Source, 1990-2020



Note: Unconventional gas recovery consists principally of production from reservoirs with low permeability (tight sands) but also includes methane from coal seams and gas from shales.

Sources: **History:** Total production and Alaska: Energy Information Administration (EIA), *Natural Gas Annual 1998*, DOE/EIA-0131(98) (Washington, DC, October 1999). Offshore, associated-dissolved, and nonassociated: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(90-98). Unconventional: EIA, Office of Integrated Analysis and Forecasting. **1999 and Projections:** EIA, *Annual Energy Outlook 2001*.

[92]Computed from Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000), Table 1.2.

sellers and purchasers, allowing for the setting of market clearing prices. The current episode with high natural gas prices and the natural gas industry's investment response confirms that the question is less "Will the natural gas be there?" and more "How much will it cost?"

Current estimates of technically recoverable natural gas resources indicate that the resource base is expected to be adequate to sustain growing production volumes for many years, based primarily on the assessments done by the U.S. Geological Survey for onshore regions and by the Minerals Management Service for the offshore. As of January 1, 1999, technically recoverable resources were 1,281 trillion cubic feet. Resources include not only proved reserves, which were 164 trillion cubic feet, but also inferred reserves from known fields and undiscovered resources from new fields. Inferred reserves, representing the expected growth from previously discovered fields, totaled 244 trillion cubic feet as of January 1, 1999, most of that located in onshore areas. Resources in lower 48 undiscovered fields not associated with oil deposits accounted for 319 trillion cubic feet of the total. Of all the undeveloped resources, the largest share belongs to unconventional natural gas from tight sandstone formations, coalbeds, and shales at 393 trillion cubic feet. Natural gas associated with oil makes up most of the balance of the total technically recoverable resource base (Figure 30). Cumulative natural gas production from 1999 through 2020 is likely to total between 480 and 512 trillion cubic feet, well under the estimate of 1,281 trillion cubic feet for recoverable natural gas resources.

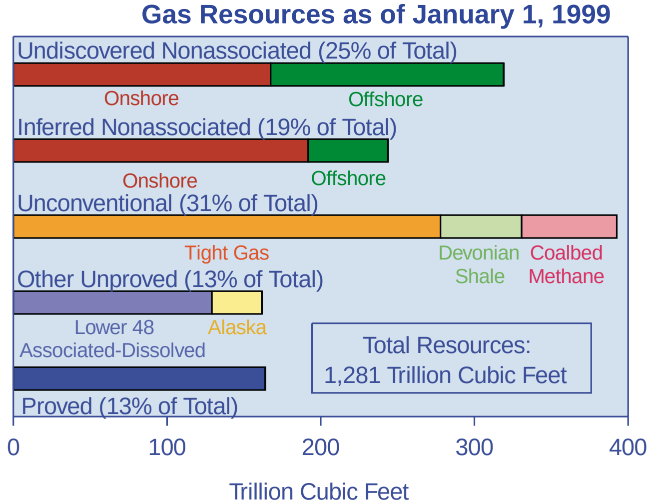
Uncertainty with regard to estimates of the Nation's natural gas resources has always been an issue in projecting production, and could affect production and prices. The uncertainty surrounding recoverable natural gas resource estimates is reflected in the differing views on the subject. For example, GRI's latest baseline[93] asserts that using current technologies only, the total recoverable resources in all categories is over 1,800 trillion cubic feet—roughly 50 percent higher than EIA's estimate. When advanced technologies are considered, GRI shows that over 1,300 trillion cubic feet is economically recoverable at $3 per thousand cubic feet. GRI's analysis is not the most optimistic assessment. Dr. William Fisher at the University of Texas at Austin has a much higher estimate, well over 2,400 trillion cubic feet.[94]

EIA's estimates are taken largely from the USGS, which tends to be cautious because it is difficult to estimate resources of oil and gas that cannot be explicitly measured.[95] Because of such uncertainties, the USGS and other resource professionals have often underestimated the size of the resource base. Because of unanticipated technological progress, professionals have also typically overestimated production costs. The *AEO2001* projects that about 512 trillion cubic feet of the 1,281 trillion cubic feet estimated recoverable resources will be produced between 1999 and 2020 at prices less than $3.05 per million Btu in 1999 dollars. Like any commodity price, however, actual natural gas prices are likely to oscillate significantly around the trend line projected in *AEO2001* as a result of business cycles in the industry, unusual seasonal temperature variations, or other special circumstances like pipeline ruptures—events that have been experienced in the past 24 months.

Imports

Net natural gas imports are expected to grow in the forecast from 16 percent of total natural gas consumption in 1999 to 17 percent or 5.8 trillion cubic feet in 2020. Most of the increase is attributable to imports from Canada, primarily from western Canada, although some new natural gas is also expected from Sable Island in the offshore Atlantic. As in the United States, Canadian resources are adequate to sustain production for many years. The Canadian Gas Potential Committee indicates that there is an estimated 184 trillion cubic feet of marketable discovered and undiscovered conventional natural gas in the Western Canada Sedimentary Basin as of

Figure 30. Technically Recoverable U.S. Natural Gas Resources as of January 1, 1999



Sources: **Onshore Conventional:** U.S. Geological Survey. Offshore: Minerals Management Service and National Petroleum Council. **Unconventional:** Advanced Resources International. **Proved:** Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(98) (Washington, DC, December 1999).

[93]Gas Research Institute, *GRI 2001Baseline Projection* (February 2001), pp. HSM 112-113. GRI and the Institute of Gas Technology (IGT) have recently merged into a combined company, Gas Technology Institute (GTI).

[94]W. Fisher, "Energy and Environment into the Twenty First Century," *Environmental Geo Sciences*, Vol. 16, No. 4 (1999), pp. 191-199.

[95]To illustrate the conservative nature of the resource estimation process and the difficulty of producing accurate estimates, the USGS crude oil recoverable estimate in 1980 would have had the U.S. run out of oil by the early 1990s.

1993.[96] Similar estimates from the National Energy Board of Canada range from 153 to 224 trillion cubic feet as of the end of 1997, with 362 trillion cubic feet of additional resources in other areas in unconventional formations.[97]

Mexico also has a considerable natural gas resource base, but natural gas trade with Mexico is expected to consist primarily of exports. Conversion of power plants from heavy fuel oil to natural gas, in compliance with Mexico's environmental regulations, is expected to gain momentum, and it is unlikely that indigenous production can be increased enough to satisfy rising demand. LNG provides another source of natural gas imports; however, given the projected low natural gas prices in the mid-term trend in the lower 48 markets, LNG is expected to supply just 2 percent (0.77 trillion cubic feet) of U.S. natural gas consumption in 2020, up from 0.6 percent in 2000.

Transmission and Distribution

AEO2001 projects a 22-percent increase in interregional pipeline capacity[98] from 1999 through 2020 to satisfy the projected demand for natural gas. Pipeline capacity crossing the 12 regions used for analysis, including import/export capacity, is projected to increase from 125 billion cubic feet per day of design capacity in 1999 to about 152 billion cubic feet per day in 2020 (Figure 31). Much of the expansion is either already completed, under construction, or far enough along in the planning and approval process to be deemed likely to occur. The added capacity will provide access to new and expanding production areas—such as Canada, the deep offshore, and unconventional resources in the Rocky Mountain region—and will accommodate shifts in demand patterns, such as new demand for natural gas to replace electricity generation capacity lost as a result of nuclear retirements.

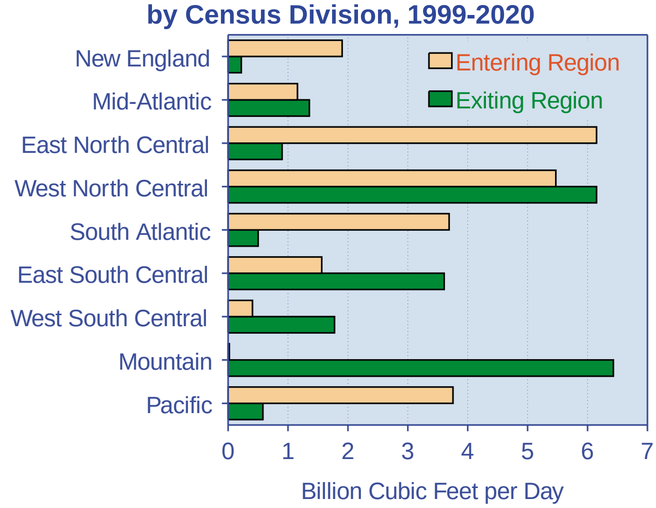
In recent history, the largest annual increase in pipeline capacity was 8.5 billion cubic feet per day in 1998. Although a large portion of the new capacity in 1998 came from the construction of several major new pipelines bringing natural gas onshore from deepwater production projects in the Gulf of Mexico, the expansion of Canadian import capacity via such projects as the Northern Border Pipeline expansion into the Midwest also added significantly to the total. In view of the historical and expected near-term annual increases in capacity, peaking at a potential 12.9 billion cubic feet per day in 2002, the ability to construct enough additional natural gas pipeline capacity to handle a total U.S. natural gas market of 35 trillion cubic feet in 2020 is not likely to be a problem.

In addition, Government policy supports an optimistic outlook for the post-2000 pipeline expansion forecast. FERC policy supports more rapid approval of expansion by the pipelines as long as they are willing to assume more risk rather than requiring firm contracts to be in place before approving an expansion.

Uncertainties in the Mid-Term Outlook for Natural Gas

Putting aside those factors that cause short-term volatility and those factors that are part of the normal business cycle for the natural gas industry, a number of sensitivity cases described in *AEO2001* examined the sensitivity of the natural gas market to alternative levels of resources, alternative rates of technological progress, and a higher growth rate for electricity demand (Table 3). Combinations of the worst of all assumptions (low resource availability, slow technology progress, and high electricity demand growth) and the best of all assumptions (high resource availability, rapid technology progress, and slow electricity demand growth) were not examined.

Figure 31. Projected Pipeline Capacity Expansion by Census Division, 1999-2020



Source: Energy Information Administration, *Annual Energy Outlook 2001*.

[96] Canadian Gas Potential Committee, *Natural Gas Potential in Canada* (Calgary: University of Calgary, 1997), p. 1.

[97] National Research Board, Canadian Energy Supply and Demand to 2025 (Calgary, 1999), p.43.

[98] Interregional pipelines transport natural gas across Census divisions.

Table 3. Natural Gas Sensitivity Analysis, Results for 2020

Forecast Scenario	Wellhead Natural Gas Price (1999 Dollars per Thousand Cubic Feet)	Natural Gas Consumption (Trillion Cubic Feet)	Cumulative Natural gas Production, 1999-2020 (Trillion Cubic Feet)
AEO2001 Reference Case	3.13	34.7	512
High Resource.	2.62	36.0	524
Low Resource	4.53	31.2	484
Rapid Technology	2.50	35.9	520
Slow Technology	4.23	32.6	500

Sources: AEO2001 National Energy Modeling System, runs AEO2001.D101600A, OGHRES.D111400A, OGLRES.D111400A, OGHTEC.D101600A, and OGLTEC.D101600A. For descriptions of the alternative scenarios, see Energy Information Administration, *Annual Energy Outlook 2001*, DOE/EIA-0383(2001) (Washington, DC, December 2000), Appendix G.

Appendix A

Memorandum from the Secretary of Energy

The Secretary of Energy
Washington, DC 20585

April 25, 2001

MEMORANDUM FOR LARRY PETTIS, ACTING ADMINISTRATOR
ENERGY INFORMATION ADMINISTRATION

FROM: SPENCER ABRAHAM Spencer Abraham

SUBJECT: Natural Gas Study

I have received numerous requests for information on natural gas markets from Governors, Members of Congress, and State legislators. Specifically, they have expressed concern about tight supplies, volatile prices, and regional price disparities. At the same time, the role of natural gas in the development of a National Energy Policy has become increasingly important due to its expanded use in the generation of electricity. Given these circumstances, I requested that the Energy Information Administration (EIA) conduct an independent study of North American natural gas markets. This memo is to serve as a formal record of that request.

The study should be in two parts: part one will be a short-term study to address the present need for timely information; and part two will address longer term issues. The short-term study should include:

1) trends in national demand, supply, transmission, and storage that have affected price;
2) circumstances leading to regionally higher prices in areas such as California and an analysis of regional price differences;
3) drilling activity in response to higher prices; and
4) EIA's short and long-term natural gas forecast, including imports from Canada, Mexico, and LNG.

The following topics should be considered in the long-term study:

1) evidence of supply response to drilling activity;
2) conditions required for additional LNG facilities to feed U.S. markets;
3) effect on supply and prices if limits to access on Federal lands are removed; and
4) areas in which further analysis or improved data are necessary to understand market trends.

The short-term study should be completed by the end of April 2001 and the long-term study should be completed by the end of October 2001. Your efforts in developing this independent analysis to shed light on natural gas markets and help guide us in our policy making efforts are much appreciated.

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