The Natural Gas Industry and Markets in 2003

This special report provides an overview of the supply and disposition of natural gas in 2003 and is intended as a supplement to the Energy Information Administration's (EIA) *Natural Gas Annual 2003 (NGA)*. Unless otherwise stated, all data and figures in this report are based on summary statistics published in the *NGA 2003*. Questions or comments on the content of this report should be directed to William Trapmann at William.trapmann@eia.doe.gov or (202) 586-6408.

Overview

The natural gas industry in 2003 experienced sustained high prices, supported at least in part by pressure on supplies as gas in storage was rebuilt from historic lows in the early part of the year. The national annual average natural gas wellhead price was $4.88 per thousand cubic feet (Mcf), which is the highest wellhead price (based on 2003 constant dollars) in the Energy Information Administration's historical data series dating to 1930. U.S. marketed production was virtually unchanged compared with the previous year at 19.9 trillion cubic feet (Tcf), despite the high prices and an increased number of drilling rigs employed in the commercial development of gas deposits. Imports of liquefied natural gas (LNG) mitigated supply declines, reaching a record high of 507 billion cubic feet (Bcf) as all four LNG import terminals in the lower 48 States were operational for the first time in two decades. However, net imports were less than levels the previous years for the second year in a row as imports declined from Canada. The supply strains and high prices resulted in a decline of 3 percent in deliveries to consumers.

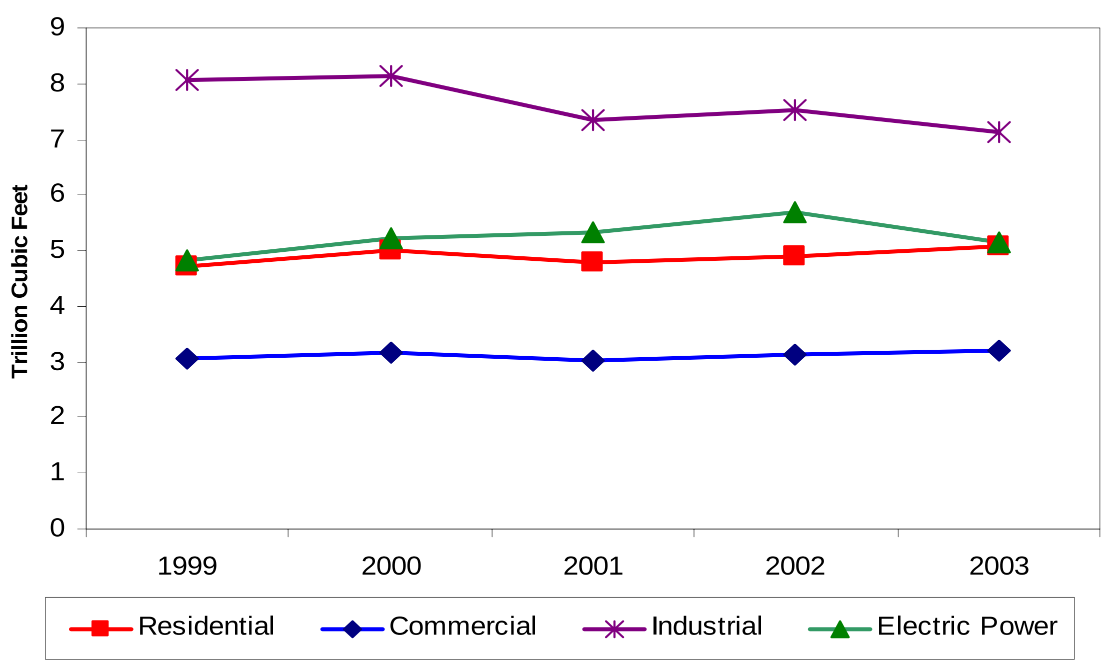
Increases in deliveries to residential and commercial customers were more than offset by declines in consumption by the more price-sensitive industrial and electric power sectors. Natural gas in storage reached adequate levels for the heating season (2003-2004), but not before the rising price of natural gas appeared to have a substantial impact on demand from the industry's largest consumers.

Natural Gas Consumption

Consumption Declined for Large End Users, While Demand Increased for Residential and Commercial End Users

Natural gas consumption fell to 22.4 Tcf from the near-record high of 23.0 Tcf in 2002, with a corresponding decline in the volume delivered to end users from 21.2 to 20.6 Tcf. Higher prices likely discouraged consumption. Residential and commercial consumption increased for the year, reflecting the influence of weather on these sectors (Figure 1). Temperatures were cooler than normal during the first quarter of the year, likely driving

Figure 1. Natural Gas Consumption By Sector, 1999-2003



the increased demand in these sectors as a result of increased space heating. The economy strengthened in 2003, yet industrial demand for natural gas declined as higher prices led price-sensitive customers to reduce consumption. After several years of large demand increases, consumption of natural gas for electric power production decreased in 2003. Despite the decline, the electric power sector remained the second-largest consumer of natural gas, reflecting the sustained growth in electric power use of gas over the past few years.

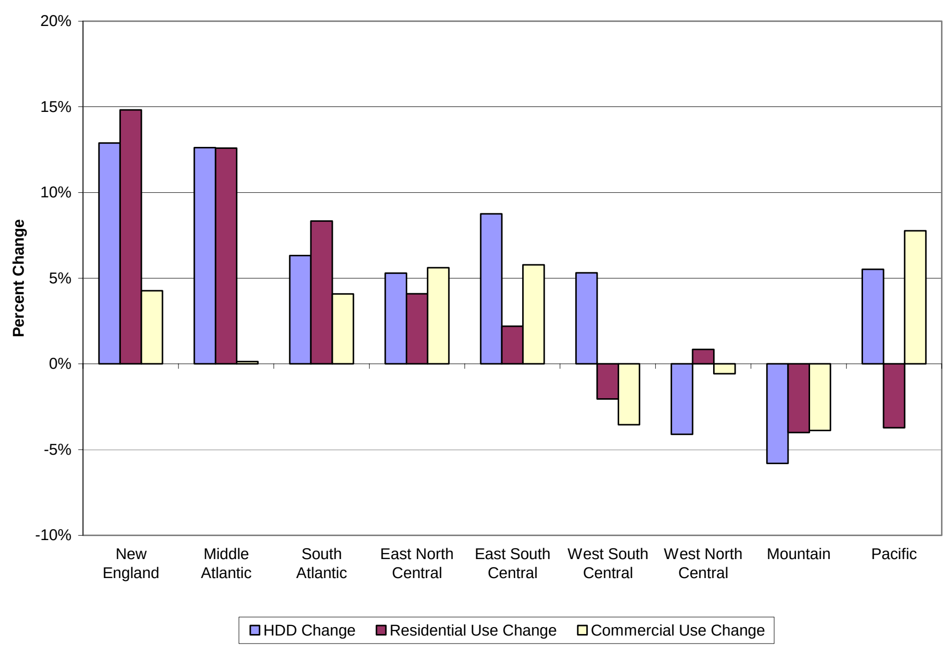
Some additional highlights related to the consumption data follow.

Space Heating Demand Increased Residential and Commercial Consumption

- **Total residential gas consumption for the United States in 2003 increased to 5,078 Bcf, or 3.9 percent over 2002.** A key factor in the increase was significantly lower temperatures than in the past year as measured by heating degree days (HDDs). Cumulative HDDs for the United States as a whole were 5.9 percent higher than levels in 2002. Residential gas consumption generally increased in the eastern half of the United States and declined in the western half, corresponding to HDD changes (Figure 2). The New England and Middle Atlantic regions had HDD percentage increases of more than 10 percent and the largest percentage gains in consumption.

- **Thirty-four states and the District of Columbia had increased residential consumption, with gains ranging up to 16.2 percent.** New York and New Jersey had the largest increases in volumes consumed, at 43.2 and 33.9 Bcf, respectively; New Jersey also had the largest percentage increase, at 16.2 percent. Sixteen states had decreased residential consumption, ranging from less than 1 percent to more than 8 percent of their 2002 levels. The state of California had the largest decrease in volumetric terms with a loss of 19.4 Bcf or 3.8 percent.

Figure 2. Percent Change in Heating Degree Days, Commercial and Residential Consumption by Census Region from 2002 to 2003



Source: **Heating Degree Days**: National Oceanic and Atmospheric Administration.

- **Total commercial consumption in 2003 increased by 72 Bcf over 2002, or 2.3 percent, to 3,217 Bcf.** Thirty-two states recorded increases, ranging from a low of 0.1 Bcf in South Dakota to a high of 24.5 Bcf in California. Delaware achieved the highest percentage increase in commercial consumption, at 12.8 percent. In the 19 states with decreased commercial consumption, three states (New York, Colorado, and Texas) accounted for more than 63 percent (37.8 Bcf) of the total decline.

- **California accounted for the largest share of residential consumption of the States, at 9.7 percent of the national total, while New York had the largest share of commercial consumption, at 10.5 percent.** New York achieved the largest share of national commercial consumption even though it also had the largest decrease in commercial consumption for 2003. As in years past, eight states (California, Illinois, New York, Michigan, Ohio, Pennsylvania, New Jersey, and Texas) account for over half of both total residential and total commercial consumption (55.0 and 52.5 percent, respectively).

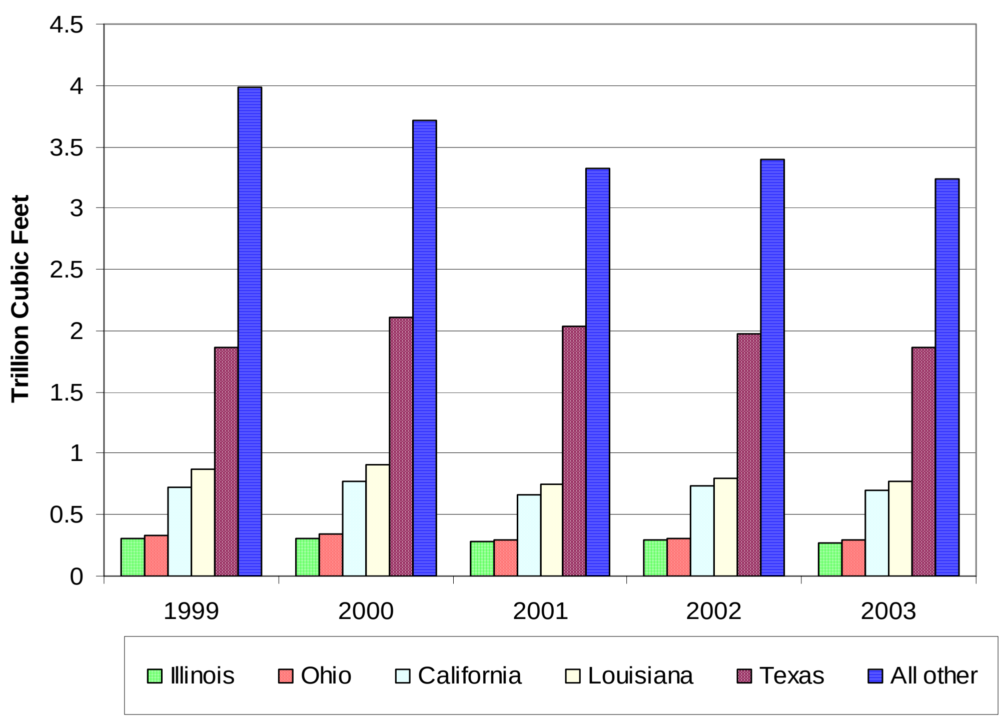
Consumption Fell by Almost 5 Percent in the Industrial Sector, the Largest Consuming Sector

- **Industrial consumption of natural gas declined by 4.9 percent, or 368 Bcf, from 2002 to 2003.** The decline was spread over 43 States. Texas represented 26 percent of the total industrial use of natural gas, and led all states with a 111-Bcf decline (Figure 3). This volume is equivalent to 30 percent of the U.S. net decline. Of the six states with increases, Oklahoma (16 Bcf) and Georgia (16 Bcf) had the greater volume gains, followed by Alaska, Iowa, Wyoming, and New Hampshire (with a total increase of less than 5 Bcf).

- **The volume of natural gas delivered for the account of others in the industrial sector decreased by 5 percent nationwide, as the number of transportation-only customers declined by less than 1 percent.** Transportation customers are those customers that purchase transportation services separately from commodity sales. Texas led both the sales and transportation volume declines. Texas also had the fourth-highest increase in the industrial price of all the States.

- **Nearly all sectors of industry that were large users of natural gas had reductions in industrial output.** Examining some specific industries that use natural gas can help to explain the loss in

Figure 3. Leading States for Consumption in the Industrial Sector, 1999-2003



consumption concurrent with an increase in total industrial output. Almost 10 percent of total industrial consumption of natural gas is for manufacture of ammonia for nitrogen fertilizer. The cost of natural gas makes up more than 80 percent of the end-use cost of fertilizer. While statistics on fertilizer production are not directly available, the increase in input cost contributed to a decline of 0.8 percent in output from the combined pesticides and fertilizer sector. About 6 Tcf of natural gas, which is more than 80 percent of the industrial use of natural gas, is in six sub-sectors of the industrial sector of the economy: chemicals, petroleum refining, primary metals, food and beverages, paper, and stone/clay/glass. Only the petroleum refining sub-sector increased industrial output from 2002 to 2003, as shown below.

Sub-sector of Industry (North American Industry Classification code)	% Change From 2002
Basic Chemicals (3251)	-1.4
Pesticides & Fertilizers (3253)	-0.8
Organic Chemicals (32511.9)	-0.3
Petroleum Refining (324.11)	+1.0
Primary Metals (331)	-1.9
Food & Beverage (311,312)	-3.6
Paper (22)	-1.1
Clay, Glass (3271,3272)	-0.7
Source: Board of Governors of the Federal Reserve System, Industrial Production and Capacity Utilization	

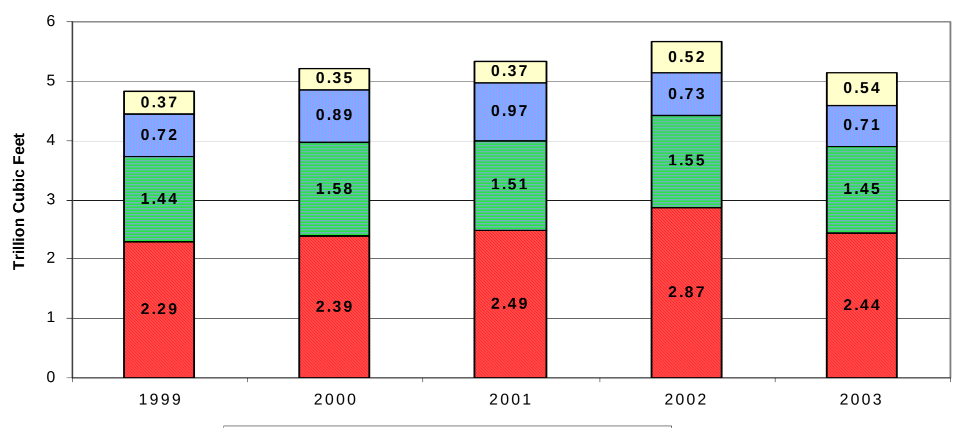
Growth Stalled for Consumption of Natural Gas by the Electric Power Sector

- **In 2003, natural gas consumed by the electric power sector for generation of electric power and useful thermal output decreased to 5.1 Tcf, reversing the upward trend that existed since 1996.** Gas consumption in the electric power sector grew by 18 percent between 1999 and 2002. However, owing largely to the increasing price of natural gas, consumption in the sector declined by 9.5 percent in 2003, as these large-volume consumers made the economic decision to use other fuels where possible as indicated by the declining share of natural gas used in power generation.

- **Although consumption in the electric power sector declined in 2003, the expansion of gas-fired capacity continued with approximately 54,184 megawatts fueled by natural gas added during the year.**[1] This is a smaller capacity addition compared with the addition of 66,816 megawatts in 2002. The capacity added during 2003 represents 96 percent of the electric generation capacity that came online during the year. States that added the most gas-fired generation capacity during 2003 were Texas (6,732 megawatts), Arizona (4,695 megawatts), and California (4,384 megawatts).

- **Three States accounted for over 52 percent of the natural gas consumed by the electric power sector (Figure 4).** The state that consumed the largest volume of natural gas in the electric power

Figure 4. Leading States for Natural Gas Use by the Electric Power Sector



Note: Data include consumption to generate useful thermal output.

[1] Energy Information Administration, *Electric Power Annual 2003*, (Washington D.C., November 2005), Table 2.6.

sector during 2003 was Texas, which consumed approximately 1.5 Tcf, or 28 percent of the 5.1 Tcf consumed by the sector. The next larger consuming states were California (705 Bcf) and Florida (535 Bcf). The largest year-to-year declines occurred in New York, where consumption dropped 105 Bcf from the 2002 level, followed by Texas (96 Bcf) and Louisiana (87 Bcf). Massachusetts showed the largest increase in 2003 (40 Bcf), followed by New Hampshire (28 Bcf) and Arizona (25 Bcf).

Natural Gas Wellhead Prices Reached Record Levels in Constant Dollars

- **End-use consumer prices increased in each sector of the natural gas market in 2003.** Prices climbed 21 percent in the residential sector, 25 percent in the commercial sector, 45 percent in the industrial sector, and 51 percent in the electric utilities sector. (Figure 5).[2]

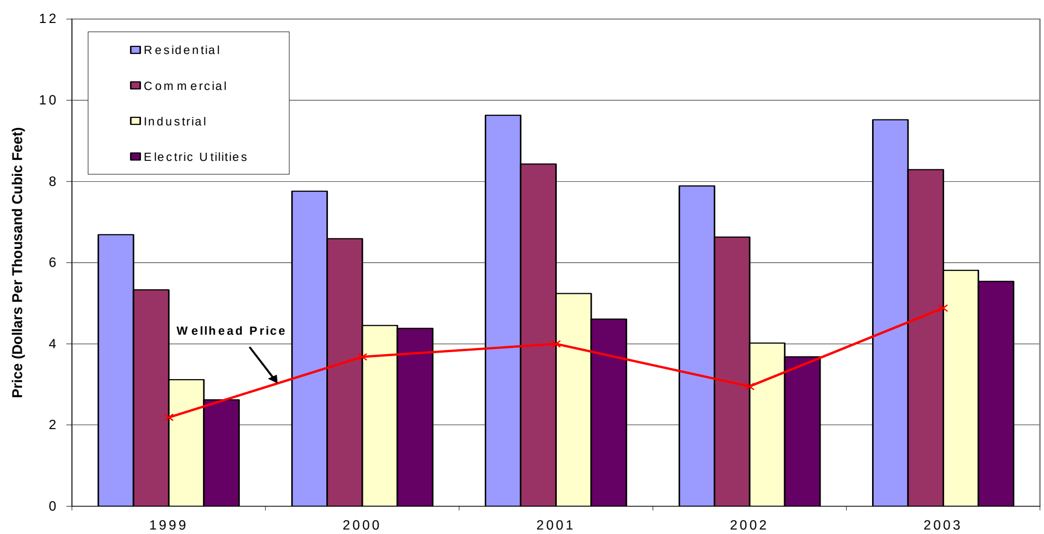
- **The national average natural gas wellhead price was $4.88 per Mcf in 2003, which was about 65 percent more than in 2002.** Measured in constant 2003 dollars, wellhead prices were the highest ever recorded, exceeding the previous record level of $4.21 in 1983 by nearly 16 percent.

- **Measured in constant dollars, sectoral prices in 2003 rose to their highest levels since 2001.** End-use price increases in 2003 fell short of matching the 2001 levels in the residential and commercial sectors while exceeding the 2001 levels of the electric power generation and industrial sectors. In the residential and commercial sectors, prices were about 5 percent below their 2001 levels, reaching the fourth- and fifth-highest levels since 1983, respectively. In the industrial and electric power sectors, prices reached their highest levels in the 7-year history of the data series, exceeding the prior record levels of 2001 by 7 and 16 percent, respectively.

- **Residential and commercial consumers continued to pay the highest prices for natural gas in 2003, at $9.52 and $8.29 per Mcf, respectively.** The residential price rose from $7.89 in 2002, an increase of $1.63 or 20.7 percent. The commercial price rose from $6.63, an increase of $1.66 or 25 percent. These changes reflect the limited options in service, the higher distribution costs to these sectors, and the high-quality services required during peak demand periods.

- **Industrial sector companies and electric utilities are large-volume customers with relatively high load factors, which enable them to take advantage of economies of scale in natural gas purchases.** Additionally, they are typically in a better position to elect whether to stay with their local distribution company (LDC) for sales, seek natural gas supplies from alternative sources, or

Figure 5. Prices by Major Consuming Sectors and at the Wellhead (1999-2003)



[2] While EIA combines gas use by nonutility power producers with that of electric utilities in volumes consumed by the electric power sector, prices reported in the *Natural Gas Annual 2003* are those paid by electric utilities only.

switch to other fuels. The average prices paid by the industrial and electric utility sectors in 2003 were $5.81 per Mcf and $5.54 per Mcf, respectively.

- **The average price for natural gas at the city gate increased by nearly 41 percent from 2002 to 2003, rising to $5.85 per Mcf—its third-highest level since 1984 as measured in constant dollars.** Citygate prices represent the total cost paid by gas distribution companies for gas received at the point where gas is physically transferred from a pipeline company or transmission system to the LDC. This price reflects all charges for the commodity, storage, and transportation associated with the LDC obtaining gas for sale to consumers.

Natural Gas Supply

The Combined Level of U.S. Natural Gas Production and Net Imports Decreased Slightly in 2003

Domestic dry marketed production and net imports decreased by a total of 86 Bcf in 2003, despite the strong economic incentives for increased supplies provided by high prices. In addition to the slight decrease to these current supplies, natural gas storage inventories were drawn down to historic lows in March of the year and greater net injections relative to previous years were needed to bring inventories to adequate levels before the heating season. Domestic production increased by more than 108 Bcf in 2003 compared with 2002 levels. Nonetheless, U.S. production remained well below 2001 levels (Figure 6). The increased domestic production came during a year in which there was a record level of drilling for gas prospects, which in turn resulted in a net increase in proved reserves. Net imports decreased by nearly 195 Bcf, despite LNG imports more than doubling LNG deliveries in 2002. Gross imports from Canada (the provider of 87 percent of gross imports during the year) were 7.8 percent less than during the previous year as Canadian production declined and Canadian consumption increased. In addition, total exports to all countries expanded by more than 175 Bcf. The average domestic wellhead price was $4.88 per Mcf, and prices for imported gas also were correspondingly higher.

Some additional highlights related to the supply data follow.

Despite Higher Drilling Activity, Natural Gas Production Increased Less than 1 Percent in 2003

- **U.S. dry natural gas production in 2003 increased 0.6 percent to 19 Tcf (Figure 7).** Louisiana, New Mexico, Oklahoma, Texas, Wyoming plus Federal

Figure 6. Natural Gas Supply, 1999-2003

offshore continue to account for the majority of total production, accounting for 79 percent of all production. Texas by itself accounted for 26 percent of production, with a total dry gas production of 4.9 Tcf. The next highest volume came from Federal offshore, which accounted for 23 percent. The increase in production reflects the impact of increased drilling in 2003. During the year, there were 22 percent more gas wells drilled than in 2002.

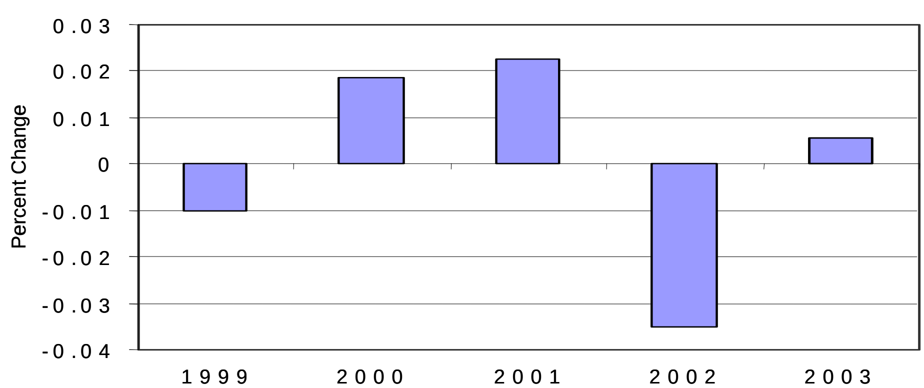
- **Production declines in the Gulf of Mexico and Michigan were offset by production increases in the Rocky Mountain States and Texas.** Texas production increased by 131 Bcf; Wyoming by 90 Bcf; and Colorado by 72 Bcf. One factor behind increases in certain states, such as Wyoming, was coalbed methane production. States in which production decreased the most were Michigan (37 Bcf), Kansas (32 Bcf), and New Mexico (29 Bcf). Production from the Federal waters of the Gulf of Mexico decreased by 105 Bcf.

- **U.S. natural gas proved reserves expanded for the fifth year in a row as reserves increased by 1 percent in 2003.** The majority of natural gas total discoveries were from extensions of existing conventional and unconventional gas fields. Reserve additions replaced 111 percent of 2003 gas production. Total discoveries of dry gas reserves were 19.3 Tcf in 2003, which was 36 percent more than the 10-year annual average and 8 percent more than in 2002. These relatively large additions likely resulted from an increase in completed gas wells during the year. Additionally, field extensions were 16.5 Tcf, which was 11 percent more than extensions in 2002 and 66 percent more than in the prior 10 years. Coalbed methane proved reserves were 18.7 Tcf, an increase of 1 percent from 2002. Coalbed methane reserves account for 10 percent of U.S. dry gas proved reserves.

Underground Storage Facilities Were Heavily Utilized in 2003 as Inventories Reached Lowest Levels on Record

- **Underground storage facilities were heavily utilized in 2003, as stocks fell to a record low at the end of the 2002-2003 heating season, then recorded a record-matching net increase by the start of the 2003-2004 heating season.** Working gas in storage began 2003 at 2,375 Bcf, which is about 1.4 percent below the average for January 1 over the previous 5 years (1998-2002). Then, the highest net withdrawals for January and February in EIA's 30-year monthly storage data base at 841 Bcf and 676 Bcf, respectively, were recorded in the first two months of the year. Working gas reached the record monthly low of 730 Bcf at the end of March 2003. The large stock draws early in the year were due at least in part to temperatures in January and February, as measured by gas-customer weighted HDDs, that were significantly colder than those of a year earlier. According to National Weather Service data, HDDs in January and February in the New England, Middle Atlantic, and East North Central Census divisions, which generally have the largest space-heating requirements, were between 24 and 39 percent greater than the previous year's, and ranged from approximately normal to 10 percent above normal. HDDs were also greater than normal for

Figure 7. Percentage Change in Dry Gas Production, 1999-2003

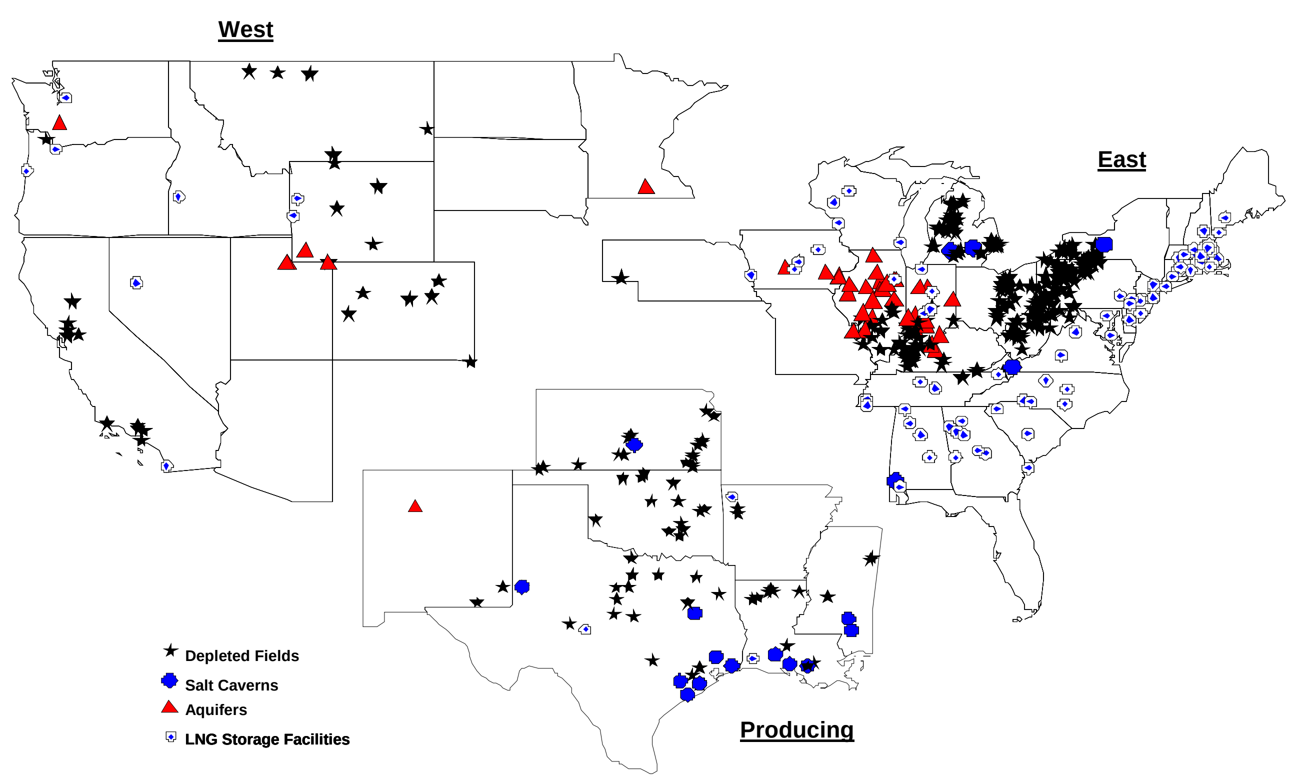


one or both months in the West North Central, South Atlantic, East South Central, and West South Central divisions. Withdrawals likely were spurred further by rapidly rising prices, which served as an indicator of high demand and provided strong economic incentives to withdraw gas from storage. By the end of 2003, stocks had recovered from their end of March low to 2,565 Bcf, a net gain of 193 Bcf compared with the end of 2002.

- **LNG storage utilization at peaking facilities increased in 2003.** Total LNG storage additions increased by 63 percent over 2002 additions, while total LNG withdrawals increased by 58 percent. As with underground storage activity, LNG storage additions exceeded withdrawals, yielding a net gain in LNG stocks in 2003. By volume, North Carolina had the largest increase in additions from 2002, at 4.1 Bcf. Massachusetts had the largest increase in LNG withdrawals by volume, at 9.1 Bcf more than in 2002. LNG storage facilities play a key role in meeting local demand peaks. Twenty nine states contain one or more LNG storage facilities, and 14 of these 29 states have only LNG storage facilities.

- **Total underground natural gas storage capacity stood at 8,206 Bcf as of the end of 2003.** The area with the highest concentration of storage facilities is the East (Figure 8). Of the individual States, Michigan has the largest share of total storage capacity in the lower 48 States, at almost 13 percent. The East region contained 258 of the 391 active storage facilities in 2003, for a total storage capacity of 4,781 Bcf in 2003, or about 58 percent of the lower 48 total. The Producing region, with 93 facilities, had 2,189 Bcf, or roughly 27 percent of total storage capacity. The West region had 40 active facilities, and, with total capacity of 1,235 Bcf, comprised 15 percent of total underground storage capacity. Depleted field storage dominated underground storage capability in terms of both numbers of facilities and proportion of total capacity, comprising more than 80 percent of each. The East region had the lion's share of depleted fields (216 of 318) and associated capacity (54 percent). It also had 37 of the 43 aquifer sites, comprising 94 percent of aquifer storage capacity. Conversely, the Producing region had 25 of 30 salt dome storage facilities, containing over 96 percent of the capacity of these high-deliverability storage facilities. The West region had no salt dome storage, 5 aquifer sites, and 35 depleted field sites.

Figure 8. Locations of Natural Gas Underground and LNG Storage Facilities



Pipeline Imports from Canada Declined, While LNG Imports Reached Historical High

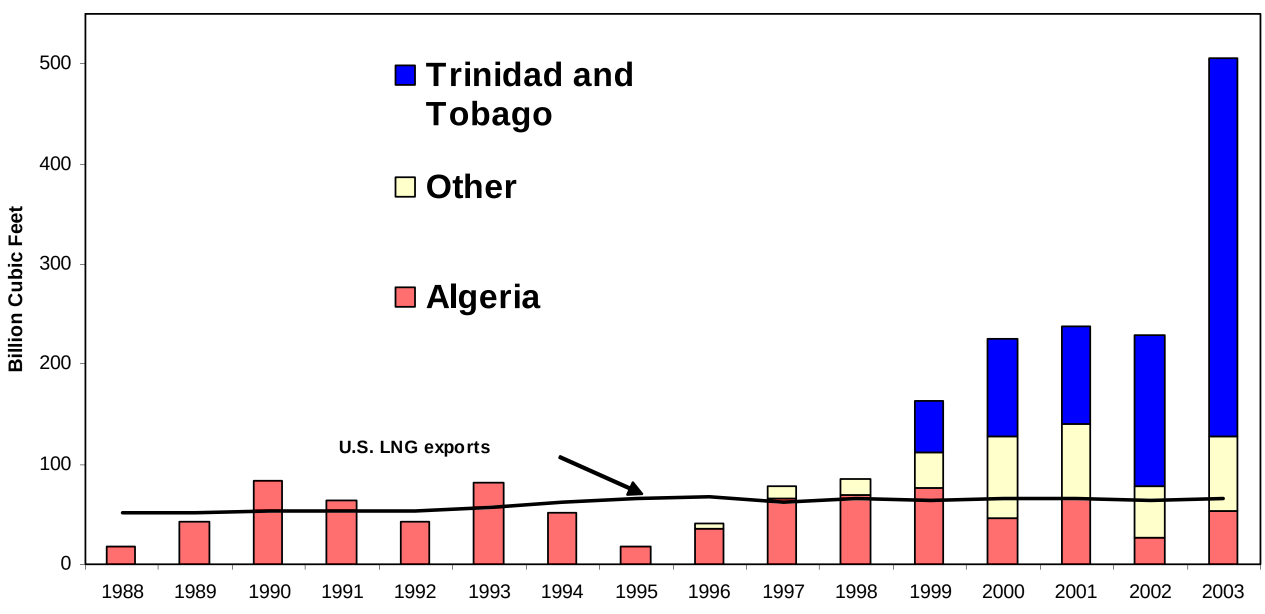
- **The volume of net imports fell for the second consecutive year, after 15 years of increases.** Net imports of natural gas to the United States declined to 3,305 Bcf, or 5.6 percent below the volume in 2002. On a gross basis, U.S. imports of Canadian gas decreased, and U.S. exports to Mexico and Canada increased. The volume of U.S. imports by pipeline declined in 2003 for the first time in 16 years. Gross pipeline imports from Canada decreased to 3,490 Bcf in 2003, which was a year-to-year decline of 7.8 percent. The decline appears to reflect the maturation of Canadian production in the Western Canadian Sedimentary Basin.

- **U.S. pipeline exports grew to a record 627 Bcf, which included a 70-Bcf increase in deliveries to Mexico for a total of 333 Bcf.** This is the largest volume of U.S. exports to Mexico ever reported and an increase of 26.5 percent from 2002. Recent Mexican demand growth primarily has come from the country's electric generation sector, which is relying increasingly on natural gas to meet incremental demand. Since 1998, U.S. pipeline exports to Mexico have grown by more than five times from 53 Bcf to 333 Bcf. Exports to Canada grew to 294 Bcf, or 55 percent over the volume in 2002, primarily as a result of greater utilization of the Vector Pipeline, which crosses the border at St. Clair, Michigan.

- **Imports of LNG, which account for a growing share of imports, rose to a record high of 507 Bcf in 2003 (Figure 9).** The previous annual record delivery volume was established in 1979, when the United States received 253 Bcf, all of which came from Algeria. Algeria served as virtually the sole supplier of LNG to the United States until the latter half of the 1990s, when shipments from other countries became more prevalent. The mix of supplies shifted greatly with the opening of the Atlantic LNG facility at Point Fortin, Trinidad and Tobago, in May 1999. While Algeria supplied just 53 Bcf in 2003, Trinidad and Tobago for the fourth consecutive year was the source country with the largest volume imports to the United States, delivering 378 Bcf (Figure 1). The United States also received LNG shipments from Nigeria (50 Bcf), Qatar (14 Bcf), Oman (9 Bcf), and Malaysia (3 Bcf).

- **In July 2003, Dominion's regasification facility in Cove Point, Maryland, received an LNG shipment from Trinidad and Tobago after two decades of dormancy from international trade.** Cove Point began commercial import operations in August, adding as much as 1 Bcf per day of peak send-out capacity into the pipeline grid and delivering a total of 66 Bcf during the year. Meanwhile, Tractebel's Distrigas facility in Everett, Massachusetts, completed an expansion in April 2003 that increased its send-out capacity by approximately 300 million cubic feet (MMcf) per day to 725 MMcf per day. In 2003, the Distrigas facility received 158 Bcf, while the Trunkline LNG facility in Lake Charles, Louisiana, and the Southern

Figure 9. LNG Imports and Exports, 1988-2003



LNG facility on Elba Island, Georgia received 238 Bcf and 44 Bcf, respectively.

Expansions on the Interstate Gas Grid contributed to increased gas movements in 2003

- **In 2003, 21 of the lower 48 States and the District of Columbia were totally dependent upon the interstate pipeline network for supply, while 10 of the States produced more gas than they consumed and used the interstate network to export their excess to other parts of the lower 48 States (Figure 10).** Overall, 33 States showed a growth in both interstate receipts and deliveries, while only 16 show a drop in both. Several new pipelines and pipeline expansions, in addition to local growth in gas demand, contributed to this increase in interstate movements.

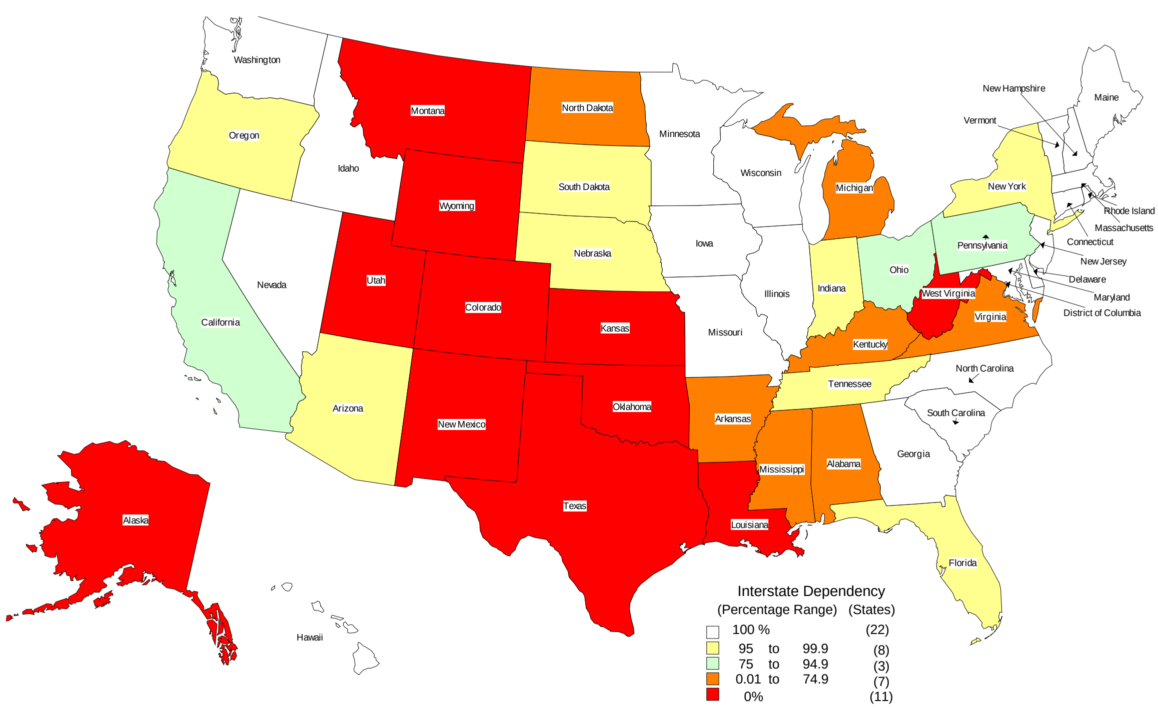
- **A doubling of pipeline capacity from 965 MMcf per day to 1,865 MMcf per day on the Kern River Transmission pipeline, between Wyoming and California, was completed and placed in service in May 2003.** Subsequently, net flow along its route increased more than 60 percent through the end of the year. In particular, the Kern River expansion boosted deliveries of natural gas to California, from Nevada, from 240 Bcf in 2002 to 402 Bcf in 2003, a 68-percent increase.

- **Flows of natural gas between Illinois and Wisconsin increased by 13 percent.** The new Guardian Pipeline, with 750 MMcf/d of capacity, finished its first full year of service. Guardian, completed in November 2002, provides gas shippers using the Chicago hub with the capability to deliver Canadian and Rocky Mountain gas supplies to northern Illinois and southern Wisconsin.

- **Expansion of the El Paso Natural Gas Pipeline system between Texas and California (Line 2000 project) in late 2002 increased its capacity by 230 MMcf per day.** This increased capacity contributed to greater interstate flows along the El Paso South System into Arizona, to supply several new gas-fired power plants built in the State, and provided additional flows into southern California, most of which went to support gas exports to Mexico via the North Baja Pipeline (completed in September 2002).

- **The 8-percent fall in gas imports from Canada between 2002 and 2003 substantially decreased**

Figure 10. Level to Which States Depended on the Interstate Pipeline Network in 2003



interstate flows along several major gas pipeline transportation corridors. In the western United States, interstate flows between northern Idaho and northern California fell an average of 16 percent from 2002 levels. In the eastern United States, flows from Canada to New York and Maine fell by 4 percent or 36 Bcf, although gas flows into New Hampshire and Vermont did increase by 3 Bcf. Interstate flows along the corridor between North Dakota/Montana/Minnesota and Midwestern markets decreased as well, but could have fallen even further were it not for a 10-percent increase in the use of the Alliance Pipeline system (North Dakota) by natural gas shippers delivering "wet" gas for processing in Illinois.

- **For the first time in several years, interstate pipeline flows increased substantially between southeast Texas, the Gulf States of Louisiana, Mississippi, and Alabama, and Midwestern markets.** The state-to-state increases averaged about 9 percent along the corridor, even though overall gas consumption decreased in all but one of the six Midwest States between 2002 and 2003. A large portion of this Southwestern increase in supply appears to have compensated for the large increase in gas flows (exports) to Canada, through Michigan, that were up 25 percent over 2002 levels.