The Natural Gas Industry and Markets in 2004

This special report provides an overview of the supply and disposition of natural gas in 2004 and is intended as a supplement to the Energy Information Administration's (EIA) *Natural Gas Annual 2004* (*NGA 2004*). Unless otherwise stated, all annual data and figures in this report are based on summary statistics published in the *NGA 2004*, and monthly data are based on data published in the *Natural Gas Monthly* (December 2005). Questions or comments on the content of this report should be directed to Jose Villar at Jose.Villar@eia.doe.gov or (202) 586-9613.

Overview

The natural gas industry in 2004 experienced sustained high prices, driven in part by pressure on supplies from a lack of production growth and the infrastructure damage wrought by Hurricane Ivan. Increased demand for natural gas in the industrial and electric generation sectors further exacerbated the tight natural gas market. The national annual average natural gas wellhead price was $5.46 per thousand cubic feet (Mcf), the highest wellhead price (based on 2004 constant dollars) in at least 50 years. Natural gas imports responded to the higher wellhead prices in 2004. Natural gas imports grew by about 8 percent in 2004 as receipts of both liquefied natural gas (LNG) and pipeline imports from Canada rose, resulting in the first increase in natural gas net imports since 2001. Recorded U.S. marketed production was 19.7 trillion cubic feet (Tcf) compared with the previous year's level of 20.0 Tcf. However, the 2004 marketed production reported in the *Natural Gas Annual 2004* was reduced by shut-ins resulting from Hurricane Ivan and an adjustment to Texas data. In 2005, EIA began collecting production data directly from operators on the new EIA-914 production survey. Subsequent analysis of these data indicated that prior Texas State and EIA data likely overstated natural gas production by about 5 percent in Texas. (See the discussion of domestic production in the Natural Gas Supply section for more detail.)

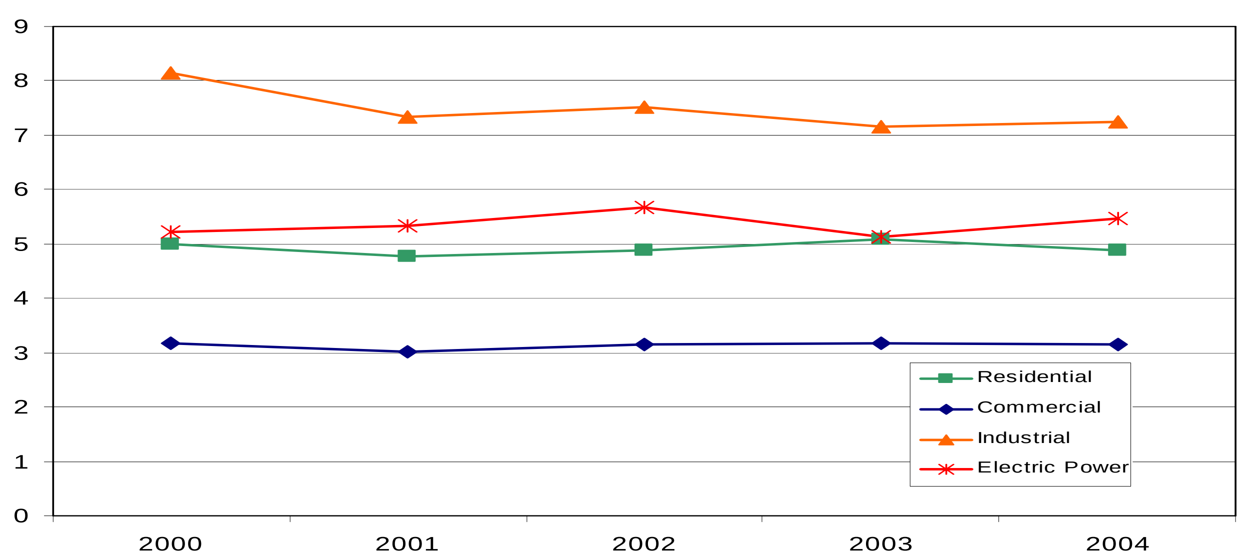
Despite high prices and supply strains that included weak production and increased exports, natural gas consumption increased by 0.7 percent. Decreases in deliveries to residential and commercial customers were more than offset by increases in consumption by the industrial and electric power sectors, spurred by the continued economic recovery in 2004. The rising cost of natural gas had a substantial impact on prices for natural gas to all sectors. Storage entering the heating season of 2004-2005 reached its highest level in 13 years.

Natural Gas Consumption

Total Natural Gas Consumed by End Users Increased in 2004

Total natural gas consumption in 2004 increased by less than 1 percent from the previous year's level to 22.4 Tcf. Higher natural gas prices likely discouraged further gains in consumption in 2004. Residential and commercial consumption decreased in 2004 (Figure 1), reflecting higher prices and reduced heating demand for

Figure 1. Natural Gas Consumption by Sector, 2000-2004 (Trillion Cubic Feet)



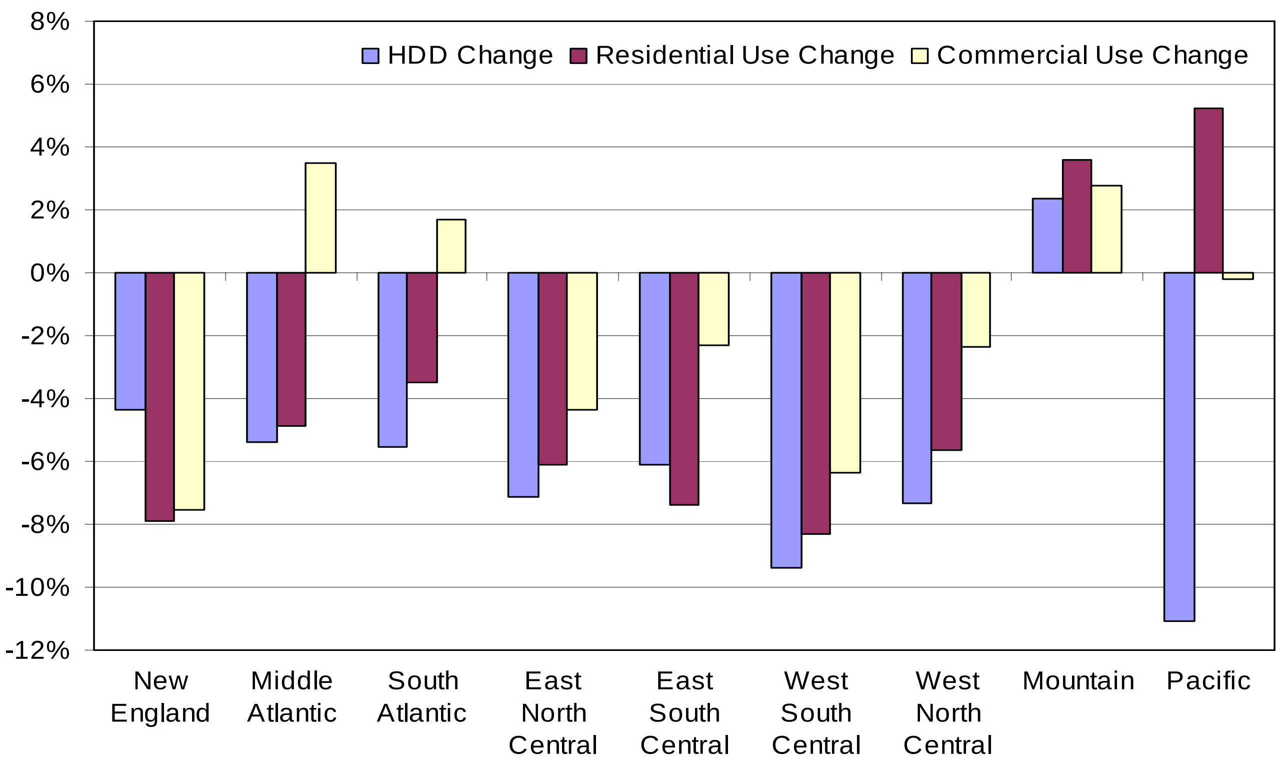
natural gas owing to warmer-than-normal temperatures during the winter months (January–March, November, and December). Increased consumption by large end users in the industrial and electric power sectors more than offset the declines in the residential and commercial sectors. In particular, natural gas consumption for electric power generation surged by more than 6 percent, after a decline in 2003, and reached a level second only to the record high in 2002 (Figure 1). This robust growth during a period of increasing prices underscores the growing importance of the electric power sector as a consumer of natural gas as the effects of recent natural-gas-fired electric generation capacity additions become more apparent. Industrial consumption of natural gas increased slightly in 2004, owing to continued strength in the economy. This increased consumption contrasts with the decreased consumption reported in 2003 when the market shed its more price-sensitive customers.

Residential and Commercial Consumption of Natural Gas Declined in 2004

- **Decreased demand for space heating contributed to decreased residential and commercial natural gas consumption in 2004.** Consumption in the residential and commercial sectors is highly seasonal and responsive to changes in weather. Residential natural gas usage fell from 5.1 Tcf in 2003 to 4.9 Tcf in 2004, a decline of 3.8 percent. Commercial usage fell from 3.2 Tcf in 2003 to 3.1 Tcf, a decline of 1.2 percent.

- **Forty States and the District of Columbia had decreased residential consumption, with some declines of more than 10 percent relative to 2003 levels.** Illinois had the largest decrease in volume consumed, 30 billion cubic feet (Bcf), while New Hampshire had the largest percentage decrease, 10.8 percent. Significantly warmer weather in 2004 than in 2003 likely contributed to most of the decline in residential and commercial usage. Temperatures were 5.5 percent warmer in 2004 than in the preceding year, as measured by heating-degree-days. Heating-degree-day decreases occurred in all regions of the contiguous United States except for the Mountain States (Figure 2). Despite recording the largest heating-degree-day decrease of 11.1 percent, the Pacific States had the largest increase in natural gas consumption, nearly 6 percent. This can be attributed at least in part to an increased number of industrial customers in the Pacific States.

Figure 2. Percent Change in Heating Degree Days and Commercial and Residential Consumption by Census Division from 2003 to 2004



Source: Heating Degree Day Data derived by the Natural Gas Division based on Gas Home Heating Customer Weighted data from the National Oceanic and Atmospheric Administration available at
ftp://ftpprd.ncep.noaa.gov/pub/cpc/htdocs/products/analysis_monitoring/cdus/degree_days/archives/.

- **California accounted for the largest share of residential consumption of the States, at 10.8 percent of the national total, while New York had the largest share of commercial consumption, at 11.4 percent.** As in years past, eight States (New York, California, Illinois, Texas, Michigan, Ohio, New Jersey, and Pennsylvania) accounted for more than half of total residential and commercial consumption. This group accounted for about 53 percent of national commercial consumption in 2004 and almost 56 percent of residential consumption.

- **Thirty States had decreased commercial consumption, with decreases up to more than 11 percent of 2003 levels.** Texas had the largest decrease in volumes consumed, with a drop of 17 Bcf, while Montana had the largest percentage decrease at 11.3 percent. Texas, Michigan, and Ohio ranked first through third, respectively, among States with decreased commercial consumption. The total decrease for States with reduced consumption was 89 Bcf. Texas, Michigan, and Ohio accounted for 42 percent of this decline.

Consumption of Natural Gas in the Industrial Sector Increased Slightly Despite Rising Prices

- **Industrial consumption of natural gas increased slightly in 2004.** Industrial usage was relatively flat, edging up to 7.3 Tcf in 2004 from 7.2 Tcf in 2003, an increase of 1.4 percent. Strong manufacturing growth in 2004 likely contributed to the gain in industrial natural gas consumption. According to the Federal Reserve, total manufacturing output for the United States for 2004 increased 5.1 percent over the 2003 level. Chemical producers that use natural gas intensively as a feedstock increased production by 4.2 percent in 2004 (Table 1).

- **Thirty States had increased industrial consumption, with increases ranging to nearly 36 percent of 2003 levels.** California had the largest increase in volume consumed with a gain of 56.7 Bcf, while Arizona had the largest percentage increase, at 35.6 percent. California, Louisiana, and Indiana ranked first through third, respectively, among States with increased industrial consumption. The total increase for States with increased consumption was 208.9 Bcf. California, Louisiana, and Indiana accounted for about 57 percent of this increase.

Table 1. Percent of Natural Gas Use in Manufacturing, 2002, and Manufacturing Production Changes, 2004

Industry	Total Manufacturing Percent	Percent of Natural Gas Used for Fuel (2002) a/	Percent of Natural Gas Used for Non-Fuel (2002) a/	Manufacturing Production Percent Change (2004) b/
Iron and Steel	7.97	7.42	0.55	3.3
Chemical, incl Petrochemical	44.01	32.97	11.04	4.2
Non-ferrous Metals	4.59	4.52	0.07	3.2
Non-metallic Minerals	7.49	7.47	0.02	4.4
Transport Equipment	3.59	3.58	0.01	2.9
Machinery	7.27	7.29	-0.02	11.9
Food, Beverage, and Tobacco	11.14	11.01	0.13	3.9
Pulp.Paper and Printing	9.71	9.71	0.00	3.3
Wood & Wood Products	1.47	1.47	0.00	0.8
Textile and Leather	2.21	2.18	0.03	-4.6
Not elsewhere specified	0.55	0.55	0.00	4.3
Total Manufacturing	100	88.17	11.83	--
Overall Manufacturing	--	--	--	5.1

a/ Percentages based on 2002 *Manufacturing Energy Consumption Survey* (MECS) data, Energy Information Administration, Office of Energy Markets and End Use.
b/ Source: Federal Reserve Statistical Release, *Industrial Production and Capacity Utilization,* (September 14, 2005), p. 7.

- **The eight States with the largest industrial natural gas consumption, in order, were Texas, California, Louisiana, Ohio, Illinois, Indiana, Michigan, and Pennsylvania.** These States accounted for almost 65 percent of national industrial consumption. The largest consuming State, Texas, accounted for 25 percent of the national total. Even though Texas was the highest-ranked State in terms of total 2004 consumption, it also had the largest decrease in industrial consumption of all the States, with a decline of slightly more than 52 Bcf.

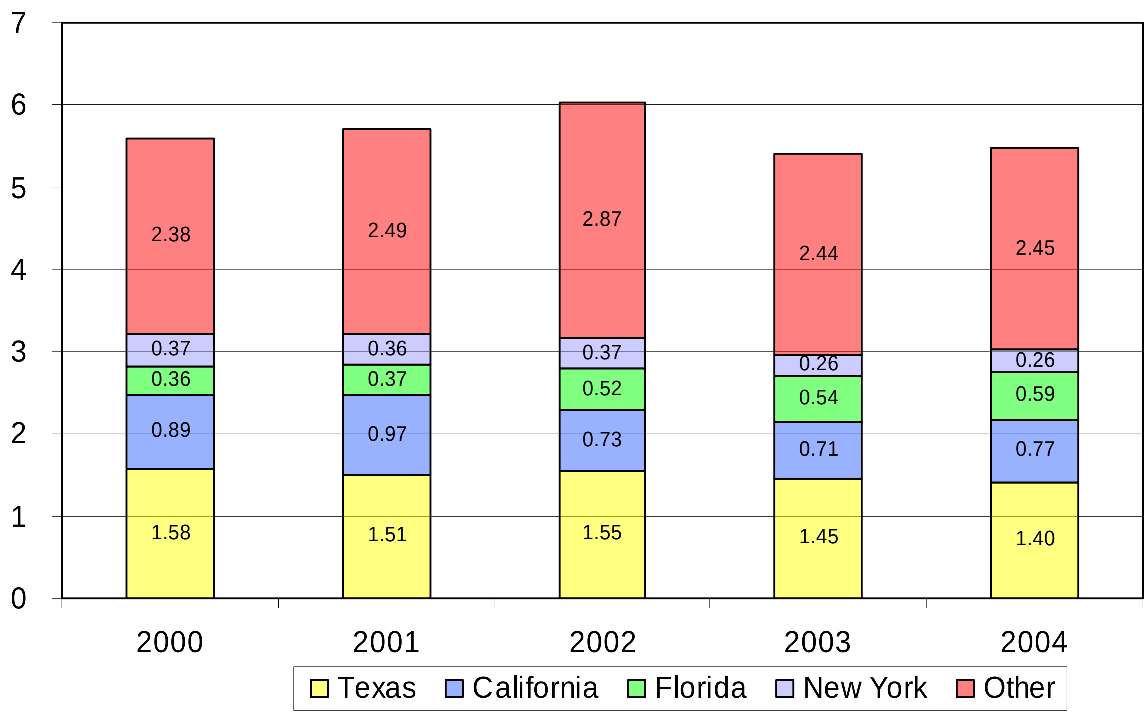
Growth of Natural Gas Consumption in the Electric Power[1] Sector Recovered in 2004

- **In 2004, natural gas consumed for generation of electric power increased to 5.5 Tcf, a 6.4-percent increase compared with 2003.** Natural gas consumption for electric power generation was 328 Bcf more than in 2003, but the increase was not large enough to offset the significant decline in 2003. The electric power sector is second in volumes of natural gas consumed only to the industrial sector accounting for more than 26 percent of natural gas delivered to consumers. This compares with 2002 and 2003, when the electric power sector accounted for 27 and 25 percent of natural gas delivered to consumers, respectively.

- **The expansion of natural-gas-fired generation capacity continued with approximately 18,305 megawatts fueled by natural gas added during the year.[2]** This is a considerable decrease from the capacity addition of 45,381 megawatts in 2003, but represents 72 percent of the electric generation capacity that came online during the year. An additional 5,565 megawatts of dual-fired natural gas and petroleum unit capacity (most of which utilize natural gas as their primary energy source) were added during the year. States that added the most natural-gas-fired generation capacity during 2004 were Pennsylvania (2,835 megawatts), Texas (2,426 megawatts), and Florida (1,518 megawatts).[3]

- **Four States accounted for more than 55 percent of the natural gas consumed by the electric power sector** (Figure 3). The State that consumed the largest volume of natural gas in the electric power sector

Figure 3. Leading States for Natural Gas Use by the Electric Power Sector, 2000-2004 (Trillion Cubic Feet)



[1] The electric power sector is an energy-consuming sector that consists of electricity only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public--i.e., North American Industry Classification System 22 plants.

[2] Energy Information Administration, *Electric Power Annual 2003* (December 2004, Washington, DC), Table 2.6 and *Electric Power Annual 2004* (November 2005, Washington, DC), Table 2.6.

[3] Energy Information Administration, *Electric Power Annual 2004* (November 2005, Washington, DC), Table 2.2.

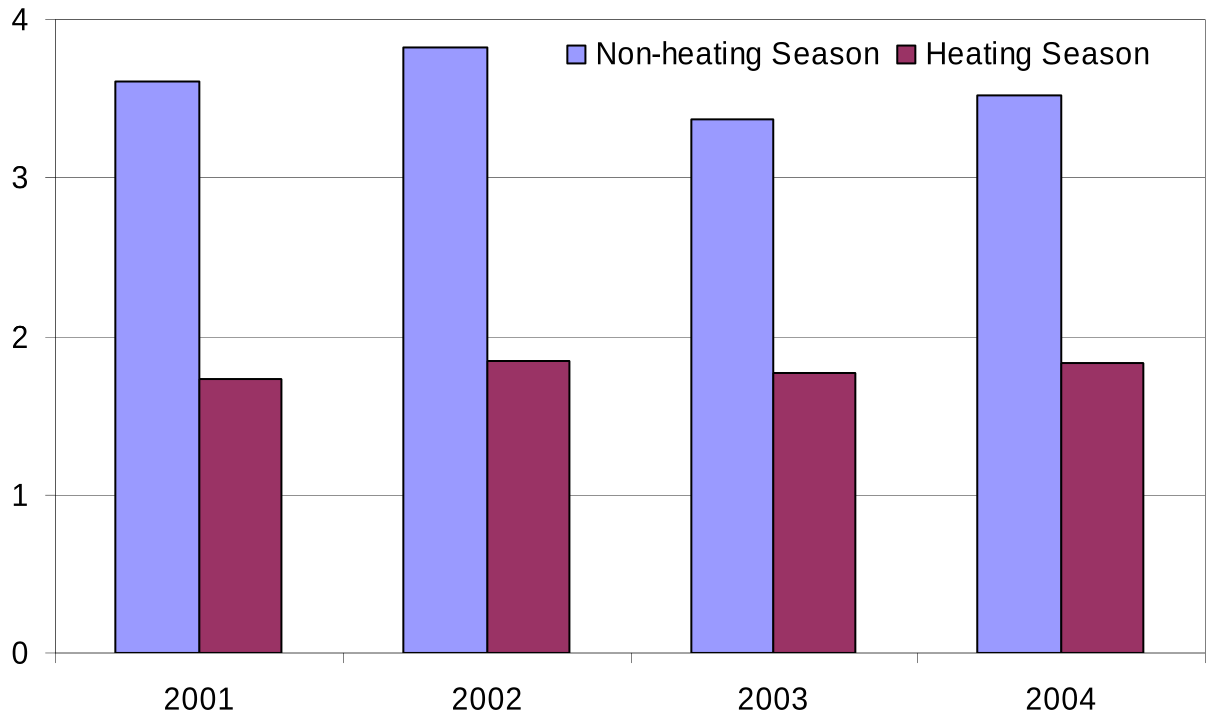
during 2004 was Texas, which consumed approximately 1.4 Tcf, or 25.5 percent of the 5.5 Tcf consumed by the entire sector. The next largest consuming States were California (771 Bcf), Florida (586 Bcf), and New York (259 Bcf). The largest year-to-year changes in consumption occurred in Arizona and California, where consumption increased by 70 and 65 Bcf, respectively, compared with the 2003 level, as warmer-than-normal summer temperatures in those States increased demand for air-conditioning. In Florida, where several new natural-gas-fired units came online during the year, consumption increased by 51 Bcf to 586 Bcf. Texas showed the largest decrease in 2004 (50 Bcf), followed by Arkansas (16 Bcf).

- **Natural gas consumption for electric power generation during the winter months of 2004 increased compared with the previous 4 years** (Figure 4)**.** While natural gas consumption for generation of electric power continues to be the highest during the summer months, consumption during the winter months of 2004 (January–March, November, and December) increased by up to 12 percent compared with 2003, indicating an increased usage of electric power as a heating fuel. In addition, the U.S. consumption of natural gas for electric power sector during winter months as a percentage of total deliveries for electric power sector has increased steadily since 2001, reaching 35 percent in 2004, compared with 32, 33, and 34 percent in 2001, 2002, and 2003, respectively.

Natural Gas End-Use Prices Reached Record Levels for the Second Year in a Row

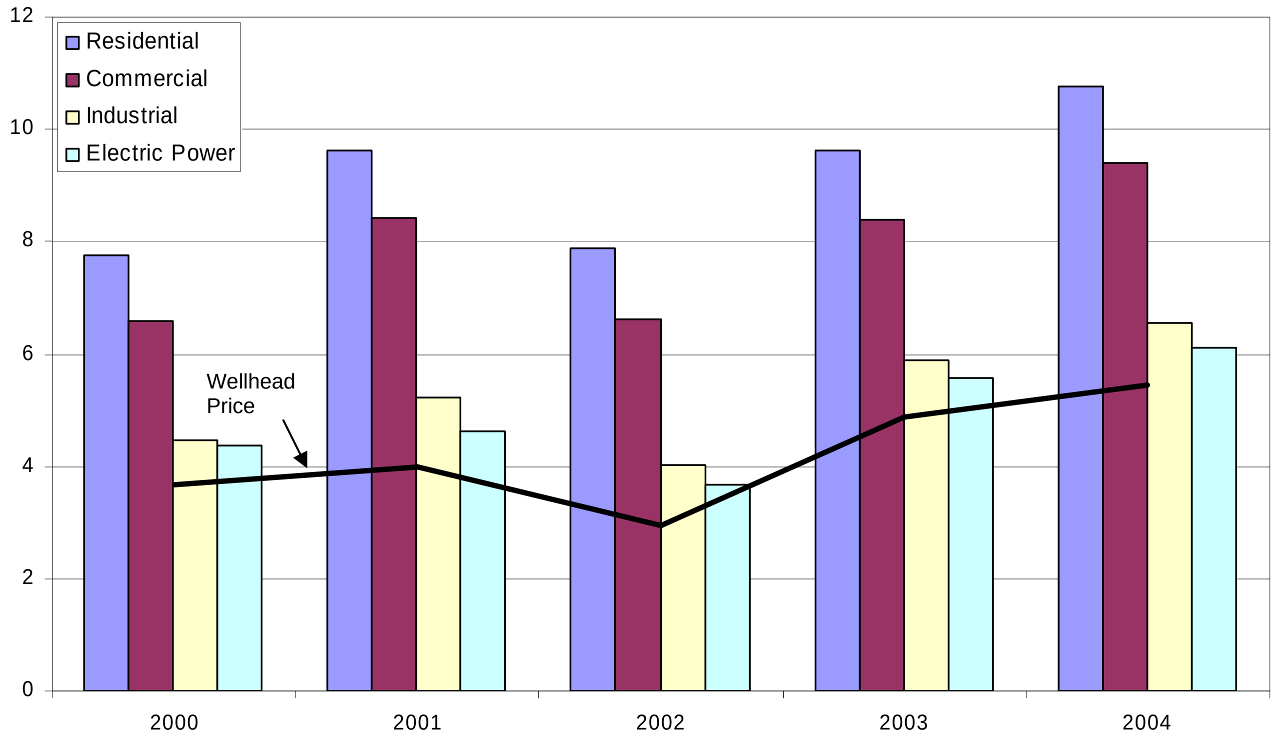
- **Natural gas prices increased in each end-use consuming sector of the natural gas market in 2004.** Prices climbed about 12 percent in the residential, commercial, and industrial sectors. The electric power end-use sector also posted an increase, with prices 10 percent higher than last year's levels, reflecting a 12-percent increase in wellhead prices (Figure 5).

Figure 4. Seasonal Natural Gas Consumption for Electric Power Generation, 2001-2004 (Trillion Cubic Feet)



Note: Heating season includes January–March, November, and December. Non-heating season includes the months of April through October.

Figure 5. Natural Gas Prices by Major Consuming Sectors and at the Wellhead, 2000-2004 (Dollars per Thousand Cubic Feet)



- **The national average natural gas wellhead price was $5.46 per Mcf in 2004, which was about 12 percent more than in 2003.** Measured in constant 2004 dollars, wellhead prices were the highest ever recorded, exceeding the record level posted in 2003 by 45 cents per Mcf, or about 9 percent. In constant 2004 dollars, the highest annual wellhead price ever recorded prior to 2003 was $4.33 per Mcf in 1983.

- **Sectoral prices reached record highs in 2004 (measured in constant 2004 dollars).** Adjusted for inflation, prices in the end-use sectors rose between 7 and 10 percent in 2004, while prices at the wellhead rose about 9 percent. This led to an increase in the differential between end-use and wellhead prices in all sectors except for the electric generation sector. Natural gas prices in the residential sector were the highest on record, exceeding the previous high of $10.26 per Mcf ($9.63 per Mcf in nominal terms) set in 2001. Meanwhile, prices in the commercial, industrial, and electric power sectors also set new record highs.

- **Residential and commercial consumers continued to pay the highest prices for natural gas in 2004, at $10.75 and $9.41 per Mcf, respectively.** The residential price rose from $9.63 in 2003, an increase of $1.12 or 11.6 percent. The commercial price rose from $8.40, an increase of $1.01 or 12.0 percent. Despite colder weather during the heating season months, increased prices discouraged consumption, leading to reduced volumes consumed in these sectors. Furthermore, increased electric power generation demand for natural gas likely increased the acquisition cost of natural gas in storage for the heating-load customers during the refill season.

- **Natural gas prices remained below $7 per Mcf both for on-system sales, which account for 23 percent of natural gas sold to industrial companies, and for sales to electric power generators.[4]** The average prices paid by the industrial and electric power sectors were $6.56 and $6.11 per Mcf, respectively. These large-volume customers have relatively high load factors, which enable them to take advantage of economies of scale

[4] Prices for the industrial sector are often associated with relatively small volumes of the total natural gas delivered. This occurs because they are reported by those that deliver natural gas and not by either the gas resellers or by the consumers. Prices of natural gas delivered to the electric power sector are derived from data reported on Form FERC-423, "Monthly Report of Cost and Quality of Fuels for Electric Power Plants," and Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report."

in natural gas purchases. Increasing demand in both sectors contributed to the price increases of 2004. However, the relative elasticity of demand of these large-volume customers (compared with residential and commercial consumers) ameliorated the relative magnitude of the price increases.

- **The average price for natural gas at the citygate increased by nearly 14 percent from 2003 to 2004, rising to $6.65 per Mcf.** At $6.65 per Mcf, the citygate price was at the highest level since 1984, when the price was $6.37 per Mcf, in constant 2004 dollars. Citygate prices represent the total cost paid by natural gas distribution companies for gas received at the point where natural gas is physically transferred from a pipeline company or transmission system to the local distribution company (LDC). This price reflects all charges for the commodity, storage, and transportation associated with the LDC obtaining natural gas for sale to consumers.

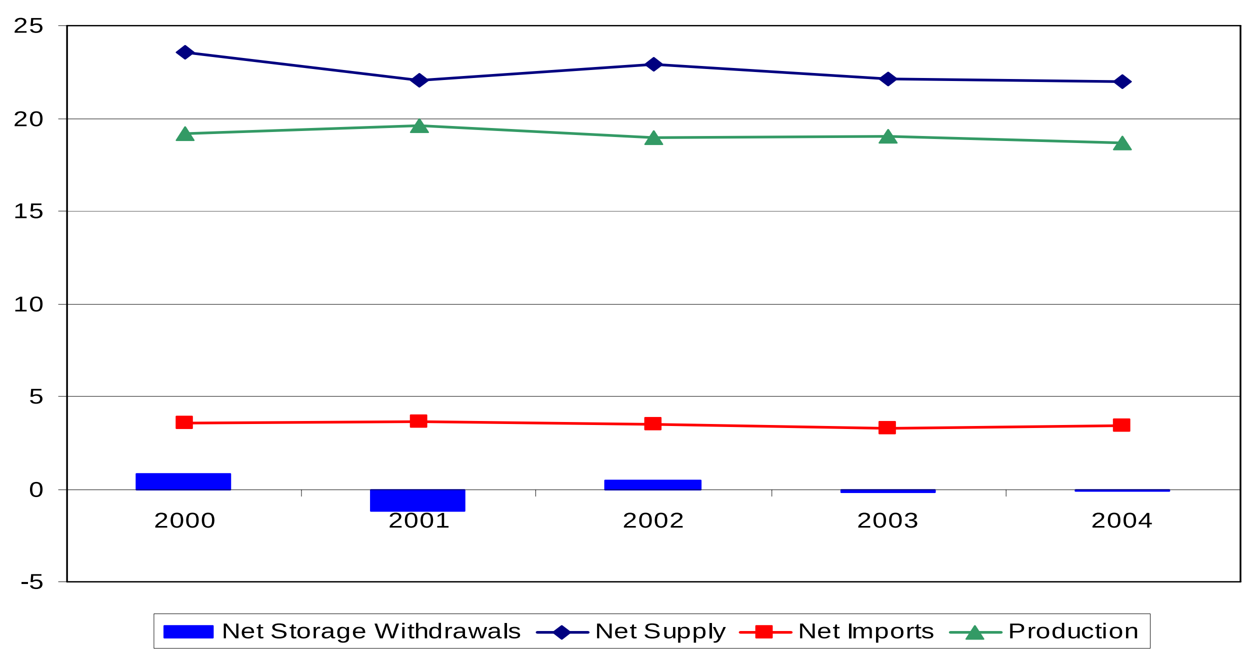
Natural Gas Supply

Natural Gas Supply Response to the High Prices in 2004 Was Limited

Recorded domestic marketed production in 2004 was 1.5 percent lower than in 2003, in part because of hurricane-related shut-ins in the Gulf of Mexico (Figure 6). Another key factor contributing to the shift in recorded production was a one-time adjustment applied to the 2004 production data (see production section below). Net imports increased by more than 4 percent in 2004, offsetting the difference in recorded production between years so current supplies slightly increased in 2004 despite the one-time data adjustment.

In 2004, drilling for natural gas prospects reached a record level for the second year in a row, showing a clear response to the high level of natural gas prices. The lack of a stronger production response to the increased natural gas drilling likely reflects the maturation of the remaining natural gas resource base, which results in declining returns to drilling activity. The average domestic wellhead price increased about 12 percent to $5.46 per Mcf, and prices for imported natural gas also increased by about 12 percent to $5.81 per Mcf. Domestic wellhead prices and import prices generally have been highly correlated.

Figure 6. Natural Gas Supply, 2000–2004 (Trillion Cubic Feet)



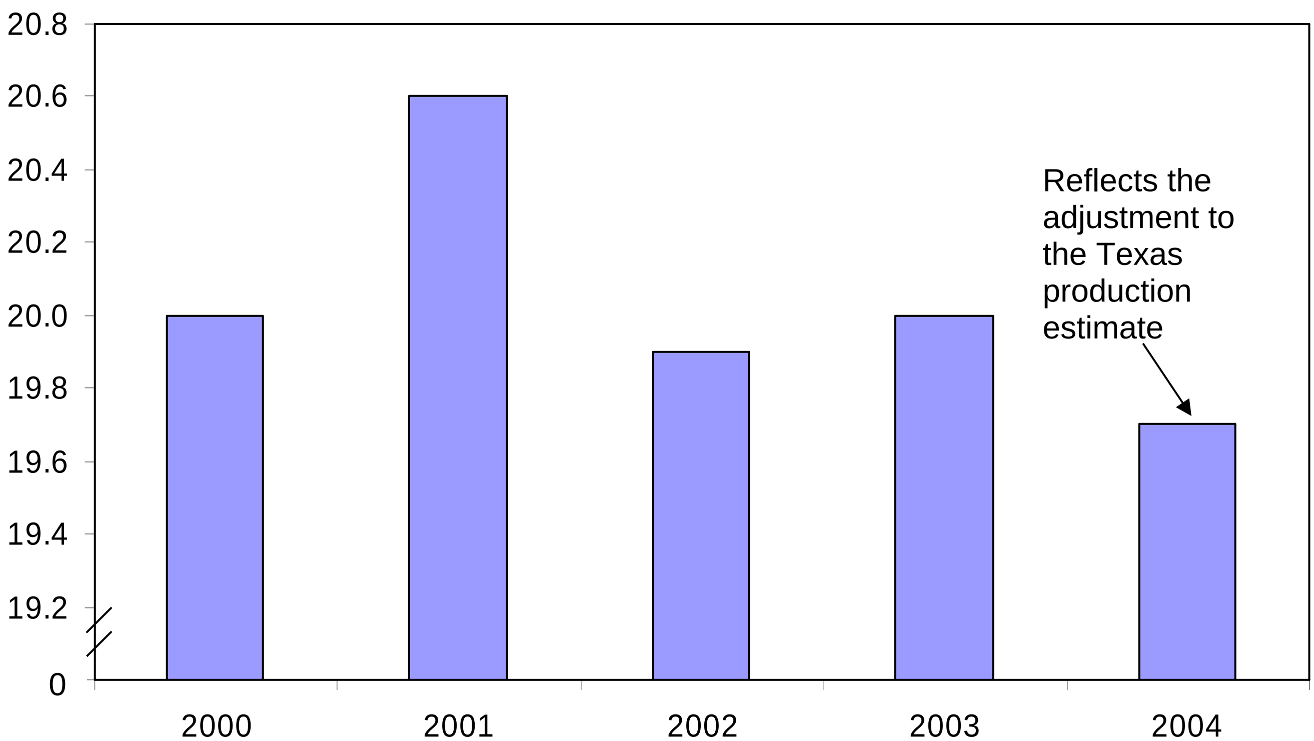
Some additional highlights related to the supply data follow.

Recorded Natural Gas Production in 2004 Reflects a Significant Data Adjustment

- **Estimates of Texas natural gas production were adjusted to account correctly for carbon dioxide (CO_2) production in 2004.** Prior to 2005, EIA relied exclusively on the voluntary reporting of production data by State and Federal Government agencies to develop its natural gas production estimates. In 2005, EIA began collecting production data directly from well operators on the new Form EIA-914, "Monthly Natural Gas Production Report." At the same time, the Texas Railroad Commission (TRRC), the agency that collects the data for the State of Texas, updated its own data collection procedures, incorporating revisions to account correctly for CO_2 production. Review of both the new Form EIA-914 data and the TRRC data for 2005 suggested that the data previously reported to the TRRC and subsequently used by EIA have overstated gross natural gas production. Accordingly, EIA adjusted the 2004 estimate of natural gas production in Texas to account correctly for CO_2 production. This adjustment was made only for the 2004 production data, and not for any of the preceding years' data owing to lack of data. The net effect of the adjustment was to reduce marketed natural gas production in 2004 by 268 Bcf, or at about 5 percent of production in Texas. A complete discussion of the changes is available in the EIA report, *Adjusted Estimates of Texas Natural Gas Production*.

- **Marketed U.S. natural gas production in 2004 was lower than the 2003 level by 290 Bcf or less than 2 percent (Figure 7).** The year-to-year decline includes the effect of adjusting for CO_2 production in the 2004 data but not in the 2003 data. If a similar CO_2 adjustment is applied to the 2003 Texas production data, reducing it by 5 percent or about 262 Bcf, then marketed production in the United States would have been only 28 Bcf lower than the 2003 level.

Figure 7. Marketed Natural Gas Production, 2000-2004 (Trillion Cubic Feet)



- **Hurricane activity in the Gulf of Mexico impeded production efforts in 2004, as significant volumes of natural gas production were shut in.** Hurricane Ivan, a Category-4 storm, struck the Gulf of Mexico in September 2004, disrupting production in the region through the remainder of the year. Owners and operators of rigs in the Gulf that were in or near the hurricane's path were forced to evacuate the employees, and producers were forced to shut in production. According to the Minerals Management Service (MMS) as of January 3, 2005, the cumulative shut-in natural gas production in 2004 totaled nearly 151 Bcf, which is equivalent to about 4 percent of the yearly marketed production in the Gulf of Mexico.

- **The number of natural gas and gas condensate wells climbed past 400,000 for the first time.** Drilling for natural gas increased in 2004, reaching a record level as the number of natural gas wells drilled during 2004 climbed by more than 2 percent to 22,673 wells (Figure 8). Natural gas rigs were 86 percent of the total natural gas and oil rig count for the year, remaining consistently above 80 percent since mid-May 2001.[5] The number of natural gas wells and rigs drilled has been steadily increasing since 2002, reflecting the steady increase in natural gas prices.

- **Proved reserves of natural gas increased for the sixth year in a row as U.S. natural gas reserves increased by almost 2 percent in 2004**. The majority of natural gas total discoveries were from extensions of existing conventional and unconventional natural gas fields. Reserve additions replaced 118 percent of 2004 natural gas production. Total discoveries of dry natural gas reserves were 20.2 Tcf in 2004, which is 32 percent more than the 10-year average and 4.5 percent more than in 2003. Field extensions were 18.2 Tcf, which was 10.6 percent more than in 2003 and 66 percent more than the average of about 11 Tcf in the prior 10 years.[6]

- **The top 5 natural gas producing States, including Texas, Oklahoma, New Mexico, Wyoming, and Louisiana, accounted for the majority of natural gas production in the United States in 2004.** The Texas onshore and State waters, which comprise the largest producing area in the United States, accounted for nearly 26 percent of the marketed production, while Oklahoma, New Mexico, Wyoming, and Louisiana together accounted for about 32 percent. Marketed production in the Federal Offshore was about 4 Tcf, or about 20 percent. The other 27 producing States accounted for less than 23 percent of marketed production.

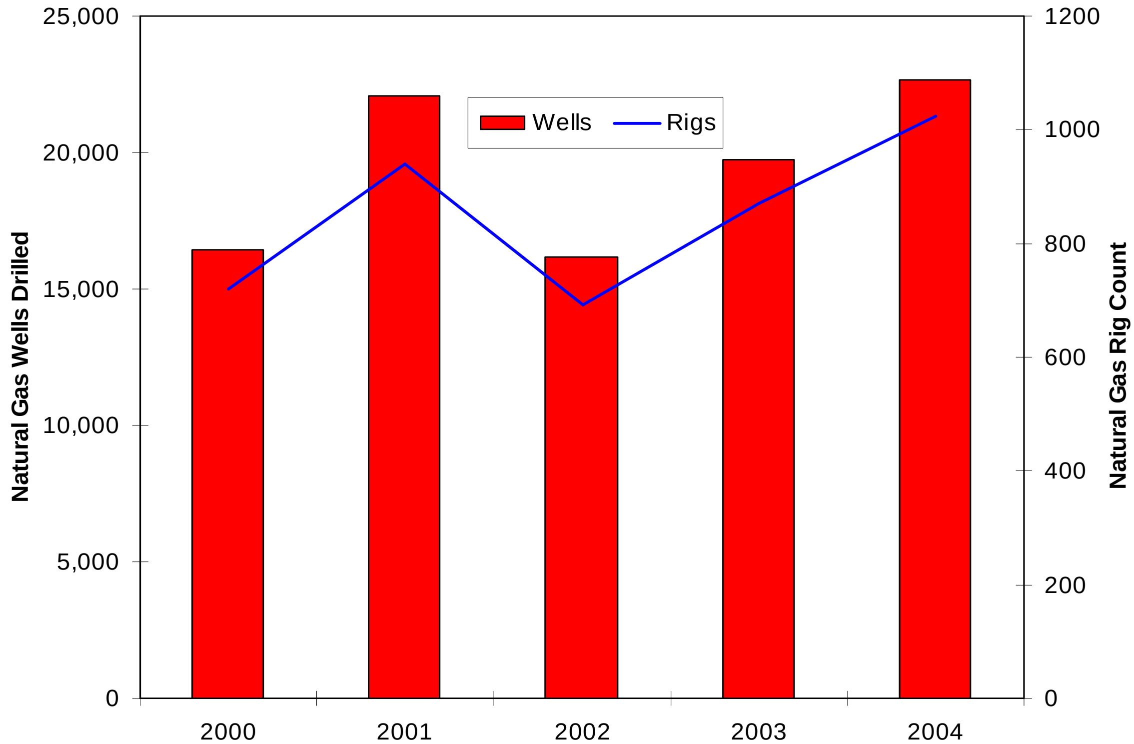
Natural Gas Imports Increased Significantly in 2004, Offsetting Increased Exports

- **In 2004, net imports to the United States increased more than 140 Bcf, or 4.3 percent, to 3.4 Tcf.** U.S. exports to Mexico and Canada were up significantly, but additional pipeline imports from Canada and net LNG imports more than offset the incremental outflows. LNG imports grew by 29 percent to 652 Bcf. Net LNG imports grew to about 17 percent of overall net imports, up from 13 percent in 2003, as net pipeline imports fell for the third straight year**.** The increase in net imports for the year was the first increase since 2001 (Figure 9). However, net imports of natural gas and LNG are still below the record volume of 3.6 Tcf set in 2001.

[5] Source: Baker Hughes, Inc. (http://www.bakerhughes.com/investor/rig/excel/US_Rig_Report_121605.xls)

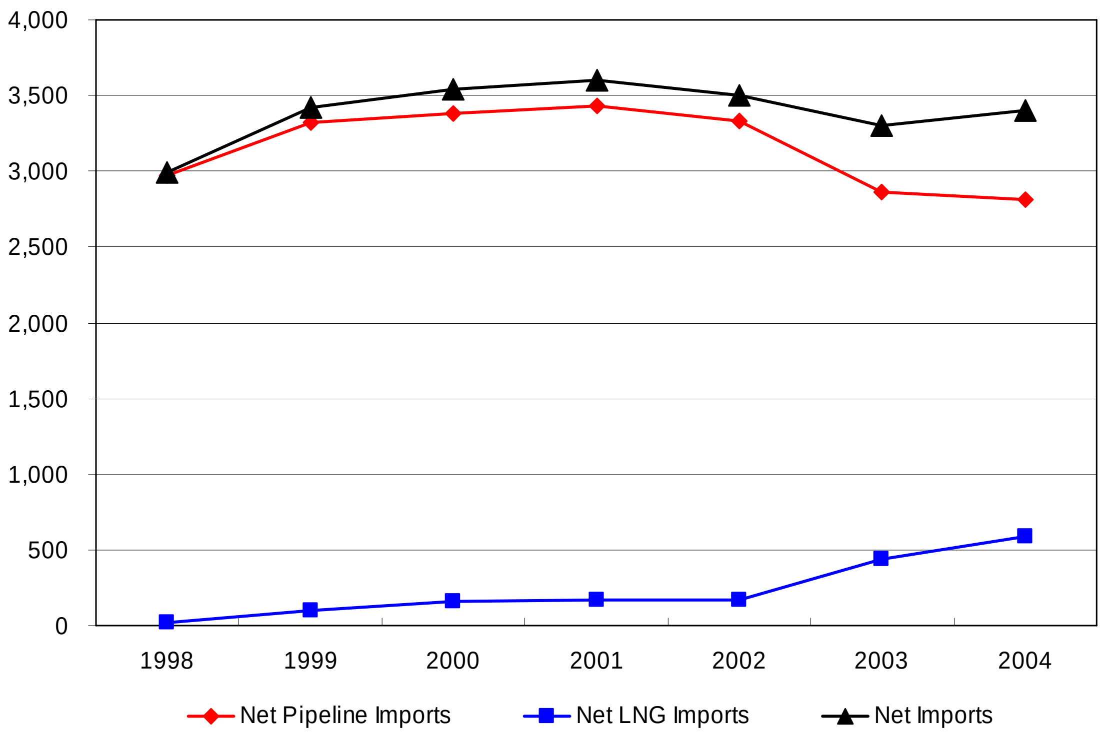
[6] Energy Information Administration, *Advance Summary U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2004 Annual Report*, October 2005.

Figure 8. Natural Gas Wells Drilled and Average Natural Gas Rigs, 2000-2004



Source: Wells: Energy Information Administration, *Monthly Energy Review* (November 2005, Washington DC), Table 5.2. Rigs: Baker Hughes, Incorporated.

Figure 9. Volume of Net Pipeline and LNG Imports, 1998-2004 (Billion Cubic Feet)

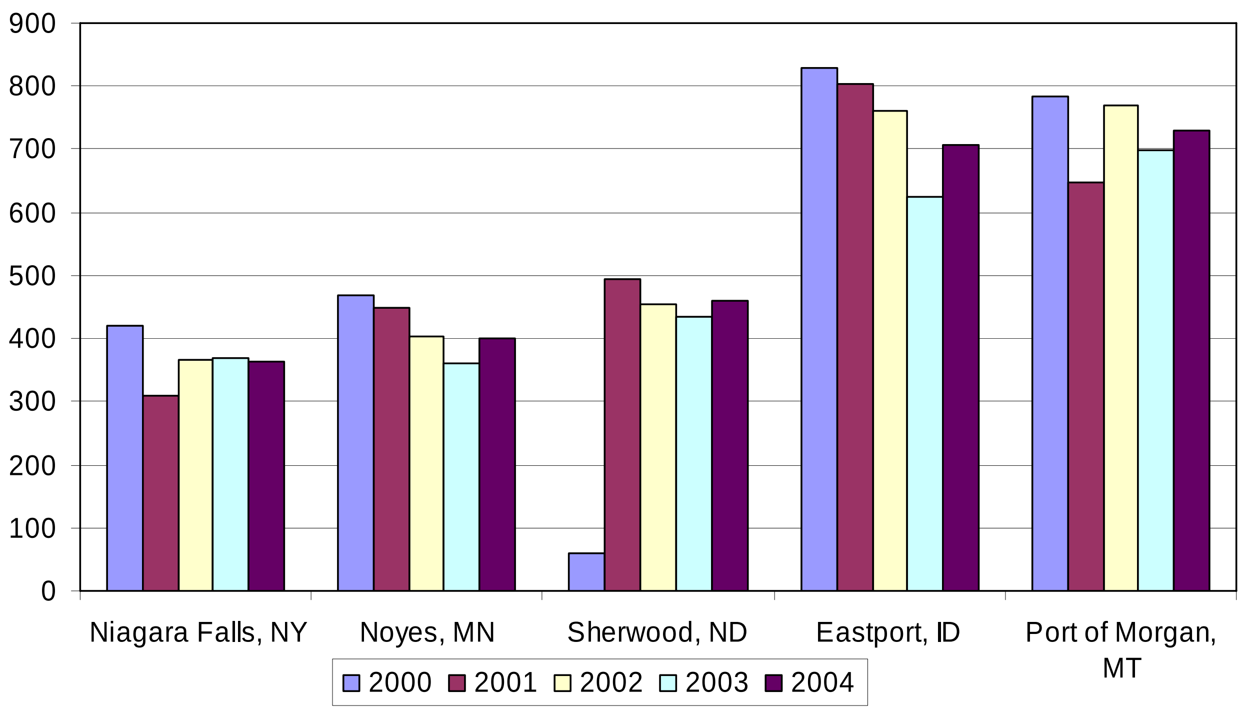


- **Gross natural gas imports from Canada in 2004 reversed their decline of the previous year, increasing 169 Bcf or 4.9 percent.** Most imports arrive via major long-haul pipelines at Canadian border locations that are closer to major consuming markets than the domestic production areas of the Southwest and the Gulf of Mexico. Imports increased at four of the five largest volume border points, with the largest increase (84 Bcf) occurring at the Eastport, Idaho, border point where the pipeline Gas Transmission Northwest enters the United States (Figure 10). However, exports from the United States were also higher during the year, leaving net imports to the United States from Canada only 46 Bcf higher than in 2003. The largest-volume export point is located along the Canadian border at St. Clair, Michigan where about 318 Bcf crossed the border. Net imports from Canada totaled 3.2 Tcf, which was still below the volumes delivered in any of the past 5 years with the exception of 2003. The slight increase reflects the difficulty producers had ramping up production despite record high prices and drilling levels.

- **U.S. pipeline exports to Mexico rose to 397 Bcf, once again reaching a record high.** The increase from 2003 was 54 Bcf, or 15.8 percent. Although the volume of exports is small relative to the size of the U.S. marketplace, exports have almost quadrupled since 2000 to serve industries near the border and supplement production from Petroleos Mexicanos (Pemex), Mexico's State-owned petroleum company.

- **The average price for all imports rose $0.64 per Mcf, or $0.62 per million British thermal units (MMBtu) to $5.81 per Mcf ($5.67 per MMBtu).** The price was 12.4 percent higher than the average price of $5.17 per Mcf ($5.05 per MMBtu) in 2003 and 84.4 percent higher than the average price of $3.15 per Mcf ($3.09 per MMBtu) in 2002. On a volumetric basis, the prices of imports by pipeline and for LNG were nearly identical at $5.80 per Mcf and $5.82, respectively. However, because of the higher Btu content of LNG compared with U.S. pipeline imports from Canada, prices for LNG on a Btu basis were less than those for pipeline imports. Prices for LNG imports averaged $5.47 per MMBtu, while prices for pipeline imports averaged $5.70.

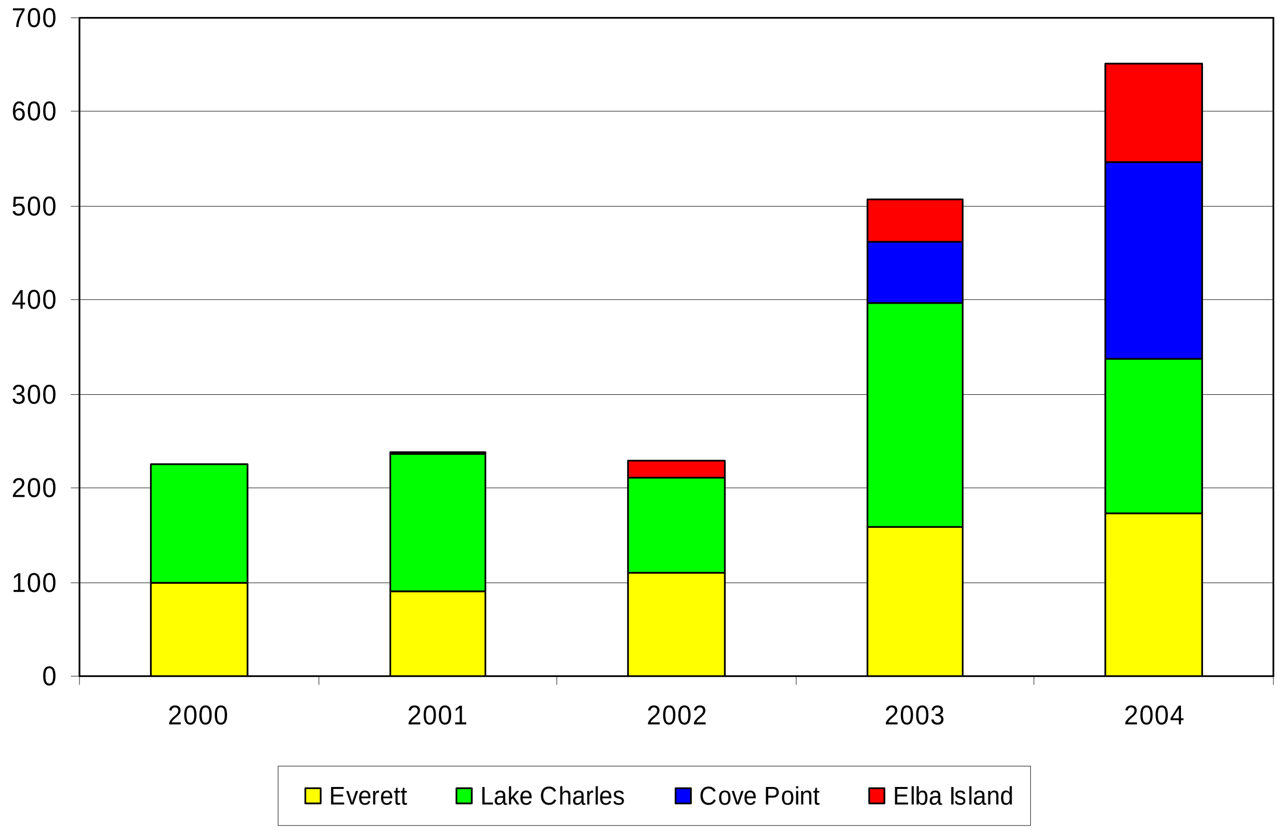
Figure 10. Annual U.S. Imports from Canada at the Five Highest Volume Border Points, 2000- 2004 (Billion Cubic Feet)



- **Prices for exports and imports were both higher than the average wellhead price in the United States.** However, the price increases from 2003 were nearly similar in percentage terms, with the domestic price rising 11.9 percent to $5.46 per Mcf ($5.32 per MMBtu) and the imports price moving up 12.4 percent to $5.81 per Mcf ($5.67 per MMBtu). The average price for exports increased 9.9 percent to $6.09 per Mcf ($6.04 per MMBtu). The difference in the U.S. wellhead prices and imports and exports likely reflects transportation costs to regional markets.

- **LNG imports rose 29 percent over 2003 to 652 Bcf as all four import terminals in the lower 48 States were operational for the entire year.** Although not operating at full capacity, the volume of LNG imports in 2004 was a record high and nearly triple the volume received in 2000. Expansion of liquefaction facilities in Trinidad and Tobago allowed for increased receipts from that country, and the supply from Algeria more than doubled. In its first full year of operating in international trade in more than two decades, the Cove Point terminal along the Chesapeake Bay in Maryland received 209 Bcf, the most of any U.S. terminal (Figure 11).

Figure 11. Annual LNG Imports by Receiving Terminal, 2004 (Billion Cubic Feet)



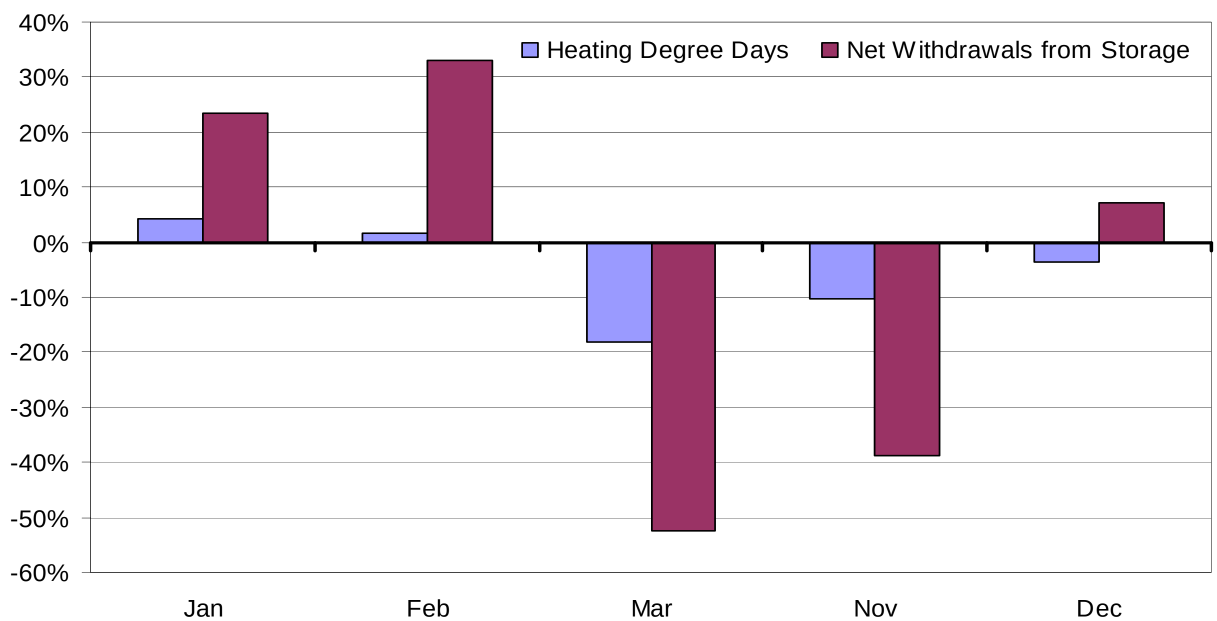
Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Division, based on data from the Department of Energy, Office of Fossil Energy.

Working Natural Gas in Storage Hit a 13-Year High in 2004, as New Storage Capacity Was Placed Into Service

- **Working natural gas in underground storage remained above the previous 5-year (1999-2003) average levels throughout most of the year, rising to more than 3.3 Tcf by the beginning of the 2004-2005 heating season – the highest working natural gas storage level since 1991.** The United States started 2004 with about 2.6 Tcf in working natural gas in storage, which was 4.5 percent higher than the previous 5-year average (1999 – 2003), and 5.2 percent higher than in 2003. January's net withdrawal of 811 Bcf was the second highest since the EIA started collecting monthly data in September 1975, exceeded only by a net withdrawal of 840 Bcf in January 2003. For the year, injections to underground storage exceeded withdrawals by more than 113 Bcf, which is 80 Bcf less than net injections in 2003. On a regional basis, injections also exceeded withdrawals in all three regions: East, West and Producing. By volume, the highest net storage additions in any State occurred in Michigan at 50 Bcf, which is an increase of 4 Bcf over last year. Michigan also has the highest underground storage capacity with 12.2 percent of total U.S. capacity. Pennsylvania had the highest net withdrawal at 8 Bcf.

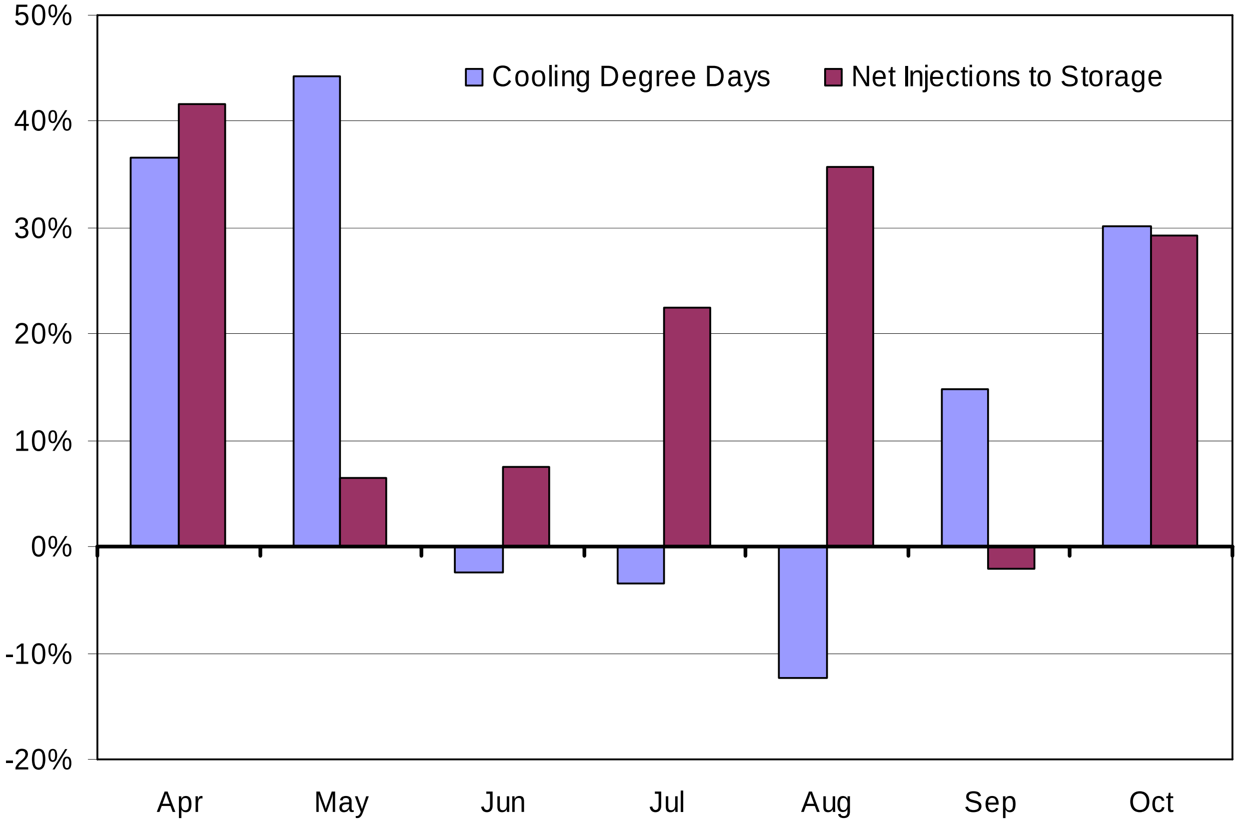
- **Monthly variations in net withdrawals or injections deviated up to 40 percent from the 5-year average and generally were consistent with weather patterns for the United States as a whole during 2004.** The following two graphs depict the deviation of monthly storage activity for 2004 from the previous 5-year average (1999 – 2003) for heating season months (Figure 12) and non-heating season months (Figure 13). During the heating season months, all of which experienced net monthly withdrawals, higher-than-average withdrawals generally occurred when temperatures were colder than normal, as measured by National Weather Service heating-degree days. Net withdrawals deviated from the 5-year average more dramatically, however, than heating-degree days deviated from normal. For the non-heating season months of the year, almost all net monthly injections were above average. For the hottest months of the year (June, July, and August) as measured by cooling-degree days, cooler-than-normal temperatures may have prompted above-average injections to storage. When summer temperatures are cooler, demand for natural gas-fired electric generation to meet air conditioning needs decreases, which means more natural gas is available for injection to storage. During the cooler

Figure 12. Deviation from the 5-year Average for Net Withdrawals of Natural Gas and Deviations from Normal for Heating Degree Days, Heating Season Months 2004



Source: Heating Degree Day Data derived by the Natural Gas Division based on Gas Home Heating Customer Weighted data from the National Oceanic and Atmospheric Administration available at ftp://ftpprd.ncep.noaa.gov/pub/cpc/htdocs/products/analysis_monitoring/cdus/degree_days/archives/.

Figure 13. Deviation from the 5-year Average for Net Injections of Natural Gas and Deviations from Normal for Cooling Degree Days, Non-heating Season Months in 2004



Source: Cooling Degree Day Data derived by the Natural Gas Division based on Population Weighted data from the National Oceanic and Atmospheric Administration available at ftp://ftpprd.ncep.noaa.gov/pub/cpc/htdocs/products/analysis_monitoring/cdus/degree_days/archives/.

months of the non-heating season (April, May, and October), when there is little demand for air conditioning, the influence of temperatures on net injections is not significant. For all months of the non-heating season, the New York Mercantile Exchange (NYMEX) futures contract for January 2005 delivery of natural gas held an average monthly premium over the Henry Hub spot price ranging from \$0.60 to \$2.50 per MMBtu. This would have provided economic incentive to inject natural gas into storage during the non-heating season months of 2004. By comparison, in the previous 3 years, monthly average premiums for the following January contracts ranged between \$0.23 and \$0.92 per MMBtu.

- **There were net gains of three storage sites and 49 Bcf of capacity added to U.S. underground storage in 2004.** There were 393 storage sites in the United States at the end of 2004 with a combined total capacity of 8,255 Bcf.[7] More than 81 percent of the sites are depleted fields, while about 11 percent are aquifers and 8 percent are salt caverns. The 49 Bcf of added capacity is less than 1 percent of total U.S. capacity. Depleted fields accounted for all changes to the number of sites. There was no change in the number of salt cavern or aquifer storage sites, although 5 Bcf of salt cavern capacity and 1 Bcf of aquifer capacity were added through expansion. The East Region's 259 storage sites represent about 66 percent of storage sites in the United States and about 58 percent of U.S. storage capacity. The Producing Region has the second highest percentage of capacity with 91 fields and 27 percent of total U.S. capacity,

[7] Total capacity is defined as the total volume of natural gas that can be stored in the facility. It includes base gas or the volume of natural gas that remains in the facility at all times, and working gas capacity, which is the amount of gas in the site that is available for withdrawal to serve customer or system needs.

and the West Region contains only 43 total fields with 15 percent of U.S. storage capacity.

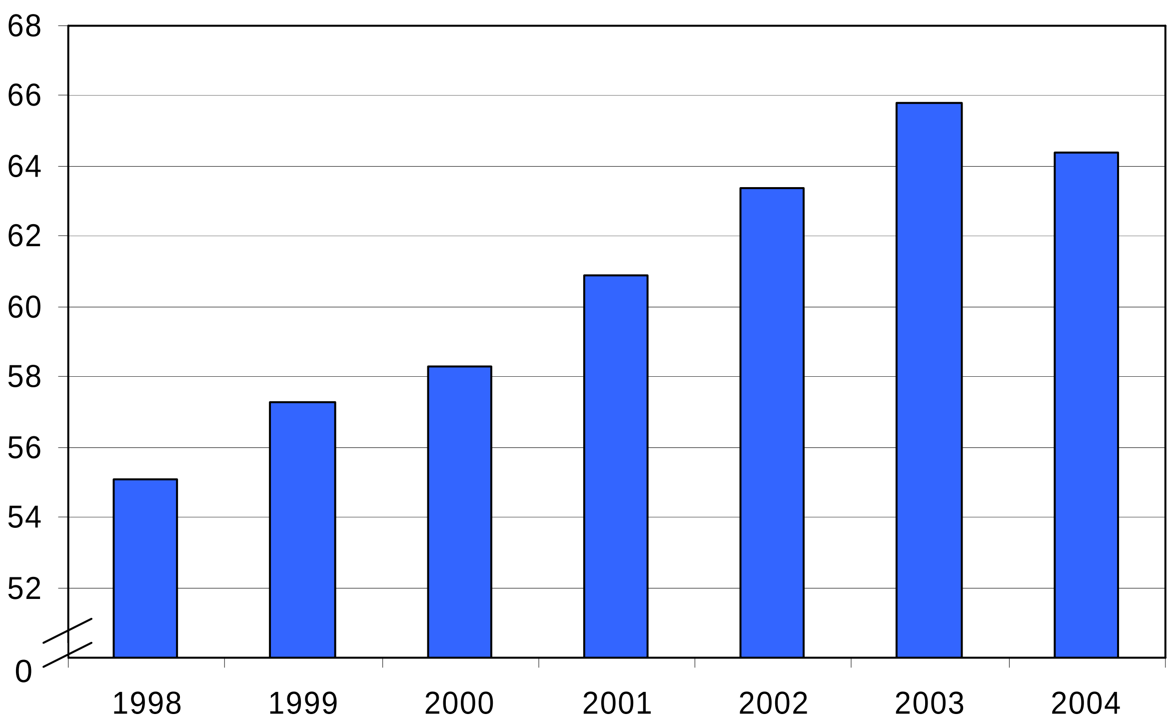
- **Additions to and withdrawals from liquefied natural gas storage in 2004 were significantly less than both 2003 and the previous 5-year (1999-2003) average.** Additions exceeded withdrawals in 2004 by 791 MMcf. Additions to LNG storage were 22 percent less than last year, and 12 percent below the 5-year average. Similarly, withdrawals were 17 percent less than last year and 13 percent below the 5-year average. Looking at State levels, 29 States contain LNG storage capacity and 14 States have LNG as the only form of storage within the State, which represents no change from 2003. Massachusetts had both the highest level of additions (9.5 Bcf) and withdrawals (11.1 Bcf), but these were 5 percent and 23 percent, respectively, less than in 2003. New Jersey had the highest net change in LNG storage activity with 1.9 Bcf in net additions. Georgia had a significant increase in both additions and withdrawals from 2003 at 3.3 Bcf and 1.2 Bcf, respectively.

Interstate natural gas movements fell 4 percent in 2004 despite an increase in consumption.

- **In 2004, for the first time in 6 years, interstate movements of natural gas decreased in volume from that of the previous year (Figure 14)**. From 2003 levels of 65.8 Tcf, volumes fell by 2.1 percent to 64.4 Tcf. Furthermore, interstate natural gas deliveries to 14 States decreased by 5 percent or more in 2004 while 11 States exhibited an increase of 5 percent or more. This compares with the pattern of 2003 when only 6 States had reduced flow levels and 20 had larger flow levels. Relatively large declines in deliveries occurs in more States in 2004 than in 2003.

- **Compared with 2003 levels, natural gas transportation from the Gulf of Mexico decreased 10 percent during the year.** Part of the reason for the decrease was the significant impact that Hurricane Ivan had on natural gas production during the month of September, and to a lesser degree, during the remainder of the year. Nevertheless, development of natural gas resources in the deepwater areas of the Gulf continued, with several new gathering systems, representing an addition of more than 1,275 MMcf per day of pipeline capacity, being placed in service during the last quarter of the year.

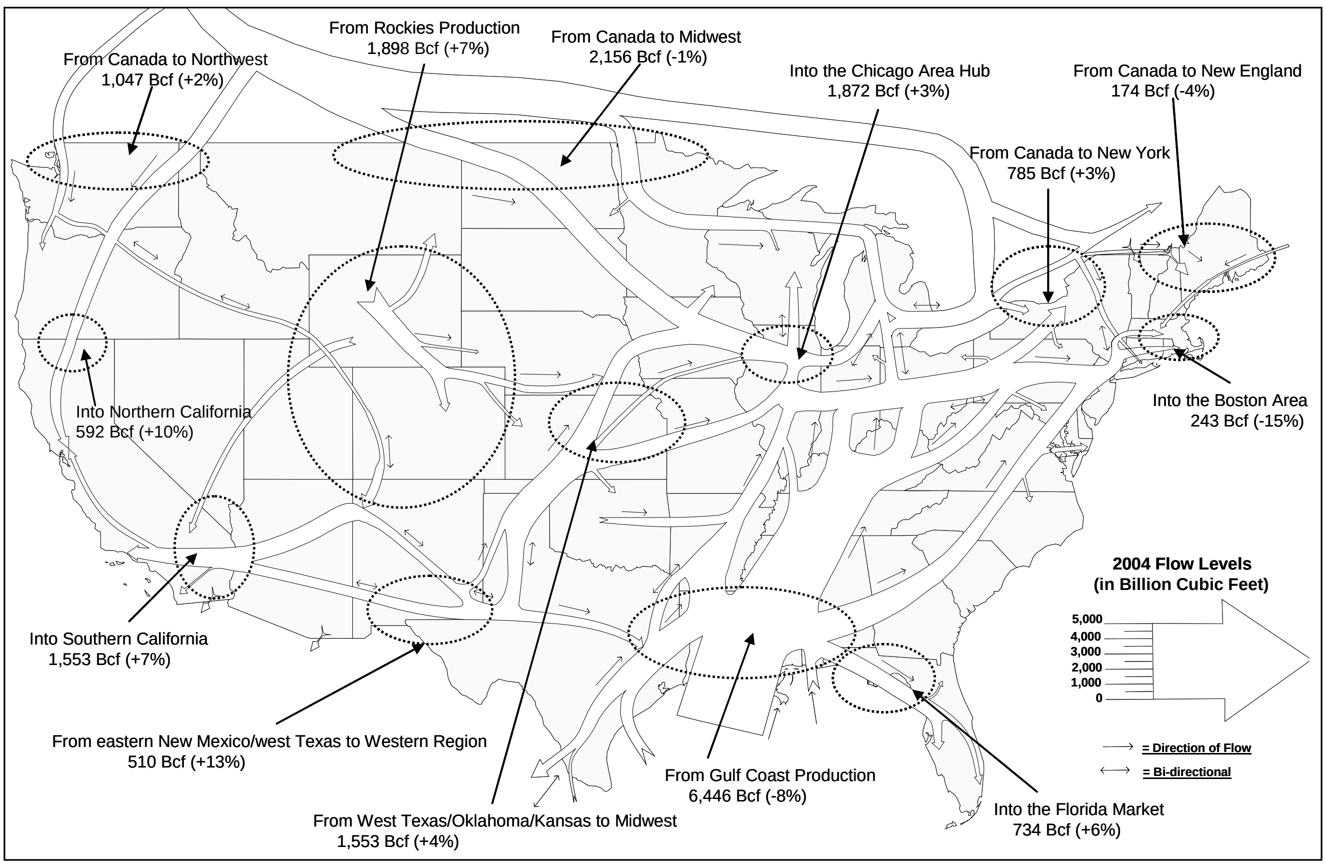
Figure 14. Annual Interstate Natural Gas Transportation Flows, 1998-2004 (Trillion Cubic Feet)



- **Growth in natural gas flows out of the prolific Rocky Mountain natural gas basins continued as increasing demand, particularly in Western markets, absorbed the increase.** Another 6-percent increase in exports from Wyoming in 2004 contributed to an 18-percent increase in transport volumes on the Kern River Gas Transmission system. The increase on the Kern River Gas Transmission system was supported primarily from conventional natural gas supply expansions in Wyoming's southwestern basins. Combined with the expanding development of natural gas resources and pipeline expansions in Colorado and northeastern Utah, the region experienced an overall 7-percent increase in interstate movements for the year (Figure 15).

- **Natural gas transported into southern California and Arizona increased substantially in 2004 as demand for natural gas in both States continued to grow.** Helping meet this demand, natural gas pipeline transportation from the San Juan Basin of New Mexico/Colorado, and from southwest Wyoming, increased accordingly. In 2004, net volumes transported into Arizona increased by almost 20 percent, or about 336 Bcf, while natural gas transportation volumes into southern California increased by 7 percent. A 320-MMcf per day expansion of the El Paso Natural Gas Company's southern system, completed in May 2004, helped support Arizona's growing needs, in addition to providing an increased capability to transport more natural gas to the North Baja Pipeline system at the California border for delivery to Mexico.

Figure 15. Major Natural Gas Pipeline Transportation Routes and 2004 Interstate Flow Levels at Selected Key Locations



Note: Boston area volumes do not include LNG imports. ( ) = Percent change in flow from 2003. Bcf = Billion cubic feet.
Sources: Energy Information Administration: **Corridors:** Interstate Natural Gas Pipeline Capacity Database. **Flow:** Form EIA176 "Annual Report of Natural Gas and Supplemental Gas Supply and Disposition."

- **Natural gas volumes transported into what is referred to as the Chicago Hub (an area of northern Illinois where a number of interstate and intrastate natural gas pipeline systems interconnect) increased 3 percent over 2003 levels.** This hub is a key destination for natural gas produced in western Canada and the natural gas basins of the Texas/Oklahoma panhandles and southwest Kansas, and a major transshipment point for natural gas destined for the U.S. Midwest and for export to Ontario, Canada. Although Canadian natural gas imports reaching the Chicago area decreased slightly (less than 0.5 percent), the 4-percent increase in gas transported from Texas /Oklahoma/Kansas into the Midwest during the year improved the overall level of natural gas entering the Chicago Hub area. The hub also provides a major portion of the natural gas that is transported into the expanding gas market of southern Wisconsin. Natural gas flows into Wisconsin from northern Illinois increased by 3 percent in 2004 and by 26 percent since 2000. Natural gas transportation volumes into northern Indiana, on the other hand, much of which is destined for export to Canada via Michigan, fell slightly, just under 1 percent (total exports to Canada from Michigan fell by 3 percent in 2004).

- **Although Canadian import volumes increased 5 percent in 2004 overall, Canadian imports into the growing natural gas market of New England fell 4 percent, or 9 Bcf, from 2003 levels (Figure 15).** Imports into New England via the Maritimes and Northeast Pipeline Corridor between Maine and Massachusetts fell for the third year in a row, contributing to an overall 15-percent decline in natural gas transportation to the greater Boston area. The decreasing availability of natural gas supplies from the Sable Island area offshore eastern Canada has increased the level of unused capacity on the Maritimes and Northeast Pipeline system and has hampered its ability to meet growing natural gas demand in the region. This situation has sparked proposals to develop LNG import facilities along the route of the Maritimes and Northeast Pipeline system as one way of providing an alternative supply source for meeting the natural gas needs of the Boston metropolitan area and the rest of the New England market.

- **In the southern Atlantic coast area, on the other hand, natural gas transported into Florida grew by 6 percent, or 38 Bcf, during the year.** Several expansions within the Florida Gas Transmission system's territory and the completion of several natural-gas-fired power plants with tie-ins to the Gulfstream Pipeline System were the main contributors to this high level of growth. Since 1998, the annual natural gas volume transported into the State has grown by 55 percent, or at an average annual rate of 8 percent. In 2002 alone, natural gas imported into the State increased 32 percent over the previous year's level. The Gulfstream Pipeline System became operational in June 2002.