Overview

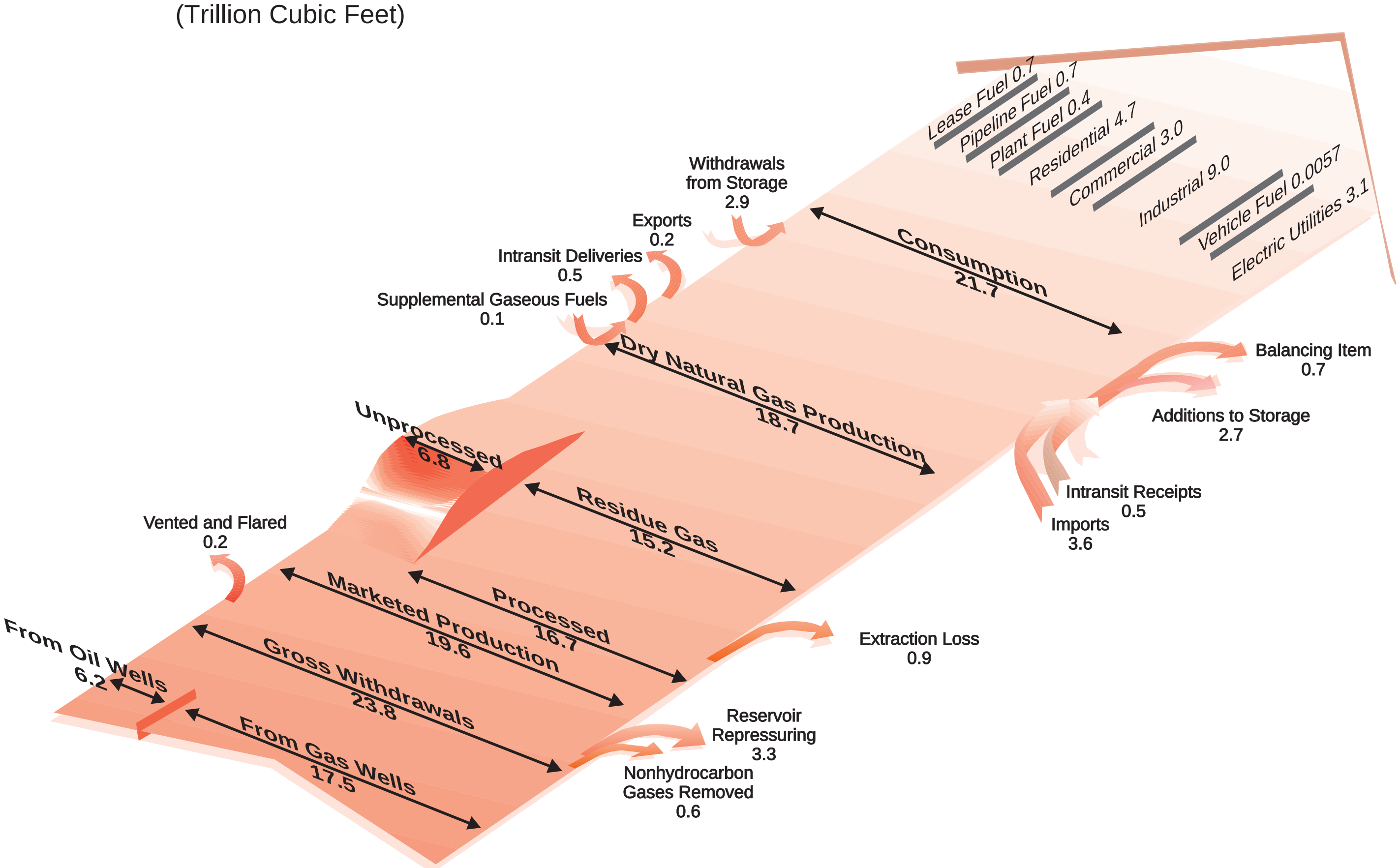
In 1999, natural gas consumption reached 21.7 trillion cubic feet, 2 percent higher than in the previous year, while marketed production at 19.6 trillion cubic feet was 1 percent less than the 1998 level. Imports continued to take on a greater role in contributing to supplies as net imports accounted for 16 percent of U.S. gas consumption in 1999. Wellhead prices rose substantially, by 11 percent, and electric utility prices followed this trend with a 9-percent increase. Prices declined in other end-use sectors but by relatively small amounts, ranging from 1 to 3 percent.

Supply

The United States had 19.6 trillion cubic feet of marketed natural gas production[1] in 1999, which was 1 percent less than in 1998. The historical peak in marketed production

[1]Marketed production is derived from gross withdrawals by subtracting quantities used for repressuring, nonhydrocarbon gases removed during processing, and gas vented and flared.

Figure 1. Natural Gas Flow Diagram, 1999
(Trillion Cubic Feet)



Note: Totals may not equal sum of components due to independent rounding.
Sources: Energy Information Administration (EIA), Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition"; Form EIA-895, "Monthly Quantity and Value of Natural Gas Report"; Form EIA-816, "Monthly Natural Gas Liquids Report"; Form EIA-759, "Monthly Power Plant Report"; Office of Fossil Energy, U.S. Department of Energy, *Natural Gas Imports and Exports*; *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, Annual Reports,* DOE/EIA-0216, and the U.S. Minerals Management Service.

occurred in 1973 at 22.6 trillion cubic feet. Four States continue to account for the majority of the natural gas produced in the United States comprising 74 percent of the total in 1999: Texas (31 percent), Louisiana (27 percent), Oklahoma (8 percent), and New Mexico (8 percent).

At the State level in 1999, Texas and Oklahoma had the largest declines in marketed production, 282 billion cubic feet and 74 billion cubic feet, respectively. These volumes were equivalent to a 4-percent drop in each State. Marketed production in Louisiana in 1999 was nearly the same as in 1998, while production in New Mexico increased by 1 percent. The States with the largest increases in marketed production during 1999 were California and Wyoming, with increases of 67 billion cubic feet (21 percent) and 62 billion cubic feet (8 percent), respectively. In California, ownership has changed in the Elk Hills oil field where natural gas is reinjected into the reservoir to assist in oil recovery. Less gas is being used for pressure maintenance, allowing more gas to be available for sale to the market.

Marketed natural gas production from State and Federal waters declined by 1 percent from 1998 to 1999, reaching 5.7 trillion cubic feet. Offshore fields accounted for 29 percent of total U.S. marketed production in both 1999 and 1998. Of the five States with offshore marketed production, Louisiana had the most with 3.9 trillion cubic feet in 1999, nearly the same level as in 1998. Texas has the second-largest amount of offshore marketed production with 1.2 trillion cubic feet in 1999, a decline of 4 percent from 1998.

The number of gas and gas condensate wells was 307,449 in 1999, a decline of 9,480 (3 percent) compared with 1998. This is the first time the number of wells has declined since 1992.

The national average wellhead price was $2.17 per thousand cubic feet in 1999, which was $0.22 per thousand cubic feet (11 percent) higher than in 1998. During the 1990’s, the greatest price changes occurred between 1995 and 1997, when the annual average wellhead price rose from $1.55 to $2.32 per thousand cubic feet. Only three States had declines in the average wellhead price from 1998 to 1999: Kentucky, New York, and South Dakota. Combined, these States accounted for only one-half percent of total marketed production in 1999. Among the four largest producing States, the smallest increase in the average wellhead price was $0.19 (10 percent) to $2.19 per thousand cubic feet in Louisiana and the largest was $0.35 (20 percent) to $2.11 per thousand cubic feet in New Mexico.

Imports and Exports

The United States continued active trading in natural gas imports and exports during 1999. Net imports reached a new record level of 3.4 trillion cubic feet, and expanded their share of total U.S. consumption, reaching 16 percent in 1999. Pipeline imports from Canada comprised 95 percent of total U.S. Imports.

Pipeline Imports

All natural gas imports from Canada enter the United States by pipeline. During 1999, pipeline imports grew by 10 percent compared with a 5 percent rise in 1998, 1 percent in 1997, and 2 percent in 1996. The higher growth rate in 1999 was due to significant increases in crossborder capacity as two pipeline projects completed in late 1998 and operational throughout 1999 made import expansion possible. The Great Lakes Transmission expansion project added 126 million cubic feet per day of capacity. It extends from Manitoba, Canada, through Noyes, Minnesota. The Northern Border Iowa-to-Illinois expansion project increased capacity from Port of Morgan, Montana, into Iowa by 700 million cubic feet per day and extended into Illinois just south of Chicago. A third project, the Portland Pipeline project, began operations in March 1999. It added a new pipeline to bring natural gas from western Canada into the U.S. Northeast through New Hampshire. Included in this project was the conversion back to oil use of the old Portland Pipeline, which crosses the Canadian border into Vermont. The project has created a net increase of 147 billion cubic feet per day of capacity serving Northeast markets.

U.S./Canadian crossborder capacity expansion has continued in 2000 with the startup of two major U.S./Canadian pipeline projects. The Maritimes and Northeast Pipeline was completed in 1999, and gas began flowing in January 2000. It established a link between the Sable Island Offshore Energy Project (SOEP) and New England markets. The SOEP, located off Nova Scotia in the northern Atlantic, marks the first commercial natural gas project in the Atlantic off North America. The SOEP is designed to supply about 530 million cubic feet per day to the Maritimes and Northeast Pipeline which will deliver about 400 million cubic feet per day to New England markets. The Alliance Pipeline, with a capacity of 1.3 billion cubic feet per day, is scheduled to begin operations in late October 2000. It will cross the Canadian border into North Dakota and serve Chicago area markets.

The price of natural gas imports from Canada also increased to $2.23 per thousand cubic feet, 14 percent above the 1998 price of $1.95 per thousand cubic feet. As in recent years, the Canadian price followed the upward trend in U.S. wellhead prices. The U.S. wellhead price also rose from 1998 to 1999, although by a smaller percentage. The 1999 wellhead price was $2.17 per thousand cubic feet, 11 percent higher than in 1998.

The United States imported 55 billion cubic feet of natural gas from Mexico by pipeline in 1999, more than three-and-one-half times the 1998 level of 15 billion cubic feet. The price of imports from Mexico was $2.14 per thousand cubic feet, 5 percent above the 1998 price.

LNG Imports

Reflecting the brisk trade in the international liquefied natural gas (LNG) market, LNG imports nearly doubled from 1998 to 1999, reaching 163 billion cubic feet, the highest level since 1979. They represented 5 percent of total U.S. imports. Algeria continued to be the major supplier of LNG imports with 76 billion cubic feet or 46 percent of total LNG imports. The United States had new sources of LNG during 1999. The new liquefaction facility and terminal in the Republic of Trinidad and Tobago targets markets in the Northeastern United States, Spain, and Puerto Rico. It began shipments to Everett, Massachusetts in May 1999. These shipments totaled 51 billion cubic feet, 31 percent of all LNG imports. Also in 1999, the United States imported LNG from Qatar and Malaysia for the first time.

There are two operational LNG-receiving terminals in the United States: Everett, Massachusetts, and Lake Charles, Louisiana. LNG imports serve as supplemental gas supplies in the markets located near these facilities. The United States has two other LNG facilities that are not presently importing. One of them, the Cove Point LNG terminal in southern Maryland, has not received LNG shipments since 1980. It became a peakshaving storage facility in 1995. Cove Point is filing an application with the Federal Energy Regulatory Commission (FERC) to resume LNG imports and expects to begin receiving shipments in 2002. The other facility, the mothballed Elba Island terminal near Savannah, Georgia, has received clearance from the FERC to go back in service and expects to reactivate operations in 2002. Elba Island last imported LNG in 1980.

Prices of LNG imports are higher than those for Canadian and Mexican pipeline imports. A number of factors contribute to this difference, including the high Btu content for LNG imports compared with North American gas. LNG prices are also influenced by the local markets that they enter. Unlike the price for pipeline imports from Canada, the price of LNG imports declined in 1999 to $2.47 per thousand cubic feet, 6 percent less than the 1998 price. This decline occurred as global demand for LNG diminished. The price of imports from Algeria, the largest single source of LNG imports, declined by a lesser amount, 4 percent, to $2.41 per million cubic feet. Most of these imports were made under long-term agreements. LNG prices are reported as either "landed," the price at the point of entry, or "tailgate," the price at the point of entry plus regasification charges.

Although LNG imports represent only about 5 percent of total U.S. imports, they are a significant supply source for several regional markets. Certain developments in the natural gas industry, such as the current rising prices for other natural gas supplies and the increased demand for gas for power generation, indicate possible substantial growth potential in the demand for LNG in the United States. International supplies of LNG are also readily available. Trinidad plans to expand its existing LNG production and export facility, which would triple its production and export of LNG by the year 2003. Much of this future LNG supply will likely be marketed in the United States.[2] Abundant supplies and increasing regional demand may work together to ensure an active LNG import market in the United States.

Exports

The United States exported natural gas to Canada, Mexico, and Japan. Natural gas exports to Canada were all by pipeline. They declined by 3 percent from 1998 to 1999 to 39 billion cubic feet. The average price of exports to Canada was $2.35 per thousand cubic feet, 4 percent above the 1998 price. Exports to Canada represented about 24 percent of total U.S. exports.

Natural gas pipeline exports from the United States to Mexico reached 61 billion cubic feet in 1999, the highest level since 1995. The price increased to $2.27 per thousand cubic feet, 11 percent above the 1998 price. Also in 1999, 275 million cubic feet of liquefied natural gas (LNG) was sent to Mexico by truck, crossing the border at Nogales, Arizona, and San Diego, California. LNG shipments to Mexico began in 1998 when 33 million cubic feet was exported at Nogales. Exports to Mexico represented about 38 percent of total U.S. natural gas exports.

LNG is shipped from southern Alaska to Japan under long-term agreements. U.S. exports to Japan declined by 4 percent to 64 billion cubic feet in 1999 while the price rose by 6 percent over the 1998 level to $3.08 per thousand

[2]U.S. Department of Energy, Office of Fossil Energy, *Natural Gas Imports and Exports*, *Fourth Quarter Report 1999*, DOE/FE-0414 (March 2000).

cubic feet. Exports to Japan represented about 39 percent of U.S. exports.

More detailed information about imports and exports including monthly data, can be found in the Special Report, " U.S. Natural Gas Imports and Exports – 1999," in the August 2000 issue of the Energy Information Administration (EIA) report, *Natural Gas Monthly*.

Storage

Natural gas in storage contributes to the supply reliability of the industry and has become an increasingly important part of industry operations in recent years. Additions to and withdrawals from storage are shown in Table 10 for the calendar year 1999. Storage levels on a monthly basis are frequently of great interest as the heating season (November through March) proceeds each year. Monthly gas storage levels are available in the EIA report, *Natural Gas Monthly*.

Storage Capacity

Data for natural gas underground storage capacities as of December 31, 1999, are presented for the first time in this report by type of facility. There are three principal types of underground storage facilities in operation in the United States today: aquifer reservoirs, depleted fields, and salt caverns. Most storage capacity, 82 percent, is in depleted natural gas or oil fields. Depleted field facility capacity is located in 25 States with Louisiana, Michigan, Ohio, Pennsylvania, Texas, and West Virginia each having more than 500 billion cubic feet of capacity. Aquifer reservoirs are water-only reservoirs conditioned to hold natural gas and account for 15 percent of total capacity. Aquifer reservoirs are located in 11 States, with 59 percent of this type of capacity in Illinois. Aquifer reservoirs and most depleted fields are designed and operated to withdraw all working gas over the course of an entire heating season.

Salt caverns account for only 2 percent of underground storage capacity. They are located in nine States but most of the capacity is in only three States: Louisiana with 18 percent of total salt cavern capacity, Mississippi, with 17 percent, and Texas with 57 percent. Salt cavern storage facilities are caverns hollowed out in salt "bed" or "dome" formations. They have greater operational flexibility than the other types of facilities; all of the working gas in a given facility can be withdrawn in a relatively short period of time.

Recent Pipeline Expansions

In 1999, at least 35 natural gas pipeline construction projects were completed and placed in service in the United States. Of the 35 projects, only 3 were wholly new pipeline systems, while the rest were extensions or expansions to existing systems, construction of large laterals off of mainline transmission systems (mainly to serve new gas-fired electric power generation facilities), or large gathering system header lines. The cumulative new installed pipeline capacity represented by these projects amounted to more than 6.6 billion cubic feet per day of capacity. These projects either added capacity directly to the interstate network, improved local intrastate service, or expanded access to producing fields or natural gas market centers.

Currently planned expansions (28 projects) for 2000 could add up to 7.2 billion cubic feet per day of new capacity to the national pipeline network. As in 1999, expansion of import capacity into the Northeast and Midwest United States will account for a large portion of the new capacity (1.3 billion cubic feet per day).

Some highlights of current U.S. pipeline expansions are:

- In the Southeastern United States, completion of four projects added about 1.2 billion cubic feet per day of pipeline capacity to the regional network in 1999. These projects included: improvement of the Columbia Gulf Transmission system; completion of the new Cardinal Pipeline and the Transcontinental Gas Pipeline system link with the Pine Needle LNG facility in North Carolina; and construction of a lateral line off the Tennessee Gas Pipeline system in Mississippi to serve a new gas-fired electric power plant.

- In the Rocky Mountains area of northern Wyoming and southern Montana (primarily the Powder River Basin), three new major gathering (header) pipelines, with a total of 1.1 billion cubic feet per day of capacity, were completed and connected to the interstate pipeline network in the region. Coal-bed methane gas reserves, which are abundant in the area and relatively easy to develop, are being brought on line rapidly, and new pipeline exit capacity is needed in the area. The Wyoming Interstate Pipeline Company, which is one of the principal transporters moving gas out of the area, increased its capacity by 36 percent in 1999 and will increase it further in 2000. The company also recently announced an additional system expansion of 675 million cubic feet per day, slated for completion in 2001.

- Also in the Rocky Mountains area, the final phase of the Transcolorado Pipeline system (300 million cubic feet per day) was completed in late 1999. This system extends from the Piceance Basin of northwestern Colorado, through the San Juan Basin in southern Colorado\northern New Mexico, to interconnections with the El Paso Natural Gas and Transwestern Pipeline systems in New Mexico which will deliver gas to California markets. The system also has interconnections at its northern terminus with regional interstate pipelines (Questar Pipeline Company, Northwest Pipeline Company and Colorado Interstate Gas Company), allowing shippers to serve area customers as well.

- Two projects completed in 1999 improved export capacity to Mexico by 293 million cubic feet per day and accounted for the largest amount of new export capacity installed during the decade. One of the projects, Tennessee Gas Pipeline Company's Reynosa/Monterrey project, as a bidirectional line, also increased import capacity to the United States for the first time since the early 1980's. The impetus for most of the increased export capacity has been to support mostly industrial and power generation customers located in the border area. At the close of 1999, export capacity to Mexico stood at 1.5 billion cubic feet per day.

- Since 1998, the number of projects adding to offshore pipeline capacity in the Gulf of Mexico has decreased significantly. In 1997 and 1998, 14 natural gas pipeline projects were completed, which represented a total of 6.4 billion cubic feet per day of new pipeline capacity in the Gulf, most of which were large capacity pipelines connecting onshore facilities with developing offshore sites, particularly in the deepwater areas of the Gulf. During 1999, four significant projects were completed, adding 1 billion cubic feet per day to the area's pipeline capacity. All of these projects were built primarily to improve gathering operations and to link new and expanding producing platforms located in the Gulf with offshore mainlines directed to onshore facilities.

- In late October 2000, the Alliance Pipeline, which will be capable of transporting up to 1.3 billion cubic feet per day of natural gas from British Columbia, Canada, to the State of Illinois, is expected to be placed in service. This project alone represents a 40 percent increase over 1998 levels in natural gas import capacity into the Midwestern United States. Also in the Midwest region, the Vector Pipeline system is scheduled for completion in late 2000 and will transport some of the Alliance Pipeline's supplies to eastern markets in the United States and Canada.

Consumption

Natural gas consumption reached 21.7 trillion cubic feet in 1999, 2 percent more than in 1998. The decade began with 18.7 trillion cubic feet of natural gas consumption in 1990 and increased steadily to 22.0 trillion cubic feet in both 1996 and 1997. Warmer-than-normal winter weather contributed to the decline in consumption to 21.3 trillion cubic feet in 1998. The historical peak in U.S. natural gas consumption occurred in 1972 when 22.1 trillion cubic feet was consumed.

End users consumed 19.9 trillion cubic feet of natural gas in 1999, 413 billion cubic feet or 2 percent more than in 1998. The largest increase occurred in California, where end-use consumption reached 2,071 billion cubic feet, an increase of 137 billion cubic feet or 7 percent compared with 1998. The largest decrease occurred in Texas, where end-use consumption declined by 128 billion cubic feet to 3,507 billion cubic feet, a drop of 4 percent compared with 1998.

Both residential and commercial customers increased their use of natural gas in 1999. Consumption rose by 5 and 2 percent, respectively, in these sectors compared with 1998. The major use of natural gas in both sectors is for space heating and even though the heating months of 1999 (January, February, March, November, and December) were generally warmer than normal, they were colder than in 1998.[3] Residential natural gas consumption in 1999 was 4.7 trillion cubic feet. Commercial natural gas consumption in 1999 was 3.0 trillion cubic feet. At the State level, the largest change in residential consumption from 1998 to 1999 occurred in Illinois, where consumption increased by 35 billion cubic feet or 9 percent. The largest change in commercial consumption at the State level occurred in California, where consumption decreased by 37 billion cubic feet or 13 percent.

Consumption of natural gas in the industrial and electric utility sectors moved in opposite directions in 1999. This was in part the result of the reclassification of some electric utility consumption. Industrial consumption in 1999 was 9.0 trillion cubic feet, 4 percent higher than in 1998. Electric utilities consumed 3.1 trillion cubic feet of natural gas in 1999, which was 4 percent less than in 1998.

[3]Comments about the weather are based on gas home customer-weighted heating degree days found in Table 26 of the Energy Information Administration's *Natural Gas Monthly*, DOE/EIA-0130, April issues in 1999 and 2000.

Restructuring of the electric utility industry is taking place on a State-by-State basis.[4] Where it is proceeding, electric utilities are selling generating plants to entities that are not regulated utilities. When such a sale occurs, these facilities are reclassified as nonutility generators, and the natural gas that they consume is reported as industrial consumption rather than electric utility consumption.

Evidence of such shifts in the natural gas consumption data can be seen in California and Massachusetts. While other factors, such as the level of industrial activity and hot summer weather,[5] also affect demand for natural gas in these sectors, both States show a large shift of natural gas consumption from the electric utility sector to the industrial sector. In California, electric utility consumption of natural gas declined by 126 billion cubic feet or 47 percent from 1998 to 1999, while industrial consumption increased by 282 billion cubic feet or 34 percent. Similarly, in Massachusetts, electric utility consumption of natural gas declined by 10 billion cubic feet or 56 percent, while industrial consumption increased by 32 billion cubic feet or 26 percent. Such shifts in natural gas consumption can be expected to continue during the next several years as restructuring efforts expand in the electricity industry.

Consumer Prices

End-use consumers paid lower prices in 1999 than in 1998 with the exception of the electric utility sector. The declines were somewhat modest: 2 percent in the residential sector, 3 percent in the commercial sector, and 1 percent in the industrial sector. In contrast, the price in the electric utility sector rose by 9 percent.

The prices paid for deliveries of natural gas to the residential and commercial sectors reflect the limited options in service and the high-quality services required during peak demand periods. Compared to industrial and electric utility customers, these sectors typically pay a higher percentage of the fixed costs of long-distance transportation and local distribution and their prices respond to changes in wellhead prices over a long time period.

Industrial companies and electric utilities are large-volume customers with relatively high load factors, which enable them to take advantage of economies of scale in purchases. Additionally, they are typically in a better position to elect whether to stay with their local distribution company (LDC) or seek supplies from alternative sources. These factors result in prices that are highly responsive to fluctuations in wellhead prices. However, the industrial prices that EIA is able to collect are associated with only a small percentage of the natural gas delivered to industrial users. Thus changes in EIA's industrial prices may not track as closely with changes in the average wellhead price as one would expect. Electric utility prices do correspond to total deliveries of natural gas in this sector.

The average price for natural gas at the city gate increased by 1 percent from 1998 to 1999 to reach $3.10 per thousand cubic feet. City gate prices represent the total cost paid by gas distribution companies for gas received at the point where the gas is physically transferred from a pipeline company or transmission system to the LDC. This price is intended to reflect all charges for the acquisition, storage, and transportation associated with the LDC obtaining natural gas for sale to consumers.

Residential consumers continued to pay the highest price for natural gas. The average price of natural gas deliveries to the residential sector declined for the second year in a row. It decreased by 2 percent from $6.82 per thousand cubic feet in 1998 to $6.69 per thousand cubic feet in 1999. In recent years, only modest changes in constant dollars have been seen for residential prices (Figure 14). Most of these consumers remain captive to LDC sales service in all but a few States. The LDCs are obligated to supply gas to residences at all times, including during heating seasons when demand is high. Providing this premium service usually results in higher prices. The second-highest prices for natural gas deliveries were seen in the commercial sector. The average price paid by commercial consumers declined by 3 percent from $5.48 in 1998 to $5.33 per thousand cubic feet in 1999. The percentage of deliveries for the account of others (i.e., for transportation-only customers) to the commercial sector has grown substantially since 1993 from 16 percent of commercial deliveries to 34 percent in 1999. In 19 States and the District of Columbia, prices in this sector were associated with less than 70 percent of deliveries in 1999.

Deliveries for the account of others in the industrial sector represented 83 percent of all deliveries to that sector during 1999 and resulted in industrial prices, as reported by EIA, associated with only 17 percent of the volumes delivered. Prices for gas purchased by the industrial customers who continue to buy from LDC suppliers declined by 1 percent from $3.14 per thousand cubic feet in 1998 to $3.10 in 1999. Electric utility prices reflect natural gas consumption by all large electric utilities and do not include gas consumed by nonutility power producers. Following the rise in the average wellhead price, the price paid by electric utilities for natural gas increased by 9 percent from $2.40 per thousand cubic feet in 1998 to $2.62 per thousand cubic feet in 1999.

[4] For information on restructuring of the electricity generation industry, see the Energy Information Administration's Internet site at http://www.eia.doe.gov.

[5] Hot weather increases the demand for electricity to meet air conditioning needs and many electricity generators rely on natural gas to meet peak levels of electricity demand.

Most of the natural gas delivered for vehicle fuel represents deliveries to refueling stations that are used primarily by fleet vehicles. Thus, the prices are often those associated with the operation of fleet vehicles and may be based on internal transfer prices for companies primarily in the natural gas business. The average price paid for deliveries of natural gas for vehicle fuel use was $4.34 per thousand cubic feet in 1999 and was associated with a very small volume of deliveries.

Changes to Tables in the *Natural Gas Annual 1999*

Some changes have been made to the types of information presented in the tables of this report. These changes were made to account for changes to the Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition," and to reflect information appropriate to the restructured natural gas industry.

The changes to the tables in the *Natural Gas Annual 1999* are:

- The average annual residential consumption and costs per consumer are no longer presented in this report because of possible double counting of the number of residential consumers. The EIA expects that there may be double counting of residential customers as they entered customer choice programs in 1998 and 1999. (See the cautionary note in the Preface.) To the extent that customers are reported both as sales and as transportation customers, calculations of average annual rates per residential consumer will result in erroneously low rates. Table 18 shows the number of sales and transportation customers for the residential sector. Tables 19 and 20 have been added to show these same data for the commercial and industrial sectors. In Table 22, columns have been added to show the percentage of total volume delivered associated with the residential price.

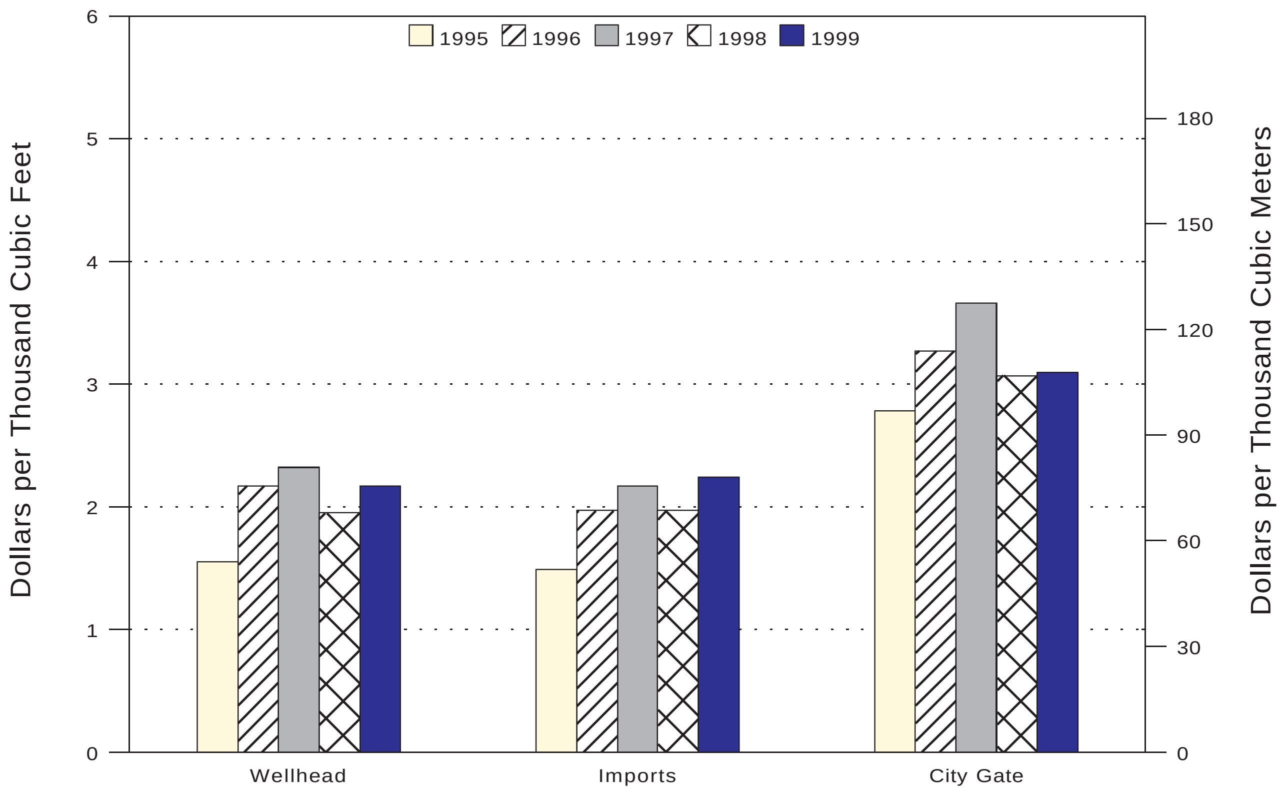
- Storage capacity data in Table 11 are now shown by type of facility: salt cavern, aquifer, or depleted field.

- Information about firm and interruptible deliveries is no longer collected on the Form EIA-176 and thus not presented in this report. These data were collected for report years 1993 through 1998 and are available in the EIA report, *Historical Natural Gas Annual*.

- Reserves data are no longer included in this report. They can be found in the comprehensive EIA report, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, Annual Report*.

- Details about natural gas liquids extracted at natural gas processing plants, previously presented in the Supply Chapter and in Appendix A, are no longer provided in this report. Total liquids extracted can be found in the EIA report, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, Annual Report*. Estimated components and products in liquids extracted can be found in the EIA reports, *Petroleum Supply Monthly* and *Petroleum Supply Annual*.

Figure 2. Selected Average Prices of Natural Gas in the United States, 1995-1999



Sources: Energy Information Administration (EIA), Form EIA-857, "Monthly Report of Natural Gas Purchases and Deliveries to Consumers"; Office of Fossil Energy, U.S. Department of Energy, *Natural Gas Imports and Exports*; Form EIA-627, "Annual Quantity and Value of Natural Gas Report" (1995); and Form EIA-895, "Monthly Quantity and Value of Natural Gas Report" (1996 through 1999).

Table 1. Summary Statistics for Natural Gas in the United States, 1995-1999

	1995	1996	1997	1998	1999
Number of Gas and Gas Condensate Wells					
Producing at End of Year	298,541	301,811	310,971	[R]316,929	307,449
Production (million cubic feet)					
Gross Withdrawals					
From Gas Wells	17,282,032	17,737,334	17,844,046	[R]17,719,241	17,540,919
From Oil Wells	6,461,596	6,376,201	6,368,631	[R]6,376,965	6,214,427
Total	**23,743,628**	**24,113,536**	**24,212,677**	**[R]24,096,206**	**23,755,345**
Repressuring	-3,565,023	-3,510,753	-3,491,542	[R]-3,437,062	-3,304,594
Nonhydrocarbon Gases Removed	-388,392	-518,425	-598,691	[R]-615,941	-609,717
Wet After Lease Separation	19,790,213	20,084,357	20,122,444	[R]20,043,203	19,841,034
Vented and Flared	-283,739	-272,117	-256,351	[R]-234,472	-245,180
Marketed Production	19,506,474	19,812,241	19,866,093	[R]19,808,731	19,595,854
Extraction Loss	-907,795	-958,178	-963,759	-937,798	-901,235
Total Dry Production	**18,598,679**	**18,854,063**	**18,902,334**	**[R]18,870,933**	**18,694,619**
Supply (million cubic feet)					
Dry Production	18,598,679	18,854,063	18,902,334	[R]18,870,933	18,694,619
Receipts at U.S. Borders					
Imports	2,841,048	2,937,413	2,994,173	3,152,058	3,585,505
Intransit Receipts	492,481	536,333	548,000	481,581	486,468
Withdrawals from Storage					
Underground Storage	2,974,102	2,911,327	2,824,245	2,377,344	2,771,534
LNG Storage	50,446	69,287	69,517	54,365	101,871
Supplemental Gas Supplies	110,290	109,455	103,153	102,189	98,247
Balancing Item	-230,002	217,114	61,024	[R]-179,642	-683,124
Total Supply	**24,837,044**	**25,634,990**	**25,502,445**	**[R]24,858,828**	**25,055,120**
Disposition (million cubic feet)					
Consumption	21,580,665	21,966,616	21,958,660	[R]21,278,888	21,694,489
Deliveries at U.S. Borders					
Exports	154,119	153,393	157,006	159,007	163,415
Intransit Deliveries	492,481	536,333	516,620	459,461	494,544
Additions to Storage					
Underground Storage	2,565,882	2,905,592	2,800,294	2,903,585	2,597,509
LNG Storage	43,897	73,057	69,865	57,887	105,163
Total Disposition	**24,837,044**	**25,634,990**	**25,502,445**	**[R]24,858,828**	**25,055,120**
Consumption (million cubic feet)					
Lease Fuel	792,315	799,629	776,306	[R]773,049	677,655
Pipeline Fuel	700,335	711,446	751,470	635,477	735,078
Plant Fuel	427,853	450,033	426,873	401,314	399,509
Delivered to Consumers					
Residential	4,850,318	5,241,414	4,983,772	4,520,276	4,724,094
Commercial	3,031,077	3,158,244	3,214,912	2,999,491	3,048,832
Industrial	8,579,585	8,870,422	8,832,450	8,686,147	8,990,216
Vehicle Fuel	2,674	2,932	4,424	5,079	5,685
Electric Utilities	3,196,507	2,732,496	2,968,453	3,258,054	3,113,419
Total Delivered to Consumers	**19,660,161**	**20,005,508**	**20,004,012**	**19,469,047**	**19,882,247**
Total Consumption	**21,580,665**	**21,966,616**	**21,958,660**	**[R]21,278,888**	**21,694,489**
Delivered for the Account of Others (million cubic feet)					
Residential	45,269	49,148	61,013	105,128	225,198
Commercial	706,139	706,667	939,332	990,265	1,032,091
Industrial	6,517,352	7,151,885	7,272,947	7,339,353	7,428,945
Electric Utilities	2,110,284	1,871,496	1,932,394	2,152,846	2,136,894

See footnotes at end of table.

Table 1. Summary Statistics for Natural Gas in the United States, 1995-1999 (Continued)

	1995	1996	1997	1998	1999
Number of Consumers					
Residential	54,322,179	55,263,673	56,186,958	57,321,746	58,200,837
Commercial	4,636,500	4,720,227	4,761,409	5,044,497	5,007,325
Industrial	209,398	206,049	238,961	231,438	230,137
Average Annual Consumption per Consumer (thousand cubic feet)					
Commercial	654	669	675	595	609
Industrial	40,973	43,050	36,962	37,531	39,065
Average Prices for Natural Gas (dollars per thousand cubic feet)					
Wellhead (Marketed Production)	1.55	2.17	2.32	[R]1.95	2.17
Imports	1.49	1.97	2.17	1.97	2.24
Exports	2.39	2.97	3.02	2.45	2.61
Pipeline Fuel	1.49	2.27	2.29	2.01	1.95
City Gate	2.78	3.27	3.66	3.07	3.10
Delivered to Consumers					
Residential	6.06	6.34	6.94	6.82	6.69
Commercial	5.05	5.40	5.80	5.48	5.33
Industrial	2.71	3.42	3.59	3.14	3.10
Vehicle Fuel	3.98	4.34	4.44	4.59	4.34
Electric Utilities	2.02	2.69	2.78	2.40	2.62

[R] = Revised data.

Notes: Beginning in 1987, prices for gas delivered to consumers are calculated using only on-system sales data. No imputations are made for prices of gas delivered for the account of others. In previous years, prices were calculated using reported values and values imputed for gas delivered for the account of others. The United States includes the 50 states and the District of Columbia. Totals may not equal sum of components due to independent rounding. Beginning in 1996, consumption of natural gas for agricultural use was classified as industrial use. In 1995, agricultural use was classified as commercial use.

Sources: Energy Information Administration (EIA), Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition"; Form EIA-627, "Annual Quantity and Value of Natural Gas Report" (1995); Form EIA-895, "Monthly Quantity and Value of Natural Gas Report" (1996 through 1999); Form EIA-857, "Monthly Report of Natural Gas Purchases and Deliveries to Consumers"; Form EIA-816, "Monthly Natural Gas Liquids Report"; Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production"; Form EIA-759, "Monthly Power Plant Report"; Form FERC-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants"; Form EIA-191, "Underground Gas Storage Report"; Office of Fossil Energy, U.S. Department of Energy, *Natural Gas Imports and Exports*; *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, Annual Reports*, DOE/EIA-0216; and the U.S. Minerals Management Service.

Figure 3. Natural Gas Supply and Disposition in the United States, 1999
(Trillion Cubic Feet)

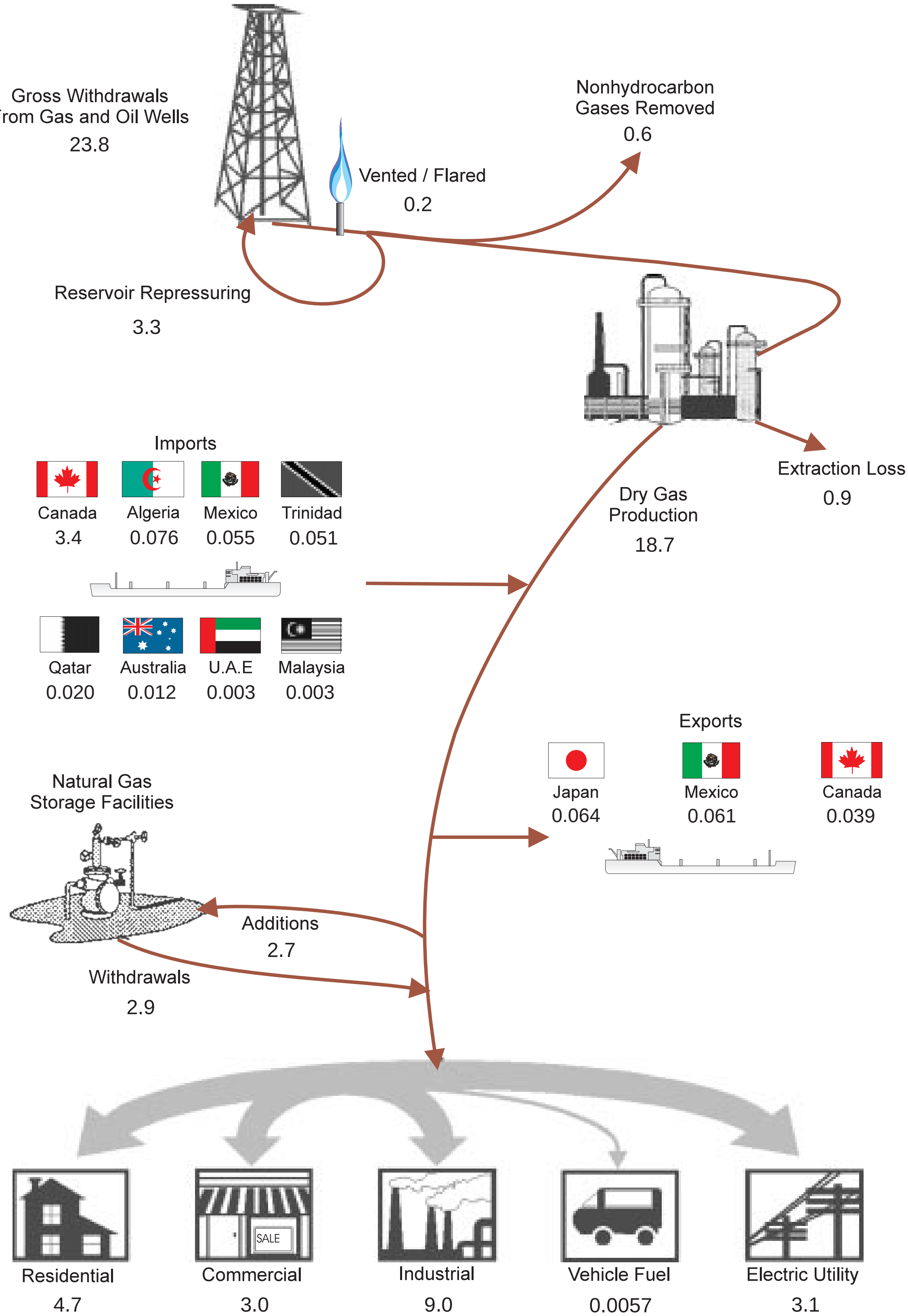


Table 2. Natural Gas Production, Transmission, and Consumption by State, 1999
(Million Cubic Feet)

State	Marketed Production	Extraction Loss	Balancing Item[a]	Net Interstate Movements[b]	Net Movements Across U.S. Borders[b]	Net Storage Changes[c]	Supplemental Gas Supplies	Consumption
Alabama	547,271	18,079	56,610	-253,049	0	-55	4	332,813
Alaska	462,967	38,412	59,086	0	-63,607	0	0	420,033
Arizona	474	0	65,122	99,504	-4,279	0	0	160,821
Arkansas	170,006	431	10,774	79,993	0	-234	0	260,576
California	382,715	10,762	-25,760	1,795,215	-3,761	-8,253	0	2,145,900
Colorado	739,085	26,423	-200,261	-199,481	0	1,502	4,526	315,944
Connecticut	0	0	-29,309	161,005	0	-66	31	131,793
D.C.	0	0	-1,398	33,635	0	0	0	32,237
Delaware	0	0	14,669	41,343	0	31	0	55,981
Florida	5,933	1,557	6,382	508,613	0	0	0	519,370
Georgia	0	0	-67,677	397,865	0	-1,403	12	331,604
Hawaii	0	0	-17	0	0	0	2,752	2,735
Idaho	0	0	8,169	-739,097	800,345	492	0	68,926
Illinois	195	55	57,445	977,570	0	2,956	2,527	1,034,725
Indiana	855	0	-25,538	587,213	0	914	5,442	567,058
Iowa	0	0	-162,029	390,907	0	-2,372	12	231,262
Kansas	553,419	48,107	11,647	-229,385	0	-15,568	0	303,142
Kentucky	76,770	2,287	-56,471	192,574	0	-2,725	3	213,313
Louisiana	5,313,794	164,794	-30,298	-3,699,296	67,362	-8,480	0	1,495,248
Maine	0	0	-570	6,597	0	15	43	6,054
Maryland	18	0	-12,612	207,457	0	556	498	194,804
Massachusetts	0	0	6,871	233,700	96,068	-2,447	134	339,219
Michigan	277,364	5,945	-98,459	1,177,341	-490,348	-32,938	20,896	913,787
Minnesota	0	0	-25,310	-632,977	998,603	565	64	339,817
Mississippi	111,021	5,462	232,694	-18,588	0	-14,502	0	334,166
Missouri	0	0	-5,142	271,677	0	567	207	266,175
Montana	61,163	435	-29,624	-782,506	805,614	-7,884	0	62,096
Nebraska	1,395	0	-85,361	205,093	0	-297	4	121,429
Nevada	8	0	22,027	129,443	0	-29	0	151,507
New Hampshire	0	0	-13,095	10,475	22,820	0	111	20,312
New Jersey	0	0	47,150	564,195	0	283	5,761	616,823
New Mexico	1,511,671	107,850	1,046	-1,173,095	0	2,289	0	229,483
New York	16,122	0	-44,292	483,771	754,484	-7,628	459	1,218,172
North Carolina	0	0	-32,546	255,366	0	1,997	21	220,844
North Dakota	52,862	5,804	-4,084	-43,203	3,416	0	53,185	56,373
Ohio	109,509	78	-99,573	819,664	0	-16,019	1,200	846,741
Oklahoma	1,570,847	88,195	-206,121	-739,067	0	6,703	0	530,761
Oregon	1,291	0	-1,987	209,999	0	661	3	208,644
Pennsylvania	174,701	879	-142,887	618,461	0	-22,528	119	672,043
Rhode Island	0	0	-2,289	86,487	0	24	1	84,176
South Carolina	0	0	17,280	141,038	0	711	18	157,625
South Dakota	1,566	0	-3,568	37,792	0	9	5	35,787
Tennessee	1,230	0	-19,475	295,768	0	-789	9	278,321
Texas	6,117,653	307,465	-82,327	-1,876,170	1,270	-5,985	17	3,858,964
Utah	262,614	11,407	-78,558	-22,170	0	-9,193	0	159,672
Vermont	0	0	888	-3,248	10,391	0	1	8,032
Virginia	72,189	0	-25,486	218,232	0	33	179	265,080
Washington	0	0	-115,105	-34,869	415,636	1,974	0	263,688
West Virginia	176,015	7,334	172,980	-236,588	0	-34,622	0	139,694
Wisconsin	0	0	8,871	365,058	0	-61	0	373,990
Wyoming	823,132	49,474	244,393	-920,258	0	1,063	0	96,730
Total	**19,595,854**	**901,235**	**-683,124**	**0**	**3,414,015**	**-170,732**	**98,247**	**21,694,489**

[a] Balancing Item volumes are equal to Total Disposition (net storage changes plus extraction loss plus consumption) minus Total Supply (marketed production plus net interstate movements plus net movements across U.S. borders plus supplemental gas supplies).
[b] Positive numbers denote net receipts; negative numbers denote net deliveries.
[c] Negative numbers indicate withdrawals from storage in excess of additions to storage and are, therefore, additions to total supply.

Note: Totals may not equal sum of components due to independent rounding.
Sources: Energy Information Administration (EIA), Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition"; Form EIA-895, "Monthly Quantity and Value of Natural Gas Report"; Form EIA-816, "Monthly Natural Gas Liquids Report"; Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production"; and the U.S. Minerals Management Service.