3. Transportation Flow Patterns

Extensive changes occurred in all areas of the natural gas industry from 1988 through 1994. During this period, U.S. natural gas consumption increased by 15 percent to reach 20.7 trillion cubic feet, the highest level since 1974.[30] By far, the most substantial growth took place in the industrial sector (26 percent), in part because of increases in nonutility generation of electricity (including cogeneration).[31] The commercial and electric utility sectors had much lower increases of 10.2 and 13.3 percent, respectively. The growth in consumption was supported by an increase in U.S. dry gas production of 1.8 trillion cubic feet and a substantial increase in imported gas from Canada. In 1994, imports of natural gas from Canada were 2.6 trillion cubic feet, double the 1988 level. Currently, Canadian imports supply approximately 13 percent of domestic consumption, up from 7 percent in 1988.

The importance of the interstate natural gas transmission network is illustrated by the fact that 27 of the lower 48 States are almost totally dependent upon the system for their natural gas supplies. These supplies must be transported from only 11 States, located primarily in the Southwest and Central Regions (Figure 1). More than 1,200 local distribution companies nationwide distribute these supplies to the ultimate consumer. The major 38 interstate pipeline companies (of more than 100 nationwide) account for more than 76,900 miles of the Nation's 250,000 miles of mainline pipe (21-inch or larger diameter).[32] More than 550 interconnections are within this network, providing customers access to supplies throughout the Nation.

Various elements have influenced gas industry operations and market outcomes since 1988. Federal legislation and regulation are key influences on the industry, especially those related to the basic restructuring of the transportation sector. The introduction of open-access transportation programs brought a whole new orientation to the natural gas pipeline industry.[33] Most throughput on the major interstate pipelines before 1988 was transported from receipt to delivery on the single system of each pipeline company because the gas was owned by the pipeline companies. Today transportation and related services dominate pipeline operations. Approximately 96 percent of all natural gas transported on the interstate system in 1994 represented transportation of gas owned by others, compared with 56 percent in 1986 and only 21 percent in 1981 when interstate pipeline companies were the primary sellers of natural gas. The transformation of the transmission segment of the industry has changed both the objectives and the participants, and altered business relationships within the marketplace (Figure 2).

This chapter discusses the changes that have taken place in natural gas flows from supply areas to markets since 1988,[34] the capability of the interstate network to deliver natural gas, and how the network is being used to accommodate the changing supply and consumption patterns. It highlights some of the differences in consumption and supply patterns since 1988 that may be related to changes in Federal policies. It also discusses the effect of industry restructuring on interstate pipeline flows.

Changes in Flow Patterns

The introduction and extension of market forces dominated the industry and its transmission patterns between 1988 and 1994. Transmission and distribution patterns of natural gas are governed by regional demand conditions, which are constrained by the capacity of the physical network used to move gas to end users. Significant system expansion has occurred since 1988 to accommodate supply and demand changes. Attributes of the expanded physical network have been augmented by the operational efficiencies resulting from the regulatory restructuring of the interstate pipeline system

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[30]Unless otherwise specified, gas consumption data are from the Energy Information Administration, *Natural Gas Annual 1993*, DOE/EIA-0131(93) (Washington, DC, November 1993), and *Monthly Energy Review*, DOE/EIA-0035(95/08) (Washington, DC, August 1995).

[31]Nonutility generators include all generators that are not included in the assets of electric utilities. These nonutility generators include qualifying cogenerators and small power producers as well as the new independent power producers. Natural gas supplies for nonutility generators are included in industrial gas deliveries.

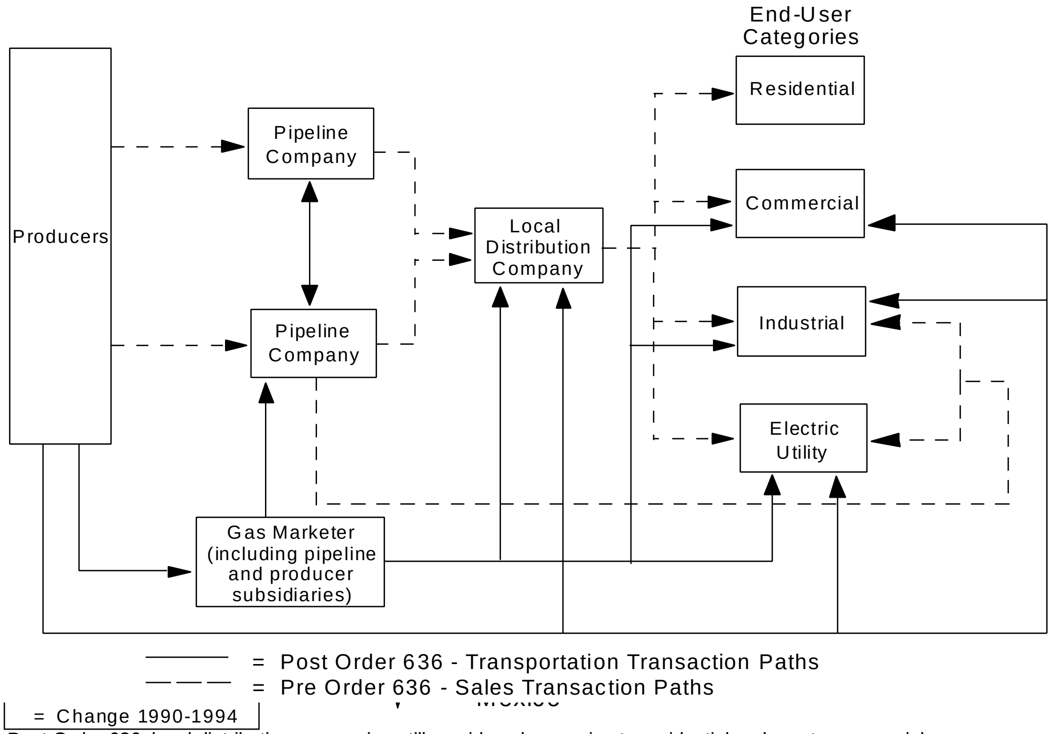
[32]Energy Information Administration (EIA), EIAGIS-NG Geographic Information System, Natural Gas Pipeline System Map files.

[33]FERC Order 436 was rendered invalid by the Courts in 1986 and ultimately was replaced by FERC Order 500, which took effect in 1987. Between 1985 and 1987, while litigation proceeded, Order 436 had little practical effect.

[34]The analysis does not always cover the entire period from 1988 to 1994, because of limited data in some areas. Data on interstate pipeline flows are available for the period 1988 through 1993 (and limited 1994). Comprehensive information on the capacity of the pipeline system is only available from 1990, when the Energy Information Administration first compiled statistics on this aspect of the industry. The discussion of capacity changes and changes in utilization rates, therefore, is limited to the 1990 to 1994 period.

Figure 2. Principal Buy/Sell Gas Transaction Paths for Natural Gas Marketing

Figure 1. Interregional Natural Gas Pipeline Capacity, 1990 and 1994
(Million Cubic Feet per Day)



Note: Post Order 636, local distribution companies still provide sales service to residential and most commercial gas consumers.
Source: Energy Information Administration, Office of Oil and Gas.
Sources: **State Export Status:** Energy Information Administration (EIA), Office of Oil and Gas, derived from: Production and Consumption, *Natural Gas Monthly* (April 1995). **Pipeline Capacity:** EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity Database, as of August 1995.

during this period. These changes to operations have greatly increased the flexibility and accessibility of the system. In addition, lower natural gas prices have increased demand for natural gas.

The principal flow patterns of natural gas from supply areas to markets in the lower 48 States have not changed significantly since 1988. However, several new routes and major increases on several existing routes developed during the period (Figure 3). These changes reflect the effort to meet regional market demands with (often distant) available supplies.[35] The major distribution patterns for natural gas remain those from the Southwest Region to markets located in the Midwest and Northeast Regions. This gas originates primarily in Texas and Louisiana and flows through the Southeast and Central Regions to those markets. Significant gas supplies also flow from the Southwest to markets in the

Western Region (primarily California). Although several major pipelines were completed in the 1970's and 1980's to import more Canadian gas to the United States, flows from Canada accounted for only 7 percent of total national consumption in 1988.

The major change in natural gas flow patterns since 1988 relates to the rapid rise in U.S. imports of Canadian natural gas (Figure 3). For instance, from 1988 through 1994:

- Imports of Canadian gas into the Western Region increased by 51 percent (Figure 4) as more supplies became available from western Canada. Lower prices for Canadian natural gas supplies, the growing demand for gas in the Western Region, and passage of stricter environmental restrictions helped spur this growth.

- Imports of Canadian gas into the U.S. Northeast rose from only 79 billion cubic feet in 1988 to 555 billion cubic feet in 1994. Growth in industrial demand, including electricity generation from both utility and nonutility generators, and in residential demand brought on this change.

- Canadian gas also became more important in the Midwest Region; imports increased by 57 percent, but natural gas consumption in the region increased by only 8 percent during the period.

[35] For instance, one of the earliest regions producing natural gas for market was the Northeast Region. As some of its fields in Appalachia became depleted in the 1940's, long-haul transmission lines began to be installed to tap into distant developing supply areas.

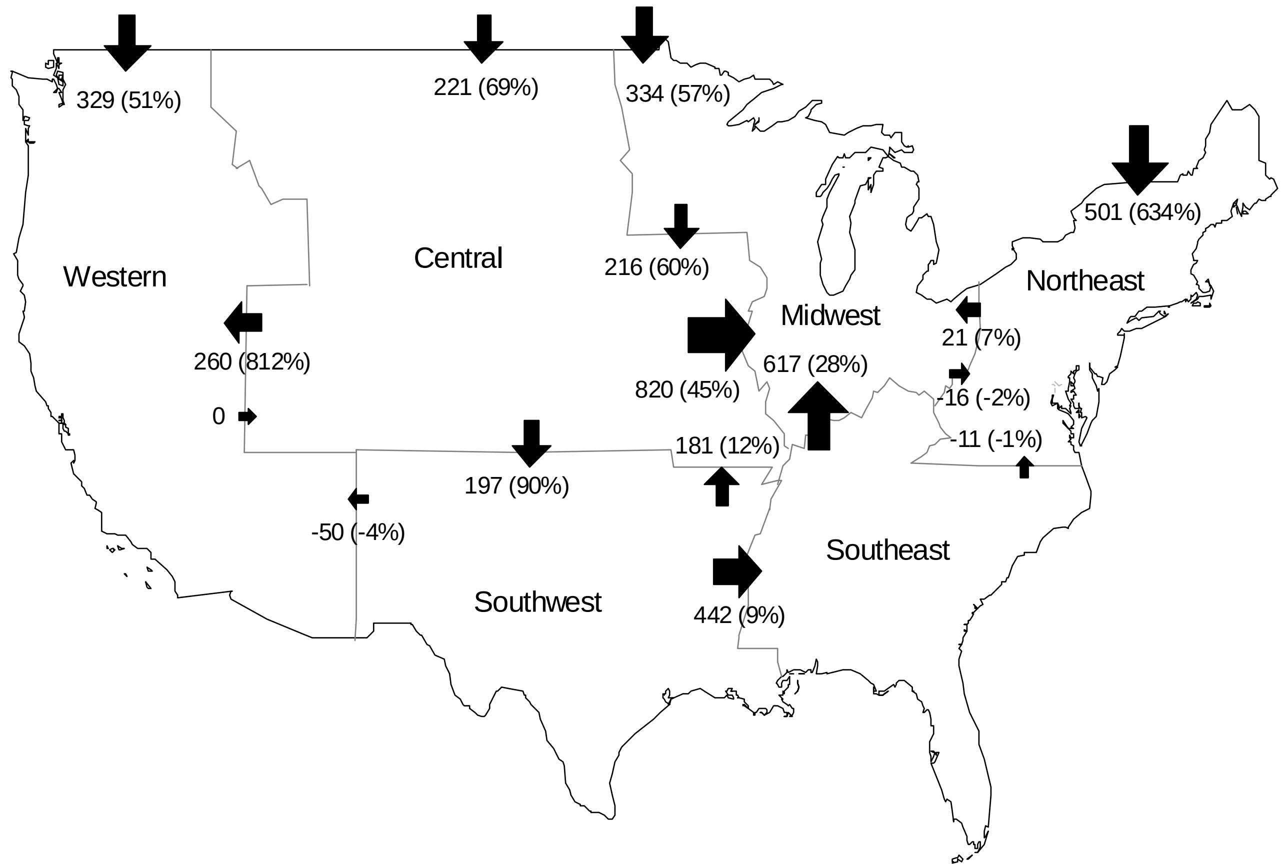
Another major change in natural gas flow patterns has been the increase in flows from the Southwest and Central Regions to the Western Region. These changes occurred as new supplies were developed in the Rocky Mountain area of Colorado/Wyoming and the coalbed methane fields of southern Colorado and northern New Mexico. Much of this production development occurred in tight gas formations and coalbeds. Production from these sources was stimulated by the Section 29 production tax credits. Volumes destined for the Western Region from the Central Region increased by 915 percent, from 33 billion cubic feet in 1988 to 335 billion cubic feet in 1994. About half of these supplies flowed to the enhanced oil recovery markets in California.

Additional variability in flow patterns has originated in natural gas trade with Mexico. Exports of U.S. natural gas to Mexico grew rapidly between 1988 and 1992, increasing from 2 billion cubic feet in 1988 to 96 billion cubic feet in 1992. But since 1992, the level of exports has fallen by half. During the early 1990's, Mexico was viewed as a large potential market for some of the additional natural gas supplies developing in the Southwest Region. Several additional export terminals were opened in 1991; these more than doubled existing crossborder capacity. Crossborder capacity will expand further with the completion of current projects designed to move gas to Mexican consumers. While several border points with Mexico provide reverse flow capability, imports of Mexican gas to the United States remain negligible.

Changes in Consumption Patterns

Changes in the demand for natural gas are the basic forces that motivate decisions in the production, import, transportation, and distribution of natural gas. Consumers of natural gas respond both to economic signals, such as increased economic activity and relative prices, and to other external influences when they make energy choices. Federal legislation and policies affect the economic environment and other external factors that influence the trends and patterns in consumer energy choices. However, consumers' current decisions about energy are seldom totally independent of their

Figure 3. Flow Patterns on the Interstate Pipeline Network, 1994



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

earlier decisions. Because most energy choices are conditioned on matching fuel to available energy-using equipment, changes in consumption patterns take place gradually as consumers purchase new equipment to expand or replace existing energy-using facilities. Thus, trends in natural gas consumption generally reflect legislative and policy initiatives over the longer term.

Total national natural gas consumption increased at an annual rate of 2.4 percent to the level of 20.3 trillion cubic feet between 1988 and 1993.[36] Gas consumption as a share of total domestic energy consumption rose correspondingly from 23.1 percent to 24.8 percent. During this same period, deliveries to end-use customers grew at an annual rate of 2.5 percent (Table 3).[37]

Natural gas consumption trends vary by sector and region. The use of natural gas for heating and its resulting seasonal pattern continues to dominate residential and commercial applications. Gas use in the industrial and electric utility sectors is increasingly related because the gas consumed by nonutility generators for the production of electricity is treated as part of industrial consumption. This section discusses trends in national and regional gas consumption. The discussion of sectoral consumption at a national level identifies differences in the relevant demand influences, while

[36]Currently, final consumption data on both a regional and sectoral basis are available only through 1993, although consumption data by customer sector are available for 1994.

[37]Nationally, deliveries to end-use consumers grew slightly faster than total consumption because natural gas consumed in production and delivery of gas (lease and plant fuel and pipeline use) grew at an annual rate of only 1.1 percent.

Figure 4. Interregional Changes in Flow Levels on the Interstate Pipeline Network Between 1988 and 1994
(Volumes in Billion Cubic Feet)

the description of regional consumption reflects the differences in regional components and the amount of demand by sector.

End-Use Consumption

From 1988 through 1993, total end-use consumption in the lower 48 States grew from 16.2 to 18.4 trillion cubic feet (Table 4), an average annual rate of 2.5 percent. The residential and commercial sectors had growth rates of only 1.4 and 1.8 percent, respectively (Table 3). Slow growth in natural gas consumption in the residential and commercial sectors reflects, at least in part, price changes of energy sources and advances in energy conservation, especially improvements that reduce the amount of energy used to heat a given amount of building space. Despite substantial increases in gas heating applications during the 1988 to 1993 period, the growth in residential and commercial sector gas consumption barely exceeded the overall increase in the population. Growing gas use for space and water heating has been partially offset by improved insulation and new gas heating technologies. A number of new Federal and State laws and policies, including programs to aid low-income home owners retrofit energy conservation measures, have encouraged end-use conservation. These initiatives, including the Energy Policy Act as discussed in Chapter 2, have been quite successful in improved energy end-use efficiency, thus slowing the increase in the growth of demand for gas, especially in the residential and commercial sectors.

Industrial consumption, which represented about 40 percent of all end-use gas consumption in 1993, rose at an annual rate of 4.5 percent. Natural gas consumed by nonutility generators (NUG's) is included in industrial sector gas consumption, so some of the increased consumption can be attributed to the development of nonutility generators of electricity. Much of

Source: Energy Information Administration, *Natural Gas Annual 1988* (October 1989) and "Natural Gas Annual 1994," draft report.

Table 3. Growth in Natural Gas Consumption and Related Factors by Region Between 1988 and 1993

Region	Percent Population Growth	Population Weighted Average Heating Degree Days[1]	Annual Percent Growth of Gas Consumption: Residential	Commercial	Industrial	Electric Utility	Total
Northeast	2.4	4,484	1.1	3.6	9.0	4.0	4.0
Southeast	7.5	2,099	2.0	1.3	4.1	3.1	3.0
Midwest	3.3	5,162	1.1	0.7	4.1	8.7	2.1
Central	4.2	4,959	2.2	0.9	5.9	3.5	3.1
Southwest	5.9	2,055	1.5	2.4	2.7	0.1	1.8
Western	10.8	2,425	1.3	1.0	7.3	-2.2	2.3
Total Lower 48 States	5.5	--	1.4	1.8	4.5	0.4	2.5

[1]Degree-days are relative measures of outdoor air temperature used as an index for heating requirements. Heating degree-days are the number of degrees per day that the daily average temperature is below 65 degrees Fahrenheit. The daily average temperature is the mean of the maximum and minimum temperatures in a 24-hour period. The values shown are calculated by weighting State values for heating seasons 1988-89 through 1993-94 by population and averaging the values over the period. A heating season is from November of one year through March of the next year.

Sources: **Population:** U.S. Department of Commerce, Bureau of Census, *Statistical Abstract of the United States, 1994* (September 1994). **Heating Degree Days:** U.S. Department of Commerce, National Oceanic and Atmospheric Administration, *State, Regional, and National Monthly and Seasonal Heating Degree Days* (July 1993) and subsequent monthly updates. **Population Weighted Average Heating Degree Days:** Energy Information Administration, Office of Oil and Gas, derived from: Population and Heating Degree Days. **Gas Consumption:** 1988—Energy Information Administration, *Natural Gas Annual 1992*, Vol. 1 (November 1993); 1993—Energy Information Administration, *Natural Gas Annual 1993* (October 1994).

Table 4. Natural Gas Deliveries to End-Use Consumers by Region and Sector, 1988 and 1993
(Billion Cubic Feet)

Region	Residential		Commercial		Industrial		Electric Utility		Total	
	1988	1993	1988	1993	1988	1993	1988	1993	1988	1993
Northeast	1,177.2	1,244.4	619.1	740.6	629.8	968.5	232.9	283.1	2,659.3	3,236.9
Southeast	369.7	407.4	269.0	286.9	766.9	938.2	196.1	228.5	1,601.6	1,860.8
Midwest	1,546.1	1,636.7	760.6	789.2	1,158.7	1,413.5	33.1	50.3	3,498.5	3,889.8
Central	507.9	564.9	334.6	350.5	397.7	530.5	37.5	44.5	1,277.6	1,490.2
Southwest	412.3	444.1	309.2	348.3	2,737.1	3,127.6	1,514.6	1,519.0	4,973.3	5,439.4
Western	604.1	645.5	355.0	373.8	625.3	887.6	590.7	528.9	2,174.9	2,436.2
Total Lower 48 States	4,617.3	4,943.0	2,647.5	2,889.3	6,315.5	7,866.9	2,604.9	2,654.3	16,185.2	18,353.5

Sources: Energy Information Administration. **1988:** *Natural Gas Annual 1992*, Vol. 1 (November 1993). **1993:** *Natural Gas Annual 1993* (October 1994).

the expansion in NUG's can be attributed to the success of Title 2 of the Public Utility Regulatory Policies Act of 1978, which established a program to encourage cogeneration and renewable resource electricity generation. The electricity producers who responded to this 1978 initiative form the backbone of the new nonutility power industry. Many of the NUG's are part of industrial plants that use cogeneration to produce both electricity and useful thermal energy. Therefore, gas consumption in industrial facilities that include NUG's cannot be separated between electricity and other industrial uses. Industrial establishments with NUG facilities are estimated to account for more than 20 percent of all industrial gas deliveries in 1993.[38]

Natural gas consumption in the electric utility sector was nearly stagnant, growing at an annual rate of only 0.4 percent. The low growth in electric utility consumption reflects the marginal role of utility gas-fired generation. Many utilities use gas as a swing fuel to fill in for shortfalls of nuclear generation or hydroelectric resources. Thus, gas consumption by these utilities varies according to the availability of generation from these lower variable cost resources. For example, gas consumption by electric utilities increased by more than 11 percent (about 300 billion cubic feet) between 1993 and 1994, partly because a drought reduced hydroelectric generation.

The use of natural gas for vehicle fuel comprises a large potential market, but it is still in its infancy. Legislative initiatives, including provisions in the Energy Policy Act and the Clean Air Act Amendments, to encourage alternatives to gasoline-powered vehicles have induced significant research and development of natural gas-powered vehicles.[39] But their total impact on natural gas consumption is barely measurable on a national scale. Natural gas used as a vehicle fuel represents a very small fraction of total consumption. The amount of natural gas delivered for use as vehicle fuel in 1993 was only 1 billion cubic feet, compared with U.S. deliveries of 18.5 trillion cubic feet to all consuming sectors. However, the rapid growth of vehicle-fuel gas consumption indicates the potential for natural gas in this developing market.

Regional End-Use Consumption

There are striking differences in gas consumption among geographic regions. Patterns of gas consumption vary in response to regional differences in gas penetration rates and to changes in the level of economic activity, as well as other, more transitory effects. Significant quantities of natural gas are used for space heating in the winter and electric generation in the summer in some regions. This temperature-sensitive gas consumption can drive fluctuations in regional consumption from year to year if there are major variations in weather patterns.

Three of the six regions—the Southwest, the Midwest and the Northeast—account for nearly 70 percent of all gas consumption. The Southwest alone consumes nearly 30 percent of all gas used in the lower 48 States. In the Southwest, gas consumption is concentrated in the industrial and electric utility sectors (85 percent of the total) (Figure 5). In this region, a significantly smaller share of gas use (less than 15 percent) is devoted to residential and commercial customers than is the case elsewhere. In the other two major gas-using regions, the Midwest and the Northeast, a much larger share of gas consumption (60 percent or more) is in the residential and commercial sectors.

Industrial gas consumption in the Southwest continues to represent the largest single regional use of gas, even though the region's share of industrial consumption fell from 43 percent in 1988 to 40 percent in 1993. The Southwest continues to attract industries, such as chemical manufacturing, that use large quantities of gas. In addition, the Southwest has been the leading region in NUG development; by 1993 the Southwest had about 32 percent of the national NUG generating capacity. Industrial consumption in other regions, noticeably the Western, Northeast, and, although from a small base, the Central Region, has shown significant growth. NUG development has contributed to this growth in industrial consumption in both the Western and Northeast Regions.

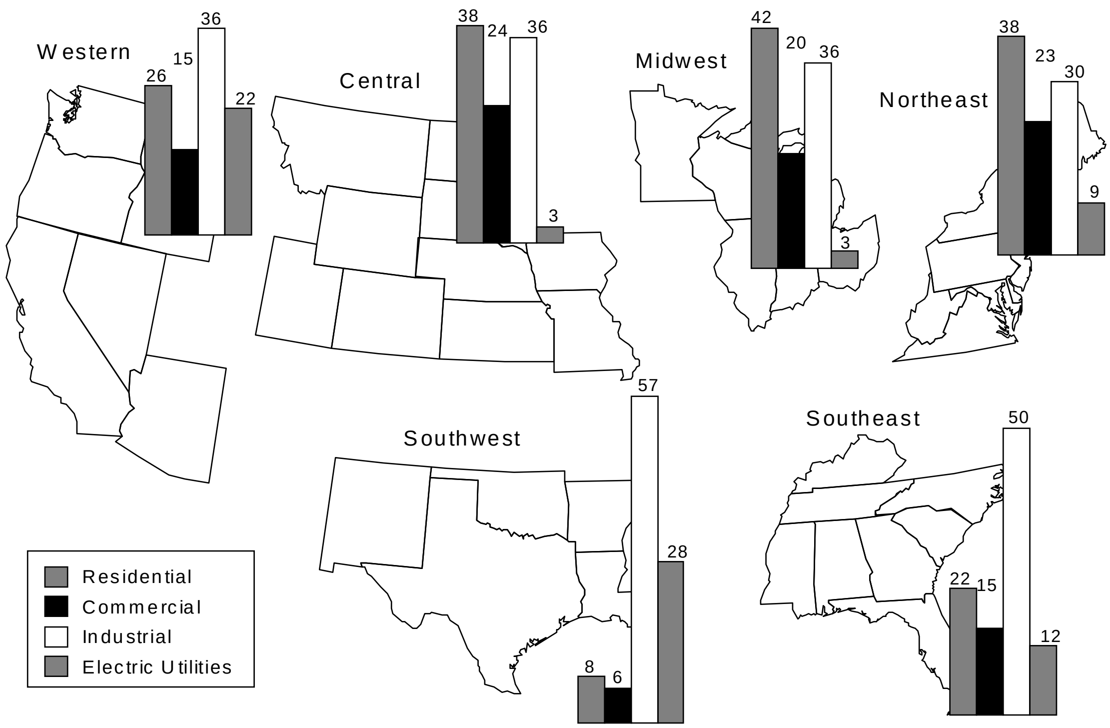
Electric utilities consume the least amount of natural gas of the end-use sectors in each region except the Southwest and Western. In 1993, utilities in the Southwest used 57 percent of all the gas supplied to electric utilities; another 20 percent was used by electric utilities in the Western Region. Although a few utilities in Florida, New York, and other States outside of these two regions also use gas regularly, their effect on gas consumption is relatively small.

As discussed in Chapter 2, patterns of increased gas consumption in large industrial and utility boilers were disrupted by the Power Plant and Industrial Fuels Use Act of

[38]The proportion of industrial gas deliveries going to establishments with nonutility generation facilities is based on data from Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

[39]In order to promote the availability of vehicular natural gas (VNG), the Federal Energy Regulatory Commission issued Order 543 on July 16, 1992, simplifying the certification process for VNG retail sales and minimizing the reporting requirements of VNG wholesalers.

Figure 5. Percent of End-Use Natural Gas Consumption by Sector Within Regions, 1993



Note: Totals may not equal 100 because of independent rounding.
Source: Energy Information Administration, *Natural Gas Annual 1993*.

1978 (FUA). FUA discouraged both utility and industrial gas-using capacity expansion. However, FUA probably helped start the surge in nonutility generation because it permitted exemptions from FUA for industrial cogenerators. On the other hand, electric utilities started to build new coal-fired and nuclear power plants during the period of FUA restrictions because they were not allowed to rely on additional gas resources. By the time FUA was modified in 1987, most utility expansion needs could be filled by these new plants and by capacity that had been built by NUG's. Therefore, electric utility consumption of gas did not grow compared to the historically high levels of consumption in earlier periods. Nor does it appear that the pollution abatement requirements of the Clean Air Act Amendments have encouraged utilities to substitute significant amounts of gas for other fuels thus far.

Moreover, the expansion of NUG's in the industrial sector makes it difficult to separate growth in industrial applications of natural gas from growth in industrial site generation. Industrial gas consumption, cushioned by NUG development and encouraged by attractive gas prices and new access to pipeline transportation, has nearly returned to levels achieved in the early 1970's. The growth of industrial gas consumption is especially impressive in regions such as the Northeast where pipeline expansions and Canadian import availability have produced annual consumption growth rates as high as 9.0 percent between 1988 and 1993 (Table 3).

Despite the electric utilities' small share in gas consumption, much interest has been focused on gas used for electricity production for two reasons. First, although utility gas consumption has been growing, it still has not returned to its historical peak levels before FUA in the early 1970's. In 1993, electric utility gas deliveries were 33 percent below the 1972 peak.

Second, rapid expansion of nonutility, gas-fired generation led many forecasters to predict that NUG demand for gas would grow substantially during the remainder of the century and would compensate for the slow recovery of utility gas consumption. However, a restructuring of the electric industry has begun in response to provisions of the Energy Policy Act of 1992. Because the restructuring process is still in an early phase, there is a great deal of uncertainty about the need for additional electric generation in a restructured industry. This uncertainty may postpone additions to gas-fired generating capacity by both electric utilities and NUG's.

Changes in Supply Patterns

Supply patterns from domestic and foreign sources have changed considerably since 1988. Changes at the natural gas supply source frequently require flow adjustments downstream. A review of the regional changes since 1988 reveal certain outcomes that are attributable to Federal actions by their direct impact on the extraction process or by affecting production decisionmaking.

Changes in Federal regulations, policies, and directives have both promoted and imposed restrictions on natural gas production or production-related activities. Production was advanced by numerous Federal actions including FERC Order 636, which increased competition among producers and drove down the price. The combined effect of lower prices and more secure service has promoted expanded gas sales and thus production in the United States.[40] To supply the expanding market, producers in the United States increased production of dry natural gas by 1.8 trillion cubic feet between 1988 and 1994, from 17.1 to 18.9 trillion cubic feet.

Other elements that stimulate natural gas supply include U.S. tax provisions, which have been modified over the years. Adjustments to existing law and inclusion of new provisions inevitably affect the expected profitability of oil and gas investments by altering the net returns or perceived risk. The net effects of tax changes that are not energy specific (e.g., changes to depreciation rules or marginal income tax rates) change over time, but for simplicity most of them are assumed to have a uniform impact across all regions. Energy specific tax provisions, such as the production tax credits for gas from coalbeds or tight formations, have a more direct impact and affect regional activity.

The interest in gas trade between the United States, Canada, and Mexico is reflected in the U.S.-Canada Free Trade Agreement (CFTA) and the North American Free Trade Agreement (NAFTA). U.S. trade with Canada more than doubled between 1988 and 1994, which indicates the stimulatory impact of the CFTA. The acceptance of NAFTA did not substantially alter U.S. trade with Mexico; however, it did formalize the process.

Environmental concerns have stimulated gas markets but have also imposed some constraints. Drilling is restricted in several areas along the Outer Continental Shelf. Currently an estimated 9.4 trillion cubic feet of the resource base in the Offshore is off-limits to drilling (see Chapter 2).

Regional Supply Patterns

Only the Southwest and Central Regions of the United States are net producing regions. The other four regions—Midwest, Northeast, Southeast, and Western—rely predominantly on supplies from the Southwest, Central States, and Canada to meet regional demand.

The Southwest Region, onshore and offshore, accounts for most of the gas produced in the lower 48 States (Figure 6). Production in the region during 1994 totaled 14.8 trillion cubic feet—79 percent of lower 48 production and 6.1 percent higher than in 1988. The Southwest Region includes the three largest producing States: Texas, Louisiana, and Oklahoma. Texas is the largest producing State, producing 6 trillion cubic feet of dry gas in 1994 from huge natural gas fields along the Texas Gulf Coast, in the Panhandle Region, and the Permian Basin (which extends into New Mexico). Louisiana possesses some of the oldest producing gas fields, including the large Monroe field in the northern region of the State (discovered in 1916). While production has grown in recent years, Federal action had a more discernible direct impact on the offshore areas than the onshore.

Production from Federal offshore waters, 99 percent from the Gulf of Mexico, increased 7 percent from 1988 to 1994 despite an overall decline in offshore reserves from 32 to 27 trillion cubic feet.[41] Widespread moratoria on offshore supply activities were implemented in 1990 by a combination of Presidential and Congressional decisions. These actions preclude supply activities in most of the Federal offshore regions of the lower 48 States. The offshore moratoria and the tougher emissions standards of the Clean Air Act Amendments clearly have not prevented development of and production from currently known fields to this point; however, the constraint on expansion likely contributes to the decline in reserves.

The Central Region is the other net producing region of natural gas. Production from the Central Region grew 59 percent between 1988 and 1994, from 1.4 to 2.2 trillion cubic feet. The region extends over a vast area and contains numerous producing areas. The producing areas of the various States within the Central Region have responded differently to Federal policy provisions. Wyoming made large increases in production in the late 1980's, boosting its 1988 production by over 50 percent to reach 780 billion cubic feet in 1994. Deep gas and new production from the Overthrust Belt were large contributors to this increase, which may be attributed more to advances in technology than to Federal policy. Much of the Kansas production of 671 billion cubic feet comes from the giant Hugoton gas field, which despite its age still produces the largest gas volume of any single U.S. gas field. Colorado is another important producing State in this region, producing 447 billion cubic feet in 1994. Most of the growth in production came from the San Juan Basin. New gas from the San Juan Basin is predominantly coalbed methane, and its phenomenal growth is attributed to the Federal tax credits available on coalbed methane production from wells drilled before January 1, 1993.

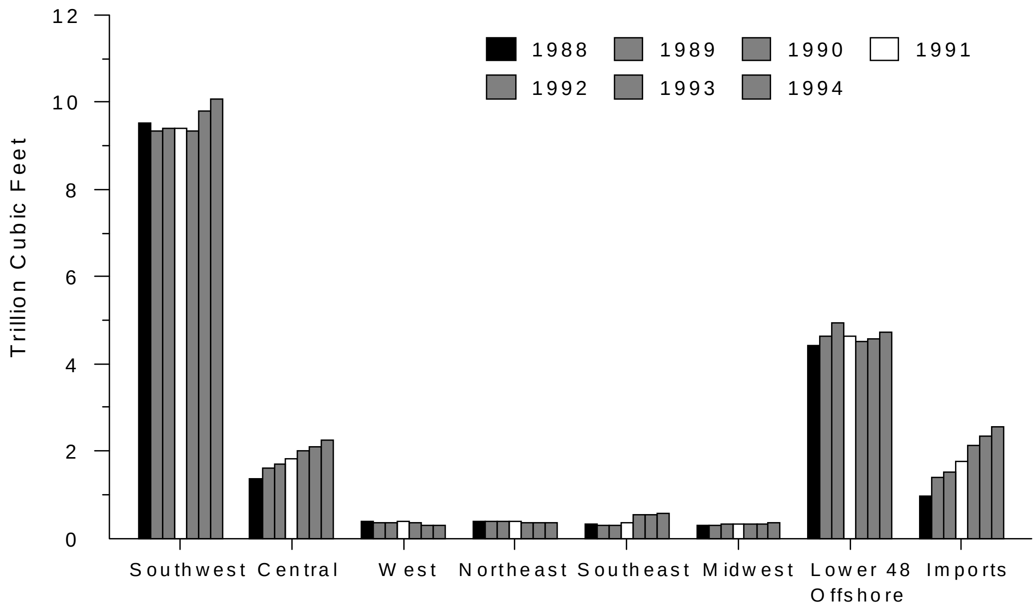
The remaining regions in the lower 48 States together accounted for only 8.6 percent of 1994 production, a slight increase from the 8.3-percent share in 1988. Although the aggregate figures are relatively modest, some of the data for individual States indicate the impact of some Federal policy provisions.

- Michigan, by far the largest producing State in the Midwest Region during 1994, increased natural gas production by 19 percent between 1988 and 1994. Some of this growth was enhanced by the unconventional gas tax credit, which

[40] Regional marketed dry gas production for 1994 was estimated based on the Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(95/04), (Washington, DC, April 1995).

[41] Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216, 1988-1994 Annual Reports (Washington, DC).

Figure 6. Dry Natural Gas Production by Region and Imports, 1988-1994



Sources: Energy Information Administration: **Onshore:** 1988—*Natural Gas Annual 1991* (October 1992). 1989-1993—*Natural Gas Annual 1993* (October 1994). 1994—*Natural Gas Monthly* (April 1995). **Offshore:** *U.S. Crude Oil*, *Natural Gas*, and *Natural Gas Liquids Reserves* (various issues, 1989-1995).

benefited production from the Antrim Shale tight formation.

- The Southeast Region increased its share of total lower 48 dry gas production from 2 percent in 1988 to

  3 percent in 1994, responding to the tax credit on coalbed production, which resulted in increased marketed production from the Black Warrior basin of Alabama.

Natural gas imports are an important adjunct to U.S. supplies. U.S. imports of Canadian gas have more than doubled since the signing of the U.S.-Canada Free Trade Agreement, reaching 2.6 trillion cubic feet in 1994. The extensive import and export trade reflects the trend toward development of an increasingly integrated North American gas industry. Canada's large resource base and relatively low-cost gas supplies provide U.S. marketers and consumers with increased supply options. The increased competition confronting domestic gas producers has been significant in keeping gas prices low, despite evidence that some domestic producers are coming close to their productive capacity. Most imported gas enters the West (more than 825 billion cubic feet in 1993), a little over a third of all imports. This is followed by the Northeast, Central, and Midwest Regions with 24, 22, and 18 percent of imports, respectively.

U.S. imports of natural gas are offset slightly by exports to Canada and Mexico from the lower 48 States (100 billion cubic feet of gas were exported to Canada and Mexico in 1994, up from only 22 billion cubic feet in 1988). The 1994 exports to both Canada and Mexico are down from the peak year of 1992 when the volume to those neighboring countries totaled 164 billion cubic feet.[42]

Transmission Network

The recent changes in the industry have increased reliance on the transmission network and have improved operational efficiency. The open-access and capacity release programs and availability of market hubs for physical transfers of gas have tended to create more gas movements among multiple pipelines. In today's natural gas marketplace the customer has had to assume greater responsibility for transportation arrangements and naturally has sought the least cost and most efficient means of delivery. As a result, the volume of gas moving among several pipeline systems on the way to market has grown. A rough measure of this change is a comparison of the relative magnitude of total reported interstate gas pipeline throughput with total domestic gas consumption.[43] Prior to 1988 (when most of the volumes transported on the major interstate pipelines was still owned by the pipelines), the ratio of reported interstate throughput to total consumption was 1.25:1; in 1994, it grew to 1.42:1. In other words, for each unit of gas consumed in 1994, 1.42 units of gas were moved on the interstate network. The growth in this measure is a subtle indicator of the increasing integration of the interstate network and the increasing competitiveness among pipeline companies.

[42]Federal policy generally has not affected liquefied natural gas (LNG) imports. The LNG facility at Lake Charles, LA, was reopened on an open-access basis by FERC directive. However, the dominant factor affecting operations at this facility and that in Everett, MA, has been the relatively low prices of alternative supplies. Even with higher prices, which are not expected in the near term by most analysts, these facilities are unlikely to be affected by Federal policy actions to date.

[43]Total sales and transported (for others) volumes reported by the major interstate pipeline companies on FERC Form 11, "Natural Gas Pipeline Company Monthly Statement," 1988 and 1994. If all gas supplies were transported from wellhead to ultimate consumer on a single interstate pipeline, this ratio would be 1:1. In fact, however, the ratio is always higher since in some cases, it is physically impossible to move gas supply to market area without routing gas over more than one interstate pipeline system. This results in some double counting of transported volumes.

Regional Use of Transportation Capacity

The availability of natural gas pipeline capacity, as well as its use, varies throughout the country. Each region has its own natural gas service profile (see Appendix B). Increased use of capacity is encouraged in today's market under FERC Order 636. Sellers and buyers have greater access to and use of pipeline capacity, resulting in the use of multiple routes to move supplies from producers to consumers. Annual throughput for the major interstate pipeline companies rose by 25 percent during the period.[44] When compared with 1990,[45] average pipeline utilization rates in 1994 increased for 15 of the 23 interregional flow combinations, whereas 6 decreased (Table 5).

Several interregional flows remain relatively low compared with available capacity. For instance, pipelines entering the Midwest, particularly from the Southeast Region, still show a relatively low average annual utilization rate, 68 percent (although up from 64 percent in 1990 (Table 5)). Absent downstream and upstream bottlenecks, capacity exists to increase volumes into the Midwest, for instance, by an average of about 7 billion cubic feet per day. The average-day utilization of capacity at other regional boundaries varied from a low of 56 percent, occurring both from the Southwest to the Central Region and from the Northeast to the Midwest, to a high of 95 percent from Canada to the Central Region.[46] However, the overall average utilization rate decreased by 1 percentage point between 1990 and 1994.

The Southwest Region, which is the Nation's principal producing region, has the capability to export as much as 35.7 billion cubic feet per day to other regions of the United States (Figure 2). That capacity was used in 1994 at an average rate of only about 63 percent, down from its 1990 level of 68 percent. This drop mainly stemmed from capacity additions that came on line to serve the Western Region, particularly California.

At the individual pipeline company level, capacity utilization has increased significantly during the past 4 years. Of the 36 pipeline companies for which data were available, 22 showed an increase in usage on a system-wide basis in 1994 when

[44]Less Kern River and Iroquois pipeline companies that did not exist in 1990, and seven trunk pipelines whose throughput volumes duplicate figures reported for the others.

[45]Data are available only from 1990 through 1994. See Energy Information Administration, *Capacity and Service on the Interstate Natural Gas Pipeline System, 1990*, DOE/EIA-0556 (Washington, DC, June 1992).

[46]Movements of gas to and from Mexico were excluded in identifying low and high capacity utilization rates, because of the relatively small volumes.

Table 5. Interregional Pipeline Capacity, Average Daily Flows, and Usage Rates, 1990 and 1994

Receiving Region	Sending Region	Capacity (MMcf per day)			Average Flow (MMcf per day)			Usage Rate (percent)		
		1994	1990	Percent Change	1994	1990	Percent Change	1994	1990	Change
Canada	Central	66	66	0	9	44	-80	14	67	-53
	Midwest	2,093	1,211	73	1,443	961	50	69	79	-10
Total into Region		2,159	1,277	69	1,452	1,005	44	67	79	-12
Mexico	Southwest	844	354	138	117	38	208	14	11	3
	Western	45	45	0	7	5	40	16	11	5
Total into Region		889	399	123	124	43	188	14	11	3
Central	Canada	1,544	1,254	23	1,469	941	56	95	75	20
	Midwest	2,333	1,765	32	1,489	974	53	[a]90	[a]75	15
	Southwest	8,483	8,716	-3	4,722	4,119	15	56	[a]49	9
	Western	298	250	19	0	196	-100	0	78	NA
Total into Region		12,658	11,985	6	7,680	6,230	23	[a]67	[a]56	11
Midwest	Canada	2,780	2,161	29	2,487	1,733	44	89	[a]84	5
	Central	9,722	8,988	8	6,986	5,684	23	72	63	9
	Northeast	2,037	2,024	1	887	714	24	[a]56	[a]45	11
	Southeast	9,815	9,645	2	6,712	6,134	9	68	64	4
Total into Region		24,354	22,818	7	17,072	14,265	20	[a]71	[a]64	7
Northeast	Canada	2,135	467	357	1,656	309	436	78	66	12
	Midwest	4,803	4,572	5	3,185	3,464	-8	66	76	-10
	Southeast	4,783	4,782	0	3,705	4,086	-9	77	85	-8
Total into Region		11,721	9,821	19	8,546	7,859	9	73	80	-7
Southeast	Northeast	535	113	373	86	69	25	[a]75	[a]69	6
	Southwest	21,051	20,006	5	14,374	14,703	-2	68	73	-5
Total into Region		21,586	20,119	7	14,460	14,772	-2	[a]68	73	-5
Southwest	Central	1,745	1,283	36	1,122	572	96	[a]79	[a]58	21
	Mexico	350	350	0	19	0	NA	5	0	NA
	Southeast	335	335	0	15	15	0	[a]60	[a]60	0
Total into Region		2,430	1,968	23	1,156	587	97	[a]64	[a]69	-5
Western	Canada	3,546	2,406	47	2,866	1,871	53	81	78	3
	Central	1,164	365	219	917	196	368	79	54	25
	Southwest	5,351	4,340	23	3,383	3,910	-13	63	90	-27
Total into Region		10,061	7,111	41	7,166	5,977	20	71	84	-13
Total Lower 48 States		**85,858**	**75,498**	**14**	**57,656**	**50,738**	**14**	**[a]69**	**[a]70**	**-1**

[a]Usage Rate shown may not equal the average daily flows divided by capacity because in some cases no throughput volumes were reported for known border crossings. This capacity was not included in the computation of usage rate.

MMcf = Million cubic feet. NA = Not applicable.

Sources: Energy Information Administration (EIA). **Pipeline Capacity:** EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity Database as of August 1995. **Average Flow:** "Natural Gas Annual 1994," draft report. **Usage Rate:** Office of Oil and Gas, derived from Pipeline Capacity and Average Flow.

compared with 1990.[47] Four pipeline systems serving the Western Region experienced a decrease, reflecting the availability of additional pipeline capacity without a corresponding increase in demand. Surprisingly, usage levels also decreased in the Northeast Region for half of the systems serving that market (which may be attributable to a relatively mild winter). Nevertheless, on average, system-wide capacity utilization levels increased in each of the consuming regions, except the Western (down 10 percent). The Northeast showed an overall increase of about 5 percent; the Southeast 12 percent; and the Midwest 4 percent. The level of pipeline capacity has grown between the United States and Canada, and the utilization of that capacity has remained high. Use of Canadian import capacity in 1994 (77 percent) was about the same as in 1990 (78 percent).

The existing level of interregional capacity, when combined with available underground storage inventories and deliver-ability, generally can accommodate current levels of peak-period demand. Sufficient capacity exists in some regions to allow the transportation of significant additional volumes during the nonpeak periods.

Network Expansion

Increases in demand and the need for additional operational flexibility under open-access programs led to substantial expansion of the interstate pipeline system during the past several years.[48] Interregional capacity on the interstate natural gas pipeline system increased by 14 percent, or more than 10 billion cubic feet per day between 1990 and 1994 (Table 5).[49] The total cost of new pipeline development and expansion during the period is estimated at about $6.5 billion.[50] The new capacity targets the anticipated growth in natural gas demand in the Western and Northeast regional markets. The expansions provide greater accessibility to supplies in western Canada and in the Central and Southwestern States of Utah, Colorado, and New Mexico.

Capacity from Canada grew from 6.3 to about 10.0 billion cubic feet per day, an increase of 59 percent. Capacity from Canada into the Northeast Region alone rose by 357 percent. Capacity from the Central to Western regional markets also increased dramatically, 219 percent (Table 5), while capacity to the Southwest increased more modestly, 23 percent. Some of the 36-percent increase from the Central to the Southwest Region actually reflects additional deliverability directed toward the western market.

While only a few relatively small expansion projects were completed in 1994, adding less than 1 percent of new interregional capacity, currently more than 40 new or expansion pipeline projects of varying sizes are under construction or before the FERC for consideration (Figure 7). These projects, if completed, would add an additional 6.0 billion cubic feet per day of capacity to current interregional capabilities. This represents a potential increase of 7 percent over levels at the end of 1994 (Table 6).

Proposed intraregional projects represent a potential 9.7 billion cubic feet per day of additional capacity. Whereas the emphasis in the 1970's and 1980's was on long-haul pipeline development projects, in today's marketplace the greater focus is on upgrading existing pipes and adding compressor stations and looping at strategic points and segments. Localized pipeline deliverability is also being improved with the installation of new laterals to link to and attract new customers in local markets with new services and added interconnections.

Expansion plans, however, may change if customer commitments fall short or potential customers drop out in the face of project delays and/or changes in market conditions. As more capacity becomes accessible and available in the capacity release market, the need for new capacity in some

[47]The capacity utilization rates discussed in this paragraph are based upon the volumes of gas carried on an entire pipeline system relative to a calculated capacity level. It is an alternative method of measuring, comparing, and evaluating the reasonableness of changes in usage rates. For 1990, the rates were based upon monthly throughput volumes (transportation plus sales) reported per pipeline divided by the largest monthly throughput reported during the period 1978 through 1990; for 1994, 1978 through 1994. The largest reported monthly volume was used as an approximation of a 100-percent load factor or a surrogate for full capacity utilization. Each pipeline system was given a region-to-region designation based on its supply-to-market flow pattern and the region in which deliveries as a percent of total system deliveries were the highest. Data from the Federal Energy Regulatory Commission, Form FERC-11, "Natural Gas Pipeline Monthly Statement," and the Energy Information Administration, Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition," were used to derive the usage rates and assignment of regions.

[48]Additional detail on regional pipeline expansion projects is presented in Appendix B to this chapter.

[49]Interregional capacity is defined as the capability to deliver gas to regional distribution networks from supply areas as measured at regional boundaries.

[50]Based on estimates of pipeline construction costs accompanying filings with the FERC or trade press announcements and compiled in the Energy Information Administration's Office of Oil and Gas Natural Gas Pipeline Construction Monitoring database, as of May 1995.

Table 6. Pipeline Capacity Additions, Actual (1991-1994) and Planned (1995-1998)
(Million Cubic Feet per Day)

Capacity Additions 1991-1994

Receiving Region	Capacity 1990	Capacity 1991	Added Capacity 1991	Capacity 1992	Added Capacity 1992	Capacity 1993	Added Capacity 1993	Capacity 1994	Added Capacity 1994
Canada	1,277	1,277	0	1,719	442	1,999	280	2,159	160
Mexico	399	889	490	889	0	889	0	889	0
Central	11,985	12,390	405	12,422	32	12,658	236	12,658	0
Midwest	22,818	23,300	482	24,068	768	24,148	80	24,355	207
Northeast	9,821	10,481	660	10,917	436	11,423	506	11,721	298
Southeast	20,119	20,802	683	21,076	274	21,467	391	21,587	120
Southwest	1,968	1,991	23	2,218	227	2,409	191	2,430	21
Western	7,111	7,111	0	8,841	1,730	10,060	1,219	10,061	0
Total	75,498	78,241	2,743	82,150	3,909	85,053	2,903	85,858	806

Planned Capacity Additions 1995-1998

Receiving Region	Estimated Capacity 1995	To Be Added 1995	Estimated Capacity 1996	To Be Added 1996	Estimated Capacity 1997	To Be Added 1997	Estimated Capacity 1998	To Be Added 1998
Canada	2,309	150	2,314	5	2,314	0	2,314	0
Mexico	889	0	1,389	500	1,693	304	1,693	0
Central	12,658	0	13,377	719	13,377	0	13,377	0
Midwest	24,713	358	24,713	0	25,873	1,160	25,873	0
Northeast	11,836	115	11,886	50	12,136	250	12,136	0
Southeast	21,960	373	22,235	275	22,465	230	22,875	410
Southwest	3,030	600	3,030	0	3,030	0	3,030	0
Western	10,122	62	10,574	452	10,574	0	10,574	0
Total	87,517	1,658	89,518	2,001	91,462	1,944	91,872	410

Sources: Energy Information Administration (EIA). **1990-1994:** EIAGIS-NG Geographic Information System, Natural Gas Pipeline State Border Capacity Database as of August 1995. **1995-1998:** EIAGIS-NG Geographic Information System, Natural Gas Pipeline Construction Monitoring Database as of August 1995, compiled from industry trade press and filings with the Federal Energy Regulatory Commission.

regions may be reevaluated and reduced. In fact, some pipeline customers are already relinquishing expiring contracted capacity rights seeking to place this service, in part, on the capacity release market.[51]

Plans may be affected by continuing evolution of the industry. Under FERC Order 636, pipeline companies are encouraged to assume more risk on new projects and are to allocate the costs associated with new projects more directly to the customers benefiting from the expansions.[52] Some of the proposed expansion projects, therefore, may not materialize,

[51]Southern California Gas Company (SoCal) will be turning back 457 decatherm per day of capacity to Transwestern Pipeline Company when its current contract expires in November 1996 (FERC Docket RP95-271). Similarly, SoCal is seeking to turn back 300 million cubic feet per day to El Paso.

[52]Under Order 636, the cost of expansion was to be passed on to the customers who benefit from the new facilities. In certain cases this has meant that some expansion costs are only charged to incremental customers. On May 31, 1995, FERC issued its "Pricing Policy for New and Existing Facilities Constructed By Interstate Natural Gas Pipelines." The principal goals of this policy are to provide the industry with as much up-front assurance as possible with respect to the rate design to be used for an expansion, while providing for a flexible assessment of the relevant facts of a specific project (see Chapter 2, "Incremental vs. Rolled-in Rates).

and others may be downsized or abandoned altogether.[53] In addition, the growing use of capacity release has lessened the need for additional construction.

A motivation for additional capacity expansion may have been the drive to promote new markets by offering more Transmission Company, also have proposed a similar packet service to support their northeastern market.

Market Hub Developments

Market centers, the so-called “hubs,” evolved out of shippers’ needs to gain access to alternative pipeline routes. Hubs have been an important development in the growth of natural gas markets. Hubs promote use of natural gas supplies by bringing buyers and sellers together in one location and by providing such services as: (1) arranging for customers to exchange gas and balance loads, (2) tracking exchanges of gas across the hub, (3) performing credit checks, (4) guaranteeing hub transactions, and (5) filing and reporting transaction information.[54] Market hubs clearly are a product of the movement to less regulation in light of their relatively recent beginnings. One of the oldest is the Henry Hub in Erath, Louisiana, founded in 1988. Deliveries through a futures contract are made at this hub.

There were only a few market hubs scattered throughout the United States in 1991. Today at least 24 operational hubs are located in the United States and 5 in Canada (Figure 8). Not surprisingly, 10 are located in Texas and 5 in Louisiana, States where hub points naturally exist because of their predominance of production and storage sources and transportation capacity. Recent new construction projects are addressing the growing need for local market deliverability and increased capacity and/or interconnections at or near hub transfer points. In addition, six more sites have been proposed, their eventual fate to be decided by the market.

It is still difficult to identify any significant influence that market hubs have had on transportation flows, although they generally are recognized as being important to the increased efficiency of the industry. Major efficiency advantages are gained through improved information, better use of the transportation network, and mitigation of the impact of increased demand on field production. Various transaction services are offered at hubs supporting the trade of natural gas. If hubs are operating effectively, these services are offered at transparent prices within markets where the bid and offer prices for gas, transportation, and storage rights are similar. The use of hubs can produce great savings if it results in reduced firm transportation requirements. Hubs also support more effective use of storage.

Market hubs are expected to increase the efficiency of the market itself. Market hubs are expected to reduce the difference in the cost of gas between market hubs that is not attributable to differential transportation costs, provided that no company can exercise significant market power. Not surprisingly, many analysts see the development of an interconnected network of market hubs as the next key step in the further integration of the industry into a “seamless” North American grid in which gas at one location will be readily substitutable or transferable for gas at other locations.

Nearly all of the physical services available at market hubs—including short-term gas sales, parking of gas for short periods of time, loaning of gas, and balancing or adjusting amount purchased or sold with amount taken or delivered—involve storage in some way. The development of hubs and the change in the general regulatory climate has increased the importance of storage, so that today underground storage is both a vital and strategic part of the natural gas industry. In 1988, while storage was a vital source of gas for reliably serving customer needs during the heating season, it was not used, as it is now, to take advantage of market movements.

Conclusion

It is clear that Federal legislation, policies and regulations have deep influences on numerous aspects of natural gas production, delivery and consumption. These influences extend from initiatives that affect decisions on resource exploration to those that affect the quantity of gas that consumers are likely to use to heat their homes and businesses. Moreover, influential Federal initiatives are not limited to those that are specifically tailored to natural gas or even energy decisions because steps intended to protect the environment, to preserve public health and safety, to encourage economic development, and to promote monetary stability may also have indirect effects on natural gas markets and delivery systems.

The restructuring of the natural gas industry to more open and flexible gas markets has created both shifts in demand and

[53] In 1994, several major proposed projects were either downsized, canceled or postponed, or withdrawn from the FERC approval process: for example, the Liberty pipeline project (182 million cubic feet per day) in New York State and the Sunshine project (330 million cubic feet per day) into Florida. The Northwest Pipeline Company Expansion II was also downsized significantly in April 1994.

[54] The INGAA Foundation, Inc., *Profile of Underground Natural Gas Storage Facilities and Market Hubs* (Washington, DC, 1995), p. III-1.

Figure 8. Locations of Major Existing and Planned Market Hubs in the United States and Canada

Source: Energy Information Administration (EIA), EIAGIS-NG Geographic Information System, Market Hubs Database, as of August 1995.

availability of supplies. Natural gas flow patterns have adjusted to accommodate these changing requirements, and this has led to new pipeline routes and additional pipeline capacity. For instance:

- The greatest change has been in the development and expansion of pipeline systems designed to accommodate increased access to Canadian supplies. Since 1990, import capacity has increased almost 60 percent. About 65 percent of the additional flows seen over the period went to the Western Region and Northeast markets.

- Domestically, transportation flow patterns have not changed greatly but some individual routes have grown significantly. The largest change in flow has occurred from the Central Region to California to support the enhanced oil recovery activities.

- Development of new domestic production fields, such as in the offshore Mobile Bay, Colorado, and northern New Mexico, has brought about new and expanded pipeline service from these areas. Tight formation and coalbed natural gas production from Colorado and New Mexico were stimulated by the Section 29 tax credit. Substantial production increases in other areas, such as the Hugoton field in Kansas, were the result of changes in infill drilling allowances.

- Market/supply hubs and increasing pipeline network integration have also provided the needed flexibility to facilitate the routing of gas supplies to growing market areas and accommodate cyclical shifts in market demand and supply. The growth in industrial consumption is especially impressive in regions such as the Northeast, for example, where pipeline expansions and Canadian import availability have produced annual consumption growth rates as high as 9 percent between 1988 and 1993.

Forecasts presented in EIA's *Annual Energy Outlook 1995* integrate the influences, Federal and other, that affect natural gas activities. These projections suggest that annual natural gas consumption could reach 22 trillion cubic feet by the year 2000. This level of consumption would match the peak levels of gas consumption experienced in the early 1970’s and could rise by an additional 1 trillion cubic feet by 2005. Much of this projected growth in natural gas consumption is forecast to serve electric generation markets. Throughout the country, electric utilities, industrial cogenerators, and independent power producers have made commitments to natural gas pipeline expansion projects. Indeed, these commitments are key supports for pipeline companies in obtaining regulatory approval to build facilities.

Not only will sufficient transmission capacity need to be available to move needed supplies from the field to the ultimate customer, but sufficient ancillary facilities will also have to be provided. The current level of proposed capacity additions, 9.7 billion cubic feet per day, would allow more than 3.5 trillion cubic feet per year of additional end-use consumption. Thus, expanded capacity is projected to be more than sufficient to serve consumption growth over the next 5 years. Storage additions are expected to provide about 20.7 billion cubic feet by 1998, the equivalent of 7.6 trillion cubic feet per year of extra service. The pipeline expansions, combined with storage capability additions, should provide adequate gas to serve customers needs.