Economic Analysis of Air Pollution Regulations: Oil and Natural Gas Production

Final Report

Submitted to

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U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Innovative Strategies and Economics Group
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This report contains portions of the economic impact analysis report that are related to the industry profile.

SECTION 2
INDUSTRY PROFILE

The petroleum industry is divided into five distinct sectors: (1) exploration, (2) production, (3) transportation, (4) refining, and (5) marketing. The NESHAP considers controls for the products and processes of the production and transportation sectors of the petroleum industry. Specifically, the oil and natural gas production and natural gas transmission and storage source categories include the separation, upgrading, storage, and transfer of extracted streams that are recovered from production wells. Thus, it includes the production and custody transfer up to the refining stage for crude oil and up to the city gate for natural gas.

Most crude oil and natural gas production facilities are classified under SIC code 1311--Crude Oil and Natural Gas Exploration and Production, while most natural gas transmission and storage facilities are classified under SIC 4923--Natural Gas Transmission and Distribution. The outputs of the oil and natural gas production industry--crude oil and natural gas--are the inputs for larger production processes of gas, energy, and petroleum products. In 1992, an estimated 594,189 crude oil wells and 280,899 natural gas production wells operated in the United States. U.S. natural gas production was 18.3 trillion cubic feet (Tcf) in 1993, continuing the upward trend since 1986, while U.S. crude oil production in 1992 was 7.2 million barrels per day (MMbpd), which is the lowest level in 30 years. The leading domestic oil and gas producing states are Alaska, Texas, Louisiana, California, Oklahoma, New Mexico, and Kansas.

The remainder of this section provides a brief introduction to the oil and natural gas production industry. The purpose is to give the reader a general understanding of the technical and economic aspects of the industry that must be addressed in the economic impact analysis. Section 2.1 provides an overview of the oil and natural gas production processes employed in the U.S. with an emphasis on those affected directly by the regulation. Section 2.2 presents historical data on crude oil and natural gas including reserves, production, consumption, and foreign trade. Section 2.3 summarizes the number of production facilities by type, location, and other parameters, while Section 2.4 provides general information on the potentially affected companies that own oil and natural gas production facilities.

2.1 PRODUCTION PROCESSES

Production occurs within the contiguous 48 United States, Alaska, and at offshore facilities in Federal and State waters. Figure 2-1 shows that, in the production process, extracted streams from production wells are transported from the wellhead (through offshore production platforms in the case of offshore wells) to tank batteries to separate crude oil, natural gas, condensates, and water from the product. Crude oil products are then transported through pump stations to a refinery, while natural gas products are directed to gas processing plants and then to final transmission lines at city gates. The equipment required in the production of crude oil and natural gas includes production wells (including offshore production platforms), separators, dehydration units, tank batteries, and natural gas processing plants.

2.1.1 Production Wells and Extracted Products

The type of production well used in the extraction process depends on the region of the country in which the well

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Figure 2-1. Crude oil and natural gas production flow diagram.

is drilled and the composition of the well stream. The recovered natural resources are naturally or artificially brought to the surface where the products (crude oil, condensate, and natural gas) are separated from produced water and other impurities. Offshore production platforms are used to extract, treat, and separate recovered products in offshore areas. Processes and operations at offshore production platforms are similar to those located at onshore facilities except that offshore platforms generally have little or no storage capacity because of the limited available space.[1]

Each producing well has its own unique properties in that the composition of the well stream (i.e., crude oil and the attendant gas) is different from that of any other well. As a result, most wells produce a combination of oil and gas; however, some wells can produce primarily crude oil and condensate with little natural gas, while others may produce only natural gas. The primary extracted streams and recovered products associated with the oil and natural gas industry include crude oil, natural gas, condensate, and produced water. These are briefly described below.

Crude oil can be broadly classified as paraffinic, naphthenic, or intermediate. Paraffinic (or heavy) crude is used as an input to the manufacture of lube oils and kerosene. Naphthenic (or light) crude is used as an input to the manufacture of gasolines and asphalt. Intermediate crudes are those that do not fit into either category. The classification of crude oil is determined by a gravity measure developed by the American Petroleum Institute (API). API gravity is a weight per unit volume measure of a hydrocarbon liquid as determined by a method recommended by the API. A heavy or paraffinic crude is one with an API gravity of 20° or less, and a light or naphthenic crude, which flows freely at atmospheric temperatures, usually has an API gravity in the range of the high 30s to the low 40s.[2]

Natural gas is a mixture of hydrocarbons and varying quantities of nonhydrocarbons that exist either in gaseous phase or in solution with crude oil from underground reservoirs. Natural gas may be classified as wet or dry gas. Wet gas is unprocessed or partially processed natural gas produced from a reservoir that contains condensable hydrocarbons. Dry gas is natural gas whose water content has been reduced through dehydration, or natural gas that contains little or no commercially recoverable liquid hydrocarbons.

Condensates are hydrocarbons that are in a gaseous state under reservoir conditions (prior to production), but which become liquid during the production process. Condensates have an API gravity in the 50° to 120° range.[3] According to historical data, condensates account for approximately 4.5 to 5 percent of total crude oil production.

Produced water is recovered from a production well or is separated from the extracted hydrocarbon streams. More than 90 percent of produced water is reinjected into the well for disposal and to enhance production by providing increased pressure during extraction. An additional 7 percent of produced water is released into surface water under provisions of the Clean Water Act. The remaining 3 percent of produced water extracted from production wells is disposed of as waste.

In addition to the products discussed above, other various hydrocarbons may be recovered through the processing of the extracted streams. These hydrocarbons include mixed natural gas liquids, natural gasoline, propane, butane, and liquefied petroleum gas.

2.1.2 Dehydration Units

Once the natural gas has been separated from the crude oil or condensate and water, residual water is removed from the natural gas by dehydration to meet sales contract specifications or to improve heating values for fuel consumption. Liquid desiccant dehydration is the most widespread technology used for natural gas with the most common process being a basic glycol system. Glycol dehydration is an absorption process in which a liquid absorbent, a glycol, directly contacts the natural gas stream and absorbs the water vapor that is later boiled off. Glycol units in operation today may use ethylene glycol (EG), diethylene glycol (DEG), triethylene glycol (TEG), and tetraethylene glycol (TREG).[4]

Dehydration units are used at several processing points in the process to remove water vapor from the gas once it has been separated from the crude oil or condensate and water. Locations where dehydration may occur include the production well site, the condensate tank battery, the natural gas processing plant, aboveground and underground storage facilities upon removal, and the city gate.

2.1.3 Tank Batteries

A tank battery refers to the collection of process equipment used to separate, treat, store, and transfer crude oil, condensate, natural gas, and produced water. As shown in Figure 2-2, the extracted products enter the tank battery through the production header, which may collect the product from many production wells. Process equipment at a tank battery may include separators that separate the product from basic sediment and water; dehydration units; heater treaters, free water knockouts, and gunbarrel separation tanks that basically remove water and gas from crude oil; and storage tanks that temporarily store produced water and crude oil.[5]

Tank batteries are classified as black oil tank batteries if the extracted stream from the production wells primarily consists of crude oil that has little, if any, associated gas. In general, any associated gas recovered at a black oil tank battery is flared. Condensate tank batteries are those that process extracted streams from production wells consisting of condensate and natural gas. Dehydration units are part of the process equipment at condensate tank batteries but not at black oil tank batteries.

2.1.4 Natural Gas Processing Plants

Natural gas that is separated from other products of the extracted stream at the tank battery is then transferred via pipeline to a natural gas processing plant. As shown in Figure 2-3

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Figure 2-2. Summary of processes at a tank battery.

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Figure 2-3. Summary of processes at natural gas processing plant.

the main functions of a natural gas processing plant include conditioning the gas by separation of natural gas liquids (NGL) from the gas and fractionation of NGLs into separate components, or desired products that include ethane, propane, butane, liquid petroleum gas, and natural gasoline. Generally, gas is dehydrated prior to other processes at a plant. Another function of these facilities is to control the quality of the processed natural gas stream. If the natural gas contains hydrogen sulfide and carbon dioxide, then sweetening operations are employed to remove these contaminants from the natural gas stream immediately after separation and dehydration.

2.1.5 Natural Gas Transmission and Storage Facilities

After processing, natural gas enters a network of pipelines and storage systems. The natural gas transmission and storage source category consists of gathering lines, compressor stations, high-pressure transmission pipeline, and underground storage sites.

Compressor stations are any facility which supplies energy to move natural gas at increased pressure in transmission pipelines or into underground storage. Typically, compressor stations are located at intervals along a transmission pipeline to maintain desired pressure for natural gas transport. These stations will use either large internal combustion engines or gas turbines as prime movers to provide the necessary horsepower to maintain system pressure.

Underground storage facilities are subsurface facilities utilized for storing natural gas which has been transferred from its original location for the primary purpose of load balancing, which is the process of equalizing the receipt and delivery of natural gas. Processes and operations that may be located at underground storage facilities include compression and dehydration.

2.2 PRODUCTS AND MARKETS

Crude oil and natural gas have historically served two separate and distinct markets. Oil is an international commodity, transported and consumed throughout the world. Natural gas, on the other hand, is typically consumed close to where it is produced. Final products of crude oil are used primarily as engine fuel for automobiles, airplanes, and other types of vehicles. Natural gas, on the other hand, is used primarily as boiler fuel for industrial, commercial, and residential applications.

2.2.1 Crude Oil

The following subsections provide historical data on the U.S. reserves, production, consumption, and foreign trade of crude oil.

2.2.1.1 Reserves. The Department of Energy defines oil reserves as "oil reserves that data demonstrate are capable of being recovered in the future given existing economic and operating conditions."[6] Table 2-1 provides total U.S. crude oil reserves for 1976 through 1993.[7] Crude oil reserves continued their decline for the sixth consecutive year in 1993, dropping by 788 million barrels (3.3 percent) to 2.3 billion barrels. Low oil prices and decreased drilling activity are the major factors for these recent declines.

Table 2-2 presents the U.S. proved reserves of crude oil as of December 31, 1993, by State or producing area.[8] As this table indicates, five areas currently account for 80 percent of the U.S. total proved reserves of crude oil with Texas leading all other areas, followed closely by Alaska, California, the Gulf of Mexico, and New Mexico. Texas, Alaska, and California accounted for roughly 82 percent of the overall decline in crude oil reserves from 1992 to 1993.

Meanwhile, the Gulf of Mexico Federal Offshore had an oil reserve increase of 237 million barrels.

2.2.1.2 Domestic Production. Because oil is an international commodity, the U.S. production of crude oil is affected by the world crude oil price, the price of alternative fuels, and existing regulations. Domestic oil production is currently in a state of decline that began in 1970. Table 2-3 shows U.S. production in 1992 at 7.2 MMbpd, which is the lowest level in 30 years.[9] Domestic production of crude oil has dropped by almost 2 MMbpd since 1985. This decline has been attributed to a transfer of U.S. investment from domestic sources to foreign production.[1]

2.2.1.3 Domestic Consumption. Crude oil is the primary input to the production of several petroleum products. Consequently, the demand for crude oil is derived from the demand of these final products. Final petroleum products include motor gasoline, diesel fuel, jet fuel, and fuels for the industrial, residential, and commercial sectors as well as for electric utilities. Historical crude oil consumption trends for 1980 through 1992 are shown in Table 2-4.[10,11] As shown in this table, a slight upturn in demand occurred in 1988, and consumption then remained fairly constant through 1992.

2.2.1.4 Foreign Trade. The world oil market is unique in that it is dominated by the Organization of Petroleum Exporting Countries (OPEC), which applies the following

[1]The investment in foreign ventures is spurred by low labor costs and less stringent regulatory environments abroad, as well as the increased likelihood of discovering larger fields in overseas activity.

TABLE 2-1. TOTAL U.S. PROVED RESERVES OF CRUDE OIL, 1976 THROUGH 1993
(million barrels of 42 U.S. gallons)

Year	Total discoveries	Production	Proved reserves
1976			33,502[a]
1977	794	2,862	31,780
1978	827	3,008	31,355
1979	636	2,955	29,810
1980	862	2,975	29,805
1981	1,161	2,949	29,426
1982	1,031	2,950	27,858
1983	924	3,020	27,735
1984	1,144	3,037	28,446
1985	995	3,052	28,416
1986	534	2,973	26,889
1987	691	2,873	27,256
1988	553	2,811	26,825
1989	716	2,586	26,501
1990	689	2,505	26,254
1991	554	2,512	24,682
1992	484	2,446	23,745
1993	785	2,339	22,957

[a]Based on following year data only.

Source: U.S. Department of Energy. Energy Information Administration. U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves: 1993 Annual Report. October 1994.

TABLE 2-2. U.S. CRUDE OIL RESERVES BY STATE AND AREA, 1993
(million barrels)

State/area	Proved reserves 12/31/92	Total discoveries and adjustments	Production	Proved reserves 12/31/93
Alaska	6,022	332	579	5,775
Alabama	41	10	10	41
Arkansas	58	17	10	65
California	3,893	161	290	3,764
Colorado	304	10	30	284
Florida	36	10	6	40
Illinois	138	-7	15	116
Indiana	17	0	2	15
Kansas	310	9	48	271
Kentucky	34	-5	3	26
Louisiana	668	77	106	639
Michigan	102	0	12	90
Mississippi	165	-12	20	133
Montana	193	-6	16	171
Nebraska	26	-1	5	20
New Mexico	757	14	64	707
North Dakota	237	19	30	226
Ohio	58	4	8	54
Oklahoma	698	68	86	680
Pennsylvania	16	-1	1	14
Texas	6,441	309	579	6,171
Utah	217	31	20	228
West Virginia	27	-1	2	24
Wyoming	689	13	78	624
Federal offshore	2,569	492	316	2,745
Pacific (California)	734	-11	50	673
Gulf of Mexico (Louisiana)	1,643	489	252	1,880
Gulf of Mexico (Texas)	192	14	14	192
Miscellaneous	29	8	3	34
Total, lower 48 States	17,723	1,219	1,760	17,182
Total, U.S.	23,745	1,551	2,339	22,957

Source: U.S. Department of Energy. Energy Information Administration. U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves: 1993 Annual Report. October 1994.

TABLE 2-3. U.S. CRUDE OIL PRODUCTION, 1982-1992

Year	Crude oil production (MMbpd)
1982	8.65
1983	8.69
1984	8.88
1985	9.00
1986	8.68
1987	8.35
1988	8.14
1989	7.61
1990	7.36
1991	7.42
1992	7.17

Source: U.S. Department of Energy. Petroleum Supply Annual 1992. DOE/EIA-0340(92)-1. Vol. 1. May 1993.

TABLE 2-4. TOTAL U.S. CRUDE OIL CONSUMPTION AND PRICE LEVELS, 1980-1992

Year	Domestic consumption (MMbpd)	Crude oil domestic wellhead price ($/barrel)	
		Current dollars	Constant 1990 dollars
1980	17.06	21.6	34.2
1981	16.06	31.8	45.7
1982	15.30	28.5	38.6
1983	15.23	26.2	34.4
1984	15.73	25.9	32.6
1985	15.73	24.1	29.3
1986	16.28	12.5	14.9
1987	16.67	15.4	17.7
1988	17.28	12.6	13.9
1989	17.33	15.9	16.8
1990	16.99	20.0	20.0
1991	16.70	16.5	15.8
1992	17.00	16.0	14.7

Sources: U.S. Department of Energy. Petroleum Supply Annual 1992. DOE/EIA-0340(92)-1. Vol. 1. May 1993.
U.S. Department of Energy. Natural Gas Annual 1991. DOE/EIA-0131(91). Washington, DC. October 1992.

economic principle: if supply is restricted, prices will rise. OPEC accounts for 38 percent of the world oil supply, while the U.S. accounts for 12 percent. Supplies from the OPEC exert a significant influence on domestic crude oil foreign trade levels. In February 1992, OPEC reimposed quotas on individual country output. The new quota signified a reduction in production intended to alter world oil prices. Any future additions to OPEC supply could reduce world crude oil prices. Additionally, if supplies to the world oil supply from the Commonwealth of Independent States (CIS) continue to decline, excess OPEC supplies can be absorbed without a significant crude oil price reduction.

As Table 2-5 demonstrates, U.S. imports of crude oil have increased steadily since 1983 at an average annual growth rate of 9.6 percent, while U.S. exports have steadily declined at an average of 4 percent annually.[12] This has resulted in a net import level in 1992 of 6 MMbpd. Oil imports are projected to exceed 8.2 MMbpd in 1993. This annual growth rate of 4.7 percent is measurably higher than the 2.9 percent rate registered in 1992.[13] Total oil imports are predicted to reach 10.1 MMbpd by the year 2000. This predicted rise in imports of crude oil corresponds to an average annual increase of 3.4 percent. The import dependency ratio is forecast to rise to 55 percent in 2000, compared to 48 percent in 1993.[14] As a result of the historical decline in domestic production and increases in demand levels, net imports of crude oil are expected to continue to increase.

TABLE 2-5. SUMMARY OF U.S. FOREIGN TRADE OF CRUDE OIL, 1983-1992

Year	Imports (MMbpd)	Domestic crude oil consumption (MMbpd)	Import percentage of domestic consumption	Exports (MMbpd)	Domestic crude oil output (MMbpd)	Export percentage of domestic output
1983	3.10	15.23	20.3	0.16	8.6	2.0
1984	3.23	15.73	20.5	0.18	8.9	2.0
1985	3.08	15.73	19.6	0.20	9.0	2.2
1986	4.13	16.28	25.4	0.15	8.7	1.7
1987	4.60	16.67	27.6	0.15	8.3	1.8
1988	5.06	17.28	29.3	0.15	8.1	1.9
1989	5.79	17.33	33.4	0.14	7.6	1.8
1990	5.87	16.99	34.5	0.11	7.4	1.5
1991	5.78	16.70	34.6	0.12	7.4	1.6
1992	6.07	17.00	35.7	0.09	7.2	1.3

Source: U.S. Department of Energy. Annual Energy Review 1991. DOE/EIA-0384(91). June 1992.

2.2.1.5 Future Trends. Table 2-6 presents the U.S. Department of Energy’s annual projections of crude oil production, consumption, and world oil price from 1993 through 2010 based on two rates of economic growth and two possible oil price scenarios.[15] U.S. crude oil supply is predicted to continue to decline between 1993 and 2010, due to low levels of drilling activities in recent years. The range of projections for 2010 is from 6.2 to 3.6 MMbpd. According to the Independent Petroleum Association of America (IPAA), U.S. crude oil production is predicted to continue its decline from 7.0 MMbpd in 1993 to 6 MMbpd by 2000.[16] This will be the lowest oil output level since 1950.

TABLE 2-6. SUPPLY, DEMAND, AND PRICE PROJECTIONS FOR CRUDE OIL, 1993-2010

Item	Actual 1993	Alternative projections to 2010: High economic growth	Low economic growth	High oil price	Low oil price
Production (MMbpd)	6.85	5.57	5.23	6.20	3.58
Consumption[a] (MMbpd)	15.30	15.9	15.9	15.8	16.00
World oil price (1993 $/barrel)	16.12	24.99	23.29	28.99	14.65

[a]Consumption is measured by U.S. refinery capacity.

Source: U.S. Department of Energy. Annual Energy Outlook 1995. DOE/EIA-0383(95). January 1995.

2.2.2 Natural Gas

The following subsections provide historical data on the U.S. reserves, production, consumption, and foreign trade of natural gas.

2.2.2.1 Reserves. Proved reserves of natural gas are the estimated amount of gas that can be found and developed in future years from known reservoirs under current prices and technologies.[17] Table 2-7 provides total U.S. natural gas reserves for 1976 through 1993.[18] Although natural gas discoveries were up considerably in 1993, increased production along with lower revisions and adjustments (resulting from new information about known gas reservoirs) led to a decline in overall natural gas reserves of 2.6 Tcf to total 162.4 Tcf. This decline reflects a 1.6 percent change in reserves from the 1992 level.

TABLE 2-7. U.S. PROVED RESERVES OF DRY NATURAL GAS, 1976 THROUGH 1993
(billion cubic feet [Bcf] at 14.73 psia and 60° F)

Year	Total discoveries	Production	Proved reserves
1976			213,278[a]
1977	14,603	18,843	207,413
1978	18,021	18,805	208,033
1979	14,704	19,257	200,997
1980	14,473	18,699	199,021
1981	17,220	18,737	201,730
1982	14,455	17,506	201,512
1983	11,448	15,788	200,247
1984	13,521	17,193	197,463
1985	11,128	15,985	193,369
1986	8,935	15,610	191,586
1987	7,175	16,114	187,211
1988	10,350	16,670	168,024
1989	10,032	16,983	167,116
1990	12,368	17,233	169,346
1991	7,542	17,202	167,062
1992	7,048	17,423	165,015
1993	8,868	17,789	162,415

[a]Based on following year data only.

Source: U.S. Department of Energy. Energy Information Administration. U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves: 1993 Annual Report. October 1994.

Table 2-8 presents the U.S. proved reserves of natural gas as of December 31, 1993, by State or producing area.[19,20] As indicated by this table, the five leading gas producing areas of Texas, the Gulf of Mexico, Oklahoma, Louisiana, and New Mexico all had declines in proved reserves from 1992 to 1993 totaling 2.6 Tcf. These declines were partially offset by substantial increases in Virginia and Colorado, where gas reserves increased by 942 Bcf over 1992.

2.2.2.2 Domestic Production. Natural gas production trends are distinct from those of crude oil. As shown in Table 2-9, production has been increasing since 1986.[21,22] This trend can be partially attributed to open access to pipeline transportation, which has resulted in more marketing opportunities for producers and greater competition, leading to higher production. Traditionally, most natural gas sold at the wellhead was sold under long-term, price-regulated contracts and purchased by pipeline companies. These pipeline companies in turn resold it to local distribution companies (from the "wellhead" to the "city gate"). Therefore, the pipelines transported natural gas as part of a larger package of "bundled" services that include acquisition and transportation. Local distribution companies then distribute gas to residential, commercial, and industrial customers and electric utilities (from the "city gate" to the "burner tip"). The end-user price thus reflected the cost of acquisition plus the cost of transport and other services along with the regulator-specified fair rate of return on investment.

TABLE 2-8. U.S. NATURAL GAS RESERVES BY STATE AND AREA, 1993
(Bcf)

State/area	Proved reserves 12/30/92	Total discoveries and adjustments	Production	Proved reserves 12/30/93
Alaska	9,725	657	396	9,986
Alabama	5,870	-371	287	5,212
Arkansas	1,752	-9	188	1,555
California	2,892	169	262	2,799
Colorado	6,463	922	406	6,979
Florida	55	12	8	59
Kansas	10,302	264	694	9,872
Kentucky	1,126	-22	68	1,036
Louisiana	10,227	830	1,516	9,541
Michigan	1,290	75	147	1,218
Mississippi	873	38	111	800
Montana	875	-141	50	684
New Mexico	20,339	1,019	1,419	19,939
New York	329	-43	22	264
North Dakota	567	75	57	585
Ohio	1,161	66	121	1,106
Oklahoma	14,732	1,246	1,879	14,099
Pennsylvania	1,533	328	139	1,722
Texas	38,141	4,736	5,030	37,847
Utah	2,018	358	178	2,198
Virginia	904	454	36	1,322
West Virginia	2,491	286	179	2,598
Wyoming	11,305	824	742	11,387
Federal offshore	28,186	4,096	4,696	27,586
Pacific (California)	1,136	32	45	1,123
Gulf of Mexico (Louisiana)	20,006	3,128	3,383	19,751
Gulf of Mexico (Texas)	7,044	936	1,268	6,712
Other states	93	13	10	96
Total, lower 48 States	163,584	15,165	18,245	160,504
Total, U.S.	173,309	15,822	18,641	170,490

Sources: U.S. Department of Energy, Petroleum Supply Annual 1992. DOE/EIA-0340(92)-1. Vol. 1. May 1993.
U.S. Department of Energy. Natural Gas Annual 1991. DOE/EIA-0131(91). Washington, DC. October 1992.

TABLE 2-9. U.S. NATURAL GAS PRODUCTION AND WELLHEAD PRICE LEVELS, 1980-1992

Year	Domestic production (Tcf)	Average annual wellhead price ($/Mcf)	
		Current dollars	Constant 1990 dollars
1980	20.18	1.6	2.5
1981	19.96	2.0	2.9
1982	17.82	2.5	3.4
1983	16.09	2.6	3.4
1984	17.47	2.7	3.3
1985	16.45	2.5	3.0
1986	16.06	1.9	2.3
1987	16.62	1.7	2.0
1988	17.10	1.7	1.9
1989	17.31	1.7	1.8
1990	17.81	1.7	1.7
1991	17.87	1.6	1.5
1992	18.47	1.8	1.7

Sources: U.S. Department of Energy. Petroleum Supply Annual 1992. DOE/EIA-0340(92)-1. Vol. 1. May 1993.
U.S. Department of Energy. Natural Gas Annual 1991. DOE/EIA-0131(91). Washington, DC. October 1992.

The Natural Gas Policy Act (NGPA) of 1978 and subsequent Federal Energy Regulatory Commission (FERC) orders throughout the 1980s promoting open access transportation have dramatically altered the industry organization of the U.S. market for natural gas by separating the marketing and transport functions of interstate pipeline companies.[2] With

[2]These Federal Energy Regulatory Commission orders include FERC Order No. 380, which effectively eliminated the requirement that customers of interstate pipelines purchase any minimum quantity of natural gas, and FERC Order No. 636, which mandates that pipelines must separate gas sales from

the separation of transportation from production in the industry, much of the natural gas is purchased directly from producers, and the pipeline companies principally provide transportation services for their customers. Independent brokers and other marketers service these transactions and bypass the traditional marketing structure.[3,23]

Also contributing to the increase in production shown in Table 2-9 are significant improvements in drilling productivity as well as more intensive utilization of existing fields since 1989. Because of lower prices in 1990 and 1991, however, producers have curtailed drilling programs and have sought ways to cut production costs, for example, by more intensive development of profitable onshore fields.

2.2.2.3 Domestic Consumption. Table 2-10 displays natural gas consumption by end user from 1980 to 1992, while Table 2-11 presents end-user prices for natural gas for the same time period.[24,25] Natural gas users include residential and commercial customers, as well as industrial firms and electric utilities. Since 1986, natural gas consumption has shown relatively steady growth, which is projected to continue through the year 2010. Because some consumers can substitute certain petroleum products for natural gas, prices of oil and gas often move in the same direction. Low crude oil prices

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transportation, thereby allowing open access to pipeline transportation for gas producers and customers.

[3]Based on USDOE/EIA information for 1991, 84 percent of natural gas was transported to the market for marketers, local distribution companies (LDCs), and end users (45 percent for independent brokers and other marketers, 32 percent for local distribution companies, and 7 percent directly to end users) as compared with only 3 percent in 1982. The remaining 16 percent in 1991 was purchased at the wellhead by interstate pipeline companies for distribution.

after the 1986 price collapse, for example, effectively pushed competing gas prices lower.

2.2.2.4 Foreign Trade. On the international market, the U.S. and Canada are the world's leading producers of natural gas, accounting for more than 59 percent of the worldwide gas processing capacity (the U.S. accounts for nearly 42 percent alone) and more than 57 percent of world natural gas production. Table 2-12 displays the level of imports and exports of natural gas as well as the import share of U.S. domestic consumption and the export share of U.S. marketed production for the years 1973 through 1993. North American gas trade is a major factor in the competitive U.S. natural gas market. Natural gas imports no longer serve as a marginal source of supply but are actively competing for market share. As shown in Table 2-12, imports increased by 6 percent to 2.3 Tcf from 1992 to 1993 providing 11 percent of U.S. domestic consumption.[26] Canadian suppliers account for most of the natural gas imports to the United States. Although no significant changes in gas trade with Mexico are expected in the near future, the North American Free Trade

TABLE 2-10. U.S. NATURAL GAS CONSUMPTION BY END-USE SECTOR, 1980-1992

Year	End-user consumption (Tcf)					Total
	Residential	Commercial	Industrial	Electric utilities	Other[a]	
1980	4.75	2.61	7.17	3.68	1.66	19.88
1981	4.55	2.52	7.13	3.64	1.57	19.40
1982	4.63	2.60	5.83	3.23	1.71	18.00
1983	4.38	2.43	5.64	2.91	1.47	16.84
1984	4.56	2.52	6.15	3.11	1.61	17.95
1985	4.43	2.43	5.90	3.04	1.47	17.28
1986	4.31	2.32	5.58	2.60	1.41	16.22
1987	4.31	2.43	5.95	2.84	1.67	17.21
1988	4.63	2.67	6.38	2.64	1.71	18.03
1989	4.78	2.71	6.82	2.79	1.70	18.80
1990	4.39	2.62	7.02	2.79	1.90	18.72
1991	4.56	2.73	7.23	2.79	1.75	19.05
1992	4.70	2.77	7.64	2.77	1.85	19.75

[a]Includes natural gas consumed as lease, plant, and pipeline fuel.

Source: Energy Statistics Sourcebook, 8th ed. PennWell Publishing Co. September 1993.

Agreement (NAFTA) will assist in developing and integrating the Mexican gas industry.[27]

TABLE 2-11. U.S. NATURAL GAS PRICE BY END-USE SECTOR, 1980-1992

	End-use sector ($/Mcf)				
Year	Residential	Commercial	Industrial	Electric utilities	Average
1980	$3.68	$3.39	$2.56	$2.27	$2.91
1981	$4.29	$4.00	$3.14	$2.89	$3.51
1982	$5.17	$4.82	$3.87	$3.48	$4.32
1983	$6.06	$5.59	$4.18	$3.58	$4.82
1984	$6.12	$5.55	$4.22	$3.70	$4.85
1985	$6.12	$5.50	$3.95	$3.55	$4.72
1986	$5.83	$5.00	$3.23	$2.43	$4.13
1987	$5.54	$4.77	$2.94	$2.32	$4.05
1988	$5.47	$4.63	$2.95	$2.33	$4.09
1989	$5.64	$4.74	$2.96	$2.43	$4.22
1990	$5.80	$4.83	$2.93	$2.39	$4.20
1991	$5.82	$4.81	$2.69	$2.18	NA
1992	$5.86	$4.87	$2.81	$2.37	NA

Source: Energy Statistics Sourcebook, 8th ed. Penn Well Publishing Co. September 1993.

Historically, imports of natural gas have increased at an average annual growth rate of 10.5 percent. Increases in natural gas imports have been driven by increased U.S. demand and additions to interstate pipeline capacity in 1991 and 1992. Exports have doubled since 1983 although yearly fluctuations have occurred. Net import levels have steadily increased over this time period to 1.79 Tcf in 1992. According to the IPAA, total gas imports, mainly from Canada, are expected to rise to 3.1 Tcf by 2000, up from 2.2 Tcf in 1992. This is an average increase of nearly 6 percent each year.

TABLE 2-12. HISTORICAL SUMMARY OF U.S. NATURAL GAS FOREIGN TRADE, 1973-1993 (Bcf)

Year	Total imports	Total exports	Net imports	Total consumption	Net imports as a percentage of total consumption	Marketed production	Exports as a percentage of marketed production
1973	1,032.9	77.2	955.7	22,049.4	4.3	22,647.6	0.3
1974	959.2	76.8	882.5	21,223.1	4.2	21,600.5	0.4
1975	953.0	72.7	880.3	19,537.6	4.5	20,108.7	0.4
1976	963.8	64.7	899.1	19,946.5	4.5	19,952.4	0.3
1977	1,011.0	55.6	955.4	19,520.6	4.9	20,025.5	0.3
1978	965.5	52.5	913.0	19,627.5	4.7	19,974.0	0.3
1979	1,253.4	55.7	1,197.7	20,240.8	5.9	20,471.3	0.3
1980	984.8	48.7	936.0	19,877.3	4.7	20,379.7	0.2
1981	903.9	59.4	844.6	19,403.9	4.4	20,177.0	0.3
1982	933.3	51.7	881.6	18,001.1	4.9	18,519.7	0.3
1983	918.4	54.6	863.8	16,834.9	5.1	16,822.1	0.3
1984	843.0	54.8	788.3	17,950.5	4.4	18,229.6	0.3
1985	949.7	55.3	894.4	17,280.9	5.2	17,197.9	0.3
1986	750.5	61.3	689.2	16,221.3	4.2	16,858.7	0.4
1987	992.5	54.0	938.5	17,210.8	5.5	17,432.9	0.3
1988	1,293.8	73.6	1,220.2	18,029.6	6.8	17,918.5	0.4
1989	1,381.5	106.9	1,274.6	18,800.8	6.8	18,095.1	0.6
1990	1,532.3	85.6	1,446.7	18,716.3	7.7	18,593.8	0.5
1991	1,773.3	129.2	1,644.1	19,129.4	8.6	18,585.8	0.7
1992	2,137.5	216.3	1,921.2	19,726.2	9.7	18,616.9	1.2
1993	2,350.1	140.2	2,209.9	20,219.0[a]	10.9	19,251.0	0.7

[a]Preliminary data.

Notes: Totals may not equal sum of components due to independent rounding. Geographic coverage is the continental United States including Alaska.

Source: U.S. Department of Energy. Energy Information Administration. Natural Gas Monthly U.S. Natural Gas Imports and Exports--1993. August 1994.

2.2.2.5 Future Trends. Currently, the domestic natural gas production industry is in transition from a period of overcapacity to one near full capacity utilization. Since 1985, demand has grown in response to low prices while drilling activity remained depressed, lowering the gap that existed between demand and supply levels. While the U.S. has a relatively large potential gas reserve base available for development, current low market prices must increase to stimulate new drilling activity and meet projected demand growth. Natural gas supplies are expected to continue to increase through the 1990s, slowing near 2000 as deliverability through existing pipelines constrains the development of some gas markets.[28]

Table 2-13 presents the U.S. Department of Energy's annual projections of natural gas production, consumption, and wellhead prices from 1993 to 2010 based on three rates of economic growth. U.S. natural gas production and consumption are projected to increase steadily over the projection period.[29] The range of projections for 2010 is from 19.89 to 21.91 Tcf. According to the IPAA, natural gas production is expected to increase through the year 2000 at an average annual rate of 1.1 percent, reaching nearly 20 Tcf by the year 2000, up from an expected level of 18.3 Tcf in 1993.[30]

TABLE 2-13. SUPPLY, DEMAND, AND PRICE PROJECTIONS FOR NATURAL GAS, 1993-2010

		Alternative projections to 2010		
	Actual 1993	Base case economic growth	High economic growth	Low economic growth
Production (Tcf)	18.35	20.88	21.91	14.89
Consumption (Tcf)	20.21	24.59	25.85	23.18
Wellhead price (1993 $/Mcf)	2.02	3.39	3.74	3.01

Source: U.S. Department of Energy. Annual Energy Outlook 1995. DOE/EIA-0383(95). January 1995.

2.3 PRODUCTION FACILITIES

The following subsections provide details on the operating facilities of the oil and natural gas production industry including production wells, dehydration units, tank batteries, and natural gas processing plants.

2.3.1 Production Wells

Table 2-14 displays the number of crude oil and natural gas wells in operation from 1983 to 1992.[31] In 1992, an estimated 594,200 crude oil wells operated in the United States, and 280,900 natural gas production wells. For offshore production, an estimated 3,841 oil and gas production platforms operated in 1991 and were associated with a total of 33,000 wells. Natural gas production wells have increased in number steadily since 1983, while crude oil wells show more volatility.

TABLE 2-14. NUMBER OF CRUDE OIL AND NATURAL GAS WELLS, 1983-1992

Year	Natural gas producing wells	Crude oil producing wells
1983	170,300	603,300
1984	193,900	620,800
1985	214,100	646,600
1986	219,100	628,700
1987	214,600	621,200
1988	217,800	623,600
1989	232,100	606,900
1990	241,100	602,400
1991	265,100	610,200
1992	280,900	594,200

Source: U.S. Department of Energy. Natural Gas 1992: Issues and Trends. DOE/EIA-0560(92). Washington, DC. March 1993.

Table 2-15 details the distribution of oil and gas well capacity by production of barrels per month.[32] Small production wells dominate the industry. Stripper wells are defined as those production wells that produce less than 10 bpd or 60 Mcf per day. In 1989, over 80 percent of the oil wells produced less than 10 bpd or 0 to 300 barrels per month, and over 78 percent of the gas wells produced within the same range. The remaining production wells produce over a wide range, from levels of 301 barrels per month to over 5,000 barrels per month.

TABLE 2-15. U.S. ONSHORE OIL AND GAS WELL CAPACITY BY SIZE RANGE, 1989

Size range (barrels/ month)	Number of oil wells	Percentage of total	Number of gas wells	Percentage of total
0-60	306,032	49.5	135,231	51.8
61-100	67,150	10.9	24,049	9.2
101-200	76,926	12.4	28,144	10.8
201-300	47,263	7.6	17,765	6.8
301-400	20,631	3.3	10,859	4.2
401-500	21,433	3.5	6,957	2.7
501-600	13,044	2.1	5,442	2.0
601-1000	29,992	4.9	12,400	4.7
1001-2000	22,134	3.6	10,042	4.0
2001-5000	9,735	1.6	6,365	2.4
5001-Over	3,555	0.6	3,806	1.4
Total	617,895	100.0	261,060	100.0

Source: Gruy Engineering Corporation. Estimates of RCRA Reauthorization Economic Impacts on the Petroleum Extraction Industry. Prepared for the American Petroleum Institute. July 20, 1991.

Table 2-16 presents the distribution of U.S. natural gas producing wells by state at the end of 1993.[33] According to World Oil, for 1993, a total of 286,168 natural gas producing wells operated at onshore and offshore locations in the

TABLE 2-16. DISTRIBUTION OF U.S. GAS WELLS BY STATE, 1993

State	1993 gas wells	Percentage of total (%)
Alabama	3,395	1.19
Alaska	157	0.05
Arkansas	2,914	1.02
California	1,072	0.37
Colorado	6,372	2.23
Federal OCS	3,532	1.23
Illinois	384	0.13
Indiana	1,327	0.46
Kansas	14,200	4.96
Kentucky	12,836	4.49
Louisiana	13,214	4.62
Michigan	3,174	1.11
Mississippi	552	0.19
Montana	2,900	1.01
Nebraska	60	0.02
New Mexico	27,832	9.73
New York	5,951	2.08
North Dakota	104	0.04
Ohio	34,581	12.08
Oklahoma	28,902	10.10
Pennsylvania	31,100	10.87
South Dakota	38	0.01
Tennessee	620	0.22
Texas	47,245	16.51
Utah	1,164	0.41
Virginia	1,340	0.47
West Virginia	38,280	13.38
Wyoming	2,880	1.01
Others	42	0.01
Total U.S.	286,168	100.00

Source: Producing Gas Well Numbers are up Once Again. World Oil. February 1993. Vol. 214, No.2.

continental U.S. and Alaska. As shown, Texas accounts for approximately 16.5 percent of U.S. natural gas wells with 47,245. A continued increase in U.S. natural gas wells is expected for 1994 based on increases in gas prices.

2.3.1.1 Gruy Engineering Corporation Database. Based on lease data, the Gruy Engineering Corporation developed "wellgroups" for both oil and gas wells in each of 37 different geographic areas across the United States.[34] For each geographic area, wellgroups are defined by well depth and then by production rate in each depth range. Four depth ranges were employed for oil wells: 0 to 2,000 feet; 2,001 to 6,000 feet; 6,001 to 10,000 feet; and deeper than 10,000 feet. Three depth ranges were developed for gas wells: 0 to 4,000 feet; 4,001 to 10,000 feet; and deeper than 10,000 feet. Furthermore, 11 production ranges were used for both oil and gas wells, expressed in barrels of oil equivalent (BOE), where one barrel of oil equals one BOE that equals 10 Mcf. The production rate ranges in BOE per month are 0 to 60; 61 to 100; 101 to 200; 201 to 300; 301 to 400; 401 to 500; 501 to 600; 601 to 1,000; 1,001 to 2,000; 2,001 to 5,000; and greater than 5,000. Therefore, each of the 37 geographic areas was divided into a possible 44 oil wellgroups and 33 gas wellgroups. The result of Gruy's analysis provides 1,004 oil wellgroups and 643 gas wellgroups (some regions had no wells of certain types). Appendix A provides data on the oil wellgroups developed by Gruy Engineering for each geographic area, and Appendix B provides data on the natural gas wellgroups.

2.3.2 Dehydration Units

The Gas Research Institute (GRI) estimates that the U.S. may have 40,000 or more glycol dehydration units. TEG and EG dehydration units account for approximately 95 percent of this total, with solid desiccant dehydration units accounting for the remaining 5 percent.[35] The primary application of solid desiccant dehydration units is to dehydrate natural gas streams at cryogenic natural gas processing plants.

For TEG dehydration units, stand-alone units dehydrate natural gas from an individual well or several wells, and units are collocated at condensate tank batteries and natural gas processing plants. Available information indicates that, on average, there is one TEG dehydration unit per condensate tank battery and two or four dehydration units (TEG, EG, or solid desiccant) per natural gas processing plant, depending on throughput capacity.[36,37]

2.3.3 Tank Batteries

According to the BID, approximately 94,000 tank batteries operated in the U.S. as of 1989.[38] Furthermore, over 85 percent of tank batteries, or an estimated 81,000 facilities, are classified as black oil tank batteries. The remaining 13,000 tank batteries are classified as condensate tank batteries.

2.3.4 Natural Gas Processing Plants

Table 2-17 shows the number of natural gas processing facilities in operation from 1987 to 1993 in the United

States.[39] Over this time period the number of natural gas processing plants has declined by over 10 percent, or a total of 82 plants over 7 years. Table 2-18 provides the number of natural gas processing facilities as of January 1, 1994, the total processing capacity, and 1993 throughput level by State.[40] The States with the largest number of natural gas processing plants are Texas, Oklahoma, Louisiana, Colorado, and Wyoming, while the top states in terms of natural gas processing capacity are Texas, Louisiana, Alaska, Kansas, and Oklahoma.

TABLE 2-17. U.S. NATURAL GAS PROCESSING FACILITIES, 1987-1993

Year	Number of facilities
1987	810
1988	760
1989	745
1990	751
1991	748
1992	735
1993	728

Source: Gas Processing Report. Oil and Gas Journal. 92(24). June 1994.

2.3.5 Natural Gas Transmission and Storage Facilities

There are an estimated 300,000 miles of high-pressure transmission pipelines and approximately 1990 compressor stations in the U.S. In addition, the natural gas industry operates over 300 underground storage sites.

2.4 FIRM CHARACTERISTICS

A regulatory action to reduce pollutant discharges from facilities producing crude oil and natural gas will potentially affect the business entities that own the regulated facilities. In the oil and natural gas production industry, facilities comprise those sites where plant and equipment extract and process extracted streams and recovered products to produce the raw materials crude oil and natural gas. Companies that own these facilities are legal business entities that have the capacity to conduct business transactions and make business decisions that affect the facility.

TABLE 2-18. U.S. NATURAL GAS PROCESSING PLANTS, CAPACITY, AND THROUGHPUT AS OF JANUARY 1, 1994, BY STATE

		Natural gas (MMcfd)	
State	Number of plants	Capacity	1993 throughput
Alabama	9	785.0	700.7
Alaska	3	7,775.0	6,502.0
Arkansas	3	878.0	520.5
California	29	1,044.0	658.5
Colorado	50	1,596.5	1,128.6
Florida	2	890.0	622.0
Kansas	22	5,122.0	3,778.4
Kentucky	3	141.0	117.9
Louisiana	72	18,334.4	11,869.4
Michigan	28	4,731.9	858.6
Mississippi	6	884.2	209.5
Montana	6	19.5	6.8
New Mexico	34	2,889.0	2,122.2
North Dakota	6	122.9	83.2
Ohio	1	20.0	8.8
Oklahoma	94	4,656.8	2,857.5
Pennsylvania	2	14.0	8.3
Texas	293	17,259.5	12,002.5
Utah	14	624.9	416.2
West Virginia	7	398.9	337.9
Wyoming	41	3,783.7	2,973.6
Total U.S.	725	71,971.2	47,783.1

Source: "Worldwide Gas Processing Report." Oil & Gas Journal. 92(24):49110. June 13, 1994.

2.4.1 Ownership

The oil and natural gas industry may be divided into different segments that include producers, transporters, and distributors. The producer segment may be further divided between major and independent producers. Major producers include large oil and gas companies that are involved in each of the five industry activities: (1) exploration, (2) production, (3) transportation, (4) refining, and (5) marketing. Independent producers include smaller firms that are involved in some but not all of the five activities. Transporters are comprised of the pipeline companies, while distributors are comprised of the local distribution companies.

During 1992, almost 7,700 companies owned the 9,391 establishments operating within SIC code 1311 (Crude Oil and Natural Gas).[41] For SIC 1311, the top 8 firms in 1992 accounted for 43.2 percent of the value of shipments, while the top 16 firms accounted for almost 60 percent. Furthermore, the top 8 firms accounted for 64 percent of industry crude oil production and 37 percent of industry natural gas production, while the top 16 firms accounted for 77.7 percent of industry crude oil production and 58.3 percent of industry natural gas production.[42]

Through the mid-1980s, natural gas was a secondary fuel for many producers. However, now it is of primary importance to many producers. The Independent Petroleum Association of America reports that 70 percent of its members' income comes from natural gas production.[43] In 1993, gas production revenues exceeded oil production revenues for the first time, accounting for 56 percent ($38 billion) of total oil and gas industry production revenues. Higher wellhead prices for natural gas, increased efficiency, and lower production costs have all contributed to increased natural gas production and improvements in producer revenues.[44]

2.4.2 Size Distribution

The Small Business Administration (SBA) defines criteria for defining small businesses (firms) in each SIC. Table 2-19 lists the primary SICs to be affected by the proposed

TABLE 2-19. NUMBER AND PROPORTION OF FIRMS IN SMALL BUSINESS CATEGORY (BY SIC CODE)

SIC Code	SIC Description	SBA size standard in number of employees or annual sales	Number of firms	Number of firms meeting SBA standard	Percentage of firms meeting SBA standard
1311	Crude petroleum and natural gas	500	429	372	87%
1381	Drilling oil and gas wells	500	132	100	76%
1382	Oil and gas exploration services	$5 million	176	77	44%
2911	Petroleum refining	1,500	141	98	70%
4922	Natural gas transmission	$5 million	79	11	14%
4923	Gas transmission and distribution	$5 million	74	6	8%
4924	Natural gas distribution	500	121	71	59%

Source: Ward's Business Directory. Volume 2. Washington, DC. 1993.

regulations and their corresponding small business criteria. SICs 1311 and 1381 have the highest percentage of small businesses--87 percent and 76 percent respectively--and SICs 4922 and 4123 have the lowest percentage--8 percent and 14 percent respectively.[45]

2.4.3 Horizontal and Vertical Integration

Because of the existence of major oil companies, the industry possesses a wide dispersion of vertical and horizontal integration. The vertical aspects of a firm's size reflect the extent to which goods and services that can be bought from outside are produced in house, while the horizontal aspect of a firm's size refers to the scale of production in a single-product firm or its scope in a multiproduct one.

Vertical integration is a potentially important dimension in analyzing firm-level impacts because the regulation could affect a vertically integrated firm on more than one level. The regulation may affect companies for whom oil and natural gas production is only one of several processes in which the firm is involved. For example, a company owning oil and natural gas production facilities may ultimately produce final petroleum products, such as motor gasoline, jet fuel, or kerosine. This firm would be considered vertically integrated because it is involved in more than one level of requiring crude oil and natural gas and finished petroleum products. A regulation that increases the cost of oil and natural gas production will ultimately affect the cost of producing final petroleum products.

Horizontal integration is also a potentially important dimension in firm-level analyses for any of the following reasons:

- A horizontally integrated firm may own many facilities of which only some are directly affected by the regulation.
- A horizontally integrated firm may own facilities in unaffected industries. This type of diversification would help mitigate the financial impacts of the regulation.

- A horizontally integrated firm could be indirectly as well as directly affected by the regulation. For example, if a firm is diversified in manufacturing pollution control equipment (an unlikely scenario), the regulation could indirectly and favorably affect it.

In addition to the vertical and horizontal integration that exists among the large firms in the industry, many major producers often diversify within the energy industry and produce a wide array of products unrelated to oil and gas production. As a result, some of the effects of control of oil and gas production can be mitigated if demand for other energy sources moves inversely compared to petroleum product demand.

In the natural gas sector of the industry, vertical integration is limited. Production, transmission, and local distribution of natural gas usually occur at individual firms. It is more likely that natural gas producers will sell their output either to a firm that will subject it to additional purification processes or directly to a pipeline for transport to an end user. Several natural gas firms operate multiple facilities. However, natural gas wells are not exclusive to natural gas firms only. Typically wells produce both oil and gas and can be owned by a natural gas firm or an oil company.

Of the independents' total revenues, 72 percent is derived from natural gas output, and the remaining 28 percent is from crude oil production. Unlike the large integrated firms that have several profit centers such as refining, marketing, and transportation, most independents have to rely only on profits generated at the wellhead from the sale of oil and natural gas. Overall, the independent producers sell their output to refineries or natural gas pipeline companies. They are typically not vertically integrated but may own one or two facilities, indicating limited horizontal integration.

2.4.4 Performance and Financial Status

In a special addition of the Oil and Gas Journal (OGJ), financial and operating results for the top 300 oil and natural gas companies are reported.[46] Table 2-20 lists selected statistics for the top 20 companies in 1993.[47] The results presented in the table reflect lower crude oil and petroleum prices in 1993, which suppressed revenues. However,

TABLE 2-20. TOP 20 OIL AND NATURAL GAS COMPANIES, 1993

Rank	Company	Total assets ($\$10^3$)	Total revenue ($\$10^3$)	Net income ($\$10^3$)	Worldwide liquids production (Mil bbl)	Worldwide natural gas production (Bcf)	U.S. liquids production (Mil bbl)	U.S. natural gas production (Mil bbl)
1	Exxon Corp.	84,145,000	111,211,000	5,280,000	568.0	1,583.0	202.0	697.0
2	Mobil Corp.	40,585,000	63,975,000	2,084,000	285.0	1,665.0	111.0	558.0
3	Chevron Corp.	34,736,000	37,082,000	1,265,000	295.0	902.0	144.0	751.0
4	Amoco Corp.	28,486,000	28,617,000	1,820,000	236.0	1,487.0	100.0	867.0
5	Shell Oil Co.	26,851,000	21,092,000	781,000	170.0	553.0	147.0	539.0
6	Texaco Inc.	26,626,000	34,071,000	1,068,000	228.0	748.0	155.0	652.0
7	ARCO (Atlantic Richfield Corp.)	23,894,000	19,183,000	269,000	250.0	449.0	221.0	332.0
8	Occidental Petroleum Corp.	17,123,000	8,544,000	283,000	79.0	238.0	21.0	219.0
9	BP (USA)	14,864,000	15,714,000	1,461,000	--	--	228.9	33.6
10	Conoco Inc.	11,938,000	15,771,000	812,000	135.0	481.0	40.0	305.0
11	Enron Corp.	11,504,315	8,003,939	332,522	3.5	262.2	2.5	240.0
12	Phillips Petroleum Co.	10,868,000	12,545,000	243,000	89.0	509.0	47.0	345.0
13	USX-Marathon Group	10,806,000	11,962,000	-29,000	57.0	317.0	41.0	193.0
14	Coastal Corp.	10,277,100	10,136,100	115,800	4.9	122.0	4.9	122.0
15	Unocal Corp.	9,254,000	8,344,000	213,000	84.0	623.0	48.0	365.0
16	Amerada Hess Corp.	8,641,546	5,872,741	-268,203	79.0	323.0	26.0	183.0
17	Columbia Gas System	6,957,900	3,398,500	152,200	3.6	71.5	3.6	71.5
18	Ashland Oil Inc.	5,551,817	10,283,325	142,234	8.3	36.2	0.4	36.2
19	Consolidated Natural Gas Co.	5,409,586	3,194,616	205,916	3.9	124.0	3.9	124.0
20	Pennzoil Co.	4,886,203	2,782,397	141,856	24.0	223.0	24.0	220.0

higher natural gas prices, consumption, and production, as well as increased consumption of petroleum production, offset these trends. Total assets for the top 300 companies fell in 1993 for the third consecutive year, a reflection of continued industry restructuring and consolidation with mergers, acquisitions, and liquidations. As a result, the number of publicly held companies was slashed. The top 300 companies, however, represent a large portion of the U.S. oil and gas industry and indicate changes and trends in industry activity and operating performance.

Net income for OGJ's top 300 companies jumped 75.5 percent in 1993 to $18.3 billion, while total revenues fell 3.9 percent to $475.1 billion. Other measures of financial performance for the group showed improvement in 1993. Capital and exploration spending totaled $50.3 billion, up 1.8 percent from 1992. In addition, the number of U.S. net wells drilled rose 24.4 percent to 8,656. Table 2-21 provides 1993 performance highlights for the OGJ's group of 22 large U.S. oil companies.[48] Earnings for the group jumped sharply in 1993, increasing by 78.6 percent from 1992. Performance in 1993 restored group profits to the 1991 level even though total revenues for the group fell 3.8 percent to $436.3 billion in 1993. Lower crude oil and petroleum product prices were the main factors in the observed decline in revenues.

TABLE 2-21. PERFORMANCE MEASURES FOR OGJ GROUP, 1993

Performance measure	1993 highlights
Total assets	$385.4 billion, down 1 percent
Net profits	$16.2 billion, up 78.6 percent
Return on equity	10.1 percent, up 4.8 points
Return on total assets	3.9 percent, up 1.9 points
Capital/exploration spending	$38.8 billion, down 5.8 percent
Net liquids production	8.4 million bpd, down 2 percent
Net natural gas production	30 bcfd, up 0.7 percent
Crude runs to stills	15.6 million bpd, up 1.2 percent
Liquid reserves	32 billion bbl, up 1.7 percent
Natural gas reserves	140.2 tcf, up 0.6 percent

Source: "Profits for OGJ Group Show Big Gain in 1993; Revenues Dip." Oil and Gas Journal. 92(24):25-30. June 13, 1994.

A more recent issue of OGJ reported on the economic status of all 110 major and nonmajor[1] natural gas pipeline companies in 1994.[49] Table 2-22 reports the sales volume, operating revenues, and net income for the top 10 U.S. natural gas pipeline companies in 1994. Operating revenues of the top 10 companies equaled $7,108,631 and represented 43 percent of the total operating revenues for major and nonmajor companies, which had declined by 24 percent from the previous year. Net income for the top 10 was over $1.5 billion and represented almost 65 percent of the total net income for all major and nonmajor companies. Despite the overall decline in operating revenues, the total net income for the 100 companies rose by 37 percent from 1993 to 1994.

[1]Major pipeline companies are those whose combined gas sold for resale and gas transported for a fee exceeded 50 bcf at 14.37 psi (60 degrees F) in each of the three previous calendar years. Nonmajors are natural gas pipeline companies not classified as majors and whose total gas sales of volume transactions exceeded 200 MMcf at 14.73 psi (60 degrees F) in each of the three previous calendar years.

TABLE 2-22. PERFORMANCE OF TOP 10[a] GAS PIPELINE COMPANIES, 1994

Company	Net Income ($000)	Operating Revenues ($000)
Tennessee Gas Pipeline Co.	489,984	1,065,285
Natural Gas Pipeline of America	158,165	1,046,660
ANR Pipeline Co.	152,057	152,057
Texas Eastern Transmission Corp.	148,887	832,405
Panhandle Eastern Pipe Line Co.	112,910	384,771
Transcontinental Gas Pipe Line Corp.	110,726	1,590,962
Northern Natural Gas Co.	97,570	702,567
El Paso Natural Gas Co.	92,978	669,439
CNG Transmission Corp.	88,055	488,754
Florida Gas Transmission Co.	78,166	175,731
Total 1994	1,529,498	7,108,631
Total All Companies 1994	2,373,245	16,547,531
Total All Companies 1993	1,113,303	21,746,475

[a]Based on net income.

Source: "U.S. Interstate Pipelines Ran More Efficiently in 1994". Oil and Gas Journal, p. 39-58. November 27, 1995.

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