United States Environmental Protection Agency
Air

Office Of Air Quality Planning And Standards
Research Triangle Park, NC 27711

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FINAL REPORT

Economic Impact Analysis of the Proposed Stationary Combustion Turbines NESHAP

Final Report

This report contains portions of the economic impact analysis report that are related to the industry profile.

SECTION 2
COMBUSTION TURBINE TECHNOLOGIES AND COSTS

This section provides background information on combustion turbine technologies. Included is a discussion of simple-cycle combustion turbines (SCCTs) and combined-cycle combustion turbines (CCCTs), along with a comparison of fuel efficiency and capital costs between the two classes of turbines.

2.1 Simple-Cycle Combustion Turbine Technologies

Most stationary combustion turbines use natural gas to generate shaft power that is converted into electricity.[1] Combustion turbines have four basic components, as shown in Figure 2-1.

1. The compressor raises the air pressure up to thirty times atmospheric.

2. A fuel compressor is used to pressurize the fuel.

3. The compressed air is heated in the combustion chamber at which point fuel is added and ignited.

4. The hot, high pressure gases are then expanded through a power turbine, producing shaft power, which is used to drive the air and fluid compressors and a generator or other mechanical drive device. Approximately one-third of the power developed by the power turbine can be required by the compressors.

Electric utilities primarily use simple-cycle combustion turbines as peaking or backup units. Their relatively low capital costs and quick start-up capabilities make them ideal for partial operation to

[1]Combustion turbine technology used for aircraft engines is virtually the same except the energy is used to generate thrust.

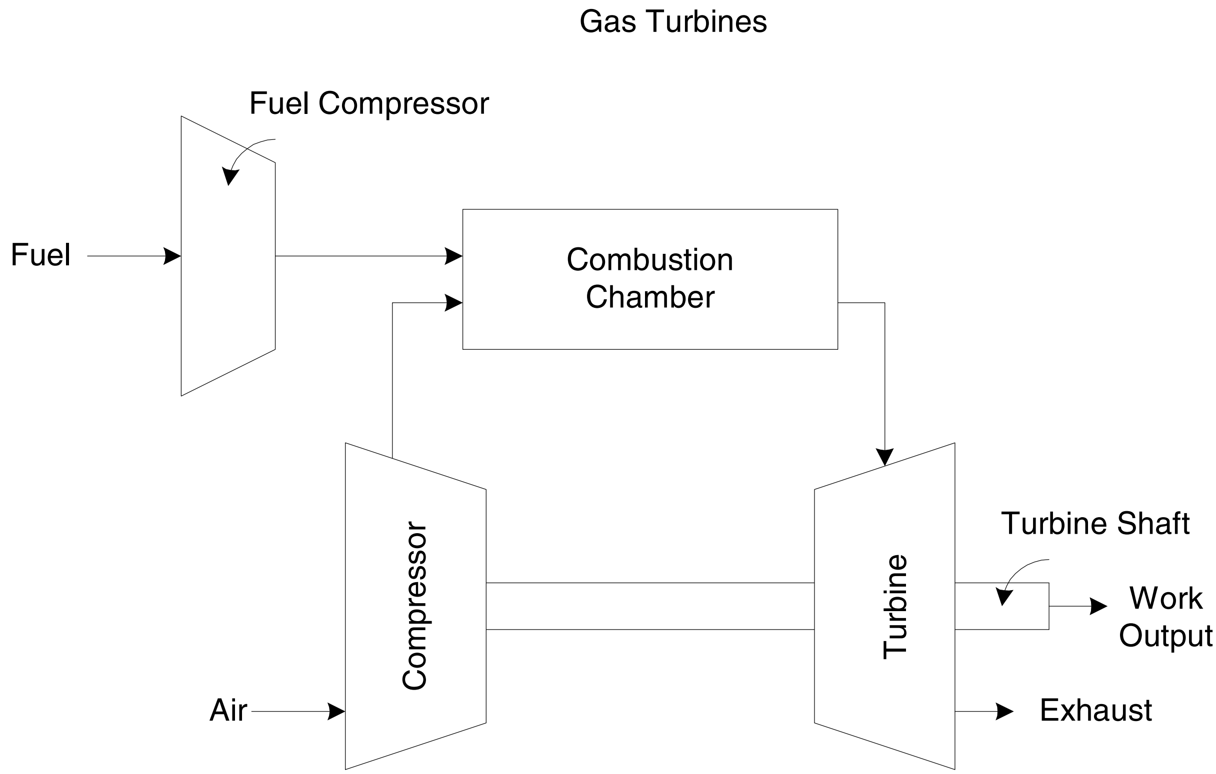


Figure 2-1. Simple-Cycle Gas Turbine

Source: Hay, Nelson E., ed. 1988. *Guide to Natural Gas Cogeneration*. Lilburn, GA: The Fairmont Press, Inc.

generate power at periods of high demand or to provide ancillary services, such as spinning reserves or black-start back-up capacity.[2] The disadvantage of simple-cycle systems is that they are relatively inefficient, thus making them less attractive as base load generating units.

2.2 Combined-Cycle Combustion Turbines Technologies

The combined-cycle system incorporates two simple-cycle systems into one generation unit to maximize energy efficiency. Energy is produced in the first cycle using a gas turbine; then the heat that remains is used to create steam, which is run through a steam turbine. Thus, two single units, gas and steam, are put together to minimize lost potential energy.

The second cycle is a steam turbine. In a CCCT, the waste heat remaining from the gas turbine cycle is used in a boiler to produce steam. The steam is then put through a steam turbine, producing

[2]Spinning reserves are unloaded generating capacity that is synchronized to the grid that can begin to respond immediately to correct for generation/load imbalances caused by generation and transmission outages and that is fully available within 10 minutes. Black-start capacity refers to generating capacity that can be made fully available within 30 to 60 minutes to back up operating reserves and for commercial purposes.

power. The remaining steam is recondensed and either returned to the boiler where it is sent through the process again or sold to a nearby industrial site to be used in a production process. Figure 2-2 shows a gas-fired CCCT.

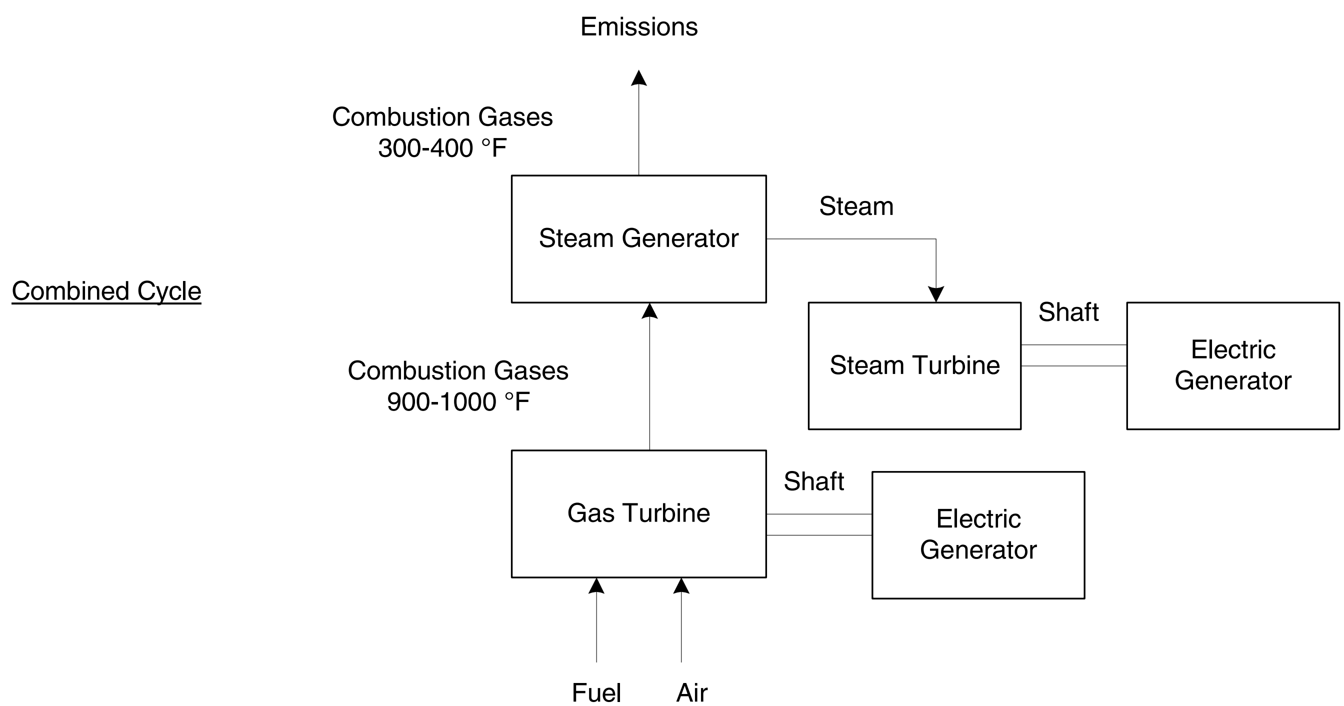


Figure 2-2. Combined-Cycle Gas Turbine

Source: Siemens Westinghouse. August 31, 1999. Presentation.

There are significant efficiency gains in using a combined-cycle turbine compared to simple-cycle systems. With SCCTs, adding a second stage allows for heat that otherwise would have been emitted and completely wasted to be used to create additional power or steam for industrial purposes. For example, a SCCT with an efficiency of 38.5 percent, adding a second stage increases the efficiency to 58 percent, a 20 percent increase in efficiency (Siemens, 1999). General Electric (1999) has recently developed a 480 MW system that will operate at 60 percent net combined-cycle efficiency.

In addition to energy efficiency gains, CCCTs also offer environmental efficiency gains compared to existing coal plants. In addition, efficiency gains associated with the CCCT lead to lower emissions compared to SCCTs. As Table 2-1 shows, the 58 percent efficiency turbine decreases NO_x emissions by 14 percent over simple-cycle combustion turbines and 89 percent over existing coal electricity generation plants. In addition, CO_2 emissions will be 5 percent lower than emissions from SCCTs and 64 percent lower than existing coal plants.

Table 2-1. Comparison of Emissions from Coal-Fired and Simple-Cycle Turbines and Combined-Cycle Turbines

	NO_x (lb/MW-hr)	CO_2 (lb/MW-hr)
Coal electricity generation	5.7	2,190
Simple-cycle turbines	0.7	825
Combined-cycle turbines	0.6	780

Source: Siemens Westinghouse. August 31, 1999. Presentation.

2.3 Capital and Installation Costs

CCCT capital and installation costs are approximately 30 percent less ($/MW) than a conventional coal or oil steam power plant's capital and installation costs, and CCCT costs are likely to decrease over the next 10 years. Gas turbine combined-cycle plants range from approximately $300 per kW installed for very large utility-scale plants to $1,000 per kW ($1998) for small industrial cogeneration installation (*GTW Handbook*, 1999). However, the prices of construction can vary as a result of local labor market conditions and the geographic conditions of the site (*GTW Handbook*, 1999). SCCTs are approximately half the cost of CCCT units.

Table 2-2 breaks down the budgeted construction costs of a gas-fired 107 MW combined-cycle cogenerating station at John F. Kennedy International Airport that was installed several years ago. As shown in Table 2-2, the construction price can range dramatically. This job finished near the top of the budget, close to $133,600,000. According to *Gas Turbine World*, the typical budget price for a 168 MW plant is $80,600,000, ($480/kW) for a plant with net efficiency of 50.9 percent (*GTW Handbook*, 1999).

Table 2-2. Overall Installation Costs

Construction costs can vary dramatically. This table shows the budgeted cost for a gas-fired 107 MW combined-cycle cogenerating station at John F. Kennedy International Airport in Brooklyn, New York. The power plant uses two 40 MW Stewart & Stevenson LM6000 gas turbine generators each exhausting into a triple pressure heat recovery steam generator raising steam for processes and to power a nominal 27 MW steam turbine generator. Budgeted prices are in 1995–1996 U.S. dollars.

Budget Equipment Pricing	**$ Amount**
Gas turbine generators	$24,000,000
Heat recovery steam generators	10,000,000
Steam turbine generator set	4,000,000
Condenser	300,000
Cooling towers	800,000
Transformer and switchgear	8,000,000
Balance of plant equipment	7,500,000
Subtotal, equipment	$54,600,000
Budget Services and Labor	
Mechanical and electrical construction	$20-75,000,000
Engineering	4,000,000
Subtotal, services	$24-79,000,000
Total Capital Cost	**$78,600,000-133,600,000**

Source: *1998–99 GTW Handbook*. "Turnkey Combined Cycle Plant Budget Price Levels." Fairfield, CT: Pequot Pub. Pgs. 16–26.

2.4 O&M Costs Including Fuel

Fuel accounts for one-half to two-thirds of total production costs (annualized capital, operation and maintenance, fuel costs) associated with generating power using combustion turbines. Table 2-3 compares the percentage of costs spent on annualized capital, operation and maintenance, and fuel for both simple turbines and CCCTs.

The fuel costs may vary depending on the plant's location. In areas where gas costs are high, for a base-load CCCT power plant, fuel costs can account for up to 70 percent of total plant costs—including acquisition, owning and operating costs, and debt service (*GTW Handbook*, 1999). General Electric's "H" design goals for future CCCT systems are to reduce power plant operating costs by at least 10 percent compared to today's technology as a direct result of using less fuel. The higher efficiency allows more power to be generated with the same amount of fuel, resulting in a substantial fuel cost savings for the plant owner (General Electric, 1999).

Table 2-3. Comparison of Percentage of Costs[a]

	Simple Cycle	Combined Cycle
% Capital costs	50	25
% Operation and maintenance	10	10
% Fuel	40	65

[a] Based on a review of marketing information from turbine manufacturers and the *GTW Handbook*.

SECTION 4

PROJECTION OF UNITS AND FACILITIES IN AFFECTED SECTORS

The proposed regulation will affect existing and new combustion turbine units with capacity over 1 MW. As a result, the economic impact estimates presented in Section 6 and the small business screening analysis presented in Section 7 are based on the population of existing units and the projection of new combustion turbine units through the year 2005. This section begins with a review of the technical characteristics and industry distribution of existing combustion turbines contained in the Agency's Inventory Database. It presents projected growth estimates for combustion turbines greater than 1 MW and describes trends in the electric utility industry. It also presents (in Section 4.3) the estimated number of existing and new combustion turbines that will be affected by this proposed rule.

4.1 Profile of Existing Combustion Turbine Units

This section profiles existing combustion turbine units (greater than 1 MW) with respect to business applications, industry of parent company, and fuel use. For nonutility combustion turbines, the population of existing sources will be used to provide the characteristics of new combustion turbines constructed through the year 2005.

The population of existing combustion turbine units used in the analysis was developed from the EPA Inventory Database V.4— Turbines (referred to as the Inventory Database). The combustion turbines contained in the Inventory Database are based on information from the Aerometric Information Retrieval System (AIRS) and Ozone Transport Assessment Group (OTAG) databases, state and local permit records, and the combustion source Information Collection Request (ICR) conducted by the Agency in 1997. The list of combustion turbine units contained in the Inventory Database was reviewed and updated by industry and environmental stakeholders as part of the Industrial Combustion Coordinated Rulemaking (ICCR), chartered under the Federal Advisory Committee Act (FACA).

From the Inventory Database, EPA identified 2,072 combustion turbines with greater than 1 MW capacity. More than 2,800 additional turbines were listed in the database, but their records lacked capacity information and/or industry information, so these units are excluded from this analysis. The total estimated population of existing combustion turbines is about 8,000, so the coverage in the Inventory Database of the estimated existing combustion turbine population is approximately 60 percent. The profiles presented below are based in the 2,072 combustion turbines in the Inventory Database above 1 MW of capacity with valid information for inclusion in the analyses conducted for this proposed rule.

4.1.1 Distribution of Units and Facilities by Industry

Table 4-1 presents the number of combustion turbines and facilities owning turbines by NAICS code. Forty-seven percent of existing combustion turbines are in Utilities (NAICS 221), 22 percent are in Pipeline Transportation, and 18 percent are in Oil and Gas Extraction (NAICS 211). Section 4 presents industry profiles for the electric power, natural gas pipelines, and oil and gas industries. The remaining units are primarily distributed across the manufacturing sector and are concentrated in the chemical and petroleum industries.

4.1.2 Technical Characteristics

This section characterizes the population of 2,072 units by MW capacity, fuel type, hours of operation, annual MWh produced (or equivalent), and simple or combined cycle.

- MW Capacity: Unit capacities in the population range between 1 and 368 MW. Although some units have large capacities in excess of 100 MW, about half (1,000 units) have capacities between 1 and 10 MW (see Figure 4-1). Only approximately 13 percent (278 units) have capacities greater than 100 MW. The total estimated capacity of all the units in the population is 79,909 MW.

- Fuel type: Natural gas is the most common fuel consumed by units in the population. About 28 percent (579 units) use distillate oil, which is more commonly known as diesel fuel. A relatively small number (53 units) consume other fuels, such as landfill gas, crude oil, and residual fuel oil.

  Although only 28 percent of units use distillate oil, in terms of the total MW capacity of the population, distillate oil fuels a disproportionate percentage, nearly 43 percent. This implies either that many of the mid- to large-sized turbines are fueled by distillate oil, that natural gas is more common in smaller units, or that a combination of the two explains this fact.

- Hours of Operation: Nearly half of all turbines (925 units) operate more than 7,500 hours per year (see Table 4-2). A year consists of approximately 8,760 hours. Although 488 units operate less than 500 hours per year, only 414 units operate between 500 and 7,500 hours per year. Information on annual hours of operation was unavailable for 245 (or 12 percent) of the 2,072 units. Because the

Table 4-1. Facilities With Units Having Capacities Above 1 MW by Industry Grouping and Government Sector

NAICS	Description	# Units	# Facilities
112	Animal Production	1	1
211	Oil and Gas Extraction	365	105
212	Mining (Except Oil and Gas)	3	3
221	Utilities	983	393
233	Building, Developing, and General Contracting	1	1
235	Special Trade Contractors	2	1
311	Food Manufacturing	18	11
321	Wood Products Manufacturing	3	2
322	Paper Manufacturing	17	11
324	Petroleum and Coal Products Manufacturing	34	11
325	Chemical Manufacturing	63	39
326	Plastics and Rubber Products Manufacturing	4	3
327	Nonmetallic Mineral Product Manufacturing	1	1
331	Primary Metal Manufacturing	13	4
332	Fabricated Metal Product Manufacturing	2	2
333	Machinery Manufacturing	2	2
334	Computer and Electronic Product Manufacturing	6	5
335	Electrical Equipment, Appliance, and Component Manufacturing	1	1
336	Transportation Equipment Manufacturing	3	3
337	Furniture and Related Product Manufacturing	1	1
339	Miscellaneous Manufacturing	3	3
422	Wholesale Trade, Nondurable Goods	6	4
486	Pipeline Transportation	448	244
488	Support Activities for Transportation	1	1
513	Broadcasting and Telecommunications	1	1
522	Credit Intermediation and Related Activities	3	1
541	Professional, Scientific, and Technical Services	2	2
561	Administrative and Support Services	1	1
611	Educational Services	10	8
622	Hospitals	23	14
721	Accommodation	1	1
923	Administration of Human Resource Programs	1	1
926	Administration of Economic Programs	1	1
928	National Security and International Affairs	42	12
Unknown	Industry Classification Unknown	6	5
Total		2,072	899

Source: Industrial Combustion Coordinated Rulemaking (ICCR). 1998. Data/Information Submitted to the Coordinating Committee at the Final Meeting of the Industrial Combustion Coordinated Rulemaking Federal Advisory Committee. EPA Docket Numbers A-94-63, II-K-4b2 through -4b5. Research Triangle Park, North Carolina. September 16-17.

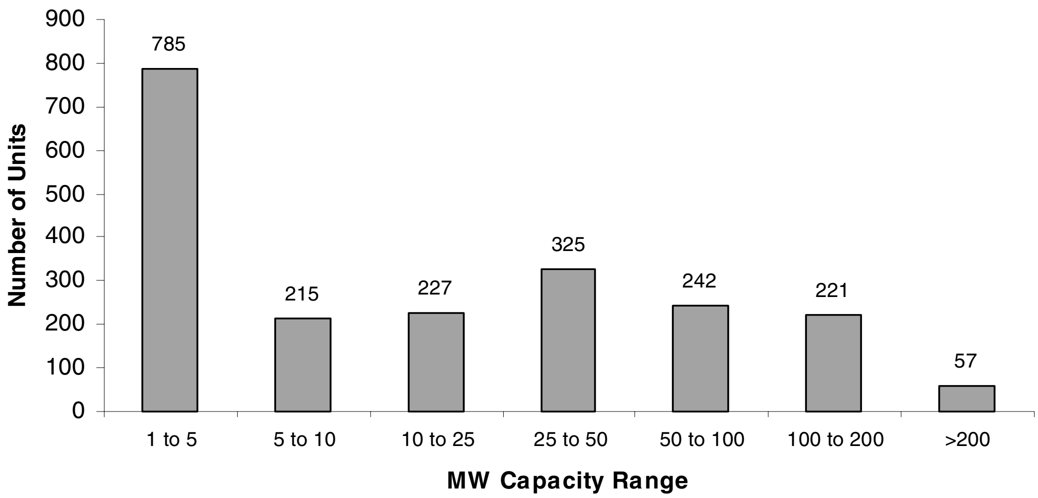


Figure 4-1. Number of Units by MW Capacity

Table 4-2. Stationary Combustion Turbine Projections

	Total Number of New Units
Utility Turbines	
Base load energy (combined cycle)	480
Peak power (simple cycle)	235
Nonutility Turbines	
Small	10
Medium	31
Large	15
Total in 5th year	771
Average per year	154

vast majority of those units were located on pipelines, which operate 24 hours a day, or at electric utility plants, many of the 245 units probably operate more than 7,500 hours a year.

- Annual MWh Equivalent: Figure 4-2 presents the distribution of units by the estimated annual MWh equivalent produced by each unit. For units that are used for compression or other functions, their likely MWh output was estimated using their MW capacity and annual hours of operation. Annual MWh for 245 units lacking annual hours of operation information was not calculated. Figure 4-3 includes data for the other 1,827 units, more than one-third of which have output of between 10,000 and 50,000 MWh a year. 360 units have output of less than 5,000 MWh, and 217 units have output greater than 500,000 MWh.

- Simple vs. combined cycle: Information was not available from the Inventory Database on the type of turbine. However, based on industry sales data, a breakdown of 1998 industry orders shows that 32 percent of the orders were for peak SCCTs and the remaining 68 percent were for CCCTs. Sixty percent of the buyers were merchant plants, 10 percent were independent power producers (IPPs), and the remaining 30 percent were rate-base utility generators (Siemens Westinghouse, 1999).

4.2 Projected Growth of Combustion Turbines

The Agency estimates there will be a total of 771 new stationary combustion turbines over the next 5 years (see Table 4-2). This projection is based on information supplied from the turbine manufacturing industry, state permit data compiled by EPA, and Gas Turbine World's *1999-2000 Handbook on Gas Turbine Orders and Installations*.

4.2.1 Comparison of Alternative Growth Estimates

Specific growth projections for combustion turbines vary with respect to the timing of the construction of new units. Table 4-3 shows that according to 1998 projections, U.S. electric utilities were planning to install 316 new units between 1998 and 2007. The units are expected to average 165 MW. The majority of these units are projected to be CCCTs (DOE, 1999d). According to a second study, the Department of Energy projects 300 GW of new generation capacity will be needed by the year 2020 (Reuters News Service, 1999).

Because the electric utility industry accounts for 70 percent of the projected new units and 97 percent of the projected new capacity in MW and nearly half of the existing units and 72 percent of the existing capacity in MW, the remainder of this section focuses on the trends in the electric utility industry.

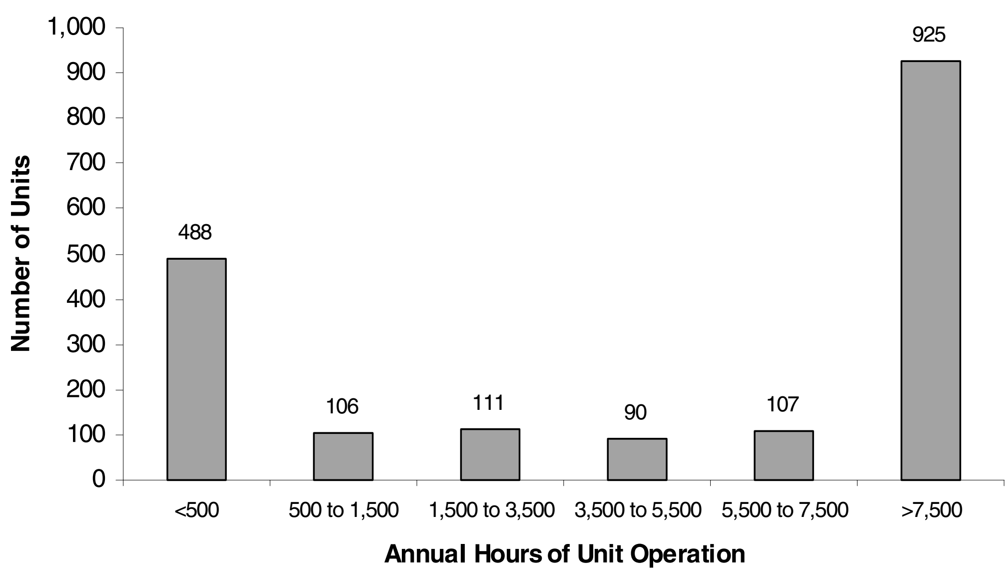


Figure 4-3. Number of Units by Annual Hours of Operation

Note: Excludes 245 units for which information on annual hours of operation was unavailable.

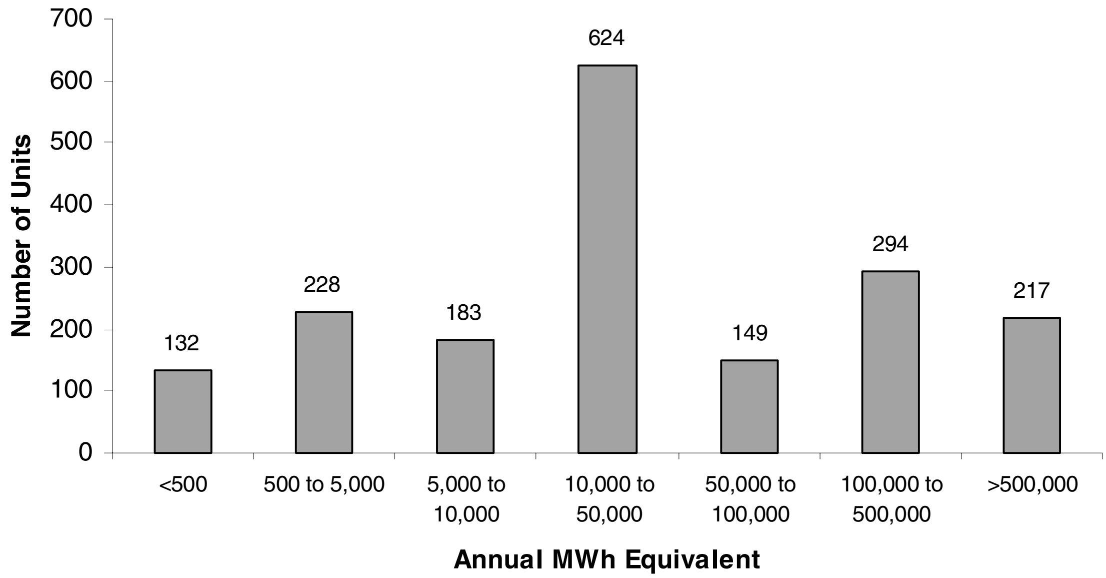


Figure 4-2. Number of Units by Annual MWh Output Equivalent

Note: Excludes 245 units for which information on annual hours of operation was unavailable.

Table 4-3. Planned Capacity Additions at U.S. Public Utilities, 1998 through 2007, as of January 1, 1998

Year	Number of Units	Generator Nameplate Capacity (MW)
U.S. Total	316	52,044
1998	60	2,020
1999	25	2,298
2000	31	3,875
2001	31	5,843
2002	35	5,978
2003	34	8,201
2004	26	5,707
2005	31	7,576
2006	22	5,879
2007	21	4,667

Notes: Total may not equal the sum of components because of independent rounding.
Source: U.S. Department of Energy, Energy Information Administration. 1999c. *Electric Power Annual 1998*. Volumes I and II. Washington, DC: U.S. Department of Energy.

4.3 Number of Affected Stationary Combustion Turbines

We estimate that 20 percent of the stationary combustion turbines affected by this proposed rule will be located at major sources. This estimate is based on an examination by EPA of permit data, which indicated that utility turbines will primarily be installed at greenfield power plants where no other sources of HAP emissions will be present. Greenfield power plants that had a total capacity of more than the calculated MW were assumed to be major sources, while those that were less were assumed to be area sources. Industrial turbines were all assumed to go into brownfield sites that were already major HAP sites. Based on this analysis of permit data, it is expected that twenty percent of new turbines will be major sources. The EPA also assumed that this percentage applied to existing sources. Since only existing LPC turbines have a MACT requirement, the EPA estimated the number of existing LPC turbines to be about ten percent of the total number of turbines. This amounts to 800 existing LPC turbines, of which twenty percent are major or an estimated 160 LPC turbines that are major. Since these 160 turbines are located at major sources, these turbines can be defined as potentially subject to a MACT standard (since all other sources would not be subject to a MACT such as this one). Of these 160 turbines, 10 or about six percent are expected to install an oxidation catalyst system to comply with the emission limitations. This estimate is for the fifth year after promulgation. The calculation that derives this estimate is in the "Cost Impacts Associated with Stationary Combustion Turbine MACT," a memo that is in the public docket. As a result, the environmental and energy impacts presented here reflect these estimates.

For new stationary combustion turbines, 771 new turbines are projected to come online by the fifth year after promulgation as shown in Table 4-2; 20 percent or 154 are expected to be at major sources. Ten of these 154 turbines are expected to require installation of an oxidation catalyst to meet the emission limitations in the rule for new sources. Thus, the percentage of new stationary combustion turbines affected is about 6.5 percent. A breakdown of these 154 turbines shows that 75 new base load energy turbines and 24 peak power turbines will be affected in the next five years. For new nonutility turbines, 56 new units will be affected in the next five years.

Based on the description in the previous two paragraphs, twenty stationary combustion turbines will have to apply an oxidation catalyst to meet the emission limitations associated with this proposed rule.

Finally, in the fifth year after promulgation, 59 turbines are expected to require performance testing. This total includes the 31 new turbines (which is 20 percent of 154) that come online that year and are required to conduct an initial performance test to demonstrate compliance. The EPA also estimates that an additional 10 percent of combustion turbines installed prior to the fifth year may be required to conduct performance testing to demonstrate compliance if the enforcing agency has reason to believe the turbine is not performing correctly. Therefore, 10 percent of the 123 affected turbines projected to be installed in the first four years after promulgation, 10 percent of the 160 affected turbines that existed before promulgation, and 31 new turbines will conduct performance testing in the fifth year, which equals 59 (12 + 16 + 31) turbines total. The calculations of these estimates are in "Cost Impacts Associated with Stationary Combustion MACT," a memo that is in the public docket

4.4 HAP and Other Emission Reductions

The proposed rule will reduce total national HAP emissions by an estimated 81 tons/year in the 5th year after the standards are promulgated. The emissions reductions achieved by the proposed rule would be come from the sources that install an oxidation catalyst control system. We estimate that about 10 existing lean premix combustion turbines will install oxidation catalyst control to comply with the standard. In addition, we estimate that about 5 percent of new stationary combustion turbines will install oxidation catalyst control to comply with the standards. The other 95 percent of new stationary combustion turbines will be lean premix, a pollution prevention technology which in most cases does not require the use of oxidation catalyst control. The lean premix turbines are currently being installed to meet NO_x emission standards. The reduction of HAP emissions for these stationary combustion turbines is difficult to assess because it is a pollution prevention technology and is being installed to meet NO_x limits, not as a result of MACT for stationary combustion turbines. Therefore, as stated previously, the HAP emissions reductions obtained by the proposed rule result only from the sources that install an oxidation catalyst control system.

To estimate the baseline HAP emissions and reductions associated with this proposed rule, national HAP emissions in the absence of the proposed rule were calculated using an emission factor from the emissions database. We assumed new stationary combustion turbines are operated 8,760 hours annually. We then assumed a HAP reduction of 95 percent, achieved by using oxidation catalyst emission control devices to comply with the emission limitation to reduce CO emissions, and applied this reduction to the baseline HAP emissions to estimate total national HAP emission reduction. The total national HAP emission reduction of 81 tons per year in the fifth year following promulgation is the sum of formaldehyde, acetaldehyde, benzene, and toluene emission reductions.

In addition to HAP emission reductions, the proposed rule will reduce criteria air pollutant emissions, primarily CO emissions, though there will be a very small amount of PM and VOC emission reductions as well. There are estimated to be 3,800 tons of CO emission reductions associated with this proposed rule. PM emissions are very low from stationary combustion turbines since virtually all of the affected turbines burn natural gas or similar gaseous fuels. Very few existing turbines burn oils, and we do not believe any new affected turbines in the next five years will exclusively use an oil fuel. Any turbines that are built to use oils are likely to be dual fuel-fired, which means they can operate off of two different types of fuel that are likely to be natural gas and diesel oil. In any event, oxidation catalyst control systems will reduce PM emissions by 25 to 50 percent. Oxidation catalyst control systems will reduce VOC emissions as well. The control efficiency depends on the specific compounds. However, we believe that VOC (and hydrocarbon (HC)) emissions from combustion turbines that are not HAP are very low and we have been unable to quantify emission reductions for these pollutants.

4.5 Energy and Other Impacts from Direct Application of Control Measures

The only energy impact from the direct application of oxidation catalyst control systems is the pressure drop across the oxidation catalyst bed of typically 1 to 1-1/2 inches of water pressure drop. According to information contained in the Gas Turbine World 1999-2000 Handbook (GTWH), a rough rule of thumb for heavy frame turbines, which are the types of turbines which we believe will mostly be installed in the next five years, is that every four inches of water pressure outlet loss is equivalent to a 0.6 percent heat rate loss resulting in a 0.6 percent power output loss. (Heat rate is a measure of the amount of inlet heat input to a turbine required to produce a certain amount of power. When the turbine heat rate increases, more inlet heat is required to produce the same amount of power resulting in a decrease in the thermal efficiency.)

Vendors state that an oxidation catalyst system can be designed so that the maximum pressure drop across the control device does not exceed 1.5 inches of water pressure drop including the catalyst system and housing. Therefore, the heat rate increase is expected to be about 0.15 percent (1/4 x 0.6 percent) increase per inch of water pressure drop increase in the turbine outlet. (Other studies by Gas Technology Institute have indicated that this value is 0.105 percent per inch of turbine outlet pressure drop. However we chose to use the GTWH value for this calculation.) Therefore for a 1.5 inch pressure drop across an oxidation catalyst system, the power output loss is estimated to be 0.225 percent (1.5 x 0.15). This represents the energy impact which is very low.

4.5.1 Water Impacts

Oxidation catalyst systems do not use water or produce water so the water impacts are expected to be very low.

4.5.2 Solid Waste Impacts

Oxidation catalyst are made with precious metals. When the catalyst charge is replaced (about every six years), the old catalyst is usually sent to a catalyst metal processor who reclaims the precious metals and the owner/operator gets a reimbursement from the processor. Therefore, because the spent catalyst is recycled, the solid waste impact is very small.

4.6 Trends in the Electric Utility Industry

Most industry and government forecasts project sizable growth of new electric power generation capacity in the near future to meet the increase in consumer demand for electricity and the retirement of aging coal and nuclear units. Experts agree that this new capacity will mainly come from SCCTs and CCCT units fueled by natural gas. Three factors have contributed to recent and projected dominance of gas combustion turbines to meet the demand for new generation capacity:

- Technology advances in combustion turbines have increased efficiency.
- Lower and less-volatile natural gas prices have increased cost-effectiveness and lowered risk.
- Deregulation of the electric utility industry has opened the market to smaller independent operators with applications ideally suited for combustion turbines.

Over the next 5 years deregulation of the electric power industry will be the main factor influencing the growth of combustion turbines to generate electric power. Deregulation is influencing the demand for utility combustion turbines in the following ways:

1. Competitive markets for wholesale power are leading to the replacement of less-efficient coal and nuclear power plants. Because of advances in gas turbine technology, new SCCTs and CCCTs are more economical compared to new oil and coal power plants and less-efficient existing plants.
2. Competitive markets for wholesale power have led to an increased demand for bulk transmission resources. However, economic and political factors continue to limit the growth in new transmission corridors. Combustion turbine units that are smaller in size and more environmentally friendly (compared to coal or nuclear power plants) can be placed throughout the grid (referred to as distributed generation) to alleviate transmission constraints.
3. Deregulation has opened the market to merchant power producers and IPPs. The smaller-scale combustion turbine power plants are ideal for these market players who

generally serve niche markets where there are capacity shortages or where industrial steam loads are high.[3]

[3]Most industry experts agree that (at least in the short run) deregulation will lead to four major regional power markets in the U.S. Bulk transmission interfaces between these four regional markets will continue to be capacity strained, implying that electricity prices may continue to vary from region to region. In addition, there will be local metropolitan areas or geographically isolated areas, such as San Francisco, where transmission constraints will restrict "perfect" competition. In these areas, small-scale distributed generation, such as CCCTs, will be able to command price premiums for electric power.

SECTION 5

PROFILES OF AFFECTED INDUSTRIES

This section contains profiles of the major industries affected by the proposed regulation of stationary combustion turbines. The Agency anticipates that most of the direct costs of the regulation will be borne by the electric services (NAICS 22111) sector. However, the crude oil and natural gas extraction (NAICS 211) and natural gas pipelines (NAICS 486) sectors will be indirectly affected through changes in industry production and fuel switching. Together, these energy sectors account for about 90 percent of the existing combustion turbines (greater than 1 MW) identified by the Agency in the Inventory Database. The remaining combustion turbines are spread across a wide variety of industries, most notably chemicals and allied products, petroleum products, health services, and national security agencies, and are primarily used for self-generated electricity or co-generated electricity and process steam. Direct costs on these industries are expected to be minimal.

The Agency projects that growth in new combustion turbines that will be affected by the proposed regulation will also be concentrated in the electric services, crude oil and natural gas extraction, and natural gas industries. This section contains background information on these three industries to help inform the regulatory process.

5.1 Electric Utility Industry (NAICS 22111)

This profile of the U.S. electric power industry provides background information on the evolution of the electricity industry, the composition of a traditional regulated electric utility, the current market structure of the electric industry, and deregulation trends and the potential future market structure of the electricity market. This profile also discusses current industry characteristics and trends that will influence the future generation and consumption of electricity.

5.1.1 Market Structure of the Electric Power Industry

The ongoing process of deregulation of wholesale and retail electric markets is changing the structure of the electric power industry. Deregulation is leading to the functional unbundling of generation, transmission, and distribution and to competition in the generation segment of the industry. This section provides background on the current structure of the industry and future deregulation trends. It begins with a brief overview of the evolution of the electric power industry because the future market structure will, in large part, be determined by the existing infrastructure and capital assets that have evolved over the past decades.

5.1.1.1 The Evolution of the Electric Power Industry

The electric utility industry began as isolated local service systems with the first electric companies evolving in densely populated metropolitan areas like New York and Chicago. Prior to World War I, rural electrification was a piecemeal process. Only small, isolated systems existed, typically serving a single town. The first high-voltage transmission network was built in the Chicago area in 1911 (the Lake County experiment). This new network connected the smaller systems surrounding Chicago and resulted in substantial production economies, lower customer prices, and increased company profits.

In light of the success of the Lake County experiment, the 1910s and 1920s saw increased consolidation and rapid growth in electricity usage. During this period, efficiency gains and demand growth provided the financing for system expansions. Even though the capacity costs (fixed costs per peak kW demanded) were typically twice as large with the consolidated/interconnected supply systems, the fixed costs per unit of energy production (kWh) were comparable to those of the old single-city system. This was the case because of load factor improvements, which resulted from aggregating customer demand.

Whereas the average fixed cost per customer was relatively unchanged as a result of the move from single-city to consolidated supply systems, large savings were realized from decreases in operating costs. In particular, fuel costs per kWh decreased 70 percent because of the improved combustion efficiency of larger plants and lower fuel prices for purchases of large quantities. In addition, operation and maintenance costs decreased 85 percent, primarily as a result of decreased labor intensity.

During the 1920s, only a small part of the efficiency gains were passed on to customers in the form of lower prices. Producers retained the bulk of the productivity increases as profits. These profits provided the internal capital to finance system expansions and to buy out smaller suppliers. Industry expansion and consolidation led to the development of large utility holding companies whose assets were shares of common stock in many different operating utilities.

The speculative fever of the 1920s led to holding companies purchasing one another, creating financial pyramids based on inflated estimates of company assets. With the stock market crash in 1929, shareholders who had realized both real economic profits and speculative gains lost large amounts of money. The financial collapse of the utility holding companies led to new levels of utility regulation.

From the 1930s through the 1960s, the regulated mandate of electric utilities was basically unchanged: to provide safe, adequate, and reliable service to all electricity users. The majority of the state and federal laws regulating utilities in place during this era had been written shortly after the Depression. The laws were primarily designed to prevent "ruinous competition" through costly duplication of utility functions and to protect customers against exploitation from a monopoly supplier.

During this period, most utilities were vertically integrated, controlling everything from generation to distribution. Economies of scale in generation and the inefficiency of duplicating transmission and distribution systems made the electric utility industry a textbook example of a natural monopoly. Electricity was viewed as a homogeneous good from which there were no product unbundling opportunities or unique product offerings on which competition could get a foothold. In addition, the industry was extremely capital-intensive, providing a sizable barrier to entry even if the monopoly status of the utilities had not been protected.

From the 1930s to the 1960s, the electric industry experienced almost continuous growth in demand. In addition, there was a steady stream of technological innovations in generation, transmission, and distribution operations. The increased economies of scale, technological advances, and fast demand growth led to steadily declining unit costs. However, in an environment of decreasing unit costs, there were few rate cases and almost no pressure from customers to change the system. This period is often referred to as the golden era for the electric utility industry.

5.1.1.2 Structure of the Traditional Regulated Utility

The utilities vary substantially in size, type, and function. Figure 5-1 illustrates the typical structure of the electric utility market. Even with the technological and regulatory changes in the 1970s and 1980s, at the beginning of the 1990s the structure of the electric utility industry could still be characterized in terms of generation, transmission, and distribution. Commercial and retail customers were in essence “captive,” and rates and service quality were primarily determined by public utility commissions.

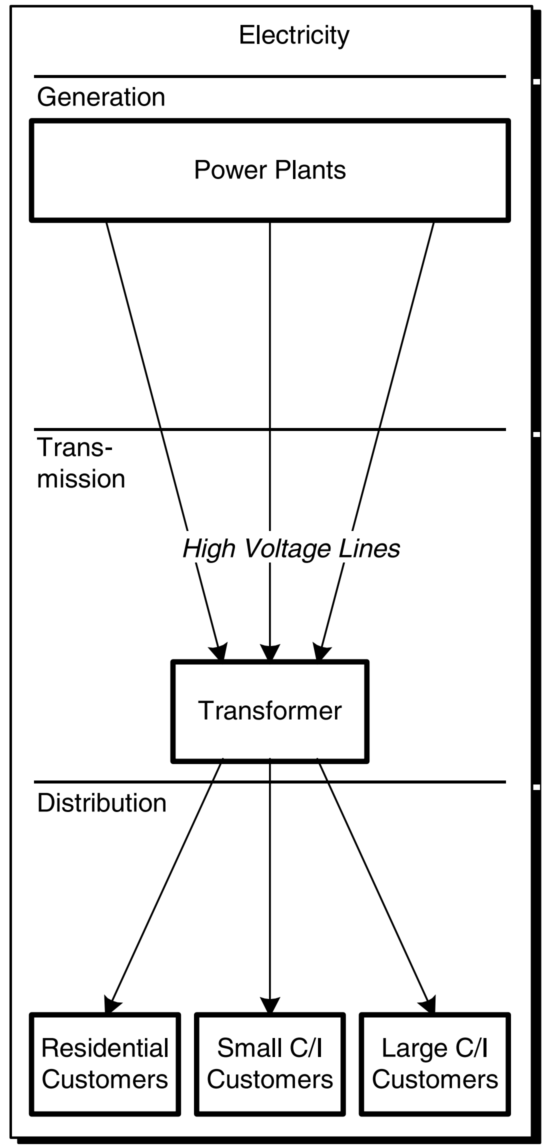


Figure 5-1. Traditional Electric Power Industry Structure

The majority of utilities are interconnected and belong to a regional power pool. Pooling arrangements enable facilities to coordinate the economic dispatch of generation facilities and manage transmission congestion. In addition, pooling diverse loads can increase load factors and decrease costs by sharing reserve capacity.

Generation. Coal-fired plants have historically accounted for the bulk of electricity generation in the United States. With abundant national coal reserves and advances in pollution abatement technology, such as advanced scrubbers for pulverized coal and flue gas-desulfurization systems, coal will likely remain the fuel of choice for most existing generating facilities over the near term.

Natural gas accounts for approximately 10 percent of current generation capacity but is expected to grow; advances in natural gas exploration and extraction technologies and new coal gasification have contributed to the use of natural gas for power generation.

Nuclear plants and renewable energy sources (e.g., hydroelectric, solar, wind) provide approximately 20 percent and 10 percent of current generating capacity, respectively. However, there are no plans for new nuclear facilities to be constructed, and there is little additional growth forecasted in renewable energy.

Transmission. Transmission refers to high voltage lines used to link generators to substations where power is stepped down for local distribution. Transmission systems have been traditionally characterized as a collection of independently operated networks or grids interconnected by bulk transmission interfaces.

Within a well-defined service territory, the regulated utility has historically had responsibility for all aspects of developing, maintaining, and operating transmissions. These responsibilities included

- system planning and expanding,
- maintaining power quality and stability, and
- responding to failures.

Isolated systems were connected primarily to increase (and lower the cost of) power reliability. Most utilities maintained sufficient generating capacity to meet customer needs, and bulk transactions were initially used only to support extreme demands or equipment outages.

Distribution. Low-voltage distribution systems that deliver electricity to customers comprise integrated networks of smaller wires and substations that take the higher voltage and step it down to lower levels to match customers' needs.

The distribution system is the classic example of a natural monopoly because it is not practical to have more than one set of lines running through neighborhoods or from the curb to the house.

5.1.1.3 Current Electric Power Supply Chain

This section provides background on existing activities and emerging participants in the electric power supply chain.[4] Because the restructuring plans and time tables are made at the state level, the issues of asset ownership and control throughout the current supply chain in the electric power industry vary from state to state. However, the activities conducted throughout the supply chain are generally the same.

[4]The electric power supply chain includes all generation, transmission, distribution, administrative, and market activities needed to deliver electric power to consumers.

Table 5-1 shows costs by utility ownership and by segment of the supply chain. Generation accounts for approximately 75 percent of the cost of delivered electric power.

Figure 5-2 provides an overview of the electric power supply chain, highlighting a combination of activities and service providers. The activities/members of the electric power supply chain are typically grouped into generation, transmission, and distribution. These three segments are described in the following sections.

Generation. As part of deregulation, the transmission and distribution of electricity are being separated from the business of generating electricity, and a new competitive market in electricity generation is evolving. As power generators prepare for the competitive market, the share of electricity generation attributed to nonutilities and utilities is shifting.

More than 7,000 electricity suppliers currently operate in the U.S. market. As shown in Table 5-2, approximately 42 percent of suppliers are utilities and 58 percent are nonutilities. Utilities include investor-owned, cooperatives, and municipal systems. Of the approximately 3,100 utilities operating in the United States, only about 700 generate electric power. The majority of utilities distribute electricity that they have purchased from power generators via their own distribution systems.

Utility and nonutility generators produced a total of 3,369 billion kWh in 1995. Although utilities generate the vast majority of electricity produced in the United States, nonutility generators are quickly eroding utilities' shares of the market. Nonutility generators include private entities that generate power for their own use or to sell to utilities or other end users. Between 1985 and 1995, nonutility generation increased from 98 billion kWh (3.8 percent of total generation) to 374 billion kWh (11.1 percent). Figure 5-3 illustrates this shift in the share of utility and nonutility generation.

Table 5-1. Total Expenditures in 1996 ($$10^3$)

Utility Ownership	Generation	Transmission	Distribution	Customer Accounts and Sales	Administration and General Expenses
Investor-owned	80,891,644	2,216,113	6,124,443	6,204,229	13,820,059
Publicly owned	12,495,324	840,931	1,017,646	486,195	1,360,111
Federal	3,685,719	327,443	1,435	55,536	443,809
Cooperatives	15,105,404	338,625	1,133,984	564,887	1,257,015
	112,178,091	3,723,112	8,277,508	7,310,847	16,880,994
	75.6%	2.5%	5.6%	4.9%	11.4%
	148,370,552				

Sources: U.S. Department of Energy, Energy Information Administration (EIA). 1998a. *Financial Statistics of Major Publicly Owned Electric Utilities, 1997*. Washington, DC: U.S. Department of Energy.

U.S. Department of Energy, Energy Information Administration (EIA). 1997. *Financial Statistics of Major U.S. Investor-Owned Electric Utilities, 1996*. Washington, DC: U.S. Department of Energy.

Utilities. There are four categories of utilities: investor-owned utilities (IOUs), publicly owned utilities, cooperative utilities, and federal utilities. Of the four, only IOUs always generate electricity.

IOUs are increasingly selling off generation assets to nonutilities or converting those assets into nonutilities (Haltmaier, 1998). To prepare for the competitive market, IOUs have been lowering their operating costs, merging, and diversifying into nonutility businesses.

In 1995, utilities generated 89 percent of electricity, a decrease from 96 percent in 1985. IOUs generate the majority of the electricity produced in the United States. IOUs are either individual corporations or a holding company, in which a parent company operates one or more utilities integrated with one another. IOUs account for approximately three-quarters of utility generation, a percentage that held constant between 1985 and 1995.

Utilities owned by the federal government accounted for about one-tenth of generation in both 1985 and 1995. The federal government operated a small number of large utilities in 1995 that supplied power to large industrial consumers or federal installations. The Tennessee Valley Authority is an example of a federal utility.

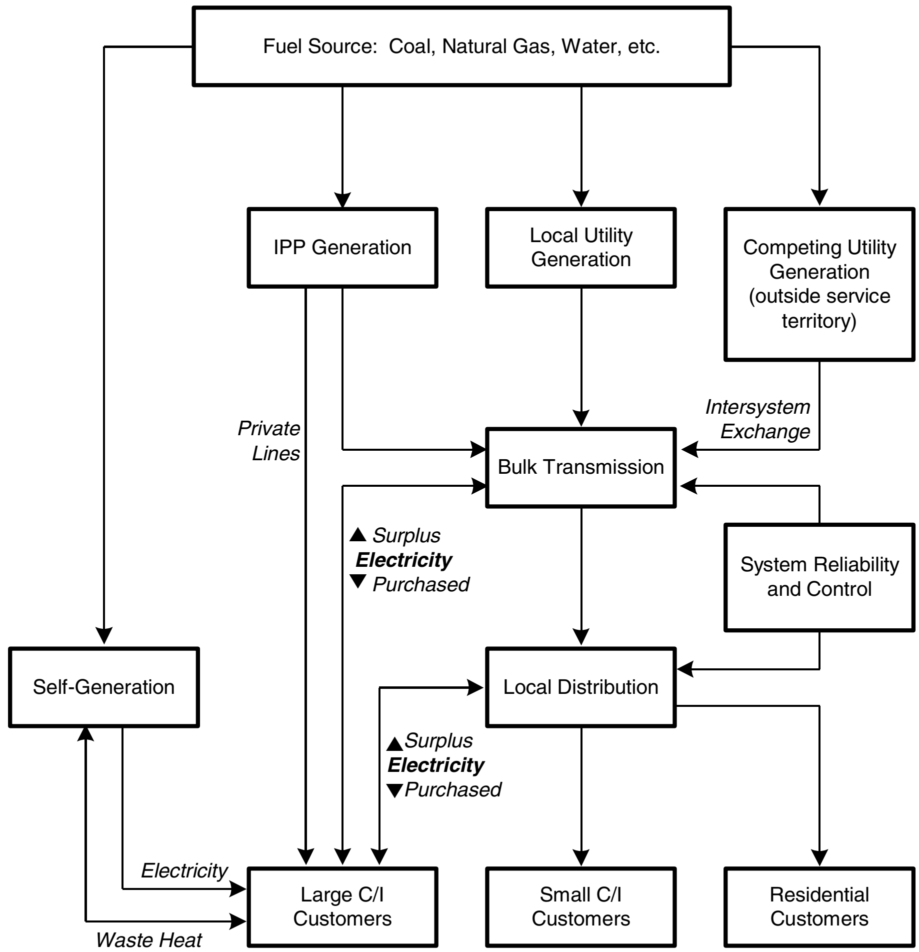


Figure 5-2. Electric Utility Industry

Many states, municipalities, and other government organizations also own and operate utilities, although the majority do not generate electricity. Those that do generate electricity operate capacity to supply some or all of their customers' needs. They tend to be small, localized outfits and can be found in 47 states. These publicly owned utilities accounted for about one-tenth of utility generation in 1985 and 1995. In a deregulated market, these generators may be in direct competition with other utilities to service their market.

Table 5-2. Number of Electricity Suppliers in 1999

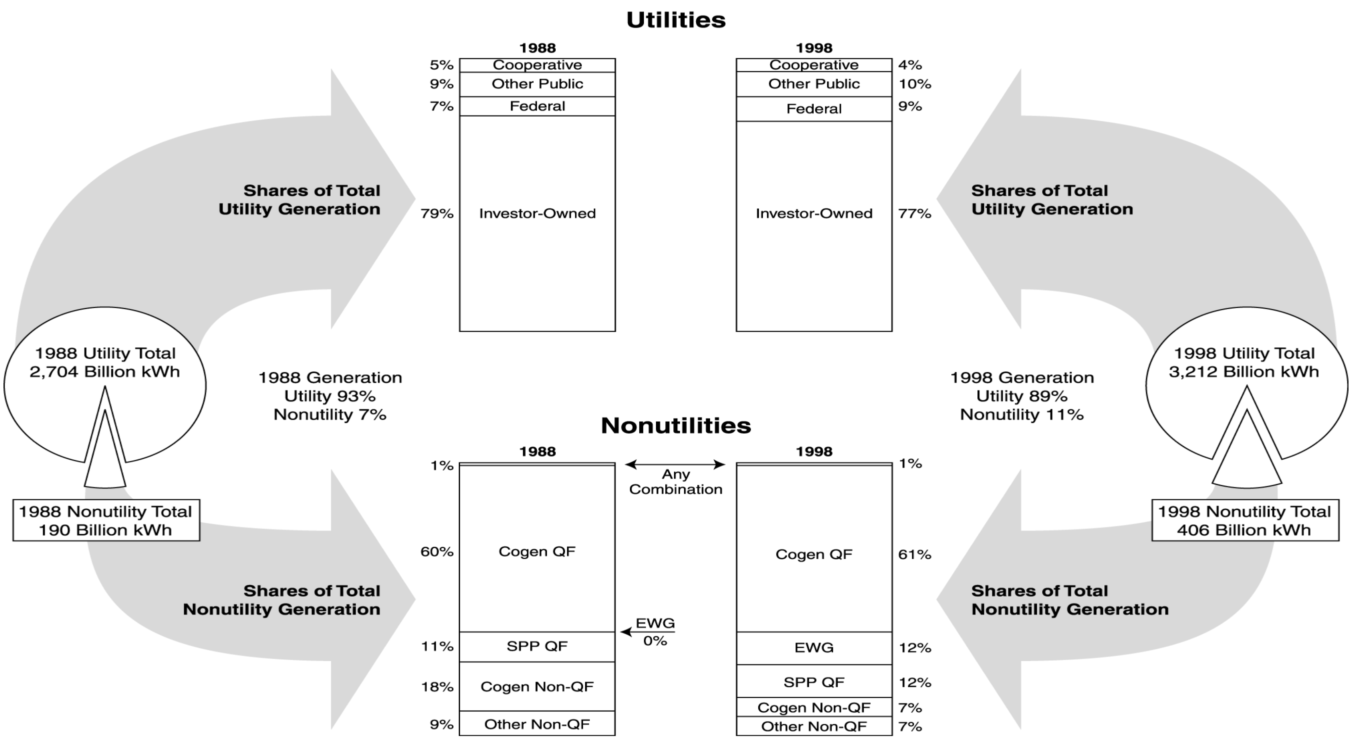
Electricity Suppliers	Number	Percent
Utilities	3,124	42%
Investor-owned utilities	222	
Cooperatives	875	
Municipal systems	1,885	
Public power districts	73	
State projects	55	
Federal agencies	14	
Nonutilities	4,247	58%
Nonutilities (excluding EWGs)	4,103	
Exempt wholesale generators	144	
Total	7,371	100%

Source: U.S. Department of Energy, Energy Information Administration (EIA). 1999g. *The Changing Structure of the Electric Power Industry 1999: Mergers and Other Corporate Combinations*. Washington, DC: U.S. Department of Energy.

Rural electric cooperatives are the fourth category of utilities. They are formed and owned by groups of residents in rural areas to supply power to those areas. Cooperatives generally purchase from other utilities the energy that they sell to customers, but some generate their own power. Cooperatives only produced 5 percent of utility generation in 1985 and only 6 percent in 1995.

Nonutilities. Nonutilities are private entities that generate power for their own use or to sell to utilities or other establishments. Nonutilities are usually operated at mines and manufacturing facilities, such as chemical plants and paper mills, or are operated by electric and gas service companies (DOE, EIA, 1998b). More than 4,200 nonutilities operate in the United States.

Between 1985 and 1995, nonutility generators increased their share of electricity generation from 4 percent to 11 percent (see Figure 5-3). In 1978, the Public Utilities Regulatory Policies Act (PURPA) stipulated that electric utilities must interconnect with and purchase capacity and energy offered by any qualifying nonutility. In 1996, FERC issued Orders 888 and 889 that opened transmission access to nonutilities and required utilities to share information about available transmission capacity. These moves established wholesale



[a] Includes facilities classified in more than one of the following FERC designated categories: cogenerator QF, small power producer QF, or exempt wholesale generator.
Cogen = Cogenerator.
EWG = Exempt wholesale generator.
Other Non-QF = Nocogenerator Non-QF.
QF = Qualifying facility.
SPP = Small power producer.
Note: Sum of components may not equal total due to independent rounding. Classes for nonutility generation are determined by the class of each generating unit.
Sources: **Utility data:** U.S. Department of Energy, Energy Information Administration (EIA). 1996b. *Electric Power Annual 1995*. Volumes I and II. DOE/EIA-0348(95)/1. Washington, DC: U.S. Department of Energy; Table 8 (and previous issues); **1985 nonutility data:** Shares of generation estimated by EIA; total generation from Edison Electric Institute (EEI). 1998. *Statistical Yearbook of the Electric Utility Industry 1998*. November. Washington, DC; **1995 nonutility data:** U.S. Department of Energy, Energy Information Administration (EIA). 1996b. *Electric Power Annual 1995*. Volumes I and II. DOE/EIA-0348(95)/1. Washington, DC: U.S. Department of Energy.

Figure 5-3. Utility and Nonutility Generation and Shares by Class, 1988 and 1998

competition, spurring nonutilities to increase generation and firms to invest in nonutility generation.

Nonutilities are frequently categorized by their FERC classification and the type of technology they employ. There are three categories of nonutilities: cogenerators, small power producers (SPPs), and exempt wholesale generators (EWGs).

Cogenerators are nonutilities that sequentially or simultaneously produce electricity and another form of energy (such as heat or steam) using the same fuel source. At cogeneration facilities, steam is used to drive a turbine to generate electricity. The waste heat and steam from driving the turbine is then used as an input in an industrial or commercial process. For a cogenerator to qualify or interconnect with utilities, it must meet certain ownership, operating, and efficiency criteria specified by FERC. In 1985, about 55 percent of nonutility generation was produced by cogenerators that qualified or met FERC's specifications and sold power to utilities. By 1995 the percentage increased to 67 percent as the push for deregulation gathered momentum. At the same time, the percentage that was produced by nonqualifying cogenerators decreased from 25 percent to 9 percent.

SPPs typically generate power using renewable resources, such as biomass, solar energy, wind, or water. However, increasingly SPPs include companies that self-generate power using combustion turbines and sell excess power back to the grid. As with cogenerators, SPPs must fulfill a series of FERC requirements to interconnect with utilities. PURPA revisions enabled nonutility renewable electricity to grow significantly, and SPPs have responded by improving technologies, decreasing costs, and increasing efficiency and reliability (DOE, EIA, 1998b). Between 1985 and 1995, the percentage of SPP nonutility generation nearly doubled to 13 percent.

EWGs produce electricity for the wholesale market. Also known as IPPs, EWGs typically contract directly with large bulk customers, such as large industrial and commercial facilities and utilities. They do not operate any transmission or distribution facilities but pay tariffs to use facilities owned and operated by utilities. Unlike with qualifying cogenerators and SPPs, utilities are not required to purchase energy produced by EWGs, but they may do so at market-based prices. EWGs did not exist until the Energy Policy Act created them in 1992, and by 1995 they generated about 2 percent of nonutility electricity.

In 1995, about 4 percent of nonutility generation was produced by facilities that were classified as any combination of cogenerator, SPP, and EWG. An additional 6 percent was produced by facilities that generate electricity for their own consumption.

Transmission. Whereas the market for electricity generation is moving toward a competitive structure, the transmission of electricity is currently (and will likely remain) a regulated, monopoly operation. In areas where power markets are developing, generators pay tariffs to distribute their electricity over established lines owned and maintained by independent organizations. Independent service operators (ISOs) will most likely coordinate transmission operations and generation dispatch over the bulk power system.

The bulk power transmission system consists of three large regional networks, which also encompass smaller groups. The three networks are geographically defined: the Eastern Interconnect in the eastern two-thirds of the nation; the Western Interconnect in the western portion; and the Texas Interconnect, which encompasses the majority of Texas. The western and eastern networks are each fully integrated with Canada. The western is also integrated with Mexico. Within each network, the electricity producers are connected by extra high-voltage connections that allow them to transfer electrical energy from one part of the network to the other.

The bulk power system makes it possible for electric power producers to engage in wholesale trade. In 1995, utilities sold 1,283 billion kWh to other utilities. The amount of energy sold by nonutilities has increased dramatically from 40 billion kWh in 1986 to 222 billion kWh in 1995, an average annual increase of 21 percent (DOE, EIA, 1996a). Distribution utilities and large industrial and commercial customers also have the option of purchasing electricity in bulk at market prices from their local utility, a nonutility, or another utility. The process of transmitting electricity between suppliers via a third party is known as wholesale wheeling.

The wholesale trade for electricity is increasingly handled by power marketers (brokers). Power marketers act as independent middlemen that buy and sell wholesale electricity at market prices (EEI, 1999). Customers include large commercial and industrial facilities in addition to utilities. Power marketers emerged in response to increased competition. Brokers do not own generation facilities, transmissions systems, or distribution assets, but they may be affiliated with a holding company that operates generation facilities. Currently, 570 power marketers operate in the United States. The amount of power sold by marketers increased from 3 million MWh to 2.3 billion MWh between 1995 and 1998. This is the equivalent of going from powering 1 million homes to powering 240 million homes (EEI, 1999). Table 5-3 lists the top ten power marketers by sales for the first quarter of 1999.

Table 5-3. Top Power Marketing Companies, First Quarter 1999

Company	Total MWh Sold
Enron Power Marketing, Inc.	78,002,931
Southern Company Energy Marketing, L.P.	38,367,107
Aquila Power Corp.	29,083,612
PG&E Energy Trading-Power, L.P.	28,463,487
Duke Energy Trading & Marketing, L.L.C.	22,276,608
LG&E Energy Marketing, Inc.	15,468,749
Entergy Power Marketing Corp.	12,670,520
PacifiCorp Power Marketing, Inc.	11,800,263
Tractebel Energy Marketing, Inc.	10,041,039
NorAm Energy Services, Inc.	9,817,306

Source: Resource Data International. 1999. "PMA Online Top 25 Power Marketer Rankings." *Power Marketers Online Magazine*. <http://www.powermarketers.com/top25a.htm.> As obtained on August 11, 1999.

Distribution. The local distribution system for electricity is expected to remain a regulated monopoly operation. But power producers will soon be able to compete for retail customers by paying tariffs to entities that distribute the power. Utilities may designate an ISO to operate the distribution system or continue to operate it themselves. If the utility operates its own system, it is required by law to charge the same tariff to other power producers that it charges producers within its own corporate umbrella. The sale of electricity by a utility or other supplier to a customer in another utility's retail service territory is known as retail wheeling.

Supporters of retail wheeling claim that it will help lower the average price paid for electricity. The states with the highest average prices for electricity are expected to be the first to permit retail wheeling; wholesale wheeling is already permitted nationwide. In 1996, California, New England, and the Mid-Atlantic States had the highest average prices for electricity, paying 3 cents or more per kilowatt-hour than the national average of 6.9 cents (DOE, EIA, 1998b). Open access to the electricity supply, coupled with a proliferation of electricity suppliers, should combine to create falling electricity prices and increasing usage. By 2002, the nationwide average price for electricity is projected to be 11 percent lower than in 1995, an average annual decline of roughly 2 percent (Haltmaier, 1998).

The explosion in computer and other information technology usage in the commercial sector is expected to offset energy efficiency gains in the residential and industrial sectors and lead to a net increase in the demand for electricity. Retail wheeling has the potential to allow customers to lower their costs per kilowatt-hour by purchasing electricity from suppliers that best fit their usage profiles.

Large commercial and industrial customers engaged in self-generation or cogeneration will also be able to sell surplus electricity in the wholesale market.

5.1.1.4 Overview of Deregulation and the Potential Future Structure of the Electricity Market

Beginning in the latter part of the 19th century and continuing for about 100 years, the prevailing view of policymakers and the public was that the government should use its power to require or prescribe the economic behavior of "natural monopolies" such as electric utilities. The traditional argument is that it does not make economic sense for there to be more than one supplier—running two sets of wires from generating facilities to end users is more costly than one set. However, since monopoly supply is not generally regarded as likely to provide a socially optimal allocation of resources, regulation of rates and other economic variables was seen as a necessary feature of the system.

Beginning in the 1970s, the public policy view shifted against traditional regulatory approaches and in favor of deregulation for many important industries including transportation, communications, finance, and energy. The major drivers for deregulation of electric power included the following:

- existence of rate differentials across regions offering the promise of benefits from more efficient use of existing generation resources if the power can be transmitted across larger geographic areas than was typical in the era of industry regulation;
- the erosion of economies of scale in generation with advances in combustion turbine technology;
- complexity of providing a regulated industry with the incentives to make socially efficient investment choices;
- difficulty of providing a responsive regulatory process that can quickly adjust rates and conditions of service in response to changing technological and market conditions; and
- complexity of monitoring utilities' cost of service and establishing cost-based rates for various customer classes that promote economic efficiency while at the same time addressing equity concerns of regulatory commissions.

Viewed from one perspective, not much changes in the electric industry with restructuring. The same functions are being performed, essentially the same resources are being used, and in a broad sense the same reliability criteria are being met. In other ways, the very nature of restructuring, the harnessing of competitive forces to perform a previously regulated function, changes almost everything. Each provider and each function become separate competitive entities that must be judged on their own.

This move to market-based provision of generation services is not matched on the transmission and distribution side. Network interactions on AC transmission systems have made it impossible to have separate transmission paths compete. Hence, transmission and distribution remain regulated. Transmission and generation heavily interact, however, and transmission congestion can prevent specific generation from getting to market. Transmission expansion planning becomes an open process with many interested parties. This open process, coupled with frequent public opposition to transmission expansion, slows transmission enhancement. The net result is greatly increased pressure on the transmission system.

Restructuring of the electric power industry could result in any one of several possible market structures. In fact, different parts of the country will probably use different structures, as the current trend indicates. The eventual structure may be dominated by a power exchange, bilateral contracts, or a combination. A strong Regional Transmission Organization (RTO) may operate in the area, or a vertically integrated utility may continue to operate a control area. In any case, several important characteristics will change:

- Commercial provision of generation-based services (e.g., energy, regulation, load following, voltage control, contingency reserves, backup supply) will replace regulated service provision. This drastically changes how the service provider is assessed.
- Individual transactions will replace aggregated supply meeting aggregated demand. It will be necessary to continuously assess each individual's performance.
- Transaction sizes will shrink. Instead of dealing only in hundreds and thousands of MW, it will be necessary to accommodate transactions of a few MW and less.
- Supply flexibility will greatly increase. Instead of services coming from a fixed fleet of generators, service provision will change dynamically among many potential suppliers as market conditions change.

5.1.2 Electricity Generation

Because of the uncertainties associated with the future course of deregulation, forecasting deregulation's impact on generation trends, and hence growth in combustion turbines, is difficult. However, most industry experts believe that deregulation will lead to increased competition in the wholesale (and eventually retail) power markets, driving out high cost producers of electricity, and that there will be an increased reliance on distributed generation to compensate for growing demands on the transmission system.

In 2000, the United States relied on fossil fuels to produce almost 74 percent of its electricity. Table 5-4 shows a breakdown of generation by energy source.[5] Whereas natural gas seems to play a relatively minor role among utility producers, it represents 30 percent of capacity among nonutility producers. This is because nonutilities use coal and petroleum to the same extent as the larger, traditionally regulated utility power producers.

Among nonutility producers, manufacturing facilities contain the largest electricity-generating capacity. Table 5-5 illustrates that, from 1995 through 1999, manufacturing facilities consistently had the capacity to produce over two-thirds of nonutility electricity generation.

[5]Nonutility power producers have approximately 10 percent of the capacity of utility power producers.

In 1997 cogenerators produced energy totaling 146 billion kWh for their own use. Cogenerators are expected to continue to increase their generation capabilities at a slightly slower rate than utilities.

Table 5-6 further disaggregates capacity by prime mover and energy source at electric utilities. As the table shows, hydroelectric and steam are the two prime movers with the most units, while steam and nuclear generators have the greatest total capacity. Combustion turbines' (including the second stage of CCCTs) generation represents approximately 10 percent of total U.S. capacity.

Table 5-4. Industry Capability by Energy Source, 2000

Energy Source	Utility Generators (MW)	Nonutility Generators (MW)	Total (MW)
Fossil fuels	424,218	173,320	597,538
Coal	259,059	56,190	315,249
Natural gas	38,964	58,668	97,632
Petroleum	26,250	13,003	39,253
Duel-fired	99,945	45,549	145,494
Nuclear	85,519	12,038	97,557
Hydroelectric	91,590	7,478	99,068
Renewable/other	1,050	16,322	17,372
Total	602,377	209,248	811,625

Sources: U.S. Department of Energy, Energy Information Administration. 2000. *Electric Power Annual, 1999*, Vol. 2. DOE/EIA-0348(99)/2. Washington, DC: U.S. Department of Energy.

Table 5-5. Installed Capacity at U.S. Nonutility Attributed to Major Industry Groups and Census Division, 1995 through 1999 (MW)

Year	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
1995	47,606	15,124[a]	2,165	3,428	544	1,388[a]	70,254
1996	49,529	16,050	2,181	3,313	542	1,575	73,189
1997	49,791	16,559	2,223	3,306	616	1,510	74,004
1998	51,255	24,527	2,506	3,275	534	15,989	98,085
1999	52,430	78,419	2,342	5,123	536	28,506	167,357

[a] Revised data.

Notes: All data are for 1 MW and greater. Data for 1997 are preliminary; data for prior years are final. Totals may not equal sum of components because of independent rounding.

Source: U.S. Department of Energy, Energy Information Administration (EIA). 2000. *Electric Power Annual 1999,* Volume II. Washington, DC: U.S. Department of Energy.

Table 5-6. Existing Capacity at U.S. Electric Utilities by Prime Mover and Energy Source, as of January 1, 1998

Prime Mover Energy Source	Number of Units	Generator Nameplate Capacity (MW)
U.S. Total	10,421	754,925
Steam	2,117	469,210
Coal only	911	276,895
Other solids[a]	15	334
Petroleum only	137	22,476
Gas only	117	10,840
Other solids/coal[a]	1	2
Solids/petroleum[b]	72	10,796
Solids/gas[b]	232	36,763
Solids/petroleum/gas[b]	1	558
Petroleum/gas	624	110,324
Internal Combustion	2,892	5,075
Petroleum only	1,799	2,671
Gas only	48	66
Petroleum/gas	1,044	2,335
Other solids only[a]	1	3
Combustion Turbine	1,549	63,131
Petroleum only	625	22,802
Gas only	179	5,776
Petroleum/gas	745	34,554
Second Stage of CCCTs	202	16,224
Petroleum only	11	470
Gas only	29	2,331
Coal/petroleum	1	326
Coal/gas	1	113
Petroleum/gas	100	8,852
Waste heat	60	4,130
Nuclear	107	107,632
Hydroelectric (conventional)	3,352	73,202
Hydroelectric (pumped storage)	141	18,669
Geothermal	27	1,746
Solar	11	5
Wind	19	14

[a] Includes wood, wood waste, and nonwood waste.
[b] Includes coal, wood, wood waste, and nonwood waste.

Source: U.S. Department of Energy, Energy Information Administration (EIA). 1999c. *Electric Power Annual 1998*. Volumes I and II. Washington, DC: U.S. Department of Energy.

5.1.2.1 Growth in Generation Capacity

The electric industry is continuing to grow and change. Throughout the country, electric utility capacity additions are slightly outpacing capacity retirements. The trend goes beyond an increasing capacity but also shows that coal units are slowly being replaced by newer, more efficient methods of producing energy. In 1997, 71 electric utility units were closed, decreasing capacity by 2,127 MW. Of those, six were coal facilities and 43 were petroleum facilities. However, of the 62 facility additions (2,918 MW), none were coal powered, while 24 use petroleum. Gas installations slightly outpaced petroleum ones, totaling 25 new units at electric utilities in 1997. Table 5-7 outlines capacity additions and retirements at U.S. electric utilities by energy source.

Planned additions indicate a strong trend towards gas-powered turbine/stationary combustion units. Three-quarters of the gas turbine/stationary combustion units are expected to be gas-powered with the remaining quarter petroleum-powered. Based on 1998 planned additions, it is likely that all additional petroleum-fueled units in the near future will be gas turbine/stationary combustion units, not steam. Table 5-8 shows planned capacity additions by prime mover and energy source.

5.1.3 Electricity Consumption

This section analyzes the growth projections for electricity consumption as well as the price elasticity of demand for electricity. Growth in electricity consumption has traditionally paralleled GDP growth. However, improved energy efficiency of electrical equipment, such as high-efficiency motors, has slowed demand growth over the past few decades. The magnitude of the relationship has been decreasing over time, from growth of 7 percent per year in the 1960s down to 1 percent in the 1980s. As a result, determining what the future growth will be is difficult, although it is expected to be positive (DOE, EIA, 1999a). Table 5-9 shows consumption by sector of the economy over the past 10 years. The table shows that since 1989 electricity sales have increased at least 10 percent in all four sectors. The commercial sector has experienced the largest increase, followed by residential consumption.

In the future, residential demand is expected to be at the forefront of increased electricity consumption. Between 1997 and 2020, residential demand is expected to increase at 1.6 percent annually. Commercial growth in demand is expected to be approximately 1.4 percent, while industry is expected to increase demand by 1.1 percent (DOE, EIA, 1999a).

Table 5-7. Capacity Additions and Retirements at U.S. Electric Utilities by Energy Source, 1997

Primary Energy Source	Additions		Retirements	
	Number of Units	Generator Nameplate Capacity (MW)	Number of Units	Generator Nameplate Capacity (MW)
U.S. total	62	2,918	71	2127
Coal	—	—	6	281
Petroleum	24	199	43	445
Gas	25	2,475	18	405
Water (pumped storage hydroelectric)	—	—	—	—
Nuclear	—	—	2	995
Waste heat	3	171	—	—
Renewable[a]	10	73	2	1

[a] Includes conventional hydroelectric; geothermal; biomass (wood, wood waste, nonwood waste); solar; and wind.
Note: Total may not equal the sum of components because of independent rounding.

Source: U.S. Department of Energy, Energy Information Administration (EIA). 1999c. *Electric Power Annual 1998*. Volumes I and II. Washington, DC: U.S. Department of Energy.

Figure 5-4 shows the annual electricity sales by sector from 1970 with projections through 2020.

The literature suggests that electricity consumption is relatively price inelastic. Consumers are generally unable or unwilling to forego a large amount of consumption as the price increases. Numerous studies have investigated the short-run elasticity of demand for electricity. Overall, the studies suggest that, for a 1 percent increase in the price of electricity, demand will decrease by 0.15 percent. However, as Table 5-10 shows, elasticities vary greatly, depending on the demand characteristics of end users and the price structure. Demand elasticities are estimated to range from a –0.05 percent elasticity of demand for a "flat rates" case (i.e., no time-of-use assumption) up to a –0.50 percent demand elasticity for a "high consumer response" case (DOE, EIA, 1999b).

Table 5-8. Fossil-Fueled Existing Capacity and Planned Capacity Additions at U.S. Electric Utilities by Prime Mover and Primary Energy Source, as of January 1, 1998

	Planned Additions[a]	
Prime Mover Energy Source	**Number of Units**	**Generator Nameplate Capacity (MW)**
U.S. Total	272	50,184
Steam	45	18,518
Coal	8	2,559
Petroleum	—	—
Gas	37	15,959
Gas Turbine/Internal Combustion	226	31,663
Petroleum	52	1,444
Gas	174	30,219

[a] Planned additions are for 1998 through 2007. Totals include one 2.9 MW fuel cell unit.

Notes: Total may not equal the sum of components because of independent rounding. The Form EIA-860 was revised during 1995 to collect data as of January 1 of the reporting year, where "reporting year" is the calendar year in which the report is required to be filed with the Energy Information Administration. These data reflect the status of electric plants/generators as of January 1; however, dynamic data are based on occurrences in the previous calendar year (e.g., capabilities and energy sources based on test and consumption in the previous year).

Source: U.S. Department of Energy, Energy Information Administration (EIA). 1999c. *Electric Power Annual 1998*. Volumes I and II. Washington, DC: U.S. Department of Energy.

5.2 Oil and Gas Extraction (NAICS 211)

The crude petroleum and natural gas industry encompasses the oil and gas extraction process from the exploration for oil and natural gas deposits through the transportation of the product from the production site. The primary products of this industry are natural gas, natural gas liquids, and crude petroleum.

5.2.1 Introduction

The United States is home to half of the major oil and gas companies operating around the globe. Although small firms account for nearly 45 percent of U.S. crude oil and natural gas output, the domestic oil and gas industry is dominated by 20 integrated petroleum

Table 5-9. U.S. Electric Utility Retail Sales of Electricity by Sector, 1989 Through July 1999 (Million kWh)

Period	Residential	Commercial	Industrial	Other[a]	All Sectors
1989	905,525	725,861	925,659	89,765	2,646,809
1990	924,019	751,027	945,522	91,988	2,712,555
1991	955,417	765,664	946,583	94,339	2,762,003
1992	935,939	761,271	972,714	93,442	2,763,365
1993	994,781	794,573	977,164	94,944	2,861,462
1994	1,008,482	820,269	1,007,981	97,830	2,934,563
1995	1,042,501	862,685	1,012,693	95,407	3,013,287
1996	1,082,491	887,425	1,030,356	97,539	3,097,810
1997	1,075,767	928,440	1,032,653	102,901	3,139,761
1998	1,124,004	948,904	1,047,346	99,868	3,220,121
Percentage change 1989-1998	19%	24%	12%	10%	18%

[a] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

Sources: U.S. Department of Energy, Energy Information Administration (EIA). 1999c. *Electric Power Annual 1998*. Volumes I and II. Washington, DC: U.S. Department of Energy.

U.S. Department of Energy, Energy Information Administration (EIA). 1996b. *Electric Power Annual 1995*. Volumes I and II. Washington, DC: U.S. Department of Energy.

and natural gas refiners and producers, such as Exxon Mobil, BP Amoco, and Chevron (Lillis, 1998). Despite the presence of many large global players, the industry experiences a more turbulent business cycle than most other major U.S. industries. Because the industry imports 60 percent of the crude oil used as an input into refineries, it is susceptible to fluctuations in crude oil output and prices, which are strongly influenced by the Organization of Petroleum Exporting Countries (OPEC). OPEC is a cartel consisting of most of the world's largest petroleum-producing countries that acts to increase the profits of member countries. In contrast, natural gas markets in the United States are competitive and relatively stable. Most natural gas used in the United States comes from domestic and Canadian sources.

NAICS 211 includes five major industry groups (see Table 5-11):

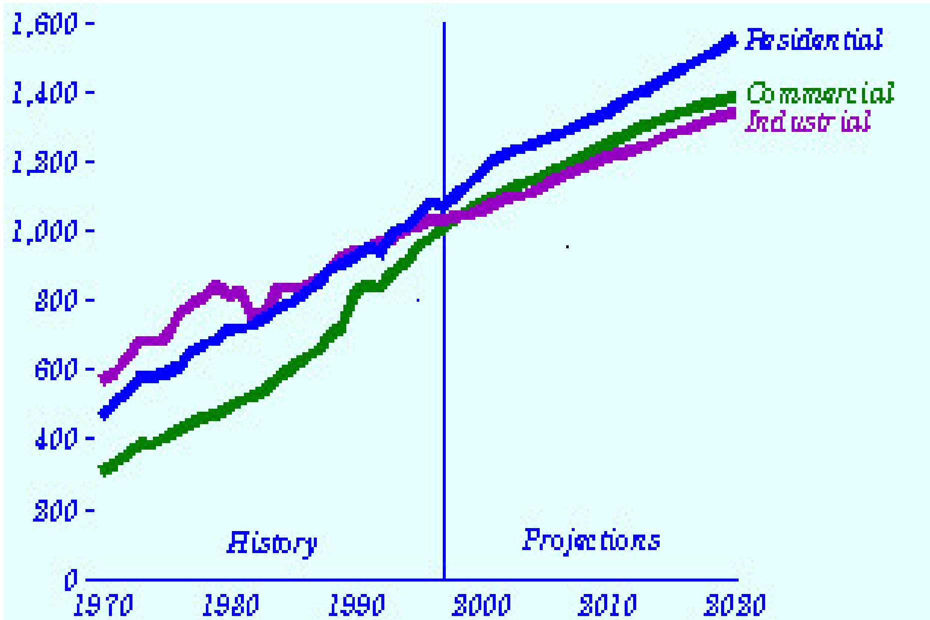


Figure 5-4. Annual Electricity Sales by Sector

- NAICS 211111 (SIC 1311): Crude petroleum and natural gas. Firms in this industry are primarily involved in operating oil and gas fields. These firms may also explore for crude oil and natural gas, drill and complete wells, and separate crude oil and natural gas components from natural gas liquids and produced fluids.

- NAICS 211112 (SIC 1321): Natural gas liquids (NGL). NGL firms separate NGLs from crude oil and natural gas at the site of production. Propane and butane are NGLs.

- NAICS 213111 (SIC 1381): Drilling oil and gas wells. Firms in this industry drill oil and natural gas wells on a contract or fee basis.

- NAICS 213112/54136 (SIC 1382): Oil and gas field exploration services. Firms in this industry perform geological, geophysical, and other exploration services.

- NAICS 213112 (SIC 1389): Oil and gas field services, not elsewhere classified. Companies in this industry perform services on a contract or fee basis that are not classified in the above industries. Services include drill-site preparations, such as building foundations and excavating pits, and maintenance.

Table 5-10. Key Parameters in the Cases

Case Name	Key Assumptions: Cost Reduction and Efficiency Improvements	Short-Run Elasticity of Demand (Percent)	Natural Gas Prices	Capacity Additions
AEO97 Reference Case	AEO97 Reference Case	—	AEO97 Reference Case	As needed to meet demand
No Competition	No change from 1995	—	AEO97 Reference Case	As needed to meet demand
Flat Rates (no time-of-use rates)	AEO97 Reference Case	-0.05	AEO97 Reference Case	As needed to meet demand
Moderate Consumer Response	AEO97 Reference Case	-0.15	AEO97 Reference Case	As needed to meet demand
High Consumer Response	AEO97 Reference Case	-0.50	AEO97 Reference Case	As needed to meet demand
High Efficiency	Increased cost savings and efficiencies	-0.15	AEO97 Reference Case	As needed to meet demand
No Capacity Additions	AEO97 Reference Case	-0.15	AEO97 Low Oil and Gas Supply Technology Case	Not allowed
High Gas Price	AEO97 Reference Case	-0.15	AEO97 High Oil and Gas Supply Technology Case	As needed to meet demand
Low Gas Price	AEO97 Reference Case	-0.15	AEO97 Reference Case	As needed to meet demand
High Value of Reliability	AEO97 Reference Case	-0.15	AEO97 Reference Case	As needed to meet demand
Half O&M	AEO97 Reference Case	-0.15	AEO97 Reference Case	As needed to meet demand
Intense Competition	AEO97 Reference Case	-0.15	AEO97 Reference Case	As needed to meet demand

— = not applicable.

Source: U.S. Department of Energy, Energy Information Administration, Office of Integrated Analysis and Forecasting. "Competitive Electricity Price Projections." <http://www.eia.doe.gov/oiaf/elepri97/chap3.html>. As obtained on November 15, 1999b.

Table 5-11. Crude Petroleum and Natural Gas Industries Likely to Be Affected by the Regulation

SIC	NAICS	Description
1311	211111	Crude Petroleum and Natural Gas
1321	211112	Natural Gas Liquids
1381	213111	Drilling Oil and Gas Wells
1382	213112	Oil and Gas Exploration Services
	54136	Geophysical Surveying and Mapping Services
1389	213112	Oil and Gas Field Services, N.E.C.

In 1997, more than 6,800 crude oil and natural gas extraction companies (NAICS 211111) generated $75 billion in revenues. Revenues for 1997 were approximately 5 percent higher than revenues in 1992, although the number of companies and employees declined 11.5 and 42.5 percent, respectively.

Table 5-12 shows the NGL extraction industry (NAICS 211112) experienced a decline in the number of companies, establishments, and employees. The industry's revenues declined nearly 8.0 percent between 1992 and 1997, from $27 billion per year to $24.8 billion per year.

Revenues for NAICS 213111, drilling oil and gas wells, more than doubled between 1992 and 1997. In 1992, the industry employed 47,700 employees at 1,698 companies and generated $3.6 billion in annual revenues. By the end of 1997, the industry's annual revenues were $7.3 billion, a 106 percent improvement. Although the total number of companies and establishments decreased from 1992 levels, industry employment increased 13 percent to 53,865.

The recent transition from the SIC system to the North American Industrial Classification System (NAICS) changed how some industries are organized for information collection purposes and thus how certain economic census data are aggregated. Some SIC codes were combined, others were separated, and some activities were classified under one NAICS code and the remaining activities classified under another. The oil and gas field services industry is an example of an industry code that was reclassified. Under NAICS, SIC 1382, Oil and Gas Exploration Services, and SIC 1389, Oil and Gas Services Not Elsewhere Classified, were combined. The geophysical surveying and mapping services portion of SIC

Table 5-12. Summary Statistics, Crude Oil and Natural Gas Extraction and Related Industries

NAICS	Industry	Number of Companies	Number of Establishments	Revenues ($1997 10^3)	Employees
211111	Crude Oil and Natural Gas Extraction				
	1992	7,688	9,391	71,622,600	174,300
	1997	6,802	7,781	75,162,580	100,308
211112	Natural Gas Liquid Extraction				
	1992	108	591	26,979,200	12,000
	1997	89	529	24,828,503	10,549
213111	Drilling Oil and Gas Wells				
	1992	1,698	2,125	3,552,707	47,700
	1997	1,371	1,638	7,317,963	53,865
213112	Oil and Gas Field Services				
	1997	6,385	7,068	11,547,563	106,339

Sources: U.S. Department of Commerce, Bureau of the Census. 1999a. *1997 Economic Census, Mining Industry Series: Crude Petroleum and Natural Gas Extraction*. EC97N-2111A. Washington, DC: U.S. Department of Commerce.

U.S. Department of Commerce, Bureau of the Census. 1995a. *1992 Census of Mineral Industries, Industry Series: Crude Petroleum and Natural Gas*. MIC92-I-13A. Washington, DC: U.S. Department of Commerce.

1382 was reclassified and grouped into NAICS 54136. The adjustments to SIC 1382/89 have made comparison between the 1992 and 1997 economic censes difficult at this time. The U.S. Census Bureau has yet to publish a comparison report. Thus, for this industry only 1997 census data are presented. For that year, nearly 6,400 companies operated under SIC 1382/89 (NAICS 213112), employing more than 100,000 people and generating $11.5 billion in revenues.

5.2.2 Supply Side

Characterizing the supply side of the industry involves describing the production processes, the types of output, major by-products, costs of production, and capacity utilization.

5.2.2.1 Production Processes

There are four major processes in the oil and gas extraction industry: exploration, well development, production, and site abandonment (EPA, 1999b). Exploration is the search for rock formations associated with oil and/or natural gas deposits. Nearly all oil and natural gas deposits are located in sedimentary rock. Certain geological clues, such as porous rock with an overlying layer of low-permeability rock, help guide exploration companies to a possible source of hydrocarbons. While exploring a potential site, the firm conducts geophysical prospecting and exploratory drilling.

After an economically viable field is located, the well development process begins. Well holes, or well bores, are drilled to a depth of between 1,000 and 30,000 feet, with an average depth of about 5,500 feet (EPA, 1999b). The drilling procedure is the same for both onshore and offshore sites. A steel or diamond drill bit, which may be anywhere between 4 inches and 3 feet in diameter, is used to chip off rock to increase the depth of the hole. The drill bit is connected to the rock by several pieces of hardened pipe known collectively as the drill string. As the hole is drilled, casing is placed in the well to stabilize the hole and prevent caving. Drilling fluid is pumped down through the center of the drill string to lubricate the equipment. The fluid returns to the surface through the space between the drill string and the rock formation or casing. Once the well has been drilled, rigging, derricks, and other production equipment are installed. Onshore fields are equipped with a pad and roads; ships, floating structures, or a fixed platform are procured for offshore fields.

Production is the process of extracting hydrocarbons through the well and separating saleable components from water and silt. Oil and natural gas are naturally occurring co-products, and most production sites handle crude oil and gas from more than one well. Once the hydrocarbons are brought to the surface, they are separated into a spectrum of substances, including liquid hydrocarbons, gas, and water and other nonsaleable constituents. After being extracted, crude oil is always delivered to a refinery for processing; natural gas may be processed at the field or at a natural gas processing plant to remove impurities. Natural gas is separated from crude oil by passing the hydrocarbons through one or two decreasing pressure chambers. Excess water is removed from the crude oil, at which point the oil is about 98 percent pure, a purity sufficient for storage or transport to a refinery (EPA, 1999b). Excess water is returned to the well to facilitate the production process, but silt is discarded. If enough natural pressure does not exist in the reservoir to force the hydrocarbons through the well, then the reservoir is pressurized using pumps or excess water to lift the hydrocarbons.

Natural gas is conditioned using a dehydration and a sweetening process, which removes hydrogen sulfide and carbon dioxide, so that it is of high enough quality to pass through transmission systems. The gas may be conditioned at the field or at one of the 623 operating gas-processing facilities located in gas-producing states, such as Texas, Louisiana, Oklahoma, and Wyoming. These plants also produce the nation's NGLs, propane and butane (NGSA et al., 2000c).

Site abandonment occurs when a site lacks the potential to produce economic quantities of natural gas or when a production well is no longer economically viable. The well(s) are plugged using long cement plugs and steel plated caps, and supporting production equipment is disassembled and moved offsite.

5.2.2.2 Types of Output

The oil and gas industry's principal products are crude oil, natural gas, and NGLs (see Tables 5-13 and 5-14). Refineries process crude oil into several petroleum products. These products include motor gasoline (40 percent of crude oil); diesel and home heating oil (20 percent); jet fuels (10 percent); waxes, asphalts, and other nonfuel products (5 percent); feedstocks for the petrochemical industry (3 percent); and other lesser products (DOE, EIA, 1999d).

Natural gas is produced from either oil wells (known as "associated gas") or wells that are drilled for the primary purpose of obtaining natural gas (known as "nonassociated gas") (see Table 5-14). Methane is the predominant component of natural gas (about 85 percent), but ethane (about 10 percent), propane, and butane are also significant components (see Table 5-13). Propane and butane, the heavier components of natural gas, exist as liquids when cooled and compressed. These latter two components are usually separated and processed as NGLs (EPA, 1999b).

Table 5-13. U.S. Supply of Crude Oil and Petroleum Products (10^3 barrels), 1998

Commodity	Field Production	Refinery Production	Imports
Crude Oil	2,281,919		3,177,584
Natural Gas Liquids	642,202	245,918	82,081
Ethane/ethylene	221,675	11,444	6,230
Propane/propylene	187,369	200,815	50,146
Normal butane/butylene	54,093	29,333	8,612
Isobutane/isobutylene	66,179	4,326	5,675
Other	112,886		11,418
Other Liquids	69,477		211,266
Finished Petroleum Products	69,427	5,970,090	437,515
Finished motor gasoline	69,427	2,880,521	113,606
Finished aviation gasoline		7,118	43
Jet fuel		556,834	45,143
Kerosene		27,848	466
Distillate fuel oil		1,249,881	76,618
Residual fuel oil		277,957	100,537
Naptha		89,176	22,388
Other oils		78,858	61,554
Special napthas		24,263	2,671
Lubricants		67,263	3,327
Waxes		8,355	613
Petroleum coke		260,061	263
Asphalt and road oil		181,910	10,183
Still gas		239,539	
Miscellaneous products		20,506	103
Total	3,063,025	6,216,008	3,908,446

Source: U.S. Department of Energy, Energy Information Administration (EIA). 1999f. *Petroleum Supply Annual 1998, Volume I*. Washington, DC: U.S. Department of Energy.

Table 5-14. U.S. Natural Gas Production, 1998

Gross Withdrawls	Production (10^6 cubic feet)
From gas wells	17,558,621
From oil wells	6,365,612
Less losses and repressuring	5,216,477
Total	18,707,756

Source: U.S. Department of Energy, Energy Information Administration (EIA). 1999e. *Natural Gas Annual 1998*. Washington, DC: U.S. Department of Energy.

5.2.2.3 Major By-products

The engines that provide pumping action at wells and push crude oil and natural gas through pipes to processing plants, refineries, and storage locations produce HAPs. HAPs produced in engines include formaldehyde, acetaldehyde, acrolein, and methanol.

5.2.2.4 Costs of Production

The 42 percent decrease in the number of people employed by the crude oil and natural gas extraction industry between 1992 and 1997 was matched by a corresponding 40 percent decrease in the industry's annual payroll (see Table 5-15). During the same period, industry outlays for supplies, such as equipment and other supplies, increased over 32 percent, and capital expenditures nearly doubled. Automation, mergers, and corporate downsizing have made this industry less labor-intensive (Lillis, 1998).

Unlike the crude oil and gas extraction industry, the NGL extraction industry's payroll increased over 6 percent even though total industry employment declined 12 percent. The industry's expenditures on capital projects, such as investments in fields, production facilities, and other investments, increased 11.4 percent between 1992 and 1997. The cost of supplies did, however, decrease 13 percent from $23.3 billion in 1992 to $20.3 billion in 1997.

Employment increased in Drilling Oil and Gas Wells. In 1992, the industry employed 47,700 people, increasing 13 percent to 53,865 in 1997. During a period where industry revenues increased over 100 percent, the industry's payroll increased 41 percent and the cost of supplies increased 182 percent.

Table 5-15. Costs of Production, Crude Oil and Natural Gas Extraction and Related Industries

NAICS	Industry	Employees	Payroll ($1997 10^3)	Cost of Supplies Used, Purchased Machinery Installed, Etc. ($1997 10^3)	Capital Expenditures ($1997 10^3)
211111	Crude Oil and Natural Gas Extraction				
	1992	174,300	$8,331,849	$16,547,510	$10,860,260
	1997	100,308	$4,968,722	$21,908,191	$21,117,850
211112	Natural Gas Liquid Extraction				
	1992	12,000	$509,272	$23,382,770	$609,302
	1997	10,549	$541,593	$20,359,528	$678,479
213111	Drilling Oil and Gas Wells				
	1992	47,700	$1,358,784	$1,344,509	$286,509
	1997	53,865	$1,918,086	$7,317,963	$2,209,300
213112	Oil and Gas Field Services				
	1997	106,339	$3,628,416	$3,076,039	$1,165,018

Sources: U.S. Department of Commerce, Bureau of the Census. 1999a. *1997 Economic Census, Mining, Industry Series: Crude Petroleum and Natural Gas Extraction*. EC97N-2111A. Washington, DC: U.S. Department of Commerce.

U.S. Department of Commerce, Bureau of the Census. 1995a. *1992 Census of Mineral Industries, Industry Series: Crude Petroleum and Natural Gas*. MIC92-I-13A. Washington, DC: U.S. Department of Commerce.

5.2.2.5 Capacity Utilization

U.S. annual oil and gas production is a small percentage of total U.S. reserves. In 1998, oil producers extracted approximately 1.5 percent of the nation's proven crude oil reserves (see Table 5-16). A slightly lesser percentage of natural gas was extracted (1.4 percent), and an even smaller percentage of NGLs was extracted (0.9 percent). The

Table 5-16. Estimated U.S. Oil and Gas Reserves, Annual Production, and Imports, 1998

Category	Reserves	Annual Production	Imports
Crude oil (10^6 barrels)	152,453	2,281	3,178
Natural gas (10^9 cubic feet)	1,330,930	18,708	3,152
Natural gas liquids (10^6 barrels)	26,792	246	NA

Sources: U.S. Department of Energy, Energy Information Administration (EIA). 1999h. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1998 Annual Report*. Washington, DC: U.S. Department of Energy.

U.S. Department of Energy, Energy Information Administration (EIA). 1999f. *Petroleum Supply Annual 1998, Volume I*. Washington DC: U.S. Department of Energy.

United States produces approximately 40 percent (2,281 million barrels) of its annual crude oil consumption, importing the remainder of its crude oil from Canada, Latin America, Africa, and the Middle East (3,178 million barrels). Approximately 17 percent (3,152 billion cubic feet) of U.S. natural gas supply is imported. Most imported natural gas originates in Canadian fields in the Rocky Mountains and off the Coast of Nova Scotia and New Brunswick.

5.2.3 Demand Side

Characterizing the demand side of the industry involves describing product characteristics. Crude oil, or unrefined petroleum, is a complex mixture of hydrocarbons that is the most important of the primary fossil fuels. Refined petroleum products are used for petrochemicals, lubrication, heating, and fuel. Petrochemicals derived from crude oil are the source of chemical products such as solvents, paints, plastics, synthetic rubber and fibers, soaps and cleansing agents, waxes, jellies, and fertilizers. Petroleum products also fuel the engines of automobiles, airplanes, ships, tractors, trucks, and rockets. Other applications include fuel for electric power generation, lubricants for machines, heating, and asphalt (Berger and Anderson, 1978). Because the market for crude oil is global and its price set by OPEC, slight increases in the cost of producing crude oil in the United States will have little effect on the price of products that use crude oil as an intermediate good. Production cost increases will be absorbed by the producer, not passed along to consumers.

Natural gas is a colorless, flammable gaseous hydrocarbon consisting for the most part of methane and ethane. The largest single application for natural gas is as a domestic or industrial fuel. However, other specialized applications have emerged over the years, such as a nonpolluting fuel for buses and other motor vehicles. Carbon black, a pigment made by burning natural gas with little air and collecting the resulting soot, is an important ingredient in dyes, inks, and rubber compounding operations. Also, much of the world's ammonia is manufactured from natural gas; ammonia is used either directly or indirectly in urea, hydrogen cyanide, nitric acid, and fertilizers (Tussing and Tippee, 1995).

5.2.4 Organization of the Industry

Many oil and gas firms are merging to remain competitive in both the global and domestic marketplaces. By merging with their peers, these companies may reduce operating expenses and reap greater economies of scale than they would otherwise. Recent mergers, such as BP Amoco and Exxon Mobil, have reduced the number of companies and facilities operating in the United States. Currently, there are 20 domestic major oil and gas companies, and only 40 major global companies in the world (Conces, 2000). Most U.S. oil and gas firms are concentrated in states with significant oil and gas reserves, such as Texas, Louisiana, California, Oklahoma, and Alaska.

Tables 5-17 through 5-20 present the number of facilities and value of shipments by facility employee count for each of the four NIACS 211 industries. In 1997, 6,802 oil and gas extraction companies operated 7,781 facilities, an average of 1.14 facilities per company (see Table 5-17). Facilities with more than 100 employees produced more than 55 percent of the industry's value of shipments. Although the number of companies and the number of facilities operating in 1992 were both greater then than in 1997, the distribution of shipment values by employee size was similar to that of 1992.

Facilities employing fewer than 50 people in the NGLs extraction industry accounted for 64 percent, or \$15.8 billion, of the industry's total value of shipments in 1997 (see Table 5-18). Four hundred eighty-seven of the industry's 529 facilities are in that employment category. This also means that a relatively small number of larger facilities produced 36 percent of the industry's annual output, in terms of dollar value. The number of facilities with zero to four employees and the number with 50 or more employees decreased during the 5-year period, accounting for most of the 10.5 percent decline in the number of facilities from 1992 to 1997. The average number of facilities per company was 5.5 and 5.9 in 1992 and 1997, respectively.

Table 5-17. Size of Establishments and Value of Shipments, Crude Oil and Natural Gas Extraction Industry (NAICS 211111), 1997 and 1992

Average Number of Employees in Facility	1997 Number of Facilities	1997 Value of Shipments ($1997 10^3)	1992 Number of Facilities	1992 Value of Shipments ($1997 10^3)
0 to 4 employees	5,249	$5,810,925	6,184	$5,378,330
5 to 9 employees	1,161	$3,924,929	1,402	$3,592,560
10 to 19 employees	661	$4,843,634	790	$4,504,830
20 to 49 employees	412	$10,538,529	523	$8,820,100
50 to 99 employees	132	$8,646,336	203	$5,942,130
100 to 249 employees	105		154	$11,289,730
250 to 499 employees	40		68	$8,135,850
500 to 999 employees	14	$41,318,227	46	$14,693,630
1,000 to 2,499 employees	5		18	$9,265,530
2,500 or more employees	2		3	D
Total	7,781	$75,162,580	9,391	$71,622,600

D = undisclosed
Sums do not add to totals due to independent rounding.

Sources: U.S. Department of Commerce, Bureau of the Census. 1999a. *1997 Economic Census, Mining, Industry Series: Crude Petroleum and Natural Gas Extraction.* EC97N-2111A. Washington, DC: U.S. Department of Commerce.

U.S. Department of Commerce, Bureau of the Census. 1995a. *1992 Census of Mineral Industries, Industry Series: Crude Petroleum and Natural Gas*. MIC92-I-13A. Washington, DC: U.S. Department of Commerce.

As mentioned earlier, the oil and gas well drilling industry's 1997 value of shipments were 106 percent larger than 1992's value of shipments (see Table 5-19). However, the number of companies primarily involved in this industry declined by 327 over 5 years, and 487 facilities closed during the same period. The distribution of the number of facilities by employment size shifted towards those that employed 20 or more people. In 1997, those facilities earned two-thirds of the industry's revenues.

Table 5-18. Size of Establishments and Value of Shipments, Natural Gas Liquids Industry (NAICS 211112), 1997 and 1992

Average Number of Employees in Facility	1997 Number of Facilities	1997 Value of Shipments ($1997 10^3)	1992 Number of Facilities	1992 Value of Shipments ($1997 10^3)
0 to 4 employees	143	$1,407,192	190	$2,668,000
5 to 9 employees	101	$1,611,156	92	$1,786,862
10 to 19 employees	122	$4,982,941	112	$5,240,927
20 to 49 employees	121	$7,828,439	145	$10,287,200
50 to 99 employees	35	$5,430,448	36	$4,789,849
100 to 249 employees	3	D	14	$2,205,819
250 to 499 employees	3	D	2	D
500 to 999 employees	1	D	0	—
1,000 to 2,499 employees	0	—	0	—
2,500 or more employees	0	—	0	—
Total	529	$24,828,503	591	$26,979,200

D = undisclosed
Sums do not add to totals due to independent rounding.

Sources: U.S. Department of Commerce, Bureau of the Census. 1999b. *1997 Economic Census, Mining, Industry Series: Natural Gas Liquid Extraction*. EC97N-2111b. Washington, DC: U.S. Department of Commerce.

U.S. Department of Commerce, Bureau of the Census. 1995b. *1992 Census of Mineral Industries, Industry Series: Natural Gas Liquids*. MIC92-I-13B. Washington, DC: U.S. Department of Commerce.

In 1997, 6,385 companies operated 7,068 oil and gas field services facilities, an average of 1.1 facilities per company. Most facilities employed four or fewer employees; however, those facilities with 20 or more employees accounted for the majority of the industry's revenues (see Table 5-20).

Table 5-19. Size of Establishments and Value of Shipments, Drilling Oil and Gas Wells Industry (NAICS 213111), 1997 and 1992

Average Number of Employees in Facility	1997 Number of Facilities	1997 Value of Shipments ($1997 10^3)	1992 Number of Facilities	1992 Value of Shipments ($1997 10^3)
0 to 4 employees	825	$107,828	1,110	$254,586
5 to 9 employees	215	$231,522	321	$182,711
10 to 19 employees	197	$254,782	244	$256,767
20 to 49 employees	200	$1,008,375	233	$572,819
50 to 99 employees	95	$785,804	120	$605,931
100 to 249 employees	75	$1,069,895	70	$816,004
250 to 499 employees	10	$435,178	19	$528,108
500 to 999 employees	14	$1,574,139	5	$97,254
1,000 to 2,499 employees	6	D	3	$238,427
2,500 or more employees	1	D	—	—
Total	1,638	$7,317,963	2,125	$3,552,707

D = undisclosed
Sums do not add to totals due to independent rounding.

Sources: U.S. Department of Commerce, Bureau of the Census. 1999c. *1997 Economic Census, Mining, Industry Series: Drilling Oil and Gas Wells*. EC97N-2131A. Washington, DC: U.S. Department of Commerce.

U.S. Department of Commerce, Bureau of the Census. 1995c. *1992 Census of Mineral Industries, Industry Series: Oil and Gas Field Services.* MIC92-I-13C. Washington, DC: U.S. Department of Commerce.

5.2.5 Markets and Trends

Between 1990 and 1998, crude oil consumption increased 1.4 percent per year, and natural gas consumption increased 2.0 percent per year. The increase in natural gas consumption came mostly at the expense of coal consumption (EPA, 1999b). The Energy Information Administration (EIA), a unit of the Department of Energy, anticipates that natural gas consumption will continue to grow at a similar rate through the year 2020 to 32 trillion cubic feet/year (DOE, EIA, 1999d). They also expect crude oil consumption to grow at an annual rate of less than 1 percent over the same period.

Table 5-20. Size of Establishments and Value of Shipments, Oil and Gas Field Services (NAICS 213112), 1997 and 1992

	1997	
Average Number of Employees at Facility	**Number of Facilities**	**Value of Shipments ($1997 10^3)**
0 to 4 employees	4,122	$706,396
5 to 9 employees	1,143	$571,745
10 to 19 employees	835	$904,356
20 to 49 employees	629	$1,460,920
50 to 99 employees	211	$1,480,904
100 to 249 employees	84	$1,175,766
250 to 499 employees	21	$754,377
500 to 999 employees	13	$1,755,689
1,000 to 2,499 employees	9	D
2,500 or more employees	1	D
Total	7,068	$11,547,563

D = undisclosed
Sums do not add to totals due to independent rounding.

Source: U.S. Department of Commerce, Bureau of the Census. 1999d. *1997 Economic Census, Mining, Industry Series: Support Activities for Oil and Gas Operations*. EC97N-2131B. Washington, DC: U.S. Department of Commerce.

5.3 Natural Gas Pipelines

The natural gas pipeline industry (NAICS 4862) comprises establishments primarily engaged in the pipeline transportation of natural gas from processing plants to local distribution systems. Also included in this industry are natural gas storage facilities, such as depleted gas fields and aquifers.

5.3.1 Introduction

The natural gas industry can be divided into three segments, or links: production, transmission, and distribution. Natural gas pipeline companies are the second link, performing the vital function of linking gas producers with the local distribution companies and their customers. Pipelines transmit natural gas from gas fields or processing plants through high compression steel pipe to their customers. By the end of 1998, there were more than 300,000 miles of transmission lines (OPS, 2000).

The interstate pipeline companies that linked the producing and consuming markets functioned mainly as resellers or merchants of gas until about the 1980s. Rather than acting as common carriers (i.e., providers only of transportation), pipelines typically bought and resold the gas to a distribution company or to some other downstream pipelines that would later resell the gas to distributers. Today, virtually all pipelines are common carriers, transporting gas owned by other firms instead of wholesaling or reselling natural gas (Tussing and Tippee, 1995).

According to the U.S. Bureau of the Census, the natural gas pipeline industry's revenues totaled \$19.6 billion in 1997. Pipeline companies operated 1,450 facilities and employed 35,789 people (see Table 5-21). The industry's annual payroll is nearly \$1.9 billion.

Table 5-21. Summary Statistics for the Natural Gas Pipeline Industry (NAICS 4862), 1997

Establishments	1,450
Revenue (\$$10^3$)	\$19,626,833
Annual payroll (\$$10^3$)	\$1,870,950
Paid employees	35,789

Source: U.S. Department of Commerce, Bureau of the Census. 2000. *1997 Economic Census, Transportation and Warehousing: Geographic Area Series*. EC97T48A-US. Washington, DC: Government Printing Office.

As noted previously, the recent transition from the SIC system to the NAICS changed how some industries are organized for information collection purposes and thus how certain economic census data are aggregated. Some SIC codes were combined, others were separated, and some activities were classified under one NAICS code and the remaining activities classified under another. The natural gas transmission (pipelines) industry is an example of an industry code that was reclassified. Under NAICS, SIC 4922, natural gas transmission (pipelines), and a portion of SIC 4923, natural gas distribution, were combined. The adjustments have made comparison between the 1992 and 1997 economic censes difficult at this time. The U.S. Census Bureau has yet to publish a comparison report. Thus, for this industry only 1997 census data are presented.

5.3.2 Supply Side

Characterizing the supply side involves describing services provided by the industry, by-products, the costs of production, and capacity utilization.

5.3.2.1 Service Description

Natural gas is delivered from gas processing plants and fields to distributers via a nationwide network of over 300,000 miles of transmission pipelines (NGSA et al., 2000a). The majority of pipelines are composed of steel pipes that measure from 20 to 42 inches in diameter and operate 24 hours a day. Natural gas enters pipelines at gas fields, storage facilities, or gas processing plants and is "pushed" through the pipe to the city gate or interconnections, the point at which distribution companies receive the gas. Pipeline operators use sophisticated computer and mechanical equipment to monitor the safety and efficiency of the network.

Reciprocating stationary combustion engines compress and provide the pushing force needed to maintain the flow of gas through the pipeline. When natural gas is transmitted, it is compressed to reduce the volume of gas and to maintain pushing pressure. The gas pressure in pipelines is usually between 300 and 1,300 psi, but lesser and higher pressures may be used. To maintain compression and keep the gas moving, compressor stations are located every 50 to 100 miles along the pipeline. Most compressors are large reciprocating engines powered by a small portion of the natural gas being transmitted through the pipeline.

There are over 8,000 gas compressing stations along U.S. gas pipelines, each equipped with one or more engines. The combined output capability of U.S. compressor engines is over 20 million hp (NGSA et al., 2000a). Nearly 5,000 engines have individual output capabilities from 500 to over 8,000 hp. The replacement cost of this subset of larger engines is estimated by the Gas Research Institute to be $18 billion (Whelan, 1998).

Before or after natural gas is delivered to a distribution company, it may be stored in an underground facility. Underground storage facilities are most often depleted oil and/or gas fields, aquifers, or salt caverns. Natural gas storage allows distribution and pipeline companies to serve their customers more reliably by withdrawing more gas from storage during peak-use periods and reduces the time needed to respond to increased gas demand (NGSA et al., 2000b). In this way, storage guarantees continuous service, even when production or pipeline transportation services are interrupted.

5.3.2.2 By-products

According to the Natural Gas Supply Association (NGSA), about 3 percent of the natural gas moved through pipelines escapes. The engines that provide pumping action at plants and push crude oil and natural gas through pipelines to customers and storage facilities produce HAPs. As noted previously, HAPs produced in engines include formaldehyde, acetaldehyde, acrolein, and methanol.

5.3.2.3 Costs of Production

Between 1996 and 2000, pipeline firms committed over $14 billion to 177 expansion and new construction projects. These projects added over 15,000 miles and 36,178 million cubic feet per day (MMcf/d) capacity to the transmission pipeline system. Table 5-22 summarizes the investments made in pipeline projects during the past 5 years. Building new pipelines is more expensive than expanding existing pipelines. For the period covered in the table, the average cost per project mile was $862,000. However, the costs for pipeline expansions averaged $542,000, or 29 cents per cubic foot of capacity added. New pipelines averaged $1,157,000 per mile at 48 cents per cubic foot of capacity.

Pipelines must pay for the natural gas that is consumed to power the compressor engines. The amount consumed and the price paid have fluctuated in recent years. In 1998, pipelines consumed 635,477 MMcf of gas, paying, on average, $2.01 per 1,000 cubic feet. Pipelines used less natural gas in

Table 5-22. Summary Profile of Completed and Proposed Natural Gas Pipeline Projects, 1996 to 2000

	All Type Projects						New Pipelines		Expansions	
Year	Number of Projects	System Mileage	New Capacity (MMcf/d)	Project Costs ($$10^6$)	Average Cost per Mile ($$10^3$)	Costs per Cubic Foot Capacity (cents)	Average Cost per Mile ($$10^3$)	Costs per Cubic Foot Capacity (cents)	Average Cost per Mile ($$10^3$)	Costs per Cubic Foot Capacity (cents)
1996	26	1,029	2,574	$552	$448	21	$983	17	$288	27
1997	42	3,124	6,542	$1,397	$415	21	$554	22	$360	21
1998	54	3,388	11,060	$2,861	$1,257	30	$1,301	31	$622	22
1999	36	3,753	8,205	$3,135	$727	37	$805	46	$527	31
2000	19	4,364	7,795	$6,339	$1,450	81	$1,455	91	$940	57
Total	177	15,660	36,178	$14,285	$862	39	$1,157	48	$542	29

Note: Sums may not add to totals because of independent rounding.

Source: U.S. Department of Energy, Energy Information Administration (EIA). 1999d. *Natural Gas 1998: Issues and Trends*. Washington, DC: U.S. Department of Energy.

Table 5-23. Energy Usage and Cost of Fuel, 1994-1998

Year	Pipeline Fuel (MMcf)	Average Price ($ per 1,000 cubic feet)
1994	685,362	1.70
1995	700,335	1.49
1996	711,446	2.27
1997	751,470	2.29
1998	635,477	2.01

Source: U.S. Department of Energy, Energy Information Administration (EIA). 1999e. *Natural Gas Annual 1998*. Washington, DC: US Department of Energy.

1998 than in previous years; the price paid for that gas fluctuated between $1.49 and $2.29 between 1994 and 1997 (see Table 5-23). For companies that transmit natural gas through their own pipelines the cost of the natural gas consumed is considered a business expense.

5.3.2.4 Capacity Utilization

During the past 15 years, interstate pipeline capacity has increased significantly. In 1990, the transmission pipeline system's capacity was 74,158 MMcf/day (see Table 5-24). By the end of 1997, capacity reached 85,847 MMcf/day, an increase of approximately 16 percent. The system's usage has increased at a faster rate than capacity. The average daily flow was 60,286 MMcf/day in 1997, a 22 percent increase over 1990's rates. Currently, the system operates at approximately 72 percent of capacity.

Table 5-24. Transmission Pipeline Capacity, Average Daily Flows, and Usage Rates, 1990 and 1997

	1990	1997	Percent Change
Capacity (MMcf per day)	74,158	85,847	16
Average Flow (MMcf per day)	49,584	60,286	22
Usage Rate (percent)	68	72	4

Source: U.S. Department of Energy, Energy Information Administration. 1999d. *Natural Gas 1998: Issues and Trends*. Washington, DC: US Department of Energy.

5.3.3 Demand Side

Most pipeline customers are local distribution companies that deliver natural gas from pipelines to local customers. Many large gas users will buy from marketers and enter into special delivery contracts with pipelines. However, local distribution companies (LDCs) serve most residential, commercial, and light industrial customers. LDCs also use compressor engines to pump natural gas to and from storage facilities and through the gas lines in their service area.

While economic considerations strongly favor pipeline transportation of natural gas, liquified natural gas (LNG) emerged during the 1970s as a transportation option for markets inaccessible to pipelines or where pipelines are not economically feasible. Thus, LNG is a substitute for natural gas transmission via pipelines. LNG is natural gas that has been liquified by lowering its temperature. LNG takes up about 1/600 of the space gaseous natural gas takes up, making transportation by ship possible. However, virtually all of the natural gas consumed in the United States reaches its consumer market via pipelines because of the relatively high expense of transporting LNG and its volatility. Most markets that receive LNG are located far from pipelines or production facilities, such as Japan—the world's largest LNG importer, Spain, France, and Korea (Tussing and Tippee, 1995).

5.3.4 Organization of the Industry

Much like other energy-related industries, the natural gas pipeline industry is dominated by large investor-owned corporations. Smaller companies are few because of the real estate, capital, and operating costs associated with constructing and maintaining pipelines (Tussing and Tippee, 1995). Many of the large corporations are merging to remain competitive as the industry adjusts to restructuring and increased levels of competition. Increasingly, new pipelines are built by partnerships: groups of energy-related companies share capital costs through joint ventures and strategic alliances (DOE, EIA, 1999d). Ranked by system mileage, the largest pipeline companies in the United States are El Paso Energy (which recently merged with Southern Natural Gas Co.), Enron, Williams Cos., Coastal Corp., and Duke Energy (see Table 5-25). El Paso Energy and Coastal intend to merge in mid-2000.

5.3.5 Markets and Trends

During the past decade, interstate pipeline capacity has increased 16 percent. Many existing pipelines underwent expansion projects, and 15 new interstate pipelines were constructed. In 1999 and 2000, proposals for pipeline expansions and additions called for a

Table 5-25. Five Largest Natural Gas Pipeline Companies by System Mileage, 2000

Company	Headquarters	Sales ($1999 10^6)	Employment (1999)	Miles of Pipeline
El Paso Energy Corporation Incl. El Paso Natural Gas Co. Southern Natural Gas Co. Tennessee Gas Pipe Line Co.	Houston, TX	$5,782	4,700	40,200
Enron Corporation Incl. Northern Border Pipe Line Co. Northern Natural Gas Co. Transwestern Pipeline Co.	Houston, TX	$40,112	17,800	32,000
Williams Companies, Inc. Incl. Transcontinental Gas Pipe Line Northwest Pipe Line Co. Texas Gas Pipe Line Co.	Tulsa, OK	$8,593	21,011	27,000
The Coastal Corporation Incl. ANR Pipeline Co. Colorado Interstate Gas Co.	Houston, TX	$8,197	13,000	18,000
Duke Energy Corporation Incl. Panhandle Eastern Pipeline Co. Algonquin Gas Transmission Co. Texas Eastern Transmission Co.	Charlotte, NC	$21,742	21,000	11,500

Sources: Heil, Scott F., Ed. *Ward's Business Directory of U.S. Private and Public Companies 1998, Volume 5*. Detroit, MI: Gale Research Inc.

Sales, employment, and system mileage: Hoover's Incorporated. 1998. Hoover's Company Profiles. Austin, TX: Hoover's Incorporated. <http://www.hoovers.com/>.

$9.5 billion investment, an increase of 16.0 billion cubic feet per day of capacity (DOE, EIA, 1999d).

The EIA (1999d) expects natural gas consumption to grow steadily, with demand forecasted to reach 32 trillion cubic feet by 2020. The expected increase in natural gas demand has significant implications for the natural gas pipeline system.

The EIA (1999d) expects the interregional pipeline system, a network that connects the lower 48 states and the Canadian provinces, to grow at an annual rate of 0.7 percent between 2001 and 2020. However, natural gas consumption is expected to grow at more than twice that annual rate, 1.8 percent, over that same period. The majority of the growth in consumption is expected to be fueled by the electric generation sector. According to the EIA, a key issue is what kinds of infrastructure changes will be required to meet this demand and what the financial and environmental costs will be of expanding the pipeline network.

The EIA addresses the discrepancy between annual consumption growth and interregional pipeline capacity growth with the following explanation: "Overall, interregional pipeline capacity (including imports) is projected to grow at an annual rate of only about 0.7 percent between 2001 and 2020 (compared with 3.7 percent between 1997 and 2000 and 3.8 percent between 1990 and 2000). However, EIA also forecasts that consumption will grow at a rate of 27 Bcf per day (1.8 percent annually) during the same period. The difference between these two growth estimates is predicted upon the assumption that capacity additions to support increased demand will be local expansions of facilities within regions (through added compression and pipeline looping) rather than through new long-haul (interregional) systems or large-scale expansions" (1999d, p. 125).

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