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Preface

The *Electric Power Annual* presents a summary of electric power industry statistics at national, regional and State levels. The objective of the publication is to provide industry decisionmakers, government policymakers, analysts and the general public with historical data that may be used in understanding U.S. electricity markets.

Background

The *Electric Power Annual* is prepared by the Survey Management Division; Office of Coal, Nuclear, Electric and Alternate Fuels; Energy Information Administration (EIA); U.S. Department of Energy. "The U.S. Electric Power Industry at a Glance" section presents a profile of the electric power industry ownership and performance, and a review of key statistics for the year. Subsequent sections present data on generating capability, including proposed capability additions; net generation; fossil-fuel statistics; retail sales; revenue; financial statistics; environmental statistics; electric power transactions; demand-side management; and nonutility power producers. In addition, the appendices provide supplemental data on major disturbances and unusual occurrences in U.S. electricity power systems. Each section contains related text and tables and refers the reader to the appropriate publication that contains more detailed data on the subject matter. Monetary values in this publication are expressed in nominal terms.

Target Audience

In the private sector, the majority of users are researchers and analysts and ultimately the policymaking and decisionmaking members of electric utility companies. Financial and investment institutions, economic development organizations interested in new power plant construction, special interest groups, lobbyists, electric power associations, and the news media will find data in the *Electric Power Annual* useful.

In the public sector, users include analysts, researchers, statisticians, and other professionals engaged in regulatory, policy, and program areas for Federal, State, and local governments. The Congress and other legislative bodies may also be interested in general trends related to electricity at State and national levels. Much of the data in this report can be used in analytic studies

to evaluate new legislation. Public service commissions and other special government groups share an interest in State-level statistics. These groups can also compare the statistics for their States with those of other jurisdictions.

Coverage of Sources

Data published in the *Electric Power Annual* are compiled from two statistical forms filed monthly and seven forms filed annually by electric utilities, and one form filed annually by nonutility power producers. These forms are described in detail in Appendix C, "Technical Notes."

These forms are: the Form EIA-759, "Monthly Power Plant Report"; the Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants"; the Form EIA-861, "Annual Electric Utility Report"; the Form EIA-860, "Annual Electric Generator Report"; the FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; the Form EIA-412, "Annual Report of Public Electric Utilities"; the Form EIA-767, "Steam-Electric Plant Operation and Design Report"; the Form EIA-867, "Annual Nonutility Power Producer Report"; the Department of Energy, Emergency Policy Form PO-411, "Coordinated Bulk Power Supply Program"; and the Department of Energy, Office of Fossil Energy, Fuels Programs, Form FE-781R, "Annual Report of International Electric Export/Import Data." In addition, the *Electric Power Annual* includes data collected on the Department of Energy Form OE-417R, "Electric Power System Emergency Report." A brief description of each of these forms follows.

The Form EIA-759 is used to collect monthly data on net generation; consumption of coal, petroleum, and gas; and end-of-the-month stocks of coal and petroleum for each plant by prime mover. Data are collected from all electric utilities that operate power plants (except those having plants solely on standby), approximately 715 of the 3,250 electric utilities in the United States.

The FERC Form 423 is a restricted census used to collect monthly data on steam-electric and combined-cycle power plants with a total generator nameplate capacity of 50 or more megawatts (approximately 230

electric utilities). Data collected on the FERC Form 423 include information on fossil fuels regarding quantity, quality, delivered cost, origin, fuel type, supplier, and type of contract under which the fuels are purchased.

The Form EIA-861 is a census of electric utilities in the United States, its territories, and Puerto Rico. The data from the Form EIA-861 contained in this publication are for the United States only. The survey is used to collect annual information on the production, sales, revenue from sales, trade of electricity, and demand-side management activities from approximately 3,250 electric utilities.

The Form EIA-860 is used to collect data annually from all electric utilities in the United States that operate power plants or plan to operate a power plant within 10 years of the reporting year. The survey is used to collect data on power plant site information, generator specifications including maximum generator nameplate capacity, net summer and winter capability, heat rate, in service date, status, prime movers, energy sources, and the ownership of generators. Information on electric generators is reported by approximately 900 electric utilities.

The FERC Form 1 is an annual restricted-universe census of the major investor-owned electric utilities in the United States having, in each of the last 3 consecutive years, sales or transmission service that exceeds one of the following: (1) 1 million megawatthours of total sales, (2) 100 megawatthours of sales for resale, (3) 500 megawatthours of power exchanges delivered, or (4) 500 megawatthours of wheeling for others (deliveries plus losses). Financial statistics including income; taxes; depreciation and amortization; electric operating revenue; electric maintenance expenses; year-end balance sheets; and, general corporate information are reported by approximately 180 major investor-owned electric utilities.

The Form EIA-412 is a restricted-universe census used annually to collect accounting, financial, and operating data from major publicly owned electric utilities in the United States. Publicly owned electric utilities engaged in the generation, transmission, or distribution of electricity that had 120,000 megawatthours of sales to ultimate consumers and/or 120,000 megawatthours of sales for resale for the 2 previous years as reported on the Form EIA-861, "Annual Electric Utility Report," must submit the Form EIA-412. These criteria result in approximately 450 submissions from publicly owned electric utilities.

The Form EIA-767 is a restricted-universe census of power plants with an organic- or nuclear-fueled steam-electric existing or planned nameplate capacity of 10 or more megawatts. The form is used to collect data

annually on plant operation and equipment design (including boiler, generator, cooling system, flue gas desulfurization units, flue gas particulate collectors, and stack data). Information regarding approximately 900 power plants on this survey is provided by 312 electric utilities.

The Form EIA-867 is a restricted-universe census used to collect annual data from all existing and planned nonutility power producers in the United States. In 1992, the reporting threshold of the Form EIA-867 was lowered to include all facilities with a combined nameplate capacity of 1 or more megawatts. Previously data were collected every 3 years from facilities with a nameplate capacity between 1 and 5 megawatts. For the purpose of this data collection, a nonutility power producer is an enterprise that has electric generating capacity and is not an electric utility. They include qualifying cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers) without a designated franchised service area. The form is used to collect data on the installed capacity, energy consumption, generation, and electric energy sales to electric utilities from approximately 2,000 facilities.

The Form PO-411 is an annual report supplied to the Department of Energy by the 10 North American Electric Reliability Councils (NERC). These reports have been compiled from data furnished by the member electric utilities. The form is used to collect information on electric utility 10-year plans and peakload information at the NERC region level. The responsibility for collecting these data has been delegated to the Office of Emergency Policy within the Department of Energy.

The Form OE-417R is used to collect information on major electric utility system emergencies, including the type of emergency, the utility and area affected, the date and time of the event, a description of the event, and expected time of restoration of service. The responsibility for collecting these data has been delegated to the Office of Emergency Management within the Department of Energy.

The Form FE-781R is used to collect monthly data annually from holders of Export Authorizations and Presidential Permits (subject to the authority of Part II, Federal Power Act) engaged in the export of electric energy across the international borders of the United States with Canada and Mexico. The information collected on the form includes the volume of energy received by and/or delivered to holders of Export Authorizations and Presidential Permits, and the costs and revenue associated with these transactions. The responsibility for collecting these data has been delegated to the Office of Fossil Energy Fuels Programs, within the Department of Energy.

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The U.S. Electric Power Industry at a Glance

The first section of this chapter provides a graphically illustrated profile of the electric power industry in the United States. The second section summarizes pertinent statistics on various aspects of the U.S. electric power industry for the year.

Industry Profile

The U.S. electric power industry is a combination of traditional and nontraditional electricity-producing companies. For the purpose of this report, the traditional electric utility industry is comprised of investor-owned, publicly owned, Federal, and cooperative electric utilities. The Public Utilities Regulatory Policies Act (PURPA) of 1978 and the continued deregulation of the industry have led to the emergence of nontraditional electricity producing companies or *nonutility power producers*, changes in wholesale transmission services, and the appearance of energy brokers and marketers.¹

Investor-Owned Electric Utilities. Investor-owned electric utilities currently account for more than 75 percent of all U.S. electric utility generating capability, generation, sales, and revenue. Like all private businesses, the fundamental objective of an investor-owned utility is to produce a return for investors. The investor-owned electric utility either distributes its profits to stockholders as dividends or reinvests these profits. It is granted a service monopoly in certain geographic areas and is obliged to serve all consumers. As franchised monopolies, these electric utilities are regulated and required to charge reasonable prices, to charge comparable prices to similar classifications of consumers, and to give consumers access to services under similar conditions. Most investor-owned electric utilities are operating companies that provide basic services for the generation, transmission, and distribution of electricity. The majority of investor-owned electric

utilities perform all three functions. Investor-owned electric utilities operate in all States except Nebraska. The electric utilities in Nebraska consist primarily of municipal systems and public power districts.

Publicly Owned Electric Utilities. Publicly owned electric utilities in the United States are nonprofit local government agencies established to serve their communities and nearby consumers at cost, returning excess funds to the consumer in the form of community contributions, economic and efficient facilities, and lower rates. Publicly owned electric utilities (which number approximately 2,000) include municipals, public power districts, State authorities, irrigation districts, and other State organizations. Most municipal electric utilities simply distribute power, although some larger ones produce and transmit electricity as well. They obtain their financing from municipal treasuries and from revenue bonds secured by proceeds from the sale of electricity. Public power districts and projects are concentrated in Nebraska, Washington, Oregon, Arizona, and California. Voters in a public power district elect commissioners or directors to govern the district, independent of any municipal government. State authorities, like the Power Authority of the State of New York or the South Carolina Public Service Authority, are agencies of their respective State governments. Irrigation districts may have still other forms of organization. In the Salt River Project Agricultural Improvement and Power District in Arizona, for example, votes for the Board of Directors are apportioned according to the size of landholdings.

U.S. Federal Electric Utilities. Power produced by U.S. Federal electric utilities is not generated for profit. As required by law, preference in purchasing the electricity produced is given to publicly owned and cooperative electric utilities and to other nonprofit entities. The Federal Government is primarily a producer and wholesaler of electricity. These wholesale producers include the U.S. Army Corps of Engineers, the U.S. Bureau of Indian Affairs, the U.S. Bureau of Rec-

¹In this report, the following definitions are used to distinguish the difference between the traditional electric utility and nonutility power producer: An electric utility is any person, corporation, municipality, State political subdivision or agency, irrigation project, Federal power administration, or other legal entity that is primarily engaged in the retail or wholesale sale, exchange, and/or transmission of electric energy. A legal entity selling electric energy produced at a qualifying facility (QF) under the Public Utility Regulatory Policies Act (PURPA) is not an electric utility, but is a nonutility power producer. A nonutility power producer is any person, corporation, municipality, State political subdivision or agency, Federal agency, or other legal entity that either: (1) produces electric energy at a qualifying facility (QF) under the Public Utility Regulatory Policies Act (PURPA), or (2) produces electric energy but is primarily engaged in business activities other than the sale of electric energy, such as agriculture, mining, manufacturing, transportation, or education.

lation, the International Water and Boundary Commission, and the U.S. Department of Energy. Electricity generated by these wholesale producers is marketed by Federal power marketing administrations: Bonneville, Southeastern, Southwestern, and Western Area. The power marketing administrations of the U.S. Department of Energy operate in all States except those in the Northeast, upper Midwest, and Hawaii. In addition to the four major power marketing administrations, the Alaska Power Administration operates and distributes power from its own projects. The Tennessee Valley Authority is the largest Federal power producer and it markets electricity in both the wholesale and retail markets.

Cooperative Electric Utilities. Cooperative electric utilities in the United States are owned by their members and are established to provide electricity to those members. The Rural Electrification Administration, U.S. Department of Agriculture, was established under the Rural Electrification Act of 1936 with the purpose of extending electric service to small rural communities (usually under 1,500 customers) and farms where it was more expensive to provide service. They are incorporated under State law and are usually directed by an elected board of directors, which in turn selects a manager. Qualifying through the Rural Electrification Administration, the National Rural Utilities Cooperative Finance Corporation, the Federal Financing Bank, and the Bank for Cooperatives are the most important sources of debt financing for cooperatives. There are approximately 950 cooperative electric utilities in the United States, currently doing business in 47 States. Cooperative electric utilities do not operate in Connecticut, Hawaii, Rhode Island, or in the District of Columbia.

U.S. Nonutility Power Producers

U.S. nonutility power producers are comprised of cogenerators and small power producers, which qualify under the Public Utility Regulatory Policies Act of 1978 (PURPA) (these facilities are generally referred to as qualifying facilities (QFs)), and other nonutility generators (including independent power producers) without a designated franchise service area. QFs receive certain benefits under PURPA. See the chapter on "Nonutility Power Producers" for a description of these benefits. Cogenerators are generating facilities that produce electricity and another form of useful thermal energy (usually heat or steam) for industrial, commercial, heating, or cooling purposes. To receive status as a QF under PURPA, the facility must produce electric energy and another form of useful thermal energy through the sequential use of energy, and meet certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Com-

mission (FERC). The FERC is responsible for the implementation of PURPA. To qualify under PURPA, a small power producer must generate electricity using biomass (waste), renewable resources (water, wind, and solar), or geothermal energy as a primary energy source. Fossil fuels can be used, but renewable resources must provide at least 75 percent of the total energy input.

The Independent Power Producers (IPP) in the United States are wholesale electricity producers, that are unaffiliated with franchised utilities in the area in which the IPP's are selling power. A facility that has QF status under PURPA is not an IPP. Unlike traditional electric utilities, IPP's do not possess transmission facilities and do not sell in any retail service territory.

A new class of IPP's—exempt wholesale generators (EWG's)—was established by the Energy Policy Act of 1992 (EPACT). This Act modified the Public Utility Holding Company Act (PUHCA) to create this new class of IPP's by exempting them from the corporate and geographic restrictions that PUHCA imposes. Public utility holding companies are allowed to own interests in IPP facilities and can form corporate subsidiaries to develop and operate independent power projects anywhere in the world.²

Wholesale Transmission Services, Energy Brokers, and Marketers

Under the EPACT, which amended the Federal Power Act, any electric utility could apply to the Federal Energy Regulatory Commission (FERC) for an order requiring another utility to provide transmission services (wheeling). Prior to EPACT, FERC could not mandate an electric utility to provide wheeling services for wholesale electric trade. This change in the law will permit operators of electric generating equipment to sell wholesale power (sales for resale) to noncontiguous utilities. The amendment to the FPA will also affect electricity marketers, a relatively new group under FERC's jurisdiction.

Marketers are business entities engaged in buying and selling electricity, but have no generating or transmission facilities. Marketers take ownership of the electricity and are involved in interstate trade. A number of energy marketers that may be involved in interstate electricity trade have filed with FERC and have had their rates authorized. When ownership of the electricity is not taken, then those transactions are not regulated by FERC (the parties handling the transactions are called energy brokers).

²EWG's are not considered utilities under PUHCA; they can only sell their output at wholesale to electric utilities and municipalities. However, EWG's are considered to be electric utilities under the Federal Power Act.

Presentation of Data

The following graphic presentation (Figures 1 through 8) on the U.S. electric utility industry by class of ownership includes: generating capability; net generation and sales of electricity; the number of utilities, generators, and ultimate consumers; and the revenue from

the sale of electricity. These data are collected and compiled from various sources as indicated in the Preface. Data on generating capability and net generation of electricity are presented for all electric utilities that produce power in the United States; data on electricity sales and revenue include all electric utilities that have retail sales in the United States.

Figure 1. Generating Capability at U.S. Electric Utilities by Class of Ownership, 1993

Notes •Generating capability is net summer capability •Data are final •Totals may not equal sum of components because of independent rounding

Sources Energy Information Administration, •Capability Form EIA-860, "Annual Electric Generator Report " •Ownership: Form EIA-861, "Annual Electric Utility Report "

Figure 2. U.S. Electric Utility Net Generation by Class of Ownership, 1993

Notes •Data are final •Totals may not equal sum of components because of independent rounding

Source Energy Information Administration, •Generation: Form EIA-759, "Monthly Power Plant Report"; •Ownership: Form EIA-861, "Annual Electric Utility Report "

Figure 3. U.S. Electric Utility Sales to Ultimate Consumers by Class of Ownership, 1993

Notes: •Data are preliminary. •Totals may not equal sum of components because of independent rounding
 Sources: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 4. Number of U.S. Electric Utilities by Class of Ownership, 1993

Notes: •Data are preliminary.
 Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 5. Number of Ultimate Consumers Served by U.S. Electric Utilities by Class of Ownership, 1993

Notes: •Data are preliminary. •The number of ultimate consumers served by Federal electric utilities is less than 1 million. •The number of ultimate consumers is an average of the number of consumers at the close of each month. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 6. Revenue from U.S. Electric Utility Sales to Ultimate Consumers by Class of Ownership, 1993

Notes: •Data are preliminary. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 7. U.S. Electric Utility Sales for Resale by Class of Ownership, 1993

Notes: *Data are preliminary. *Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 8. Revenue from U.S. Electric Utility Sales for Resale by Class of Ownership, 1993

Notes: *Data are preliminary. *Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

A Review of 1993

This section includes a graphic presentation as a supplement to the text. Various statistics related to the U.S. electric power industry by sector, energy source, or facility type are provided in Figures 9 through 15 following the text.

Renewable Energy Resources

Section 171 of Public Law 102-486, the Energy Policy Act of 1992, requires the Administrator of the Energy Information Administration to annually collect and publish the results of a survey of electricity production from domestic renewable energy resources. This requirement includes reporting data on electricity production in kilowatthours, total installed capacity, and measures of production efficiency such as capacity factor that distinguish the results between various renewable energy resources. The information described in this section on "Renewable Energy Resources" and in Table 1, "Electric Power Industry Summary Statistics in the United States, 1993 and 1992," represents the information required by Section 171 of the Act aggregated at the U.S. level. More detailed information is included in other tables in this publication.

In 1993, net generation from renewable energy sources³ accounted for about 11 percent (356,722 million kilowatthours) of the electric power industry's production of electricity (Table 1).⁴ Conventional hydroelectric generation accounts for the greatest share (97 percent) of electric utility net generation from renewable sources. Generation from biomass accounts for the greatest share (69 percent) of nonutility gross generation from renewable sources.

Electric Utilities. Exclusive of conventional hydroelectric power, generation from renewable sources accounted for 0.3 percent of total electric utility generation in 1993. Electric utilities generated 7,571 million kilowatthours from geothermal steam; 1,990 million kilowatthours from biomass; and 4 million kilowatthours from photovoltaic. The capacity factors for electric utility geothermal and biomass plants were

49 percent each in 1993.⁵ Photovoltaic plants had a capacity factor of about 12 percent. The efficiency⁶ for biomass plants averaged 26 percent, or about 13,000 Btu per kilowatthour.⁷ In contrast, the efficiency of fossil-fueled electric utility boilers is approximately 33 percent.

Exclusive of hydroelectric capability, the net summer capability at electric utility plants that used renewables as primary energy sources totaled 2,211 megawatts, as of year-end 1993. This represents 0.3 percent of total electric utility generating capacity. In contrast, nonutility capacity that used renewable energy sources was 13,669 megawatts (excluding conventional hydroelectric plants) or 23 percent of total nonutility generating capacity.

Nonutility. Nonutility generation from renewable sources accounted for 25 percent of total nonutility generation.⁸ In 1993, nonutilities generated 55,746 million kilowatthours from biomass; 11,511 million kilowatthours from water (conventional hydroelectric); 9,749 million kilowatthours from geothermal steam; 3,052 million kilowatthours from wind; 895 million kilowatthours from solar thermal plants and 2 million kilowatthours from photovoltaic plants. The capacity factor for geothermal plants averaged 84 percent in 1993; 63 percent for biomass plants; 48 percent for conventional hydroelectric plants; 29 percent for solar thermal plants; 19 percent for wind-powered plants; and 3 percent for photovoltaic plants. The average efficiency of all biomass plants operated by nonutilities was approximately 12 percent or 285,500 Btu per kilowatthour. Some nonutility biomass plants produce steam for industrial processes in addition to generating electricity. The calculated efficiency for these plants is misleadingly low because only electric output is used in the computation. The overall efficiency of cogenerator plants is generally good but difficult to calculate because the proportion of industrial steam to electricity varies greatly. For biomass plants that produce only electricity, average efficiency is about 18 percent or 19,000 Btu per kilowatthour.

The total installed capacity of nonutility power producer plants that used renewable sources was 16,410 megawatts (including 2,741 megawatts of conventional hydroelectric capacity) as of year-end 1993.

³Renewable energy sources include hydroelectric (conventional), geothermal, biomass (wood, wood waste, peat, wood liquors, railroad ties, pitch, wood sludge, municipal solid waste, agricultural waste, straw, tires, landfill gases, fish oils, and other waste), wind, solar thermal, and photovoltaic.

⁴Includes net generation from electric utilities and gross generation from nonutility power producers with an installed nameplate capacity of 1 or more megawatts. The gross generation from nonutilities was converted to net generation to derive an industry total. For a description of the conversion methodology, see the Technical Notes.

⁵The capacity factor is the ratio of the average load on the plant(s) for a considered period of time to the aggregate capacity of the plant(s).

⁶Efficiency is calculated using the ratio of energy consumed to energy produced. Information to calculate efficiency is only available for combustible fuels.

⁷Plants that consumed 50 or more percent biomass fuels based on Btu input.

⁸Nonutility power producers with an installed electric generating capacity of 1 or more megawatts.

U.S. Electric Utility Statistics

Sales. U.S. sales of electricity to ultimate consumers in 1993 reached 2,861 billion kilowatthours, an increase of 4 percent from 2,763 billion kilowatthours sold in 1992 (Table 1). In 1993, sales increased in all sectors. The residential sector increased by 6 percent, commercial by 4 percent, industrial by less than 1 percent, and other by 2 percent. Average revenue per kilowatthour of electricity sold to ultimate consumers in 1993 was 6.93 cents, an increase of 0.11 cents from the 1992 level.

Generation. During 1993, a record level of net generation was set when 2,883 billion kilowatthours were produced, 3 percent more than last year. The increase in electricity demand was caused primarily by weather factors and to a lesser extent by rising economic growth.⁹ To meet the overall increase in demand for electricity, electric utilities increased production at coal-fired, petroleum-fired, and hydroelectric facilities. However, net generation from nuclear-powered plants was 1 percent lower than in 1992. This was the first time since 1980 that a decline in nuclear-powered generation from the previous year was reported. Most of the decline in nuclear-powered generation was attributed to the fact that several units were out of service for a substantial amount of time during the year for scheduled refueling, maintenance, or repair outage.

The hot summer in 1993 contributed to record levels of generation in July, followed by near-record levels in August. The need to compensate for the decrease in nuclear-powered generation and to meet the overall increase in demand was fulfilled by a 4-percent increase (63 billion kilowatthours) in coal-fired generation in 1993 from 1992.

However, record coal consumption during July and near-record levels in August, flood conditions throughout several midwestern States during the summer, and the strike by the United Mine Workers of America (UMWA) are the primary reasons for a 39-million short ton decrease in stocks of coal that occurred from the end of May 1993 (151 million short tons) to the end of December 1993 (111 million short tons). End-of-year coal stockpiles were at the lowest level since the late 1970's. Most of the decline in coal stockpiles occurred in the East North Central and South Atlantic Census Divisions (both large consumers of coal). Combined, these two Census divisions reported 23 million short tons less at the end of 1993 compared with December 31, 1992.

Fossil-Fuel Receipts and Costs. In 1993, electric utilities received 769 million short tons of coal, 148 million

barrels of petroleum, and 2,575 billion cubic feet (Bcf) of gas at a total delivered cost of \$31 billion.¹⁰ Coal accounted for 82 percent of the total Btu content of fossil fuels delivered in 1993 while gas and petroleum accounted for 13 and 5 percent, respectively.

The major factors affecting the quantity and cost of fossil fuels delivered to electric utilities in 1993 were:

1. A lengthy strike by UMWA coal miners (May 10, 1993 to December 7, 1993)
2. Record coal consumption in July and August
3. Extreme weather conditions including an intense summer heatwave throughout the East and the South, and major flooding along the upper Mississippi and Missouri River basins from June through August
4. Higher levels of hydroelectric generation in the western United States
5. A 43-million short ton decrease in end-of-year stocks of coal at electric utility plants.

• **Coal.** In 1993, receipts of coal to electric utilities totaled 769 million short tons, a decrease of 7 million short tons from 1992. Over the last 5 years, receipts of coal have ranged between 753 and 787 million short tons. The average delivered cost of coal to electric utilities in 1993 was \$28.58 per short ton, a 3-percent decrease from the \$29.36 per short ton reported in 1992.¹¹ It is also the lowest average annual cost of coal delivered to electric utilities since 1979 and continues the general trend of a lower delivered cost for coal that began in 1985.¹² In 1993, the average cost of contract coal decreased \$0.96 to a level of \$28.93 per short ton based on receipts of 616 million short tons. Typically, the cost of contract coal is not substantially affected by short-term volatility in the coal markets that are caused by events such as strikes or extremely hot summers. Rather, it is more influenced by events, trends, or perceptions that will affect the long-term supply and demand for coal.

There are several reasons for the continuing decrease in the delivered cost of contract coal. Some electric utilities have found it economical to pay a fee to "buy out" older contracts and increase purchases under newer, less expensive contracts. Also, the cost of coal under some contracts is adjusted annually according to changes in energy-related indices, while some contracts are periodically opened for renegotiation. Because the cost

⁹Energy Information Administration, *Short-Term Energy Outlook* First Quarter 1994, DOE/EIA-0202(94/1Q), p. 22.

¹⁰Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." This survey covers over 99 percent of coal and approximately 95 percent of petroleum and gas delivered to electric utilities.

¹¹The delivered cost of fossil fuels includes all costs (including transportation and taxes) incurred by the electric utility for delivery of the fuel to the plant. It does not include unloading charges.

¹²Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1993*, DOE/EIA-0191(93) and prior issues.

of coal has been decreasing for the past several years, renegotiation of contracts or index-related adjustments usually result in a reduction in the cost of coal delivered under contract to an electric utility. In addition, several electric utilities have been able to reduce the cost of transporting the coal to the power plant. This is often done either by renegotiation of contracts or by increasing competition among the carriers. Not all high-cost contracts are renegotiable and many remain in effect with a delivered cost of coal as high as \$50.00 to \$80.00 per short ton.

Receipts of spot-market coal totaled 153 million short tons, an increase of 27 million short tons from 1992 receipts. This increase was due in part to some electric utilities purchasing spot-market coal to make up for contract coal not delivered because of the strike. In addition, several electric utilities were purchasing coal in the spot market to conduct test-burns in advance of the January 1, 1995, deadline for compliance with the Clean Air Act Amendments of 1990.

The average delivered cost of spot-market coal increased \$0.55 per short ton to \$27.19 per short ton. The spot market is heavily influenced by events such as coal strikes or changes in weather conditions that affect short-term supply and demand. During the first 6 months of 1993, the cost of coal delivered under spot-market purchases (contracts of less than 1-year duration) reflects a continuation of the 1992 markets in which spot-market coal costs were either steady or decreasing. However, the delivered cost of spot-market coal increased in the latter half of 1993, reflecting a market affected by an intense summer heatwave and the coal strike.

- **Petroleum.** In 1993, receipts of petroleum to electric utilities totaled 148 million barrels, an increase of 4 million barrels from receipts in 1992. This increase in petroleum receipts was due in part to an increase in consumption caused by the intense summer heatwave in the eastern United States, and to more favorable (lower) petroleum costs. End-of-year stocks of petroleum totaled 62 million barrels, down from 72 million barrels at the end of 1992. Receipts of petroleum to electric utilities peaked at 626 million barrels in 1977 and have since decreased to a point that only a few electric utilities, located primarily in Florida, New York, and Massachusetts, depend heavily on the fuel for electric generation.¹³

The average delivered cost of petroleum to electric utilities in 1993 was \$15.42 per barrel, a decrease of \$0.73 from 1992, and the lowest average

annual cost since 1988. On a dollars-per-million-Btu basis, the average annual cost of petroleum (\$2.43) was lower than that of gas (\$2.56) for the first time since data collection on the FERC Form 423 began in 1972.¹⁴

- **Gas.** Receipts of gas to electric utilities in 1993 totaled 2,575 billion cubic feet (Bcf), a decrease of 63 Bcf from 1992. Over the last 5 years, national level demand for gas by electric utilities has held steady at between 2.5 and 2.6 trillion cubic feet. Receipts of gas to California decreased from last year because more hydroelectric generation was available. In Florida, gas receipts decreased while receipts and consumption of petroleum increased substantially. In Texas, gas receipts increased 109 Bcf or 11 percent because of a reduction in nuclear generation and to an increase in total generation resulting from the summer heatwave.

The average annual cost of gas delivered to electric utilities in 1993 was \$2.62 per thousand cubic feet, an increase of \$0.24 from the 1992 average annual cost. In comparing the two years, the cost of gas during the first 7 months of 1992 was low due to an excess in supply. However, later in 1992 the cost of gas began to increase. Several factors have been noted as contributing to this price increase including "shut-in" wells (wells where production has been stopped due to low prices), the Organization of Petroleum Exporting Countries reduced production of heavier crudes that compete with gas, and Hurricane Andrew, which destroyed an estimated 5 percent of the gas-producing wells in the Gulf of Mexico.¹⁵ This brought supply and demand into balance for the remainder of 1992 and throughout 1993, and resulted in a higher average cost for gas in 1993.

Capability. Capability in the United States totaled 699,971 megawatts, as of year-end 1993. Based on primary energy source, coal-fired capability totaled 300,795 megawatts; gas-fired, 132,495 megawatts; nuclear, 99,041 megawatts; renewables, 76,975 megawatts; petroleum, 69,519 megawatts; and hydroelectric (pumped storage), 21,146 megawatts. This capability included 3,460 megawatts of newly added capability. More than 50 percent of the capability that entered service in 1993 was accounted for by gas-fired capability; a single nuclear unit accounted for 33 percent of capability additions; petroleum-fired capability additions represented 13 percent; and hydroelectric capability additions represented 3 percent. No new coal-fired units started operation in 1993. A total of 95 generating units representing 2,271 megawatts was retired during 1993. These retirements include 1 nuclear unit (Trojan) representing 1,104 megawatts, 69 petroleum-

¹³Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1993*, DOE/EIA-0191(93) and prior issues.

¹⁴Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1993*, DOE/EIA-0191(93) and prior issues.

¹⁵Standard & Poor's Industry Survey, *Natural Gas*, Vol. 160, No. 47, November 19, 1992.

fired units representing 671 megawatts, and the remainder in small coal- and gas-fired units and conventional hydroelectric units.

At the end of 1993, U.S. electric utilities planned to add 38,732 megawatts of capability over the next 10 years. This includes 24,101 megawatts of gas-fired capability. Gas-fired capability additions will be primarily in simple-cycle turbines and gas turbines operating as combined-cycle units. These gas-fired simple-cycle and combined-cycle gas turbine units are expected to supply 21,306 megawatts (55 percent) of additional capability over the next 10 years. An additional 2,005 megawatts is combined-cycle steam capability using waste heat from the gas-fired gas turbines. Gas turbines have relatively short construction times, and can be brought on line quickly, at a relatively low cost.

Emissions. In 1993, emissions from electric utility fossil-fueled steam plants used for the generation of electricity in the United States were estimated to be: sulfur dioxide (SO₂), 14 million tons; nitrogen oxides (NO_x), 6 million tons; and carbon dioxide, (CO₂), 1,946 million tons.¹⁶

Financial Status. In 1993, electric utility operating revenues (\$176.3 billion) for major U.S. investor-owned electric utilities were up a modest 4.1 percent; however, net income (\$17.9 billion) showed a decline of 2.7 percent from 1992 revenue. Operating income decreased \$0.2 billion due to increases in operating and maintenance expenses, depreciation, and taxes other than income taxes. Electric operating expenses (\$146.1 billion) increased by 5.1 percent.

Other income, as well as extraordinary items after taxes, were affected negatively due to after tax write offs and regulatory rate decisions directly related to the treatment of nuclear plants. Earnings available to common stock decreased by \$0.2 billion or 1.3 percent. Dividends paid to owners of common stock increased to 95.1 percent in 1993, compared with 91.1 percent in 1992, based on dividends declared during the year. Earnings available per average common share were \$2.63, up for the third consecutive year.

In 1993, investment in the major U.S. investor-owned segment of the industry was \$566.6 billion, an increase

of \$60.3 billion from 1992. Electric utility construction work in progress (CWIP) was \$18.0 billion, a decrease of 12.6 percent. The total asset turnover ratio (operating revenues divided by total assets) declined slightly to 0.34.

Total capitalization of \$360.5 billion increased by 1.2 percent from that in 1992. The ratio of long-term debt to total capitalization stood at 48.5, marginally down from the ratio in the previous year.

In 1993, electric utility operating revenue (\$22.5 billion) for the major publicly owned generator electric utilities grew by 3.6 percent. Generator electric utility operating expenses increased by 5.4 percent, resulting in a decrease in net income (\$0.7 billion) of 31.4 percent. Total assets for generator electric utilities increased 4.9 percent to \$112.2 billion. For the major publicly owned nongenerator electric utilities, electric utility operating revenue (\$7.6 billion) grew by 4.5 percent. Nongenerator electric utility operating expenses increased by 3.8 percent to end the year at \$7.1 billion. Net income for nongenerators was \$0.4 billion, up 10.2 percent. Total assets for nongenerator electric utilities increased by 8.4 percent to end the year at \$10.2 billion.

Demand-Side Management (DSM). In 1993, energy savings and peakload reductions, resulting from demand-side management programs, were reported by 971 electric utilities. Of these, 539 were classified as large utilities,¹⁷ an increase of 35 utilities since 1992. These large utilities estimated that they reduced their annual peak loads by 23,181 megawatts in 1993, compared to 17,204 megawatts in 1992. In 1993, their potential, contractually available peakload reduction was 29,140 megawatts. Energy efficiency programs accounted for 45 percent of actual peakload reduction in 1993. Direct load control and interruptible load programs accounted for 46 percent of actual peakload reductions and 91 percent of potential peakload reductions. Energy savings increased from 36,164 million kilowatthours in 1992 to 44,349 million kilowatthours in 1993. Ninety-one percent of energy savings resulted from energy efficiency programs. Total utility cost increased 23 percent from \$2.2 billion to \$2.8 billion.¹⁸

Of the ten North American Electric Reliability Council (NERC) regions, three regions accounted for the ma-

¹⁶Emissions are estimated for electric utility power plants with an existing or planned nameplate capacity of 10 or more megawatts. The methodology used to calculate these estimates is described in the Technical Notes.

¹⁷Large utilities are those reporting sales to ultimate consumers or sales for resale larger than or equal to 120,000 megawatt-hours. These utilities are required to report incremental and annual peakload reductions and energy savings for the reporting year (1993), and annual peakload reductions and energy savings for the first and fifth forecast years (1994 and 1998), and itemized direct and indirect utility costs for all three years (1993, 1994, and 1998). Small utilities with sales to ultimate consumers or sales for resale of less than 120,000 megawatt-hours are only required to report incremental energy savings and peakload reductions, and total utility, total nonutility, and total DSM costs for the reporting year and for the first and fifth forecast years.

¹⁸It is tempting, but misleading, to compare DSM costs to supply-side investments on an unadjusted cost-per-kilowatthour or cost-per-kilowatt basis. The calculation of appropriate measures for economic comparisons of DSM and supply-side investments requires that consideration of the life-cycle costs of the options being compared be addressed on an integrated basis (i.e. the interaction of the change in end-use patterns with the production function of the utility must be considered over the expected life of the various options being compared). In addition, the rate impacts of each alternative must be compared because alternative DSM/supply-side combinations may result in differing patterns of revenue requirements over time. The data presented are not sufficient to allow for such comparison.

jority of all DSM activity in the United States. The Southeastern Electric Reliability Council (SERC) and the Western Systems Coordinating Council (WSCC) Regions accounted for 55 percent of actual peakload reduction, 64 percent of energy savings, and 51 percent of utility cost. With the addition of the Northeast Power Coordinating Council Region (NPCC) to the SERC and WSCC Regions, the three regions accounted for 79 percent of total energy savings and 72 percent of total utility cost.

The residential sector accounted for 43 percent of energy savings while the commercial sector accounted for 37 percent of energy savings. Electric utilities reported that the industrial sector accounted for 42 percent of potential peak reduction, but only 27 percent of actual reduction. The residential sector led in actual peak reduction with 39 percent of the total.

In 1994, energy savings are expected to increase 20 percent over 1993 levels to 53,319 million kilowatthours, potential peakload reductions by direct load control and interruptible load are projected to increase over 4 percent to 27,652 megawatts, and total utility cost is projected to increase by 9 percent to \$3 billion. Between 1994 and 1998, DSM savings and cost are expected to continue to grow. Energy savings are projected to increase at an annual rate of 14 percent to 90,075 million kilowatthours, potential peakload reductions are expected to increase at an annual rate of 5 percent to 36,992 megawatts. Utility costs are projected to increase to \$3.9 billion in 1998.

Imports and Exports. In 1993, the United States imported over 39 billion kilowatthours of electricity from Canada and Mexico and, during this same period, exported nearly 11 billion kilowatthours. Almost 19 billion kilowatthours entered the United States at the Northeastern border, while the next largest amount entered through Minnesota and North Dakota. More than 50 percent of the electricity exported to Mexico was transmitted from California. Most of the electricity exported to Canada was transmitted from the upper Midwest and Northeastern areas of the country.

U.S. Nonutility Power Producer Statistics

Generation. In 1993, U.S. nonutility power producers with facilities having an installed capacity of 1 or more megawatts (before 1992, the cutoff was 5 or more megawatts) generated 325 billion kilowatthours of electricity. U.S. nonutility power producers received 85 billion kilowatthours from and delivered 203 billion kilowatthours to electric utilities and other nonutilities. Nonutility power producers delivered approximately 62 percent of their gross generation to electric utilities and other nonutilities and used 208 billion

kilowatthours for power plant operation and for industrial processes. The highest level of nonutility production of electricity occurred in California and Texas, with 63 and 53 billion kilowatthours, respectively. For California, this is an increase of 6 percent.

Gross generation for nonutility power producers (with an installed capacity of 1 or more megawatts) in 1993 was 10 percent higher than that of a year earlier. Slightly more than half of the generation by nonutility power producers was gas-fired, with generation from wood and waste accounting for 17 percent of the total. Of the total nonutility generation, 268 billion kilowatthours were from qualifying facilities, more than four times the quantity from nonqualifying facilities. (See the Chapter on "Nonutility Power Producers" for a definition of these facilities). The largest share of gross generation was produced by facilities in the West South Central Census Division, followed by the Pacific Census Division. The manufacturing sector dominates electricity generation and is concentrated in the West South Central and South Atlantic Census Divisions where there is a large potential for cogeneration in the refining and paper and pulp industries, respectively.

Capacity. The total installed capacity of nonutility power producers with an installed capacity of 1 or more megawatts in the United States was 60,778 megawatts at the end of 1993. The installed capacity for facilities of 1 or more megawatts increased by 7 percent from 1992. Nonutility capacity in 1993 was equivalent to 8 percent of the traditional U.S. electric utility installed capacity.¹⁹

Natural gas was the fuel most used by nonutilities. Of all energy sources, gas accounted for the largest amount (23,463 megawatts) of nonutility capacity. The West South Central Census Division accounted for 42 percent of that gas-fired capacity. The second largest share of nonutility capacity was provided by petroleum, followed by wood and waste. The largest volume of petroleum capacity (3,494 megawatts) was located in the Middle Atlantic Census Division. Cogeneration accounts for 74 percent of nonutility capacity (62 percent qualifying facility capacity and 12 percent nonqualifying facility capacity). Small power producers and independent power producers account for 15 and 12 percent, respectively, of nonutility capacity.

The greatest number (554) of nonutility generating facilities was in the Pacific Census Division, and most of the capacity (13,385 megawatts) was also in the Pacific Census Division. In the Pacific Census Division, California dominated because the State actively promoted alternative energy choices in the 1970's and 1980's by providing incentives to nontraditional electricity producers. Many of these incentives have since expired or have been rescinded, but they served to assist in the

¹⁹Energy Information Administration, *Inventory of Power Plants in the United States 1993*, DOE/EIA-0095(93).

development of nonutility generation. In the West South Central Census Division, Texas dominated mainly because of the large potential for cogeneration in the petroleum refining industry, where thermal and electric load requirements are co-located.

Nonutilities generally install generator facilities with minimal regulatory requirements which result in considerably less lead time to finance and build as compared to electric utility facilities. As a result, nonutilities generally plan for 3 years while requirements of electric utilities make a 10-year period more appropriate. Capacity additions planned through 1996 by U.S. nonutilities total 15,688 megawatts, compared with 17,823 megawatts (generator nameplate capacity) planned for the same period by U.S. electric utilities.

However, electric utilities have planned 45,573 megawatts (generator nameplate capacity) in capacity additions for the 10-year period, 1994-2002. Of the nonutility planned capacity, 59 percent is petroleum and/or gas-fired. Coal-fired capacity represents 24 percent of the total planned nonutility additions.

Emissions. In 1993, estimated air emissions from nonutility facilities of 1 megawatt or more were 1,267 thousand short tons of SO₂, 1,300 thousand short tons of NO_x, and 535,999 thousand short tons of CO₂. This is a 4-percent increase of SO₂ emissions from the previous year. Emissions of SO₂ should not increase at the same rate as NO_x and CO₂ emissions, because nonutility control of SO₂ emissions is more widespread than for other air pollutants.

Figure 9. U.S. Electric Utility Sales to Ultimate Consumers by Sector, 1993

Notes: *Other includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales. *Data are preliminary. *Totals may not equal sum of components because of independent rounding. Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 10. U.S. Electric Utility Average Revenue per Kilowatthour by Sector, 1993

Notes: *Other includes sales to public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales. *Data are preliminary.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 11. U.S. Electric Utility Net Generation by Energy Source, 1993

Notes: *The total net generation value includes 10 billion kilowatthours from other energy sources (including geothermal, wood, wind, waste, and photovoltaic), which represents less than 1 percent of total generation. *Data are final. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Figure 12. Monthly U.S. Electric Utility Net Generation, 1993 and 1992

Note: *Data are final.

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Figure 13. Generating Capability at U.S. Electric Utilities by Energy Source, 1993

Notes: *The total generating capability value includes 2 gigawatts of other generating capability (geothermal, nonwood waste, wood and wood waste, photovoltaic and wind), which represents less than 1 percent of total generating capability. *Data are final.

*Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Figure 14. Installed Capacity at U.S. Nonutility Generating Facilities by Type of Facility, 1993

QF = Qualifying Facility

Notes: *Data are preliminary *Totals may not equal sum of components because of independent rounding

Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report"

Figure 15. Planned Capacity Additions for U.S. Nonutility Generating Facilities by Energy Source, as of December 31, 1993

* = Value rounds to less than 1 percent

Notes: *Totals may not equal sum of components because of independent rounding *Other includes hydrogen, sulfur, batteries, chemicals, and spent sulfite liquor *Data for planned capacity additions represent all planned generating facilities that meet one or more of three criteria presented in Chapter 10, "Nonutility Power Producers" *Data are preliminary

Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report"

Table 1. Electric Power Industry Summary Statistics for the United States, 1993 and 1992

Item	1993	1992	Percent Change
Electric Power Industry¹			
Generating Capability (megawatts)	754,955	746,563	1.1
Net Generation (million kilowatthours)	3,196,924	3,083,367	3.7
Emissions (thousand short tons)			
Sulfur Dioxide (SO ₂)	15,208	15,432	-1.5
Nitrogen Oxides (NO _x)	6,695	6,675	0.3
Carbon Dioxide (CO ₂)	2,342,210	2,240,271	4.6
Electric Utilities			
Generating Capability (megawatts) ²	699,971	695,059	0.7
Coal	300,795	300,547	0.1
Petroleum	69,519	71,852	-3.2
Gas	132,495	129,092	2.4
Nuclear	99,041	98,965	0.1
Renewable			
Hydroelectric (conventional)	74,763	74,345	1.0
Geothermal	1,747	1,739	0.5
Biomass ³	459	464	-1.1
Wind	1	1	233.3
Solar Thermal	0	0	0
Photovoltaic	4	3	33.3
Hydroelectric Pumped Storage	21,146	19,030	11.1
Net Generation (million kilowatthours)	2,852,525	2,797,219	2.0
Coal	1,639,151	1,575,895	4.0
Petroleum ⁴	99,539	98,916	11.9
Gas	256,915	263,872	-1.9
Nuclear	610,291	618,776	-1.4
Renewable			
Hydroelectric (conventional)	269,098	243,736	10.4
Geothermal	7,571	8,104	-6.6
Biomass ⁵	1,990	2,093	-4.9
Wind	0	0	0
Solar Thermal	0	0	0
Photovoltaic	4	3	33.3
Hydroelectric Pumped Storage ⁶	-4,036	-4,177	-3.4
Consumption			
Coal (million short tons)	814	780	4.4
Petroleum (million barrels) ⁷	162	147	10.2
Gas (billion cubic feet)	2,682	2,766	-3.0
Stocks (Year End)			
Coal (million short tons)	111	154	-27.9
Petroleum (million barrels) ⁸	82	72	-13.9
Receipts			
Coal (million short tons)	769	776	-0.9
Petroleum (million barrels) ⁹	146	144	2.6
Gas (billion cubic feet) ¹⁰	2,575	2,638	-2.4
Cost (cents per million Btu)¹¹			
Coal	138.5	141.2	-1.9
Petroleum ¹²	243.3	266.1	-4.6
Gas	256.0	232.6	10.0
Sales To Ultimate Consumers			
(million kilowatthours)	2,961,441	2,763,366	3.5
Residential	994,775	935,639	6.3
Commercial	794,572	781,271	4.4
Industrial	977,161	972,714	0.5
Other ¹³	94,944	93,442	1.6
Revenue From Sales to Ultimate Consumers			
(billion dollars)	198	168	5.3
Residential	83	77	7.8
Commercial	62	58	6.9
Industrial	47	47	0
Other ¹⁴	7	6	16.7
Average Revenue per Kilowatthour (cents)	5.93	6.82	1.6
Residential	8.32	8.21	1.3
Commercial	7.74	7.66	1.0
Industrial	4.85	4.83	0.4
Other ¹⁵	6.88	6.74	2.1
Emissions (thousand short tons)¹⁶			
Sulfur Dioxide (SO ₂)	14,432	14,680	-1.7
Nitrogen Oxides (NO _x)	5,852	5,674	3.1
Carbon Dioxide (CO ₂)	1,949,266	1,863,361	4.4
Noncoincident Summer Peak Load (megawatts)	727,187	681,270	8.7
DSM Actual Peak Load Reductions (megawatts)	29,181	17,204	34.7
DSM Energy Savings (million kilowatthours)	44,349	36,164	22.6
DSM Cost (million dollars)	2,768	2,243	23.5

Table 1. Electric Power Industry Summary Statistics for the United States, 1993 and 1992
(Continued)

Item	1993	1992	Percent Change
Nonutility Power Producers			
Installed Capacity (megawatts)	60,778	56,614	7.0
Coal ¹	9,772	8,503	14.9
Petroleum Only ²	2,043	1,730	18.1
Gas Only ³	23,463	21,542	8.9
Petroleum/Natural Gas (combined)	8,505	8,478	.3
Nuclear ⁴	20	20	0
Renewable			
Hydroelectric (conventional)	2,741	2,684	2.1
Geothermal	1,318	1,254	5.1
Biomass ⁵	10,177	9,812	3.7
Wind	1,813	1,822	-.5
Solar Thermal	354	354	0
Photovoltaic	7	7	0
Other ⁶	568	611	-7.4
Gross Generation (million kilowatt-hours)	325,226	296,001	9.9
Coal ¹	53,367	47,363	12.7
Petroleum ²	13,364	10,963	21.9
Gas ³	174,282	158,798	9.8
Nuclear ⁴	78	67	16.4
Renewable			
Hydroelectric (conventional)	11,511	9,446	21.9
Geothermal	2,749	8,578	13.7
Biomass ⁵	55,746	53,607	4.0
Wind	3,052	2,915	4.7
Solar Thermal	895	743	20.5
Photovoltaic	2	4	-50.0
Other ⁶	3,181	3,516	-9.5
Supply and Disposition (million kilowatt-hours)			
Gross Generation	325,226	296,001	9.9
Receipts ⁷	85,323	83,421	2.3
Deliveries ⁸	209,035	175,160	15.9
Facility Use	207,514	204,261	1.6
Emissions (thousand short tons)⁹			
Sulfur Dioxide (SO ₂)	1,267	1,208	4.9
Nitrogen Oxides (NO _x)	1,300	1,218	6.6
Carbon Dioxide (CO ₂)	535,999	504,074	6.3

¹ Electric utility and nonutility values (capacity versus capacity, net versus gross generation, total emissions versus emissions for the production of electricity) may not be summed directly—see Technical Notes for summation methodology.

² Net summer capability based on primary energy source, waste heat, waste gases, and waste steam are included in the original primary energy source (i.e., coal, petroleum, or gas)—historical data have been revised to reflect this change.

³ Includes wood, wood waste, peat, wood liquors, railroad ties, pitch, wood sludge, municipal solid waste, agricultural waste, straw, tires, landfill gases, fish oils, and/or other waste.

⁴ Includes petroleum coke.

⁵ Represents total pumped storage facility production minus energy used for pumping.

⁶ Does not include petroleum coke consumption of 1,220 thousand short tons in 1993 and 999 thousand short tons in 1992.

⁷ Does not include petroleum coke stocks of 88 thousand short tons at year end 1993 and 87 thousand short tons at year end 1992.

⁸ Does not include petroleum coke receipts of 1,248 thousand short tons in 1993 and 667 thousand short tons in 1992.

⁹ Includes small amounts of coke-oven, refinery, and blast furnace gas.

¹⁰ Average cost of fuel delivered to electric generating plants with a total steam-electric nameplate capacity of 50 or more megawatts. Average cost values are weighted by Btu.

¹¹ Does not include petroleum coke cost of 70.3 cents per million Btu in 1993 and 75.0 cents per million Btu in 1992.

¹² Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

¹³ Includes only those power plants with a fossil-fueled steam-electric nameplate capacity (existing or planned) of 10 or more megawatts. As of 1993, emission factors for the calculation of carbon dioxide emissions and reductions from nitrogen oxide control technologies have been changed—historical data were revised to reflect that change—see the Technical Notes for more information.

¹⁴ Includes coal, anthracite culm and coal waste.

¹⁵ Includes petroleum coke, diesel, kerosene, and petroleum sludge and tar.

¹⁶ Includes natural gas, butane, ethane, propane, waste heat and waste gases.

¹⁷ Nuclear reactor and generator at Argonne National Laboratory used primarily for research and development in testing reactor fuels as well as for training. The generation from the unit is used for internal consumption.

¹⁸ Includes hydrogen, sulfur, batteries, chemicals, and spent sulfite liquor.

¹⁹ Includes purchases, interchanges, and exchanges of electric energy with utilities and other nonutilities.

²⁰ Includes sales, interchanges, and exchanges of electric energy with utilities and other nonutilities. The disparity in these data and data reported on other EIA surveys occurs due to differences in the respondent universe. The Form EIA-867 is filed by nonutilities reporting the energy delivered, while other data sources are filed by electric utilities reporting energy received. Differences in terminology and accounting procedures attribute to the disparity. In addition, since the frame for the Form EIA-867 is derived from utility surveys, the Form EIA-867 universe lags 1 year.

²¹ As of 1993, emission factors for the calculation of carbon dioxide emissions and reductions from nitrogen oxide control technologies have been changed—historical data were revised to reflect that change—see Technical notes for more information.

Notes *Data for nonutility power producers, demand-side management, emissions, sales to ultimate consumers, revenue from sales, and average revenue per kilowatt-hour are preliminary for 1993, other data in this table are final. *Totals may not equal sum of components because of independent rounding. *Percent change is calculated before rounding. * = less than 0.5 megawatts. *DSM = Demand-Side Management.

Sources *Energy Information Administration, Form EIA-759, "Monthly Power Plant Report", Form EIA-860, "Annual Electric Generator Report", Form EIA-861, "Annual Electric Utility Report", Form EIA-767, "Steam-Electric Plant Operation and Design Report", Form EIA-867, "Annual Nonutility Power Producer Report". *Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants".

*Office of the Assistant Secretary for Emergency Planning and Operations, Form OE-411, "Coordinated Bulk Power Supply Program".

Generating Capability at U.S. Electric Utilities

More than one-third of the primary energy in the Nation is used to generate electricity.²⁰ Consumers expect electricity to be instantly available, that is, at the flick of a switch. In fact, electricity is so important to the functioning of our society that its unavailability is newsworthy. The U.S. electric power industry is organized to ensure that an adequate supply of electricity is available to meet all demand requirements at any given instant, both now and in the future. This chapter provides an inventory of the capability of various methods for converting energy into electricity and information regarding the plans the industry has for building additional capability.

Background

The generating units operated by an electric utility vary by intended usage, that is, by the type of load requirements the utility must meet. The load requirements placed on an electric utility are generally categorized as *base load*, *intermediate load*, and *peak load*. A baseload generating unit is normally used to satisfy all or part of the minimum load of the system and, as a consequence, produces electricity at an essentially constant rate and runs continuously. These units are generally the newest, largest, and most efficient of the three types. (The *operating efficiency* of a generating unit is a function of the amount of net heat that it can extract from the energy source for use in the production of electricity.) A peakload generating unit, which is normally the least efficient of the three types of units, is used to meet requirements during the periods of greatest load on the system. Intermediate-load generating units meet system requirements that are greater than base load but less than peak load. These units are used during the transition between baseload and peakload requirements. Utilities also have reserve or

standby generating units, which are available to the system in the event of an unexpected increase in load or an unexpected outage within the system. Consequently, an inventory of net capability must account for reserve or standby capability, as well as generating units that are not available to the system for various reasons (such as routine maintenance).

Net capability in this report, unless otherwise stated, refers to that which is *operable* and includes both active and inactive capability. Once a new generator has been declared available to generate power to the electrical grid, it is considered a part of the operable capability of the utility until it is retired from service. Generating units that are used for standby service, generators that are placed in cold reserve or cold standby, and generators that are out of service for an extended period (exceeding 1 year) comprise the inactive operable capability.²¹ Active operable capability includes generators that are generating or available to generate; this includes generators that may be down for scheduled maintenance, refueling, or forced outages.

An electric utility plant (station) contains generating units and auxiliary equipment that are used to convert various types of energy into electric energy. A fossil-fueled generating unit may be designed to use (burn) one or more fossil fuels to produce electricity. A generating unit capable of burning more than one fossil fuel is referred to as a dual-fired unit. Some dual-fired units can only burn one fuel at a time (that is, the fuels are fired sequentially), while others can burn more than one fuel simultaneously (concurrent firing of different fuels). A sequentially fired unit generally uses one fossil fuel as its primary energy source but can switch to a second fossil fuel as an alternate energy source. Unless stated otherwise, information regarding generating capability in this report is based on the primary energy source.

²⁰Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/10), pp. 11 and 35.

²¹As of the year-end 1993, about 3 percent of the operable capability was inactive. Energy Information Administration, *Inventory of Power Plants in the United States 1993*, DOE/EIA-0095(93), p. 31.

Prime Movers

Electric utilities use a variety of prime movers based on the loads, availability of fuels, and energy requirements of the utility. The most common prime movers are the steam turbine, internal-combustion engine, gas combustion turbine, water turbine, and wind turbine.²² Most prime movers used to produce electricity today are turbines. The energy sources most often used with prime movers are the fossil fuels -- coal, petroleum, and natural gas.

Steam-Turbine Generating Units. Most of the electricity in the United States is produced in steam turbines. In a *fossil-fueled* steam turbine, the fuel is burned in a boiler to produce steam. The resulting steam then turns the turbine blades that turn the shaft of the generator to produce electricity. In a *nuclear-powered* steam turbine, the boiler is replaced by a reactor containing a core of nuclear fuel (primarily enriched uranium). Heat produced in the reactor by fission of the uranium is used to make steam. The steam is then passed through the turbine generator to produce electricity, as in the fossil-fueled steam turbine. Steam-turbine generating units are used primarily to serve the base load of electric utilities. Fossil-fueled steam-turbine generating units range in size (nameplate capacity) from 1 megawatt to over 1,000 megawatts. Nuclear-powered steam-turbine generating units in operation today range in size from 75 megawatts to over 1,400 megawatts.

Gas Turbine Generating Units. In a gas turbine (combustion-turbine) unit, hot gases produced from the combustion of natural gas and distillate oil in a high-pressure combustion chamber are passed directly through the turbine, which spins the generator to produce electricity. Gas turbines are commonly used to serve the peak loads of the electric utility. Gas-turbine units can be installed at a variety of site locations, because their size is generally less than 100 megawatts. Gas-turbine units also have a quick startup time, compared with steam-turbine units. As a result, gas-turbine units are suitable for peaking, emergency, and reserve-power requirements.

The gas turbine, as is typical with peaking units, has a lower efficiency than the steam turbine used for baseload power. The efficiency of the gas turbine is increased when coupled with a steam turbine in a *combined-cycle* operation. In this operation, hot gases (which have already been used to spin one turbine generator) are moved to a waste-heat recovery steam boiler where the water is heated to produce steam that, in turn, produces electricity by running a second steam-turbine generator. In this way, two generators produce electricity from one initial fuel input. All or part of the heat required to produce steam may come from the

exhaust of the gas turbine. Thus, the steam-turbine generator may be supplementarily fired in addition to the waste heat. Combined-cycle generating units generally serve intermediate loads.

Internal-Combustion Engines. These prime movers have one or more cylinders in which the combustion of fuel takes place. The engine, which is connected to the shaft of the generator, provides the mechanical energy to drive the generator to produce electricity. Internal-combustion (or diesel) generators can be easily transported, can be installed upon short notice, and can begin producing electricity nearly at the moment they start. Thus, like gas turbines they are usually operated during periods of high demand for electricity. They are generally about 5 megawatts in size.

Hydroelectric Generating Units. Hydroelectric power is the result of a process in which flowing water is used to spin a turbine connected to a generator. The two basic types of hydroelectric systems are those based on *falling water* and those based on *natural river current*. In the first system, water accumulates in reservoirs created by the use of dams. This water then falls through conduits (penstocks) and applies pressure against the turbine blades to drive the generator to produce electricity. In the second system, called a *run-of-the-river* system, the force of the river current (rather than falling water) applies pressure to the turbine blades to produce electricity. Since run-of-the-river systems do not usually have reservoirs and cannot store substantial quantities of water, power production from this type of system depends on seasonal changes and stream flow. These conventional hydroelectric generating units range in size from less than 1 megawatt to 700 megawatts. Because of their ability to start quickly and make rapid changes in power output, hydroelectric generating units are suitable for serving peak loads and providing spinning reserve power, as well as serving baseload requirements.

Another kind of hydroelectric power generation is the *pumped storage* hydroelectric system. Pumped storage hydroelectric plants use the same principle for generation of power as the conventional hydroelectric operations based on falling water and river current. However, in a pumped storage operation, low-cost off-peak energy is used to pump water to an upper reservoir where it is stored as potential energy. The water is then released to flow back down through the turbine generator to produce electricity during periods of high demand for electricity.

Other Generating Units. Other methods of electric power generation, which presently contribute only small amounts to total power production, have potential for expansion. These include *geothermal*, *solar*,

²²A turbine converts the kinetic energy of a moving fluid (liquid or gas) to mechanical energy. Turbines have a series of blades mounted on a shaft against which fluids are forced, thus rotating the shaft connected to the generator. The fluids most commonly used in turbines are steam, hot air, or combustion products, and water.

wind, and biomass (wood, municipal solid waste, agricultural waste, etc.). *Geothermal* power comes from heat energy buried beneath the surface of the earth. Although most of this heat is at depths beyond current drilling methods, in some areas of the country, magma²³ flows close enough to the surface of the earth to produce steam. That steam can then be harnessed for use in conventional steam-turbine plants. *Solar power* is derived from the energy (both light and heat) of the sun. *Photovoltaic conversion* generates electric power directly from the light of the sun; whereas, *solar-thermal* electric generators use the heat from the sun to produce steam to drive turbines. *Wind power* is derived from the conversion of the energy contained in wind into electricity. A wind turbine is similar to a typical wind mill. However, because of the intermittent nature of sunlight and wind, high capacity utilization factors cannot be achieved for these plants. Several electric utilities have incorporated wood and waste (for example, municipal waste, corn cobs, and oats) as energy sources for producing electricity at their power plants. These sources replace fossil fuels in the boiler. The combustion of wood and waste creates steam that is typically used in conventional steam-electric plants.

Generator Rating

The rating of a generator is a measure of its ability to produce electricity. Generators are rated by nameplate capacity. The *nameplate capacity* is the full-load continuous rating of the generator under specified conditions, as designated by the manufacturer, and is usually indicated on a metal plate attached physically to the generator. *Net capability* is the steady hourly output that the generating unit is expected to supply to the system load, as demonstrated by test procedures. The capability of the generating unit in the summer is generally less than in the winter due to high ambient-air and cooling-water temperatures, which cause generating units to be less efficient. The measure used in this publication for electric utilities is net summer capability. The nameplate capacity of a generator is generally greater than its net capability.

Planned Generating Unit Additions

Electric utilities must provide a continuous and dependable supply of electricity to their consumers. They must maintain a balance between supply and demand and, at the same time, maintain an adequate reserve margin to ensure system reliability. To accomplish this, electric utilities continually assess their need for new generating capability.

The most important factor in determining the need for new electric generating capability is growth in the demand for electricity. Growth in demand is influenced primarily by economic forces (for example, the Gross National Product) and the cost of fuels and electricity. Electric utilities constantly monitor their peak demands and energy requirements and usually update their forecasts of these annually. Electric utilities use various methodologies to forecast annual peak demand and energy requirements, from which they determine the amount of capability that is needed to meet expected demand. Two additional factors that contribute to the need for new generating capability are the retirements of older generators and the decreasing efficiency of aging generating units.

Before deciding to add new capability, electric utilities consider other options that may be more cost-effective in meeting future demand. Also, they may choose to combine the addition of new capability with other options that include repowering and/or life extension of their existing capability, load-management programs and/or purchases of power from nonutilities.

Electric utilities are considering repowering as a cost-effective means of meeting future energy requirements. Several repowering technologies have been developed. Repowering generally consists of modifying old coal-fired electric generating units by replacing the boiler with a new combustion technology which results in better performance and an increase in capacity. Several repowering technologies were reported as part of the 10-year construction plans of utilities. In some cases, an existing steam-electric plant is reconfigured as a combined-cycle plant by adding a gas turbine. Several electric utilities have already completed this kind of repowering and more repowering is included in their 10-year construction plans. Other technologies repower with clean-coal technology. Repowering with clean-coal technology includes replacing the furnace and boiler in an old plant with new, cleaner-burning, high-efficiency coal combustion or gasification technology. Although utilities are considering their reported plans for implementing these technologies as "demonstration" projects, test programs have shown that these technologies do have dependability for future use by electric utilities in the United States.

Although life extension (plant refurbishment) adds little, if any, new capability, some utilities have chosen to refurbish their plants since refurbishment can add about 20 years of life to aged plants nearing retirement and is less expensive than repowering.

With concerns about future demand, in particular, future peak demands, utilities are studying and implementing ways to encourage customers to reduce or shift loads. These techniques include allowing customers to have more choice in setting the cost of their

²³Magma is the molten matter under the earth's crust from which igneous rock is formed by cooling.

energy, controlling their energy use and at the same time reducing overall demand. Reducing demand delays the need for new capability.

Once the decision has been made to add capability, either by building new power plants or adding new generating units at existing power plants, the type of capability to be added is determined by matching the load to be served with the appropriate type of generating unit. If the needs of a utility are limited to capability required to meet peak demand, then gas turbine, internal-combustion, or pumped-storage hydroelectric generating units are likely to be the choice for new additions. To meet other energy requirements (intermediate and base load), the options available to the utility include the addition of steam-electric, combined-cycle, or conventional-hydroelectric generating units.

Data Sources

The following tables contain a summary of the number of electric generators and the amount of electric generating capability in the United States at national, regional, and State levels for the period 1989 through 1993, as well as capability additions planned by electric utilities for 1994 through 2003.

During the past year, several updates were made for these data. These changes include the installation of new generators; the retirement of existing generators; the use of a primary energy source for dual-fired units different from that which has been reported in the past;

and the modification of generators, such as the rewinding of stators or the retrofit of associated generator equipment. Data previously reported in error were corrected. Respondents that did not meet the reporting requirements of Form EIA-860 were deleted. The capacity of generators sold to nonutilities was also deleted. The inclusion of new respondents also resulted in data changes.

Estimates of net summer capability and net winter capability are made for operable nonnuclear electric generating units with no reported capability. Additionally, estimates are made for all electric generating units that are not nuclear or coal-fired and are under construction or in the planning stage. These estimates are calculated using a statistical relationship that exists between the capability (summer and winter) and installed generator nameplate capacity for units that were in commercial operation as of the end of 1992. For a description of the estimation formula, see Technical Notes, Appendix C.

Data in the tables were obtained from the Form EIA-860, "Annual Electric Generator Report." Data are reported annually on the Form EIA-860 by approximately 900 electric utilities in the United States that operate power plants or plan to operate power plants within 10 years of the reporting year. These 10-year plans include generating units that are under construction or in various stages of planning at the time data are submitted. More detailed statistics on operable capacity and planned capacity additions are published in the *Inventory of Power Plants in the United States*.²⁴

Table 2. Generating Capability at U.S. Electric Utilities by Prime Mover and Primary Energy Source, End of Year, 1989 Through 1993 (Megawatts)

Prime Mover/Primary Energy Source	1993	1992	1991	1990	1989
Fossil Steam	446,315	446,201	446,575	446,985	443,866
Coal-Fired	300,796	300,647	299,811	299,878	296,614
Petroleum-Fired	41,905	44,472	45,711	49,789	51,340
Gas-Fired	103,614	101,182	101,253	97,320	85,912
Gas Turbine/Internal Combustion	66,494	64,291	62,700	60,861	56,022
Petroleum-Fired	27,614	27,391	27,235	27,275	27,018
Gas-Fired	28,881	26,910	25,555	23,516	23,004
Hydroelectric	86,910	83,376	82,081	80,368	78,487
Nuclear	99,041	86,985	99,589	99,824	98,161
Other¹	2,211	2,207	2,031	2,111	2,103
U.S. Total	699,971	696,059	693,016	690,466	684,619

¹ Refers to renewables (excluding hydroelectric) including biomass, geothermal, wind, and photovoltaic.

Notes: *Waste heat, waste gases, and waste steam are included in the original primary energy source category (i.e., coal, petroleum, or gas). *Data are final. *Totals may not equal sum of components because of independent rounding. *Generating capability is net summer capability.

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

²⁴Energy Information Administration, *Inventory of Power Plants in the United States 1993*, DOE/EIA-0095(93) (Washington, DC, October 1994).

Table 3. Summary of Capability Additions, Retirements, and Total Operable Capability at U.S. Electric Utilities by Energy Source, End of Year, 1993

Primary Energy Source	Added		Retired		Operable	
	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)
Coal	0	0	6	104	1,223	300,795
Petroleum	60	456	69	671	3,360	69,519
Gas	28	1,762	11	378	2,170	132,495
Hydroelectric	14	92	6	13	3,531	95,910
Nuclear	1	1,150	1	1,104	109	69,041
Other ²	3	1	0	0	78	2,211
U.S. Total	107	3,450	95	2,271	10,471	666,971

¹ Not summer capability.

² Refers to renewables (excluding hydroelectric) including biomass, geothermal, wind, and photovoltaic.

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding. *Total capability cannot be calculated from the prior year's capability by adjusting for retirements and newly added capability because capability ratings for independent generators change each year and generators are purchased from or sold to nonutilities. *Waste heat, waste gases, and waste steam are included in the original primary energy source category (i.e., coal, petroleum, or gas).

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 4. Planned Capability Additions at U.S. Electric Utilities by Energy Source, 1994 Through 2003

Year	Total		Petroleum & Gas		Coal	
	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)
1994	65	3,358	50	2,346	1	540
1995	76	7,392	59	3,527	2	776
1996	63	4,090	42	2,754	5	1,253
1997	30	1,514	25	1,381	1	116
1998	42	2,878	25	2,460	0	0
1999	49	3,908	34	3,068	2	660
2000	55	3,953	32	3,088	1	750
2001	42	4,498	41	3,748	1	750
2002	30	4,355	27	3,317	2	1,000
2003	29	3,278	27	2,519	1	657
1994-2003	480	59,019	362	28,260	16	6,602

	Nuclear		Hydroelectric		Other ²	
	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)
1994	0	0	14	472	0	0
1995	2	2,340	13	748	0	0
1996	0	0	15	75	1	8
1997	0	0	4	17	0	0
1998	0	0	17	216	0	0
1999	0	0	13	179	0	0
2000	0	0	19	122	3	42
2001	0	0	0	0	0	0
2002	0	0	1	38	0	0
2003	0	0	0	0	0	0
1994-2003	2	2,340	69	1,669	4	50

¹ Not summer capability.

² Refers to renewables (excluding hydroelectric) including biomass, geothermal, wind, and photovoltaic.

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding. *Waste heat, waste gases, and waste steam are included in the original primary energy source category (i.e., coal, petroleum, or gas).

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 5. Generating Capability at Electric Utilities by Census Division and State, End of Year, 1993 and 1992

Census Division State	1993		1992	
	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)
New England	673	22,871	670	22,644
Connecticut	83	6,754	87	6,968
Maine	188	2,402	188	2,405
Massachusetts	201	9,461	196	9,494
New Hampshire	45	2,508	43	2,507
Rhode Island	21	153	21	156
Vermont	135	1,094	135	1,094
Middle Atlantic	964	80,004	967	78,378
New Jersey	120	13,850	119	13,624
New York	586	32,731	614	31,106
Pennsylvania	236	33,423	234	33,446
East North Central	1,885	114,208	1,879	113,499
Illinois	333	32,789	333	32,636
Indiana	156	20,901	155	20,821
Michigan	564	22,412	559	22,374
Ohio	239	27,188	241	27,130
Wisconsin	393	10,838	391	10,637
West North Central	1,882	54,798	1,865	54,722
Iowa	399	8,074	406	8,092
Kansas	423	9,708	425	9,583
Minnesota	341	8,964	328	8,680
Missouri	355	15,433	342	15,385
Nebraska	251	5,512	247	5,453
North Dakota	48	4,478	45	4,478
South Dakota	67	2,733	72	2,744
South Atlantic	1,571	134,916	1,340	133,242
Delaware	30	2,269	27	2,082
District of Columbia	4	806	4	806
Florida	577	34,814	565	33,411
Georgia	208	21,504	208	21,399
Maryland	106	10,709	111	10,862
North Carolina	202	20,182	200	20,148
South Carolina	212	18,131	216	18,314
Virginia	178	14,054	155	13,772
West Virginia	56	14,448	56	14,448
East South Central	474	58,558	474	58,557
Alabama	147	19,972	147	19,930
Kentucky	110	15,297	110	15,300
Mississippi	62	7,045	62	7,032
Tennessee	155	16,224	165	16,294
West South Central	808	163,284	807	161,890
Arkansas	105	9,872	102	9,639
Louisiana	110	16,585	109	16,589
Oklahoma	153	12,559	153	12,881
Texas	440	63,868	443	62,671
Mountain	830	49,837	814	48,674
Arizona	123	15,034	122	14,973
Colorado	172	8,648	167	8,642
Idaho	116	2,304	115	2,357
Montana	95	4,871	95	4,871
Nevada	65	5,235	65	5,119
New Mexico	54	5,062	54	5,062
Utah	148	4,812	140	4,802
Wyoming	56	5,869	60	5,847
Pacific Contiguous	1,147	78,704	1,119	79,221
California	676	44,313	653	43,783
Oregon	193	10,133	189	11,237
Washington	278	24,259	277	24,221
Pacific Noncontiguous	647	3,313	633	3,232
Alaska	550	1,711	438	1,672
Hawaii	97	1,602	95	1,560
U.S. Total	10,471	688,971	10,268	685,058

¹ Not summer capability.

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 6. Coal-Fired, Nuclear, Hydroelectric, and Other Generating Capability at Electric Utilities by Census Division and State, End of Year, 1993

Census Division State	Coal		Nuclear		Hydroelectric		Other ¹	
	Number of Generators	Capability ² (megawatts)	Number of Generators	Capability ² (megawatts)	Number of Generators	Capability ² (megawatts)	Number of Generators	Capability ² (megawatts)
New England	15	2,441	8	6,392	374	3,136	10	112
Connecticut	1	385	4	3,211	35	137	2	84
Maine	0	0	1	870	136	421	0	0
Massachusetts	9	1,679	1	865	64	1,656	5	0
New Hampshire	5	578	1	1,150	33	291	0	0
Rhode Island	0	0	0	0	1	1	0	0
Vermont	0	0	1	496	105	430	3	47
Middle Atlantic	99	23,088	19	17,393	377	8,532	0	0
New Jersey	6	1,644	4	3,853	3	380	0	0
New York	32	3,879	6	4,831	329	7,240	0	0
Pennsylvania	59	17,480	9	8,709	45	1,912	0	0
East North Central	388	76,956	23	20,114	483	2,845	10	194
Illinois	68	15,063	13	12,609	16	12	0	0
Indiana	80	19,542	0	0	21	69	0	0
Michigan	77	11,929	6	3,967	232	2,200	0	0
Ohio	119	23,147	2	2,042	7	124	3	90
Wisconsin	52	7,276	3	1,496	207	440	7	104
West North Central	197	34,936	6	5,582	189	3,911	13	85
Iowa	50	5,818	1	515	25	125	1	0
Kansas	19	5,189	1	1,134	0	0	2	0
Minnesota	51	5,708	3	1,564	64	144	10	85
Missouri	48	10,796	1	1,125	29	1,110	0	0
Nebraska	15	3,103	2	1,254	20	188	0	0
North Dakota	12	3,856	0	0	5	645	0	0
South Dakota	2	467	0	0	26	1,020	0	0
South Atlantic	216	64,564	27	23,553	458	11,342	3	0
Delaware	5	931	0	0	0	0	0	0
District of Columbia	0	0	0	0	0	0	0	0
Florida	29	10,030	5	3,826	8	47	0	0
Georgia	39	13,115	4	3,825	118	2,853	0	0
Maryland	15	4,628	2	1,660	13	428	0	0
North Carolina	47	12,503	5	4,639	104	1,960	0	0
South Carolina	24	4,812	7	6,364	125	3,448	0	0
Virginia	24	4,217	4	3,849	70	3,109	3	0
West Virginia	33	14,328	0	0	22	106	0	0
East South Central	140	36,801	6	6,186	205	7,486	0	0
Alabama	39	11,579	5	4,835	69	2,955	0	0
Kentucky	58	14,093	0	0	30	795	0	0
Mississippi	6	2,238	1	1,143	0	0	0	0
Tennessee	37	8,691	2	2,217	66	3,748	0	0
West South Central	67	31,368	8	8,462	130	2,967	1	0
Arkansas	5	3,817	2	1,894	43	1,325	0	0
Louisiana	6	3,343	2	2,006	0	0	0	0
Oklahoma	10	4,874	0	0	37	1,009	0	0
Texas	36	19,336	4	4,782	50	652	1	0
Mountain	103	28,773	3	3,810	432	10,267	9	48
Arizona	14	5,108	3	3,510	41	2,761	0	0
Colorado	31	4,949	0	0	53	1,098	0	0
Idaho	0	0	0	0	114	2,299	0	0
Montana	6	2,260	0	0	64	2,478	2	13
Nevada	8	2,717	0	0	17	1,031	0	0
New Mexico	13	3,901	0	0	6	59	0	0
Utah	12	4,271	0	0	68	253	7	35
Wyoming	19	5,567	0	0	28	287	0	0
Pacific Contiguous	5	1,698	5	5,416	658	43,416	29	1,773
California	0	0	4	4,910	425	13,448	27	1,716
Oregon	1	508	0	0	176	8,006	1	11
Washington	4	1,390	1	1,100	255	20,960	1	48
Pacific Noncontiguous	5	64	0	0	67	366	3	0
Alaska	5	54	0	0	53	352	3	0
Hawaii	0	0	0	0	4	8	0	0
U.S. Total	1,223	308,795	109	99,041	3,531	95,910	78	2,211

¹ Refers to renewables (excluding hydroelectric) including biomass, geothermal, wind, and photovoltaic.

² Net summer capability.

* = Value less than 0.5.

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding. **Waste heat, waste gases, and waste steam are included in the original primary energy source category (i.e., coal, petroleum, or gas).

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 7. Petroleum-, Gas-, and Dual-Fired Steam Generating Capability at Electric Utilities by Census Division and State, End of Year, 1993

Census Division State	Petroleum		Gas		Dual-Fired Petroleum/Gas		Total Petroleum and Gas	
	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)
New England	41	6,337	2	105	18	3,010	61	8,452
Connecticut	15	2,054	0	0	2	528	17	2,582
Maine	13	1,041	0	0	0	0	13	1,041
Massachusetts	12	2,201	2	105	13	1,882	27	4,288
New Hampshire	0	0	0	0	1	408	1	408
Rhode Island	1	41	0	0	2	84	3	125
Vermont	0	0	0	0	0	0	0	0
Middle Atlantic	44	8,814	48	8,954	12	2,673	86	19,841
New Jersey	15	1,288	15	1,990	3	117	33	3,393
New York	16	4,268	26	6,163	8	2,556	51	12,987
Pennsylvania	13	3,260	1	201	0	0	14	3,461
East North Central	21	3,361	22	1,783	10	1,707	53	6,852
Illinois	11	2,035	10	1,265	8	166	29	3,466
Indiana	5	193	2	120	0	0	7	313
Michigan	4	1,070	3	300	4	1,541	11	2,911
Ohio	1	64	1	17	0	0	2	81
Wisconsin	0	0	5	92	0	0	5	92
West North Central	5	72	75	2,518	5	50	85	2,640
Iowa	3	22	6	121	0	0	9	143
Kansas	0	0	42	1,677	3	22	45	1,699
Minnesota	2	50	9	88	0	0	11	138
Missouri	0	0	5	90	2	38	7	128
Nebraska	0	0	11	259	0	0	11	259
North Dakota	0	0	0	0	0	0	0	0
South Dakota	0	0	2	66	0	0	2	66
South Atlantic	44	5,854	64	7,543	34	7,572	142	20,969
Delaware	1	84	1	176	4	580	6	839
District of Columbia	2	550	0	0	0	0	2	550
Florida	25	3,365	52	6,812	25	4,747	102	14,925
Georgia	2	115	8	288	1	125	11	529
Maryland	7	690	1	137	3	1,302	11	2,129
North Carolina	2	28	1	68	0	0	3	96
South Carolina	2	92	0	0	0	0	2	92
Virginia	3	926	1	62	1	818	5	1,806
West Virginia	0	0	0	0	0	0	0	0
East South Central	2	68	34	2,770	3	865	39	3,693
Alabama	0	0	4	92	0	0	4	92
Kentucky	2	58	1	115	0	0	3	173
Mississippi	0	0	29	2,583	3	865	32	3,427
Tennessee	0	0	0	0	0	0	0	0
West South Central	2	198	321	66,788	0	0	323	66,986
Arkansas	0	0	16	2,515	0	0	16	2,515
Louisiana	2	198	73	11,048	0	0	75	11,246
Oklahoma	0	0	33	6,108	0	0	33	6,108
Texas	0	0	198	36,119	0	0	198	36,119
Mountain	0	0	72	3,773	0	0	72	3,773
Arizona	0	0	21	1,509	0	0	21	1,509
Colorado	0	0	14	254	0	0	14	254
Idaho	0	0	0	0	0	0	0	0
Montana	0	0	1	70	0	0	1	70
Nevada	0	0	10	814	0	0	10	814
New Mexico	0	0	24	966	0	0	24	966
Utah	0	0	2	160	0	0	2	160
Wyoming	0	0	0	0	0	0	0	0
Pacific Contiguous	2	88	114	20,884	9	1,070	125	22,042
California	0	0	113	20,736	9	1,070	122	21,806
Oregon	0	0	1	148	0	0	1	148
Washington	2	88	0	0	0	0	2	88
Pacific Noncontiguous	26	1,179	2	85	0	0	28	1,264
Alaska	0	0	2	85	0	0	2	85
Hawaii	26	1,179	0	0	0	0	26	1,179
U.S. Total	187	34,949	748	183,814	91	16,056	1,026	145,819

¹ Net summer capability.

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding. *Waste heat, waste gases, and waste steam are included in the original primary energy source category (i.e., coal, petroleum, or gas).

Source: Energy Information Administration, Form EIA-850, "Annual Electric Generator Report."

Table 8. Petroleum-, Gas-, and Dual-Fired Gas Turbine/Internal Combustion Generating Capability at Electric Utilities by Census Division and State, End of Year, 1993

Census Division State	Petroleum		Gas		Dual-Fired Petroleum/Gas		Total Petroleum and Gas	
	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)
New England	182	1,149	0	114	14	378	206	1,638
Connecticut	24	375	0	0	0	0	24	375
Maine	39	70	0	0	0	0	39	70
Massachusetts	73	490	0	114	13	358	95	962
New Hampshire	4	56	0	0	1	17	5	63
Rhode Island	17	27	0	0	0	0	17	27
Vermont	26	120	0	0	0	0	26	120
Middle Atlantic	226	6,493	123	4,749	10	52	361	10,234
New Jersey	27	1,756	44	2,771	1	23	72	4,550
New York	105	2,032	68	1,792	9	29	180	3,799
Pennsylvania	96	1,615	13	246	0	0	109	1,861
East North Central	491	3,659	251	3,376	79	799	739	7,235
Illinois	51	506	115	972	23	52	219	1,619
Indiana	26	267	17	679	5	11	48	977
Michigan	149	509	69	782	21	55	239	1,406
Ohio	62	809	30	386	14	487	105	1,703
Wisconsin	33	799	20	548	15	183	118	1,590
West North Central	623	3,725	420	3,668	377	842	1,420	7,836
Iowa	160	490	57	749	98	235	313	1,474
Kansas	57	317	137	896	162	272	356	1,484
Minnesota	126	856	46	217	38	134	212	1,237
Missouri	146	1,404	70	744	52	127	270	2,275
Nebraska	50	304	100	396	23	38	203	726
North Dakota	27	68	2	10	0	0	29	78
South Dakota	23	257	6	88	6	36	37	361
South Atlantic	278	6,166	164	6,364	83	2,217	625	13,778
Delaware	15	124	3	336	1	39	19	499
District of Columbia	2	256	0	0	0	0	2	256
Florida	120	3,369	106	2,405	9	212	235	5,986
Georgia	22	942	6	73	8	168	34	1,183
Maryland	42	718	21	1,188	2	7	65	1,864
North Carolina	18	276	8	218	17	500	43	994
South Carolina	10	195	14	582	30	529	54	1,415
Virginia	48	276	6	693	18	761	72	1,570
West Virginia	1	12	0	0	0	0	1	12
East South Central	31	1,206	48	1,296	8	80	82	2,562
Alabama	1	18	9	494	0	0	10	512
Kentucky	9	78	8	110	3	50	19	296
Mississippi	2	31	11	208	0	0	13	237
Tennessee	20	1,080	20	488	0	0	40	1,568
West South Central	53	279	208	4,190	28	52	289	4,460
Arkansas	19	204	9	105	11	11	39	320
Louisiana	1	16	26	276	0	0	27	282
Oklahoma	11	30	46	810	16	26	73	668
Texas	22	29	122	2,939	6	13	150	2,980
Mountain	96	368	95	2,496	20	296	211	3,147
Arizona	3	97	37	1,727	4	9	44	1,827
Colorado	42	141	20	125	12	80	74	346
Idaho	2	6	0	0	0	0	2	6
Montana	0	0	2	50	0	0	2	50
Nevada	20	48	7	413	4	212	31	673
New Mexico	6	24	5	113	0	0	11	137
Utah	16	25	24	66	0	0	39	93
Wyoming	8	15	0	0	0	0	8	15
Pacific Contiguous	47	652	74	3,111	6	484	127	4,167
California	37	658	57	2,174	4	301	98	3,033
Oregon	2	6	10	348	2	103	14	457
Washington	8	88	7	590	0	0	15	678
Pacific Noncontiguous	524	929	29	682	1	36	564	1,640
Alaska	457	501	29	682	1	36	487	1,221
Hawaii	67	428	0	0	0	0	67	428
U.S. Total	2,463	22,953	1,416	26,418	625	5,123	4,504	56,494

¹ Net summer capability.

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding. *Waste heat, waste gases, and waste steam are included in the original primary energy source category (i.e., coal, petroleum, or gas).

Source: Energy Information Administration, Form EIA-880, "Annual Electric Generator Report."

Table 9. Planned Capability Additions at Electric Utilities by Energy Source, North American Electric Reliability Council Region, and Hawaii, 1994 Through 2003

North American Electric Reliability Council Region and Hawaii	Total		Petroleum & Gas		Coal	
	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)
ECAR	40	3,074	35	3,005	0	0
ERCOT	34	8,877	30	4,020	4	2,857
MAAC	32	9,875	31	9,575	1	300
MAIN	33	2,488	29	2,330	1	116
MAPP(U.S.)	16	626	16	626	0	0
NPOC(U.S.)	34	611	8	451	0	0
SERC	142	16,105	131	10,510	6	2,399
SPP	31	1,946	27	1,332	1	500
WSCC(U.S.)	89	3,497	40	2,291	3	590
Contiguous U.S.	481	38,898	345	28,138	18	6,502
ASCC	7	3	5	2	0	0
Hawaii	12	118	12	118	0	0
U.S. Total	499	39,019	362	29,260	16	6,502

	Nuclear		Hydroelectric		Other ²	
	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)
ECAR	0	0	5	68	0	0
ERCOT	0	0	0	0	0	0
MAAC	0	0	0	0	0	0
MAIN	0	0	0	0	3	42
MAPP(U.S.)	0	0	0	0	0	0
NPOC(U.S.)	0	0	27	153	1	6
SERC	2	2,340	3	856	0	0
SPP	0	0	3	114	0	0
WSCC(U.S.)	0	0	66	678	0	0
Contiguous U.S.	2	2,340	94	1,867	4	50
ASCC	0	0	2	1	0	0
Hawaii	0	0	0	0	0	0
U.S. Total	2	2,340	96	1,868	4	50

¹ Net summer capability.

² Refers to renewables (excluding hydroelectric) including biomass, geothermal, wind, and photovoltaic.

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding. *The Alaska Systems Coordinating Council (ASCC) became a NERC Region member in 1998. *Waste heat, waste gases, and waste steam are included in the original primary energy source category (i.e., coal, petroleum, or gas).

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 10. Planned Capability Additions at Electric Utilities by Energy Source, Census Division, and State, 1994 Through 2003

Census Division and State	Total		Petroleum & Gas		Coal	
	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)
New England	11	356	3	304	0	0
Connecticut	0	0	0	0	0	0
Maine	5	43	0	0	0	0
Massachusetts	0	0	0	0	0	0
New Hampshire	0	0	0	0	0	0
Rhode Island	3	304	3	304	0	0
Vermont	3	10	0	0	0	0
Middle Atlantic	34	2,124	14	2,017	0	0
New Jersey	11	1,670	11	1,670	0	0
New York	23	254	3	147	0	0
Pennsylvania	0	0	0	0	0	0
East North Central	66	4,172	60	4,013	1	116
Illinois	7	751	7	751	0	0
Indiana	13	1,284	13	1,284	0	0
Michigan	2	3	2	3	0	0
Ohio	11	580	9	587	0	0
Wisconsin	23	1,546	19	1,388	1	116
West North Central	44	2,331	43	1,831	1	500
Iowa	9	207	9	207	0	0
Kansas	11	33	11	33	0	0
Minnesota	2	3	2	3	0	0
Missouri	17	1,671	16	1,171	1	500
Nebraska	3	238	3	238	0	0
North Dakota	0	0	0	0	0	0
South Dakota	2	179	2	179	0	0
South Atlantic	135	13,960	125	10,405	7	2,699
Delaware	0	0	0	0	0	0
District of Columbia	0	0	0	0	0	0
Florida	26	3,209	24	2,517	2	692
Georgia	49	4,302	46	3,446	0	0
Maryland	21	2,005	20	1,705	1	300
North Carolina	16	1,316	16	1,316	0	0
South Carolina	11	1,575	9	860	2	925
Virginia	12	1,653	10	771	2	782
West Virginia	0	0	0	0	0	0
East South Central	42	5,347	37	2,941	5	0
Alabama	20	1,436	20	1,436	0	0
Kentucky	14	1,188	11	1,132	0	0
Mississippi	6	373	6	373	0	0
Tennessee	2	2,340	0	0	0	0
West South Central	42	7,228	36	4,457	4	2,657
Arkansas	3	114	0	0	0	0
Louisiana	0	0	0	0	0	0
Oklahoma	2	250	2	250	0	0
Texas	37	6,864	33	4,207	4	2,657
Mountain	53	2,373	25	1,621	3	530
Arizona	9	672	4	272	1	360
Colorado	2	92	1	65	0	0
Idaho	6	155	1	71	0	0
Montana	8	167	0	0	0	0
Nevada	16	1,170	14	1,060	1	80
New Mexico	1	23	1	23	0	0
Utah	11	18	4	7	0	0
Wyoming	1	60	0	0	1	50
Pacific Contiguous	44	1,005	13	682	0	0
California	26	562	10	385	0	0
Oregon	3	226	2	217	0	0
Washington	15	217	1	70	0	0
Pacific Noncontiguous	19	121	17	121	0	0
Alaska	7	3	6	2	0	0
Hawaii	12	118	12	118	0	0
U.S. Total	480	35,019	362	28,290	16	6,502

¹ Net summer capability.

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding. *Waste heat, waste gases, and waste steam are included in the original primary energy source category (i.e., coal, petroleum, or gas).

Source: Energy Information Administration, Form EIA-880, "Annual Electric Generator Report."

Table 10. Planned Capability Additions at Electric Utilities by Energy Source, Census Division, and State, 1994 Through 2003 (Continued)

Census Division and State	Nuclear		Hydroelectric		Other ¹	
	Number of Generators	Capability ² (megawatts)	Number of Generators	Capability ² (megawatts)	Number of Generators	Capability ² (megawatts)
New England	0	0	7	45	1	0
Connecticut	0	0	0	0	0	0
Maine	0	0	5	43	0	0
Massachusetts	0	0	0	0	0	0
New Hampshire	0	0	0	0	0	0
Rhode Island	0	0	0	0	0	0
Vermont	0	0	2	2	1	0
Middle Atlantic	0	0	20	107	0	0
New Jersey	0	0	0	0	0	0
New York	0	0	20	107	0	0
Pennsylvania	0	0	0	0	0	0
East North Central	0	0	2	2	2	42
Illinois	0	0	0	0	0	0
Indiana	0	0	0	0	0	0
Michigan	0	0	0	0	0	0
Ohio	0	0	2	2	0	0
Wisconsin	0	0	0	0	2	42
West North Central	0	0	0	0	0	0
Iowa	0	0	0	0	0	0
Kansas	0	0	0	0	0	0
Minnesota	0	0	0	0	0	0
Missouri	0	0	0	0	0	0
Nebraska	0	0	0	0	0	0
North Dakota	0	0	0	0	0	0
South Dakota	0	0	0	0	0	0
South Atlantic	0	0	3	66	0	0
Delaware	0	0	0	0	0	0
District of Columbia	0	0	0	0	0	0
Florida	0	0	0	0	0	0
Georgia	0	0	3	356	0	0
Maryland	0	0	0	0	0	0
North Carolina	0	0	0	0	0	0
South Carolina	0	0	0	0	0	0
Virginia	0	0	0	0	0	0
West Virginia	0	0	0	0	0	0
East South Central	2	2,340	3	67	0	0
Alabama	0	0	0	0	0	0
Kentucky	0	0	3	67	0	0
Mississippi	0	0	0	0	0	0
Tennessee	2	2,340	0	0	0	0
West South Central	0	0	3	114	0	0
Arkansas	0	0	3	114	0	0
Louisiana	0	0	0	0	0	0
Oklahoma	0	0	0	0	0	0
Texas	0	0	0	0	0	0
Mountain	0	0	25	322	0	0
Arizona	0	0	4	40	0	0
Colorado	0	0	1	24	0	0
Idaho	0	0	5	34	0	0
Montana	0	0	0	167	0	0
Nevada	0	0	0	0	0	0
New Mexico	0	0	0	0	0	0
Utah	0	0	7	7	0	0
Wyoming	0	0	0	0	0	0
Pacific Contiguous	0	0	91	354	0	0
California	0	0	10	197	0	0
Oregon	0	0	1	10	0	0
Washington	0	0	14	146	0	0
Pacific Noncontiguous	0	0	2	1	0	0
Alaska	0	0	2	1	0	0
Hawaii	0	0	0	0	0	0
U.S. Total	2	2,340	98	1,369	4	50

¹ Refers to renewables (excluding hydroelectric) including biomass, geothermal, wind, and photovoltaic.

² Net summer capability.

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding. *Waste heat, waste gases, and waste steam are included in the original primary energy source category (i.e., coal, petroleum, or gas).

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Net Generation from U.S. Electric Utilities

This chapter provides summary statistics on the amount of electricity produced by electric utilities in the United States. The different energy sources used by electric utilities to produce electric power are also discussed in this chapter.

Background

The production of electricity is generally referred to as generation, and is measured in kilowatthours. Gross generation is the amount of power produced by an electric power plant (station), measured at the terminals of the plant (that is, prior to the point at which the power leaves the station and is available to the system). Some of the electric power generated at a power plant is used to operate equipment at the plant. Power used at the plant generally ranges between 1 percent (for hydroelectric units) and 7 percent (for steam-electric units). Net generation is the power available to the system (gross generation less use at the plant); however, it is greater than that available to consumers due to losses during transmission and distribution (approximately 8 to 9 percent). Net generation is the measure used for electric power production by electric utilities in this report.

Generation from Fossil Fuels

Coal. Historically, most generation of electricity in the United States has been from coal. After the Arab oil embargo of 1973, concerns over the availability of petroleum imports, increasing petroleum costs, and curtailments of natural gas made coal-fired generation even more important. In 1978, the passage of the Powerplant and Industrial Fuel Use and the Natural Gas Policy Acts encouraged further use of coal by electric utilities. Although both Federal and State environmental laws and regulations existed during the 1970's, renewed interest in environmental issues raised concerns about electric power plant emissions, particularly from those burning coal. The Clean Air Act Amendments of 1990 established a goal of a 10-million-ton reduction in sulfur dioxide emissions and a 2-million-ton reduction in nitrogen oxide emissions by 2000 from 1980 levels (see the chapter on Environmental Statistics). Coal-fired generation continues to provide more than one-half the total net generation of electricity by electric utilities in the Nation. Most of the electricity production from coal by electric utilities

occurs in the East North Central and South Atlantic Census Divisions where substantial amounts of coal are mined.

Petroleum. During the early 1970's, electric utilities used petroleum extensively to generate electricity. However, after the 1973 embargo by the Organization of Petroleum Exporting Countries (OPEC) on petroleum exports to the United States, petroleum prices rose sharply. Further price increases occurred in 1979 and 1980 following the Iranian revolution and subsequent reductions in Iranian petroleum exports. Consequently during the past decade, utilities have not built large, petroleum-fired steam units. In addition, many utilities have either converted steam units to coal or switched fuels where dual-fired capability exists. Most of the utilities that still rely heavily on petroleum to generate electricity are located along the eastern seaboard and in California.

Gas. The demand for gas (primarily natural gas) to heat homes and serve business and industry has historically taken priority over demand from electric utilities under both Federal and State regulations. In the 1970's, many utilities were on occasion denied gas when available pipelines reached capacity in serving heating demand during the months from November to March (the peak heating season). By the middle 1970's, curtailments to electric utilities also occasionally occurred during the nonheating season as producers conserved supply in preparation for heating season demand. In the face of an attractive interstate price structure but deprived of supplies during many months of the year, utilities in the 1970's used relatively less-expensive gas when it was available, then switched to other more expensive fuels when gas supplies were curtailed. Gas became more available to utilities with the passage of the Natural Gas Policy Act of 1978 and more frequent exemptions from the gas-use restrictions of the Powerplant and Industrial Fuel Use Act (Fuel Use Act) of 1978. Amendments to the Fuel Use Act in 1987 created potential for additional use of gas. These amendments eased restrictions on the use of gas by removing a legal requirement to obtain an exemption for the construction of new gas-fired generating capability. The West South Central Census Division, where most of the gas production in the Nation occurs, supplies more than half of the gas-fired generation in the country.

Nuclear-Powered Generation

Generation from nuclear power has generally increased since the 1950's, and this trend continues. Since 1984, nuclear plants have provided the second largest share of total U.S. generation of electricity, after coal-fired plants. Although no new nuclear units have been ordered since 1978 and units ordered after 1974 were not built, many units that were under construction have either been completed and entered service or will enter service in the near future. Licensing delays, questions about radioactive waste disposal, and concern about nuclear plant safety have slowed these units from entering service and are still major obstacles to additional growth in the use of this energy source for generating electricity. Most of the nuclear-powered generation comes from the Middle Atlantic, East North Central, and South Atlantic Census Divisions (where over 60 percent of the nuclear units in the country are located.)

Generation from Renewable Fuels

Hydroelectric. Water is currently the leading renewable energy source used by electric utilities to generate electric power. Hydroelectric plants operate where suitable waterways are available; many of the best of these sites have already been developed. Generating electricity using water has several advantages. The major advantage is that water, a renewable resource, is a source of cheap power. In addition, because there is no fuel combustion, there is little air pollution in comparison with fossil-fuel plants and limited thermal pollution compared with nuclear plants. Like other energy sources, the use of water for generation has limitations, including environmental impacts caused by

damming rivers and streams, which affects the habitats of the local plant, fish, and animal life. Over 60 percent of the hydroelectric power in the United States is generated in the Pacific and Rocky Mountain States.

Other Sources. Other renewable resources -- geothermal (heat energy beneath the surface of the earth), wood, waste, wind, and the sun (solar) -- are energy sources that are constantly replenished. These energy sources have received increased attention in recent years, but a limited number of such generating facilities are in use today. Currently, renewable resources (other than water) supply less than 1 percent of the electricity generated by electric utilities. Most of the electricity produced from this category is from geothermal power. Electric utilities currently operate geothermal plants in two States (California and Utah). The Geysers, operated by the Pacific Gas and Electric Company, is the largest geothermal plant in the Nation. Only a few utilities operate units that produce electricity from wind and solar energy. The largest share of the electricity from these energy sources is produced from facilities in California. Wood and waste resources can be used to replace fossil fuels in utility boilers. To date, just a few electric generating units have been built that use wood or waste products as a primary fuel.

Data Sources

The data in the following tables are aggregated at national, regional, and State levels for the period 1989 through 1993. Data in the tables were obtained from the Form EIA-759, "Monthly Power Plant Report," which is used to collect monthly data from all operators of electric utilities (approximately 715) in the United States. More detailed statistics from the Form EIA-759 are published in the *Electric Power Monthly*.²⁵

Table 11. Net Generation from U.S. Electric Utilities by Energy Source, 1989 Through 1993
(Million Kilowatthours)

Energy Source	1993	1992	1991	1990	1989
Coal	1,628,151	1,575,895	1,551,157	1,559,604	1,553,661
Petroleum ¹	99,538	88,918	111,483	117,017	166,316
Steam	96,070	86,046	108,176	113,402	151,111
Gas Turbine/Internal Combustion	3,469	2,871	3,287	3,615	7,207
Gas	258,915	283,872	284,172	264,089	268,598
Steam	237,345	245,812	245,880	245,901	245,057
Gas Turbine/Internal Combustion	21,570	18,260	18,281	18,188	21,542
Hydroelectric	265,963	239,559	275,519	279,926	265,063
Nuclear	610,281	615,776	612,585	676,882	528,355
Other ²	9,585	10,200	14,137	10,851	11,309
U.S. Total	2,882,525	2,797,219	2,825,023	2,808,151	2,794,904

¹ Includes petroleum coke

² Refers to renewables (excluding hydroelectric) including biomass, geothermal, wind, and photovoltaic

Notes: *Data are final *Totals may not equal sum of components because of independent rounding

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report"

²⁵Energy Information Administration, *Electric Power Monthly*, DOE/EIA-0226(93/1-12)(Washington, DC)

Table 12. Net Generation from Electric Utilities by Selected Prime Mover, Census Division, and State, 1993 and 1992
(Million Kilowatthours)

Census Division State	Total		Fossil Steam		Gas Turbine/Internal Combustion	
	1993	1992	1993	1992	1993	1992
New England	83,895	84,585	34,898	41,111	487	575
Connecticut	28,715	28,154	6,152	7,838	10	11
Maine	8,076	8,335	759	1,261	2	-
Massachusetts	28,164	32,838	23,385	27,429	441	553
New Hampshire	14,586	13,451	4,537	4,618	-	-
Rhode Island	54	109	45	101	9	8
Vermont	4,301	4,598	21	64	4	2
Middle Atlantic	308,800	308,430	166,080	175,750	1,566	1,128
New Jersey	34,285	31,187	8,516	8,961	880	749
New York	106,315	112,229	51,943	62,172	481	309
Pennsylvania	168,201	165,034	105,622	104,617	124	88
East North Central	513,781	487,568	381,023	384,313	372	321
Illinois	140,081	124,824	61,630	50,988	38	24
Indiana	98,951	97,300	99,410	96,716	93	21
Michigan	92,250	92,679	62,765	62,726	94	228
Ohio	133,735	138,297	123,377	120,307	101	30
Wisconsin	47,783	48,484	33,842	32,967	46	17
West North Central	218,960	212,826	168,308	162,584	615	345
Iowa	30,992	29,427	26,899	24,994	101	32
Kansas	36,433	31,784	28,251	23,076	282	197
Minnesota	41,254	37,764	28,002	25,420	19	32
Missouri	53,202	56,627	41,559	47,043	151	51
Nebraska	22,724	22,987	14,863	12,527	49	30
North Dakota	29,500	28,592	27,084	26,693	1	-
South Dakota	5,256	6,246	2,650	2,631	14	3
South Atlantic	575,398	547,468	398,930	371,854	6,087	3,489
Delaware	8,306	6,267	7,409	5,099	886	269
District of Columbia	188	74	185	61	4	13
Florida	140,067	133,877	111,843	107,129	2,126	1,497
Georgia	95,738	91,779	63,628	59,401	124	40
Maryland	43,488	39,587	29,076	26,825	455	273
North Carolina	88,754	83,007	59,567	54,204	221	214
South Carolina	75,588	71,479	26,630	23,160	118	52
Virginia	52,182	48,964	26,878	24,144	2,142	1,132
West Virginia	71,078	72,394	70,718	71,911	-	-
East South Central	273,876	264,028	223,337	196,417	1,918	789
Alabama	94,124	90,792	67,126	61,074	140	61
Kentucky	84,998	77,351	81,838	73,582	5	2
Mississippi	23,234	20,486	14,722	11,576	609	636
Tennessee	71,614	75,396	59,651	50,085	264	68
West South Central	384,287	378,465	337,058	318,574	6,116	6,204
Arkansas	36,049	37,370	20,010	22,654	10	-
Louisiana	59,353	56,188	44,288	44,237	866	595
Oklahoma	48,811	45,943	41,702	39,961	2,812	2,752
Texas	248,174	239,964	231,058	209,692	2,826	2,857
Mountain	254,983	257,180	191,876	203,779	1,518	1,173
Arizona	88,025	70,109	37,934	36,721	1,020	868
Colorado	82,687	31,889	30,790	30,843	40	52
Idaho	2,023	6,260	-	-	-	-
Montana	23,447	26,466	13,808	17,157	12	8
Nevada	19,620	20,963	17,582	16,867	278	94
New Mexico	28,384	27,708	28,037	27,428	33	25
Utah	33,461	32,921	32,359	32,027	136	128
Wyoming	40,155	41,662	39,367	41,217	0	-
Pacific Contiguous	250,298	244,845	69,331	68,847	3,636	3,548
California	125,782	119,310	47,011	55,324	1,495	1,611
Oregon	40,743	41,220	3,508	3,688	1,716	1,478
Washington	83,771	84,115	8,812	9,635	446	400
Pacific Noncontiguous	10,888	11,028	5,724	6,523	3,824	3,578
Alaska	4,581	4,187	768	722	2,522	2,527
Hawaii	6,084	6,861	4,968	5,801	1,102	1,051
U.S. Total	2,882,525	2,797,219	1,972,588	1,907,653	25,039	21,131

* - Value less than 0.5 million kilowatthours

Notes: *Data are final. *Negative generation denotes that electric power consumed for plant use exceeds gross generation. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-769, "Monthly Power Plant Report."

Table 13. Net Generation from Electric Utilities by Energy Source, Census Division, and State, 1993 and 1992
(Million Kilowatthours)

Census Division State	Coal		Petroleum ¹		Gas	
	1993	1992	1993	1992	1993	1992
New England	14,987	16,284	17,376	21,293	2,003	4,100
Connecticut	1,808	2,148	4,208	5,297	47	203
Maine	—	—	790	1,282	—	—
Massachusetts	9,816	10,549	11,113	13,282	2,897	3,751
New Hampshire	3,283	3,167	1,203	1,374	12	57
Rhode Island	0	0	29	75	25	35
Vermont	—	—	6	3	21	83
Middle Atlantic	127,876	182,588	20,827	21,023	19,943	23,324
New Jersey	5,466	5,409	1,029	1,016	2,951	3,265
New York	21,820	24,921	14,439	17,786	16,186	18,774
Pennsylvania	100,390	102,199	4,559	2,221	797	265
East North Central	378,692	399,285	1,919	1,489	2,794	2,980
Illinois	59,785	49,815	719	434	1,184	773
Indiana	98,778	95,746	196	287	529	704
Michigan	61,559	61,435	620	495	680	1,022
Ohio	123,025	120,529	276	195	177	213
Wisconsin	33,559	32,741	105	54	224	189
West North Central	188,672	190,162	1,498	846	2,794	1,822
Iowa	26,643	24,844	50	38	308	146
Kansas	26,500	22,153	76	45	1,657	1,076
Minnesota	27,111	24,443	630	639	279	370
Missouri	40,689	46,830	634	81	386	183
Nebraska	14,740	12,402	19	9	153	145
North Dakota	27,049	26,895	36	29	—	—
South Dakota	2,642	2,826	12	7	11	1
South Atlantic	399,390	315,715	43,381	34,641	22,248	21,987
Delaware	5,195	3,814	2,094	1,830	1,027	824
District of Columbia	—	—	188	74	—	—
Florida	61,889	61,631	34,278	28,176	17,803	18,818
Georgia	63,296	56,236	237	125	218	77
Maryland	24,881	23,625	3,954	2,812	885	881
North Carolina	59,369	54,011	166	147	240	259
South Carolina	26,632	23,014	95	69	121	150
Virginia	24,782	22,676	2,159	1,423	2,140	1,177
West Virginia	70,492	71,709	211	182	13	21
East South Central	216,880	191,848	3,949	966	3,546	4,593
Alabama	66,758	60,880	72	82	436	363
Kentucky	61,722	73,476	97	84	24	24
Mississippi	8,820	7,799	3,546	372	2,868	4,147
Tennessee	56,500	49,886	235	127	121	30
West South Central	194,648	186,186	2,370	901	146,158	135,811
Arkansas	18,026	20,030	66	50	1,928	2,584
Louisiana	18,368	18,788	1,838	483	23,751	24,554
Oklahoma	28,990	27,686	14	16	15,510	15,051
Texas	128,266	119,673	453	254	104,957	93,821
Mountain	193,807	198,218	461	580	7,327	8,155
Arizona	37,021	34,602	60	73	1,872	2,914
Colorado	30,456	30,002	9	39	364	393
Idaho	—	—	—	—	—	—
Montana	13,776	17,129	21	18	24	23
Nevada	15,628	16,443	247	328	1,986	2,210
New Mexico	25,507	25,348	38	36	2,528	2,088
Utah	31,819	31,649	32	34	543	575
Wyoming	39,301	41,134	57	55	9	5
Pacific Contiguous	12,307	13,388	2,072	346	48,809	68,548
California	—	—	2,008	325	48,499	68,510
Oregon	3,503	3,583	32	9	1,887	1,474
Washington	8,804	9,825	32	6	422	484
Pacific Noncontiguous	323	290	5,539	7,288	2,497	2,562
Alaska	323	290	459	407	2,497	2,552
Hawaii	—	—	8,070	8,851	—	—
U.S. Total	1,639,151	1,575,886	99,839	83,916	268,916	263,872

¹ Includes petroleum coke.

— Value less than 0.5 million kilowatthours.

Notes: *Data are final. +Negative generation denotes that electric power consumed for plant use exceeds gross generation. +Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-750, "Monthly Power Plant Report."

Table 13. Net Generation from Electric Utilities by Energy Source, Census Division, and State, 1993 and 1992 (Continued)
(Million Kilowatthours)

Census Division State	Nuclear		Hydroelectric ¹		Other ²	
	1993	1992	1993	1992	1993	1992
New England	44,288	36,474	3,760	3,858	471	488
Connecticut	21,802	18,771	345	380	406	374
Maine	5,740	6,355	1,575	1,715	—	—
Massachusetts	4,338	4,742	—	114	—	—
New Hampshire	9,047	7,888	1,002	954	—	—
Rhode Island	—	—	0	0	—	—
Vermont	3,372	3,735	838	800	64	92
Middle Atlantic	111,152	105,883	27,588	25,871	19	8
New Jersey	24,832	21,585	—	—	—	—
New York	20,888	24,186	26,988	25,583	19	0
Pennsylvania	58,331	60,133	1,124	1,217	—	—
East North Central	128,374	118,604	9,728	9,844	284	488
Illinois	78,373	73,742	40	52	0	8
Indiana	—	—	448	582	—	—
Michigan	20,525	18,848	856	875	—	—
Ohio	10,011	14,808	183	244	64	310
Wisconsin	11,465	11,207	2,191	2,123	220	150
West North Central	99,307	99,895	9,888	9,575	440	428
Iowa	3,255	3,405	737	881	20	14
Kansas	7,900	8,491	—	—	—	—
Minnesota	11,888	11,188	834	758	414	407
Missouri	8,381	8,084	3,110	1,450	1	—
Nebraska	8,805	8,748	1,002	1,075	8	8
North Dakota	—	—	1,415	1,699	—	—
South Dakota	—	—	2,591	3,612	—	—
South Atlantic	158,054	155,401	15,315	16,724	—	—
Delaware	—	—	—	—	—	—
District of Columbia	—	—	—	—	—	—
Florida	25,887	25,118	211	298	—	—
Georgia	27,233	27,988	4,753	5,342	—	—
Maryland	12,301	10,584	1,858	1,825	—	0
North Carolina	23,759	22,754	5,207	6,835	—	—
South Carolina	45,188	45,537	2,651	2,710	—	—
Virginia	22,889	23,234	473	353	—	—
West Virginia	—	—	362	423	—	—
East South Central	29,032	43,225	28,583	23,617	—	—
Alabama	17,823	19,397	9,034	10,288	—	—
Kentucky	—	—	3,155	3,787	—	—
Mississippi	7,904	5,174	—	—	—	—
Tennessee	3,305	15,654	8,394	9,590	—	—
West South Central	40,327	48,178	18,591	9,228	285	281
Arkansas	13,522	11,328	4,606	3,380	—	—
Louisiana	14,398	10,356	—	—	—	—
Oklahoma	—	—	4,285	5,210	—	—
Texas	12,407	24,498	1,788	2,638	285	281
Mountain	22,049	25,808	31,312	29,362	225	285
Arizona	22,048	25,808	7,023	6,911	—	—
Colorado	—	—	1,658	1,505	0	0
Idaho	—	—	9,023	6,280	—	—
Montana	—	—	9,549	8,223	78	79
Nevada	—	—	1,980	1,982	—	—
New Mexico	—	—	294	255	—	—
Utah	—	—	818	580	148	185
Wyoming	—	—	787	638	—	—
Pacific Contiguous	35,694	45,988	148,778	118,646	7,836	8,292
California	31,551	35,244	38,284	19,205	7,430	7,825
Oregon	—	4,573	35,531	31,475	11	8
Washington	7,135	5,882	66,953	67,967	395	381
Pacific Noncontiguous	—	—	1,317	928	0	0
Alaska	—	—	1,308	918	0	0
Hawaii	—	—	14	10	—	0
U.S. Total	810,291	815,775	288,083	238,589	9,545	10,208

¹ Station losses include energy used for pumped storage. Energy used in 1993 for pumping was 23,588 million kilowatthours and in 1992 was 23,249 million kilowatthours.

² Refers to renewables (excluding hydroelectric) including biomass, geothermal, wind, and photovoltaic.

* — Value less than 0.5 million kilowatthours.

Notes: *Data are final. *Negative generation denotes that electric power consumed for plant use exceeds gross generation. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

**Table 14. Petroleum-Fired Net Generation from Electric Utilities by Selected Prime Mover,
Census Division, and State, 1993 and 1992
(Million Kilowatthours)**

Census Division State	Total ¹		Steam		Gas Turbine/Internal Combustion	
	1993	1992	1993	1992	1993	1992
New England	17,375	21,293	17,179	21,061	197	232
Connecticut	4,206	5,297	4,197	5,287	10	11
Maine	760	1,262	759	1,261	2	"
Massachusetts	11,113	13,252	10,941	13,091	171	191
New Hampshire	1,263	1,374	1,262	1,374	"	"
Rhode Island	29	75	20	67	9	6
Vermont	5	3	"	1	4	2
Middle Atlantic	20,027	21,023	19,843	20,799	394	257
New Jersey	1,029	1,016	906	913	123	103
New York	14,439	17,786	14,267	17,678	171	108
Pennsylvania	4,559	2,221	4,469	2,175	90	46
East North Central	1,918	1,469	1,819	1,447	99	23
Illinois	719	434	701	428	18	6
Indiana	186	287	177	286	20	1
Michigan	620	498	602	492	17	6
Ohio	276	195	248	188	28	7
Wisconsin	105	64	90	53	15	2
West North Central	1,458	846	1,345	809	113	38
Iowa	50	36	29	30	21	6
Kansas	76	45	53	27	24	17
Minnesota	630	639	620	636	11	3
Missouri	634	61	567	78	47	4
Nebraska	19	6	15	6	4	3
North Dakota	36	29	35	29	1	"
South Dakota	12	7	6	4	6	3
South Atlantic	43,861	34,841	42,542	33,896	639	745
Delaware	2,084	1,830	2,060	1,821	14	6
District of Columbia	188	74	165	61	4	13
Florida	34,278	28,176	33,770	27,630	507	548
Georgia	237	128	144	94	94	34
Maryland	3,854	2,612	3,835	2,570	119	42
North Carolina	165	147	130	124	35	23
South Carolina	95	68	73	58	23	10
Virginia	2,158	1,423	2,114	1,355	43	88
West Virginia	211	182	211	162	"	"
East South Central	3,849	665	3,799	615	169	50
Alabama	72	82	67	71	5	12
Kentucky	97	84	94	84	2	"
Mississippi	3,545	372	3,546	371	"	"
Tennessee	235	127	92	89	143	36
West South Central	2,370	901	2,348	787	22	14
Arkansas	66	50	56	49	10	"
Louisiana	1,838	483	1,837	486	1	-3
Oklahoma	14	15	13	14	1	1
Texas	453	254	443	237	10	16
Mountain	461	680	462	559	9	21
Arizona	60	73	56	67	3	5
Colorado	9	39	9	35	"	4
Idaho	"	"	"	"	"	"
Montana	21	16	21	15	"	"
Nevada	247	328	244	321	2	6
New Mexico	35	36	35	35	"	"
Utah	32	34	29	30	3	4
Wyoming	57	55	57	55	0	"
Pacific Contiguous	2,072	340	1,975	285	97	55
California	2,008	325	1,863	275	44	60
Oregon	32	9	5	6	26	4
Washington	32	6	7	5	25	1
Pacific Noncontiguous	6,629	7,256	4,969	5,602	1,360	1,456
Alaska	459	407	1	1	458	406
Hawaii	6,070	6,851	4,968	5,601	1,102	1,051
U.S. Total	99,539	88,916	86,070	88,046	3,469	2,871

¹ Includes petroleum coke

" = Value less than 0.5 million kilowatthours

Notes: "Data are final" "Negative generation denotes that electric power consumed for plant use exceeds gross generation" "Totals may not equal sum of components because of independent rounding"

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report"

**Table 15. Gas-Fired Net Generation from Electric Utilities by Selected Prime Mover,
Census Division, and State, 1993 and 1992**
(Million Kilowatthours)

Census Division State	Total		Steam		Gas Turbine/Internal Combustion	
	1993	1992	1993	1992	1993	1992
New England	9,002	4,109	2,732	2,746	276	363
Connecticut	47	203	47	203	—	—
Maine	—	—	—	—	—	—
Massachusetts	2,897	3,751	2,627	3,388	270	363
New Hampshire	12	57	12	57	0	0
Rhode Island	25	35	25	35	—	—
Vermont	21	63	21	63	—	—
Middle Atlantic	19,943	23,324	14,762	22,455	1,182	669
New Jersey	2,981	3,285	2,144	2,838	836	646
New York	16,166	19,774	15,655	19,573	310	201
Pennsylvania	797	265	763	243	34	22
East North Central	2,794	2,900	2,622	2,502	273	298
Illinois	1,184	773	1,164	755	20	16
Indiana	528	704	456	684	73	20
Michigan	880	1,022	603	800	77	222
Ohio	177	213	104	189	73	23
Wisconsin	224	189	194	173	30	15
West North Central	2,794	1,922	2,291	1,614	503	308
Iowa	308	146	228	120	80	26
Kansas	1,657	1,076	1,399	890	258	160
Minnesota	279	370	271	341	8	30
Missouri	366	183	283	137	104	47
Nebraska	153	145	106	119	45	28
North Dakota	—	—	—	—	—	—
South Dakota	11	1	2	1	8	—
South Atlantic	22,246	21,967	16,996	19,243	6,248	2,744
Delaware	1,027	624	143	364	583	260
District of Columbia	—	—	—	—	—	—
Florida	17,803	16,818	16,184	17,867	1,619	951
Georgia	218	77	188	71	30	6
Maryland	685	881	348	690	336	230
North Carolina	240	259	54	69	186	191
South Carolina	121	150	25	108	96	42
Virginia	2,140	1,177	41	113	2,098	1,064
West Virginia	13	21	13	21	—	—
East South Central	3,568	4,563	2,676	3,644	892	719
Alabama	436	363	301	313	135	49
Kentucky	24	24	21	22	2	1
Mississippi	2,966	4,147	2,357	3,508	609	638
Tennessee	121	30	0	0	121	30
West South Central	146,156	135,811	140,062	129,622	6,094	8,190
Arkansas	1,928	2,684	1,928	2,584	—	0
Louisiana	23,751	24,554	23,085	23,958	665	599
Oklahoma	15,510	15,061	12,700	12,301	2,811	2,751
Texas	104,967	93,521	102,349	90,781	2,818	2,840
Mountain	7,327	6,156	6,817	7,001	1,510	1,154
Arizona	1,872	2,814	856	2,052	1,016	862
Colorado	364	353	324	306	40	48
Idaho	—	—	—	—	—	—
Montana	24	23	13	15	11	8
Nevada	1,966	2,210	1,710	2,122	276	68
New Mexico	2,528	2,088	2,486	2,044	33	25
Utah	543	578	410	464	133	124
Wyoming	8	8	8	8	—	—
Pacific Contiguous	48,809	59,548	45,048	55,049	3,559	3,484
California	48,499	59,610	45,048	55,049	1,451	1,561
Oregon	1,697	1,474	0	0	1,687	1,474
Washington	422	464	1	5	421	459
Pacific Noncontiguous	2,497	2,552	433	431	2,064	2,121
Alaska	2,497	2,552	433	431	2,064	2,121
Hawaii	—	—	—	—	—	—
U.S. Total	258,915	269,872	237,346	245,612	21,670	16,340

* = Value less than 0.5 million kilowatthours.

Notes: *Data are final. *Negative generation denotes that electric power consumed for plant use exceeds gross generation. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

U.S. Electric Utility Fossil-Fuel Statistics

This chapter contains statistics on consumption of fossil fuels by U.S. electric utilities to generate electricity, and end-of-year fossil-fuel stocks for all U.S. electric utility plants. Statistics are also included for receipts and costs of fossil fuels at power plants with a steam-electric and combined-cycle nameplate capacity of 50 or more megawatts, approximately 86 percent of the total capability at U.S. electric utilities. These data are aggregated to national, Census division, and State levels.

Background

Various sources of energy are used by electric utilities to produce electricity; however, fossil fuels supply about 70 percent of the energy sources for the generation requirements of the Nation. Coal, petroleum, and gas are currently the dominant fossil fuels used by the industry.²⁶ Statistics on consumption, purchases (receipts), and stocks of fossil fuels at electric utilities are interdependent. That is, the stocks on site at the utility at the end of the current year result from the stocks that were available at the end of the prior year, the amount of fuel purchased during the current year, and the amount of fuel consumed during the year.

Fossil-Fuel Consumption and Stocks

Coal, the energy source used by electric utilities to generate more than one-half of the electricity needed in the Nation, is consumed extensively throughout the United States (particularly in the East North Central, West North Central, West South Central, and the South Atlantic Census Divisions). The use of petroleum for generation is not as common on a national level as during the early 1970's; however, some areas of the country (such as in the New England, Middle Atlantic, and South Atlantic Census Divisions) continue to use it extensively. Consumption of gas occurs mostly in areas of the country where it is readily accessible, particularly in the West South Central Census Division, and in dual-fired generator units, which use gas and petroleum as substitute fuels.

The purposes of on-site storage are to provide an uninterrupted supply, to allow bulk shipments, and to

take advantage of favorable market conditions. Electric utilities maintain stockpiles of coal and petroleum to minimize the effect of an interruption or curtailment in fuel availability (for example, railroad strikes, coal-mine strikes, or oil embargoes). Since gas is generally not stored, there are no stocks of gas.

Fossil-Fuel Receipts and Costs

Statistics on electric utility receipts provide information regarding the delivery of fossil fuels to steam-electric plants. The costs include all costs incurred by an electric utility in the purchase and delivery of fuel to the plant. The type of contract under which a fuel is purchased has a significant effect on the cost of the fuel delivered and can be used as a good indicator of market conditions. Transactions where petroleum and coal are obtained by the utility under purchase orders or contracts with a duration of 1 year or more are referred to as *contract purchases*. Shipments of petroleum and coal under purchase orders or contracts of less than 1-year duration are considered *spot purchases*. Transactions to secure gas that are conducted under a contract with uninterrupted delivery are identified as *firm purchases*. *Interruptible purchases* are those in which the gas is received under a contract that permits curtailment of service under certain circumstances. For example, under both Federal and State regulations, requirements for gas to heat homes and serve industry have priority over requirements of the electric power industry. Consequently, a contract under which gas is purchased is most generally one that allows for an interruption in its accessibility.

Coal. Coal is obtained from three major coal-producing areas in the United States. *Appalachian coal* is mined in both surface and underground mines located in Pennsylvania, Maryland, Virginia, West Virginia, eastern Kentucky, Tennessee, Alabama, and Ohio. This coal is bituminous in rank and of low-to-medium sulfur content. Its heat content in British Thermal Units (Btu) averages over 12,000 Btu per pound. The coal is transported primarily by train, barge, and truck to electric utility plants throughout the eastern United States. *Interior coal* is mined in both surface and underground mines located primarily in Illinois, Indiana, western Kentucky, and Missouri. It is bituminous coal

²⁶Other fossil fuels include petroleum coke, refinery gas, coke oven gas, blast furnace gas, and liquefied petroleum gas.

with a high percentage of sulfur and contains approximately 11,000 Btu per pound. Most of this coal is delivered to plants in the central and Southeastern United States. *Western coal* is mined in Montana, Wyoming, Colorado, Utah, North Dakota, Arizona, and New Mexico. It is delivered to plants throughout the western and central United States. Over one-half of the coal in this region is subbituminous coal that is low in sulfur content (less than 0.5 percent) and contains approximately 9,000 Btu per pound. Most of this coal originates in the Powder River basin of northeast Wyoming and southeast Montana. Coal from this region is delivered by unit train to plants as far east as Indiana and Georgia.

The cost of coal delivered to electric utilities can vary significantly from State to State. Coal delivered to the New England Census Division from the Appalachian coal fields may cost as much as \$60 per short ton due to transportation costs and the higher cost of producing eastern coal (generally in underground mines). Environmental restrictions within a State may require electric utilities to burn only the more expensive, low-sulfur coal resulting in a higher delivered cost. In the West, especially in the Mountain Census Division, coal-burning plants are often built close to the mine thus reducing transportation costs. In addition, the cost of mining coal from large surface mines located in the western United States is significantly less than that of underground eastern mines, resulting in a delivered cost of under \$15 per short ton for States such as Montana and Wyoming. In States such as North Dakota, South Dakota, and Texas, the cost of coal delivered to electric utilities is well below the national average because of the lower cost of low-grade lignite.

Petroleum. Although nationwide receipts at electric utilities are less than one-half the volume of the 1970's, several electric utilities in the New England area, and in New York, Florida, and Hawaii still depend on petroleum for a significant portion of their fossil-fuel requirements. Receipts can vary widely from year to year at electric utilities due to changes in the cost of petroleum. Fuel oil numbers 4, 5, and 6 (heavy oil) constitute the majority of all petroleum receipts at electric utilities. Smaller amounts of fuel oil number 2 (light oil) are also used by electric utilities primarily for start-up and flame stabilization of the boilers.

The cost of petroleum delivered to electric utilities varies considerably from State to State. The most important factor in determining cost is the type of fuel oil that is being delivered. States receiving only low-grade heavy oil will show a delivered cost much lower than a State receiving only light oil. Most of the petroleum delivered to the New England, Middle Atlantic,

and South Atlantic Census Divisions, California, and Hawaii for use by electric utilities is the number 6 fuel oil. The cost of fuel oil can also vary because of its sulfur content. Electric utilities that are required to meet stringent environmental standards must purchase low-sulfur fuel oil at premium prices.

Gas. Gas is used extensively as a primary fuel throughout areas of the country where it is readily accessible (for example, the West South Central Census Division and in California). Large volumes of gas are also transported by pipeline to the Middle Atlantic, and South Atlantic Census Divisions. Gas receipts in these Census divisions and in California can vary considerably from year to year because some electric utilities switch between use of petroleum and gas in dual-fired generating units. The highest volume of gas receipts at electric utilities occurs during the summer months when demand for electricity peaks and when there is a greater amount available to electric utilities because of lower demands from residential and commercial consumers. In some northern parts of the United States, receipts of gas at electric utilities are limited during the winter months due to the priority for residential heating and industry needs. Many electric utilities have the capability of burning either petroleum or gas. The cost of the fuel is usually the determining factor. One major advantage of gas over all other fossil fuels is that it is a clean burning fuel. Therefore, some electric utilities use gas in order to comply with environmental regulations.

Petroleum Coke. Petroleum coke is the final product or residue produced from the process of breaking down complex petroleum hydrocarbons into lighter petroleum products, such as gasoline. This process is known as *cracking*.

Data Sources

Data in the following tables were obtained from two sources. The first is the Form EIA-759, "Monthly Power Plant Report," which is used to collect monthly data from all operators of power plants (approximately 715) in the United States. More detailed statistics on stocks and consumption are published in the *Electric Power Monthly*.²⁷ The second source is the Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," which is a restricted census used to collect data from approximately 230 electric utilities. More detailed statistics on receipts and costs of fossil fuels are published in the *Cost and Quality of Fuels for Electric Utility Plants*.²⁸

²⁷Energy Information Administration, *Electric Power Monthly*, DOE/EIA-0226(93/1-12)(Washington, DC).

²⁸Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1993* DOE/EIA-0191(93)(Washington, DC, August 1993).

Caution should be used in comparing stocks, receipts, and consumption data since all operators of power plants are surveyed by the Form EIA-759, while the

FERC Form 423 is limited to operators of power plants with a fossil-fueled steam-electric and combined-cycle nameplate capacity of 50 or more megawatts.

Table 16. Consumption of Fossil Fuels and Year-End Stocks of Coal and Petroleum at U.S. Electric Utilities, 1989 Through 1993

Item	1993	1992	1991	1990	1989
Consumption					
Coal (thousand short tons)	813,508	779,860	772,268	773,649	766,888
Petroleum (thousand barrels) ¹	162,454	147,335	184,886	186,054	287,451
Gas (million cubic feet)	2,662,440	2,786,606	2,789,014	2,787,332	2,787,012
Stocks					
Coal (thousand short tons)	111,341	154,130	157,876	158,166	135,860
Petroleum (thousand barrels) ¹	62,443	71,849	74,993	83,501	61,270

¹ Does not include petroleum coke.

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-758, "Monthly Power Plant Report."

Table 17. Receipts and Average Delivered Cost of Fossil Fuels at U.S. Electric Utilities, 1989 Through 1993

Item	1993	1992	1991	1990	1989
Receipts					
Coal (thousand short tons)	¹ 769,152	¹ 775,863	769,923	766,627	753,217
Petroleum (thousand barrels) ²	147,901	144,390	169,625	209,360	246,422
Gas (million cubic feet)	³ 2,674,523	³ 2,637,678	2,630,616	2,490,979	2,472,506
Cost (dollars)					
Coal (per short ton)	28.58	29.36	30.02	30.45	30.15
Contract	28.93	29.59	30.55	30.74	30.38
Spot	27.19	28.64	27.02	29.11	29.07
Petroleum (per barrel) ²	16.42	16.15	16.09	21.28	18.17
Contract	15.74	16.17	16.12	21.27	18.17
Spot	14.89	16.07	16.04	21.30	18.17
Gas (per thousand cubic feet)	2.62	2.38	2.20	2.38	2.42
Firm	2.59	2.37	2.19	2.27	2.34
Interruptible ⁴	2.68	2.40	2.22	2.48	2.60

¹ Data for 1991 through 1993 include approximately 3 million short tons of lignite delivered each year to Unit 4 of the Sandow Plant at the Texas Utilities Electric Company.

² Does not include petroleum coke.

³ Data for 1991 through 1993 include approximately 125 billion cubic feet of gas delivered each year to combined-cycle gas turbines.

⁴ Includes spot-market purchases.

Notes: *Data are final. *As of 1992, data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. *Data for 1989-1990 are for steam-electric plants with a generator nameplate capacity of 50 or more megawatts. *Totals may not equal sum of components because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 18. Consumption of Fossil Fuels at Electric Utilities by Census Division and State, 1993 and 1992

Census Division State	Coal (thousand short tons)		Petroleum ¹ (thousand barrels)		Gas (million cubic feet)	
	1993	1992	1993	1992	1993	1992
New England	5,736	5,112	29,119	34,552	30,141	42,349
Connecticut	745	517	7,032	9,786	557	2,100
Maine	—	—	1,392	2,237	—	—
Massachusetts	3,652	4,044	18,269	21,455	28,793	38,341
New Hampshire	1,339	1,251	2,338	2,315	136	833
Rhode Island	0	0	72	176	387	469
Vermont	—	—	17	6	268	601
Middle Atlantic	51,079	52,498	33,895	34,832	215,737	250,882
New Jersey	2,123	2,116	2,095	2,092	35,631	38,772
New York	8,899	9,863	23,968	29,201	171,803	208,731
Pennsylvania	40,257	40,407	7,803	3,538	8,304	3,100
East North Central	179,532	189,028	4,691	4,231	49,294	47,512
Illinois	31,744	25,264	2,122	2,271	16,022	9,293
Indiana	45,835	45,837	393	264	5,667	7,771
Michigan	28,749	28,238	1,388	1,125	18,896	24,908
Ohio	51,458	60,358	565	489	2,737	2,955
Wisconsin	19,049	18,231	123	82	3,070	2,584
West North Central	187,594	182,557	912	565	38,809	25,456
Iowa	16,823	15,357	122	90	4,303	2,265
Kansas	17,225	14,066	106	104	21,636	13,951
Minnesota	15,844	15,841	91	83	3,910	4,906
Missouri	21,945	23,815	390	209	4,891	2,351
Nebraska	9,297	7,881	42	25	1,876	1,903
North Dakota	23,280	23,192	69	58	1	1
South Dakota	2,350	2,402	32	19	185	48
South Atlantic	132,285	126,095	70,009	56,569	219,499	239,787
Delaware	2,223	1,626	3,397	2,708	8,665	5,284
District of Columbia	—	—	477	250	—	—
Florida	25,108	25,016	54,351	44,940	174,361	202,578
Georgia	25,339	23,656	508	268	3,026	1,182
Maryland	8,521	8,969	7,567	5,111	8,817	11,575
North Carolina	23,056	21,011	351	314	2,911	3,159
South Carolina	10,410	9,078	199	159	1,851	1,795
Virginia	9,447	8,881	3,402	2,310	15,735	10,836
West Virginia	27,782	26,050	357	307	133	201
East South Central	80,965	80,293	4,294	1,212	46,395	58,109
Alabama	27,593	24,988	130	141	4,639	3,369
Kentucky	35,264	31,715	214	196	269	269
Mississippi	3,787	3,227	5,536	651	39,900	54,180
Tennessee	23,801	20,263	413	225	1,531	291
West South Central	154,008	129,351	1,427	689	1,491,347	1,392,093
Arkansas	11,118	12,241	131	95	21,191	27,016
Louisiana	13,099	13,077	703	93	243,993	254,922
Oklahoma	17,686	16,699	27	26	153,665	148,960
Texas	92,135	87,333	508	473	1,072,508	965,165
Mountain	104,083	106,440	852	1,073	81,092	49,679
Arizona	18,315	17,290	110	135	20,480	30,959
Colorado	16,252	15,902	28	84	4,560	5,019
Idaho	—	—	—	1	—	—
Montana	6,689	10,788	48	35	270	220
Nevada	7,608	7,914	438	564	21,305	24,356
New Mexico	14,942	14,775	72	73	27,725	22,466
Utah	13,985	13,857	55	62	8,305	6,576
Wyoming	24,111	25,114	104	100	87	83
Pacific Contiguous	7,527	8,142	3,454	637	487,127	564,982
California	—	—	3,336	605	466,061	594,432
Oregon	1,891	1,894	58	19	16,167	14,284
Washington	5,646	6,148	62	13	4,899	5,385
Pacific Noncontiguous	296	277	11,501	12,748	28,025	28,963
Alaska	296	277	845	755	28,025	28,963
Hawaii	—	—	10,656	11,993	—	—
U.S. Total	815,598	773,899	162,454	147,395	2,862,449	2,795,996

¹ Does not include petroleum coke. Petroleum coke consumption in 1993 was 1,220 thousand short tons and in 1992 was 999 thousand short tons.

* — Value less than 0.5 thousand barrels or 0.5 million cubic feet.

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

**Table 19. Petroleum Consumption at Electric Utilities by Selected Prime Mover,
Census Division, and State, 1993 and 1992
(Thousand Barrels)**

Census Division State	Total		Steam		Gas Turbine/Internal Combustion	
	1993	1992	1993	1992	1993	1992
New England	29,119	34,983	29,690	34,550	429	432
Connecticut	7,032	8,788	7,003	8,758	29	31
Maine	1,382	2,237	1,365	2,233	7	4
Massachusetts	18,290	21,455	17,909	21,083	380	372
New Hampshire	2,338	2,315	2,335	2,314	2	2
Rhode Island	72	179	55	162	18	17
Vermont	17	8	3	2	14	7
Middle Atlantic	33,895	34,832	32,641	34,116	1,455	716
New Jersey	2,095	2,092	1,786	1,827	329	266
New York	22,098	29,201	22,582	28,908	465	293
Pennsylvania	7,603	3,539	7,343	3,381	260	157
East North Central	4,591	4,251	4,378	4,165	212	126
Illinois	2,122	2,271	2,089	2,249	53	22
Indiana	393	264	342	256	51	8
Michigan	1,386	1,125	1,327	1,087	61	38
Ohio	585	489	471	451	94	38
Wisconsin	123	82	70	63	53	19
West North Central	912	955	882	898	300	160
Iowa	122	90	59	61	63	29
Kansas	168	104	111	64	55	41
Minnesota	91	63	43	39	48	24
Missouri	390	208	224	187	156	41
Nebraska	42	25	28	19	14	12
North Dakota	69	58	66	56	3	1
South Dakota	32	19	11	8	21	12
South Atlantic	70,869	68,369	68,647	64,633	1,982	1,716
Delaware	3,397	2,708	3,362	2,684	35	24
District of Columbia	477	250	480	204	18	46
Florida	54,351	44,940	53,234	43,769	1,117	1,172
Georgia	506	288	286	182	220	86
Maryland	7,657	5,111	7,289	5,008	279	103
North Carolina	351	314	219	214	132	101
South Carolina	198	159	125	103	75	58
Virginia	3,402	2,310	3,316	2,182	86	128
West Virginia	357	307	356	307	-	-
East South Central	8,294	1,212	8,012	1,121	282	91
Alabama	130	141	116	124	14	17
Kentucky	214	195	208	193	6	2
Mississippi	5,538	651	5,536	650	1	-
Tennessee	412	225	162	163	261	71
West South Central	1,427	689	1,571	648	68	41
Arkansas	131	95	107	94	24	1
Louisiana	703	33	699	92	4	1
Oklahoma	27	28	23	25	3	2
Texas	566	473	541	437	26	36
Mountain	852	1,073	818	1,018	34	55
Arizona	110	135	100	121	10	14
Colorado	28	84	23	72	5	12
Idaho	-	1	-	-	-	1
Montana	48	35	47	34	1	1
Nevada	438	584	424	585	12	19
New Mexico	72	73	71	72	1	1
Utah	55	62	46	54	6	8
Wyoming	104	100	104	100	0	0
Pacific Contiguous	3,454	437	3,262	501	202	136
California	3,336	605	3,227	482	109	124
Oregon	56	19	10	9	46	9
Washington	62	13	16	10	47	3
Pacific Noncontiguous	11,601	12,748	8,644	18,048	2,857	2,701
Alaska	545	755	2	4	543	751
Hawaii	10,556	11,889	8,642	10,039	2,014	1,950
U.S. Total	162,464	147,336	154,996	141,168	7,549	6,172

* = Value less than 0.5.

Notes: +Data are final. +Totals may not equal sum of components because of independent rounding. =Does not include petroleum coks. Petroleum coke consumption in 1993 was 1,220 thousand short tons and in 1992 was 999 thousand short tons.

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

**Table 20. Gas Consumption at Electric Utilities by Selected Prime Mover,
Census Division, and State, 1993 and 1992
(Million Cubic Feet)**

Census Division State	Total		Steam		Gas Turbine/Internal Combustion	
	1993	1992	1993	1992	1993	1992
New England	30,141	42,343	27,551	36,657	2,590	3,686
Connecticut	557	2,100	557	2,100	—	—
Maine	—	—	—	—	—	—
Massachusetts	25,793	36,341	25,202	34,655	2,590	3,686
New Hampshire	136	633	136	633	0	0
Rhode Island	387	469	387	469	—	—
Vermont	268	601	268	601	—	—
Middle Atlantic	216,737	250,802	196,931	235,829	19,806	11,963
New Jersey	35,631	38,772	25,153	30,221	10,478	8,551
New York	171,803	206,731	166,947	205,618	4,855	3,113
Pennsylvania	8,304	3,100	7,831	2,801	473	299
East North Central	46,354	47,513	42,266	43,700	4,088	3,813
Illinois	16,022	9,293	15,690	9,002	332	291
Indiana	5,867	7,771	4,703	7,470	964	302
Michigan	18,898	24,908	17,934	22,470	964	2,438
Ohio	2,737	2,856	1,363	2,450	1,374	506
Wisconsin	3,070	2,594	2,809	2,308	461	276
West North Central	36,803	25,468	29,583	21,160	7,221	4,296
Iowa	4,303	2,265	2,996	1,735	1,307	531
Kansas	21,838	13,991	18,197	11,892	3,638	2,258
Minnesota	3,910	4,906	3,656	4,557	255	349
Missouri	4,891	2,351	3,365	1,602	1,527	750
Nebraska	1,576	1,903	1,281	1,530	696	372
North Dakota	1	1	—	1	1	—
South Dakota	186	48	59	43	127	5
South Atlantic	219,499	239,787	194,737	206,841	54,762	33,146
Delaware	8,665	8,364	1,206	5,818	7,457	2,546
District of Columbia	—	—	—	—	—	—
Florida	174,361	202,576	165,347	188,689	19,013	13,907
Georgia	3,028	1,162	2,623	1,066	403	97
Maryland	8,617	11,575	4,762	8,725	4,056	2,850
North Carolina	2,911	3,159	0	0	2,911	3,159
South Carolina	1,851	1,795	261	1,065	1,590	730
Virginia	19,735	10,806	403	1,088	19,332	9,838
West Virginia	133	201	133	201	—	—
East South Central	46,335	63,109	28,792	42,485	17,543	15,623
Alabama	4,636	3,368	3,219	3,030	1,417	358
Kentucky	269	269	221	240	48	29
Mississippi	39,900	54,180	25,352	39,215	14,547	14,966
Tennessee	1,531	291	0	0	1,531	291
West South Central	1,491,347	1,389,093	1,419,710	1,328,391	71,637	70,692
Arkansas	21,131	27,015	21,130	27,015	1	0
Louisiana	243,993	254,922	236,258	247,797	7,724	7,125
Oklahoma	163,666	143,980	123,397	119,069	30,269	29,892
Texas	1,072,506	968,165	1,039,894	934,490	33,643	33,675
Mountain	91,032	89,679	64,196	75,941	16,835	13,738
Arizona	20,480	30,939	9,833	21,545	10,647	9,394
Colorado	4,660	5,019	4,264	4,318	597	701
Idaho	—	—	—	—	—	—
Montana	270	220	114	116	156	104
Nevada	21,305	24,355	16,135	22,822	3,171	1,534
New Mexico	27,725	22,485	27,285	22,172	440	315
Utah	6,365	6,576	4,479	4,886	1,885	1,690
Wyoming	87	83	87	83	—	—
Pacific Contiguous	487,127	584,092	453,212	547,659	33,914	36,434
California	466,061	584,432	453,182	547,514	12,869	16,819
Oregon	16,167	14,264	0	0	16,167	14,264
Washington	4,899	5,395	20	44	4,879	5,340
Pacific Noncontiguous	28,025	28,953	0	0	28,025	28,953
Alaska	28,025	28,953	0	0	28,025	28,953
Hawaii	—	—	—	—	—	—
U.S. Total	2,862,440	2,766,606	2,429,981	2,543,273	252,469	222,336

* = Value less than 0.5

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-769, "Monthly Power Plant Report."

**Table 21. Coal and Petroleum Stocks at Electric Utilities by Census Division and State,
as of December 31, 1993 and 1992**

Census Division State	Coal (thousand short tons)		Petroleum ¹ (thousand barrels)	
	1993	1992	1993	1992
New England	967	1,237	4,565	6,073
Connecticut	160	150	1,435	2,152
Maine	—	—	685	681
Massachusetts	449	727	2,090	2,563
New Hampshire	358	361	323	528
Rhode Island	0	0	4	104
Vermont	—	—	29	36
Middle Atlantic	12,564	17,743	10,060	15,536
New Jersey	501	771	1,268	1,622
New York	953	2,106	7,532	11,665
Pennsylvania	11,110	14,866	1,260	1,859
East North Central	27,298	40,250	2,486	2,798
Illinois	4,019	7,399	995	1,226
Indiana	6,835	11,204	177	190
Michigan	6,206	7,402	657	727
Ohio	7,249	10,395	477	487
Wisconsin	2,987	3,760	191	197
West North Central	14,123	19,712	1,666	1,694
Iowa	3,401	4,301	206	187
Kansas	2,008	2,747	602	655
Minnesota	1,182	2,175	154	167
Missouri	3,555	6,271	386	374
Nebraska	1,272	1,796	206	205
North Dakota	2,417	2,194	48	46
South Dakota	287	286	64	60
South Atlantic	17,877	27,877	14,892	24,357
Delaware	192	361	510	302
District of Columbia	—	—	67	118
Florida	3,451	4,021	8,928	6,221
Georgia	2,825	4,892	528	528
Maryland	1,455	2,400	1,261	1,610
North Carolina	2,667	4,612	208	231
South Carolina	1,648	2,206	298	343
Virginia	1,418	1,922	2,676	2,833
West Virginia	4,001	7,863	219	175
East South Central	8,370	13,401	2,042	1,651
Alabama	2,331	4,071	210	169
Kentucky	3,990	5,415	128	119
Mississippi	417	899	1,030	904
Tennessee	1,832	3,016	676	461
West South Central	13,367	16,483	8,220	8,297
Arkansas	1,865	1,572	276	269
Louisiana	1,932	1,701	1,774	1,743
Oklahoma	1,944	3,086	612	617
Texas	8,125	10,149	5,557	5,688
Mountain	15,529	16,009	1,469	1,383
Arizona	3,887	3,543	647	748
Colorado	3,428	3,410	181	185
Idaho	—	—	—	14
Montana	721	795	15	14
Nevada	1,195	1,447	433	253
New Mexico	1,508	1,570	99	103
Utah	3,264	3,183	41	28
Wyoming	1,726	2,153	43	42
Pacific Contiguous	743	1,312	15,758	18,841
California	—	—	15,174	18,211
Oregon	312	615	237	269
Washington	431	687	347	360
Pacific Noncontiguous	5	6	1,264	1,219
Alaska	5	6	231	306
Hawaii	—	—	1,033	914
U.S. Total	111,341	154,190	62,443	71,849

¹ Does not include petroleum coke. Petroleum coke stocks at the end of 1993 were 89 thousand short tons and in 1992 were 67 thousand short tons.

— Value less than 0.5.

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Table 22. Fossil-Fuel Receipts at Electric Utilities by Census Division and State, 1993 and 1992

Census Division State	Coal (thousand short tons)		Petroleum ¹ (thousand barrels)		Gas (million cubic feet)	
	1993	1992	1993	1992	1993	1992
New England	5,417	6,213	27,617	35,861	29,440	42,007
Connecticut	740	793	6,263	9,106	554	2,000
Maine	—	—	1,317	2,188	—	—
Massachusetts	3,570	4,194	17,828	21,871	28,283	37,913
New Hampshire	1,308	1,226	1,964	2,605	136	916
Rhode Island	—	—	243	80	400	458
Vermont	—	—	2	—	267	800
Middle Atlantic	44,511	53,860	31,399	38,740	201,570	229,709
New Jersey	1,845	2,205	2,711	2,438	26,561	32,305
New York	7,448	10,393	21,798	32,080	167,703	195,476
Pennsylvania	37,219	41,062	8,861	3,522	7,005	1,929
East North Central	165,685	188,346	3,983	5,920	43,858	43,401
Illinois	28,091	25,449	1,607	2,299	17,084	8,952
Indiana	43,789	47,838	389	270	4,784	7,487
Michigan	27,666	27,876	1,162	929	17,754	22,222
Ohio	47,662	50,586	490	369	1,425	2,458
Wisconsin	17,850	17,569	70	54	2,540	2,300
West North Central	101,895	101,643	688	486	27,489	16,203
Iowa	15,767	15,037	67	80	3,131	1,816
Kansas	16,465	13,634	67	51	16,426	10,437
Minnesota	15,969	15,154	33	36	2,393	3,006
Missouri	19,217	24,502	289	289	4,241	1,592
Nebraska	8,888	7,758	31	8	1,226	1,310
North Dakota	23,603	23,427	66	53	—	—
South Dakota	2,152	2,130	6	—	52	39
South Atlantic	121,802	125,181	67,855	64,488	201,428	217,978
Delaware	2,008	1,532	3,321	2,214	7,239	2,188
District of Columbia	—	—	371	231	—	—
Florida	24,115	24,377	53,854	43,311	184,475	191,121
Georgia	29,327	22,861	326	217	2,984	1,189
Maryland	8,509	9,264	6,181	5,076	4,801	8,564
North Carolina	21,194	20,660	211	183	2,373	2,917
South Carolina	9,781	9,265	81	84	486	1,316
Virginia	6,937	8,915	3,098	2,601	16,947	10,433
West Virginia	24,031	28,307	402	381	118	219
East South Central	88,677	80,758	8,043	1,108	29,020	41,671
Alabama	25,697	24,586	116	131	2,686	2,823
Kentucky	34,979	32,292	309	221	220	240
Mississippi	3,310	3,208	5,557	607	26,104	38,508
Tennessee	22,481	20,372	151	148	—	—
West South Central	138,971	128,757	1,357	627	1,457,748	1,585,720
Arkansas	10,754	11,630	96	97	19,788	27,137
Louisiana	13,073	12,675	808	93	234,579	287,693
Oklahoma	16,433	16,840	7	115	148,893	145,415
Texas	90,710	87,613	452	324	1,064,210	955,515
Mountain	103,137	102,617	882	799	73,138	80,491
Arizona	18,383	16,315	38	140	19,306	29,420
Colorado	16,070	15,697	4	27	2,045	1,521
Idaho	—	—	—	—	—	—
Montana	8,849	10,860	24	18	110	118
Nevada	7,376	7,894	909	380	20,516	22,804
New Mexico	14,856	14,829	70	74	26,595	21,061
Utah	13,980	12,840	51	29	4,478	4,684
Wyoming	29,580	24,181	108	114	87	83
Pacific Contiguous	6,946	7,788	966	38	483,781	580,334
California	—	—	322	1	487,486	586,819
Oregon	1,621	1,932	11	19	16,255	14,684
Washington	5,324	5,836	23	15	20	30
Pacific Noncontiguous	—	—	7,278	8,324	17,189	18,886
Alaska	—	—	—	—	17,180	18,086
Hawaii	—	—	7,278	8,324	—	—
U. S. Total	768,152	776,983	147,901	144,398	2,574,523	2,837,678

¹ Does not include petroleum coke. Petroleum coke receipts in 1993 were 1,245 thousand short tons and in 1992 were 687 thousand short tons.

—Value less than 0.5.

Notes: *Data are final. *Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. *Totals may not equal sum of components because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 23. Average Delivered Cost of Fossil-Fuel Receipts at Electric Utilities by Census Division and State, 1993 and 1992

Census Division State	Coal			Petroleum ¹			Gas		
	1993		1992	1993		1992	1993		1992
	(\$ per short ton)	(cents per 10 ⁶ Btu)	(cents per 10 ⁶ Btu)	(\$ per barrel)	(cents per 10 ⁶ Btu)	(cents per 10 ⁶ Btu)	(\$ per Mcf)	(cents per 10 ⁶ Btu)	(cents per 10 ⁶ Btu)
New England	45.34	166.3	172.0	16.67	248.3	233.2	2.73	264.6	258.9
Connecticut	44.80	170.4	194.6	15.26	239.6	241.0	3.90	377.8	265.9
Maine	—	—	—	13.49	213.7	228.8	—	—	—
Massachusetts	43.39	167.5	168.7	18.93	251.7	236.3	2.72	263.0	259.3
New Hampshire	42.39	160.8	168.3	11.69	183.7	185.8	2.21	217.2	205.9
Rhode Island	—	—	—	20.19	312.7	195.0	2.51	238.9	213.4
Vermont	—	—	—	27.34	465.1	—	2.01	201.6	202.4
Middle Atlantic	36.86	146.0	149.8	16.31	257.7	287.3	2.88	358.9	337.4
New Jersey	47.50	177.3	173.1	16.81	266.0	309.3	2.36	229.9	210.9
New York	38.63	149.6	148.6	16.30	257.0	263.8	2.73	264.8	241.2
Pennsylvania	35.73	143.6	149.4	18.15	266.8	275.2	2.65	267.6	297.2
East North Central	30.98	142.3	145.6	19.99	326.4	326.9	1.90	251.4	221.2
Illinois	35.30	170.4	173.7	18.67	296.0	305.1	2.48	244.4	220.1
Indiana	26.73	126.6	131.2	24.24	420.7	443.3	2.77	273.7	247.7
Michigan	33.17	152.8	153.6	16.91	305.8	296.8	.92	241.7	195.4
Ohio	34.05	141.3	143.5	23.34	407.4	451.4	2.94	285.6	229.6
Wisconsin	22.96	121.0	133.3	23.94	406.7	463.7	2.86	263.0	240.0
West North Central	16.88	100.9	110.0	21.33	359.2	318.5	2.41	244.0	209.8
Iowa	17.53	101.2	110.4	23.69	405.0	424.0	3.12	310.1	306.8
Kansas	17.89	102.2	117.9	23.43	402.4	437.6	2.26	232.0	199.9
Minnesota	20.07	113.4	118.6	25.63	442.0	450.9	2.47	245.0	183.7
Missouri	24.40	123.9	133.6	18.16	296.8	234.9	2.34	231.8	187.2
Nebraska	12.82	75.5	74.6	24.26	420.1	464.9	2.66	272.7	239.2
North Dakota	9.86	71.4	72.1	25.60	441.6	457.7	4.59	424.9	403.3
South Dakota	13.30	109.8	113.3	27.47	467.2	—	2.41	237.8	262.7
South Atlantic	40.80	163.7	165.8	14.34	224.3	244.5	2.47	243.7	290.5
Delaware	44.02	169.0	173.4	14.61	230.0	241.9	2.69	260.9	280.0
District of Columbia	—	—	—	18.32	303.8	360.4	—	—	—
Florida	43.68	176.7	182.0	14.02	220.1	241.7	2.36	234.1	227.7
Georgia	43.29	176.2	180.1	20.74	346.8	434.4	3.31	323.6	282.2
Maryland	40.78	159.9	159.5	14.48	228.9	230.3	3.01	289.8	255.0
North Carolina	42.36	169.9	172.6	23.68	406.0	441.1	3.63	351.6	286.0
South Carolina	40.17	156.9	152.7	24.69	425.5	481.7	2.97	291.1	169.0
Virginia	37.57	146.6	147.3	13.42	212.6	247.1	2.89	278.0	237.2
West Virginia	35.42	141.6	147.2	27.01	461.9	483.8	4.36	435.5	392.5
East South Central	33.30	138.9	138.5	12.44	194.6	317.5	2.49	243.8	183.2
Alabama	42.56	178.0	172.7	24.60	426.4	459.6	2.65	260.4	222.9
Kentucky	27.29	116.7	116.2	26.68	437.8	479.4	3.07	301.1	271.5
Mississippi	40.51	164.2	159.7	11.35	176.2	200.0	2.47	241.6	179.7
Tennessee	30.94	126.1	127.3	25.08	431.3	480.2	—	—	—
West South Central	22.14	144.8	147.4	16.42	246.8	416.4	2.55	247.3	221.8
Arkansas	29.50	170.2	185.3	26.91	457.9	480.8	2.27	220.5	153.2
Louisiana	26.66	158.6	153.5	14.23	222.7	387.9	2.49	239.5	182.8
Oklahoma	21.32	123.6	123.4	20.39	349.6	435.6	3.29	310.7	308.2
Texas	20.81	143.5	149.1	15.17	245.3	399.0	2.47	240.7	219.6
Mountain	22.11	113.4	111.3	24.43	399.8	405.7	2.46	241.6	201.8
Arizona	27.78	136.2	137.4	30.18	511.4	466.6	2.86	280.7	221.3
Colorado	21.59	109.2	109.2	27.63	480.6	479.3	2.53	250.1	214.0
Idaho	—	—	—	—	—	—	—	—	—
Montana	11.76	69.3	70.8	31.12	525.6	509.1	3.12	268.1	341.9
Nevada	32.34	145.6	145.2	22.35	358.3	331.3	2.45	237.7	186.7
New Mexico	24.61	136.5	132.2	26.89	505.6	516.5	2.23	219.3	195.4
Utah	27.34	119.0	120.9	31.81	539.1	464.1	2.31	217.6	174.5
Wyoming	14.03	79.9	75.9	27.63	473.0	479.3	3.44	329.7	320.1
Pacific Contiguous	21.55	139.1	129.6	14.68	241.8	448.7	3.03	294.0	259.9
California	—	—	—	14.46	234.7	217.9	3.05	296.3	271.8
Oregon	19.75	112.2	110.1	22.51	362.6	449.2	2.28	225.2	193.7
Washington	22.09	138.0	137.3	27.66	468.9	466.0	3.95	376.0	315.5
Pacific Noncontiguous	—	—	—	19.23	308.6	282.1	1.25	125.4	117.6
Alaska	—	—	—	—	—	—	1.25	125.4	117.6
Hawaii	—	—	—	19.33	306.5	282.1	—	—	—
U. S. Total	25.55	136.5	141.2	16.42	242.3	255.1	2.62	260.0	232.8

¹ Does not include petroleum coke. Petroleum coke cost in 1993 was 70.3 cents per million Btu and in 1992 was 75.0 cents per million Btu.

Mcf = thousand cubic feet.

Notes: *Data are final. *Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. *Totals may not equal sum of components because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

 

U.S. Electric Utility Retail Sales and Revenue

This chapter provides summary statistics on the sale of electricity to ultimate consumers by U.S. electric utilities, its associated revenue, and the average revenue per kilowatthour sold at the national, Census, and State levels.

Background

Because electricity itself cannot be stored, it must be generated, transmitted to the consumer, and consumed instantaneously. Electric utility companies were formed to provide these services. An electric system consists of energy conversion plants (stations) that convert different forms of energy to electric power; transformers to raise the voltage in order to reduce losses in transmitting the power; transmission lines to transmit the power to the general vicinity of consumption; transformers to lower the voltage; and distribution lines to distribute the power to the ultimate consumers. The entire system of generating stations, transformers, transmission lines, distribution lines, etc., is a power system. Power companies plan, design, build, and operate this power system. Some companies may only operate part of a power system. For example, many small power companies only distribute power to ultimate consumers, buying their power from other companies that generate power. Power systems are interconnected for mutual operating and economic advantages.

U.S. electric utilities are high-investment businesses and historically have been treated as monopolies because duplicate facilities, particularly transmission and distribution lines, would be inefficient. Thus, franchises are granted to electric utilities for given geographical areas by regulatory officials. To obtain a franchise, electric utilities must provide service to all consumers in their territories at a reasonable cost.

The service territory of an electric utility is usually composed of many different combinations of consumers. Electric utilities classify their consumers by different factors such as demand, rate schedule, Standard Industrial Classification (SIC) code, distribution voltage, accounting methods, end-use applications, and

other social and economic characteristics. Electric utilities use consumer classifications for planning purposes (load growth, peak demands) and for deriving their rate schedules, often with the approval of a government regulatory agency.

End-Use Sectors

Consumers within the service territory of an electric utility are generally grouped into end-use sectors -- residential, commercial, and industrial. The categorization of consumer is determined by the electric utility based on its service territory, size, location, ownership, and regulatory structure.

The residential sector includes private households and apartment buildings, where energy is consumed primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking, and clothes drying.

The commercial sector includes nonmanufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, and retail stores; and, health, social, and educational institutions. However, electric utilities may classify commercial service as that to all consumers, including light manufacturers, whose demand or annual usage fall within a specified range. The range may be set by the electric utility based on its rate schedule.

The industrial sector includes manufacturing, construction, mining, agriculture, fishing, and forestry establishments -- Standard Industrial Classification (SIC) codes 1-39. However, electric utilities may classify industrial service based on demand or annual usage exceeding a specified range. As in the commercial sector, the range may be set by the electric utility based on its rate schedule.

Other sales include public street and highway lighting, railroads and railways, municipalities, divisions or agencies of State and Federal governments under special contracts or agreements, and other utility departments as defined by the pertinent regulatory agency and/or electric utility.

Revenue Requirements

The revenue requirements of an electric utility are set to reimburse the utility for providing electric service. The revenue requirement is the anticipated cost of providing services for some period of time in the future, usually a year. Revenue requirements are based on operating expenses, depreciation expense, taxes, and return on the ratebase (profit of the electric utility). The process of determining electricity prices generally follows three stages (1) identification of revenue requirements, (2) allocation of the requirements for different classes of service (sectors), and (3) establishment of rate schedules for each sector.

The rate schedules developed to generate revenue requirements for electric utilities are unique to each utility. The authority for the approval of these rates is based on the ownership class applicable to the utility. For example, investor-owned electric utilities are regulated by State public service commissions and the Federal Energy Regulatory Commission. Public electric utilities, in most States, are controlled through locally elected or appointed officials. A more detailed discussion on utility classes of ownership is contained in the "Industry Profile" section in the first chapter of this publication.

A rate schedule is a statement that the utility will provide service to a particular class of consumer at a certain price. Prices between sectors vary based on various objectives of the utility. These objectives include the need to allocate the various costs incurred in providing service, to maintain the existing consumer base of the utility, and to promote new business.

Average Revenue per Kilowatthour

The average revenue per kilowatthour of electricity sold by electric utilities is calculated by dividing total annual revenue by total annual retail sales for each sector and State. The resulting measurement is the cost (per kilowatthour of electricity sold) for providing service to a sector, given the rate schedule of the electric utility for that particular sector. The average revenue per kilowatthour is calculated for all consumers and for each sector (residential, commercial, industrial, and other sales). Utilities typically employ a number of rate schedules within a single sector. These alternative rate schedules reflect the varying consumption levels and patterns of these customers and their associated impact on the cost to the electric utility for providing electrical service. The average revenue per kilowatthour by sector reported in this publication represents a weighted average of customer revenue and sales within that sector and across sectors for all consumers.

The electric revenue used to derive the average revenue per kilowatthour is the operating revenue reported by the electric utility. Operating revenue includes energy charges, demand charges, consumer service

charges, environmental surcharges, fuel adjustments, and other miscellaneous charges.

Utility operating revenues cover—among other costs of service—State and federal income taxes and taxes other than income taxes paid by the utility. The federal component of these taxes are, for the most part, "payroll" taxes. State and local authorities will tax the value of plant (property taxes), the amount of revenues (gross receipts taxes), purchases of materials and services (sales and use taxes), and a potentially long list of other taxes that vary extensively by taxing authority. Taxes deducted from an employee's pay such as federal income taxes and the employee's share of social security taxes are not a part of the utility's "tax costs," but are paid to the taxing authorities in the name of the employees. These taxes are included in the utility's cost of service (for example, revenue requirements) and are included in the amounts recovered from the customer in rates and reported in operating revenues.

Electric utilities, like many other business enterprises, are required by various taxing authorities to collect and remit taxes assessed on its customers. In this regard, the utility serves as an agent for the taxing authority. Taxes assessed on the consumer, such as a gross receipts tax or sales tax, are referred to as "pass through" taxes. These taxes do not represent a cost of the utility and are not recorded in the operating revenues of the utility. However, taxing authorities differ in whether a specific tax is assessed on the utility or the consumer which in turn determines whether or not the tax is included in the electric utility's operating revenue.

Average revenue per kilowatthour from residential consumers is generally higher than for any other sector. This is due, in part, to the higher costs associated with serving many consumers who use relatively small amounts of electricity. These costs include direct-load costs (such as those for distribution lines, transformers, and meters) in addition to consumer or administrative costs. The industrial sector, which generally covers consumers with the highest use of electricity, has the lowest average revenue per kilowatthour. This is because of the economies of serving a few consumers who use relatively large amounts of electricity.

Federal electric utilities generally have the lowest average revenue per kilowatthour for the ownership classes because they have access to relatively low-cost financing and mostly utilize less expensive hydroelectric facilities. Because publicly owned electric utilities also have access to relatively low-cost financing and are nonprofit entities, they have lower average revenue per kilowatthour than investor-owned electric utilities. Although cooperative electric utilities have economic advantages similar to those of the publicly owned electric utilities, they generally serve sparsely populated areas. As a consequence, cooperative electric utilities generally have higher average revenue per kilowatthour than do investor-owned utilities.

Because of the type and availability of capacity and the cost of fuel, the average revenue per kilowatt-hour differs across U.S. Census divisions. The New England and Middle Atlantic Census Divisions tend to have an average revenue per kilowatt-hour that is higher than average because of their reliance on petroleum; whereas, the East and West South Central Census Divisions rely on gas-fired generation and the East North Central and South Atlantic Census Divisions rely on coal-fired generation. Petroleum is generally a more expensive energy source than coal and natural gas. Because the Mountain Census Division relies on less expensive hydroelectric generation, the average revenue per kilowatt-hour in this region is usually below the national average for all classes of consumers. The Census divisions where Federal hydroelectric facilities provide significant amounts of electricity, such as the East

South Central Census Division, also have lower than average revenue per kilowatt-hour.

Data Sources

Summary statistics on retail sales of electricity by electric utilities and average revenue are provided in the following tables. These data were obtained from the Form EIA-861, "Annual Electric Utility Report." The form is used to collect annual data from all electric utilities (approximately 3,250), that own and/or operate facilities within the United States, its territories, and Puerto Rico, for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. More detailed statistics on sales, average revenue, and average revenue per kilowatt-hour are published in the *Electric Sales and Revenue*.²⁹

Table 24. U.S. Electric Utility Sales to Ultimate Consumers and Associated Revenue by Sector, 1989 Through 1993

Item	1993	1992	1991	1990	1989
Sales (million kilowatt-hours)					
Residential	984,775	935,939	955,417	924,019	905,525
Commercial	794,572	761,271	765,864	751,027	725,981
Industrial	977,151	972,714	948,563	945,522	925,659
Other ¹	84,944	93,442	84,339	91,969	89,765
U.S. Total	2,861,441	2,763,366	2,752,003	2,712,537	2,646,930
Revenue (million dollars)					
Residential	82,814	76,848	76,628	72,378	69,240
Commercial	61,522	58,343	57,655	55,117	52,228
Industrial	47,356	48,993	45,737	44,857	43,719
Other ¹	6,326	6,296	6,138	6,591	5,609
U.S. Total	198,018	190,480	185,358	178,943	170,797

¹ Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

Notes: *Data for 1993 are preliminary; data for prior years are final. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 25. Average Revenue per Kilowatt-hour for U.S. Electric Utilities by Sector, 1989 Through 1993 (Cents)

Sector	1993	1992	1991	1990	1989
Residential	8.32	8.21	8.04	7.83	7.65
Commercial	7.74	7.66	7.53	7.34	7.20
Industrial	4.85	4.83	4.83	4.74	4.72
Other ¹	6.88	6.74	6.51	6.40	6.25
All Sectors	6.49	6.32	6.25	6.17	6.15

¹ Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

Notes: *Data for 1993 are preliminary; data for prior years are final. *The average revenue per kilowatt-hour of electricity sold is calculated by dividing revenue by sales. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

²⁹Energy Information Administration, *Electric Sales and Revenue 1992*, DOE/EIA-0540(92)(Washington, DC, April 1994).

Table 26. Electric Utility Sales to Ultimate Consumers by Sector, Census Division, and State, 1993 and 1992
(Million Kilowatthours)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other ¹	
	1993	1992	1993	1992	1993	1992	1993	1992	1993	1992
New England	104,797	103,896	38,057	37,694	38,997	37,929	28,191	26,328	1,892	2,836
Connecticut	27,236	27,127	10,597	10,495	10,677	10,485	5,597	5,780	368	367
Maine	11,952	11,453	3,872	3,830	2,868	2,790	5,040	4,753	172	171
Massachusetts	45,281	44,998	15,795	15,560	18,897	18,629	9,605	9,693	994	1,146
New Hampshire	8,761	8,854	3,428	3,428	2,123	2,077	3,100	3,333	118	116
Rhode Island	8,546	8,393	2,412	2,393	2,532	2,491	1,419	1,359	189	180
Vermont	5,016	4,941	1,971	1,927	1,570	1,527	1,431	1,440	44	47
Middle Atlantic	315,799	307,880	103,394	99,512	106,471	104,774	89,782	90,864	14,172	14,010
New Jersey	65,616	63,122	22,041	20,547	26,491	27,403	14,596	14,987	490	465
New York	130,170	128,470	39,897	39,720	47,728	46,591	30,187	31,027	12,357	12,132
Pennsylvania	119,981	118,288	41,455	39,245	32,252	30,779	44,949	44,869	1,325	1,394
East North Central	489,033	498,279	140,288	136,830	127,909	113,809	200,478	204,849	14,948	14,791
Illinois	117,788	112,521	35,226	32,367	34,355	31,457	40,249	40,898	7,956	7,798
Indiana	81,931	78,977	24,978	22,837	17,015	16,083	39,415	37,439	523	819
Michigan	87,589	83,840	26,770	25,671	26,930	21,208	30,572	35,957	1,316	1,304
Ohio	148,570	145,016	41,950	39,141	33,298	31,818	68,591	69,874	4,491	4,383
Wisconsin	53,156	50,925	17,373	16,815	13,710	13,243	21,410	20,382	682	686
West North Central	261,631	199,687	74,413	67,729	54,394	62,038	67,884	65,947	5,140	4,798
Iowa	32,104	30,208	11,103	10,290	7,299	7,019	12,465	12,134	1,267	765
Kansas	28,808	27,069	9,866	8,873	9,753	9,400	8,702	8,450	367	346
Minnesota	49,211	47,412	15,597	14,848	8,535	8,291	24,364	23,557	694	716
Missouri	56,622	54,411	24,182	21,294	19,814	18,792	13,818	13,440	908	886
Nebraska	18,748	17,784	7,226	6,581	5,471	5,266	4,983	4,752	1,089	1,204
North Dakota	7,432	7,128	3,209	3,020	1,831	1,752	1,905	1,836	487	521
South Dakota	6,905	6,494	3,109	2,843	1,621	1,518	1,847	1,777	327	356
South Atlantic	582,428	552,841	238,504	219,372	167,518	159,131	159,901	156,608	15,505	17,730
Delaware	9,121	8,932	3,044	2,786	2,605	2,445	3,417	3,248	56	53
District of Columbia	10,375	10,043	1,635	1,488	5,418	5,227	2,976	2,967	346	341
Florida	152,748	147,010	78,827	73,189	54,876	52,620	19,298	19,497	4,747	4,704
Georgia	89,191	83,391	33,667	30,528	25,168	23,715	29,064	29,187	1,071	952
Maryland	53,870	50,969	21,547	19,762	11,320	10,770	20,194	19,768	809	689
North Carolina	99,778	94,195	37,742	34,781	26,747	25,142	33,468	32,522	1,800	1,770
South Carolina	61,533	58,401	20,897	19,940	13,177	12,975	26,867	26,305	602	781
Virginia	81,372	76,448	32,472	29,780	22,727	21,810	17,390	16,714	8,783	8,345
West Virginia	24,442	23,831	8,882	8,138	5,480	5,228	10,187	10,370	92	95
East South Central	247,774	241,080	85,245	80,844	32,941	33,884	124,598	121,745	4,992	4,776
Alabama	65,044	62,167	22,622	21,137	11,253	10,917	30,517	29,476	652	637
Kentucky	66,166	67,068	19,226	17,787	9,833	9,576	36,328	37,084	2,778	2,622
Mississippi	34,749	33,241	13,200	12,422	6,895	6,732	14,229	13,491	635	596
Tennessee	79,816	78,584	30,196	29,498	5,171	6,470	43,521	41,895	927	922
West South Central	390,033	371,248	137,779	127,816	98,251	92,060	139,880	135,738	16,324	15,646
Arkansas	31,863	28,451	11,752	10,440	6,698	6,177	12,809	11,251	594	583
Louisiana	67,758	65,098	22,430	21,188	14,398	13,639	28,439	27,466	2,488	2,906
Oklahoma	40,531	38,267	15,901	14,254	10,824	10,338	11,899	11,589	2,107	2,076
Texas	250,083	239,431	87,695	81,934	64,331	61,686	86,832	85,421	11,134	10,361
Mountain	171,193	187,973	54,001	61,695	53,891	52,875	58,853	58,856	6,736	6,848
Arizona	44,408	43,651	16,705	16,230	14,813	14,468	10,989	11,055	1,901	1,898
Colorado	32,958	31,822	10,656	10,216	14,422	13,898	7,024	6,949	856	860
Idaho	18,720	19,006	6,245	5,739	4,969	5,340	7,222	7,551	284	379
Montana	12,929	13,096	3,598	3,288	3,026	2,959	5,837	6,414	499	536
Nevada	18,499	17,896	6,281	6,064	4,298	4,175	7,181	6,728	740	734
New Mexico	14,927	14,431	3,894	3,791	4,759	4,630	4,816	4,809	1,487	1,401
Utah	18,887	18,567	4,728	4,505	5,020	4,958	6,221	6,212	900	894
Wyoming	11,865	11,700	1,908	1,763	2,493	2,350	7,363	7,442	122	148
Pacific	345,550	346,677	114,987	111,789	110,794	110,789	107,764	110,544	12,005	12,593
California	210,500	218,447	67,358	68,121	79,058	80,235	58,189	57,090	7,894	8,002
Oregon	44,578	42,910	16,696	15,202	12,206	11,818	15,012	15,123	654	768
Washington	90,473	89,319	30,932	29,498	19,531	18,727	36,563	38,332	3,447	3,825
Pacific Noncontiguous	13,833	13,006	4,098	4,079	4,426	4,391	4,271	4,316	238	231
Alaska	4,375	4,339	1,829	1,640	2,062	2,035	501	504	182	180
Hawaii	8,658	8,667	2,469	2,438	2,363	2,356	3,770	3,811	56	61
U. S. Total	2,861,441	2,783,365	894,775	835,839	794,672	761,271	977,151	972,714	94,944	83,442

¹ Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

Notes: *Data for 1993 are preliminary; data for prior years are final. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 27. Number of Ultimate Consumers Served by Electric Utilities by Sector, Census Division, and State, 1993 and 1992
(Thousands)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other ¹	
	1993	1992	1993	1992	1993	1992	1993	1992	1993	1992
New England	6,148	6,108	5,431	5,387	646	637	27	26	44	46
Connecticut	1,448	1,446	1,312	1,311	125	125	5	5	5	5
Maine	681	675	591	585	70	70	3	1	18	19
Massachusetts	2,693	2,665	2,371	2,350	294	285	14	14	14	16
New Hampshire	579	579	498	496	76	75	2	2	3	6
Rhode Island	442	440	394	391	45	45	2	3	1	1
Vermont	306	304	265	263	37	36	1	1	3	3
Middle Atlantic	15,949	15,834	14,193	13,998	1,742	1,732	85	55	49	49
New Jersey	3,354	3,327	2,954	2,931	377	372	14	14	10	10
New York	7,259	7,216	6,398	6,355	618	616	12	12	31	31
Pennsylvania	5,336	5,290	4,751	4,711	548	542	29	29	8	8
East North Central	18,826	18,727	16,957	16,773	1,822	1,798	72	78	74	83
Illinois	4,953	4,910	4,477	4,434	454	446	5	6	17	21
Indiana	2,556	2,524	2,278	2,247	251	246	17	16	10	12
Michigan	4,218	4,175	3,781	3,745	405	397	12	15	18	18
Ohio	4,856	4,810	4,338	4,294	470	465	32	32	16	19
Wisconsin	2,342	2,307	2,083	2,053	242	237	5	5	12	12
West North Central	8,642	8,556	7,488	7,408	969	968	48	46	117	117
Iowa	1,335	1,327	1,159	1,152	158	160	4	4	14	11
Kansas	1,236	1,224	1,050	1,038	162	161	13	13	11	11
Minnesota	2,072	2,050	1,834	1,812	204	203	10	11	24	24
Missouri	2,507	2,474	2,212	2,184	268	264	12	11	14	15
Nebraska	823	819	670	666	106	108	4	5	40	39
North Dakota	322	318	270	268	44	44	3	3	5	5
South Dakota	347	345	294	289	43	42	2	2	8	11
South Atlantic	21,566	21,216	19,019	18,863	2,311	2,264	81	80	156	208
Delaware	332	327	296	293	33	33	1	1	1	1
District of Columbia	221	220	193	193	27	27				
Florida	7,022	6,930	6,200	6,082	750	733	22	21	50	94
Georgia	3,162	3,085	2,810	2,750	313	308	14	14	25	25
Maryland	2,017	1,988	1,813	1,787	192	190	11	11	1	1
North Carolina	3,437	3,363	2,984	2,917	412	402	13	14	26	30
South Carolina	1,739	1,712	1,505	1,478	218	213	4	4	12	19
Virginia	2,747	2,702	2,442	2,401	264	261	5	5	36	36
West Virginia	888	877	773	764	101	99	11	11	3	3
East South Central	7,374	7,347	6,395	6,388	873	856	64	56	42	42
Alabama	1,889	1,852	1,723	1,698	247	240	12	12	7	7
Kentucky	1,779	1,748	1,555	1,528	195	192	11	10	17	18
Mississippi	1,203	1,186	1,036	1,021	152	149	8	7	8	9
Tennessee	2,404	2,360	2,082	2,048	279	277	33	29	10	8
West South Central	12,584	12,389	10,946	10,757	1,398	1,368	113	113	135	148
Arkansas	1,184	1,174	1,040	1,021	118	115	23	23	13	15
Louisiana	1,916	1,881	1,687	1,658	197	191	15	15	19	20
Oklahoma	1,609	1,592	1,390	1,374	190	188	15	17	13	14
Texas	7,863	7,739	6,829	6,708	886	874	58	59	91	100
Mountain	6,875	6,487	5,762	5,624	784	766	35	35	94	72
Arizona	1,725	1,687	1,536	1,495	168	164	5	5	16	22
Colorado	1,710	1,658	1,458	1,438	205	203	2	2	45	15
Idaho	516	502	434	420	76	74	4	4	3	4
Montana	432	425	355	348	60	58	4	4	13	13
Nevada	841	816	557	538	81	78	1	1	2	2
New Mexico	716	701	615	600	88	86	5	5	8	9
Utah	887	864	695	688	86	82	11	10	5	4
Wyoming	248	245	201	199	40	39	3	3	4	4
Pacific Contiguous	16,240	16,094	14,228	14,075	1,898	1,881	67	65	76	83
California	12,390	12,316	10,841	10,761	1,484	1,469	39	39	45	46
Oregon	1,438	1,415	1,243	1,224	176	173	7	7	13	12
Washington	2,412	2,363	2,135	2,090	245	239	11	11	20	23
Pacific Noncontiguous	630	620	539	531	84	83	1	1	5	6
Alaska	240	237	202	199	33	33			4	4
Hawaii	390	384	337	331	51	50	1	1	2	2
U. S. Average	114,738	113,298	100,966	99,513	12,528	12,367	553	548	796	856

¹ Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

* Value less than 0.5 thousand.

Notes: +Data for 1993 are preliminary; data for prior years are final. *Totals may not equal sum of components because of independent rounding.

*The number of ultimate consumers is an average of the number of consumers at the close of each month.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 29. Revenue from Electric Utility Sales to Ultimate Consumers by Sector, Census Division, and State, 1993 and 1992
(Million Dollars)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other ¹	
	1993	1992	1993	1992	1993	1992	1993	1992	1993	1992
New England	10,486	10,096	4,277	4,067	3,886	3,628	2,163	2,137	238	243
Connecticut	2,706	2,723	1,207	1,162	1,072	1,034	464	476	52	61
Maine	1,087	1,039	443	430	271	253	351	326	23	22
Massachusetts	4,518	4,347	1,737	1,652	1,828	1,735	832	831	121	129
New Hampshire	951	893	421	389	234	216	290	272	16	16
Rhode Island	681	658	275	264	258	249	128	125	21	19
Vermont	453	435	194	184	146	141	107	105	6	6
Middle Atlantic	20,013	20,442	11,728	10,839	11,011	10,368	5,865	5,987	1,348	1,298
New Jersey	6,554	6,004	2,514	2,233	2,774	2,558	1,190	1,132	86	81
New York	13,960	13,082	5,256	4,813	5,564	5,204	2,012	2,017	1,129	1,057
Pennsylvania	9,499	9,347	3,959	3,793	2,674	2,606	2,713	2,788	153	159
East North Central	31,799	30,383	12,202	11,363	9,403	8,466	8,132	8,640	1,663	1,034
Illinois	6,123	6,655	3,622	3,332	2,748	2,545	2,192	2,236	558	541
Indiana	4,235	4,081	1,866	1,567	991	964	1,530	1,499	47	51
Michigan	6,258	6,063	2,185	2,082	2,319	1,756	1,832	2,104	120	121
Ohio	8,240	8,782	3,508	3,225	2,528	2,409	2,824	2,885	280	273
Wisconsin	2,938	2,793	1,232	1,148	815	782	863	816	46	48
West North Central	12,184	11,491	5,411	4,854	3,431	3,285	3,011	2,932	332	309
Iowa	1,916	1,807	880	825	463	446	489	487	74	49
Kansas	1,902	1,775	785	701	654	627	430	417	33	31
Minnesota	2,758	2,618	1,105	1,041	529	508	1,072	1,020	50	50
Missouri	3,710	3,488	1,757	1,584	1,247	1,200	842	843	64	62
Nebraska	1,039	983	452	411	311	297	200	193	78	81
North Dakota	433	414	203	191	119	114	92	89	19	20
South Dakota	428	404	219	202	109	103	85	83	15	16
South Atlantic	38,503	36,961	18,846	18,903	11,327	10,608	7,643	7,337	1,187	1,134
Delaware	637	571	274	241	189	172	167	153	7	6
District of Columbia	703	650	117	98	387	381	178	170	22	21
Florida	10,994	10,261	6,137	5,671	3,689	3,461	858	828	330	320
Georgia	5,863	5,563	2,640	2,381	1,873	1,779	1,379	1,342	91	83
Maryland	3,748	3,489	1,770	1,575	812	764	1,100	1,068	87	61
North Carolina	6,619	6,213	3,068	2,820	1,754	1,666	1,841	1,802	127	125
South Carolina	3,472	3,231	1,518	1,361	820	763	1,090	1,061	45	45
Virginia	5,072	4,800	2,459	2,273	1,393	1,347	729	715	489	485
West Virginia	1,276	1,203	547	502	317	295	404	398	8	8
East South Central	12,947	12,371	6,319	4,960	2,144	2,104	5,187	4,949	297	278
Alabama	3,687	3,482	1,544	1,413	780	748	1,324	1,264	38	37
Kentucky	2,944	2,812	1,086	1,013	520	506	1,198	1,170	130	122
Mississippi	2,147	2,006	940	871	498	488	653	595	55	50
Tennessee	4,168	4,090	1,738	1,682	346	420	2,011	1,920	73	68
West South Central	24,738	22,782	10,867	9,822	6,872	6,217	6,114	5,759	1,065	884
Arkansas	2,096	1,908	873	865	471	439	611	565	41	39
Louisiana	4,242	3,914	1,741	1,592	1,062	995	1,282	1,160	177	168
Oklahoma	2,415	2,219	1,136	1,022	672	631	484	448	124	118
Texas	15,984	14,740	7,017	6,343	4,467	4,152	3,757	3,587	743	658
Mountain	10,521	9,182	4,105	3,985	3,604	3,493	2,428	2,395	383	378
Arizona	3,645	3,551	1,611	1,555	1,288	1,250	838	837	107	109
Colorado	1,884	1,917	771	736	639	601	318	314	68	65
Idaho	749	735	312	283	219	230	203	206	14	17
Montana	564	548	208	192	154	148	161	166	21	24
Nevada	1,087	1,008	409	375	280	264	362	331	36	35
New Mexico	1,079	1,027	357	344	388	383	234	221	90	79
Utah	896	878	324	314	299	296	235	229	40	38
Wyoming	506	500	114	107	126	121	258	262	8	9
Pacific Contiguous	25,674	25,522	9,473	9,561	9,749	9,874	5,486	5,676	568	609
California	20,401	20,612	7,613	7,544	8,289	8,291	4,121	4,333	398	443
Oregon	1,974	1,850	838	760	601	576	499	488	35	38
Washington	3,298	3,061	1,422	1,268	879	807	876	856	122	128
Pacific Noncontiguous	1,366	1,260	465	443	473	441	378	338	30	29
Alaska	443	432	182	178	197	192	41	39	23	23
Hawaii	923	819	303	266	276	248	337	289	6	6
U. S. Total	199,220	188,480	82,614	76,848	61,822	58,343	47,356	48,993	6,528	6,298

¹ Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

Notes: *Data for 1993 are preliminary, data for prior years are final. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 29. Average Revenue per Kilowatthour for Electric Utilities by Sector, Census Division, and State, 1993 and 1992
(Cents)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other ¹	
	1993	1992	1993	1992	1993	1992	1993	1992	1993	1992
New England	10.01	9.72	11.24	10.87	9.85	9.57	8.26	8.12	12.66	11.85
Connecticut	10.26	10.04	11.39	11.07	10.04	9.86	8.29	8.22	14.06	13.92
Maine	9.10	9.05	11.43	11.37	9.45	9.27	6.96	6.90	13.22	12.91
Massachusetts	9.99	9.68	11.00	10.62	9.67	9.31	8.66	8.60	12.21	11.27
New Hampshire	10.65	9.97	12.31	11.36	11.01	10.38	9.04	8.17	13.30	13.43
Rhode Island	10.40	10.30	11.38	11.17	10.17	10.05	9.03	9.22	11.14	10.27
Vermont	9.04	8.83	9.84	9.56	9.31	9.24	7.50	7.90	13.50	12.88
Middle Atlantic	9.50	9.24	11.34	11.00	10.15	9.90	8.58	8.66	9.65	9.26
New Jersey	9.98	9.51	11.41	10.87	9.73	9.33	8.09	7.71	17.54	15.74
New York	10.72	10.19	13.17	12.43	11.66	11.17	6.66	6.50	9.14	8.71
Pennsylvania	7.92	8.04	9.55	9.67	8.29	8.47	6.04	6.21	11.56	11.43
East North Central	6.60	6.47	8.34	8.31	7.39	7.43	4.56	4.66	7.04	6.99
Illinois	7.75	7.69	10.28	10.26	8.00	8.09	5.45	5.47	7.03	6.93
Indiana	5.17	5.30	6.67	6.86	5.62	5.00	3.88	4.00	9.00	8.19
Michigan	7.14	7.23	8.16	8.11	6.02	6.28	5.34	5.90	9.15	9.30
Ohio	6.22	6.08	8.36	8.24	7.69	7.67	4.25	4.14	6.23	6.22
Wisconsin	5.52	5.48	7.03	6.91	5.95	5.91	3.98	4.00	6.98	7.04
West North Central	6.84	6.03	7.27	7.32	6.31	6.33	4.44	4.45	6.45	6.46
Iowa	6.97	6.98	8.02	8.02	6.97	6.35	3.92	4.02	6.85	6.38
Kansas	5.60	5.56	7.86	7.90	6.70	6.67	4.94	4.93	6.91	6.86
Minnesota	5.60	5.52	7.09	7.01	6.19	6.13	4.40	4.38	7.17	6.94
Missouri	6.33	6.41	7.26	7.44	6.26	6.39	4.71	4.78	7.10	7.06
Nebraska	5.54	5.53	6.25	6.27	5.68	5.64	4.04	4.05	6.99	6.77
North Dakota	5.83	5.91	6.31	6.33	6.46	6.48	4.85	4.87	3.99	3.85
South Dakota	6.20	6.22	7.04	7.10	6.75	6.78	4.80	4.68	4.55	4.55
South Atlantic	6.61	6.51	7.84	7.71	6.79	6.69	4.72	4.69	6.41	6.40
Delaware	6.88	6.70	9.01	8.88	7.25	7.01	4.88	4.71	11.78	10.82
District of Columbia	6.78	6.47	7.18	6.61	7.15	6.91	5.91	5.68	6.47	6.23
Florida	7.20	6.99	7.99	7.75	6.69	6.58	5.26	6.02	6.96	6.81
Georgia	6.71	6.67	7.79	7.73	7.44	7.50	4.74	4.76	8.50	8.70
Maryland	6.96	6.80	8.21	7.97	7.17	7.09	5.45	5.40	8.26	8.92
North Carolina	6.63	6.60	8.18	8.11	6.60	6.63	4.90	4.93	7.07	7.07
South Carolina	5.64	5.53	7.33	7.19	6.22	6.17	4.06	4.03	5.87	5.72
Virginia	6.23	6.28	7.57	7.63	6.14	6.23	4.19	4.28	6.56	6.67
West Virginia	5.22	5.05	6.30	6.17	5.78	5.63	3.96	3.84	9.22	8.59
East South Central	6.23	5.13	6.24	6.16	6.51	6.42	4.16	4.07	5.95	5.82
Alabama	5.67	5.67	6.83	6.69	6.93	6.65	4.94	4.29	5.89	5.84
Kentucky	4.92	4.19	5.70	5.70	5.29	5.29	3.30	3.16	4.58	4.65
Mississippi	6.18	6.03	7.12	7.01	7.45	7.27	4.59	4.41	8.70	8.45
Tennessee	5.22	6.21	5.75	5.70	6.68	6.60	4.62	4.60	7.92	7.42
West South Central	6.34	6.14	7.89	7.68	6.93	6.75	4.38	4.24	6.65	6.29
Arkansas	6.62	6.71	8.27	8.28	7.04	7.11	4.85	5.02	6.93	6.77
Louisiana	6.26	6.01	7.76	7.62	7.99	7.19	4.44	4.22	7.11	6.44
Oklahoma	5.96	5.60	7.14	7.17	6.21	6.10	4.14	3.86	5.87	5.68
Texas	6.39	6.16	8.00	7.74	6.94	6.73	4.82	4.20	6.66	6.34
Mountain	6.15	6.05	7.40	7.67	6.70	6.83	4.29	4.28	5.88	5.83
Arizona	8.21	8.13	9.65	9.58	8.70	8.64	5.80	5.76	5.84	6.74
Colorado	6.05	6.02	7.24	7.20	5.82	5.77	4.52	4.59	7.72	7.61
Idaho	4.00	3.87	4.99	4.93	4.42	4.30	2.81	2.72	4.89	4.43
Montana	4.36	4.19	5.77	5.84	5.10	5.17	3.10	2.89	4.51	4.49
Nevada	5.57	5.89	6.51	6.19	6.51	6.33	5.04	4.92	4.87	4.82
New Mexico	7.23	7.12	9.18	9.06	8.37	8.27	4.86	4.80	6.13	5.86
Utah	5.33	5.30	6.85	6.97	5.96	5.87	3.78	3.68	4.49	4.36
Wyoming	4.25	4.27	5.96	6.08	5.04	5.17	3.50	3.52	5.62	6.40
Pacific Contiguous	7.43	7.36	8.58	8.58	8.80	8.73	6.18	6.14	4.58	4.84
California	9.69	9.65	11.30	11.07	10.46	10.33	7.38	7.69	5.05	5.64
Oregon	4.43	4.31	5.02	4.93	4.93	4.86	3.39	3.22	5.33	4.98
Washington	3.85	3.43	4.60	4.46	4.50	4.31	2.40	2.24	3.53	3.34
Pacific Noncontiguous	10.46	9.81	11.83	10.87	10.89	10.93	8.88	7.82	12.42	12.97
Alaska	10.12	9.85	11.15	10.62	9.55	9.45	8.19	7.74	12.77	14.21
Hawaii	10.66	9.44	12.28	10.90	11.66	10.53	8.95	7.83	11.26	8.71
U. S. Average	6.93	6.82	8.32	8.21	7.74	7.66	4.85	4.63	6.88	6.74

¹ Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales. The average revenue for other sales may include ownership, operation, maintenance, and rental fees for equipment and/or demand and service charges.

Notes: *Data for 1993 are preliminary, data for prior years are final. *The average revenue per kilowatthour of electricity sold is calculated by dividing revenue by sales. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

U.S. Electric Utility Financial Statistics

This chapter presents data on the financial results of operations for major U.S. investor-owned and publicly owned electric utilities. Composite financial data on other segments of the U.S. electric utility industry, for example, Federal electric utilities and rural electric cooperatives, are not included. The data exhibited consist of the Composite Statement of Income, the Composite Balance Sheet, Financial Indicators, and Revenue and Expense Statistics. Historical data are provided for a 5-year period on major U.S. investor-owned and U.S. publicly owned electric utilities. Statistics on the average operating expenses for all plants owned by major U.S. investor-owned electric utilities are also provided.

Background

Today, virtually all investor-owned electric utilities are subject to State and Federal regulatory jurisdiction. State commissions have the authority to regulate electric rates of utilities engaged in providing service to ultimate consumers (retail sales) and to oversee the issuance of mortgage bonds, debentures, notes, preferred stock, and common stock. The Federal Energy Regulatory Commission (FERC) regulates, among other things, electric rates for interstate wholesale transactions. The ratemaking process sets rates at levels that cover all operating expenses and taxes with a remaining balance that will enable a utility to pay a fair return on funds invested by the stockholders.

A component of any economic regulatory activity is the determination of financing and accounting rules. As a consequence of regulatory jurisdiction, regulations for financing and accounting are more critical to the electric power industry than to most other nonregulated industries. Both FERC and State commissions normally use quasi-judicial proceedings for financial and accounting regulation.

Many of the publicly owned electric utilities are self-regulated (for example, the City of Dover, Delaware), while some fall under the jurisdiction of the public utility commission within the State(s) where they provide electricity to ultimate consumers (as in the State of Ohio). Because of the absence of any requirement for reporting to a specific regulatory body, the accounting practices and policies of publicly owned electric utilities vary greatly. Many publicly owned electric utilities use the FERC Uniform System of Accounts or variations of this (and other) accounting systems.

As a result, the composite statistics provided must be viewed with an appropriate degree of caution.

Electric utilities must submit data for a 12-month period (does not necessarily end on December 31) and show consistency in their methods and reporting dates. Because of the respondent burden in preparing this information, publicly owned electric utilities are permitted to use the year-end period on which their fiscal practices are based. Data are provided for the major publicly owned electric utilities by generator and nongenerators. Data presented prior to 1992 provided a subset of the major publicly owned electric utilities with fiscal years ending June 30 and December 31.

Composite Statement of Income

This statement provides a summary of the revenue collected from consumers in return for services rendered within the reporting period; reflects the costs incurred by the electric utility in the production and delivery of electricity; and reports the net income or profit that remains for the owners of the business. Because of the unique nature of regulated electric utilities, the income statement that is standard to other nonregulated industries has been recast to reflect the reporting conventions in the electric power industry. For example, accounting for capital used in construction requires additional reporting on the income statement because of the perpetual nature of construction work in progress. Also, on occasion, electric utilities are required to defer the recovery of certain costs and earnings from consumers until a future period. This introduces additional accounting requirements, which must be reflected on all financial statements.

Composite Balance Sheet

The balance sheet represents an accounting at a particular time. For this section, the composite balance sheets are presented for major investor-owned electric utilities at the end of a calendar year and for major publicly owned electric utilities for the 12-month fiscal year ending in 1993. A summary of plant, property, and cash held by the electric utilities, as well as the receivables of the electric utilities, are represented as assets on the composite balance sheet. Future funds obligated by the electric utilities to acquire assets are shown as liabilities and any increased investment by

stockholders is shown as capital on the balance sheet. The standard balance sheet used in the electric power industry emphasizes capital intensity while the balance sheet used by nonregulated industries emphasizes liquidity.

Composite Financial Indicators

The financial statement accounts presented in this chapter represent compiled statistics resulting from the activity of the selected electric utilities. The measurement of how well the electric utility industry performs in different areas can be approximated by comparing some of the asset and income accounts to other relevant accounts. Using the financial statement information, some basic indicators that can be used to analyze or assess the financial condition of the industry are provided. The method used to derive these selected financial indicators is ratio analysis.

Activity ratios of the investor-owned electric utilities evaluate how assets are managed. The electric utility industry is one of the most capital intensive industries in the United States and activity ratios are paramount indicators of the magnitude of this capital intensity. These ratios demonstrate the financial relationship, which exists between the assets and revenue, sales, and income that these fixed and total assets generate. The ratios on *electric-fixed-asset (net plant) turnover* and *total-asset turnover* assess the efficient use of assets in the generation of income.

Leverage ratios of the investor-owned electric utilities summarize the overall debt burden and debt structure. In addition, these ratios indicate the financial ability to meet debt service requirements and how well management uses leverage to increase the value of the investment of the stockholders. The financial soundness of an industry is directly related to the ability of the industry to raise capital and to be able to provide a reasonable return on the capital invested. In order to measure the ability to do this, a number of indicators are used. *Current assets to current liabilities* is a measure of liquidity. For example, do the investor-owned electric utilities have sufficient cash and other assets (current), which can be quickly converted to cash to cover maturing obligations (current liabilities)? *Long-term debt to capitalization*, *preferred stock to capitalization*, and *common-stock equity to capitalization* portray the financial structure and highlight the extent to which debt and other fixed obligations are used to finance operations. *Total debt to total assets* shows the amount of debt that has been incurred in relationship to the total assets possessed. As the value of this ratio increases, the financial risks also become greater and more apparent. *Common-stock equity to total assets* evaluates financial strength. As net worth increases in relationship to total assets, the debt portion is decreased and financial risks are lowered. *Interest coverage before taxes without AFUDC* (Allowance for Funds Used During Construction), a noncash source of income, is

an indicator of the ability of the investor-owned electric utility to ensure its payment of annual interest costs and maintain its credit ratings.

Profitability ratios of the investor-owned electric utilities indicate operating effectiveness and are used to further evaluate the management of income. The *profit margin* is equal to net income divided by revenue. This ratio is used extensively and represents the overall measure of income performance. *Return on average-common-stock equity* measures the rate of return on equity capital invested. Since one of the main objectives of management is to earn the highest return permissible, this ratio is the best single measure of the effectiveness of management from the perspective of the stockholders. *Return on investment* measures the overall rate of return that has been earned on assets. This ratio, determined by dividing total assets into net income, provides an indicator of overall financial performance.

Ratios on the publicly owned electric utilities are provided to assist in understanding the financial performance of the publicly owned segment of the industry. Six ratios are calculated from the statement of income and five ratios are calculated from the balance sheet. *Electric utility plant per dollar of revenue* highlights the capital intensity of the utility. *Current assets to current liabilities* provides a measure of the ease by which the utility can meet its current obligations. *Electric utility plant as a percent of total assets* represents the total gross investment in electric plant divided by the total assets. A significant variation in this ratio should signal a relatively fundamental change in the activities of the electric utility. *Net electric utility plant as a percent of total assets* represents the remaining book value and a significant variation should signal a change for the electric utility. *Debt as a percent of total liabilities* represents the amount of debt compared to total liabilities and other credits. *Accumulated provision for depreciation as a percent of total electric plant* measures the cost of recovery of the use of the assets over a period of time for an electric utility; an increase indicates that plant asset life is being used up. The ratios of *electric operating and maintenance expenses*, *electric depreciation and amortization*, *taxes and tax equivalents*, and *interest on long-term debt to electric operating revenue* are indicators of how resources were used to produce income. *Net income per dollar of revenue* provides the amount of the revenue dollar that exceeds expenses and deductions.

As a number of initiatives are being considered for a more competitive electric power industry, three new operating ratios that measure specific cost associated with the sale of each kilowatt-hour(s) of electricity have been added in this issue. They are purchase power per kilowatt-hour(s), generated cost per kilowatt-hour(s), and total power supply expense per kilowatt-hour(s) sold. Purchase power cost per kilowatt-hour(s) is the ratio of the cost of purchased power to the number of kilowatt-hour(s) purchased. This ratio measures the purchased power component of power supply cost. Generated cost per kilowatt-hour(s) is the ratio of the

cost of labor, materials used and expenses incurred in the production of electric generation. This ratio measures the generation component of production expenses. Total power supply per kilowatthour(s) is the ratio of the total cost of power supply to total sales to both ultimate and resale customers. This ratio measures all power supply cost, including generation and purchase power, associated with the sale of each kilowatthour(s) of electricity.

Revenue and Expense Statistics

These summary statistics are basic in any analysis of the operating soundness of an electric utility. In order to conduct this analysis, it is necessary to separate the electric utility revenue and expense information from other utility revenue and expense data. Emphasis is placed on total electric operating expenses. Data are presented so that operating costs are separate from maintenance, depreciation, and taxes. For comparative purposes, the ratio of income from utility operations is also included.

Electric Operating Expenses

In order to provide the consumer with electricity, it first must be either produced (generated) or purchased, then transmitted to the general area where it will be consumed, and finally distributed to the individual consumer. Hence, electric utilities separate their costs of providing power into four functional areas: *generation, transmission, distribution, and administration*. Costs incurred at the generation site for the production of electricity are generally referred to as operating expenses.

Operating expenses include recurring expenses to operate and maintain the physical condition or operating efficiency of the plant. These expenses include wages and benefits of the operators, plant maintenance, security, supervision, materials (such as spare parts), and supplies (except fuel consumed during plant operation and maintenance). The fuel expenses include the costs of purchasing, handling, preparing, and transporting fuel. Operating expenses do not include capital carrying costs, such as interest on debt, return on equity, depreciation, amortization expenses, and associated taxes. Capital carrying costs must be added to the operating expenses to obtain total generation expenses.

Investor-owned electric utilities are the major contributors of total electricity generation, accounting for about 80 percent of the total utility generation in the United States in 1993. Publicly owned electric utilities generated about 10 percent of the total U.S. utility

generation, while the remainder was accounted for by Federal and cooperative electric utilities. Operating expenses per unit of output (kilowatthour) for the major investor-owned electric utilities from 1989 through 1993 are provided by the following categories: fossil-fueled steam, nuclear, hydroelectric, and other (includes gas turbine and small scale electric plants).

Data Sources

Financial Statistics. The financial statistics reported in this chapter on the investor-owned electric utilities are compiled from data extracted from the FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." This survey is a restricted-universe census used annually to collect detailed accounting, financial, and operating data from major investor-owned electric utilities having, in each of the last 3 consecutive years, sales or transmission service that exceeds one of the following:

- 1 million megawatthours of total sales
- 100 megawatthours of sales for resale
- 500 megawatthours of power exchanges delivered
- 500 megawatthours of wheeling for others (deliveries plus losses).

Approximately 180 investor-owned electric utilities are required to submit the FERC Form 1. These major investor-owned electric utilities represent about two-thirds of all investor-owned electric utilities. The electric utilities are required to follow the Uniform System of Accounts prescribed by the FERC (in cooperation with the National Association of Regulatory Utility Commissioners). More detailed financial statistics on investor-owned electric utilities are published in the *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*.³⁰

The financial statistics on the publicly owned electric utilities are compiled from data extracted from the Form EIA-412, "Annual Report of Public Electric Utilities." This form is a restricted-universe census used annually to collect detailed accounting, financial, and operating data from major publicly owned electric utilities having, in each of the last 2 consecutive years, sales that exceed any one of the following:

- 120,000 megawatthours of sales to ultimate consumers
- 120,000 megawatthours of sales for resale.

Approximately 500 publicly owned electric utilities are required to submit the Form EIA-412. These major

³⁰Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*, DOE/EIA-0437(93)/1 (Washington, DC); data for 1992 are published in the *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*, DOE/EIA-0431(92)/1; data for 1991 are published in the *Financial Statistics of Major Investor-Owned Electric Utilities*, DOE/EIA-0437/1; data for 1989 and 1990 are published in the *Financial Statistics of Selected Investor-Owned Electric Utilities*, DOE/EIA-0437/1.

publicly owned electric utilities represent about one-fourth of all publicly owned electric utilities and over 80 percent of total sales by publicly owned electric utilities to ultimate consumers. These electric utilities are requested, but not required, to follow the FERC

Uniform System of Accounts. More detailed financial statistics on public electric utilities, Federal electric utilities, and rural electric cooperatives are published in the *Financial Statistics of Major U.S. Publicly Owned Electric Utilities*.³¹

³¹Energy Information Administration (EIA), *Financial Statistics of Major U.S. Publicly Owned Electric Utilities*, DOE/EIA-0437(93)/2; data for 1992 are published in the *Financial Statistics of Major Publicly Owned Electric Utilities*, DOE/EIA-0437(92)/2; data for 1991 are published in the *Financial Statistics of Major Publicly Owned Electric Utilities*, DOE/EIA-0437/2; data for 1989 and 1990 are published in the *Financial Statistics of Selected Publicly Owned Electric Utilities*, DOE/EIA-0437/2.

**Table 30. Composite Statement of Income for Major U.S. Investor-Owned Electric Utilities,
1989 Through 1993**
(Thousand Dollars)

Description	1993	1992	1991 ¹	1990	1989
Operating Revenue	193,837,843	185,493,456	182,850,728	172,909,864	167,667,596
Electric	176,354,365	169,468,035	166,603,643	157,278,537	150,903,317
Gas	16,668,812	14,837,370	14,560,221	14,611,058	15,119,408
Other Utility	506,667	1,008,053	1,086,863	1,110,362	1,044,871
Operating Expenses	161,908,147	153,682,429	150,361,969	142,471,389	136,500,226
Electric	146,118,013	139,009,093	135,947,991	127,909,834	121,552,060
Fuel	81,214,057	30,264,398	31,312,220	32,694,846	32,937,516
Other Operating and Maintenance	72,561,067	69,212,541	66,645,950	60,231,131	54,785,240
Depreciation ²	18,098,736	17,091,753	16,127,176	14,858,584	15,032,961
Taxes Other Than Income Taxes	13,040,400	12,760,162	12,270,379	11,493,264	10,796,423
Income Taxes	8,296,800	7,197,662	7,690,521	7,146,959	6,848,389
Deferred Income Tax	2,993,143	3,017,335	2,294,676	1,855,377	1,479,626
Investment Tax Credit (Net)	-515,791	-524,768	-382,831	-289,428	-326,075
Gas	15,234,557	13,691,253	13,406,370	13,523,155	13,972,207
Income Taxes	251,539	279,618	308,656	428,107	398,680
Other	14,063,024	13,411,635	13,097,714	13,095,048	13,635,547
Other Utility	555,577	982,083	1,007,809	1,047,680	976,958
Income Taxes	10,763	26,066	3,530	7,806	16,480
Other	544,814	955,127	1,004,079	1,039,775	959,478
Operating Income	31,729,696	31,811,026	32,088,758	30,528,586	30,667,370
Electric	30,236,352	30,478,942	30,655,652	29,377,303	29,351,256
Gas	1,452,354	1,246,117	1,153,652	1,087,301	1,147,200
Other	40,990	85,970	79,055	62,782	66,913
Other Income and Deductions	1,346,396	1,699,045	523,325	1,830,496	2,590,680
Allowance for Other Funds Used During					
Construction	591,445	611,514	706,102	1,080,217	1,202,004
Less Taxes	1,118,561	379,461	852,579	399,448	943,175
Deferred Earnings (Misc.) (acct 421)	677,960	1,341,354	1,271,525	1,477,520	1,073,178
Less Other Income and Expenses ³	-1,197,174	-115,638	601,723	337,793	-1,228,653
Total Income Before Interest Charges	33,076,094	33,500,074	32,612,083	32,359,081	33,128,030
Net Interest Charges	14,700,488	15,223,174	15,796,248	15,735,830	14,662,296
Interest Expense	14,566,753	15,307,441	16,010,348	16,186,426	15,848,011
Less Allowance for Borrowed Funds Used During					
Construction	555,021	558,348	635,525	814,229	1,142,007
Other Charges-Net	668,756	474,060	361,424	363,433	346,291
Net Income Before Extraordinary Charges	18,375,606	18,276,900	16,815,835	16,623,461	18,275,735
Less Extraordinary Items After Taxes³	464,409	-107,544	-73,829	-279,715	982,074
Net Income	17,911,197	18,384,444	16,949,664	16,903,166	17,312,761
Preferred Stock Dividend Requirements	1,765,296	2,039,449	1,945,219	2,025,167	2,417,239
Earnings Available for Common Stocks	16,125,912	16,344,995	15,004,451	14,872,009	14,895,522
Common Stock Dividends	16,354,377	14,867,808	14,427,570	14,188,677	14,030,562
Additions to Retained Earnings	296,171	2,184,266	234,189	424,940	795,327
Average Shares of Common Stock Outstanding	6,129,893	6,261,284	5,932,492	5,595,635	6,824,221
Earnings Available Per Average Common Share (Dollars)	2.63	2.61	2.53	2.66	2.54

¹ Due to its emergence from bankruptcy, the 1991 financial statements for the Public Service Company of New Hampshire are from May 16 through December 31.

² Includes amortization and depletion.

³ Other Income and Expenses and Extraordinary Items After Taxes were affected negatively by aftertax write offs, accounting adjustments, and regulatory rate decisions. The majority of the charges were directly related to the treatment of nuclear plants.

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." See Appendix C for a detailed description of this restricted-universe census.

**Table 31. Composite Balance Sheet for Major U.S. Investor-Owned Electric Utilities,
1989 Through 1993
(Thousand Dollars)**

Description	1993	1992	1991 ¹	1990	1989
Assets					
Utility Plant - Net	393,829,243	388,884,734	378,771,703	371,310,083	363,223,996
Electric Utility Plant - Net	363,829,459	358,300,259	349,811,025	344,912,770	337,460,182
Electric Utility Plant	519,207,367	499,118,599	479,822,229	458,061,342	429,700,561
Construction Work in Progress	18,048,849	20,848,234	18,077,211	22,558,726	33,714,555
Less Accumulated Depreciation	173,426,758	160,486,573	146,288,414	135,727,298	124,954,934
Nuclear Fuel - Net	5,964,178	6,836,719	8,911,845	7,812,038	8,700,644
Other Utility Plant - Net	24,035,606	21,727,759	20,249,033	18,585,255	17,062,568
Other Property and Investments	28,083,595	18,045,977	17,385,415	17,703,829	16,136,757
Current and Accrued Assets	42,406,938	43,447,871	43,367,786	41,834,882	41,516,183
Deferred Debits	110,838,398	57,993,875	50,824,920	47,322,574	44,846,822
Total Assets	586,841,282	508,362,461	487,539,823	477,871,029	466,722,937
Capitalization and Liabilities					
Capitalization	360,455,273	366,026,792	348,839,405	340,993,206	334,006,986
Common Stock Equity (End of Year)	160,296,897	156,346,650	151,571,304	147,424,082	145,175,875
Common Stock	107,470,858	109,983,697	99,729,170	98,502,507	94,602,732
Retained Earnings (Adjusted)	52,826,059	52,362,963	51,948,134	50,921,576	50,573,148
Preferred Stock	25,304,294	25,538,216	25,262,285	26,621,038	26,844,650
Long-term Debt	174,854,082	174,140,896	171,884,816	167,939,084	162,946,440
Current and Other Liabilities	206,188,010	150,325,898	138,711,418	136,887,824	131,653,870
Other Noncurrent Liabilities	11,478,308	8,627,882	8,931,193	7,224,672	7,803,119
Current and Accrued Liabilities	48,878,978	45,557,801	43,367,438	44,283,442	42,023,659
Deferred Credits	145,828,731	96,140,215	86,422,789	85,379,510	81,827,192
Accumulated Deferred Income Taxes	104,964,188	65,020,984	59,188,298	56,528,757	53,826,188
Accumulated Deferred Investment Tax Credit	13,428,995	14,048,840	14,889,786	16,290,316	15,886,416
Other Deferred Credits (Adjusted)	27,435,549	17,072,382	14,544,705	13,559,436	12,812,588
Total Capitalization and Liabilities	586,841,282	508,362,461	487,539,823	477,871,029	466,722,937

¹ Due to its emergence from bankruptcy, the 1991 financial statements for the Public Service Company of New Hampshire are from May 16 through December 31.

² In 1993, Other Regulatory Assets (a new line item) was added to the Balance Sheet and accounts for the large increase in Deferred Debits from 1992.

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." See Appendix C for a detailed description of this restricted-universe census.

Figure 16. Allocation of the Revenue Dollar from Electric Operations for Major U.S. Investor-Owned Electric Utilities, 1993

Notes: *Depreciation includes amortization and depletion. *Totals may not equal sum of components because of independent rounding. *Data are final.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." See Appendix C for a detailed description of this restricted-universe census.

Table 32. Composite Financial Indicators for Major U.S. Investor-Owned Electric Utilities, 1989 Through 1993

Description ¹	1993	1992	1991 ²	1990	1989
Activity					
1 Electric Fixed Asset (Net Plant) Turnover	0.48	0.47	0.48	0.46	0.46
2 Total Asset Turnover	34	37	37	36	36
Leverage					
3 Current Assets to Current Liabilities	87	95	100	94	99
4 Long-term Debt to Capitalization	48.51	48.91	49.28	49.25	48.78
5 Preferred Stock to Capitalization	7.02	7.17	7.24	7.51	7.77
6 Common Stock Equity to Capitalization	44.47	43.91	43.48	43.24	43.48
7 Total Debt to Total Assets ³	32.48	33.13	36.69	36.79	36.26
8 Common Stock Equity to Total Assets	28.28	30.88	31.11	30.85	31.17
9 Interest Coverage Before Taxes without AFUDC	2.78	2.62	2.49	2.38	2.46
Profitability					
10 Profit Margin	9.24	9.91	9.29	8.77	10.36
11 Return on Average Common Stock Equity ⁴	11.30	11.94	11.33	11.55	12.09
12 Return on Investment	3.16	3.63	3.48	3.54	3.72

¹ Indicators 1, 2, 3, and 9 are ratios. Indicators 4 through 6 and 10 through 12 are percentages.

² Due to its emergence from bankruptcy, the 1991 financial statements for the Public Service Company of New Hampshire are from May 15 through December 31.

³ Total debt is the sum of Long-term Debt and Short-term Debt. The values for Short-term Debt included in Current and Accrued Liabilities (Notes Payable) were \$9,210,645 for 1993, \$8,791,477 for 1992, \$6,866,980 for 1991, \$7,874,293 for 1990, and \$5,928,421 for 1989.

⁴ The Average Common Stock Equity is the average of the beginning and ending year balances. The values for the beginning of each year were \$160,298,897 for 1993, \$158,346,650 for 1992, \$151,671,304 for 1991, \$147,424,082 for 1990, and \$145,175,878 for 1989.

AFUDC=Allowance for Funds Used During Construction

Notes: *Data are final. *Formulas for computing the financial indicators are in Appendix C. *Indicators 4, 5, and 6 may not sum to 100 percent because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." See Appendix C for a detailed description of this restricted universe census.

Figure 17. Electric Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 1993

Notes: *Other includes transmission, distribution, customer account, customer service, and sales. *Totals may not equal sum of components because of independent rounding. *Data are final.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." See Appendix C for a detailed description of this restricted-universe census.

Table 33. Revenue and Expense Statistics for Major U.S. Investor-Owned Electric Utilities, 1989 Through 1993
(Thousand Dollars)

Description	1993	1992	1991 ¹	1990	1989
Utility Operating Revenue	193,637,843	185,493,458	182,450,728	172,999,954	167,067,896
Electric Utility	176,354,365	169,486,035	165,803,843	157,278,537	150,903,817
Other Utility	17,283,479	16,006,423	15,646,884	15,721,418	16,164,279
Utility Operating Expenses	161,908,147	153,882,428	150,381,969	142,471,399	136,600,226
Electric Utility	146,118,013	139,009,093	135,847,891	127,900,634	121,652,060
Operation	91,328,230	87,272,134	85,933,743	81,086,488	76,451,124
Production	68,780,803	66,879,805	65,101,628	62,501,048	59,235,893
Cost of Fuel	31,214,057	30,254,388	31,312,220	32,634,845	32,937,516
Purchased Power	27,715,512	26,212,238	24,169,252	20,340,504	17,858,051
Other	9,851,234	10,513,169	10,620,066	9,625,698	8,339,926
Transmission	1,354,058	1,308,101	1,247,268	1,130,272	1,113,547
Distribution	2,595,023	2,498,514	2,530,490	2,443,859	2,393,944
Customer Accounts	3,418,487	3,347,124	3,203,212	3,247,245	2,992,829
Customer Service	1,652,267	1,531,368	1,451,507	1,180,636	959,473
Sales	203,291	188,647	203,230	212,233	208,855
Administrative and General	13,124,300	11,408,575	11,186,490	10,371,185	9,646,783
Maintenance	12,446,814	12,194,805	12,024,427	11,779,489	11,271,632
Depreciation	18,068,736	17,091,753	16,127,176	14,888,584	15,032,961
Taxes and Other	24,344,133	22,450,401	21,882,645	20,146,073	18,796,243
Other Utility	15,790,134	14,673,336	14,413,879	14,570,735	14,948,165
Income From Utility Operations	31,729,696	31,611,029	32,068,758	30,528,555	30,467,670

¹ Due to its emergence from bankruptcy, the 1991 financial statements for the Public Service Company of New Hampshire are from May 16 through December 31.

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." See Appendix C for a detailed description of this restricted-universe census.

Table 34. Revenue and Expense Percentages for Major U.S. Investor-Owned Electric Utilities, 1989 Through 1993

Description	1993	1992	1991 ¹	1990	1989
Utility Operating Revenue	100.0	100.0	100.0	100.0	100.0
Electric Utility	91.1	91.4	91.4	90.9	90.3
Other Utility	8.9	8.6	8.6	9.1	9.7
Utility Operating Expenses	83.6	82.5	82.4	82.4	81.7
Electric Utility	75.5	74.9	74.5	73.9	72.8
Operation	47.2	47.0	47.1	46.9	45.8
Production	35.5	36.1	36.2	36.1	35.5
Cost of Fuel	16.1	16.3	17.2	18.9	18.7
Purchased Power	14.3	14.1	13.2	11.8	10.7
Other	6.1	5.7	5.6	5.6	5.0
Transmission	7	7	7	7	7
Distribution	1.3	1.3	1.4	1.4	1.4
Customer Accounts	1.8	1.8	1.8	1.8	1.8
Customer Service	1.0	.8	.8	.7	.6
Sales	1	1	1	1	1
Administrative and General	6.8	6.2	6.1	6.0	5.7
Maintenance	6.4	6.6	6.6	6.8	6.7
Depreciation	9.3	9.2	8.8	8.6	9.0
Taxes and Other	12.5	12.1	12.0	11.6	11.3
Other Utility	8.2	7.9	7.9	8.4	8.9
Income From Utility Operations	16.4	17.1	17.6	17.6	18.3

¹ Due to its emergence from bankruptcy, the 1991 financial statements for the Public Service Company of New Hampshire are from May 16 through December 31.

Notes: *Data are final. *Percentages in this table are percentage of utility operating revenues. *Totals may not equal sum of components because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." See Appendix C for a detailed description of this restricted-universe census.

Table 35. Average Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 1989 Through 1993
(Mills per Kilowatthour)

Plant Type	1989	1992	1991 ¹	1990	1989
Operation					
Nuclear	10.20	10.43	10.49	10.04	10.29
Fossil Steam	2.97	2.36	2.29	2.21	1.99
Hydroelectric ²	3.62	4.33	3.88	3.35	3.27
Gas Turbine and Small Scale ³	6.47	10.18	9.61	8.76	5.66
Maintenance					
Nuclear	5.73	5.93	5.50	5.68	5.87
Fossil Steam	2.96	2.95	2.96	2.97	2.78
Hydroelectric ²	2.85	3.30	2.89	2.58	2.39
Gas Turbine and Small Scale ³	7.52	12.16	12.93	12.23	8.90
Fuel					
Nuclear	5.88	6.12	6.71	7.18	7.45
Fossil Steam	17.65	17.49	17.91	18.55	18.28
Hydroelectric ²	—	—	—	—	—
Gas Turbine and Small Scale ³	26.39	28.59	30.96	32.57	34.77
Total⁴					
Nuclear	21.60	22.48	22.70	22.91	23.61
Fossil Steam	22.97	22.83	23.17	23.72	23.05
Hydroelectric ²	6.47	7.63	6.76	5.93	5.66
Gas Turbine and Small Scale ³	40.38	50.92	53.51	53.56	49.03

¹ Due to its emergence from bankruptcy, the 1991 financial statements for the Public Service Company of New Hampshire are from May 16 through December 31.

² Includes Pumped Storage.

³ Includes gas turbine, internal combustion, photovoltaic, and wind plants.

⁴ Totals may not equal sum of components because of independent rounding.

Notes: *Data are final. *Expenses are average expenses weighted by net generation. *A mill is a monetary cost and billing unit equal to 1/1000 of the U.S. dollar (equivalent to 1/10 of 1 cent).

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." See Appendix C for a detailed description of this restricted-universe census.

Figure 18. Average Operating Expenses of Fossil-Fueled and Nuclear Steam-Electric Plants for Major U.S. Investor-Owned Electric Utilities, 1993

Notes: *Totals may not equal sum of components because of independent rounding. *Data are final.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." See Appendix C for a detailed description of this restricted-universe census.

Table 36. Composite Statement of Income for Major U.S. Publicly Owned Generator Electric Utilities, 1989 Through 1993
(Thousand Dollars)

Description	1993	1992	1991	1990	1989
Operating Revenue - Electric	22,471,620	21,686,349	21,062,870	20,470,371	19,261,832
Operating Expenses - Electric	18,118,998	17,190,847	16,886,921	16,480,700	15,721,118
Operation Excluding Fuel	8,769,380	8,591,495	8,062,917	8,188,194	8,723,046
Fuel	3,437,909	2,935,940	3,072,158	2,749,890	2,587,003
Maintenance	1,563,258	1,504,782	1,446,295	1,455,786	1,486,423
Depreciation and Amortization ¹	2,582,885	2,417,279	2,300,532	2,075,595	2,051,058
Taxes and Tax Equivalents	755,456	681,140	595,719	550,042	500,424
Net Contributions and Services	--	--	389,300	431,193	373,165
Operating Income - Electric	4,352,711	4,495,793	4,195,949	4,009,671	3,540,714
Other Income and Deductions	1,217,997	1,628,944	1,843,761	1,849,720	1,977,538
Income from Electric Plant Leased to Others	23,388	15,129	5,942	11,330	5,325
Allowance for Funds Used During Construction	26,476	24,183	71,025	123,282	231,996
Other Income Net	1,454,450	1,839,484	1,890,138	1,735,107	1,740,217
Less Other Electric Deductions	268,325	248,852	123,345	--	--
Total Income Before Interest Charges	5,570,708	6,124,646	6,039,790	5,879,390	5,516,252
Net Interest Charges	4,681,822	5,025,758	5,205,799	5,064,998	4,740,199
Interest Expenses	4,432,886	4,757,583	4,775,003	4,863,114	4,337,962
Other Income Deductions	248,956	268,175	430,796	401,822	402,229
Net Income Before Extraordinary Charges	888,887	1,098,889	833,911	814,455	776,052
Less Extraordinary Items	214,707	115,276	88,544	108,958	653,861
Net Income	674,179	983,613	745,367	705,497	122,191

¹ In 1992 and 1993, nuclear fuel included.

* Net income reflects \$584 million of extraordinary deduction associated with the abandonment of the Rancho Seco Nuclear Plant reported by the Sacramento Municipal Utility District.

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding. *The number of publicly owned generating electric utilities that reported were 222 for 1993, 225 for 1992, 218 for 1991, 216 for 1990, and 214 for 1989.

Source: Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities."

Table 37. Composite Balance Sheet for Major U.S. Publicly Owned Generator Electric Utilities, 1989 Through 1993
(Thousand Dollars)

Description	1993	1992	1991	1990	1989
Assets					
Electric Utility Plant-Net Inc Nuclear Fuel	62,442,804	61,710,753	60,737,416	59,598,453	58,324,873
Electric Utility Plant Inc Nuclear Fuel	88,272,085	85,359,878	81,535,543	78,244,146	74,665,195
Accumulated Provision for Depreciation and Amortization	25,829,281	23,649,125	20,798,127	18,647,693	15,340,263
Other Property and Investments	20,485,211	18,226,937	17,332,581	15,801,311	15,037,749
Current and Accrued Assets	15,325,249	14,990,707	14,084,691	13,867,162	12,985,449
Deferred Debits	13,988,009	12,017,041	10,890,161	9,826,695	8,729,005
Total Assets	112,239,273	106,947,439	103,044,849	99,191,621	95,057,077
Liabilities and Other Credits					
Investment of Municipality - Surplus	23,471,967	22,823,228	22,222,042	21,881,128	21,049,661
Long-Term Debt	76,160,999	72,004,391	68,971,516	65,510,223	63,401,457
Other Noncurrent Liabilities	590,789	688,351	622,507	435,870	401,987
Current and Accrued Liabilities	8,587,318	8,060,777	7,844,671	7,283,479	7,213,148
Deferred Credits	3,428,200	3,340,894	3,484,113	3,281,121	3,291,514
Total Liabilities and Other Credits	112,239,273	106,947,439	103,044,849	99,191,621	95,057,077

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding. *The number of publicly owned generating electric utilities that reported were 222 for 1993, 225 for 1992, 218 for 1991, 216 for 1990, and 214 for 1989.

Source: Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities."

Table 38. Composite Financial Indicators for Major U.S. Publicly Owned Generator Electric Utilities, 1989 Through 1993

Description	1993	1992	1991	1990	1989
Electric Utility Plant per Dollar of Revenue	3.9	3.9	3.9	3.8	3.9
Current Assets to Current Liabilities	1.8	1.9	1.8	1.9	1.8
Electric Utility Plant as a Percent of Total Assets	78.6	79.8	79.1	78.9	78.5
Net Electric Utility Plant as a Percent of Total Assets	55.6	57.7	56.9	60.1	61.4
Debt as a Percent of Total Liabilities	75.5	74.9	74.4	74.4	74.0
Accumulated Provision for Depreciation as a Percent of Electric Utility Plant	29.3	27.7	25.5	23.8	21.9
Electric Operation and Maintenance Expenses as a Percent of Electric Operating Revenues	66.7	65.0	64.5	65.5	66.4
Electric Depreciation and Amortization as a Percent of Electric Operating Revenues	10.9	10.5	10.9	10.1	10.6
Taxes and Tax Equivalents as a Percent of Electric Operating Revenues	2.4	3.1	2.6	2.7	2.6
Interest Expenses as a Percent of Electric Operating Revenues	19.7	21.9	22.6	22.8	22.5
Net Income as a Percent of Electric Operating Revenues	3.0	4.5	3.6	3.4	6
Purchase Power (Cents Per Kilowatt-hour)	3.6	3.7	3.8	3.8	4.2
Generated Cents Per Kilowatt-hour	1.9	1.9	1.8	1.8	1.6
Total Power Supply Per Kilowatt-hour Sold	2.6	2.6	2.6	2.6	2.6

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding. *The number of publicly owned generating electric utilities that reported were 222 for 1993, 225 for 1992, 218 for 1991, 216 for 1990, and 214 for 1989.

Source: Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities."

Table 39. Revenue and Expense Statistics for Major U.S. Publicly Owned Generator Electric Utilities, 1989 Through 1993 (Thousand Dollars)

Description	1993	1992	1991	1990	1989
Operating Revenue - Electric	22,471,826	21,666,348	21,062,670	20,470,371	19,261,832
Operating Expenses - Electric	18,116,906	17,190,647	16,886,921	16,460,700	15,721,118
Operation Including Fuel	13,207,269	12,527,435	12,155,075	11,948,084	11,310,048
Production	10,225,044	9,712,324	9,465,070	9,525,315	8,976,237
Transmission	578,017	534,512	508,711	471,867	440,256
Distribution	406,393	368,703	362,654	328,897	314,678
Customer Accounts	314,989	299,209	289,388	272,649	246,501
Customer Service	93,652	82,731	73,801	60,411	62,431
Sales	17,088	17,545	19,077	18,043	11,927
Administrative and General	1,570,915	1,492,411	1,437,265	1,270,683	1,256,018
Maintenance	1,563,258	1,564,792	1,446,295	1,455,786	1,486,423
Depreciation and Amortization Excluding Nuclear Fuel	2,439,926	2,295,607	2,300,692	2,075,596	2,061,058
Taxes and Tax Equivalents	765,456	681,140	595,719	550,042	500,424
Net Contributions and Services	--	--	389,300	431,193	373,165
Income from Electric Utility Operations	4,352,711	4,495,703	4,195,949	4,009,671	3,540,714

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding. *The number of publicly owned generating electric utilities that reported were 222 for 1993, 225 for 1992, 218 for 1991, 216 for 1990, and 214 for 1989.

Source: Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities."

Table 40. Composite Statement of Income for Major U.S. Publicly Owned Nongenerator Electric Utilities, 1989 Through 1993
(Thousand Dollars)

Description	1993	1992	1991	1990	1989
Operating Revenue - Electric	7,673,861	7,247,407	7,119,875	6,978,762	6,662,712
Operating Expenses - Electric	7,106,516	6,843,539	6,859,619	6,740,926	6,354,588
Operation Excluding Fuel	8,459,040	8,244,812	8,119,381	8,030,028	7,693,914
Fuel	26	19	4	*	--
Maintenance	208,080	192,835	186,287	191,621	182,509
Depreciation and Amortization ¹	259,941	251,079	246,694	231,197	200,580
Taxes and Tax Equivalents	178,429	154,884	135,491	133,125	124,160
Net Contributions and Services	--	--	158,882	154,858	153,431
Operating Income - Electric	467,164	403,868	260,256	237,836	188,118
Other Income and Deductions	100,534	74,486	138,039	156,148	170,943
Income from Electric Plant Leased to Others	2,583	1,773	9,284	2,121	1,727
Allowance for Funds Used During Construction	106	88	1,806	-213	-302
Other Income Net	174,103	172,938	147,117	154,240	169,518
Less Other Electric Deductions	76,258	100,264	13,548	--	--
Total Income Before Interest Charges	567,689	478,354	396,294	393,975	369,062
Net Interest Charges	173,193	140,961	130,906	137,311	122,408
Interest Expenses	114,929	109,376	112,081	109,972	101,469
Other Income Deductions	58,264	31,585	27,775	27,340	20,934
Net Income Before Extraordinary Charges	394,506	337,493	265,488	256,663	246,658
Less Extraordinary Items	25,120	2,156	9,252	11,315	-14,950
Net Income	369,386	335,338	256,236	245,348	261,608

¹ In 1992 and 1993, nuclear fuel included

* = Value less than 0.5

Notes: *Data are final *Totals may not equal sum of components because of independent rounding *The number of publicly owned nongenerating electric utilities that reported were 273 for 1993, 256 for 1992, 252 for 1991, 251 for 1990, and 240 for 1989

Source: Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities"

Table 41. Composite Balance Sheet for Major U.S. Publicly Owned Nongenerator Electric Utilities, 1989 Through 1993
(Thousand Dollars)

Description	1993	1992	1991	1990	1989
Assets					
Electric Utility Plant-Net Inc Nuclear Fuel	5,303,008	4,861,003	4,662,421	4,407,579	4,112,590
Electric Utility Plant Inc Nuclear Fuel	8,398,157	7,783,037	7,318,688	6,861,881	6,344,572
Accumulated Provision for Depreciation and Amortization	3,085,148	2,852,034	2,656,267	2,454,302	2,231,882
Other Property and Investments	1,913,916	1,880,451	1,849,607	1,770,583	1,710,086
Current and Accrued Assets	2,627,823	2,227,864	2,102,131	2,063,831	1,834,261
Deferred Debits	425,222	366,263	324,440	271,452	249,858
Total Assets	10,168,770	9,384,601	8,998,600	8,513,545	8,008,871
Liabilities and Other Credits					
Investment of Municipality - Surplus	6,039,007	5,522,242	5,244,951	4,994,123	4,675,254
Long-Term Debt	2,806,801	2,713,721	2,642,435	2,348,678	2,216,899
Other Noncurrent Liabilities	10,749	10,284	55,488	38,157	40,842
Current and Accrued Liabilities	1,046,801	962,587	968,924	949,345	887,078
Deferred Credits	166,812	154,889	165,803	183,244	185,789
Total Liabilities and Other Credits	10,168,770	9,384,601	8,998,600	8,513,545	8,008,871

Notes: *Data are final *Totals may not equal sum of components because of independent rounding *The number of publicly owned nongenerating electric utilities that reported were 273 for 1993, 256 for 1992, 252 for 1991, 251 for 1990, and 240 for 1989

Source: Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities"

Table 42. Composite Financial Indicators for Major U.S. Publicly Owned Nongenerator Electric Utilities, 1989 Through 1993

Description	1993	1992	1991	1990	1989
Electric Utility Plant per Dollar of Revenue	1.1	1.1	1.0	1.0	1.0
Current Assets to Current Liabilities	2.4	2.3	2.2	2.2	2.2
Electric Utility Plant as a Percent of Total Assets	82.6	82.4	81.3	80.6	79.2
Net Electric Utility Plant as a Percent of Total Assets	52.1	52.0	51.8	51.6	51.4
Debt as a Percent of Total Liabilities	38.9	39.4	39.0	38.7	38.8
Accumulated Provision for Depreciation as a Percent of Electric Utility Plant	38.9	38.9	38.3	35.8	35.2
Electric Operation and Maintenance Expenses as a Percent of Electric Operating Revenues	88.0	88.8	88.6	89.2	89.7
Electric Depreciation and Amortization as a Percent of Electric Operating Revenues	3.4	3.4	3.5	3.3	3.1
Taxes and Tax Equivalents as a Percent of Electric Operating Revenues	2.4	2.1	1.9	1.9	1.9
Interest Expenses as a Percent of Electric Operating Revenues	1.5	1.5	1.6	1.6	1.5
Net Income as a Percent of Electric Operating Revenues	4.9	4.6	3.5	3.5	4.0
Purchase Power (Cents Per Kilowatt-hour)	4.1	4.1	4.1	4.0	4.0

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding. *The number of publicly owned nongenerating electric utilities that reported were 278 for 1993, 256 for 1992, 252 for 1991, 251 for 1990, and 240 for 1989.
Source: Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities."

Table 43. Revenue and Expense Statistics for Major U.S. Publicly Owned Nongenerator Electric Utilities, 1989 Through 1993
(Thousand Dollars)

Description	1993	1992	1991	1990	1989
Operating Revenue - Electric	7,573,881	7,247,407	7,119,875	6,978,762	6,552,712
Operating Expenses - Electric	7,106,516	6,843,539	6,859,819	6,740,926	6,264,593
Operation Including Fuel	6,459,066	6,244,831	6,119,365	6,030,028	5,683,914
Production	5,788,863	5,817,261	5,523,601	5,478,640	5,052,577
Transmission	84,373	32,956	82,284	30,119	28,459
Distribution	190,965	176,188	184,147	144,862	233,363
Customer Accounts	117,355	109,196	102,488	98,305	93,509
Customer Service	17,403	15,829	15,638	18,987	13,583
Sales	8,826	11,849	11,667	11,222	5,065
Administrative and General	300,261	261,854	259,782	251,514	269,857
Maintenance	209,080	192,835	186,287	191,821	182,509
Depreciation and Amortization Excluding Nuclear Fuel	255,452	248,040	246,594	231,197	200,580
Taxes and Tax Equivalents	178,428	154,994	138,491	133,125	124,160
Net Contributions and Services	—	—	168,882	154,956	159,431
Income from Electric Utility Operations	467,184	403,868	260,255	237,826	188,118

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding. *The number of publicly owned nongenerating electric utilities that reported were 273 for 1993, 256 for 1992, 252 for 1991, 251 for 1990, and 240 for 1989.
Source: Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities."

U.S. Electric Utility Environmental Statistics

When fossil fuels are burned in the production of electricity, a variety of gases and particulates are formed. If these gases and particulates are not captured by some pollution control equipment, they are released into the atmosphere. This chapter provides a brief summary of the gaseous emissions from U.S. electric utilities and the methods employed to reduce or eliminate their release into the atmosphere.

Background

Among the gases emitted during the burning of fossil fuels are sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon dioxide (CO_2). Coal-fired generating units produce more SO_2 and NO_x than other fossil-fuel units for two reasons. First, because coal generally contains more sulfur than other fossil fuels, it creates more SO_2 when burned. Second, there are more NO_x emissions from coal-fired plants because more coal-fired capacity than other fossil-fueled capacity is in use.

Sulfur is an element that is present in almost all coal, although some kinds of coal contain more sulfur than others depending on the geographic location of the coal mine and the type of coal being mined. Western coal has less sulfur than eastern coal. Over one-half of the coal mined in the West is subbituminous coal that is low in sulfur content (about 0.5 percent) and contains approximately 9,000 Btu per pound. Bituminous eastern coal can exceed both a 5-percent sulfur content and a heat content of 12,000 Btu per pound. The average percent of sulfur contained in coal ranges from 0.3 percent in the West to approximately 2.5 percent in the East. During combustion, the sulfur combines with the oxygen in the air to form SO_2 . As the SO_2 mixes further with oxygen and trace substances in the air, a variety of sulfate compounds emerges. How these transformations take place, and in what proportions, is a subject of vigorous research. The behavior of SO_2 emissions depends partly on the type of coal used and how it is burned. In addition, the presence of light, moisture, and other pollutants in the atmosphere may also be important in triggering the complex changes that SO_2 emissions undergo. To a lesser degree, sulfur is also contained in petroleum and varies according to the type of petroleum (for example, light oil, heavy oil, etc.). Petroleum burned at utility power plants can range from almost no sulfur to about 3.5 percent sulfur. The weighted average percent of sulfur contained in petroleum consumed by utility plants ranges from

about .5 percent in western plants to about 1.4 percent for plants in New England. The amount of sulfur contained in natural gas is insignificant.

Nitrogen is a colorless, odorless gas that makes up about 78 percent of the atmosphere. Nitrogen in the atmosphere during the combustion process (burning of fuels at the plant) combines with oxygen and water to form several NO_x . Also, a small amount of nitrogen in the coal is converted to NO_x . The most important is nitrogen dioxide, one of the compounds that gives photochemical smog its characteristic yellowish-brown color. Only about 10 percent of the nitrogen compounds in the air are the result of human activity. The rest are formed by natural processes, such as the decay of organic matter. However, since the human-made 10 percent is emitted mostly in industrial urban areas, concentration there can become high enough to cause concern.

SO_2 and NO_x are referred to as precursors to acid deposition, because, under the right set of conditions, they react with other chemicals in the atmosphere to form sulfuric acid and nitric acid, respectively. These two acids do not accumulate in the atmosphere, but are absorbed by rain droplets, thus cleansing the atmosphere and discharging acid onto the earth in the form of "acid rain." In addition, sulfuric acid may form microscopic droplets that can be deposited directly onto the ground. This form of deposition, as well as the direct capture of SO_2 by vegetation, is referred to as dry deposition.

CO_2 is a colorless, odorless, nontoxic gas formed by the combustion of carbon and carbon compounds found in coal, petroleum, and gas. Currently, the only way to limit the emission of CO_2 when burning fossil fuels is extremely expensive. CO_2 is normally removed from the atmosphere by green plants and absorbed by the ocean. The increased use of fossil fuels in recent years, as well as extensive deforestation, has caused a buildup of CO_2 in the atmosphere. This increase of CO_2 causes the atmosphere to absorb infrared radiation reflected from the earth that would otherwise have been dissipated into space. This phenomenon could increase temperature and is called the "greenhouse" effect because it is similar to the trapping of the energy of the sun in a greenhouse. These potential increases in temperatures are of concern because they could cause dramatic climatic changes, shifts in agricultural zones, and partial melting of the polar ice caps resulting

in flooding of coastal areas. However, significant uncertainties exist regarding global warming, and no conclusions can be drawn regarding future warming based on past temperature records.

Efforts are underway to determine what methods can be employed to reduce or eliminate the release of CO₂ from power plants. Tail gas cleanup (CO₂ scrubbing) is currently the only technological option. This option would require the adaptation by the electric utility industry of acid gas removal technologies used by the petroleum and petrochemical industries. Because of the potential expense involved and the uncertainty concerning the impacts of emissions from the gas, no emission standards or required reductions exist.

Additionally, the Department of Energy is developing clean coal technologies (such as pressurized fluidized-bed combustion) for new plants and repowering applications. Due to the increased conversion efficiencies of these technologies, CO₂ emissions are reduced.

Emission Standards

To respond to concerns about emissions of SO₂ and NO_x as well as several other air pollutants, Congress passed the Clean Air Act (CAA) in 1963. It was not until 1970, however, that the Environmental Protection Agency was empowered to set enforceable air quality standards. In 1971, this Agency established New Source Performance Standards (NSPS) that required coal-fired utility boilers built after August 17, 1971, to emit no more than 1.2 pounds of SO₂ per million Btu of heat input. Requirements for NO_x were more complex, with allowable limits ranging from 0.2 pounds per million Btu to 0.8 pounds per million Btu, depending on the type of fuel burned and the combustion device used.

In 1977, Congress amended the CAA to require States to set limits on existing sources in regions not attaining goals established in the Act. In 1979, the Environmental Protection Agency established the Revised New Source Performance Standards (RNSPS). The new standards retain the 1971 NSPS of 1.2 pounds of SO₂ per million Btu of heat input, but require SO₂ emissions from all new or modified (post 1978) boilers to be reduced by at least 90 percent unless 90-percent removal reduces emissions to less than 0.6 pounds per million Btu. If emissions fall below that level, reductions between 70 and 90 percent are permitted, depending on the sulfur content of the coal. RNSPS for NO_x are complex and, as with NSPS, set limits varying from 0.2 to 0.8 pounds per million Btu, depending on the type of fuel burned and combustion device used. RNSPS for NO_x differ from NSPS in the number of categories of combustion into which they are divided.

The primary goals of the Clean Air Act Amendments (CAAA) of 1990 that impact generators of electricity are a 10-million-ton reduction in SO₂ emissions and a

2-million-ton reduction in NO_x emissions from 1980 levels. The reduction in SO₂ is to occur in two phases that begin in 1995 and 2000, respectively. The CAAA established an innovative marketable emission allowance program. The CAAA contains a list of the allowances to be issued in Phase 1 and the Environmental Protection Agency published a preliminary list of Phase 2 allowances in June 1992.

Emission Reductions

Sulfur Dioxide. One method available to reduce the SO₂ emitted when burning coal, is to switch to a coal that has a lower sulfur content. Emissions of sulfur dioxide may also be reduced by using less-polluting fuels, particularly gas. Another approach is to install equipment designed to remove SO₂ from the gas (flue gas) released through the flues of the plant. Additional methods for reducing emissions of SO₂, which include converting boilers to the fluidized-bed combustion process and employing the technology of integrated-gasification combined cycle, are currently under study and not in extensive use.

Nitrogen Oxides. Formation of NO_x is less dependent on the type of fuel burned than on how the fuel is burned. Apart from the nitrogen content of the fuel, the extent of nitric-oxide formation depends primarily on the combustion temperature. NO_x emissions can be reduced by low excess-air firing; low-combustion temperatures; use of low-nitrogen fuels (such as natural gas and light distillate oil); staged combustion in which localized fuel-rich conditions are created where both thermal and fuel NO_x are minimized; and use of low-NO_x burners and fluidized-bed combustion.

Environmental Equipment

While not the only kind of environmental equipment installed at power plants, flue gas desulfurization units, particulate collectors, and cooling towers are the most significant. In a flue gas desulfurization unit (scrubber), the gases resulting from combustion are passed through tanks containing a material that captures and neutralizes the SO₂. Particulate matter is most frequently removed from the combustion gases by either filtering (a series of filter bags that trap the ash and dust much like a household vacuum cleaner) in a baghouse or with an electrostatic precipitator. In the latter, the particulates are given an electric charge and collected. Particulate collection is mainly centered on coal combustion because of the large percentage of ash that coal contains. Petroleum has very little ash and natural gas has practically none.

For a fossil-fueled steam-electric generating unit, about two-thirds of the heat produced by burning the fuel is released to the environment, and only about one-third is used to produce electricity. Most waste heat (contained in the cooling water) is dissipated into a body

Table 44. Estimated Emissions from Fossil-Fueled Steam-Electric Generating Units at U.S. Electric Utilities, 1989 Through 1993
(Thousand Short Tons)

Emission	1989	1992	1991	1990	1988
Sulfur Dioxide (SO ₂)	14,432	14,880	15,012	15,368	15,780
Nitrogen Oxides (NO _x) ¹	5,852	5,674	5,801	5,801	5,956
Carbon Dioxide (CO ₂) ¹	1,848,288	1,883,381	1,878,839	1,874,153	1,917,608

¹ As of 1989 data, CO₂ emissions from the emission factor for light oil and NO_x emissions reductions from control technologies have been revised due to a software problem—(see Technical Notes)—historical data were revised to reflect these changes.

Notes: *Estimates for 1993 are preliminary; estimates for prior years are final. *Emissions of CO₂, NO_x, and SO₂ have been revised from the updated (July 1993) Air Pollutant Emissions Factors (AP-42 release IV) of the Environmental Protection Agency (see Technical Notes). *Estimates are for steam-electric plants 10 megawatts and larger, based on fuel consumption data.

Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report."

Table 45. Number and Capacity of Fossil-Fueled Steam-Electric Generators for U.S. Electric Utility Plants with Environmental Equipment, 1989 Through 1993

Environmental Equipment	Scrubbers		Particulate Collectors	
	Number of Generators	Capacity ¹ (megawatts)	Number of Generators	Capacity ¹ (megawatts)
1993	153	70,890	1,155	351,451
1992	154	71,351	1,168	353,525
1991	154	70,554	1,173	352,890
1990	153	69,122	1,177	349,319
1989	150	67,534	1,173	347,885

	Cooling Towers		Total ²	
	Number of Generators	Capacity ¹ (megawatts)	Number of Generators	Capacity ¹ (megawatts)
1993	496	184,951	1,334	377,473
1992	485	185,305	1,346	379,194
1991	486	185,937	1,353	378,963
1990	478	182,557	1,360	376,894
1989	466	180,087	1,357	375,257

¹ Nameplate capacity.

² Components are not additive since some generators are included in more than one category and not all units have environmental equipment.

Notes: *Data for 1993 are preliminary; data for prior years are final. *These data are only for plants with a fossil-fueled steam-electric capacity of 100 or more megawatts. *Historical data have been revised to reflect additional data reported by respondents.

Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report."

of water, such as a river, lake, or bay. Cooling towers are installed where there is insufficient cooling water and where the waste heat discharged into the cooling water affects plants or marine life. A cooling tower is a structure for transferring heat in the water to the atmosphere. The most common type of cooling tower is the wet tower, also called the evaporative tower. In a wet tower, cooling is caused mainly by evaporation of the water and partly by direct-heat transfer.

Environmental equipment can be a significant part of the cost of a power plant. This additional cost includes the initial capital cost of installation and the recurring operation and maintenance (O&M) costs. Capital costs are given as a cost per kilowatt of installed nameplate capacity.

Data Sources

Estimates are provided in the following tables on SO₂, NO_x, and CO₂ emissions from fossil-fueled steam-electric generating units. The methodology for computing emission estimates is described in Appendix C. Additional detailed information on emissions from electric utilities can be obtained in Chapter 6 of the *Annual Energy Outlook*.³² Also presented in the following tables are the number and capacity of fossil-fueled steam-

electric generators with environmental equipment (scrubbers, particulate collectors, and cooling towers). Because power plants can have more than one type of environmental equipment, the generators at these plants can be included in more than one category. Also, not all utility plants have environmental equipment. Data regarding the quality of fossil fuels used to produce electricity by electric utilities, including heat, sulfur, and ash content, are also provided in the following tables. Lastly, average flue gas desulfurization costs (that is, operation and maintenance costs per kilowatt-hour of generation and installation costs per kilowatt of nameplate capacity) are presented.

These estimates were either derived or obtained directly from the Form EIA-767, "Steam-Electric Plant Operation and Design Report." This form is a restricted-universe census used to collect boiler-specific data from almost 900 U.S. electric utility power plants with organic- or nuclear-fueled steam-electric nameplate capacity of 10 or more megawatts operated by over 300 electric utilities. The entire form, including data on environmental equipment, is filed by about 700 power plants with a nameplate capacity of 100 or more megawatts. Information on power plants with a nameplate capacity between 10 and 100 megawatts is submitted only for fuel consumption and flue gas desulfurization equipment. There are 71 nuclear power plants in the Form EIA-767 respondent universe.

³²Energy Information Administration, *Annual Energy Outlook* DOE/EIA-0383(93)(Washington, DC, 1993).

Table 46. Estimated Emissions from Fossil-Fueled Steam-Electric Generating Units at Electric Utilities by Census Division and State, 1993 and 1992
(Thousand Short Tons)

Census Division State	1993			1992		
	Sulfur Dioxide	Nitrogen Oxides ¹	Carbon Dioxide ¹	Sulfur Dioxide	Nitrogen Oxides ¹	Carbon Dioxide ¹
New England	227	74	31,488	298	80	38,785
Connecticut	28	11	6,563	34	12	7,763
Maine	6	1	740	7	2	1,204
Massachusetts	142	44	19,243	201	55	24,771
New Hampshire	51	18	4,736	66	16	4,720
Rhode Island	•	•	50	•	•	109
Vermont	•	•	125	•	•	191
Middle Atlantic	1,471	408	162,839	1,862	439	179,332
New Jersey	80	34	8,747	59	38	9,549
New York	281	99	48,322	336	117	57,142
Pennsylvania	1,130	273	106,870	1,167	277	104,141
East North Central	4,970	1,463	397,582	4,767	1,388	379,343
Illinois	794	275	64,259	821	229	54,050
Indiana	1,206	400	109,073	1,169	406	105,606
Michigan	358	237	66,405	346	230	65,448
Ohio	2,132	425	126,831	2,172	425	123,585
Wisconsin	182	117	31,015	200	111	30,655
West North Central	1,019	667	181,932	1,198	627	183,361
Iowa	175	116	26,599	174	110	24,810
Kansas	70	111	32,792	68	82	27,023
Minnesota	88	117	34,006	78	105	30,879
Missouri	404	179	49,454	656	204	50,466
Nebraska	58	66	16,896	52	56	14,413
North Dakota	131	57	39,325	130	59	32,922
South Dakota	31	11	2,961	32	11	2,847
South Atlantic	3,348	1,838	382,480	3,379	1,001	381,012
Delaware	50	20	7,871	39	16	6,003
District of Columbia	1	•	216	1	•	97
Florida	700	281	101,102	731	283	87,519
Georgia	689	147	59,448	767	142	55,881
Maryland	269	78	29,241	254	71	26,977
North Carolina	421	168	59,111	398	152	53,963
South Carolina	178	69	27,122	159	81	23,749
Virginia	189	61	26,722	173	56	24,044
West Virginia	850	217	71,586	897	221	72,785
East South Central	2,258	889	224,914	2,155	609	197,824
Alabama	548	186	68,177	523	189	62,026
Kentucky	827	267	83,141	749	268	74,647
Mississippi	141	37	14,066	100	31	10,883
Tennessee	634	176	59,510	783	159	50,267
West South Central	796	877	391,821	756	842	289,324
Arkansas	62	59	21,472	66	68	23,931
Louisiana	119	122	38,375	110	120	37,744
Oklahoma	104	121	39,689	108	114	38,055
Texas	501	575	202,085	472	540	189,496
Mountain	493	520	285,636	487	634	199,219
Arizona	130	104	31,826	125	89	27,889
Colorado	83	100	32,811	85	99	32,362
Idaho	•	•	•	•	•	•
Montana	20	42	16,926	22	52	19,707
Nevada	53	49	20,087	58	62	21,172
New Mexico	58	98	30,062	56	97	19,417
Utah	31	43	33,182	30	50	32,759
Wyoming	78	84	41,923	78	84	45,904
Pacific Contiguous	87	120	42,900	88	137	48,268
California	5	74	28,749	1	88	33,107
Oregon	13	13	3,691	14	13	4,013
Washington	70	33	10,480	70	38	11,149
Pacific Noncontiguous	21	9	4,764	23	10	5,521
Alaska	1	•	1	1	•	2
Hawaii	20	9	4,753	23	10	5,520
U.S. Total	14,432	5,852	1,946,288	14,890	5,674	1,863,861

¹ As of 1993 data, CO₂ emissions from the emission factor for light oil and NO_x emissions reductions from control technologies have been revised due to a software problem—(see Technical Notes)—historical data were revised to reflect these changes.

• = Value less than 0.5.

Notes: • Estimates for 1993 are preliminary; estimates for prior years are final. • Emissions of CO₂, NO_x, and SO₂ have been revised from the updated (July 1993) Air Pollutant Emissions Factors (AP-42 release IV) of the Environmental Protection Agency (see Technical Notes). • Estimates are for steam-electric plants 10 megawatts and larger, based on fuel consumption data.

Source: Energy Information Administration, Form EIA-787, "Steam-Electric Plant Operation and Design Report."

Table 47. Estimated Emissions from Fossil-Fueled Steam-Electric Generating Units at Electric Utilities by Fossil Fuel, Census Division, and State, 1993 (Thousand Short Tons)

Census Division State	Coal			Petroleum			Gas			Other ¹		
	Sulfur Dioxide	Nitrogen Oxides ²	Carbon Dioxide ²	Sulfur Dioxide	Nitrogen Oxides ²	Carbon Dioxide ²	Sulfur Dioxide	Nitrogen Oxides ²	Carbon Dioxide ²	Sulfur Dioxide	Nitrogen Oxides ²	Carbon Dioxide ²
New England	119	47	15,296	197	21	18,551	*	6	1,661	1	1	959
Connecticut	8	4	1,985	19	5	3,833	0	*	35	1	1	738
Maine	0	0	0	6	1	740	0	0	0	0	0	0
Massachusetts	72	26	9,734	70	13	7,807	*	6	1,690	*	*	102
New Hampshire	40	17	3,565	12	1	1,144	0	*	8	*	*	21
Rhode Island	0	0	0	*	*	28	0	*	23	0	0	0
Vermont	0	0	0	*	0	*	0	*	15	*	*	109
Middle Atlantic	1,383	347	130,307	87	29	19,894	*	31	12,893	*	*	45
New Jersey	56	27	6,222	3	2	1,012	*	6	1,508	*	*	6
New York	211	53	22,726	69	21	14,610	*	24	10,883	0	*	2
Pennsylvania	1,116	267	101,358	15	5	3,972	*	1	502	*	*	38
East North Central	4,661	1,453	392,429	8	3	2,230	*	6	2,138	1	1	785
Illinois	790	271	62,197	4	2	1,104	*	2	958	0	0	0
Indiana	1,204	408	108,574	*	*	163	*	1	335	0	0	0
Michigan	354	233	65,084	3	1	713	*	2	608	0	*	0
Ohio	2,191	424	126,012	*	*	218	0	*	83	1	1	518
Wisconsin	181	116	30,562	*	*	32	*	1	154	*	*	267
West North Central	1,016	849	188,837	2	*	316	*	7	1,882	1	1	1,098
Iowa	175	115	26,237	*	*	28	*	1	225	*	*	110
Kansas	70	107	31,609	*	*	52	*	4	1,130	0	0	0
Minnesota	87	115	32,770	*	*	20	*	1	228	1	1	987
Missouri	463	178	45,067	1	*	167	*	1	219	0	*	*
Nebraska	58	88	15,806	*	*	14	0	*	78	0	*	*
North Dakota	131	57	33,298	*	*	27	0	0	*	0	0	0
South Dakota	31	11	2,850	*	*	7	0	*	4	0	0	0
South Atlantic	3,050	941	334,732	297	63	37,623	*	32	9,853	1	*	292
Delaware	39	16	5,790	10	4	1,841	0	*	71	1	*	155
District of Columbia	0	0	0	1	*	210	0	0	0	*	*	6
Florida	460	197	82,468	239	53	29,299	*	31	9,296	*	*	32
Georgia	687	147	59,140	1	*	145	*	*	160	*	*	8
Maryland	238	70	25,016	32	5	9,856	*	1	288	*	*	82
North Carolina	421	165	68,988	*	*	123	0	0	0	0	0	0
South Carolina	178	69	27,039	*	*	67	0	*	16	*	0	1
Virginia	178	59	24,883	11	2	1,815	0	*	26	0	0	0
West Virginia	850	217	71,390	*	*	167	0	*	7	0	0	0
East South Central	2,297	677	219,866	59	6	3,292	*	6	1,756	0	0	0
Alabama	548	186	67,326	*	*	57	*	1	193	0	0	0
Kentucky	526	287	83,029	*	*	99	0	*	13	0	0	0
Mississippi	88	26	9,478	63	6	3,080	*	5	1,550	0	0	0
Tennessee	834	176	59,435	*	*	75	0	0	0	0	0	0
West South Central	783	822	215,416	3	1	729	*	264	85,476	0	0	0
Arkansas	62	56	20,128	*	*	52	*	4	1,292	0	0	0
Louisiana	116	79	23,653	3	1	980	*	42	14,342	0	0	0
Oklahoma	104	96	32,336	*	*	11	*	25	7,342	0	0	0
Texas	500	390	139,299	*	*	285	*	184	62,501	0	0	0
Mountain	452	808	291,583	1	1	403	*	11	3,440	0	*	*
Arizona	130	102	31,194	*	*	45	*	2	566	0	0	0
Colorado	83	99	32,620	*	*	5	*	1	286	0	*	*
Idaho	*	*	*	*	*	*	*	*	*	*	*	*
Montana	20	42	15,909	*	*	11	0	*	7	0	0	0
Nevada	52	45	18,763	1	*	235	*	4	1,090	0	0	0
New Mexico	58	94	28,411	*	*	34	*	4	1,637	0	0	0
Utah	31	43	32,868	*	*	24	*	*	268	0	0	0
Wyoming	78	84	41,869	*	*	49	0	*	5	0	0	0
Pacific Contiguous	83	45	15,447	4	3	1,738	*	71	27,024	*	*	690
California	0	0	0	4	3	1,728	*	71	27,024	0	0	0
Oregon	13	13	3,885	*	*	6	0	0	0	0	0	0
Washington	70	33	9,782	*	*	7	0	*	1	*	*	690
Pacific Noncontiguous	1	0	0	20	0	4,754	0	0	0	0	0	0
Alaska	1	0	0	*	*	1	0	0	0	0	0	0
Hawaii	0	0	0	20	0	4,763	0	0	0	0	0	0
U.S. Total	13,844	5,298	1,711,873	593	136	84,129	1	424	146,864	4	4	3,880

¹ Includes light oil, methane, coal/oil mixture, propane gas, blast furnace gas, wood, and refuse.

² As of 1993 data, CO2 emissions from the emission factor for light oil and NOx emissions reductions from control technologies have been revised due to a software problem—(see Technical Notes)—historical data were revised to reflect these changes.

Notes: *Estimates for 1993 are preliminary; estimates for prior years are final. *Emissions of CO2, NOx, and SO2 have been revised from the updated (July 1993) Air Pollutant Emissions Factors (AP-42 release IV) of the Environmental Protection Agency (see Technical Notes). *Estimates are for steam-electric plants 10 megawatts and larger, based on fuel consumption data. *—Value less than 0.5.

Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report."

Table 49. Number and Capacity of Petroleum- and Gas-Fired Steam-Electric Generators for Electric Utility Plants with Environmental Equipment by Census Division and State, 1993

Census Division State	Generating Units ¹		Scrubbers		Particulate Collectors		Cooling Towers	
	Number of Generators	Capacity ² (megawatts)	Number of Generators	Capacity ² (megawatts)	Number of Generators	Capacity ² (megawatts)	Number of Generators	Capacity ² (megawatts)
New England	25	6,244	0	0	24	5,829	1	415
Connecticut	11	2,098	0	0	10	1,883	1	415
Maine	4	848	0	0	4	848	0	0
Massachusetts	6	2,754	0	0	6	2,754	0	0
New Hampshire	1	414	0	0	1	414	0	0
Rhode Island	3	132	0	0	3	132	0	0
Vermont	0	0	0	0	0	0	0	0
Middle Atlantic	41	12,081	0	0	38	10,185	4	2,012
New Jersey	10	1,737	0	0	9	1,602	2	311
New York	21	6,818	0	0	21	6,818	0	0
Pennsylvania	10	3,526	0	0	8	1,884	2	1,701
East North Central	18	2,575	0	0	11	1,042	5	1,533
Illinois	1	210	0	0	0	0	1	210
Indiana	5	970	0	0	3	278	2	92
Michigan	6	1,743	0	0	4	512	2	1,231
Ohio	2	154	0	0	2	154	0	0
Wisconsin	2	88	0	0	2	88	0	0
West North Central	18	1,494	0	0	5	188	14	1,337
Iowa	3	65	0	0	3	65	0	0
Kansas	10	1,255	0	0	0	0	10	1,255
Minnesota	1	92	0	0	1	92	0	0
Missouri	4	83	0	0	1	22	4	83
Nebraska	0	0	0	0	0	0	0	0
North Dakota	0	0	0	0	0	0	0	0
South Dakota	0	0	0	0	0	0	0	0
South Atlantic	53	12,588	0	0	48	12,339	17	4,425
Delaware	4	597	0	0	4	597	2	132
District of Columbia	2	580	0	0	0	0	2	580
Florida	21	9,976	0	0	22	8,626	9	1,351
Georgia	0	0	0	0	0	0	0	0
Maryland	12	2,534	0	0	10	1,216	3	1,480
North Carolina	0	0	0	0	0	0	0	0
South Carolina	0	0	0	0	0	0	0	0
Virginia	4	1,902	0	0	4	1,902	1	562
West Virginia	0	0	0	0	0	0	0	0
East South Central	5	428	0	0	1	147	4	281
Alabama	0	0	0	0	0	0	0	0
Kentucky	1	147	0	0	1	147	0	0
Mississippi	4	281	0	0	0	0	4	281
Tennessee	0	0	0	0	0	0	0	0
West South Central	40	14,074	0	0	4	2,268	37	12,915
Arkansas	2	183	0	0	0	0	2	183
Louisiana	14	2,535	0	0	2	1,184	13	1,943
Oklahoma	19	4,950	0	0	1	587	18	3,793
Texas	54	7,006	0	0	1	507	54	7,006
Mountain	32	2,787	0	0	4	284	32	2,787
Arizona	13	1,382	0	0	0	0	13	1,382
Colorado	3	111	0	0	2	101	3	111
Idaho	0	0	0	0	0	0	0	0
Montana	0	0	0	0	0	0	0	0
Nevada	4	243	0	0	0	0	4	243
New Mexico	9	800	0	0	0	0	9	800
Utah	3	252	0	0	2	183	3	252
Wyoming	0	0	0	0	0	0	0	0
Pacific Contiguous	30	3,279	0	0	5	368	29	3,216
California	30	3,979	0	0	5	368	29	3,216
Oregon	0	0	0	0	0	0	0	0
Washington	0	0	0	0	0	0	0	0
Pacific Noncontiguous	0	0	0	0	0	0	0	0
Alaska	0	0	0	0	0	0	0	0
Hawaii	0	0	0	0	0	0	0	0
U.S. Total	309	59,596	0	0	132	32,626	183	28,922

¹ Components are not additive since some generators are included in more than one category and not all units have environmental equipment.

² Nameplate capacity.

Notes: *Totals may not equal sum of components because of independent rounding. *These data are only for plants with a fossil-fueled steam-electric capacity of 100 or more megawatts. *Data are preliminary.

Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report."

Table 48. Number and Capacity of Coal-Fired Steam-Electric Generators for Electric Utility Plants with Environmental Equipment by Census Division and State, 1993

Census Division State	Generating Units ¹		Scrubbers		Particulate Collectors		Cooling Towers	
	Number of Generators	Capacity ² (megawatts)	Number of Generators	Capacity ² (megawatts)	Number of Generators	Capacity ² (megawatts)	Number of Generators	Capacity ² (megawatts)
New England	15	2,772	0	0	15	2,773	0	0
Connecticut	1	400	0	0	1	400	0	0
Maine	0	0	0	0	0	0	0	0
Massachusetts	9	1,764	0	0	9	1,764	0	0
New Hampshire	5	609	0	0	5	609	0	0
Rhode Island	0	0	0	0	0	0	0	0
Vermont	0	0	0	0	0	0	0	0
Middle Atlantic	85	24,117	9	4,690	85	24,117	16	11,386
New Jersey	8	1,732	0	0	8	1,732	0	0
New York	26	3,721	1	655	25	3,721	0	0
Pennsylvania	52	18,664	6	4,035	52	18,664	16	11,366
East North Central	297	82,024	17	6,220	297	82,024	41	28,439
Illinois	55	17,123	4	1,439	55	17,123	2	562
Indiana	58	21,565	10	4,468	58	21,565	23	9,395
Michigan	49	12,124	0	0	49	12,124	2	199
Ohio	87	24,179	3	2,314	87	24,179	11	6,664
Wisconsin	38	7,033	0	0	38	7,033	3	1,478
West North Central	136	35,699	26	11,372	136	35,699	38	11,753
Iowa	27	5,645	1	176	27	5,645	6	1,661
Kansas	20	5,644	6	3,930	20	5,644	9	3,268
Minnesota	25	5,417	8	3,393	25	5,417	9	3,787
Missouri	37	11,426	3	1,125	37	11,426	6	767
Nebraska	14	3,092	0	0	14	3,092	4	430
North Dakota	12	4,009	6	2,809	12	4,009	4	1,826
South Dakota	1	456	0	0	1	456	0	0
South Atlantic	213	68,076	14	6,968	211	68,013	63	35,264
Delaware	6	1,034	0	0	6	1,034	1	442
District of Columbia	0	0	0	0	0	0	0	0
Florida	27	10,752	7	3,976	27	10,752	11	6,167
Georgia	37	13,958	1	123	37	13,958	12	9,774
Maryland	15	4,943	0	0	15	4,943	2	1,370
North Carolina	47	12,556	0	0	45	12,484	8	3,188
South Carolina	24	5,324	4	1,501	24	5,324	13	3,787
Virginia	24	4,549	0	0	24	4,549	3	713
West Virginia	33	14,958	2	1,968	33	14,958	13	9,522
East South Central	132	40,471	23	6,822	132	40,471	28	12,833
Alabama	39	12,586	4	1,597	39	12,586	4	2,589
Kentucky	54	15,956	17	6,625	54	15,956	21	9,394
Mississippi	6	2,150	2	400	6	2,150	3	900
Tennessee	33	9,780	0	0	33	9,780	0	0
West South Central	57	33,463	16	10,547	57	33,463	30	17,035
Arkansas	5	3,958	0	0	5	3,958	4	3,400
Louisiana	6	3,572	1	721	6	3,572	4	2,454
Oklahoma	10	5,210	1	520	10	5,210	8	4,072
Texas	36	20,724	14	9,306	36	20,724	14	7,109
Mountain	87	30,268	48	20,471	87	30,268	76	26,783
Arizona	13	5,324	5	2,453	13	5,324	11	4,922
Colorado	26	4,976	5	1,974	26	4,976	24	4,524
Idaho	—	—	—	—	—	—	—	—
Montana	5	2,464	4	2,273	5	2,464	4	2,273
Nevada	6	2,769	5	879	6	2,769	7	1,951
New Mexico	10	4,262	10	4,262	10	4,262	6	2,012
Utah	10	4,604	7	3,969	10	4,604	10	4,604
Wyoming	15	5,838	8	4,641	15	5,838	14	6,476
Pacific Contiguous	3	2,020	0	0	3	2,020	2	1,460
California	0	0	0	0	0	0	0	0
Oregon	1	561	0	0	1	561	0	0
Washington	2	1,460	0	0	2	1,460	2	1,460
Pacific Noncontiguous	0	0	0	0	0	0	0	0
Alaska	0	0	0	0	0	0	0	0
Hawaii	0	0	0	0	0	0	0	0
U.S. Total	1,025	316,893	153	70,890	1,023	315,530	293	156,926

¹ Components are not additive since some generators are included in more than one category and not all units have environmental equipment.

² Nameplate capacity.

Note: *Totals may not equal sum of components because of independent rounding. *These data are only for plants with a fossil-fueled steam-electric capacity of 100 or more megawatts. *Data are preliminary.

Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report."

Table 50. Average Quality of Fossil Fuels Burned at Electric Utilities by Census Division and State, 1993 and 1992

Census Division State	Coal						Petroleum				Gas	
	1993			1992			1993		1992		1993	1992
	Average Btu per Pound	Sulfur Percent by Weight	Ash Percent by Weight	Average Btu per Pound	Sulfur Percent by Weight	Ash Percent by Weight	Average Btu per Gallon	Sulfur Percent by Weight	Average Btu per Gallon	Sulfur Percent by Weight	Average Btu per Cubic Foot	Average Btu per Cubic Foot
New England	12,972	1.14	7.7	13,109	1.24	7.5	151,209	1.34	151,320	1.40	1,033	1,030
Connecticut	13,053	.56	6.9	13,212	.57	6.9	151,667	.91	151,145	.91	1,029	1,030
Maine	—	—	—	—	—	—	150,791	1.26	150,768	1.03	—	—
Massachusetts	12,908	1.10	8.1	13,071	1.20	8.2	150,581	1.50	150,864	1.51	1,034	1,031
New Hampshire	13,104	1.68	8.8	13,159	1.80	8.4	154,184	1.72	155,755	1.74	1,016	1,019
Rhode Island	—	—	—	—	—	—	151,508	1.00	148,327	1.00	1,032	1,031
Vermont	—	—	—	—	—	—	140,000	.30	—	—	1,000	1,000
Middle Atlantic	12,519	1.89	11.0	12,549	1.93	11.2	150,485	.75	150,249	.74	1,031	1,031
New Jersey	13,076	1.29	8.2	13,105	1.26	8.2	148,931	.56	149,048	.42	1,033	1,034
New York	12,860	1.59	8.3	12,880	1.63	8.3	150,629	.81	150,430	.78	1,031	1,031
Pennsylvania	12,416	1.89	11.7	12,438	2.05	12.1	149,980	.51	149,388	.62	1,033	1,031
East North Central	10,770	1.84	8.6	10,889	1.78	8.4	145,580	.59	146,172	.60	999	1,018
Illinois	10,138	1.57	7.8	10,601	2.02	8.5	149,684	.60	149,639	.62	1,016	1,016
Indiana	10,470	1.84	8.5	10,497	1.87	8.5	136,961	.35	137,137	.35	1,017	1,020
Michigan	10,692	.67	6.9	10,791	.67	6.8	144,440	.73	145,056	.73	954	1,015
Ohio	12,009	2.46	11.2	11,937	2.60	11.4	137,845	.37	137,711	.36	1,029	1,034
Wisconsin	9,392	.51	6.2	9,589	.77	6.2	139,432	.39	139,188	.30	1,012	1,009
West North Central	8,417	.71	6.9	8,623	.88	7.2	142,192	.84	143,418	1.08	980	982
Iowa	8,684	.80	5.8	8,797	.88	5.8	137,833	.50	138,026	.45	1,005	1,008
Kansas	8,673	.46	5.4	8,827	.48	6.7	143,489	.73	140,329	.50	980	970
Minnesota	8,796	.52	6.4	8,774	.52	6.6	138,462	.33	138,675	.42	1,006	1,006
Missouri	9,803	1.27	7.0	10,197	1.77	7.8	144,102	1.14	147,201	1.60	1,007	1,002
Nebraska	8,505	.58	5.1	8,524	.58	5.1	138,969	.21	139,080	.22	975	958
North Dakota	6,539	.73	9.8	6,488	.75	9.6	138,908	.47	139,463	.50	1,082	1,022
South Dakota	8,245	.58	8.5	8,245	.58	9.0	136,757	.34	138,041	.38	1,020	1,020
South Atlantic	12,401	1.42	8.9	12,279	1.52	10.9	151,176	1.40	151,074	1.36	1,010	1,012
Delaware	12,656	.85	8.0	12,953	1.01	8.9	150,184	.95	150,159	1.07	1,033	1,037
District of Columbia	—	—	—	—	—	—	143,546	.94	143,643	.92	—	—
Florida	12,209	1.59	8.2	12,209	1.73	8.4	151,883	1.47	151,548	1.38	1,006	1,010
Georgia	12,094	1.45	10.2	11,937	1.67	10.3	141,348	1.33	142,504	1.13	1,023	1,024
Maryland	12,730	1.31	10.4	12,745	1.34	10.6	150,783	1.40	150,042	1.56	1,041	1,045
North Carolina	12,456	.86	10.0	12,470	.92	10.1	138,433	.20	138,106	.20	—	—
South Carolina	12,717	1.17	9.0	12,743	1.13	8.9	143,725	1.09	140,089	.44	1,022	1,022
Virginia	12,805	1.00	9.6	12,814	1.02	9.5	149,381	1.05	149,847	1.08	1,014	1,037
West Virginia	12,405	1.93	11.7	12,447	2.01	11.4	139,344	.31	139,824	.33	1,000	1,000
East South Central	12,021	1.80	10.3	11,871	1.90	10.1	152,291	2.67	148,572	1.71	1,022	1,028
Alabama	12,055	1.32	11.7	12,048	1.43	11.8	137,061	.33	137,086	.33	1,024	1,022
Kentucky	11,841	2.18	10.2	11,778	2.21	10.1	138,966	.31	138,933	.30	1,020	1,022
Mississippi	12,321	1.44	8.7	12,348	1.70	8.2	153,455	2.87	152,579	2.73	1,022	1,029
Tennessee	12,201	1.84	9.1	12,126	2.03	8.4	138,314	.31	138,688	.31	—	—
West South Central	7,997	.83	9.8	7,978	.86	10.3	148,483	.87	138,550	.44	1,026	1,024
Arkansas	8,625	.32	5.1	8,526	.31	5.0	137,556	.30	139,050	.62	1,027	1,024
Louisiana	7,936	.53	7.1	7,980	.50	7.1	152,306	1.11	142,976	.49	1,036	1,037
Oklahoma	8,604	.38	5.1	8,710	.41	6.2	139,864	.50	140,615	.62	1,030	1,031
Texas	7,261	.73	11.6	7,169	.77	12.5	145,124	.19	137,290	.36	1,023	1,026
Mountain	9,813	.54	11.1	9,805	.54	11.0	144,215	.62	143,828	.56	1,033	1,026
Arizona	10,251	.51	12.3	10,322	.51	12.4	142,030	.44	140,141	.35	1,028	1,032
Colorado	9,817	.38	7.1	9,818	.38	7.0	137,093	.26	138,913	.52	975	962
Idaho	—	—	—	—	—	—	—	—	—	—	—	—
Montana	8,493	.65	9.0	8,577	.66	8.9	141,000	.50	138,885	.50	1,165	1,206
Nevada	11,840	.48	9.7	11,651	.48	9.7	148,485	.70	147,734	.73	1,029	1,025
New Mexico	9,114	.80	21.8	9,150	.80	21.6	134,793	.10	134,864	.11	1,018	1,021
Utah	11,608	.48	11.1	11,470	.47	11.4	138,428	.34	139,175	.33	1,083	1,074
Wyoming	8,702	.51	7.6	8,725	.53	7.5	139,143	.30	140,502	.34	1,045	1,039
Pacific Contiguous	8,361	.62	11.0	8,476	.58	11.1	146,381	.43	147,497	.50	1,030	1,032
California	—	—	—	—	—	—	146,416	.43	147,759	.50	1,030	1,032
Oregon	8,336	.37	5.1	8,416	.40	4.3	138,800	.50	138,800	.50	—	—
Washington	8,198	.70	13.0	8,172	.65	13.3	140,979	.30	140,903	.31	1,040	1,027
Pacific Noncontiguous	7,958	.16	8.6	7,906	.16	8.4	149,251	.89	148,521	.88	—	—
Alaska	7,858	.16	8.6	7,906	.16	8.4	134,356	.38	134,360	.39	—	—
Hawaii	—	—	—	—	—	—	149,256	.89	148,527	.88	—	—
U.S. Average	10,319	1.18	9.5	10,338	1.27	9.8	150,585	1.20	150,486	1.18	1,025	1,027

Notes: *Data for 1993 are preliminary; data for prior years are final. *Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-787, "Steam-Electric Plant Operation and Design Report."

Table 51. Average Flue Gas Desulfurization Costs at Electric Utilities by Census Division and State, 1989 Through 1993

Census Division State	Average O&M Costs (mills per kilowatthour)					Average Installed Costs (dollars per kilowatt)				
	1993	1992	1991	1990	1989	1993	1992	1991	1990	1989
New England										
Connecticut										
Maine										
Massachusetts										
New Hampshire										
Rhode Island										
Vermont										
Middle Atlantic	3.98	4.91	6.01	5.15	4.92	184	183	178	157	174
New Jersey	NM	NM				398	398			
New York	1.09	1.03	1.07	1.22	1.24	331	319	319	212	212
Pennsylvania	4.65	6.04	6.20	6.25	5.90	157	157	149	149	168
East North Central	1.80	1.83	2.18	2.41	2.41	190	147	139	138	137
Illinois	2.62	2.47	2.63	2.36	2.89	147	197	197	147	146
Indiana	1.58	1.56	2.12	2.41	2.28	143	149	133	154	153
Michigan										
Ohio	2.25	2.06	2.03	2.52	2.76	89	83	89	47	47
Wisconsin										
West North Central	.68	.76	.72	.74	.73	84	83	75	75	74
Iowa	1.67	2.42	2.63	2.93	2.30	202	202	202	202	202
Kansas	.48	.66	.53	.61	.59	72	72	71	71	71
Minnesota	.43	.40	.40	.27	.26	73	73	73	73	73
Missouri	1.86	2.12	1.89	2.02	2.05	87	87	87	87	87
Nebraska										
North Dakota	.61	.74	.61	.92	.91	102	101	71	71	65
South Dakota										
South Atlantic	.98	1.28	1.63	1.58	1.47	119	143	144	86	92
Delaware ¹		NM	28.62	35.60	30.80		1,385	1,385	1,385	1,385
District of Columbia										
Florida	.78	1.15	1.23	1.07	.94	69	69	69	80	80
Georgia										
Maryland										
North Carolina										
South Carolina	.69	.64	.60	.54	.61	43	43	43	34	46
Virginia										
West Virginia	2.09	2.23	2.66	2.41	2.11	217	260	258	113	111
East South Central	1.45	1.88	1.81	1.48	1.48	137	140	153	131	120
Alabama	.69	1.00	.94	.91	.76	80	80	82	82	82
Kentucky	1.76	1.91	1.70	1.70	1.73	132	135	155	146	133
Mississippi	.27	.30	.41	.34	.33	70	70	70	70	70
Tennessee	NM	NM	NM			198	202	202		
West South Central	1.01	1.22	1.17	.93	.99	74	79	89	69	69
Arkansas										
Louisiana	NM	NM	NM	NM	NM	75	75	75	75	75
Oklahoma	.64	.56	.57	.66	.54	92	92	92	92	92
Texas	1.03	1.26	1.20	.95	1.03	72	72	67	67	67
Mountain	.88	.69	.79	.74	.70	149	148	149	184	149
Arizona	.42	.66	.63	.77	.71	160	175	175	175	136
Colorado	.67	.57	.63	.45	.43	69	69	69	69	69
Idaho										
Montana	1.10	.90	.94	1.19	1.04	274	274	274	274	274
Nevada	.99	.93	3.80	1.11	1.51	126	126	126	126	126
New Mexico	1.07	1.03	1.14	.96	.91	165	165	167	192	182
Utah	.37	.46	.56	.43	.62	97	97	97	97	97
Wyoming	.54	.55	.87	.72	.56	137	137	137	137	137
Pacific Contiguous										
California										
Oregon										
Washington										
Pacific Noncontiguous										
Alaska										
Hawaii										
U.S. Average	1.19	1.32	1.40	1.25	1.33	126	132	139	118	117

¹ The high cost shown for Delaware is attributable to the flue gas desulfurization (FGD) units belonging to a plant that provides steam for sale and steam used to produce electricity. The FGD costs include the costs incurred in the production of steam for sale. In 1992 the plant was sold to a nonutility power producer.

O&M = Operation and Maintenance

NM = Not meaningful because these plants did not generate during the year.

Notes: *Data for 1993 are preliminary; data for prior years are final. *Totals may not equal sum of components because of independent rounding. *A mill is a monetary cost and billing unit equal to 1/1000 of the U.S. dollar (equivalent to 1/10 of 1 cent).

Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report."

Table 62. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1993

Utility Plant and FGD No.	Nameplate Capacity (megawatts)		Initial Start up Date of FGD System	Design Cost Sulfur (Percent by WT)	FGD Type	Sorbent	Designed SO ₂ Removal (Percent Efficiency)
	by Plant	by Unit with FGD System					
Alabama Electric Coop Inc							
Charles R Lowman 2	538	236	7803	1 80	Spray	Limestone	85 0
Charles R Lowman 3	-	236	8005	1 80	Spray	Limestone	85 0
Arizona Electric Pwr Coop Inc							
Apache Station 2	464	195	7901	70	Packed	Limestone	85 0
Apache Station 3	-	195	7901	70	Packed	Limestone	85 0
Arizona Public Service Co							
Cholla 1	1,105	114	7312	1 00	Venturi	Limestone	50 7
Cholla 2	-	289	7806	1 20	Venturi	Limestone	85 0
Cholla 4	-	414	8108	1 20	Packed	Limestone	95 0
Four Corners 1	2,270	190	7201	80	Venturi	Lime	72 0
Four Corners 2	-	190	7201	80	Venturi	Lime	72 0
Four Corners 3	-	253	7201	80	Venturi	Lime	72 0
Four Corners 4	-	818	8601	80	Tray	Lime	72 0
Four Corners 5	-	818	8601	80	Tray	Lime	72 0
Associated Electric Coop Inc							
Thomas Hill FGD3	1,136	670	8207	4 80	Spray	Limestone	91 1
Basin Electric Power Coop							
Antelope Valley FGD1	870	495	8307	1 20	Spray Dry	Lime/Alkaline Fly Ash	81 0
Antelope Valley FGD2	-	495	8511	1 20	Spray Dry	Lime/Alkaline Fly Ash	81 0
Laramie River 1	1,710	570	8007	80	Spray	Limestone	80 0
Laramie River 2	-	570	8107	80	Spray	Limestone	90 0
Laramie River 3	-	570	8405	50	Spray Dry	Lime/Alkaline Fly Ash	85 0
Big Rivers Electric Corp							
D B Wilson W1	508	508	8811	3 80	Spray	Limestone	90 0
R D Green G1	527	264	7812	4 00	Spray	Lime	90 0
R D Green G2	-	264	8101	4 00	Spray	Lime	90 0
Central Illinois Light Co							
Duck Creek 1	441	441	7607	5 40	Venturi	Limestone	95 0
Central Illinois Pub Serv Co							
Newton 1	1,235	617	7812	4 00	Spray	Sodium Carbonate	90 0
Central Louisiana Elec Co Inc							
Dodot Hills 1	721	721	8604	70	Spray	Limestone	76 0
Cincinnati Gas & Electric Co							
East Bend 2	669	669	8103	5 20	Spray Dry	Lime	98 0
W H Zimmer 1	1,426	1,426	8103	4 50	Spray	Lime	99 0
Columbus Southern Power Co							
Conesville 5	2,175	444	7705	7 80	Spray	Lime	89 7
Conesville 6	-	444	7706	7 90	Spray	Lime	89 7
Coop Power Assn							
Coal Creek 1	1,012	508	7906	1 00	Spray	Lime	90 0
Coal Creek 2	-	508	8107	1 00	Spray	Lime	90 0
Deseret Generation & Tran Coop							
Bonanza 1-1	400	400	8805	50	Spray	Limestone	95 0
Duquesne Light Co							
Elrama SCRB	510	510	7809	2 50	Venturi	Lime	83 0
F R Philips SCRB	411	411	7406	2 50	Venturi	Lime	83 0
East Kentucky Power Coop Inc							
H L Spurlock 2	814	508	8306	3 80	Spray Dry	Lime	90 0
Georgia Power Co							
Yates Y1FG	1,488	123	8210	2 50	Bubbling Reactor	Limestone	90 0

See footnotes at end of table

Table 52. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1993—Continued

Utility Plant and FGD No.	Nameplate Capacity (megawatts)		Initial Start up Date of FGD System	Design Coal Sulfur (Percent by WT)	FGD Type	Sorbent	Designed SO ₂ Removal (Percent Efficiency)
	by Plant	by Unit with FGD System					
Grand Haven City of J B Sims 3	78	55	8308	2.80	Tray	Lime	90.0
Grand River Dam Authority GRDA 2	1,010	520	8604	1.50	Spray Dry	Lime/Alkaline Fly Ash	85.0
Hoosier Energy R & E Inc Marion 1FGD	1,080	540	8309	3.00	Spray	Limestone	90.0
Marion 2FGD	-	540	8202	3.00	Spray	Limestone	90.0
Houston Lighting & Power Co Limestone FGD1	1,827	813	8611	3.10	Spray	Limestone	90.0
Limestone FGD2	-	813	8611	3.10	Spray	Limestone	90.0
W A Parish FGD8	3,853	815	8212	.50	Spray	Limestone	85.0
Indianapolis Power & Light Co Petersburg 3	1,873	574	7711	-	Tray	Limestone	85.0
Petersburg 4	-	574	8604	-	Spray	Limestone	96.0
Jacksonville Electric Auth St Johns River Power 1	1,358	679	8703	2.20	Spray	Limestone	90.0
St Johns River Power 2	-	679	8805	2.20	Spray	Limestone	90.0
Kansas City Power & Light Co La Cygne 1	1,579	593	7308	5.40	Venturi	Limestone	90.0
Kentucky Utilities Co Green River 1	284	75	7510	3.80	Venturi	Lime	90.0
Lakeland City of C D McIntosh Jr 3	593	384	8209	1.80	Spray	Limestone	86.0
Los Angeles City of Intermountain 1000	1,784	892	8807	.30	Spray	Limestone	90.0
Intermountain 2000	-	892	8707	.90	Spray	Limestone	90.0
Louisville Gas & Electric Co Cane Run 4	792	183	7812	3.50	Packed	Other	85.0
Cane Run 5	-	209	7805	3.50	Spray	Other	85.0
Cane Run 8	-	272	7904	3.50	Tray	Other	90.0
Mill Creek 1	1,717	356	8112	6.00	Spray	Limestone	90.0
Mill Creek 2	-	356	8012	6.00	Spray	Limestone	90.0
Mill Creek 3	-	463	8510	5.00	Spray	Limestone	90.0
Mill Creek 4	-	544	8207	6.30	Spray	Limestone	90.0
Trimble County 1	566	566	8012	4.50	Spray	Limestone	90.7
Lower Colorado River Authority Sam Seymour 3	1,640	480	8804	1.70	Spray	Limestone	90.0
Marquette City of Shree 3	40	40	8307	.50	Spray Dry	Limestone	80.0
Michigan South Central Pwr Agcy Endicott Generating 1	55	50	8905	4.30	Spray	Limestone	90.0
Minnesota Power & Light Co Boswell Energy Center AOC82	1,073	558	8004	1.00	Spray	Alkaline Fly Ash	83.2
Boswell Energy Center SCR3	-	365	7302	1.00	Spray	Alkaline Fly Ash	25.4
Laikin Energy Center SCR1	116	58	7105	1.00	Spray	Alkaline Fly Ash	-
Laikin Energy Center SCR2	-	58	7105	1.00	Spray	Alkaline Fly Ash	-
Minnesota Power Coop Inc Milton R Young FGD2	734	477	7808	1.20	Spray	Lime/Alkaline Fly Ash	77.9

See footnotes at end of table.

Table 52. Flue Gas Desulfurization (FGD) Capacity In Operation at U.S. Electric Utility Plants as of December 1993—Continued

Utility Plant and FGD No.	Nameplate Capacity (megawatts)		Initial Start up Date of FGD System	Design Coal Sulfur (Percent by WT)	FGD Type	Sorbent	Designed SO ₂ Removal (Percent Efficiency)
	by Plant	by Unit with FGD System					
Monongahela Power Co							
Pleasants 1	1,368	684	7803	4.50	Tray	Lime	90.0
Pleasants 2	-	684	8012	4.50	Tray	Lime	90.0
Montana Power Co							
Colstrip 1	2,273	358	7511	.80	Venturi	Lime/Alkaline Fly Ash	88.8
Colstrip 2	-	358	7808	.80	Venturi	Lime/Alkaline Fly Ash	88.8
Colstrip 3	-	778	8401	.80	Venturi	Lime/Alkaline Fly Ash	95.0
Colstrip 4	-	778	8604	.80	Venturi	Lime/Alkaline Fly Ash	85.0
Montana-Dakota Utilities Co							
Coyote FGD1	450	450	8106	.80	Spray Dry	Lime/Alkaline Fly Ash	70.0
Missourine City of							
Muscataine 9	276	176	8308	3.20	Spray	Limestone	98.0
Nevada Power Co							
Reid Gardner 1	612	114	7404	.50	Spray	Sodium Carbonate	90.6
Reid Gardner 2	-	114	7404	.50	Spray	Sodium Carbonate	90.5
Reid Gardner 3	-	114	7607	.50	Spray	Sodium Carbonate	90.6
Reid Gardner 4	-	270	8307	.90	Spray	Sodium Carbonate	85.0
New York State Elec & Gas Corp							
Kinloch 1	655	655	8408	3.80	Spray	Limestone	90.0
Northern Indiana Pub Serv Co							
Billy 78	616	616	9206	-	Packed	Limestone	90.0
R M Schahfer 17	1,843	424	8304	3.20	Spray	Other	90.0
R M Schahfer 18	-	424	8602	3.20	Spray	Other	90.0
Northern States Power Co							
Riverside 7	404	165	8101	1.30	Spray Dry	Lime/Alkaline Fly Ash	70.0
Sherburne County 1	2,129	680	7806	.90	Venturi	Limestone/Aik Fly Ash	50.0
Sherburne County 2	-	680	7704	.90	Spray	Limestone/Aik Fly Ash	50.0
Sherburne County 3	-	808	8711	.90	Spray Dry	Lime/Alkaline Fly Ash	72.3
Orlando Utilities Comm							
Stanton Energy 1	928	485	8707	3.50	Spray	Limestone	90.0
PacificCorp							
Dave Johnston SC44	817	380	7202	.40	Venturi	Lime	-
Hunter (Emery) 1	1,339	446	7808	.80	Spray	Lime	80.0
Hunter (Emery) 2	-	446	8006	.80	Spray	Lime	80.0
Hunter (Emery) 3	-	446	8306	.80	Spray	Limestone	90.0
Huntington 1	893	448	7802	.60	Spray	Lime	80.0
Jim Bridger SC71	2,242	561	8008	1.00	Tray	Soda Liquor Waste	88.4
Jim Bridger SC72	-	561	8608	1.00	Tray	Soda Liquor Waste	88.4
Jim Bridger SC73	-	561	8808	1.00	Tray	Soda Liquor Waste	88.4
Jim Bridger SC74	-	561	7811	1.00	Tray	Soda Liquor Waste	81.0
Naughton 3	707	326	8110	.80	Tray	Sodium Carbonate	70.0
Wyodak SC81	362	362	8612	.80	Spray Dry	Lime	75.2
Pennsylvania Power Co							
Bruce Mansfield 1	2,741	914	7804	4.80	Venturi	Lime	82.1
Bruce Mansfield 2	-	914	7710	4.80	Venturi	Lime	82.1
Bruce Mansfield 3	-	914	8008	4.80	Spray	Lime	82.1
Philadelphia Electric Co							
Cromby 1	418	188	8212	2.60	Spray	Magnesium Oxide	95.0
Eddystone 1	1,489	354	8212	2.60	Spray	Magnesium Oxide	92.0
Eddystone 2	-	354	8212	2.60	Spray	Magnesium Oxide	92.0
Maine Elec Gen&Trans Coop Inc							
Escalante 1	233	233	8412	.80	Spray	Limestone	95.0

See footnotes at end of table.

Table 52. Flue Gas Desulfurization (FGD) Capacity In Operation at U.S. Electric Utility Plants as of December 1993—Continued

Utility Plant and FGD No.	Nameplate Capacity (megawatts)		Initial Start up Date of FGD System	Design Coal Sulfur (Percent by WT)	FGD Type	Sorbent	Designed SO ₂ Removal (Percent Efficiency)
	by Plant	by Unit with FGD System					
Platte River Power Authority Rawhide 101	285	285	8404	0.30	Spray Dry	Lime/Alkaline Fly Ash	80.0
Public Service Co of Colorado Cherokee 4	710	350	8905	.40	Spray Dry	Other	26.0
Public Service Co of NM San Juan 1	1,779	361	7804	1.30	Tray	Other	90.0
San Juan 2	-	350	7808	1.30	Tray	Other	90.0
San Juan 3	-	534	8203	1.30	Tray	Other	90.0
San Juan 4	-	534	8204	1.30	Tray	Other	90.0
PSI Energy Inc Gibson 5	3,340	668	8210	4.40	Spray	Limestone	88.0
Richmond City of Whitewater Valley LFC	-	-	9410	2.10	Spray Dry	Limestone	72.6
Salt River Proj Ag I & P Dist Coronado FGD1	822	411	7912	1.00	Spray	Limestone	82.6
Coronado FGD2	-	411	8011	1.00	Spray	Limestone	82.6
San Antonio City of J K Spruce FGD1	546	546	9212	.60	Spray	Limestone	70.0
San Miguel Electric Coop Inc San Miguel SM-1	410	410	8201	2.00	Spray	Limestone	88.0
Seminole Electric Coop Inc Seminole 1	1,304	652	8402	3.00	Spray	Limestone	88.0
Seminole 2	-	652	8412	3.00	Spray	Limestone	88.0
Sierra Pacific Power Co North Valmy 2	621	267	8507	.50	Spray Dry	Lime	70.0
Sikeston City of Sikeston 1	281	281	8111	2.80	Venturi	Limestone	75.5
South Carolina Pub Serv Auth Cross 2	1,147	556	8312	1.60	Spray	Limestone	81.4
Winyah 2	1,260	315	7707	1.10	Venturi	Limestone	45.0
Winyah 3	-	315	8008	2.30	Spray	Limestone	90.0
Winyah 4	-	315	8111	1.70	Spray	Limestone	90.4
South Mississippi El Pwr Assn R D Morrow 1	400	200	7809	1.50	Spray	Limestone	85.0
R D Morrow 2	-	200	7806	1.50	Spray	Limestone	85.0
Southern Illinois Power Corp Marion 4	272	173	7904	4.40	Venturi	Limestone	89.4
Southern Indiana Gas & Elec Co A B Brown 1	530	265	7804	4.50	Spray	Sodium Ash	85.0
A B Brown 2	-	265	8802	4.50	Spray	Sodium Ash	90.0
Southwestern Electric Power Co Pike 1	721	721	8501	1.50	Spray	Limestone	85.0
Soyland Power Corp Inc Pearl Station 1A	22	22	7811	3.40	Venturi	Other	11.8
Springfield City of Cellman 33	388	207	8012	3.30	Packed Tray	Limestone	85.0
Southwest 1	194	194	7704	3.20		Limestone	87.0

See footnotes at end of table.

Table 52. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1993—Continued

Utility Plant and FGD No.	Nameplate Capacity (megawatts)		Initial Start up Date of FGD System	Design Coal Sulfur (Percent by WT)	FGD Type	Sorbent	Designed SO ₂ Removal (Percent Efficiency)
	by Plant	by Unit with FGD System					
Sunflower Electric Power Corp							
Holcomb SDA1	348	348	8308	1.00	Spray Dry	Lime/Alkaline Fly Ash	80.0
Holcomb SDA2	-	348	8308	1.00	Spray Dry	Lime/Alkaline Fly Ash	80.0
Holcomb SDA3	-	348	8308	1.00	Spray Dry	Lime/Alkaline Fly Ash	80.0
Tampa Electric Co							
Big Bend FGD4	1,623	485	8502	3.50	Spray	Limestone	90.0
Tennessee Valley Authority							
Paradise 1	2,558	704	8309	3.20	Spray	Limestone	84.2
Paradise 2	-	704	8312	3.20	Spray	Limestone	84.2
Widows Creek 7	1,088	575	8112	4.00	Spray	Limestone	83.4
Widows Creek 8	-	550	7801	4.50	Tray	Limestone	80.0
Texas Municipal Power Agency							
Gibbons Creek 1	444	444	8310	2.30	Spray	Limestone	90.0
Texas Utilities Electric Co							
Martin Lake 1	2,380	793	7705	.90	Spray	Limestone	91.0
Martin Lake 2	-	793	7805	.90	Spray	Limestone	91.0
Martin Lake 3	-	793	7904	.90	Spray	Limestone	91.0
Monticello 3	1,080	783	7808	1.50	Spray	Limestone	74.0
Sandoz 4	591	591	8105	1.60	Spray	Limestone	73.9
Tri-State G & T Assn Inc							
Craig C1	1,339	448	8010	.40	Spray	Limestone	85.0
Craig C2	-	448	8005	.40	Spray	Limestone	85.0
Craig C3	-	448	8410	.40	Spray Dry	Lime	85.0
Tucson Electric Power Co							
Springerville 1	850	425	8508	.70	Spray Dry	Lime/Alkaline Fly Ash	81.3
Springerville 2	-	-	8006	.70	Spray Dry	Lime/Alkaline Fly Ash	81.3
United Power Assn							
Elk River 1	48	48	8903	-	Spray Dry	Lime	90.0
Stanton 10	172	172	8208	.70	Spray Dry	Lime	70.0
West Penn Power Co							
Mitchell 33	449	299	8208	4.00	Spray	Lime	85.0
West Texas Utilities Co							
Oklahoma 1	720	720	8612	.40	Spray	Limestone	88.8
Western Resources, Inc							
Jeffrey Energy Centr 1	2,160	720	7807	.30	Spray	Limestone	60.0
Jeffrey Energy Centr 2	-	720	8005	.30	Spray	Limestone	60.0
Jeffrey Energy Centr 3	-	720	8305	.30	Spray	Limestone	80.0
Lawrence 4N	614	114	8808	.90	Venturi	Limestone	73.0
Lawrence 4S	-	114	8808	.90	Venturi	Limestone	73.0
Lawrence 6N	-	413	7105	.80	Venturi	Limestone	62.0
Lawrence 6S	-	413	7105	.90	Venturi	Limestone	52.0

Notes: *Data are preliminary. * SO₂ = Sulfur Dioxide; WT=weight; FGD=Flue Gas Desulfurization.
Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report."

U.S. Electric Power Transactions

This chapter provides summary information for the U.S. electric utility industry on its operations and wholesale electricity trade at the international (Canada and Mexico), national, and North American Electric Reliability Council (NERC) region levels. The NERC is an organization established by the electric utility industry for maintaining, coordinating, and promoting reliability among the interconnected systems of North America.

Background

An electric power system is a group of generation, transmission, distribution, communication, and other facilities that are physically connected and operated as a single unit under one control. Transmission and distribution lines and associated facilities are used to transmit electricity from its point of origin (the generator) to the ultimate consumer. Although, due to its physical characteristics, electricity flows along all available paths, it follows the path of least resistance. The flow of electricity must be closely monitored to ensure that sufficient generating capacity is available and on-call to satisfy all demand (load) for electricity placed on the power system. In addition, for system standardization and reliability purposes, the flow is maintained at a frequency of 60 cycles per second.

The flow of electricity within the system is maintained and monitored by dispatch centers. The dispatch center must inventory and prioritize all generating capacity available to it, track transactions involving the buying or selling of either electric power or capacity, monitor current load, and anticipate future load on the system. It is the responsibility of the dispatch center to match the supply of electricity with its demand. The demand for electricity is not constant in nature. That is, load requirements fluctuate continuously, based on such factors as time of day, season of the year, and the characteristics of territory served by the system. Nonetheless, the dispatch center must be ready to meet the highest level of load placed on the system. The dispatch center must accommodate the loss of generating facilities (both when planned and when unexpected). In addition, the center must monitor transmission lines to determine whether the flow of electricity is approaching the carrying limits of the lines. In order to carry out its responsibilities in a timely fashion, the dispatch center is authorized to buy and sell electricity based on system requirements.

Authority for these transactions has been preapproved under interconnection agreements (contracts) that have been signed by all the electric utilities that are physically interconnected and/or have coordination agreements with other utilities not physically interconnected. (All these agreements are subject to regulatory approval.) Within these agreements, there are transaction categories that include purchases, sales for resale, exchanges, and wheeling of energy.

Purchase transactions involve buying power among electric utilities and nonutility producers of electricity. Sales for resale transactions refer to power sold by one electric utility to other utilities for distribution. Some transactions involving the trade of electric energy are based on the availability of excess generating capacity or the diversity in load requirements. For example, if one electric utility has its lowest load during the winter season, it may arrange to offer its available excess generating capacity in exchange for excess generating capacity available at a facility with low summer load. This type of arrangement is an exchange transaction. However, the repayment or replacement of exchange energy may extend over several years. Wheeling transactions are the movement of electricity from one utility to another utility over the transmission facilities of the intervening utilities.

Electric Utility Transactions

Electric utility transactions (*wholesale electricity trade*) allow electric utilities to share resources and to provide mutual assistance in time of potential and actual need. They allow the utility systems to provide lower cost service to their consumers by taking advantage of the load diversity of each utility. These transactions also allow each utility to conserve its own resources, to share the benefits of reduced operating costs with its consumers, to receive emergency energy support from other utilities, and to reduce the cost of its own requirements for operating reserve. However, due to the complexity of electric power transactions involving the specifics of contracts, simultaneous energy transactions, the unintended receipt and delivery of energy (inadvertent flow), and losses, the reporting of both the classification and quantity of each transaction among utilities may not be consistent.

Electric utilities originally became interested in energy transactions because of the savings gained from re-

duced or avoided production costs. They avoided building expensive additional capacity by obtaining it from other sources. Purchasing power from other utilities helped utilities meet peakload without using expensive oil- or gas-fired turbines. Similarly, utilities benefitted from being able to delay or stagger construction of additional baseload plants. Electric utilities have also delayed or replaced new plant construction by purchasing electricity from nonutility generators under long-term contracts.

Power Pool Transactions

In addition to dealing in one-time purchase and sale transactions, many electric utilities have joined together and formed power pools to achieve better operating efficiencies and to gain additional support for maintaining a functional electrical system. Thus, they share the benefits achieved by joint planning, coordinated use of generating and transmission facilities, and/or coverage of facility outages. This coordination also provides the opportunity to manage short-term saving, much of it coming from varying fuel prices and the costs associated with different mixes of capacity.

Power pools can be made up of two electric utilities, like the Michigan Electric Coordinated System (Detroit Edison Company and Consumer Power Company), include all the major investor-owned utilities within a State (the New York Power Pool), or cross State lines (the PJM Power Pool includes parts or all of Pennsylvania, New Jersey, Maryland, and Delaware).

Power pools may run under a single-system dispatch to meet combined-load requirements and maintenance programs, or just share the benefits of planned or hourly wholesale sales of power and energy among the member utilities. Power pools may have responsibility for coordinating flow within the geographic area of the interconnected systems. In any case, they are bound by the operating standards established by the electric power industry. These standards require the coordination and maintenance of system stability and reliable service on a regional basis.

NERC Profile

The North American Electric Reliability Council (NERC) consists of 10 regional reliability councils whose memberships comprise essentially all of the electric utility systems in the contiguous United States, Canada, and Baja California Norte, Mexico. The regional councils are responsible for maintaining and setting standards on the reliability and stability requirements for the electricity flowing within the three power grids (the Eastern Power Grid, the Western Power Grid, and the Electric Reliability Council of Texas Power Grid) present in the contiguous United States.

The data for NERC regions in this publication are based upon the assignment of all electric utilities to an individual region and are for the U.S. portion of the regions only (Figure 19).

Regulation of U.S. Electric Utility Transactions

The Federal Energy Regulatory Commission (FERC) is responsible for regulating interstate wholesale transactions. U.S. electric utilities file with the FERC for approval of proposed rate schedules for transmission services and charges, and for wholesale transactions. Transmission filings cover the allocation of electric power flows on the transmission line systems. Other categories described in the filings usually cover the responsibilities of the utilities to one another during normal and emergency conditions, operating-reserves support, diversity exchanges, and unscheduled or inadvertent-energy flows. Recently, new authority was granted the FERC by the Energy Policy Act of 1992 to ensure that any wholesale generator-electric utility or nonutility--can access the transmission grid to reach their markets. After application, the FERC can order electric utilities to provide transmission (wheeling) services, provided that the proposed transaction is in the public interest and meets key criteria related to pricing, reliability, and self-dealing.

Wholesale transactions include *capacity sales*, *energy sales*, and *energy exchanges*. Wholesale transactions are further divided by duration of the sale and the type of capacity and energy sold. The length of the sale can be for an hour, a day, a week, a month (or several months), a season, several years, or some combination of these time periods.

Capacity sales are usually considered *firm sales* (that is, associated energy may be taken, or the capacity must be paid for if the energy is not taken; and the delivery is scheduled during normal system operating conditions). This capacity may be made available from the entire system or from an identified generating unit. The capacity offered in these transactions may be available only during a set period of seasonal diversity, an off-peak time of the day, or from a generator, which is currently not fully utilized, that is fired by a particular fuel. The energy associated with this capacity sale, if required, has a separate cost schedule from the capacity charge attached to each kilowatt of power.

Nonfirm sales, sometimes called *energy*, *economy*, or *interruptible sales*, do not have a demand or capacity charge included in the price of the transaction. These transactions are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions. The sales are often based on splitting the benefits gained by the parties involved. They are used to gain operational savings, such as avoiding the use of more expensive fuels, and

Figure 19. North American Electric Reliability Council Regions for the Contiguous United States and Alaska

Regional Electric Area Council Areas:

ECAR-	East Central Area Reliability Coordination Agreement	SERC-	Southeastern Electric Reliability Council
MAIN-	Mid-American Interpool Network	SPP-	Southwest Power Pool
MAAC-	Mid-Atlantic Area Council	ERCOT-	Electric Reliability Council of Texas
MAPP (U.S.)-	Mid-Continent Area Power Pool	WSCC (U.S.)-	Western Systems Coordinating Council
NPCC (U.S.)-	Northeast Power Coordinating Council	ASCC-	Alaska Systems Coordinating Council

Source: North American Electric Reliability Council.

selling electricity generated by the spillage of excess reservoir water.

Energy exchanges involve transfers of energy to other systems at no monetary charge. The energy must be returned in kind at a later date agreed upon by both parties. Otherwise, the receiving party pays for the energy received. The incidental miscellaneous transfer of energy and inadvertent flow are also handled in the same manner. In total, these wholesale transactions have become very important tools used by the U.S. electric utility industry to reduce costs and avoid expensive new capacity.

Other Wholesale Electricity Trade Concerns

Environmental issues associated with air, solid-waste disposal, water quality, and aquatic habitat have received more attention from utility and power plant operators. Plant operating restrictions caused by air and water emissions have altered or restricted the dispatching of some facilities and in certain cases, plant cooling water sources have been contaminated or shut down due to aquatic organisms. Transmission line right-of-ways and projected line construction are also being affected because of concerns linked to generated electromagnetic forces surrounding the transmission lines.

Legislative and regulatory initiatives have been implemented to address emissions at power plants. For example, the Clean Air Act Amendments of 1990 established emission allowances for Nitrogen Oxides, Sulfur Dioxides, and Carbon Dioxides for power plants based on historical levels. (The implementation will be on a two-tiered time horizon, 1995 for an identified set of utility plants and 2000 for all others.) The cost of compliance is expected to increase the cost of the output of some existing plants, alter construction approaches to new facilities, and change the fuel use of other power plants. The impact of the changes will affect the availability of future power from power plants

emitting high levels and increase the attractiveness of acquiring power from other facilities and electrical systems emitting low levels. In addition, traditional wholesale trade patterns may be altered through changing costs and availability of electrical energy.

International Transactions

U.S. electric utilities have also taken advantage of being able to enter into international trade agreements to acquire energy from Canada and Mexico. These trade agreements between utilities cover a variety of transaction options. These options include purchasing nonfirm energy from relatively inexpensive renewable resources (hydroelectric from Canada and geothermal from Mexico); acquiring additional generating capability to support the requirements for supply at U.S. electric utilities; the holding of purchased electricity (as reservoir water) to be reacquired when needed by U.S. electric utilities; and sharing the benefits of coordinated operations planning for the systems. In some instances, consumers can be served more efficiently if they are connected to foreign transmission lines, because they are geographically closer to those lines.

Data Sources

Statistics on electricity transactions among U.S. electric utilities and on international electricity trade (including the United States, Canada, and Mexico) are presented in the following tables. These data were obtained from the Form EIA-861, "The Annual Electric Utility Report"; the Form EIA-860, "Annual Electric Generator Report"; the Department of Energy, Office of the Assistant Secretary for Emergency Policy, Form PO-411, "Coordinated Bulk Power Supply Program"; and the Department of Energy, Office of the Assistant Secretary for Fossil Energy, Form FE-781R, "Annual Report of International Electric Export/Import Data." More detailed information on U.S. electric power transactions is published in the *Electric Trade in the United States*.³³

³³Energy Information Administration, *Electric Trade in the United States*, DOE/EIA-0531(92)(Washington, DC, 1994).

Table 53. Sources and Disposition of Electricity at U.S. Electric Utilities, 1989 Through 1993
(Million Kilowatthours)

Item	1993	1992	1991	1990	1989
Source					
Net Generation	2,897,815	2,805,092	2,835,377	2,821,493	2,811,398
Purchases from Utilities	1,218,858	1,146,323	1,127,669	968,525	959,375
Purchases from Nonutilities	188,537	166,283	139,438	118,065	89,813
Net Exchange	-2,725	-3,504	1,172	-1,130	2,369
Net Wheeling	4,668	5,756	4,983	6,077	3,526
Disposition					
Sales to Ultimate Consumers	2,861,441	2,763,365	2,762,003	2,712,655	2,648,809
Requirements and Nonrequirements Sales for Resale	1,200,047	1,119,348	1,119,656	989,268	976,676
Energy Furnished Without Charge	5,003	4,409	4,210	6,996	6,647
Energy Used by Utility Electric Department	14,249	15,651	15,154	18,974	19,501
Energy Losses ^a	226,414	216,592	210,596	204,839	218,846

^a The shift in magnitude for net exchange reflects a change in accounting procedures by electric utilities because of reclassification of various transactions for bulk trade. In addition, the Tennessee Valley Authority reduced their net exchanges by 15 billion kilowatthours from 1989.

^b These values are not measured, however, they represent losses and unaccounted for energy. These values are calculated in order that source and disposition of energy are equivalent.

Notes: *Data for 1993 are preliminary, data for prior years are final. *Annual net generation data shown here should only be used in comparison with other Form EIA-861 data. Differences in this net generation data and net generation reported on the Form EIA-759, "Monthly Power Plant Report," (Table 1) occur due to the time frame in reporting. Since the components of net generation are provided monthly by the Form EIA-759 by prime mover and energy source, the Form EIA-759 is used as the official Energy Information Administration source for net generation. *Totals may not equal sum of components because of independent rounding. *The source and disposition of electricity represent the total volume of energy transactions between utilities. These data should not be summed as they are the aggregation of data reported for each utility and could be double counted due to the nature and types of electricity trade. *Due to the complexity of electric power transactions that involve specifics of contracts, simultaneous energy transactions, the unintended receipt and delivery of energy (inadvertent flow), and losses, uniformity in reporting the classification and quantity of each transaction among utilities may not exist.

Source: Energy Information Administration, Form EIA 861, "Annual Electric Utility Report."

Table 54. Net Generation from Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1989 Through 1993
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1993	1992	1991	1990	1989
ECAR	494,802	483,530	488,102	486,128	487,859
ERCOT	198,187	190,442	192,000	188,586	185,011
MAAC	205,552	193,330	197,235	193,389	193,889
MAW	217,284	200,266	206,908	201,663	200,660
MAPP(U.S.)	124,808	120,063	122,981	120,750	116,410
NPCC(U.S.)	185,140	202,978	218,053	227,866	233,624
SERC	667,464	637,893	630,662	611,708	612,643
SPP	256,901	242,514	244,415	244,762	239,032
WSCC(U.S.)	527,428	522,863	528,488	535,242	530,205
Contiguous U.S.	2,867,366	2,793,801	2,823,732	2,808,067	2,799,130
ASCC	4,660	4,735	4,654	4,660	4,575
Hawaii	5,790	6,555	6,981	7,746	7,692
U.S. Total	2,897,815	2,805,092	2,835,377	2,821,493	2,811,398

Notes: *Data for 1993 are preliminary, data for prior years are final. *Annual net generation data shown here should only be used in comparison with other Form EIA-861 data. Differences in this net generation data and net generation reported on the Form EIA-759, "Monthly Power Plant Report," (Table 1) occur due to the time frame in reporting. Since the components of net generation are provided monthly by the Form EIA-759 by prime mover and energy source, the Form EIA-759 is used as the official Energy Information Administration source for net generation. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA 861, "Annual Electric Utility Report."

Table 55. Electric Utility Sales to Ultimate Consumers by Sector, North American Electric Reliability Council Region, and Hawaii, 1989 Through 1993
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	All Sectors	Residential	Commercial	Industrial	Other ¹
1993					
ECAR	447,082	139,068	108,441	189,527	10,028
ERCOT	212,181	76,887	55,601	70,508	9,185
MAAC	220,031	77,450	89,027	70,881	2,873
MAIN	207,004	81,610	57,843	78,858	8,693
MAPP(U.S.)	124,142	44,717	28,588	49,353	3,504
NPCC(U.S.)	238,012	78,417	86,723	56,570	14,302
SERC	638,209	256,270	158,891	204,825	18,223
SPP	249,889	88,012	62,863	90,606	8,306
WSCC(U.S.)	514,212	168,376	184,187	162,078	19,583
Contiguous U.S.	2,848,742	990,805	790,225	973,093	94,708
ASCC	4,374	1,629	2,062	501	182
Hawaii	8,325	2,340	2,285	3,646	54
U.S. Total	2,951,441	994,775	794,572	977,151	94,844
1992					
ECAR	429,591	129,847	97,007	192,916	9,820
ERCOT	203,208	71,802	53,342	68,306	8,755
MAAC	210,799	72,221	85,871	68,797	2,810
MAIN	200,571	56,685	54,013	81,314	8,568
MAPP(U.S.)	117,263	41,724	25,510	46,877	3,171
NPCC(U.S.)	233,393	76,773	84,838	57,553	14,228
SERC	609,139	239,899	153,232	196,441	17,567
SPP	235,320	80,251	59,864	87,121	7,864
WSCC(U.S.)	511,395	162,773	183,083	165,298	20,331
Contiguous U.S.	2,760,695	931,976	736,982	948,534	93,223
ASCC	4,338	1,640	2,034	504	160
Hawaii	8,332	2,323	2,274	3,676	59
U.S. Total	2,763,365	938,939	761,271	972,714	93,442
1991					
ECAR	430,314	134,703	98,125	187,458	10,029
ERCOT	204,319	73,819	53,249	68,425	8,826
MAAC	212,728	74,002	85,821	70,044	2,861
MAIN	201,815	81,858	55,904	75,198	8,859
MAPP(U.S.)	120,522	44,449	25,873	48,609	3,502
NPCC(U.S.)	233,643	76,755	85,036	57,666	14,185
SERC	601,988	239,164	157,981	187,386	17,467
SPP	238,328	84,615	60,682	84,701	8,330
WSCC(U.S.)	505,986	162,191	158,783	164,919	20,044
Contiguous U.S.	2,749,584	951,644	761,463	942,486	94,101
ASCC	4,255	1,603	2,005	468	182
Hawaii	8,154	2,270	2,205	3,623	55
U.S. Total	2,762,093	955,417	766,664	946,583	94,339

See footnotes at end of table

Table 55. Electric Utility Sales to Ultimate Consumers by Sector, North American Electric Reliability Council Region, and Hawaii, 1989 Through 1993 (Continued)
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	All Sectors	Residential	Commercial	Industrial	Other ¹
1990					
ECAR	418,732	125,258	93,318	180,496	9,661
ERCOT	202,090	72,451	54,140	68,791	6,708
MAAC	207,770	70,571	63,606	70,796	2,799
MAIN	193,068	57,060	53,600	73,936	8,481
MAPP(U.S.)	115,912	42,156	24,751	45,692	3,313
NPCC(U.S.)	234,542	78,498	84,787	69,281	13,979
SERC	588,223	232,383	153,914	184,980	18,946
SPP	236,253	84,325	60,574	83,012	8,343
WSCC(U.S.)	503,744	159,484	158,280	184,479	21,541
Contiguous U.S.	2,700,334	920,153	746,949	941,461	91,770
ASCC	4,263	1,661	1,872	469	181
Hawaii	7,969	2,204	2,106	3,601	56
U.S. Total	2,712,555	924,019	751,027	945,522	91,968
1989					
ECAR	414,977	126,538	91,610	187,166	9,663
ERCOT	195,848	70,005	52,988	67,763	4,872
MAAC	207,325	70,758	62,117	71,849	2,803
MAIN	188,425	56,918	52,258	71,518	8,330
MAPP(U.S.)	113,692	42,050	23,584	44,531	3,526
NPCC(U.S.)	233,573	76,090	84,682	58,968	13,815
SERC	571,569	226,987	146,376	162,469	18,739
SPP	223,134	77,907	57,480	79,450	8,298
WSCC(U.S.)	488,675	156,102	150,856	158,203	21,515
Contiguous U.S.	2,836,019	981,762	721,960	921,764	89,582
ASCC	4,142	1,643	1,887	450	151
Hawaii	7,549	2,129	2,014	3,454	52
U.S. Total	2,848,800	906,625	726,881	926,669	89,766

¹ Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

Notes: *Data for 1993 are preliminary, data for prior years are final. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 56. Generating Capability at Electric Utilities by North American Electric Reliability Council Region and Hawaii, as of December 1989 Through 1993
(Megawatts)

North American Electric Reliability Council Region and Hawaii	1993	1992	1991	1990	1989
ECAR	104,818	104,861	104,925	104,179	102,645
ERCOT	52,689	51,688	51,213	51,016	49,738
MAAC	51,589	51,553	51,331	50,323	50,071
MAIN	50,314	49,730	48,644	48,475	48,511
MAPP(U.S.)	30,915	30,968	31,057	30,772	30,376
NPCC(U.S.)	58,043	54,637	55,443	55,567	54,480
SERC	149,748	148,127	148,447	148,286	145,129
SPP	71,009	70,771	70,642	70,519	70,468
WSCC(U.S.)	129,334	129,894	129,348	128,280	129,286
Contiguous U.S.	696,850	691,828	688,946	687,437	681,589
ASCC	1,711	1,672	1,547	1,542	1,546
Hawaii	1,602	1,580	1,521	1,487	1,483
U.S. Total	699,971	695,059	693,018	690,465	684,619

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 57. Noncoincidental Peak Load at Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1989 Through 1993 (Megawatts)

North American Electric Reliability Council Region and Hawaii	1993	1992	1991	1990	1989
Summer					
ECAR	80,533	78,550	81,539	79,258	76,442
ERCOT	44,255	42,619	41,870	42,737	40,402
MAAC	46,494	43,658	45,937	42,613	41,514
MAIN	41,858	39,819	41,598	40,740	39,460
MAPP(U.S.)	24,396	22,638	25,498	24,994	23,531
NPOC(U.S.)	46,706	43,658	^R 46,594	44,116	45,031
SERC	138,101	128,206	124,888	121,149	117,051
SPP	57,108	51,324	51,885	52,541	49,439
WSCC(U.S.)	97,809	99,205	92,096	97,389	90,657
Contiguous U.S.	575,356	548,707	^R 551,705	545,537	522,627
ASCC	511	504	471	463	455
Hawaii	¹	¹	¹	¹	¹
U.S. Total	575,867	549,211	^R 551,176	546,000	523,082
Winter					
ECAR	81,846	72,885	71,181	67,097	73,090
ERCOT	36,407	35,055	35,448	35,815	38,388
MAAC	41,406	37,915	37,983	36,551	38,161
MAIN	34,986	31,289	33,420	32,481	33,770
MAPP(U.S.)	21,955	21,898	21,432	21,113	20,899
NPOC(U.S.)	42,063	41,125	^R 41,786	40,545	42,588
SERC	133,635	121,250	119,575	117,231	121,985
SPP	41,644	39,912	38,759	38,949	42,288
WSCC(U.S.)	88,911	91,686	86,087	84,252	84,766
Contiguous U.S.	521,733	492,983	^R 485,881	484,614	495,717
ASCC	632	635	622	613	626
Hawaii	¹	¹	¹	¹	¹
U.S. Total	622,365	493,618	^R 486,303	484,827	495,343

¹ Data for Hawaii are not submitted for this form

R = Revised data

Notes: *Data are final *Totals may not equal sum of components because of independent rounding

Sources: Data for 1989: North American Reliability Council, *Electricity Supply and Demand 1994-2003*. Data for prior years: Department of Energy, Office of Emergency Policy, Form PD-411, "Coordinated Bulk Power Supply Program."

Table 58. Electric Utility Receipts by North American Electric Reliability Council Region and Hawaii, 1989 Through 1993
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Receipts ¹	Purchased Power	Exchange Received	Wheeling Received
1993				
ECAR	201,395	167,277	2,927	31,191
ERCOT	144,489	93,520	54,253	26,716
MAAC	93,046	76,958	3,250	13,132
MAIN	67,930	52,511	400	5,018
MAPP(U.S.)	109,222	89,875	2,567	16,781
NPOC(U.S.)	249,585	178,147	3,822	67,815
SERC	399,454	340,931	30,391	27,132
SPP	166,844	135,035	6,282	25,526
WSCC(U.S.)	465,155	287,564	59,660	137,931
Contiguous U.S.	1,916,121	1,491,518	163,589	351,244
ASCC	3,009	2,682	0	456
Hawaii	3,106	3,103	3	0
U.S. Total	1,922,266	1,497,204	163,591	351,701
1992				
ECAR	190,220	155,564	2,653	31,003
ERCOT	130,049	99,661	46,311	24,077
MAAC	92,676	71,675	11,134	9,868
MAIN	55,910	52,108	213	3,489
MAPP(U.S.)	125,334	81,610	32,062	11,661
NPOC(U.S.)	227,570	163,419	3,464	60,687
SERC	378,689	325,039	26,439	27,211
SPP	150,395	123,644	4,943	21,749
WSCC(U.S.)	478,769	275,031	76,224	127,514
Contiguous U.S.	1,829,463	1,307,759	203,643	318,060
ASCC	3,021	2,531	12	478
Hawaii	2,328	2,324	4	0
U.S. Total	1,834,801	1,312,906	203,655	318,538
1991				
ECAR	195,606	151,284	14,030	30,293
ERCOT	127,343	97,905	48,603	20,834
MAAC	84,589	61,395	17,352	5,842
MAIN	59,405	48,185	6,420	3,819
MAPP(U.S.)	114,659	78,176	26,999	9,484
NPOC(U.S.)	211,379	140,964	13,242	57,173
SERC	381,671	321,277	31,937	29,457
SPP	150,048	122,420	5,477	22,150
WSCC(U.S.)	503,361	281,678	77,218	144,466
Contiguous U.S.	1,827,860	1,263,162	241,278	322,820
ASCC	2,676	2,343	20	514
Hawaii	1,605	1,601	4	0
U.S. Total	1,831,541	1,267,106	241,302	323,183

See footnotes at end of table

Table 58. Electric Utility Receipts by North American Electric Reliability Council Region and Hawaii, 1989 Through 1993 (Continued)
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Receipts ¹	Purchased Power	Exchange Received	Wheeling Received
1990				
ECAR	243,183	106,802	103,430	32,841
ERCOT	111,413	58,788	36,144	16,481
MAAC	79,405	52,639	20,892	5,774
MAIN	69,759	35,701	32,807	1,451
MAPP(U.S.)	115,894	70,821	38,795	8,477
NPOC(U.S.)	180,396	123,171	18,613	48,613
SERC	365,567	290,825	65,471	29,281
SPP	147,874	108,909	11,674	27,091
WSCC(U.S.)	517,074	283,989	100,968	152,097
Contiguous U.S.	1,880,364	1,111,535	426,714	322,116
ASCC	2,900	2,345	2	552
Hawaii	714	710	4	0
U.S. Total	1,883,977	1,114,590	426,720	322,667
1989				
ECAR	208,000	90,953	93,949	21,098
ERCOT	102,501	56,354	34,733	9,414
MAAC	86,257	46,871	31,511	8,385
MAIN	63,790	33,699	28,677	1,215
MAPP(U.S.)	114,246	68,948	36,090	8,208
NPOC(U.S.)	183,999	125,693	15,109	42,897
SERC	363,654	276,755	62,163	22,726
SPP	140,237	107,120	13,526	19,591
WSCC(U.S.)	485,872	239,294	84,754	164,824
Contiguous U.S.	1,766,575	1,046,488	420,730	299,359
ASCC	2,748	2,253	28	465
Hawaii	452	446	6	0
U.S. Total	1,769,773	1,049,187	420,764	299,622

¹ Equals purchased power plus exchange received plus wheeling received.

Notes: *Data for 1993 are preliminary, data for prior years are final. *Totals may not equal sum of components because of independent rounding. *This is a summation of utility trade for utilities that operate within the NERC Region. *Due to the complexity of electric power transactions that involve specifics of contracts, simultaneous energy transactions, the unintended receipt and delivery of energy (unadvertised flow), and losses, uniformity in reporting the classification and quantity of each transaction among utilities may not exist. *Includes utility, import, export, and nonutility transactions.

Source: Energy Information Administration, Form EIA-881, "Annual Electric Utility Report."

Table 59. Electric Utility Deliveries by North American Electric Reliability Council Region and Hawaii, 1989 Through 1993
(Million Kilowatthours)

North American Electric Reliability Council Region	Total	Requirements and Nonrequirements	Exchange	Wheeling
ERCOT	114,854	33,790	3,193	30,994
MAAC	80,558	47,526	54,409	26,888
MAIN	82,541	57,410	1	13,830
MAPP(U.S.)	98,325	77,943	180	4,961
NPCC(U.S.)	189,109	118,632	4,251	16,130
SERC	374,073	321,445	1,923	67,553
SPP	151,816	118,353	27,304	25,324
WSOC(U.S.)	442,857	238,351	7,044	25,419
Contiguous U.S.	1,710,224	1,197,987	67,816	138,489
ASCC	2,938	2,490	166,961	346,576
Hawaii	6	0	0	456
U.S. Total	1,713,165	1,200,047	166,966	347,692
1992				
ECAR	212,729	178,224	2,887	31,618
ERCOT	102,988	32,299	46,577	24,090
MAAC	59,416	48,394	1,272	9,779
MAIN	40,706	37,240	62	3,404
MAPP(U.S.)	116,200	71,447	33,906	10,847
NPCC(U.S.)	178,803	118,451	1,857	60,495
SERC	357,147	300,686	31,053	25,408
SPP	137,540	109,596	6,306	21,638
WSOC(U.S.)	431,563	223,114	83,426	125,023
Contiguous U.S.	1,636,170	1,117,421	207,145	312,304
ASCC	3,020	2,528	14	478
Hawaii	3	0	3	0
U.S. Total	1,639,893	1,119,948	207,162	312,782
1991				
ECAR	221,435	182,081	9,193	30,161
ERCOT	101,790	31,383	49,470	20,937
MAAC	51,269	31,670	13,776	5,842
MAIN	49,267	36,136	6,982	3,739
MAPP(U.S.)	106,020	68,849	29,235	7,935
NPCC(U.S.)	177,038	112,476	7,635	56,925
SERC	384,167	308,718	30,001	27,447
SPP	136,561	107,864	6,600	22,078
WSOC(U.S.)	465,535	235,142	87,801	142,592
Contiguous U.S.	1,672,100	1,114,341	240,103	317,656
ASCC	2,849	2,314	21	514
Hawaii	5	0	5	0
U.S. Total	1,674,854	1,116,855	240,130	318,170

See footnotes at end of table

Table 59. Electric Utility Deliveries by North American Electric Reliability Council Region and Hawaii, 1989 Through 1993 (Continued)
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Deliveries ¹	Requirements and Nonrequirements Sales for Resale	Exchange Delivered	Wheeling Delivered
1990				
ECAR	278,660	153,283	92,614	32,753
ERCOT	85,076	32,153	38,428	16,496
MAAC	49,821	20,683	23,164	5,774
MAIN	63,588	24,191	37,883	1,414
MAPP(U.S.)	109,484	64,006	37,824	7,656
NPCC(U.S.)	166,593	98,972	19,222	48,399
SERC	387,832	279,722	59,336	28,174
SPP	196,099	96,289	13,824	26,965
WSCC(U.S.)	484,479	228,643	107,448	148,388
Contiguous U.S.	1,740,822	996,941	427,843	316,038
ASCC	2,863	2,327	3	552
Hawaii	5	0	5	0
U.S. Total	1,743,709	999,268	427,850	316,591
1991				
ECAR	246,874	152,703	72,177	20,994
ERCOT	78,668	32,355	35,017	8,297
MAAC	55,290	17,940	28,990	8,360
MAIN	60,612	23,746	35,661	1,206
MAPP(U.S.)	105,500	59,451	37,852	8,197
NPCC(U.S.)	164,838	99,653	22,634	42,351
SERC	375,248	277,693	75,670	21,885
SPP	134,664	86,202	18,558	19,824
WSCC(U.S.)	469,148	213,689	91,833	163,623
Contiguous U.S.	1,667,840	973,432	416,392	295,836
ASCC	2,705	2,244	*	461
Hawaii	3	0	3	0
U.S. Total	1,669,348	975,676	416,395	296,297

¹ Equals sales for resale plus exchange delivered plus wheeling delivered

* = Value less than 0.5

Notes: *Data for 1993 are preliminary, data for prior years are final. *Totals may not equal sum of components because of independent rounding.

*This is a summation of utility trade for utilities that operate within the NERC Region. *Due to the complexity of electric power transactions that involve species of contracts, simultaneous energy transactions, the unintended receipt and delivery of energy (inadvertent flow), and losses, uniformity in reporting the classification and quantity of each transaction among utilities may not exist. *Includes utility, import, export, and nonutility transactions.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 60. Electric Utility Net Energy Flow by North American Electric Reliability Council Region and Hawaii, 1989 Through 1993
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Net Energy Flow ¹	Receipts ²	Deliveries ³
1993			
ECAR	-14,898	201,395	216,284
ERCOT	29,834	144,489	114,654
MAAC	32,491	93,046	60,556
MAIN	5,388	87,930	62,541
MAPP(U.S.)	10,686	109,222	98,325
NPCC(U.S.)	60,478	249,585	189,109
SERC	24,381	368,454	374,079
SPP	15,029	166,844	151,516
WSCC(U.S.)	42,496	485,155	442,857
Contiguous U.S.	205,897	1,916,121	1,710,224
ASCC	103	3,039	2,936
Hawaii	3,101	3,106	5
U.S. Total	208,101	1,922,296	1,713,165
1992			
ECAR	-22,509	190,220	212,729
ERCOT	27,062	130,049	102,966
MAAC	33,260	92,676	59,416
MAIN	15,105	55,810	40,706
MAPP(U.S.)	9,134	125,334	116,200
NPCC(U.S.)	46,967	227,570	176,603
SERC	21,542	376,689	357,147
SPP	12,795	150,385	137,540
WSCC(U.S.)	47,206	478,769	431,689
Contiguous U.S.	192,593	1,829,453	1,636,870
ASCC	1	3,021	3,020
Hawaii	2,825	2,828	3
U.S. Total	194,909	1,834,901	1,639,893
1991			
ECAR	-25,829	185,606	221,435
ERCOT	26,569	127,343	101,790
MAAC	33,300	84,569	51,269
MAIN	10,136	58,405	48,267
MAPP(U.S.)	8,540	114,659	106,020
NPCC(U.S.)	34,340	211,379	177,036
SERC	17,505	381,671	364,167
SPP	13,487	150,046	135,561
WSCC(U.S.)	37,626	503,961	465,535
Contiguous U.S.	154,960	1,827,060	1,672,160
ASCC	27	2,676	2,849
Hawaii	1,600	1,605	5
U.S. Total	156,586	1,831,541	1,674,954

See footnotes at end of table

Table 60. Electric Utility Net Energy Flow by North American Electric Reliability Council Region and Hawaii, 1989 Through 1993 (Continued)
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Net Energy Flow ¹	Receipts ²	Deliveries ³
1990			
ECAR	-35,487	243,163	278,650
ERCOT	26,337	111,413	85,076
MAAC	26,784	79,405	49,621
MAIN	6,171	69,759	63,588
MAPP(U.S.)	6,406	115,894	109,484
NPCC(U.S.)	23,603	190,396	166,593
SERC	18,355	385,587	367,232
SPP	11,575	147,674	136,099
WSCC(U.S.)	32,594	517,074	484,479
Contiguous U.S.	178,542	1,660,384	1,740,822
ASCC	17	2,900	2,883
Hawaii	708	714	5
U.S. Total	120,268	1,663,977	1,743,709
1989			
ECAR	-39,674	206,000	245,674
ERCOT	25,833	102,501	76,666
MAAC	30,977	86,287	55,290
MAIN	3,178	63,790	60,612
MAPP(U.S.)	8,745	114,246	105,500
NPCC(U.S.)	19,361	183,998	164,636
SERC	8,416	383,664	375,246
SPP	5,552	140,237	134,684
WSCC(U.S.)	16,726	485,872	469,146
Contiguous U.S.	78,916	1,796,675	1,867,898
ASCC	41	2,746	2,705
Hawaii	449	452	3
U.S. Total	79,405	1,798,773	1,880,396

¹ Equals receipts minus deliveries

² Equals purchased power plus exchange received plus wheeling received

³ Equals sales for resale plus exchange delivered plus wheeling delivered

Notes: *Data for 1993 are preliminary; data for prior years are final. *Totals may not equal sum of components because of independent rounding. *This is a summation of utility trade for utilities that operate within the NERC Region. *Due to the complexity of electric power transactions that involve specifics of contracts, simultaneous energy transactions, the unintended receipt and delivery of energy (inadvertent flow), and losses, uniformity in reporting the classification and quantity of each transaction among utilities may not exist. *Includes utility, import, export, and nonutility transactions.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 61. Electric Utility Purchases of Nonutility Generated Electricity by North American Electric Reliability Council Region and Hawaii, 1989 Through 1993
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1993	1992	1991	1990	1989
ECAR	11,962	10,420	8,649	7,879	2,024
ERCOT	24,267	23,966	23,036	23,570	22,694
MAAC	18,083	16,433	12,721	8,007	5,479
MAIN	401	347	273	289	179
MAPP(U.S.)	582	576	1,563	348	148
NPCC(U.S.)	42,724	36,116	29,220	15,037	10,182
SERC	19,021	16,304	12,914	10,828	6,914
SPP	6,609	5,457	5,705	3,514	2,611
WSCC(U.S.)	61,580	55,637	49,951	45,979	37,145
Contiguous U.S.	186,429	163,967	138,033	116,542	89,576
ASCC	4	1	1	1	1
Hawaii	3,103	2,324	1,402	522	235
U.S. Total	188,537	166,283	139,439	116,065	89,813

Notes: *Data for 1993 are preliminary; data for prior years are final. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 62. Net Imports at Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1989 Through 1993
(Thousand Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1993	1992	1991	1990	1989
ECAR	831,879	-231,967	-446,412	-10,918,913	-5,426,212
ERCOT	-7,760	-169,142	-195,548	-6,744	-10,315
MAAC	--	--	--	--	--
MAIN	--	--	--	--	--
MAPP(U.S.)	7,806,665	6,821,800	3,307,714	742,954	-373,343
NPOC(U.S.)	16,756,045	12,053,907	10,989,137	6,582,311	11,147,862
SERC	--	--	--	--	--
SPP	--	--	--	--	--
WSCC(U.S.)	2,938,533	9,773,701	8,617,259	5,802,571	5,637,853
Contiguous U.S.	28,427,162	28,348,299	22,272,150	1,860,179	10,975,843
ASCC	--	--	--	--	--
Hawaii	--	--	--	--	--
U.S. Total	28,427,162	28,348,299	22,272,150	1,860,179	10,975,843

-- Value less than 0.5

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding. *Values identify point of entry or exit, but do not necessarily identify point of consumption. *These data reflect electricity imported from Canada and Mexico. *Net imports data represent gross imports minus gross exports.

Source: Office of Fuels Programs, Fossil Energy, Form FE-781R, "Annual Report of International Electric Export/Import Data."

Table 63. Imports to Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1989 Through 1993
(Thousand Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1993	1992	1991	1990	1989
ECAR	959,746	82,151	106,606	38,234	13,451
ERCOT	14	--	14	1,121	1,333
MAAC	--	--	--	--	--
MAIN	--	--	--	--	--
MAPP(U.S.)	10,767,276	8,573,852	4,708,775	3,072,170	2,260,780
NPOC(U.S.)	18,741,212	14,899,838	13,051,823	9,272,554	13,707,666
SERC	--	--	--	--	--
SPP	--	--	--	--	--
WSCC(U.S.)	8,513,566	13,846,735	12,845,048	10,122,141	10,127,191
Contiguous U.S.	29,061,814	27,204,176	20,812,266	22,506,220	26,110,432
ASCC	--	--	--	--	--
Hawaii	--	--	--	--	--
U.S. Total	29,061,814	27,204,176	20,812,266	22,506,220	26,110,432

-- Value less than 0.5

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding. *Values identify point of entry or exit, but do not necessarily identify point of consumption. *These data reflect electricity imported from Canada and Mexico.

Source: Office of Fuels Programs, Fossil Energy, Form FE-781R, "Annual Report of International Electric Export/Import Data."

Table 64. Exports from Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1989 Through 1993
(Thousand Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1993	1992	1991	1990	1989
ECAR	28,067	314,118	553,018	10,957,147	5,439,863
ERCOT	7,774	169,142	195,562	9,896	1,648
MAAC	—	—	—	—	—
MAIN	—	—	—	—	—
MAPP(U.S.)	2,959,591	1,661,862	1,401,061	2,329,216	2,634,133
NPCC(U.S.)	1,986,167	2,646,731	2,082,686	2,710,243	2,669,806
SERC	—	—	—	—	—
SPP	—	—	—	—	—
WSCC(U.S.)	5,675,033	4,075,034	4,327,789	4,519,570	4,489,338
Contiguous U.S.	10,654,632	8,855,877	8,540,116	20,526,041	15,134,589
ASCC	—	—	—	—	—
Hawaii	—	—	—	—	—
U.S. Total	10,654,632	8,855,877	8,540,116	20,526,041	15,134,589

* — Value less than 0.5

Notes: *Data are final. *Totals may not equal sum of components because of independent rounding. *Values identify point of entry or exit, but do not necessarily identify point of consumption. *These data reflect electricity imported from Canada and Mexico.

Source: Office of Fuels Programs, Fossil Energy, Form FE-781R, "Annual Report of International Electric Export/Import Data."

U.S. Electric Utility Demand-Side Management

U.S. electric utilities have come to realize that a flexible and diverse management strategy provides the greatest opportunity for success in the competitive and uncertain environment in which they operate. An important component of this strategy has been the increasing reliance on demand-side management (DSM) programs to modify the growth in demand and energy use, to cost-effectively meet customer energy service requirements, to selectively expand customer services, and to improve the use of generating resources. This chapter provides a brief description of the key elements of electric utility DSM program development in the United States.

Background

DSM consists of the planning, implementing, and monitoring of utility activities that are designed to encourage consumers to modify their pattern of electricity usage, including the timing and level of electricity demand. The primary objective of most DSM programs is to provide cost-effective energy and capacity resources to help defer the need for new sources of power supply, including generating facilities, power purchases, and transmission and distribution capacity additions. Identifying the right mix of DSM options can be mutually beneficial to the utility, the consumer, and society. The utility can benefit from lowered cost of service, improved operating efficiency, reduced capital requirements, and enhanced consumer service. Consumers can benefit from reduced costs and improved value of service. Society can benefit from reduced emissions and the conservation of energy resources.

DSM programs have become a key component of the integrated resource plans (IRPs) of a growing number of electric utilities. The IRP process differs from traditional utility planning practices primarily in its increased attention to DSM programs and its integration of supply and demand-side resources into a flexible resource portfolio. Utilities and State regulatory commissions are using the IRP process to assess a variety of resource options that cost-effectively meet consumer energy-service requirements, while being responsive to external changes such as economic conditions, energy prices, new technologies and changes in regulatory and tax policy. Regulatory review of utility resource planning along with requirements that utilities follow an IRP process evolved from the forecasting

and siting reviews that were begun by many States in the 1970's. The evolution to periodic advance review of utility resource planning was, in part, a response by regulators to the completion of controversial capacity additions over which there had been limited or no advance regulatory oversight. Over 40 States have implemented integrated resource planning. In addition to balanced consideration of supply and demand-side options, the IRP process includes consideration of risk and diversity of supply, maintaining system reliability, and in some instances the application of specific values to reflect environmental and other impacts.

Identify Program Alternatives

The types of DSM programs that utilities select to alter the timing and level of demand for electricity will vary significantly depending on their overall organizational and market environment, strategic objectives, and system operating characteristics. DSM programs generally promote one of four basic objectives that differ in their intended effects on electricity use (measured in kilowatt-hours) and demand (measured in kilowatts). First, energy efficiency, or conservation, programs are aimed at reducing the energy used by specific end-use devices and systems through the promotion of high-efficiency equipment and building design, typically reducing energy consumption throughout many hours of the year. Such high-efficiency measures generally use less electricity to provide consumers an equivalent or greater level of electric energy services (light, heat, cooling, or drive power). This category covers the great majority of DSM programs across all consumer classes. Second, load management programs are aimed at reducing or shifting demand at certain critical times (such as summer or winter peak), and are focused on changing the timing of electricity demand. These program types usually have only a minor effect on the amount of annual electricity consumption. For example, residential and commercial air conditioners or water heaters may be allowed to operate unimpeded during off-hour peak demand hours, but are cycled on and off by direct control of the utility during a few peak-demand hours. Third, flexible load shape programs provide consumers a price signal or incentive to modify their consumption in response to changes in the utility's cost of providing power. Real time pricing is an example of this type of program. Fourth, strategic load growth or electrification programs are designed to increase electricity consumption typically by building

usage during valleys of low consumption or introducing new, efficient electrotechnologies. Such programs may facilitate the efficient operation of baseload generating units, reduce rates, and help customers meet environmental requirements, enhance product quality, or lower costs by replacing less efficient energy sources.

The energy savings and peak load reductions reported by electric utilities to EIA fall into one of six DSM program types.³⁴

Energy Efficiency - Energy efficiency programs vary by season and time-of-day and are aimed at reducing the energy used by specific end-use devices and systems, typically without reducing the level of energy services provided. These programs reduce overall electricity consumption over many hours during the year, although the largest impacts of cost-effective programs often coincide with periods of peak usage. Such savings are generally achieved by substituting technically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include high-efficiency appliances, efficient lighting, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motors and drive systems, and heat recovery systems. Energy efficiency programs frequently incorporate rebates, financing or other financial incentives for participation, rather than relying primarily on alternative rate structures as do some other program categories.

Direct Load Control - This category represents the consumer load that can be interrupted during the periods of peak load by direct control of the utility system operator. This type of control usually involves residential consumers.

Interruptible Load - This category accounts for the consumer load that, in accordance with contractual arrangements, can be interrupted during periods of peak load either by the direct control of the utility system operator or by the action of the consumer at the direct request of the system operator. It usually affects large-volume commercial and industrial consumers.

Other Load Management - This category refers to programs other than Direct Load Control and Interruptible Load that limit peakloads, or shift peak load from on-peak to off-peak time periods, or encourage customers to respond to changes in the utility's cost of providing power. It includes technologies that primarily shift all or part of a load from one time-of-day to an-

other and secondarily may have an impact on energy consumption. Examples include space heating and water heating storage systems, cool storage systems, and load limiting devices in energy management systems. This category also includes programs that aggressively promote time-of-use (TOU) rates and other innovative rates such as real time pricing. These rates are intended to reduce consumer bills and shift hours of operation of equipment from on-peak to off-peak or high-cost to low-cost periods through the application of time-differentiated rates.

Other Demand-Side Management Program - This residual category captures the effects of DSM programs that cannot be meaningfully included in any of the other program categories. The energy effects attributable to this category represent the net effects of all the residual programs. Programs that promote consumer's substitution of other energy types for electricity and self-generation of electricity for consumers' own use are included.³⁵

Load Building - This category represents programs that are aimed at increasing the usage of existing electric equipment or the addition of electric equipment. Examples include industrial technologies such as induction heating and melting, direct arc furnaces and infrared drying; cooking for commercial establishments; and heat pumps for residences. Load Building includes programs that promote the substitution of electricity for other fuels.

Planning and Selection of Programs

The key elements of the DSM program planning and selection process are to identify and evaluate key consumer characteristics that influence acceptance and response to DSM programs and utility considerations affecting resource requirements and the cost of alternative resource options. Among the consumer characteristics that influence a program's success are demographics, income, knowledge and awareness, attitude and motivation, discount rate, and price experience. External influences such as economic conditions, energy prices, technologies, regulation, and tax credits also influence consumer's decisions regarding fuel and appliance choices, appliance and equipment efficiency, and appliance use. The utility's considerations are usually focused on the interaction of load shape changes and supply-side resources options, transmission and distribution effects, and regulatory compliance.

To compare DSM programs to other demand- and supply side resources, regulators have developed standardized benefit/cost tests. There are five benefit/cost tests

³⁴Growth in energy sales and peak demand attributable to load building programs were reported to the EIA for the first time on the 1992 Form EIA-861, "Annual Electric Utility Report." These data are not included in the tables in this chapter.

³⁵Self-generation of electricity for consumers' use is also included in the Other Demand-Side Management category only to the extent that it is not accounted for as backup generation in Other Load Management or Interruptible Load categories. Also, it includes only that capacity for use by the consumer that is part of the utility's DSM program. Self-generation that is driven by market forces is excluded.

that are widely used in planning to identify cost effective DSM programs.³⁶ For each test, the net present value and benefit/cost ratio can be determined. The present value equals total benefits of the program less total costs; the benefit cost ratio is the ratio of total benefits to total costs. Based on these values, the utility can prioritize DSM programs to determine which, if any, might be implemented.

The Utility Cost Test measures the net benefits or costs of programs based on costs incurred by and the revenue requirements of the utility (i.e., it excludes participant costs). It determines if the utility's cost for DSM programs is less than the avoided supply cost.

The Participant Test measures the quantifiable benefits and costs to consumers who participate in the DSM program. It attempts to answer whether or not the participant is better off with the DSM technology and likely to participate in programs.

The Rate Impact Measure Test captures the present value impact on all consumers' average rates due to the DSM program. It evaluates whether average rates for consumers (including nonparticipants) will go up, down, or remain unaffected.

The Total Resource Cost Test shows the net benefits or costs of a DSM program as a resource option based on the total costs of the program, including both participants and utility cost (the Societal Cost Test is a variant of this test which incorporates externalities and excludes tax credits). It determines if the total cost of DSM to participants and non-participants is less than the supply cost for an equivalent amount of capacity and energy.

The Societal Test considers the broadest point of view, including the total resource cost and external costs and benefits, such as environmental impacts. It determines if the total cost of the DSM program is less than the alternative supply cost (including environmental costs).

The inclusion of environmental externalities in planning generally affects DSM options favorably. For example, if only traditional costs are considered in the planning process, a supply-side option might appear more attractive than a particular energy efficiency program.

However, traditional costs seldom reflect the full cost to society of utility activities that adversely affect the environment. In assessing supply and demand-side options for planning purposes, regulators have been mov-

ing to consider broad impacts of utility resource acquisition on society, including environmental and other externalities. Environmental externalities are real impacts on the production or utility functions of others, including impacts on health and property values, which are not reflected in the prices of goods and services.³⁷ Under traditional command-and-control air quality regulation, the additional emissions associated with operating a polluting facility for more hours do not increase the production costs of the source. Thus, many residual air emissions are classified as externalities. Externalities also may include national security costs associated with reliance on foreign oil or transition costs associated with local economic dislocations. Environmental externalities have become a part of the criteria for comparison and selection of utility resource options in 26 states and the District of Columbia.³⁸

Implement Programs

Another component of DSM program development is the marketing plan to implement a package of cost-effective programs through customer education, direct contact, trade ally cooperation (for example, building contractors and appliance dealers), advertising/promotion, alternative pricing, incentives, financing, and direct installation. The programs differ in the types of services offered to consumers. For example, general information programs attempt to inform consumers about DSM options through such mechanisms as brochures, bill stuffers, television and radio advertisements, and workshops. Direct installation programs involve installation of energy efficiency measures in the facilities of participating consumers by the utility, or its contractors. These programs generally cover low-cost measures, such as water-heater wraps and compact fluorescent lamps. Energy audits provide information on the physical and operating characteristics of a building and its energy uses and processes. Audit services vary from simple walk-throughs to building management training programs and site-specific process and efficiency evaluations. Incentive programs offer cash or noncash awards to manufacturers of energy efficient electric equipment, deliverers of energy products or service such as appliance and equipment dealers, building contractors, and architectural and engineering firms, or directly to consumers, that encourage consumer participation in a DSM program and adoption of recommended measures. Appliance rebates and zero- or low-interest loans are common examples of incentive programs. Lastly, utilities offer alternative-rate programs, such as discounts or refunds on monthly electric bills, in return for consumer participation in

³⁶California Public Utilities Commission and California Energy Commission, *Standard Practice Manual: Economic Analysis of Demand-Side Management Programs* (Sacramento, California, December 1987).

³⁷Baumol, William J. and Wallace E. Oates, *The Theory of Environmental Policy*, 2nd Ed., (Cambridge University Press, New York, 1989) p. 17.

³⁸The Consumer Energy Council of America Research Foundation, *Incorporating Environmental Externalities into Utility Planning* (Consumer Energy Council of American Research Foundation, Washington, D.C., 1993).

programs designed to reduce peak demand or to modify the load shape.

Most DSM programs are aimed at specific subsets of the utility population, typically by consumer classes and market segments. For example, the residential sector is often subdivided by housing type (for example, single-unit, multi-unit, mobile home). Residential sector programs typically consider the relative similarity of end uses and consumption patterns to identify load-shape modification opportunities with relatively predictable outcomes. Because per-unit electricity consumption in the residential sector is less than that of the commercial and industrial sectors, residential DSM programs are usually designed to achieve high-participation rates in order to alter the load curve of the utility system significantly.

Most commercial electricity consumption is for lighting, air conditioning, and space heating. However, the relative importance of the different end uses varies significantly across consumer types. Office buildings, retail establishments, schools, supermarkets, and restaurants exhibit distinctly different patterns of electricity consumption. Recently, utility-sponsored efforts to develop DSM potential in the commercial sector have increased significantly, with program activities focusing on energy-management assistance, cool storage, lighting, heating and air conditioning, and water heating improvements.

DSM program development in the industrial sector has been slow compared with its development in the residential and commercial sectors. The wide variety of industrial process uses initially hindered the design of DSM programs tailored to the industrial sector. Utilities traditionally relied on alternative rate-design approaches, such as interruptible service and time-of-use rates to achieve DSM objectives in the industrial sector. Utilities have broadened their DSM approach to include incentive and financing programs for industrial lighting, thermal storage, electrotechnology, advanced motors and drive systems, compressed-air systems, and other process-energy uses, which have the potential to meet energy-efficiency and load-management objectives. A number of utilities have developed flexible custom measure programs which allow industrial energy users and utilities to work together to identify cost-effective measures.

Recently, a number of utilities have pursued coordinated programs aimed at transforming specific market segments. For example, 24 utilities contributed to a \$30 million incentive pool which will be paid to the manufacturer of new super-efficient refrigerators designed to reduce energy consumption 30 percent below 1993 Federal appliance efficiency standards, while eliminating the use of chlorofluorocarbons (CFC's).

Additional, joint market transformation programs are being developed.

Monitor and Evaluate Programs

Electric utilities must rely on systematic measurement, statistical analysis, and engineering expertise to evaluate the operation and performance of DSM programs to verify DSM results, to assess the effectiveness of the program, and to provide feedback on the results that are essential for future decisions about DSM programs. Utilities report DSM-program results in a number of ways, depending largely on the load modification objectives of their programs. For example, utilities interested in peak clipping typically measure program success in terms of total peakload reduction or its reduction per consumer. Utilities interested in reducing overall energy consumption measure both peak reduction and total energy savings. When evaluating program success, utilities typically determine the level of load-and-energy reductions, program costs per unit of energy and/or demand savings, and program participation rates.

While the consumption of electricity can be measured in a variety of ways, such as monthly electric bills, special short-term metering, whole-building load-research data, or end-use load monitoring, the saving of electricity—the difference between actual consumption and what would have occurred in the absence of a DSM program—can only be estimated based on engineering data or statistical analysis.

The analytical procedures applied to estimate electricity and load changes involve a variety of techniques. These techniques include using engineering estimates to derive the energy-saving effect per installation of an energy-efficient device, monitoring electricity use for selected consumers before and after participation in a DSM activity, and contrasting the aggregated effects of DSM program participants and nonparticipants.

Evaluation and verification to determine whether DSM programs achieve their stated objectives are essential because (1) utilities are scheduled to invest billions of dollars in DSM programs, (2) utilities are counting on the saved electricity as one source of supply to meet expected increases in future electricity demand, (3) State regulators are increasingly allowing utilities to collect financial incentives and recover cost revenues based on the results of DSM programs, (4) the results of conservation programs may be recognized for purposes of environmental compliance; and (5) utilities and regulators need to know what mix of DSM technologies and techniques yields the most cost-effective energy savings.³⁹

³⁹General Accounting Office, *Electricity Supply, Utility Demand-Side Management Programs Can Reduce Electricity Use*, GAO/RCED-92-13 (Washington, DC, October 1991).

As utility DSM budgets have grown, exceeding \$2.7 billion in 1993, it has become increasingly important to know what DSM programs have accomplished. This has led to more sophisticated efforts to measure and evaluate a greater number of programs. Nevertheless, detailed impact and process evaluations have been completed on only a small fraction of all DSM programs. These evaluations may vary with respect to the methodologies employed, the issues and types of programs studied, and the purposes for which evaluations were conducted. Because practices may vary substantially from one utility to the next, it is difficult to generalize regarding the quality of the data supporting the estimates of energy savings and peak reductions reported to EIA or the extent to which such estimates have been subject to after-the-fact verification. EIA is in the process of examining DSM data verification procedures and their effects on data reported on the Form EIA-861.⁴⁰ The analysis includes an assessment of program evaluation practices and how they vary among utilities. The extent to which DSM data reported to EIA is based on verified data is also being evaluated. In addition, EIA is interested in identifying state-of-the-art DSM program evaluations and the relationship between data evaluation and verification. Typical evaluation and verification methodologies and the factors which influence the extent to which it is reasonable to reach broad conclusions about the quality of savings estimates reported to EIA are also under review. The EIA will publish the results of the study when available.

Data Sources

The data in the following tables were collected on Schedule V of the 1993 Form EIA-861, "Annual Electric Utility Report." Schedule V collects utility information on actual and potential peak load reductions and energy savings for six program categories (Energy Efficiency, Direct Load Control, Interruptible Load, Other Load Management, Other DSM Programs, and Load Building) by four major consumer sectors (residential, commercial, industrial, and other). Utilities provide information for the reporting year (1993) and the first-and fifth-forecast years (1994 and 1998).

Both annual and incremental energy savings and peak reductions are collected for the reporting year. Annual effects are the total effects in energy use and peak load caused by all new and prior year participants in the DSM programs that are in place during a given year. It includes all participants in existing and new programs (those implemented during the given year). Incremental effects are the annual effects in energy use and peak load caused by new participants in DSM programs during a given year. Incremental effects are annualized to indicate the program effects that would have occurred had these participants been in the program on January 1 of the given year.

DSM costs are reported in one of three categories. If the cost can be tracked to a specific program category (energy efficiency, direct load control, etc.), it is reported as a direct utility cost under that program category. If the cost cannot be tracked to a program category, it is reported as an indirect utility cost under the appropriate accounting category (administrative, marketing, monitoring and evaluation, or other). Total nonutility cost is also reported.⁴¹

⁴⁰In 1993, for the first time, utilities provided information on the methodologies used to estimate and verify the energy savings and peak load reductions of their DSM programs.

⁴¹On Schedule V, utilities are asked to identify specific energy efficiency end uses (heating and cooling systems, water heating, lighting, new construction, etc.) and program types (rebates, audits, loans) by consumer sector that they promote. These data will be presented in an EIA publication on utility-specific DSM activities that is scheduled for release in the Spring of 1995.

Table 65. Annual Demand-Side Management Peakload Reductions, Energy Savings, and Cost at U.S. Electric Utilities, 1989 Through 1993

Item	1993	1992	1991	1990	1989
Actual Peakload Reductions (megawatts) ^{1, 2}	23,131	17,204	16,739	14,773	12,463
Energy Savings (million kilowatthours) ^{1, 3}	44,346	30,164	23,343	19,671	16,266
Cost (thousand dollars) ⁴	2,768,662	2,243,279	1,747,833	1,177,457	\$72,935

¹ Represents the total effects caused by all participants in demand-side management programs in effect during a given year. Included are new and existing participants in existing programs (those implemented in prior years that are in place during the reporting year) and all participants in new programs (those implemented during the reporting year).

² Represents the actual reduction in annual peak load achieved by consumers in the following demand-side management program categories: energy efficiency, direct load control, interruptible load, other load management, other demand-side management, reflects real changes in the demand for electricity at the time of annual peak load, as opposed to the installed peakload reduction capability (i.e., Potential Peak Reduction).

³ The large increase in energy savings for 1992 and 1993 is due to the WSCC region's calculation revisions by Bonneville Power Administration and Southern California Edison for 1992 and 1993. Changes to energy savings data for 1989-1991 will be revised in an upcoming DSM publication due out in the spring of 1995.

⁴ Referred to in the *Electric Power Annual, 1992* as "Expenditures," these data represent the sum of the direct and indirect utility costs for the year and reflect the total cash expenditures incurred for the year, reported in nominal dollars, that flowed out to support demand-side management programs.

Notes: *Data for 1993 are preliminary, data for prior years are final. *Data are provided for electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 120,000 megawatthours. *Data for 1993 for peakload growth (497,997 megawatts), energy sales (3,362,133 megawatthours), and cost (\$31,178 (thousands)) attributable to Load Building programs are excluded.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 66. Annual Actual Reductions in Peak Load at Electric Utilities by Demand-Side Management Program, North American Electric Reliability Council Region, and Hawaii, 1990 Through 1993 (Megawatts)

North American Electric Reliability Council Region and Hawaii	Total Actual Peakload Reduction	Direct Load Control	Interruptible Load	Energy Efficiency	Other Load Management	Other Demand-Side Management
1993						
ECAR	1,671	179	773	573	115	31
ERCOT	1,414	42	114	949	291	17
MAAC	1,493	328	516	301	340	7
MAIN	844	60	247	494	39	4
MAPP(U.S.)	2,121	793	632	413	270	12
NPPC(U.S.)	1,966	201	228	1,520	18	*
SERC	5,447	1,770	2,792	3,329	439	115
SPP	889	395	323	111	38	23
WSCC(U.S.)	4,322	183	1,003	2,783	250	104
Contiguous U.S.	23,189	3,953	6,528	16,475	1,799	315
ASCC	7	2	0	*	4	0
Hawaii	5	0	0	5	0	0
U.S. Total	23,191	3,953	6,528	16,480	1,803	315
1992						
ECAR	661	128	49	379	101	4
ERCOT	592	22	131	389	65	2
MAAC	1,677	631	317	216	512	0
MAIN	840	32	466	323	20	*
MAPP(U.S.)	1,542	655	420	270	190	9
NPPC(U.S.)	1,796	169	323	1,257	48	*
SERC	5,559	1,592	684	2,636	487	106
SPP	624	370	117	85	6	46
WSCC(U.S.)	3,902	198	1,074	2,351	237	52
Contiguous U.S.	17,194	3,777	3,579	7,469	1,099	261
ASCC	7	2	0	*	4	0
Hawaii	4	0	0	1	3	0
U.S. Total	17,204	3,779	3,579	7,490	1,076	261
1991						
ECAR	1,401	319	515		487	
ERCOT	311	68	30		213	
MAAC	1,494	573	657		244	
MAIN	762	64	389		329	
MAPP(U.S.)	1,424	902	305		217	
NPPC(U.S.)	1,493	215	343		935	
SERC	5,696	2,030	602		3,364	
SPP	1,165	506	426		221	
WSCC(U.S.)	2,888	414	287		1,967	
Contiguous U.S.	16,694	5,991	3,646		7,957	
ASCC	5	2	3		0	
Hawaii	40	0	25		15	
U.S. Total	16,739	5,993	3,674		7,972	
1990						
ECAR	1,057	189	589		329	
ERCOT	333	40	173		120	
MAAC	1,083	263	569		251	
MAIN	549	66	197		267	
MAPP(U.S.)	1,116	629	261		226	
NPPC(U.S.)	1,304	129	445		730	
SERC	6,188	1,577	1,473		3,138	
SPP	761	429	203		129	
WSCC(U.S.)	2,308	370	275		1,663	
Contiguous U.S.	14,729	3,691	4,185		6,853	
ASCC	4	1	3		0	
Hawaii	39	0	31		6	
U.S. Total	14,772	3,692	4,219		6,861	

Notes: *Data for 1993 are preliminary; data for prior years are final. *Data are provided for electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 120,000 megawatt-hours. *These data reflect actual real changes in the demand for electricity at the time of annual peak load, as opposed to the installed peakload reduction capability (i.e., Potential Peak Reduction), achieved by all program participants during the reporting year. Program participants included new and existing participants in existing programs (those implemented in prior years that are in place during the reporting year) and all participants in new programs (those implemented during the reporting year). * - Value Less than 0.5.

Source: Energy Information Administration, Form EIA-851, "Annual Electric Utility Report."

Table 67. Annual and Incremental Effects at U.S. Electric Utilities by Demand-Side Management Program, 1993

Program	Potential Peakload Reduction ¹ (megawatts)	Actual Peakload Reduction ² (megawatts)	Energy Savings (million kilowatthours)
Annual Effects³			
Large Electric Utilities⁴			
Energy Efficiency ⁵	--	10,460	40,174
Direct Load Control	6,268	3,955	319
Interruptible Load	18,235	6,826	2,119
Other Load Management ⁶	2,182	1,603	223
Other Demand-Side Management ⁷	457	315	1,514
Total Electric Utilities	29,140	23,161	44,349
Incremental Effects⁸			
Large Electric Utilities⁴			
Energy Efficiency ⁵	--	1,858	8,801
Direct Load Control	1,297	594	25
Interruptible Load	3,536	1,604	75
Other Load Management ⁶	371	297	19
Other Demand-Side Management ⁷	94	55	389
Small Electric Utilities⁹			
Energy Efficiency ⁵	--	9	12
Direct Load Control	189	105	6
Interruptible Load	47	33	2
Other Load Management ⁶	50	38	1
Other Demand-Side Management ⁷	5	1	2
Total Electric Utilities	5,669	4,653	9,131

¹ Reflects the installed, contractually available, peakload reduction by program category, excluding energy efficiency, during the electric utility's annual system peak load. Energy Efficiency includes programs aimed at reducing energy consumption over many hours during the year. These programs reduce load, and if they coincide with periods of peak usage, they are included in the actual peakload reduction. However, these programs cannot be implemented specifically at the time of peak usage and are therefore not included in the potential peakload reduction.

² Reflects real changes in peak load by program categories, including energy efficiency, during the electric utility's annual system peak load.

³ Represents the total effects caused by all participants in demand-side management programs in effect during a given year. Included are new and existing participants in existing programs (those implemented in prior years that are in place during the reporting year) and all participants in new programs (those implemented during the reporting year).

⁴ Refers to electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 120,000 megawatthours.

⁵ Includes programs aimed at reducing energy consumption over many hours during the year. These programs reduce load and if they coincide with periods of peak usage they are included in the actual peakload reduction. However, these programs cannot be implemented specifically at the time of peak usage and are therefore not included in the potential peakload reduction.

⁶ Refers to programs other than direct load control and interruptible load that limit or shift load from on-peak to off-peak time periods, including technologies that primarily shift all or part of a load from one time-of-day to another and secondarily may have an impact on energy consumption. Examples include space heating and water heating storage systems, cool storage systems, load limiting devices in energy management systems, and programs that aggressively promote time-of-use rates and other innovative rates such as real time pricing.

⁷ Includes programs that promote consumer's substitution of electricity by other energy types and self-generation of electricity for consumer use. Self-generation is included only to the extent that it is not accounted for as backup generation in other load management or interruptible load categories, used by the consumer, and initiated by the electric utility (i.e., not a consumer response driven by market forces).

⁸ Represents the total effects caused by new participants in existing demand-side management programs and all participants in new programs during the year. Incremental effects are annualized to indicate the program effects that would have resulted had participants been initiated into the program on January 1 of the reporting year.

⁹ Refers to electric utilities with sales to ultimate consumers and sales for resale less than 120,000 megawatthours.

Note: Data are preliminary.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 68. Annual and Incremental Effects at U.S. Electric Utilities by Sector, 1993

Sector	Potential Peakload Reduction ¹ (megawatts)	Actual Peakload Reduction ² (megawatts)	Energy Savings (million kilowatthours)
Annual Effects³			
Large Electric Utilities⁴			
Residential	7,836	8,938	18,931
Commercial	6,216	7,557	16,291
Industrial ⁵	12,381	6,276	8,209
Other ⁶	724	408	856
Total Electric Utilities	29,140	23,181	44,349
Incremental Effects⁷			
Large Electric Utilities⁴			
Residential	1,187	1,156	2,632
Commercial	886	1,432	4,596
Industrial ⁵	2,978	2,017	1,548
Other ⁶	250	62	193
Small Electric Utilities⁸			
Residential	124	76	14
Commercial	55	35	4
Industrial ⁵	67	47	3
Other ⁶	45	28	2
Total Electric Utilities	5,588	4,853	9,131

¹ Reflects the installed, contractually available, peakload reduction by program category, excluding energy efficiency, during the electric utility's annual system peak load. Energy Efficiency includes programs aimed at reducing energy consumption over many hours during the year. These programs reduce load, and if they coincide with periods of peak usage, they are included in the actual peakload reduction. However, these programs cannot be implemented specifically at the time of peak usage and are therefore not included in the potential peakload reduction.

² Reflects real changes in peak load by program categories, including energy efficiency, during the electric utility's annual system peak load.

³ Represents the total effects caused by all participants in demand-side management programs in effect during 1993. Included are new and existing participants in existing programs (those implemented in prior years that were in place during 1993) and all participants in new programs (those implemented during 1993).

⁴ Refers to electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 120,000 megawatthours.

⁵ Represents manufacturing, construction, mining, agriculture, fishing, and forestry establishments.

⁶ Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

⁷ Represents the total effects caused by new participants in existing demand-side management programs and all participants in new programs during the year. Incremental effects are annualized to indicate program effects that would have resulted had participants been initiated into the program on January 1 of the reporting year.

⁸ Refers to electric utilities with sales to ultimate consumers and sales for resale less than 120,000 megawatthours.

Note: Data are preliminary.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 69. Annual Potential Peakload Reduction at Electric Utilities by Direct Load Control, Interruptible Load, North American Electric Reliability Council Region, and Hawaii, Selected Years (Megawatts)

North American Electric Reliability Council Region and Hawaii	Existing				Projected	
	1993	1992	1991	1990	1994	1995
Direct Load Control						
ECAR	227	222	397	219	294	437
ERCOT	164	121	68	40	211	314
MAAC	1,033	933	756	422	1,164	1,638
MAIN	190	147	84	86	283	566
MAPP(U.S.)	1,252	1,054	1,020	760	1,347	1,691
NPCC(U.S.)	219	188	222	135	232	269
SERC	3,950	3,814	3,271	2,383	4,345	5,366
SPP	816	533	569	480	630	733
WSCC(U.S.)	612	612	731	682	665	888
Contiguous U.S.	8,265	7,624	7,038	5,208	9,121	11,946
ASCC	2	2	2	1	2	2
Hawaii	0	0	0	0	12	15
U.S. Total	8,266	7,626	7,040	5,207	9,133	11,962
Interruptible Load						
ECAR	1,466	1,214	1,036	853	1,637	1,805
ERCOT	1,966	1,736	1,293	1,624	1,704	1,443
MAAC	1,152	838	724	790	1,240	1,510
MAIN	903	667	735	766	1,046	1,255
MAPP(U.S.)	823	789	882	674	997	1,163
NPCC(U.S.)	358	371	379	572	273	244
SERC	6,824	4,204	2,759	2,331	6,967	7,027
SPP	2,041	1,181	813	705	1,767	2,216
WSCC(U.S.)	2,997	3,363	3,038	2,646	3,166	4,052
Contiguous U.S.	14,232	14,563	11,469	10,961	18,516	20,713
ASCC	0	0	3	3	0	0
Hawaii	12	13	25	31	0	0
U.S. Total	14,235	14,566	11,487	10,965	18,516	20,713

Notes: *Data for 1993, 1994, and 1995 are preliminary; data for prior years are final. *Totals may not equal sum of components because of independent rounding. *Data are provided for electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 120,000 megawatt-hours. *These data reflect total installed, contractually available, peakload reduction by participants in all program categories (except energy efficiency) during the electric utility's annual system peak load. Program participants include new and existing participants in existing programs (those implemented in prior years that are in place during the reported year) and all participants in new programs (those implemented during the reported year).

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 70. Annual Demand-Side Management Energy Savings at Electric Utilities by North American Electric Reliability Council Region and Hawaii, Selected Years
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Existing					Projected	
	1993	1992	1991	1990	1989	1994	1995
ECAR	1,779	1,129	1,072	636	557	2,483	6,366
ERCOT	2,266	1,013	393	227	191	2,483	3,295
MAAC	1,150	964	549	460	439	2,122	5,248
MAIN	2,125	1,212	1,081	721	409	2,555	5,015
MAPP(U.S.)	1,581	940	494	465	326	2,075	4,415
NPOC(U.S.)	6,769	5,049	3,657	2,065	1,373	8,332	13,263
SERC	11,264	10,492	11,900	10,512	10,153	11,685	17,536
SPP	365	273	156	146	105	458	695
WSCC(U.S.) ¹	17,009	15,062	3,877	2,993	2,569	21,104	33,948
Contiguous U.S.	44,330	36,155	23,179	16,515	16,122	53,297	89,771
ASCC	2		0	0	4	5	15
Hawaii	17	9	164	156	142	18	290
U.S. Total	44,349	36,164	23,343	16,671	16,266	53,319	90,075

¹ The large increase in energy savings for the WSCC region is due to calculation revisions by Bonneville Power Administration and Southern California Edison for 1992 and 1993. Changes to energy savings data for 1989-1991 will be revised in an upcoming DSM publication due out in the spring of 1995.

² =Value less than 0.5.

Notes: *Data for 1993, 1994, and 1995 are preliminary; data for prior years are final. *Totals may not equal sum of components because of independent rounding. *Data are provided for electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 120,000 megawatt-hours. *These data reflect the savings in aggregate electricity for consumers that participate in one or more demand-side management programs. They represent changes at the consumer meter and include those activities implemented by third parties under contract to the electric utility. Data represent the energy savings of new and existing participants in existing programs (those implemented in prior years that are in place during the reporting year) and all participants in new programs (those implemented during the reporting year).

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 71. Demand-Side Management Utility Cost at Electric Utilities by North American Electric Reliability Council Region and Hawaii, Selected Years
(Thousand Dollars)

North American Electric Reliability Council Region and Hawaii	Existing					Projected	
	1993	1992	1991	1990	1989	1994	1995
ECAR	187,137	130,903	36,534	15,355	11,177	195,555	256,429
ERCOT	62,593	55,575	52,701	33,147	31,184	65,556	79,156
MAAC	262,111	178,420	131,103	116,565	93,322	302,236	655,328
MAIN	126,507	133,610	93,315	89,651	77,068	125,275	235,569
MAPP(U.S.)	102,895	85,021	56,082	39,612	20,897	128,766	182,975
NPOC(U.S.)	565,145	542,222	511,632	317,640	168,570	561,746	441,833
SERC	643,046	510,489	331,751	258,695	243,866	684,068	826,562
SPP	33,376	30,927	24,852	22,648	13,867	31,865	56,785
WSCC(U.S.)	762,111	574,926	510,156	289,964	213,158	931,017	1,092,955
Contiguous U.S.	2,768,961	2,243,195	1,747,929	1,177,277	872,729	3,027,196	3,826,062
ASCC	419	315	0	177	197	884	1,256
Hawaii	1,292	760	4	9	9	671	36,766
U.S. Total	2,768,682	2,243,270	1,747,933	1,177,457	872,935	3,028,961	3,864,113

Notes: *Data for 1993, 1994, and 1995 are preliminary; data for prior years are final. *Totals may not equal sum of components because of independent rounding. *Data are provided for electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 120,000 megawatt-hours. *These data refer to electric utility costs and represent the total cash expenditures incurred during the year, in nominal dollars, that flows out to support demand-side management programs. *Electric utility load building cost (\$31,178 (thousands) in 1993) is excluded.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

**Table 72. Direct and Indirect Utility Cost at U.S. Electric Utilities by Demand-Side Management Program, Selected Years
(Thousand Dollars)**

Program	Existing	Projected	
	1993	1994	1998
Total Direct Cost ¹	2,306,804	2,580,780	3,390,318
Energy Efficiency	1,626,013	1,858,882	2,459,148
Direct Load Control	367,752	363,077	473,459
Interruptible Load	206,466	226,554	278,820
Other Load Management	50,767	57,891	70,734
Other Demand-Side Management	54,906	56,796	68,157
Total Indirect Cost ²	460,159	448,171	513,797
Administrative	199,035	186,487	191,153
Marketing	50,130	63,263	73,025
Monitoring and Evaluation	73,831	87,619	86,853
Other ³	128,162	130,802	162,766
Total Utility Cost ⁴	2,766,962	3,028,951	3,904,115

¹ Reflects electric utility cost incurred during the year that are identified with one of the demand-side program categories. Load building cost (\$31,178 (thousands) for 1993, \$44,684 (thousands) for 1994, and \$41,397 (thousands) for 1998) are excluded.

² Reflects electric cost incurred during the year that are not meaningfully identified with any particular demand-side management program category, but can be attributable to one of several accounting cost categories.

³ Includes the indirect costs of demand-side management programs that cannot be meaningfully included in any of the other cost categories, including costs incurred in the research and development of demand-side management technologies.

⁴ Reflects the sum of the total incurred direct and indirect utility cost for the year. Utility cost reflect the total cash expenditures for the year, in nominal dollars, that flows out to support demand-side management programs.

Notes: *Data for 1993, 1994, and 1998 are preliminary; data for prior years are final. *Totals may not equal sum of components because of independent rounding. *Data are provided for electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 120,000 megawatt-hours. *Nonutility cost (\$338,635 (thousands) by 83 utilities in 1993, \$368,712 (thousands) by 86 utilities in 1994, and \$398,793 (thousands) by 84 utilities in 1998) are excluded.

Source: Energy Information Administration, Form EIA-881, "Annual Electric Utility Report."

Table 73. Number of U.S. Electric Utilities Having Different Energy End Uses and Program Types by Sector, 1993

Item	Residential	Commercial	Industrial
End Uses			
Heating System	271	180	108
Cooling System	272	206	139
Water Heating	268	152	103
Lighting	185	215	178
Building Shell	193	123	91
New Construction	204	140	100
Appliances	137	66	42
Motors	—	146	160
Process Heating	—	45	85
Electrolysis	—	10	28
Other System	20	27	28
Program Types			
Energy Audits	285	249	187
Rebates	276	203	143
Loaning	144	81	66
Other Incentives ¹	95	79	67
Other	96	79	60

¹ This category reflects programs that offer cash or noncash awards to electric energy efficiency deliverers, such as appliance and equipment dealers, building contractors, and architectural and engineering firms, that encourage consumer participation in a demand-side management program and adoption of recommended measures.

Notes: *Data are preliminary. *Data represent the total number of electric utilities that focus energy efficiency activities on specific end uses and program types.

Source: Energy Information Administration, Form EIA-881, "Annual Electric Utility Report."

U.S. Nonutility Power Producers

For over a decade, electric power produced by nonutility power producers re-emerged as an increasing part of U.S. electricity generation. While more than 50 percent of the electricity in the United States was produced by the industrial sector at the turn of the century, by 1950 it had decreased to 15 percent. This decrease was due to the steady growth of the traditional electric utility industry during the first half of the century. Traditional utilities include investor-owned, publicly owned, Federal, and cooperative electric utilities. In the 1970's, inflation, the energy crises, environmental concerns, and the rising costs of nuclear power raised electricity rates and reduced investment in new capacity. These factors led to a re-examination of alternatives such as nonutility electric power, which led to the passage of the Public Utility Regulatory Policies Act (PURPA) of 1978.

In 1989, the Energy Information Administration (EIA) began collecting nonutility electricity generation data on the Form EIA-867, "Annual Nonutility Power Producer Report." This enabled the EIA to supplement its data on electric utility production and to fill the information gap on this growing source of electric power. The initial survey was developed to include capacity, fuel consumption, generation, and deliveries of electricity to traditional utilities. Due to the sensitivity of data on costs and reliability expressed by representatives of the nonutility power producers, these data were excluded from the survey. See "Form EIA-867" in Appendix C.

This chapter provides an overview of U.S. nonutility power producers, their generating technologies, and statistical data on capacity, generation, sales, and emissions for 1989 through 1993. These data are aggregated at the U.S. and Census division levels. Since nonutility data are confidential, the EIA implemented information disclosure rules. See "Nondisclosure of Data" in Appendix C.

Background

During the early part of the 20th century, the development of large central-station power plants, economies of scale, decreased rates, and greatly improved reliability made electricity inexpensive and demand soared. Most industrial plants shifted away from generating their own power and opted to purchase electricity from their local utilities. By 1950, the electric

utility industry was serving virtually all electricity demand, except for a few industries that generated small amounts for their own use. Electricity was inexpensive, capacity growth appeared to be limitless, and electric utilities were strictly regulated to protect the consumers. During the 1970's, however, the electric utility industry changed from one characterized by decreasing marginal costs to one of increasing costs. Inflation, the energy crises, environmental concerns, and the rising costs of nuclear power led to increased electricity rates and reduced growth in capacity.

A nonutility power producing facility seeking to establish an interconnected operation with an electric utility faced three major obstacles. First, utilities were seldom willing either to purchase the electric power output of nonutility producers or pay a fair rate for that output. Second, some utilities charged high rates for backup services to nonutility power producers. Third, facilities that provided electricity to a utility connected to the grid risked being considered a public utility and subject to extensive State and Federal regulation.

In the late 1970's, Congress acted to relieve a nationwide energy crisis by enacting the National Energy Act of 1978, which encompassed PURPA and four other laws: the National Energy Conservation Policy Act, the Powerplant and Industrial Fuel Use Act, the Natural Gas Policy Act, and the Energy Tax Act. PURPA provided for increased conservation of energy and increased efficiency in the use of facilities and resources by electric utilities. It called for State regulatory authorities to encourage conservation and utility efficiency and to provide for equitable rates. Some of the provisions of PURPA were designed to encourage the development of cogeneration and small power production by loosening the economic, regulatory, and institutional barriers that discouraged cogeneration and the use of renewable energy resources.

PURPA makes a distinction between facilities that qualify for benefits, referred to as qualifying facilities (QF's), and other generating facilities. The QF's include certain cogenerators, small power producers, and other nonutility generators. Cogeneration is an energy efficient technology, while small power production is defined in PURPA as a technology that primarily uses renewable energy sources. Other generating facilities include industrial and commercial generators and independent power producers without a designated

franchised service area. The Federal Energy Regulatory Commission (FERC) is responsible for the implementation of PURPA and has established rules to encourage the development of cogenerators and small power production facilities. In addition, each State regulatory authority is required to implement such rules for each electric utility under its rate-making authority. The rules for the FERC program that define QF's are published in the *Code of Federal Regulations*, Title 18, Part 292.

Under FERC rules, cogeneration and small power production facilities may be designated as QF's based on meeting specific ownership⁴², operating, and efficiency criteria. A facility may file an information report, known as a "self qualifying notice," with the FERC if it meets the requirements of FERC published rules, or it may apply to the FERC for certification as a QF under PURPA. QF's are guaranteed that electric utilities will purchase their output at the utility's avoided cost, which is the incremental cost that an electric utility would incur to produce or purchase an amount of power equivalent to that purchased from QF's. Additionally, QF's are guaranteed that electric utilities will provide back-up service at prevailing (non-discriminatory) rates.

Recent Legislative and Regulatory Activities

Recently the U.S. Congress passed the Energy Policy Act of 1992 amending the Public Utility Holding Company Act (PUHCA). PUHCA was designed to discourage holding companies from structuring their operations in ways that would prevent effective State regulation. The following are provisions of the Act, potentially impacting the nonutility industry:

- The creation of exempt wholesale generators (EWG's), corporate entities who are engaged exclusively in the business of wholesale electric generation and who are exempt from corporate or organizational restrictions under PUHCA. Entities who are currently subject to PUHCA registered holding companies and exempt utility holding companies and entities who are not currently subject to PUHCA (nonutilities and non-holding company utilities) are permitted to own EWG's without limitation. For registered holding companies, approval from the Securities Exchange Commission is required for financing of EWG's and service sales and construction contracts involving EWG's. The Act removes obstacles to wholesale power competition in the PUHCA by allowing both utilities and nonutilities to form exempt wholesale generators without triggering the restrictions of the 1935 Act.
- The Act allows FERC to order upon application wholesale, but not retail, transmission access on

a case-by-case basis and transmission service by utilities, subject to certain protection.

- The establishment of a program for providing Federal support on a competitive basis for renewable energy technologies. Also expands program to promote the export of these renewable energy technologies to emerging markets in developing countries.

Nonutility Classifications

Cogeneration. The major technology used in nonutility generation is known as cogeneration. Cogeneration is the combined production of electric power and another form of useful energy (such as heat or steam) through the use of one energy source. The process can begin either with heat or steam production or with electricity generation, where the unused energy from the first process can be used as input to the second process. The primary energy source is generally a fossil fuel (coal, petroleum, or natural gas), although renewables are also used, particularly wood and waste. To receive QF status under PURPA from FERC, a cogenerating facility must meet the operating criteria to produce electric energy and "another form of useful thermal energy through the sequential use of energy." In addition, depending on the technology of the cogeneration facility, it must meet specific efficiency criteria.

Cogeneration uses a number of technologies to produce both electric power and another form of useful energy. The technology selected depends on the requirement for processed steam. Cogenerating technologies are classified as "topping-cycle" and "bottoming-cycle" systems, depending on whether electrical or thermal energy is produced first. In a typical topping-cycle system (Figure 20), the energy input to the system is first transformed into electricity by using high-temperature, high-pressure steam from a boiler to drive a turbine to generate electricity. The waste heat, or the lower pressure steam exhausting from the turbine, is used as a source of processed heat. Topping-cycle systems are the most common and are used in commercial, rural, and industrial applications. The two configurations in Figure 20 represent most topping-cycle facilities.

In a bottoming-cycle system (Figure 21), high-temperature thermal energy is produced first for applications such as reheat furnaces, glass kilns, or aluminum metal furnaces. Heat is extracted from the hot exhaust stream and transferred (through one or more mediums) to drive a turbine. Bottoming-cycle systems are generally used by industrial processes that require very high-temperature heat, thus, making it economical to recover the waste heat.

⁴²FERC rules require that QF's be less than 50 percent owned by electric utilities.

Fossil-fueled steam turbine systems are used in most industrial cogenerating processes, while gas-turbine systems are used in most other processes. Gas-turbine systems use combustion gases to drive a turbine to produce electricity and recover heat from the exhaust gases for waste-heat boilers. Compared with gas turbine systems, diesel engine systems are limited in application since they provide less useable processed heat per unit of electric power output. In a diesel system, the engine is cooled with water. The heated water is then used for processed steam, heat, or hot water applications. Exhaust gases can be used in a similar manner. Diesel systems are attractive to small cogenerating applications that need an instantaneous supply of electricity where the electric power requirement is generally greater than the heat requirement. With diesel systems, boiler warmup time is not necessary as required by some technologies.

Small Power Production. To be designated as a small power producer under the 1978 PURPA regulations, a facility was limited to a capacity no greater than 80 megawatts and had to generate electricity using renewable energy as a primary source. In 1990, for specific energy sources (biomass (waste), solar, geothermal, and wind), the size restriction to qualify as a small power producer was removed. Fossil fuels can be used, but 75 percent or more of total energy consumption must be derived from renewable resources and the aggregate of fossil fuel usage cannot exceed 25 percent of total energy input during any calendar year. Reliance on these technologies can reduce the need to consume fossil fuels to generate electric power.

Renewable energy includes solar, wind, biomass, geothermal, and water (hydraulic). Solar thermal technology converts solar energy through high concentration and heat absorption into electricity or process energy and is mainly used in the Pacific Contiguous Census Division. Wind generators produce a mechanical energy directly through shaft power. Windmills rotating parallel or perpendicular to the ground are the most common harnesses used in wind technology and are mainly concentrated in the Pacific Contiguous and West South Central Census Divisions. Biomass energy is derived from a variety of resources. The biomass resource base potentially includes hundreds of plant species, various agricultural and industrial residues and processing wastes, municipal solid waste and sewage, and animal wastes. Industrial wood and wood waste is the most prevalent form of biomass energy used by nonutilities. The industries that produce paper, wood, and agricultural products are increasing their use of biomass to improve efficiency of their operations and to contribute to their on-site energy requirements. These industries are indigenous to the South Atlantic and Pacific Contiguous Census Divisions. Geothermal technologies convert heat naturally present in the earth into heat energy and electricity by tapping into high- and low-temperature fluids and by extracting steam. Hydropower is derived by converting the potential energy of water to electrical energy using a hydraulic

turbine connected to a generator. Hydropower and geothermal technologies are mainly concentrated in the Pacific Contiguous Census Division.

Other Nonutility Generators. In addition to facilities that are classified as qualifying cogenerators and small power producers, other nonutility companies produce electric power for their own use and for sale to electric utilities. They include independent power producers (IPP's), nonqualifying cogenerators, and other commercial and industrial establishments. These nonutility companies are built mainly to supply and sell power to electric utilities. They do not qualify under PURPA because of the ownership, operating, or efficiency criteria established by FERC. IPP's are defined by FERC as producers of electric power other than QF's that are unaffiliated with franchised utilities in the IPP's market area and that for other reasons lack significant market power. IPP's may lack market power due to site or access to transmission.

Nonutility Operations

Business Classification. The nonutility power producing industry operates in various sectors of the U.S. economy and is classified according to the *Standard Industrial Classification (SIC) Manual* of the Office of Management and Budget. The main classifications are:

- Agriculture, Forestry, and Fishing
- Mining
- Construction
- Manufacturing
- Transportation and Public Utilities
- Wholesale and Retail Trade
- Finance, Insurance, and Real Estate
- Services
- Public Administration
- Other.

A list of the categories of primary business activity within each classification is contained in Appendix C.

The nonutility power producing industry includes business entities that transform materials or substances into new products using mechanical or chemical processes. In some processes the energy is transformed into steam for generating both electricity and another useful thermal output. This thermal output can be used directly in a manufacturing process such as paper production and indirectly for heating buildings or by other end users. In the agricultural and manufacturing sectors, the useful thermal energy is primarily for process steam, while in the financial sector the useful thermal energy is primarily for space heating.

Energy Sources. Most nonutility power producers use fossil fuels in their production processes. Many of them are able to switch from one fossil fuel to another when fuel supply is interrupted or when there is a price advantage in switching to another fuel. For example,

they may switch from gas to oil in winter when their gas supplies are diverted to residential use, or from oil to coal when oil prices rise. Other nonutility power producers use various renewable energy sources. Increasingly, many firms are also able to switch from fossil fuels to renewable fuels. Many nonutility power producers use combustors that are able to burn two or more different fuels simultaneously, in varying combinations, to generate the desired heat output. Other nonutility power producers can only burn one fuel at a time, but their combustors can be converted to burn different fuels. Finally, many producers have multiple combustors that use different fuels to supply heat or power. Thus, the adaptability of nonutility power producers to use multiple fuel sources depends primarily on the type of generating equipment available and on economic conditions. A nonutility power producer with many options as to fuel choice has a great economic advantage over a producer who is tied to only one fuel source.

Data Sources

Summary statistics on nonutility capacity, generation, sales, and emissions in the United States are provided in the following tables. Data for 1993 are preliminary; data for 1989 through 1992 are final. These data were obtained from the Form EIA-867, "Annual Nonutility Power Producer Report." The Form EIA-867 is a mandatory survey of all existing and planned nonutility electric generating facilities in the United States with a total generator nameplate capacity of 1 or more megawatts. In 1992, the reporting threshold of the Form EIA-867 was lowered to include all facilities with a combined nameplate capacity of 1 or more megawatts. Previously, data were collected every 3 years from facilities with a nameplate capacity between 1 and 5 megawatts. Planned generators are defined as a proposal by a company to install electric generating equipment at an existing or planned facility. The proposal is based on the owner having obtained (1) all environmental and regulatory approvals, (2) a signed contract for the electric energy, or (3) financial closure of the facility. Nonutilities generally install small, turn-key packaged generating facilities with minimal regulatory requirements which result in considerably less lead time to finance and build, as compared to traditional

electric utility facilities. Data on planned nonutility capacity additions as of December 31, 1993, are presented by energy source in Figure 15. These data represent all nonutility planned generating facilities that meet one or more of the criteria defined earlier.

Some nonutility power producers of 1 or more megawatts use only fossil fuels; some use only renewable energy; and some use a combination of both fossil fuels and renewable energy sources. Although the majority of nonutility power producers generate electric power using fossil energy, those using renewable energy represent a large portion of capacity. Because of the consumption of multiple energy sources by some generating units, capacity and generation were allocated by energy source. The algorithms used to allocate installed capacity and generation by energy source are discussed in the Technical Notes (Appendix C).

The other energy sources in Tables 74, 76, and 79 include hydrogen, sulfur, batteries, chemicals, fish oil and spent sulfite liquor. Data previously published for other energy sources in 1989 and 1990 have been reclassified and are included in the category that best reflects its characteristics.

The change in data previously published in 1989 and 1990 for major industry groups in Tables 78 and 81 was due to a clarification of a nonutility facility's "primary" business activity.

The change between the number of facilities previously published as qualifying and non-qualifying in Tables 77 and 80 in 1989 and 1990, is due to changes in facility status. The number of facilities shown for 1993 includes operational facilities in 1992 and new facilities or planned facilities that became operational during that year.

The total capacity for 1989 through 1993 (Table 74) includes all operable generating units including units not normally used but on standby with little or no generation, and units out of service for the entire reporting year that are expected to be returned to service in the future. Units on standby and out of service represented 5 percent of the total nonutility generating capacity in 1993.

Figure 20. Topping-Cycle Plant Configuration

1. A boiler produces steam to power a turbine-generator to produce electricity. The turbine steam leaving the turbine is used in thermal applications such as space heating or food preparation.
2. A combustion turbine or diesel engine burns fuel to spin a shaft connected to a generator to produce electricity. Waste heat from the burning fuel is recaptured in a waste-heat recovery boiler and is used for direct heating or is used to produce steam for thermal applications.

Source: Federal Energy Regulatory Commission, *Cogeneration*, 1985.

Figure 21. Bottoming-Cycle Plant Configuration

A furnace is used in a smelting or forming process. A waste-heat recovery boiler recaptures the unused energy and uses it to produce steam to drive a steam turbine generator to produce electricity.

Source: Federal Energy Regulatory Commission, *Cogeneration*, 1986.

Table 74. Summary Statistics for U.S. Nonutility Power Producers, 1989 Through 1993

Item	1993		1992		1991	1990	1989
	1 Megawatt or More	5 Megawatts or More	1 Megawatt or More	5 Megawatts or More	5 Megawatts or More		
Installed Capacity (megawatts)	80,778	68,055	66,814	66,163	48,171	42,869	36,646
Coal ¹	9,772	9,712	8,503	8,443	7,291	6,712	6,228
Petroleum ²	2,043	1,859	1,730	1,579	1,207	811	917
Natural Gas ³	23,483	23,009	21,542	21,104	20,259	16,682	13,999
Petroleum/Natural Gas (Combined)	8,505	8,377	8,478	8,354	5,049	6,167	4,439
Hydroelectric	2,741	2,173	2,684	2,133	1,587	1,477	1,386
Geothermal	1,318	1,307	1,254	1,243	1,048	1,031	944
Solar	360	360	360	360	360	360	200
Wind	1,813	1,775	1,822	1,788	1,652	1,405	1,339
Wood ⁴	7,046	6,983	6,806	6,735	6,580	5,786	5,254
Waste ⁵	3,131	2,910	3,006	2,805	2,627	2,230	1,742
Nuclear ⁶	20	20	20	20	20	20	20
Other ⁷	565	562	611	602	491	187	176
Gross Generation (million kilowatt-hours)	325,226	318,843	296,001	289,856	248,446	217,241	187,356
Coal ¹	53,367	53,166	47,363	47,160	40,587	32,131	31,511
Petroleum ²	13,364	13,089	10,863	10,682	7,814	7,330	5,742
Natural Gas ³	174,282	171,785	158,798	156,317	131,940	116,706	98,975
Hydroelectric	11,611	9,583	9,448	7,611	6,243	6,235	5,931
Geothermal	9,749	9,704	8,578	8,539	7,651	6,672	5,048
Solar	897	897	746	746	779	683	489
Wind	3,052	2,999	2,916	2,872	2,806	2,261	1,833
Wood ⁴	37,421	37,206	36,255	36,024	33,785	30,812	27,835
Waste ⁵	18,325	17,187	17,352	16,330	13,956	11,415	8,296
Nuclear ⁶	78	78	67	67	80	116	48
Other ⁷	3,181	3,189	3,516	3,504	3,809	2,710	1,750
Supply and Disposition (million kilowatt-hours)							
Gross Generation	325,226	318,843	296,001	289,856	248,446	217,241	187,356
Receipts ⁸	85,323	77,379	83,421	76,198	58,264	53,743	61,479
Deliveries ⁹	203,005	199,442	175,160	171,836	140,537	126,048	99,916
Facility Use	207,514	196,780	204,281	194,218	176,175	154,936	149,918

¹ Includes coal, anthracite culm and coal waste.² Includes petroleum, petroleum coke, diesel, kerosene, and petroleum sludge and tar.³ Includes natural gas, butane, ethane, propane, waste heat and waste gases.⁴ Includes wood, wood waste, peat, wood liquors, railroad ties, pitch and wood sludge.⁵ Includes municipal solid waste, agricultural waste, straw, trees, landfill gases and other waste.⁶ Nuclear reactor and generator at Argonne National Laboratory used primarily for research and development in testing reactor fuels as well as for training. The generation from the unit is used for internal consumption.⁷ Includes hydrogen, sulfur, batteries, chemicals, and spent sulfite liquor. Data previously published for other energy sources in 1989 and 1990 have been reclassified and are included in the category that best reflects its characteristics.⁸ Includes purchases, interchanges, and exchanges of electric energy with utilities and other nonutilities.⁹ Includes sales, interchanges, and exchanges of electric energy with utilities and other nonutilities. The disparity in this data and data reported on other EIA surveys occurs due to differences in the respondent universe. The Form EIA-867 is filed by nonutilities reporting the energy delivered, while other data sources are filed by electric utilities reporting energy received. Differences in terminology and accounting procedures attribute to the disparity. In addition, since the frame for the Form EIA-867 is derived from utility surveys the Form EIA-867 universe lags 1 year.

Notes: *Data for 1993 are preliminary, data for prior years are final. *Totals may not equal sum of components because of independent rounding.

*Percent change is calculated before rounding. *See the Technical Notes for the methodology for allocating capacity and generation by energy sources, respectively.

Source: Energy Information Administration, (EIA) Form EIA-867, "Annual Nonutility Power Producer Report."

Table 75. Installed Capacity at U.S. Nonutility Generating Facilities by Fossil Fuels, Renewable Energy Sources, and Census Division, 1989 Through 1993
(Megawatts)

Census Division	Fossil Fuels ¹	Renewables/ Other/ Nuclear ²	Both Fossil Fuels and Renewables/ Other/ Nuclear
1993 (1 Megawatt or More)			
New England	2,388	1,479	882
Middle Atlantic	7,107	1,068	535
East North Central	4,079	421	1,048
West North Central	972	143	148
South Atlantic	8,357	1,368	2,587
East South Central	444	253	1,037
West South Central	10,873	255	2,142
Mountain	1,042	835	344
Pacific	7,420	5,205	780
U.S. Total	40,493	10,836	9,478
1992 (1 Megawatt or More)			
New England	2,115	1,428	851
Middle Atlantic	5,883	1,081	415
East North Central	4,024	387	1,038
West North Central	956	141	127
South Atlantic	5,418	1,388	2,642
East South Central	486	188	882
West South Central	10,239	266	2,176
Mountain	988	601	285
Pacific	6,841	5,239	688
U.S. Total	37,022	10,718	8,074
1991 (5 Megawatts or More)			
New England	1,842	1,180	834
Middle Atlantic	3,690	821	429
East North Central	3,833	240	959
West North Central	882	105	118
South Atlantic	3,597	1,250	2,416
East South Central	455	162	872
West South Central	10,019	41	1,986
Mountain	584	445	283
Pacific	6,044	4,506	587
U.S. Total	30,825	8,754	8,492
1990 (5 Megawatts or More)			
New England	1,238	891	1,088
Middle Atlantic	2,568	582	436
East North Central	3,986	108	948
West North Central	829	56	185
South Atlantic	2,933	662	2,365
East South Central	248	W	W
West South Central	7,857	38	3,870
Mountain	450	W	W
Pacific	5,384	3,792	964
U.S. Total	28,304	6,578	10,986
1989 (5 Megawatts or More)			
New England	582	871	881
Middle Atlantic	2,137	402	435
East North Central	2,609	108	893
West North Central	632	55	185
South Atlantic	1,099	480	2,346
East South Central	196	W	W
West South Central	7,268	88	3,818
Mountain	324	W	W
Pacific	4,599	3,482	908
U.S. Total	20,346	5,819	10,480

¹ Includes petroleum, natural gas, and coal as a single energy source.

² Includes hydroelectric, geothermal, solar, wind, wood, wood waste, peat, wood liquors, railroad ties, pitch, municipal solid waste, other waste, agricultural waste, straw, tires, landfill gases, fish oils, sludge, other (sulfur, hydrogen, batteries, chemicals, spent sulfate liquors), and/or nuclear as energy sources.

W = Withheld to avoid disclosure of individual company data.

Notes: *For a summary of 1992 and 1993 data for 5 megawatts or more, see Table 74. *See Technical Notes for a description of allocating capacity.

*Data for 1993 are preliminary; data for prior years are final. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

Table 76. Installed Capacity at U.S. Nonutility Generating Facilities by Energy Source and Census Division, 1989 Through 1993 (Megawatts)

Census Division	Coal ¹	Natural Gas ²	Petroleum ³ only / and Natural Gas ⁴	Hydroelectric/ Geothermal/ Solar / Wind	Wood ⁵ / Waste ⁶	Other ⁷ / Nuclear	Total
1993 (1 Megawatt or More)							
New England	983	587	1,780	587	1,412	—	4,729
Middle Atlantic	2,049	1,850	3,494	W	656	W	8,730
East North Central	1,783	2,523	525	W	646	W	5,546
West North Central	756	118	157	79	156	—	1,261
South Atlantic	2,770	1,654	2,332	209	2,953	376	10,303
East South Central	289	222	W	—	1,099	W	1,734
West South Central	828	9,915	1,022	W	1,089	W	13,089
Mountain	233	806	W	548	166	W	2,020
Pacific	749	5,768	W	4,099	1,801	W	13,385
U.S. Total	9,772	23,453	18,548	6,282	10,177	695	60,778
1992 (1 Megawatt or More)							
New England	281	413	1,702	579	1,448	—	4,404
Middle Atlantic	1,582	1,570	2,871	W	787	W	7,379
East North Central	1,240	2,845	619	W	626	W	6,449
West North Central	737	146	146	73	122	—	1,224
South Atlantic	2,649	826	2,474	205	2,870	420	9,443
East South Central	286	255	W	—	889	W	1,535
West South Central	828	9,521	1,020	W	1,095	W	12,660
Mountain	175	790	W	514	166	W	1,852
Pacific	743	5,176	W	4,037	1,806	W	12,848
U.S. Total	8,503	21,542	10,207	6,120	9,812	630	56,814
1991 (5 Megawatt or More)							
New England	353	798	1,066	432	1,192	—	3,856
Middle Atlantic	1,326	1,053	1,636	239	684	—	4,940
East North Central	1,035	2,840	523	59	577	—	5,033
West North Central	W	W	84	55	104	—	1,103
South Atlantic	2,114	632	1,165	155	2,609	388	7,263
East South Central	276	239	W	—	874	W	1,489
West South Central	W	9,244	800	—	1,157	W	12,056
Mountain	182	489	W	363	159	W	1,292
Pacific	W	W	824	3,343	1,652	13	11,138
U.S. Total	7,281	20,256	6,258	4,847	9,207	510	48,171
1990 (5 Megawatts or More)							
New England	358	218	1,052	418	1,171	—	3,216
Middle Atlantic	1,053	409	1,386	239	507	—	3,695
East North Central	1,181	2,679	736	50	401	—	5,040
West North Central	640	W	W	55	122	—	869
South Atlantic	1,738	621	953	W	2,392	W	5,980
East South Central	258	W	—	—	817	W	1,273
West South Central	692	8,771	1,261	—	941	—	11,766
Mountain	W	347	W	308	84	W	878
Pacific	W	W	1,489	W	1,570	—	10,150
U.S. Total	6,712	16,682	6,579	4,274	8,018	206	42,868
1989 (5 Megawatts or More)							
New England	W	W	571	398	1,108	—	2,333
Middle Atlantic	997	358	1,044	191	386	—	2,974
East North Central	1,087	1,287	721	50	453	—	3,607
West North Central	643	W	W	55	122	—	872
South Atlantic	1,895	328	425	W	1,996	W	4,824
East South Central	298	W	—	—	661	W	1,123
West South Central	726	8,626	1,002	—	771	—	11,124
Mountain	W	263	W	283	91	W	823
Pacific	W	3,001	1,490	W	1,397	—	8,863
U.S. Total	8,229	13,999	6,556	3,870	8,997	195	36,645

¹ Includes coal, anthracite culm and coal waste

² Includes natural gas, butane, ethane, propane, waste heat and waste gases

³ Includes petroleum, petroleum coke, diesel, kerosene, and petroleum sludge and tar

⁴ Includes petroleum used as a single energy source, and petroleum and natural gas used as a fuel combination by themselves and with other fuels

⁵ Includes wood, wood waste, peat, wood liquors, railroad ties, pitch and wood sludge

⁶ Includes municipal solid waste, agricultural waste, straw, tree, landfill gases, fish oils, and other waste

⁷ Includes hydrogen, sulfur, batteries, chemicals, and spent sulfate liquor. Data previously published for other energy sources have been reclassified and are included in the category that best reflects its characteristics

Notes: *For a summary of 1992 and 1993 data for 5 megawatts or more, see Table 74. *Data for 1990 are preliminary, data for prior years are final

*Totals may not equal sum of components because of independent rounding. *W = Withheld to avoid disclosure of individual company data

Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report"

Table 77. Installed Capacity at U.S. Nonutility Generating Facilities by Qualifying Facility Status and Census Division, 1989 Through 1993 (Megawatts)

Census Division	OF Capacity		Non-OF Capacity		Total Capacity	
	No. of Facilities	Capacity (megawatts)	No. of Facilities	Capacity (megawatts)	No. of Facilities	Capacity (megawatts)
1993 (1 Megawatt or More)						
New England	116	3,404	73	1,326	189	4,729
Middle Atlantic	230	8,351	44	878	274	9,230
East North Central	96	3,403	101	2,143	199	5,546
West North Central	25	512	49	749	74	1,261
South Atlantic	189	7,011	97	3,291	286	10,303
East South Central	24	661	30	853	54	1,514
West South Central	107	11,159	60	1,810	167	13,069
Mountain	81	1,446	36	574	119	2,020
Pacific	412	11,606	142	1,779	554	13,385
U.S. Total	1,292	47,774	634	13,904	1,926	60,778
1992 (1 Megawatt or More)						
New England	111	3,077	75	1,327	186	4,404
Middle Atlantic	211	6,924	48	455	259	7,379
East North Central	95	3,341	99	2,106	194	5,449
West North Central	23	506	44	720	67	1,224
South Atlantic	127	6,256	95	3,187	222	9,443
East South Central	23	822	23	713	46	1,536
West South Central	107	10,581	59	2,128	166	12,689
Mountain	73	1,313	37	540	110	1,852
Pacific	409	10,972	149	1,876	558	12,848
U.S. Total	1,179	43,760	629	13,054	1,808	56,814
1991 (5 Megawatts or More)						
New England	68	2,719	22	1,137	91	3,856
Middle Atlantic	105	4,474	17	467	122	4,940
East North Central	38	3,080	52	1,954	90	5,033
West North Central	14	478	22	825	36	1,303
South Atlantic	86	5,149	47	2,113	133	7,263
East South Central	16	753	17	736	33	1,489
West South Central	87	10,316	30	2,040	117	12,056
Mountain	28	643	15	449	43	1,292
Pacific	276	9,458	86	1,681	362	11,139
U.S. Total	719	35,959	308	11,202	1,027	48,171
1990 (5 Megawatts or More)						
New England	68	2,352	16	886	84	3,238
Middle Atlantic	90	3,142	15	453	105	3,595
East North Central	37	3,072	50	1,959	87	5,040
West North Central	14	476	11	391	25	869
South Atlantic	79	4,621	35	1,359	114	5,980
East South Central	14	543	15	730	29	1,273
West South Central	84	9,890	25	1,875	109	11,765
Mountain	26	634	10	344	36	979
Pacific	248	8,592	77	1,556	325	10,150
U.S. Total	656	33,323	256	9,546	914	42,869
1989 (5 Megawatts or More)						
New England	59	1,768	15	588	74	2,333
Middle Atlantic	73	2,513	16	481	89	2,974
East North Central	34	1,837	46	1,970	82	3,607
West North Central	14	478	11	394	25	872
South Atlantic	68	3,414	38	1,411	106	4,824
East South Central	14	543	13	580	27	1,123
West South Central	79	9,165	24	1,959	103	11,124
Mountain	21	483	10	341	31	823
Pacific	214	7,431	74	1,533	288	8,963
U.S. Total	574	27,423	249	9,218	825	36,645

OF = Nonutility generating facilities that have obtained status as qualifying facilities under the Public Utility Regulatory Policies Act of 1978

Notes: *For summary statistics of 1992 and 1993 for 5 megawatts or more, see Table 74. *Data for 1993 are preliminary, data for prior years are final. *The number of facilities shown includes operational, new, and planned facilities. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report"

Table 78. Installed Capacity at U.S. Nonutility Generating Facilities by Major Industry Group and Census Division, 1989 Through 1993
(Megawatts)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
1993 (1 Megawatt or More)							
New England	2,248	2,363	W	--	W	--	4,729
Middle Atlantic	5,807	1,889	511	W	W	223	8,790
East North Central	4,861	301	271	W	W	W	5,646
West North Central	702	184	165	W	W	W	1,251
South Atlantic	6,925	2,914	158	W	W	269	10,303
East South Central	1,676	18	W	W	W	--	1,734
West South Central	12,246	442	203	180	--	--	13,069
Mountain	772	566	158	245	--	278	2,020
Pacific	4,878	5,532	324	2,439	239	173	13,385
U.S. Total	39,954	14,399	1,908	3,248	406	1,005	60,778
1992 (1 Megawatt or More)							
New England	2,120	2,167	W	--	W	--	4,404
Middle Atlantic	5,112	1,395	410	W	W	162	7,379
East North Central	4,864	253	239	W	W	W	5,449
West North Central	895	W	138	W	W	W	1,224
South Atlantic	6,371	2,824	150	W	W	61	9,443
East South Central	1,497	W	W	W	W	--	1,535
West South Central	11,885	442	183	180	--	--	12,690
Mountain	746	474	157	197	--	278	1,852
Pacific	4,342	6,200	239	1,580	326	182	12,848
U.S. Total	37,612	13,951	1,643	2,413	483	713	56,814
1991 (5 Megawatts or More)							
New England	1,825	1,898	83	--	--	--	3,856
Middle Atlantic	3,329	984	184	W	W	162	4,940
East North Central	4,627	109	189	W	--	W	5,039
West North Central	607	W	130	W	--	--	1,103
South Atlantic	5,474	1,587	124	--	W	W	7,263
East South Central	1,465	W	--	--	W	--	1,488
West South Central	11,281	464	W	W	--	--	12,066
Mountain	493	316	W	W	--	268	1,292
Pacific	3,558	W	W	W	W	W	11,188
U.S. Total	32,767	10,946	1,111	2,189	453	693	48,171
1990 (5 Megawatts or More)							
New England	1,558	W	W	--	--	--	3,218
Middle Atlantic	2,387	727	132	W	W	162	3,566
East North Central	4,850	109	185	W	--	W	5,040
West North Central	661	W	W	W	--	--	869
South Atlantic	4,868	918	W	--	W	W	5,980
East South Central	1,250	W	--	--	W	--	1,273
West South Central	10,990	464	W	W	--	--	11,765
Mountain	249	264	W	W	--	268	876
Pacific	3,382	W	W	W	315	W	10,150
U.S. Total	29,985	8,937	863	1,955	452	670	42,969
1989 (5 Megawatts or More)							
New England	1,203	W	W	--	--	--	2,393
Middle Atlantic	2,082	531	76	W	W	W	2,974
East North Central	3,220	109	182	W	--	W	3,607
West North Central	554	W	W	W	--	--	872
South Atlantic	4,263	468	W	--	W	W	4,824
East South Central	1,100	W	--	--	W	--	1,123
West South Central	10,453	361	W	W	--	--	11,124
Mountain	240	194	W	W	--	W	823
Pacific	3,076	W	W	1,125	315	W	8,963
U.S. Total	26,190	7,058	777	1,716	482	482	36,645

W = Withheld to avoid disclosure of individual company data.

Notes: *Data shown in this table are based on the facility's consumption. *Data for 1989 are preliminary; data for prior years are final. *See Technical Notes for Standard Industrial Classifications for these industry groups. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

Table 79. Gross Generation for U.S. Nonutility Power Producers by Energy Source and Census Division, 1989 Through 1993
(Million Kilowatthours)

Census Division	Coal ¹	Petroleum ²	Natural Gas ³	Hydroelectric	Geothermal/ Solar/Wind	Wood ⁴ / Waste ⁵	Other ⁶ / Nuclear	Total
1993 (1 Megawatt or More)								
New England	2,417	1,764	12,460	2,528	—	9,082	—	28,229
Middle Atlantic	10,850	W	28,381	1,724	—	5,714	W	48,705
East North Central	7,138	627	14,274	W	—	3,602	W	26,211
West North Central	2,852	63	687	336	—	737	—	4,675
South Atlantic	15,466	2,774	7,886	963	—	14,821	1,710	43,820
East South Central	2,289	W	2,170	—	—	6,019	W	10,741
West South Central	5,796	3,239	63,077	W	—	5,904	W	80,073
Mountain	1,317	112	4,638	948	1,688	787	201	9,572
Pacific	5,140	2,905	40,708	W	12,110	9,220	W	73,400
U.S. Total	53,957	13,964	174,282	11,511	13,688	55,746	3,259	326,226
1992 (1 Megawatt or More)								
New England	2,397	1,508	11,056	2,854	—	8,415	—	26,071
Middle Atlantic	9,747	W	22,504	1,915	—	5,244	W	40,890
East North Central	6,589	510	13,549	W	—	3,156	W	24,358
West North Central	2,565	50	749	338	—	670	—	4,371
South Atlantic	13,122	2,354	5,266	1,095	—	14,936	2,030	38,804
East South Central	2,152	W	2,401	—	—	5,183	W	9,982
West South Central	5,354	2,129	62,489	W	—	5,586	W	77,050
Mountain	1,131	40	3,450	600	1,214	816	204	7,455
Pacific	4,327	3,017	37,364	W	11,028	9,607	W	67,040
U.S. Total	47,963	10,953	158,798	9,446	12,241	53,607	3,593	298,001
1991 (5 Megawatts or More)								
New England	2,527	1,282	8,710	2,284	—	7,553	—	20,347
Middle Atlantic	7,741	W	11,050	877	—	3,933	W	24,888
East North Central	5,456	W	12,173	286	W	3,084	—	21,424
West North Central	1,841	36	745	227	—	456	—	3,316
South Atlantic	11,504	1,583	3,706	760	—	12,991	2,249	32,773
East South Central	2,005	W	2,132	—	—	4,735	W	9,013
West South Central	5,459	W	60,095	—	—	5,404	W	73,404
Mountain	1,044	15	1,932	511	991	755	193	5,442
Pacific	3,009	W	32,796	1,337	W	8,820	W	57,843
U.S. Total	40,687	7,814	131,340	6,245	11,035	47,741	3,638	248,448
1990 (5 Megawatts or More)								
New England	1,922	1,592	1,518	2,374	—	6,905	—	14,412
Middle Atlantic	5,242	1,173	7,186	989	—	2,856	—	17,425
East North Central	5,473	478	11,006	242	—	2,745	—	20,843
West North Central	W	W	438	167	—	509	—	2,641
South Atlantic	9,976	1,414	W	W	—	11,079	885	28,024
East South Central	2,058	W	1,511	—	—	4,860	W	8,055
West South Central	W	W	57,938	—	—	4,924	W	59,199
Mountain	789	W	1,459	402	844	839	W	4,313
Pacific	1,946	W	W	W	8,942	8,209	W	52,319
U.S. Total	32,131	7,330	116,708	6,235	9,788	42,227	2,826	217,241
1989 (5 Megawatts or More)								
New England	378	1,681	708	2,045	—	6,101	—	10,912
Middle Atlantic	4,638	1,038	5,190	742	—	1,828	—	13,834
East North Central	5,722	402	5,415	189	—	2,293	—	14,030
West North Central	W	W	449	185	—	306	—	1,839
South Atlantic	10,695	1,497	W	W	—	9,761	777	26,720
East South Central	2,127	W	1,154	—	—	3,666	W	7,100
West South Central	4,693	105	66,099	—	—	5,014	843	86,755
Mountain	W	W	1,322	443	W	842	W	3,848
Pacific	1,318	877	W	W	W	6,520	—	42,417
U.S. Total	31,511	5,742	98,875	5,931	7,367	36,130	1,799	187,356

¹ Includes coal, anthracite culm and coal waste

² Includes petroleum, petroleum coke, diesel, kerosene, and petroleum sludge and tar

³ Includes natural gas, butane, ethane, propane, waste heat and waste gases

⁴ Includes wood, wood waste, peat, wood liquors, railroad ties, pitch and wood sludge

⁵ Includes municipal solid waste, agricultural waste, straw, tires, landfill gases, fish oils, and other waste

⁶ Includes hydrogen, sulfur, batteries, chemicals, and spent sulfate liquor. Data previously published for other energy sources have been reclassified and are included in the category that best reflects its characteristics.

Notes: *For a summary of 1992 and 1993 data for 5 megawatts or more, see Table 74. *Data for 1993 are preliminary; data for prior years are final.

*Totals may not equal sum of components because of independent rounding. *W = Withheld to avoid disclosure of individual company data.

Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

Table 80. Gross Generation at U.S. Nonutility Generating Facilities by Qualifying Facility Status and Census Division, 1989 Through 1993
(Million Kilowatthours)

Census Division	QF Generation		Non-QF Generation		Total Generation	
	No. of Facilities	Generation (million kilowatthours)	No. of Facilities	Generation (million kilowatthours)	No. of Facilities	Generation (million kilowatthours)
1993 (1 Megawatt or More)						
New England	116	20,936	73	7,293	189	28,229
Middle Atlantic	230	46,602	44	2,102	274	48,705
East North Central	98	17,238	101	8,973	199	26,211
West North Central	25	2,257	49	2,418	74	4,675
South Atlantic	139	32,132	97	11,488	236	43,620
East South Central	24	5,383	30	5,358	54	10,741
West South Central	107	68,884	60	11,190	167	80,073
Mountain	81	7,391	38	2,181	119	9,572
Pacific	412	66,820	142	6,580	554	73,400
U.S. Total	1,232	267,641	634	57,584	1,866	325,226
1992 (1 Megawatt or More)						
New England	111	18,717	75	7,354	186	26,071
Middle Atlantic	211	38,758	48	2,132	259	40,890
East North Central	95	15,683	98	8,675	194	24,358
West North Central	23	2,073	44	2,298	67	4,371
South Atlantic	127	28,916	95	9,688	222	38,604
East South Central	23	5,418	23	4,549	46	9,967
West South Central	107	66,080	59	11,970	166	77,050
Mountain	73	5,507	37	1,948	110	7,455
Pacific	409	60,979	149	6,061	558	67,040
U.S. Total	1,179	241,126	629	54,875	1,808	296,001
1991 (5 Megawatts or More)						
New England	69	15,448	22	4,689	91	20,137
Middle Atlantic	106	23,202	17	1,684	122	24,886
East North Central	36	13,169	52	8,255	90	21,424
West North Central	14	1,984	22	1,391	36	3,375
South Atlantic	86	23,982	47	8,791	133	32,773
East South Central	16	4,909	17	4,104	33	9,013
West South Central	87	81,661	30	11,743	117	93,404
Mountain	28	3,673	15	1,769	43	5,442
Pacific	276	51,570	88	6,273	362	57,843
U.S. Total	719	199,599	308	49,249	1,027	248,848
1990 (5 Megawatts or More)						
New England	66	11,276	18	2,636	84	14,412
Middle Atlantic	90	16,748	15	1,678	105	17,425
East North Central	37	12,394	50	8,449	87	20,843
West North Central	14	2,002	11	639	25	2,641
South Atlantic	79	21,129	36	6,895	114	28,024
East South Central	14	3,718	15	4,352	29	8,085
West South Central	84	58,346	26	10,860	109	69,199
Mountain	26	3,046	10	1,267	36	4,313
Pacific	248	46,710	77	5,608	325	52,319
U.S. Total	666	174,896	256	42,374	914	217,241
1989 (5 Megawatts or More)						
New England	59	8,284	15	2,548	74	10,912
Middle Atlantic	73	11,788	16	1,847	89	13,634
East North Central	34	6,398	48	8,692	82	14,030
West North Central	14	1,290	11	649	25	1,939
South Atlantic	68	19,924	38	8,796	106	28,720
East South Central	14	3,691	13	3,409	27	7,100
West South Central	79	55,404	24	11,350	103	66,755
Mountain	21	2,459	10	1,389	31	3,848
Pacific	214	36,606	74	5,609	288	42,417
U.S. Total	576	144,867	249	42,489	825	187,356

QF = Nonutility generating facilities that have obtained status as qualifying facilities under the Public Utility Regulatory Policies Act of 1978

Notes: *For a summary of 1982 and 1993 data for 5 megawatts or more, see Table 74. *Data for 1993 are preliminary; data for prior years are final.
*The number of facilities shown includes operational, new, and planned facilities. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-887, "Annual Nonutility Power Producer Report."

Table 81. Gross Generation by U.S. Nonutility Power Producers by Major Industry Group and Census Division, 1989 Through 1993
(Million Kilowatthours)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
1993 (1 Megawatt or More)							
New England	12,844	15,120	468	--	--	--	28,229
Middle Atlantic	31,989	11,669	2,609	W	W	1,273	48,705
East North Central	23,613	1,688	987	W	W	W	28,211
West North Central	2,883	341	W	W	W	W	4,575
South Atlantic	23,179	8,461	657	W	W	1,184	43,820
East South Central	10,531	72	W	W	W	--	10,741
West South Central	76,103	2,232	611	1,127	--	--	80,073
Mountain	4,622	2,899	875	W	--	W	9,572
Pacific	26,689	25,056	2,038	17,228	1,530	659	73,400
U.S. Total	221,334	67,549	8,976	20,877	2,671	3,628	326,226
1992 (1 Megawatt or More)							
New England	12,165	13,444	461	--	--	--	26,071
Middle Atlantic	27,882	7,330	2,329	W	W	1,124	40,890
East North Central	21,838	1,366	750	W	W	W	24,356
West North Central	2,758	W	W	W	W	W	4,371
South Atlantic	31,230	6,739	536	W	W	W	38,804
East South Central	9,772	W	W	W	W	--	9,862
West South Central	73,635	1,897	601	1,116	--	--	77,060
Mountain	3,564	2,156	537	--	--	W	7,456
Pacific	24,944	27,283	1,477	10,666	2,091	628	67,040
U.S. Total	207,789	69,415	7,589	14,923	3,183	2,322	296,001
1991 (5 Megawatts or More)							
New England	9,513	10,670	164	--	--	--	20,347
Middle Atlantic	16,413	4,376	844	W	W	1,158	24,889
East North Central	19,332	791	810	W	--	W	21,424
West North Central	2,587	W	W	W	--	--	3,916
South Atlantic	27,959	4,401	131	--	W	W	32,773
East South Central	8,883	W	--	--	W	--	9,013
West South Central	69,738	2,288	W	W	--	--	73,404
Mountain	2,260	1,705	W	W	--	515	5,442
Pacific	20,786	24,086	W	W	1,984	W	57,843
U.S. Total	177,472	48,652	4,597	12,369	2,958	2,499	248,448
1990 (5 Megawatts or More)							
New England	7,453	W	W	--	--	--	14,412
Middle Atlantic	12,078	3,307	354	W	W	433	17,425
East North Central	19,093	793	577	W	--	W	20,843
West North Central	2,225	W	W	--	--	--	2,641
South Atlantic	24,689	3,122	W	--	W	W	28,024
East South Central	7,847	W	--	--	W	--	8,066
West South Central	65,775	1,890	W	W	--	--	68,199
Mountain	1,517	1,331	W	W	--	545	4,313
Pacific	18,906	W	W	W	2,089	W	62,319
U.S. Total	169,522	38,838	3,489	11,840	2,847	1,796	217,241
1989 (5 Megawatts or More)							
New England	5,076	W	W	--	--	--	10,912
Middle Atlantic	10,023	2,314	292	W	W	W	13,634
East North Central	12,807	550	517	W	--	W	14,030
West North Central	1,728	W	W	--	--	--	1,939
South Atlantic	24,262	2,184	W	--	W	W	26,720
East South Central	7,014	W	--	--	W	--	7,100
West South Central	63,263	W	512	W	--	--	66,755
Mountain	1,534	966	W	W	--	W	3,848
Pacific	16,558	W	W	6,142	1,471	W	42,417
U.S. Total	142,056	31,066	3,046	8,197	1,875	1,097	187,356

W = Withheld to avoid disclosure of individual company data

Notes: *Data shown in this table are based on the facility's consumption. *Data for 1993 are preliminary, data for prior years are final. *See Technical Notes for Standard Industrial Classifications for these industry groups. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-887, "Annual Nonutility Power Producer Report."

Table 82. U.S. Nonutility Electricity Supply and Disposition for Facilities by Census Division and State, 1993
(Million Kilowatthours)

Census Division and State	Gross Generation		Receipts ¹		Deliveries ²		Facility Use	
	1 megawatt or more	5 megawatts or more	1 megawatt or more	5 megawatts or more	1 megawatt or more	5 megawatts or more	1 megawatt or more	5 megawatts or more
New England	28,229	27,499	3,964	3,675	22,667	22,101	9,596	8,975
Connecticut	4,384	4,269	328	W	3,680	3,601	1,033	W
Maine	7,837	7,721	2,891	2,890	4,926	4,834	5,802	5,777
Massachusetts	9,229	9,043	439	295	8,035	7,967	1,633	1,371
New Hampshire	1,704	1,422	W	W	1,334	1,036	W	W
Rhode Island	4,723	4,887	84	W	4,392	4,387	416	W
Vermont	351	337	W	W	291	276	W	W
Middle Atlantic	48,706	47,518	4,879	4,121	40,150	39,308	13,433	12,329
New Jersey	14,428	14,194	658	416	13,085	12,960	2,020	1,849
New York	18,627	17,859	1,288	1,149	15,673	15,041	4,249	3,996
Pennsylvania	15,652	15,433	2,932	2,656	11,413	11,306	7,171	6,663
East North Central	26,211	25,317	16,401	14,846	11,982	11,616	30,620	29,345
Illinois	3,711	3,389	4,989	4,469	384	280	8,316	7,598
Indiana	W	W	4,839	4,546	W	W	8,610	8,256
Michigan	14,563	14,199	1,567	1,098	11,304	11,139	4,825	4,158
Ohio	1,584	W	2,680	2,626	65	W	4,190	4,125
Wisconsin	W	W	2,347	1,905	W	W	4,889	4,208
West North Central	4,675	4,456	4,774	4,691	1,333	1,267	8,119	7,791
Iowa	W	W	1,392	1,337	W	W	2,113	2,043
Kansas	317	W	W	W	W	W	W	W
Minnesota	2,893	2,818	2,434	2,379	966	920	4,360	4,278
Missouri	W	W	161	173	W	W	374	335
Nebraska	W	W	W	W	W	W	W	W
North Dakota	W	W	W	W	W	W	W	W
South Dakota	W	W	W	W	W	W	W	W
South Atlantic	43,620	43,030	15,713	14,814	21,351	21,082	37,982	35,962
Delaware	763	W	W	W	W	W	W	W
District of Columbia	W	W	W	W	W	W	W	W
Florida	12,485	12,352	2,257	1,889	5,812	5,805	8,941	8,436
Georgia	5,997	5,897	W	W	W	W	7,835	7,163
Maryland	1,543	W	W	W	W	W	W	W
North Carolina	6,886	6,805	2,936	2,506	4,337	4,324	5,466	4,988
South Carolina	2,690	2,628	1,597	W	730	W	3,557	3,420
Virginia	9,480	9,296	2,999	2,896	7,571	7,416	4,909	4,779
West Virginia	3,825	3,796	1,574	1,574	1,535	1,535	3,864	3,836
East South Central	10,741	10,583	7,947	7,088	497	487	18,191	17,264
Alabama	5,543	5,467	2,863	W	166	W	8,340	7,905
Kentucky	W	W	W	W	W	W	W	W
Mississippi	2,808	2,768	1,552	W	68	W	4,282	4,219
Tennessee	2,389	2,348	3,403	2,929	223	136	5,568	5,140
West South Central	60,073	59,868	19,397	17,830	37,267	37,292	82,183	80,235
Arkansas	2,567	2,546	W	W	W	W	3,239	3,197
Louisiana	20,180	20,064	6,934	6,229	4,769	4,769	22,345	21,545
Oklahoma	4,508	4,489	W	W	W	W	2,241	2,187
Texas	52,820	52,549	10,742	9,937	29,203	29,180	34,359	33,308
Mountain	9,572	9,649	3,843	3,732	6,774	6,392	6,691	6,390
Arizona	W	W	W	W	W	W	560	W
Colorado	1,591	W	165	W	1,191	1,059	566	467
Idaho	1,627	W	W	W	1,446	1,308	W	1,185
Montana	451	W	W	W	W	W	W	W
Nevada	W	3,730	W	W	3,521	3,480	269	W
New Mexico	380	W	1,186	W	W	W	1,589	1,523
Utah	626	W	W	W	W	W	W	W
Wyoming	635	622	W	552	W	W	1,180	W
Pacific	73,400	71,724	8,384	7,784	60,999	60,008	20,761	19,502
Alaska	1,047	989	W	W	W	W	1,051	960
California	62,753	61,480	3,086	2,677	63,403	62,677	12,436	11,461
Hawaii	4,051	4,006	56	52	3,164	3,194	943	924
Oregon	1,200	1,053	W	W	W	W	1,057	1,036
Washington	4,349	4,236	4,478	4,351	3,555	3,465	5,273	5,122
U.S. Total	325,226	316,849	65,323	77,378	203,035	198,442	207,514	196,780

¹ Includes purchases, interchanges, and exchanges of electric energy with utilities and other nonutilities.

² Includes sales, interchanges, and exchanges of electric energy with utilities and other nonutilities. The disparity in this data and data reported on other EIA surveys occurs due to differences in the respondent universe. The Form EIA-867 is filed by nonutilities reporting the energy delivered, while other data sources are filed by electric utilities reporting energy received. Differences in terminology and accounting procedures attribute to the disparity. In addition, since the frame for the Form EIA-867 is derived from utility surveys, the Form EIA-867 universe lags one year.

W = Withheld to avoid disclosure of individual company data.

Notes: *Data for 1993 are preliminary. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

Table 83. Estimated Emissions from U.S. Nonutility Power Producers Facilities by Census Division, 1989 Through 1993 (Thousand Short Tons)

Census Division	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide ¹
1993 (1 Megawatt or More)			
New England	45	49	33,616
Middle Atlantic	127	166	56,659
East North Central	205	307	92,877
West North Central	83	42	14,236
South Atlantic	374	250	118,221
East South Central	130	75	45,715
West South Central	227	250	102,544
Mountain	20	33	10,318
Pacific Contiguous	44	111	55,062
Pacific Noncontiguous	12	15	6,742
U.S. Total	1,297	1,300	656,989
1992 (1 Megawatt or More)			
New England	39	46	32,106
Middle Atlantic	89	156	49,970
East North Central	201	275	84,484
West North Central	80	37	13,046
South Atlantic	384	231	112,364
East South Central	119	70	41,064
West South Central	237	258	103,096
Mountain	21	29	9,683
Pacific Contiguous	45	102	51,545
Pacific Noncontiguous	13	15	6,708
U.S. Total	1,208	1,219	504,074
1990 (5 Megawatts or More)			
New England	49	32	21,764
Middle Atlantic	121	111	34,222
East North Central	180	290	81,164
West North Central	45	22	6,932
South Atlantic	303	164	86,636
East South Central	103	59	32,953
West South Central	176	238	84,424
Mountain	15	21	8,072
Pacific Contiguous	26	97	41,467
Pacific Noncontiguous	8	10	4,507
U.S. Total	1,028	1,042	401,151
1989 (5 Megawatts or More)			
New England	41	26	18,751
Middle Atlantic	107	83	26,614
East North Central	172	266	72,370
West North Central	39	20	5,989
South Atlantic	253	165	75,300
East South Central	69	57	26,122
West South Central	78	219	77,205
Mountain	7	27	9,162
Pacific Contiguous	17	79	33,500
Pacific Noncontiguous	7	8	3,696
U.S. Total	790	971	347,711

¹ As of 1993 data, emission factors for the calculation of carbon dioxide emissions and reductions from nitrogen oxide control technologies have been changed--historical estimates were revised to reflect that change--See Technical Notes for more information

Notes: *Estimates for 1993 are preliminary, estimates for prior years are final. *Historical data have been revised to reflect a change in methodology--see Technical Notes for more information. *Totals may not equal sum of components because of independent rounding. *See Appendix C, "Technical Notes," for methodology

Source: Estimated using data from the Form EIA-887, "Annual Nonutility Power Producer Report."

Appendix A

Major Disturbances and Unusual Occurrences in U.S. Electric Power Systems

Major Disturbances and Unusual Occurrences in U.S. Electric Power Systems

Electric power systems are subject to a variety of incidents that, to a smaller or greater degree, may adversely affect the delivery of electricity to consumers. Among these are natural phenomena (such as storms and earthquakes); failure of electric system components; accidental or purposeful activities inimical to continued safe operation of U.S. electric power systems; and difficulties associated with the normal operation of large, extremely complex, real-time systems.

Under current Federal regulations, some disturbances are reported to the Federal Government. The legal basis for the requirements and the specifications of information reported are detailed in Title 10, Part 205, Subpart W, of the *Code of Federal Regulations*, Sections 205.350 through 205.353, published in the *Federal Register*, October 31, 1986. Underlying the formulation of the reporting criteria, requirements and procedures was the need for the Federal Government to be aware of potentially dangerous situations, tempered by the desire to minimize burden on the reporting utilities. Another consideration in the development of the rules was the benefit gained from knowledge of the causes and effects of undesired events that may have been caused by unforeseen system defects or by purposeful adverse actions to system design and operation. The final rules reflect modification of the preliminary rules, as published in the *Federal Register*, based on comments from the electric power industry and the general public.

In general, the incidents to be reported are grouped into two categories: mandatory in all cases; and mandatory if the incident meets specified criteria. A report is mandatory in all cases when, for the purpose of maintaining the reliability of the bulk power supply system, a utility (1) initiates a system voltage reduction of 3 percent or more, (2) disconnects circuits supplying over 100 megawatts of firm customer load, or (3) issues

an appeal to the public for a voluntary reduction in the use of electricity. A report is also mandatory in regard to any actual or suspected act of sabotage or terrorism directed at the bulk power supply system. For the second category of mandatory incidents, the electric utility involved is permitted to exercise some judgment as to whether the criteria requiring mandatory reporting have been met.

In general, reports are to be made by telephone to the Emergency Operating Center, Department of Energy, in Washington, DC, as soon as practicable for instances of load shedding or loss of service, and, at the latest, within 3 hours of the beginning of a service interruption. For other disturbances, the allowable reporting time ranges from 24 hours to days. Written reports may be required by the Director, Office of Energy Emergency Operations, if the circumstances so indicate.

The operation of the bulk power system in the United States should be as trouble-free as possible. To that end, information is collected, as discussed above, regarding major disturbances to the normal functioning of that system. Events, such as damage to some local distribution circuits by storms or other uncontrollable events, do not greatly affect the supply of bulk power to the system as a whole. These events are more properly the concern of local and State authorities.

Data Sources

The information contained in Table A1 is based on data from the Form OE-417R, "Electric Power System Emergency Report." These data are collected by the Office of Emergency Management (under the Office of Nonproliferation and National Security).

Table A1. Major Disturbances and Unusual Occurrences in U.S. Electric Power Systems, 1993

Date	Time	Area	Utility/Power Pool (NERC Council)	Type of Disturbance	Loss (megawatt)	Number of Customers Affected	Restoration Time
1/01/93	10 19 AM	Portola, CA	Plumas-Sierra Rural Electric Coop (WSCC)	*Line Fault	16	5,592	10 21 AM Same Day
1/01/93	11 19 AM	Portola, CA	Plumas-Sierra Rural Electric Coop (WSCC)	*Line outage	16	5,492	11 33 AM Same Day
1/01/93	2 14 PM	Portola, CA	Plumas-Sierra Rural Electric Coop (WSCC)	*Line fault	16	5,492	3 23 PM Same Day
1/04/93	5 28 PM	Puget Sound area, WA	Bonnaville Power Administration (WSCC)	*Circuit Bkr	514	NA	6 23 PM Same Day
1/06/93	7 36 PM	Portola, CA	Plumas-Sierra Rural Electric Coop (WSCC)	*Line Fault	16	5,492	7 42 PM Same Day
1/07/93	1 39 AM	Portola, CA	Plumas-Sierra Rural Electric Coop (WSCC)	*Line Fault	16	5,492	2 15 PM Same Day
1/07/93	4 52 AM	Portola, CA	Plumas-Sierra Rural Electric Coop (WSCC)	*Line open	16	5,492	1 17 PM Same Day
1/10/93	1 27 AM	Portola, CA	Plumas-Sierra Rural Electric Coop (WSCC)	*Storm	5	16	1 41 PM Same Day
1/20/93	6 00 AM	Lewis County WA	P U D No. 1 of Lewis County, WA (WSCC)	*Storm	120	20,000	Midnight 1/23/93
1/20/93	7 30 AM	Puget Sound area, WA	Puget Sound Power and Light Company (WSCC)	*Storm	2,000	500,000	9 00 AM 1/25/93
2/17/93	3 09 PM	Watertown, SD	Western Area Power Administration (MAPP)	*C B Fail	40	NA	3 27 PM Same Day
3/12/93	8 00 PM	Alabama	Alabama Power Company (APC) (SERC)	*Storm	NA	255,000	12 00 PM 3/17/93
3/12/93	9 41 PM	West Central FL	Florida Power Corporation (FPC) (SERC)	*Storm	1,000	400,000	12 00 AM 3/18/93
3/12/93	Evening	Eastern TN, Northeast AL, Northern GA	Tennessee Valley Authority (TVA) (SERC)	*Storm	1,000	517,817	Morning 3/22/93
3/13/93	1 00 AM	Southern and Eastern, FL	Florida Power and Light Company (FPL) (SERC)	*Storm	1,600	500,000	3 00 PM 3/16/93
3/13/93	6 30 AM	Georgia	Oglethorpe Power Corporation (OPC) (SERC)	*Storm	626	300,000	6 00 PM 3/19/93
3/13/93	3 36 PM	New England	New England Power Pool (NEPOOL) (NPCC)	*Storm	NA	115,000	9 00 AM 3/15/93
3/13/93	2 53 AM	Delmarva Peninsula	Delmarva Power and Light Company (MAAC)	*Storm	NA	20,000	4 14 PM 3/14/93

See endnotes at end of table

Table A1. Major Disturbances and Unusual Occurrences in U.S. Electric Power Systems, 1993—Continued

Date	Time	Area	Utility/Power Pool (NERC Council)	Type of Disturbance	Loss (megawatt)	Number of Customers Affected	Restoration Time
3/13/93	Late PM	Western, MD	Potomac Edison Company (ECAR)	*Storm	NA	3,500	1:00 PM 3/15/93
3/13/93	1:13 PM	Long Island, N.Y.	Long Island Lighting Company (LILCO) (NPCC)	*Storm	NA	145,000	1:00 PM 3/14/93
3/13/93	Early AM	S.E. New York State	Orange and Rockland Utilities (NPCC)	*Storm	NA	5,000	Morning 3/14/93
3/13/93	Morning	S.E. New York State	Rochester Gas and Electric Company (NPCC)	*Storm	NA	4,500	12:00 PM 3/14/93
3/13/93	NA	Baltimore and Northeast MD	Baltimore Gas and Electric Company (MAAC)	*Storm	NA	132,000	12:00 AM 3/14/93
3/13/93	NA	Washington DC and Southern MD	Potomac Electric Power Company (MAAC)	*Storm	NA	6,500	NA 3/14/93
3/13/93	NA	New York City	Consolidated Edison Company of NY (NPCC)	*Storm	NA	5,000	12:00 PM 3/14/93
3/13/93	NA	Atlantic City NJ	Atlantic Electric Company (MAAC)	*Storm	NA	25,000	Evening 3/14/93
3/13/93	NA	Central and Eastern PA	Pennsylvania Power and Light Company (MAAC)	*Storm	NA	49,000	Morning 3/15/93
3/13/93	7:00 AM	New Jersey	Public Service Electric and Gas Company (MAAC)	*Storm	NA	26,000	12:00 PM 3/14/93
3/13/93	Midday	East Central NJ	Jersey Central Power and Light Company (MAAC)	*Storm	NA	74,000	6:00 PM 3/14/93
3/13/93	6:00 AM	Philadelphia PA and Suburbs	Philadelphia Electric Company (MAAC)	*Storm	NA	100,000	Evening 3/14/93
3/22/93	5:37 AM MST	Eastern WSOC	Western Area Power Administration (WAPA) (WSOC)	*Equipment	50	13 Wholesale	6:25 AM Same Day
4/27/93	10:48 AM	New York City	Consolidated Edison Company of N.Y. (NPCC)	*V.R. Test	120	2,857,035	11:44 AM Same Day
5/27/93	11:35 AM MAST	Salt Lake City Utah	Pacificorp East NW Power Pool (WSOC)	*Bus Trips	230	NA	11:54 AM Same Day
5/04/93	7:01 PM PAST	Vancouver, Is. B.C. Canada	British Columbia Hy. and Power Authority (WSOC)	*Lightning	730	NA	7:25 PM Same Day
5/04/93	3:00 PM	Logan, W. Va. and Virginia	Appalachian Power (ECAR)	*Storm	750	185,612	5:00 PM 6/10/93
6/07/93	6:54 PM	Lake Park, IA	L & O Power Coop. Rock Rapids, IA (MAPP)	*Tornado	NA	1,000	7:44 PM Same Day

See endnotes at end of table.

Table A1. Major Disturbances and Unusual Occurrences in U.S. Electric Power Systems, 1993—Continued

Date	Time	Area	Utility/Power Pool (NERC Council)	Type of Disturbance	Loss (megawatt)	Number of Customers Affected	Restoration Time
6/10/93	10:30 AM	Pierre, SD	Western Area Power Administration (WAPA)	*Accident	23	NA	11:15 AM Same Day
6/27/93	12:41 PM MAST	Wyoming Colorado, Border	Tri-State G. & T. Association, Inc (WSCC)	*Forest fire	None	None	NA
7/02/93	11:41 PM MAST	S.W. Wyoming and S.E. Idaho	Pacificorp-East (WSCC)	*Line Fault	75	NA	
7/14/93	9:43 AM PAST	S. Oregon and N. California	Pacificorp-West (WSCC)	*Fallen trees	356	100,000	11:18 AM Same Day
7/20/93	1:20 PM CDT	S.W. Missouri	Empire District Electric Company (SPP)	*High Load	225	NA	4:30 PM Same Day
7/20/93	9:40 PM	Southern Illinois	Southern Illinois Power Cooperative (MAIN)	*Vandalism	15	14,500	1:17 PM 7/21/93
7/26/93	12:00 PM	Kansas City, Missouri	Uthricorp United Inc Mo. Pub. Service (SPP)	*Fuel Supply	None		Not Applicable
8/21/93	6:03 PM CDT	Orbit, Illinois	Central Illinois Public Service Company (MAIN)	*Sabotage	NA	1,000	7:30 PM Same day
8/25/93	5:06 AM HST	Honolulu, Oahu, Hawaii	Hawaiian Electric Company Hawaii	*Equipment	NA	79,000	8:00 AM Same day
9/09/93	2:45 PM	New York State	New York Power Pool (NYOPC)	*Fuel Low	None		Not Applicable
10/04/93	2:14 AM	Seattle, WA Business Area	Seattle City Light (WSCC)	*Cable Fire	10.9	1,800	12:00 AM 10/08/93
10/10/93	1:06 AM PAST	Washington State	BPA and several P.U.D.s (WSCC)	*Equipment	713	NA	2:22 AM Same Day
10/10/93	3:25 AM	West Columbia, AL	Alabama Power Company (SERC)	*Sabotage	NA	100	3:05 AM 10/11/93
10/12/93	6:04 AM PAST	Los Angeles South Nevada, Utah	LA Dept. of Wtr. and Pwr. Intermt. Pwr. (WSCC)	*Operation	None	None	Not Applicable
10/30/93	NA	Sylmar, CA	LA Dept. of Wtr. and Pwr. (WSCC)	*Fire	NA	NA	NA
12/26/93	2:23 AM	Bakersfield, CA	Pacific Gas & Elec. Co. Southern Calif. Ed. (WSCC)	*Equipment	30	29,000	3:18 PM Same Day

* A tree fell into the Pacific Gas and Electric Company line that supplies the cooperative, causing the line to trip.

* The Pacific Gas and Electric Company line supplying the cooperative was out of service. No cause was stated.

* A 21-kilovolt circuit fell into the 60-kilovolt circuit from Pacific Gas and Electric that supplies the cooperative, the supply line tripped.

* The 230-kilovolt circuit breaker at the Olympia Substation of Bonneville Power Administration (BPA) caught fire, causing loss of the east bus. This breaker was on the 230-kilovolt line to Kitsap. The Olympia-to-Shelton No. 4 230-kilovolt line then was tripped by protective relays (reason unknown), separating the Olympia peninsula from the 230-kilovolt system. The resulting overload caused tripping of the Shelton-Kitsap No. 2 115 kilovolt line within 12 seconds of the breaker fire and also resulted in tripping of the 230/115 kilovolt transformer at Fairmount Substation on overload. Load was restored in times ranging from 9 minutes to 57 minutes. Customers without service were Deshows Paper Mill, Rayonier Paper Mill, U.S. Navy, and an unknown number of customers in the service areas of City of Port Angeles, Puget Sound Power and Light Company and Clallum County (WA) Public Utility District No. 1.

- * Outage of supply line from Pacific Gas and Electric Company due to fault on neutral overcurrent
- * Fault on the Pacific Gas and Electric Company supply line, reason unknown
- * Outage of supply line from Pacific Gas and Electric Company, a jumper burned open on the first pole out of Quincy substation on the Pacific Gas and Electric system
- * Supply line from Pacific Gas and Electric Company looked out due to storm
- * A windstorm caused trees to fall into overhead lines, breaking poles, crossarms and insulators, and damaging distribution transformers. Many miles of line conductor were knocked to the ground
- * By noon on January 20, 1993, the storm which had begun at about 7:30 AM had caused the loss of about 500,000 customers. As of 10:00 AM on January 21, some 340,000 customers were still without power. At 6:30 AM on January 22, about 180,000 customers were still without power, with 350 line crews working on service restoration. There were no significant generation problems but many distribution lines and about 60 transmission lines were down
- * Failure of a 115-kilovolt bus circuit breaker de-energized the bus and circuits to Watertown, South Dakota and the East River Cooperative. The total load of the two systems was about 40-megawatts. Watertown has a population of about 17,000. Power to the cooperative was restored in one minute by switching to an alternate feeder. Power to Watertown was restored in 18 minutes
- * Heavy snowfall and storm conditions damaged distribution facilities and tripped 18 transmission lines. Lines out of service at various times during the storm were: 16 at 115-kilovolts, 1 at 161-kilovolts, 2 at 230-kilovolts. The 500 kilovolt lines did not trip
- * Severe weather with winds gusting to 100 mph and sustained winds of 20-30 mph traversed the 32-county service area of FPC. Winds damaged microwave facilities at Crystal River Plant and at major load centers in the Orlando area. Salt spray contamination and flooding to the level of switchyard foundation caps also occurred at the Crystal River plant. Tie-line, substation and generation control and indication circuits were lost. High winds hampered aerial bucket-truck work. An FPC Phase I Capacity Alert was declared at 5:00 PM on March 13 due to severe cold front, 2 large steam units on annual maintenance and one large unit on forced outage. On Sunday March 14, two additional large steam units were forced out due to failure of contaminated insulation, and a Statewide Capacity Alert was declared for Monday morning March 15 because state operating reserve margin was less than the required amount. On March 15, an FPC Phase II Capacity Alert was declared at 6:00 AM because high loads were anticipated and some generating units were unavailable. A Statewide Capacity Emergency was declared because it appeared possible that firm loads might have to be curtailed. An FPC Phase III Capacity Alert was declared at 7:06 AM. Load management, interruptible load actions were implemented, a 1.5 percent voltage reduction was initiated and emergency power purchases were made. Firm loads were not curtailed. At 7:53 AM, the FPC Phase III Capacity Alert was terminated. The Phase II and Phase I Capacity Alerts were ended at 11:00 AM. On March 17, transmission problems were again experienced because of wind-blown salt contamination and misting rain and fog. Problems at the Crystal River plant 230-kilovolt and 500-kilovolt switchyards caused loss of all remaining units at the plant (1,350 megawatt scheduled off and 2,000 megawatt forced out). The last customers were returned to service on March 18
- * The TVA service area was subjected to blizzard conditions on the evening of March 12 and the morning of March 13. Winds and falling trees damaged the distribution system, mainly in the area from Scottsboro, Alabama to Bristol, Virginia. Ten transmission and subtransmission lines tripped and were restored in about 2.5 hours on the average. As of March 22 about 2,500 customers, mostly in the mountainous terrain of northern Alabama and northern Georgia, were still without electrical service. About 125 line crews were used to restore service, made up of TVA construction and maintenance personnel and crews from TVA distributors in the central and western portions of TVA's service area. The total customers without power on March 13 were: Tennessee 348,950, Alabama 91,157, Georgia 77,500
- * Heavy winds, lightning and a cold front traversed the FPL service area beginning Saturday, March 13. Fifteen transmission lines tripped out of service, some of them several times. Thirteen of the lines serve a total of 47 distribution substations. All transmission lines and substations were back in service by the end of the day on March 13. All distribution feeders were back in service by Tuesday morning March 16. At the height of the storm on March 13 about 500,000 customers were without service. The number was reduced to 140,000 by Sunday morning March 14. As of 3:00 PM on Tuesday March 16, 13,500 customers were still without service, in northeastern Florida. The company had 1,650 utility and contract working crews on service restoration
- * OPC provides wholesale power to 39 of the 42 Electric Membership Corporations in Georgia. "Tornado-like winds" in southern Georgia and a blizzard in the central and northern parts of the state, beginning early Saturday, March 13 and continuing through Sunday, March 14 damaged distribution facilities. Transmission facilities were mostly intact
- * A blizzard with 70-mph winds and much snow caused tripping of two 345-kilovolt lines and three generators. In addition, nuclear units Millstone 1 and 2 had to reduce output because their cooling water intakes were clogged by debris due to high seas. Brayton Point 2 had its output reduced because of wet coal; the Canal plant had its output reduced because of opacity problems and Merrimack No. 2 unit had its output reduced because of a forced draft fan problem. Customer outages were due to distribution circuit damage
- * A storm tripped a 69-kilovolt line and affected numerous distribution circuits. At the Indian River Power Plant, a temporary operating problem occurred when high winds blew water out of the cooling water intake
- * Customer outages were due to storm effects on distribution circuits. The transmission system and generating plants were not affected
- * Customer outages were due to storm effects on distribution circuits. There were no transmission problems, although winds gusting to 80 MPH knocked down some trees. At Northport Power Plant, one 380-megawatt unit tripped due to salt contamination on a standoff insulator and at Port Jefferson Power Plant one 190-megawatt unit tripped because of salt contamination on an insulator. Some contractor crews were called in to assist company line crews
- * Customer outages were caused by storm effects on distribution circuits. There were no generation or transmission problems
- * The storm affected distribution circuits but not the generation or transmission facilities
- * Customers were affected by storm damage to distribution facilities but transmission facilities were not affected. Crane Generating Plant tripped when a static wire failed but the Plant was restored to service without difficulty
- * The storm disrupted service to some customers by damaging distribution circuits. There were no generation or transmission problems and no need to activate the Edison Electric Institute Mutual Assistance Pact. Contractor crews were used to supplement the company's line crews in service restoration work
- * Some distribution circuits were out of service because of the storm. Several transmission circuits tripped but were restored to service within two hours
- * Distribution circuit damage interrupted service to some customers. No other difficulties were reported
- * Some distribution circuits were out of service because of the storm, interrupting some customer service
- * Distribution circuits tripped, interrupting customers. There were no problems with generation or transmission
- * The service interruptions were caused by breakage of 35 distribution poles, 315 wire sections down, 2 circuit breaker trips and outage of 36 distribution circuits
- * One transmission substation tripped when hit by lightning but was restored to service. Generating plants were not affected. Customer outages were caused by distribution circuit damage
- * A conductor of the Warren-Skyline 115-kilovolt line fell to the ground (cause unknown). The associated circuit breaker at Archer Substation failed to trip, causing the tripping of four additional 115-kilovolt lines and three 230 kilovolt lines out of Archer, and the Poudre-Richard Lake 115-kilovolt line. The HVDC Converter Stations at Staggall (110 megawatt) and Sidney (200 megawatt) tripped with 300 megawatt flowing from MAPP to WSCC, and Unit 1 at Hayden Power Plant in Colorado, carrying 180 megawatt, also tripped. Frequency rose to 60.01 cycles and fell to 59.98. Sixty megawatts of firm load being supplied to 13 wholesale customers was lost. Transmission restoration began within 6 minutes, generation was restored within 17 minutes and load within 48 minutes. There were no adverse effects in MAPP
- * Consolidated Edison Company instituted a test of its voltage reduction procedures: 6 percent at 10:45 AM, 5 percent at 10:54 AM, 3 percent at 11:14 AM, normal voltage at 11:44 AM
- * The 138-kilovolt PacificCorp East 90th South Substation was in a single bus configuration for maintenance, work was in progress to return it to the normal double bus arrangement. The 138-kilovolt bus differential relaying operated inadvertently to clear the East and West buses, tripping five 138-kilovolt lines, two 345/138-kilovolt transformers and three 138/48 kilovolt transformers. Two megawatts of small hydro generation (at Stars and Granite hydro plants) tripped, as well as 230 megawatts of firm load. Restoration began immediately
- * One of the two 138-kilovolt cable from Amot Substation (mainland) to Vancouver Island Terminal was out of service due to a failed cable. The

two 500-kilovolt lines from Cheeky Substation to Malaspina (on the mainland) to Dunsmuir Substation (on Vancouver Island) then tripped and the remaining 138-kilovolt cable from Amnot opened at the Vancouver Island terminal. One pole of the Amnot-Vancouver Terminal DC line blocked but the other pole maintained the tie in service for the 27 minutes needed to resynchronize. Three synchronous condensers at Vancouver Terminal, 27 megawatts of hydro generation and 230-kilovolt line on the island tripped. The frequency on the island dropped to 58.6 HZ and the frequency in the portion of the WSCC interconnection rose to 60.09 HZ before conditions returned to normal.

¹⁰ From the afternoon of June 4 through the early morning hours of June 5 a storm traversed the service area of Appalachian Power Company, damaging subtransmission lines and distribution circuits. As of June 4 late evening customer outages were 141,680 in Virginia and 48,832 in West Virginia (total was 188,512). By June 5 evening the total was 54,366 and by Sunday evening June 8 it was 22,318. Total load lost was 750 megawatts. As of Monday, June 7, 17,306 customers were without service. Damage was due to trees, broken and uprooted by the wind, falling on conductors and breaking them, in addition to damage by lightning. One 138/34.5 kilovolt transformer was damaged and was temporarily replaced by a mobile transformer.

¹¹ Distribution circuit poles were knocked over by a tornado near Lake Park, Iowa. Power to Lake Park was restored at 7:44 PM CDT that day.

¹² A 115-kilovolt circuit breaker in the WAPA Pierre substation, feeding the City of Pierre, South Dakota tripped and locked out, interrupting about 23 megawatts of the city's load. Inspection of equipment in the city's substation did not reveal any reason for the trip and lockout signal. It is believed telephone company personnel engaged in cable location activities injected a signal into the cables used for relaying and communications, that tripped the WAPA circuit breaker. All load was restored by 11:15 AM.

¹³ A forest fire northeast of Walden, Colorado on the Colorado-Wyoming border, burning under the 345-kilovolt Craig-Ault transmission line, caused a C-phase to ground fault at 12:41 PM MAST. The line tested at 12:44 PM MAST, the test was satisfactory, and the line was closed via a circuit breaker at Craig substation at 12:46 PM; it tripped in 5 seconds on a ground fault to a A-phase on the line. As the breaker was opening to clear the fault it developed a ground fault on its fault on its A-phase. The circuit breaker failure relay did not operate, thereby causing tripping of adjacent lines and transformers and all circuits emanating from the Craig 345-kilovolt South Bus. Craig Generating Unit No. 3, carrying 408 megawatts, then tripped, causing frequency to drop to 58.945 HZ before it recovered to normal. Lines were restored to normal by 5:40 PM and Craig Unit No. 3 was restored to service at 3:21 AM on June 28. No customers were affected, as spinning reserve picked up the load when Craig No. 3 tripped.

¹⁴ A three-phase ground fault on the Naughton-Monument 230-kilovolt line resulted from burning of the center pole of a three-pole wooden structure located 5 miles from Naughton. The line tripped, re-closed and tripped again. When the system dispatcher reclosed the line circuit breaker at Naughton into the fault, the breaker and the associated breaker of the breaker-and-a-half scheme tripped in less than 3 cycles to clear the fault. A breaker failure relay then mis-operated, tripping the West bus at Naughton and causing 8 other 230-kilovolt lines to trip. Three generating units at Naughton then tripped: No. 1 on underexcitation, No. 2 on excessive current and No. 3 on indication of a transformer ground fault; the total generation dropped was 630 megawatts. All lines were returned to transformer service by 10:34 PM MAST on July 3. Generating Unit No. 1 was restored to service at 3:31 AM on July 3, No. 2 at 5:23 AM on July 3 and No. 3 was kept off line until 1:31 PM on July 4 for repair of a boiler tube leak. One of the 230-kilovolt lines that tripped (Naughton-Treasurer) did so at maximum phase angle difference on the power swing, causing failure of a lightning arrester and subsequent tripping of the 230-kilovolt bus at Treasurer.

¹⁵ The Dixonville-Grants Pass 230-kilovolt line tripped when struck by a fallen tree. This led to tripping of the Kenneth Falls-Boyle 230-kilovolt line and the Weed Junction-Cascade 115-kilovolt tie to Pacific Gas and Electric Company. Generating units delivering a total of 206 megawatts (56 U.S. Bureau of Reclamation and 150 megawatts Pacificorp) tripped as follows: J.C. Boyle unit 2; COPOD units 11, 21, 22; Rogue River-Prospect; Bureau of Reclamation Lost Creek; Green Springs; Biomass Cogent; several small hydro units. The customers who lost service were in the area of Medford and Grants Pass in southeastern Oregon. The transmission circuits were restored by 10:26 AM and the lost generating units by 11:40 AM same day. Service to customers was restored between 8:56 AM and 11:15 AM same day.

¹⁶ High temperature and high humidity caused high loads. Empire District could not purchase sufficient capacity to supplement its own capacity because of low voltage in the area due to cascading tripping of 18 transmission lines in the region: Grand River Dam Authority lost a 345-kilovolt interconnection to Southwestern Electric Power Company, this trip was followed by tripping of another 345-kilovolt line, eight 161-kilovolt lines and eight 69-kilovolt lines. During this incident nominal 161-kilovolt transmission voltages in the area around Joplin, Missouri sagged as low as 137-kilovolt.

¹⁷ Vandals cut guy wires on a three-pole dead-end structure and sawed part way through one of the poles immediately east of the Franklin Junction (Illinois) Switching Station of Southern Illinois Power Cooperative. A 138-kilovolt conductor fell and contacted a 69-kilovolt conductor, causing the 138-kilovolt tie from Franklin Junction to Central Illinois Public Service Company to trip. Loss of the tie and the 69-kilovolt line made it necessary to close the emergency tie between the City of Fairfield and Wayne-White Counties Electric Cooperative and to ask the City of McLeansboro, Illinois to generate. Southern Illinois Cooperative lost about 6,000 customers, Fairfield 7,000 and McLeansboro 1,500.

¹⁸ Coal stocks on hand at the Boley Power Plant are at less than 50 percent of the normal amount for this time of the year. The company reports that the coal-pile reduction is due to the combined effects of a coal strike and floods in the Midwest. Potential flooding has forced rail yards to close, interrupting coal delivery by normal routes. Power supply to customers has not been interrupted. At this time the 490 megawatt plant (3 generating units) has an 18-day supply of coal on hand. This situation was reported in accordance with Section 205.351(d) of the regulations for the reporting of electric power system emergencies (CFR Title 10, Part 205, Subpart W).

¹⁹ The oil valve on a 138-kilovolt transformer was opened by persons unknown, allowing the oil to drain out and causing the transformer to overheat. Power was lost to about 1,000 customers including the Federal prison at Marion, Illinois. The prison used its back-up generator to supply power during the outage.

²⁰ Leakage current across insulators caused a pole-top fire on a 138-kilovolt structure, allowing a line conductor to contact a guy wire and a shield wire. The shield wire fell into the substation bus. The circuit breaker that should have opened to isolate the fault did not trip; it was later discovered that the breaker trip coil was open because of previous voltage impulses. The back-up circuit breaker failed to operate because of an open circuit, forcing several other breakers to trip.

²¹ The New York Power Pool Manager of Operations reported that coal supply at the C.R. Huntley power plant of Niagara Mohawk Power Corporation, in Tonawanda, New York, had been reduced to 25 days of normal operations. A shipment of coal is expected within several days. The situation is not regarded as critical but was reported under Section 4.1 of the disturbance reporting requirements.

²² A short circuit in 4-kilovolt secondary cables in an underground vault, located in the downtown area of Seattle, caused a fire that destroyed two 13-kilovolt main cables, five 13-kilovolt branch cables, two 4-kilovolt cables and several 120/208-volt bus ties. As cables began tripping under control of protective relays, system operators opened circuits to prevent damage to transformers and other secondary circuits from overloads. Businesses, high-rise condominiums, the Pacific Science Center and two television stations (KIRO and KOMO) lost power. Partial restoration of power was effected at 8:19 AM on October 4 and at 10:00 PM on October 7. By noon on Friday October 8 service had been restored to all customers.

²³ A static wire broke and dropped across the Longview-Alilton No. 3 230-kilovolt transmission line, three 230-kilovolt feeders at Longview Substation and one 12.5-kilovolt distribution line owned by Cowitz County Public Utility District (PUD) No. 1. The resulting faults caused loss of load as follows: Bonneville Power Administration 276 megawatt, Clatskanie County PUD 90 megawatt, Cowitz County PUD 930 and Lewis County PUD 18 megawatts. At the Beaver Power Plant of Portland General Electric Company, units 2 and 3 tripped with a total of 80 megawatts of generation and unit 7 was manually taken off line. Frequency rose to 60.103 HZ and returned to normal in about 2 minutes. The Longview-Alilton line was carrying 908 megawatts when tripped by the static wire accident; it was restored to service at 11:36 PM PAST the same day. The generating units were returned to service the same day as follows: No. 7 at 2:19 AM, No. 3 at 2:53 AM, No. 2 at 8:23 AM.

²⁴ A lock was cut from the gate of the district substation and all the oil was drained from the transformer. The transformer overheated and the associated 115-kilovolt line (39 miles long) tripped. Four industrial customers and less than 100 residential customers lost power. Most power was restored within 1.5 hours but one industrial was without service for nearly 24 hours.

²⁵ The Victorville-Adelanto No. 2 500-kilovolt line tripped when contaminated insulators on two towers flashed over in heavy fog. As a result both poles of the Intermountain-Adelanto D.C. line blocked, causing both Intermountain generating units to trip, dropping 1580 megawatt of generation. Frequency dropped to 59.978 Hz and recovered to normal in about 15 minutes. Intermountain No. 2 was returned to service at 7:28 AM same day and Unit 1 at 8:22 AM same day. The Victorville-Adelanto line was left out of service for later replacement of insulators.

²⁶ According to a report in Electric Utility Week of November 6 a fire in the Sylmar Converter Station destroyed a thyristor device associated with the Pacific D.C. Interline, reducing the capacity of the line by about 1000 megawatts. The D.C. Interline runs from the Dalles, in north central Oregon near the Washington border, to the Sylmar Converter Station in Los Angeles County. As of December 18 the Department of Energy has not received a report of this incident.

* A broken static wire caused a fault that tripped the two 230-kilovolt lines from Midway switching station to Kern switching station (Midway-Kern 1 and 2) at 2:23 PM PST. The Midway-Vincent No. 3 500-kilovolt line also tripped, as did Diablo Canyon No. 1 nuclear unit (carrying 1077 megawatts at that time). A 6 megawatt cogeneration unit tripped, and the Midway No. 11 500 kilovolt/230 kilovolt transformer was tripped by its sudden pressure relay. Loss of the 230-kilovolt lines interrupted power to two 230-kilovolt/21-kilovolt transformer banks, cutting off power to 29,000 customers. Frequency dropped to 58.89 Hz, stabilized at 58.875 and returned to the normal 60 Hz in 21 minutes after a delay caused by an erroneous tie reading to the Automatic Generation Control (AGC) computer. Service interruption to 12,000 customers was only momentary; service restoration to 17,000 customers was delayed 55 minutes by failure of an automatic transfer arrangement.

Note: Under the Code of Federal Regulations (10 CFR Part 205) and published in the Federal Register of October 31, 1988, the United States Department of Energy does not receive reports of distribution system outages that are local in nature and affect only a small area or a small number of customers; the following abbreviations may be applicable:

PAST=Pacific Advanced Standard Time,
 CDT=Central Daylight Time,
 EDT=Eastern Daylight Time,
 EST=Eastern Standard Time,
 HST=Hawaiian Standard Time,
 Int=Interruption of service,
 LF=Line Fault (Accidental contact of energized conductors or of energized conductors with ground)
 LR=Load Reduction,
 LTNG=Lightning Strike,
 MAST=Mountain Advanced Standard Time,
 MW=Megawatts,
 NA=Not Available,
 PA=Public Appeal,
 EMC=Electric Membership Corporation,
 UO=Unusual Occurrence,
 VR=Voltage Reduction,
 LS=Load Shedding,
 LC=Curtailment and interruptible customers were to drop some load
 IPL=Indianapolis Power and Light Company,
 PSI=Public Service of Indiana,
 HE=Hoosier Energy Rural Electric Cooperative,
 IM=Indiana Michigan Power Company (subsidiary of American Electric Power Company).

Source: Office of Emergency Management, Form OE-417R, "Electric Power System Emergency Report."

Appendix B

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34. Energy Information Administration, Office of Energy Markets and End Use, *Commercial Building Consumption and Expenditures 1989*, DOE/EIA-0318(89) (Washington DC, April 1992).

Appendix C

Technical Notes

Technical Notes

Sources of Data

The *Electric Power Annual* is prepared by the Survey Management Division; Office of Coal, Nuclear, Electric and Alternate Fuels; Energy Information Administration (EIA); U.S. Department of Energy (DOE). Data published in the *Electric Power Annual* are compiled from two statistical forms filed monthly and seven forms filed annually by electric utilities; and one form filed annually by nonutilities. Those forms are: the Form EIA-759, "Monthly Power Plant Report"; the FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants"; the Form EIA-861, "Annual Electric Utility Report"; the Form EIA-860, "Annual Electric Generator Report"; the Federal Energy Regulatory Commission (FERC) Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others"; the Form EIA-412, "Annual Report of Public Electric Utilities"; the Form EIA-767, "Steam-Electric Plant Operation and Design Report"; the Form EIA-867, "Annual Nonutility Power Producer Report"; the Department of Energy, Office of Emergency Planning Form PO-411, "Coordinated Bulk Power Supply Program"; and the Department of Energy, Office of Fuels Programs, Fossil Energy Form FE-781R, "Annual Report of International Electric Export/Import Data." The *Electric Power Annual* also includes data collected on the Department of Energy Form OE-417R, "Electric Power System Emergency Report." Each form is summarized below.

Form EIA-759

The Form EIA-759 is a mandatory census of all operators of electric utility plants producing electric power for public use. The Form EIA-759 is used to collect monthly data on net generation, consumption of coal, petroleum, and natural gas; and end-of-the-month stocks of coal and petroleum for each plant by prime mover and fuel-type combination. Summary data from the Form EIA-759 are also published in the *Electric Power Monthly (EPM)*, the *Monthly Energy Review (MER)*, and the *Annual Energy Review (AER)*. These reports present aggregated data for electric utilities at the U.S., Census division, and North American Electric Reliability Council Region (NERC) levels.

Instrument and Design History. Prior to 1936, the Bureau of the Census and the U.S. Geological Survey collected, compiled, and published data on the electric power industry. In 1936, the Federal Power Commission (FPC) assumed all data collection and publication responsibilities for the electric power industry and implemented the FPC Form 4. The Federal Power Act, Sections 311 and 312, and FPC Order 141 define the legislative authority to collect power production data. The Form EIA-759 replaced the FPC Form 4 in January 1982.

Data Processing. The Form EIA-759, along with a return envelope, is mailed to respondents approximately 4 working days before the end of the month. The respondents names are obtained from a computerized mailing address file. The completed forms are to be returned to the EIA by the 10th working day after the end of the reporting month. After receipt, data from the completed forms are manually logged in and edited before being keypunched for automatic data processing. An edit program checks the data for errors not found during manual editing. The electric utility companies are telephoned to obtain data in cases of missing reports and to verify data when questions arise during editing. Following verification of the data, text and tables of aggregated data are produced for inclusion in the *EPM*. Following EIA approval of the *EPM*, the data are made available for public use, on a cost-recovery basis, through custom computer runs, data tapes, or in publications.

FERC Form 423

The FERC Form 423, a restricted census, is a monthly record of delivered-fuel purchases, submitted by approximately 230 electric utilities for each plant with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. Summary data from the FERC Form 423 are also published in the *EPM*, the *MER*, and the *Cost and Quality of Fuels for Electric Utility Plants* annual report. These reports present aggregated data on electric utilities at the U.S. and Census division level.

Instrument and Design History. On July 7, 1972, the FPC issued Order Number 453 enacting the New Code of Federal Regulations, Section 141.61, legally creating

the Form 423. Originally, the form was used to collect data only on fossil-steam plants, but was amended in 1974 to include data on internal combustion and combustion turbines. The FERC Form 423 replaced the FPC Form 423 in January 1983. Peaking units were eliminated from the FERC Form 423. In addition, the nameplate capacity threshold was changed from 25 megawatts to 50 megawatts. This reduction in coverage eliminated approximately 50 utilities and 250 plants. All Form 423 historical data in this publication have been revised to reflect the new nameplate capacity threshold of 50 or more megawatts.

In 1991, the FERC Form 423 was amended to include combined-cycle generating units. This increase in coverage added 5 electric utilities and approximately 15 additional electric plants. Several plants, already reporting on the FERC Form 423, began including fuel receipts for combined-cycle units starting with 1991 data.

Data Processing. A computerized mailing-address file was used to send a 12-month supply of forms to respondents. Completed forms were to be returned to the EIA by the 45th day following the end of the reporting month. Data from the completed forms were manually logged in and edited before being key-punched for automatic data processing. The electric utility companies were telephoned to obtain data in cases of missing reports and to verify data when questions arose during editing. Following verification of the data, text and tables of aggregated data were produced for inclusion in the *EPM*. After the *EPM* received EIA approval, the data became available for public use, on a cost-recovery basis, through custom computer runs, data tapes, or in publications.

Starting with the January 1993 data, the FERC began collection of the data directly from the respondents. The FERC will process the data through edits and each month provide the EIA with a diskette containing the data. The EIA will review the data for accuracy. Publication schedules will not be effected.

Form EIA-861

The Form EIA-861 is a mandatory census of electric utilities in the United States, its territories, and Puerto Rico. The Form EIA-861 data contained in this publication are for the United States only. The survey is used to collect information on power production and sales of electricity from approximately 3,250 electric utilities. The data collected are used to update the electric utility frame data base maintained by the EIA. This data base supports queries from the Executive Branch, Congress, other public agencies, and the general public. Summary data from the Form EIA-861 are also contained in the *EPM*; the *Electric Sales and Revenue*; the *Financial Statistics of U.S. Major Investor-Owned Electric Utilities*; the *Financial Statistics of Major U.S. Publicly Owned Electric Utilities*; *Annual Energy*

Outlook; and the *Electric Trade in the United States*. These reports present aggregate totals for electric utilities on a national level, by State, and by ownership type.

Demand-side management data collected on the Form EIA-861 are estimated by electric utilities based on engineering data or statistical analysis. The utilities also use a variety of verification methodologies for these estimates. The Energy Policy Act (EPACT) of 1992, Section 171(a), mandated that EIA verify DSM data estimates and the methodologies used for estimation and verification. In response to this mandate, EIA is conducting a study of DSM estimation methodologies and DSM verification methodologies. A technical report is planned for publication by EIA in early 1995. The report will describe typical estimation methodologies and DSM verification methodologies, as well as the difficulties in reaching broad conclusions concerning the quality of savings estimates reported to EIA.

Instrument and Design History. The Form EIA-861 was implemented in January 1985 to collect data as of year-end 1984. The Federal Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data.

Data Processing. The Form EIA-861 is mailed to the respondents in January to collect data as of the end of the preceding calendar year. The completed forms are to be returned to the EIA by May 1. The data are manually pre-edited before being entered into the interactive on-line system. Internal edit checks are performed to verify that current data total across and between schedules, and are comparable to data reported the previous year. Edit checks are also performed to compare data reported on the Form EIA-861 and similar data reported on the Forms EIA-826, "Monthly Electric Utility Sales and Revenue Report with State Distributions," the FERC Form 1, and the Form EIA-412, "Annual Report of Public Electric Utilities." These are utility-level checks. Respondents are telephoned to obtain clarification of reported data and to obtain missing data.

Detailed comparisons and descriptions of conceptual problems affecting the quality of the data are discussed in the report, *An Assessment of the Quality of Selected EIA Data Series: Electric Power Data*. (See Appendix B, References.) One example of such a problem inherent in data on electricity sales is that the sectoral classification scheme can vary from utility to utility as influenced by the local public utility commission.

Form EIA-860

The Form EIA-860 is a mandatory census of electric utilities in the United States that operate power plants or plan to operate a power plant within 10 years of the reporting year. The survey is used to collect data on existing power plants from the electric utilities and

their 10-year plans for constructing new plants, and modifying and retiring existing plants. Data on the survey are collected at the generating unit level. These data are then aggregated to provide totals by energy source (coal, petroleum, gas, water, uranium, other) and geographic area (State, NERC region, Federal region, Census division). Additionally, at the national level, data are aggregated to provide totals by prime mover. Data from the Form EIA-860 are also summarized in the *Inventory of Power Plants in the United States*, and are used as input to publications and studies by other offices in the DOE.

Instrument and Design History. The Form EIA-860 was implemented in January 1985 to collect data as of year-end 1984. The Federal Energy Administration Act of 1974 (Public Law 93-273) defines the legislative authority to collect these data.

Data Processing. The Form EIA-860 is mailed to approximately 900 respondents in December and the completed forms are to be returned to the EIA by February 15 containing data as of the end of the preceding calendar year. Data for each respondent are preprinted from the applicable data base. Respondents are instructed to verify all preprinted data and to supply missing data. The data are manually edited before being keyed for automatic data processing. Computer programs containing additional edit checks are run. Respondents are telephoned to obtain correction or clarification of reported data and to obtain missing data, as a result of the manual and automatic editing process.

FERC Form 1

The FERC Form 1 is a mandatory restricted-universe census of major investor-owned electric utilities in the United States having, in each of the last 3 consecutive years, sales or transmission service that exceeds one of the following: (1) 1 million megawatthours of total sales, (2) 100 megawatthours of sales for resale, (3) 500 megawatthours of power exchanges delivered, or (4) 500 megawatthours of wheeling for others (deliveries plus losses). All major U.S. investor-owned electric utilities, licensees, or others subject to the Federal Power Act of 1935 must submit this form annually to the FERC. Classification of such entities is provided in the FERC Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act. Approximately 180 electric utilities are classified as major. Excluded from the summary data are the independent power producers and cooperatives jurisdictional to the FERC. The FERC has determined that six independent power producers (IPP's): Catalyst Old River Hydroelectric Limited Partnership, Entergy Power Incorporated, Nevada Sun-Peak Limited Partnership, Ocean State Power, Ocean State Power II, and Terra Comfort Corporation are under FERC jurisdiction. These IPP's must therefore submit the FERC Form 1 for 1992. The

FERC has also determined that Golden Spread Electric Cooperative and Old Dominion Electric Cooperative should file a FERC Form 1 under Section 201 of the Federal Power Act. Data from these two entities were not included since they are classified as cooperative electric utilities on the Form EIA-861.

The FERC Form 1 is used to collect data on income and earnings, taxes, depreciation and amortization, distribution of salaries and wages, electric operating revenues, electric maintenance expenses, generating plant statistics, planned construction data, year-end balance sheets, and general corporate information. Respondents are required to report data on historical plant cost and power production expenses for their hydroelectric plants with a generator nameplate capacity of 10 or more megawatts; each steam-electric plant with a generator nameplate capacity of 25 or more megawatts; and each gas-turbine plant with a generator nameplate capacity of 10 or more megawatts. Less detailed data are required for other plants.

Instrument and Design History. The Federal Power Commission's (FPC) Form 1, the predecessor of the FERC Form 1, was implemented in 1935 by the FPC. When the FPC was merged with the DOE in October 1977, the processing of data on the survey became the responsibility of the EIA. In 1991, the collection responsibility reverted to the FERC. This mandatory survey is conducted in accordance with the FERC *Uniform System of Accounts Prescribed for Private Utilities and Licensees*.

Data Processing. The completed surveys are to be returned to the FERC on or before April 30, containing data for the preceding calendar year. A copy of each survey is forwarded to the EIA for processing. Manual editing of the reported data is completed prior to data entry. Additional edit checks of the data are performed through computer programs. The program edits include both deterministic checks, in which records are checked for the presence of data in required fields, and statistical checks, in which the data are checked against a range of values based on historical data values and for logical or mathematical consistency with data elements reported in the survey. Discrepancies found in the data, as a result of these checks, are resolved either by the processing office or by further information obtained from a telephone call to the respondent company.

Form EIA-412

The Form EIA-412 is a restricted-universe census used annually to collect accounting, financial, and operating data from major publicly owned electric utilities in the United States. Those publicly owned electric utilities engaged in the generation, transmission, or distribution of electricity which had 120,000 megawatthours of sales to ultimate consumers and/or 120,000 megawatthours of sales for resale for the 2 previous

years, as reported on the Form EIA-861, "Annual Electric Utility Report," must submit the Form EIA-412. The criteria used to select the respondents for this survey results in approximately 450 publicly owned electric utilities.

Federal electric utilities are required to file the Form EIA-412. The financial data for the U.S. Army Corps of Engineers (except for Saint Mary's Falls at Sault St. Marie, Michigan); the U.S. International Boundary and Water Commission; and the U.S. Department of Interior, Bureau of Reclamation were collected on the Form EIA-412 from the Federal power marketing administrations.

Instrument and Design History. The FPC created the FPC Form 1M in 1961 as a mandatory survey. It became the responsibility of the EIA in October 1977 when the FPC was merged with DOE. In 1979, the FPC Form 1M was superseded by the Economic Regulatory Administration (ERA) Form ERA-412, and in January 1980 by the Form EIA-412.

Data Processing. The processing of data reported on this survey is the responsibility of the Survey Management Division within the Office of Coal, Nuclear, Electric and Alternate Fuels. The completed surveys are due in this office on or before April 30. Nonresponse follow-up procedures are used to attain 100-percent response. Manual editing of the reported data is completed prior to data entry. Additional edit checks of the data are performed through computer programs. The program edits include both deterministic checks, in which records are checked for the presence of data in required fields, and statistical checks, in which the data are checked against a range of values based on historical data values and for logical or mathematical consistency with data elements reported in the survey. Discrepancies found in the data, as a result of these checks, are resolved either by the processing office or by further information obtained from a telephone call to the respondent company.

Form EIA-767

The Form EIA-767 is a mandatory restricted-universe census of all electric power plants with a total existing or planned organic- or nuclear-fueled steam-electric generator nameplate rating of 10 or more megawatts. The entire form is filed by approximately 700 power plants with a nameplate capacity of 100 or more megawatts. An additional 200 power plants with a nameplate capacity between 10 and 100 megawatts submit information only on fuel consumption/quality, boiler/generator configuration, and flue-gas desulfurization equipment, if applicable. The Form EIA-767 is used to collect data annually on plant operations and equipment design (including boiler, generator, cooling system, flue gas desulfurization, flue gas particulate collectors, and stack data). Data from the Form EIA-767 are used for economic, regulatory, and environmental

analyses conducted by the DOE, the FERC, the Environmental Protection Agency, and the Department of Commerce.

Instrument and Design History. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data. The predecessor form, FPC-67, "Steam-Electric Plant Air and Water Quality Control Data," was used to collect data from 1969 to 1980, when the form number was changed to Form EIA-767. In 1982, the form was completely redesigned and given the name Form EIA-767, "Steam-Electric Plant Operation and Design Report." In 1986, the respondent universe of 700 was increased to 900 to include plants with nameplate capacity from 10 megawatts to 100 megawatts. Respondents for these 200 additional plants complete only pages 1, 5, 6, and, if applicable, 13, and 14.

Data Processing. The Form EIA-767 is mailed to respondents in January to collect data as of the end of the preceding calendar year. The completed forms are to be returned to the EIA by May 1. Equipment design data for each respondent are preprinted from the applicable data base. Respondents are instructed to verify all preprinted data and to supply missing data. The data are manually reviewed before being keyed for automatic data processing. Computer programs containing additional edit checks are run. Respondents are telephoned to obtain correction or clarification of reported data and to obtain missing data, as a result of the manual and automatic editing process.

Form EIA-867

The Form EIA-867 is a mandatory survey of all existing and planned nonutility electric generating facilities in the United States with a total generator nameplate capacity of 1 or more megawatts. In 1992, the reporting threshold of the Form EIA-867 was lowered to include all facilities with a combined nameplate capacity of 1 or more megawatts. Previously, data were collected every 3 years, from facilities with a nameplate capacity between 1 and 5 megawatts. Planned generators are defined as a proposal by a company to install electric generating equipment at an existing or planned facility. The proposal is based on the owner having obtained (1) all environmental and regulatory approvals, (2) a contract for the electric energy, or (3) financial closure on the facility. The Form consists of Schedules I, "Identification and Certification"; Schedule II, "Facility Information"; Schedule III, "Standard Industrial Classification Code Designation"; Schedule IVA, "Facility Fuel Information"; Schedule IVB, "Facility Thermal and Generation Information"; Schedule V, "Facility Environmental Information"; Schedule VI, "Electric Generator Information."

Submission of the Form EIA-867 is required from all facilities that have a combined facility nameplate capacity of 1 megawatt or more. Schedule V "Facility

Environmental Information" is only required of those facilities of 25 megawatts or more.

The form is used to collect data on the installed capacity, energy consumption, generation, and electric energy sales to electric utilities and other nonutilities by facility. Additionally, the form is used to collect data on the quality of fuels burned and the types of environmental equipment used by the respondent.

Instrument and Design History. The Form EIA-867 was implemented in December 1989 to collect data as of year-end 1989. The Federal Energy Administration Act of 1984 (Public Law 93-275) defines the legislative authority to collect these data.

Data Processing. The Form EIA-867 is mailed to the respondents in late January to collect data as of the end of the preceding calendar year. Static data for each respondent are preprinted from the previous year, and the respondents are instructed to verify all preprinted information and to supply the missing data. The completed forms are to be returned to the EIA by April 30. The response rate for all facilities that addresses were confirmed was 100 percent. The data are manually edited before being keyed for automatic data processing. Computer programs containing additional edit checks are run. Respondents are telephoned to obtain corrections or clarifications of reported data and to obtain missing data as a result of the manual and automated editing.

Data Quality. The Manufacturing Energy Consumption Survey (MECS) produces detailed estimates of manufacturing electricity generation by industry and Census Division on a triennial basis. The data are published in the *Manufacturing Energy Consumption Survey, Consumption of Energy*. Gross generation by nonutility power producers by major industry groups, and Census division, for 1989 through 1993 presented in this report, are reasonable given the growth in manufacturing on site generation that occurred between 1985 and 1988 as reported in MECS. As a historical reference, these tables are Table 9 in the 1985 MECS Consumption publication and Tables 14 through 17 and Tables 20 through 24 in the 1988 publication.

Data for the Form EIA-867 are collected from all existing and planned nonutility generating facilities in the United States with a total generator nameplate capacity of 1 or more megawatts. These data are aggregated to provide geographic totals for selected States and at the Census division and national levels. Since the Form EIA-867 data are considered confidential, suppression of some data is necessary to protect the confidentiality of the individual respondent data. See "Confidentiality of the Data" in this section for further information on the nondisclosure of data.

Allocating Capacity

The installed capacity for nonutility generating units is allocated to one energy source using the following algorithms:

- For generating units using a single fossil energy source, the capacity is allocated totally to that energy source.
- For generating units that use hydraulic, geothermal, solar, biomass, or wind energy, the capacity is allocated to that energy source (even if a secondary fuel is burned).
- For generating units using a combination of fossil energy and renewable energy sources, capacity is classified as fossil or renewable based on the greatest percentage of Btu consumed when summed.
- To allocate capacity by fuel within the fossil energy and renewable energy sources, the single fuel within that energy source with the greatest percentage of Btu consumed is used.

Allocating Generation

The generation for nonutility facilities is allocated to one energy source using the following algorithms:

- For generating units that use energy sources that are not burned (hydraulic, geothermal, nuclear, solar, or wind energy), the generation is allocated to that energy source (even if a secondary fuel is burned).
- For facilities having generating units using energy sources that are burned, the generation is allocated based on the percentage of Btu consumed. This algorithm assumes that unit efficiency is the same for all energy sources.

A comparison of installed capacity for facilities of 1 megawatts or more of EIA's data with data published by Edison Electric Institute (EEI) in *Capacity and Generation of Non-Utility Sources of Energy* shows a difference of approximately 1 percent.

Gross-to-Net Generation Conversion Methodology

Gross electricity generation data from the Form EIA-867, reported by generator, are aggregated to provide totals by energy source and geographic area. Nonutility power producers report gross electricity generated on the Form EIA-867 unlike electric utilities that report net generation on various EIA and FERC forms. Nonutilities generally do not measure and record electrical consumption used solely for the production of electricity. Nonutility generators and associated auxiliary equipment are often an integral part of a manufacturing or other industrial process and indi-

vidual watthour meters are not generally installed on auxiliary equipment.

Estimated values for net generation from nonutility power producers were developed by EIA using gross generation, prime mover, fuels, and type of air pollution control data reported on the Form EIA-867. The difference between gross and net generation is the electricity consumed by auxiliary equipment and environmental control devices such as pumps, fans, coal pulverizers, particulate collectors, and flue gas desulfurization (FGD) units. The difference between gross and net generation is sometimes called parasitic load. In smaller power plants rotating auxiliaries are almost always electric motors. In large power plants that produce steam, rotating auxiliaries can be powered by either steam turbines or electric motors and sometimes both because of cold startup requirements.

This methodology for estimating net generation from gross generation is based on determining typical energy consumption for auxiliary electrical equipment associated with electrical generators. For instance, wind turbines have none of the auxiliaries common to a coal-burning power plant such as a coal pulverizers, fans, and emission controls. On the other hand, windfarms do consume electricity since automatic, computer-based control systems are used to control blade pitch and speed thereby affecting generator electricity output.

Shown below are the conversion factors used to estimate net generation by nonutility generators. The factors are typical of a modern electric power plant but could vary significantly between individual plants. Net generation is calculated by multiplying the appropriate conversion factor by the reported gross electrical generation.

Prime Mover Type	Gross-to-Net Generation Conversion Factor
Gas (Combustion) Turbine)	.98
Steam Turbine	.97 ^a
Internal Combustion	.98
Wind Turbine	.99
Solar-Photovoltaic	.99
Hydraulic Turbine	.99
Fuel Cell	.99
Other	.97

^aFactor reduced by .01 if the facility has flue gas particulate collectors and another .03 if the facility has flue gas desulfurization (FGD) equipment. Facilities under 25 megawatts and burning coal in traditional boilers (e.g., not fluidized bed boilers) are assumed to have particulate and FGD equipment.

These conversion factors were estimated by the staff of the Office of Coal, Electric, and Alternate Fuels, Energy Information Administration. The primary reference used in developing the conversion factors was *Steam, its generation and use*, 40th Edition, Babcock & Wilcox, Barberton, Ohio.

Emissions for the Production of Electricity Methodology

Emissions for nonutility power producers include emissions from cogeneration facilities that produce electric power as an integral part of a manufacturing or other thermal consuming process. Emissions are directly proportional to the quantities of fuels consumed. To calculate emissions for the production of electricity, a methodology was developed to estimate the consumption of fuel associated for the production of electricity by cogeneration facilities. The methodology is based on net generation heat rates by primary fuel and prime-mover. The primary fuel is the predominant energy source for the generator based on fuel consumption at the facility expressed in total Btu by fuel type. The heat rates were estimated by the staff of the Office of Coal, Nuclear, Electric, and Alternate Fuels, Energy Information Administration. The primary reference used in developing the conversion factors was *TAG--Technical Assessment Guide*, Volume 1: Electricity Supply--1986, Electric Power Research Institute, Palo Alto, California, December 1986. The procedure to estimate the fuel consumed for the production of electricity is to calculate net generation by primary fuel and prime-mover (see gross-to-net generation methodology), multiply the net generation by the appropriate heat rate to obtain total Btu consumed for the production of electricity, and apportion by the total Btu weighted by energy source.

Net generation heat rates by primary fuel and prime mover are as follows:

Prime Mover	Heat Rate (Btu/kWh - net) By Primary Fuel			
	Coal	Petroleum	Natural Gas	Other
Gas (Combustion) Turbine				
Single Cycle	N/A	14,000	14,500	N/A
Combined Cycle	N/A	8,100	8,200	N/A
Steam Turbine				
Single Cycle	10,200	9,600	9,600	16,500
Combined Cycle	9,000	9,000	9,000	10,500
Internal Combustion	N/A	11,700	11,700	N/A
Other	10,200	11,700	11,700	10,500

Nameplate Capacity to Summer Capability Conversion Methodology

Form EIA-867, "Annual Nonutility Power Producer Report," collects nameplate capacity for electric generating units. Estimated values for net summer capability from nameplate capacity are aggregated to provide a U.S. total. The methodology used for estimating summer capability from nameplate capacity is the same methodology shown in this Appendix for the Form EIA-860.

Business Classification. The nonutility industry consists of all manufacturing, agricultural, forestry, transportation, finance, service and administrative industries, based on the Office of Management and Budget's Standard Industrial Classification (SIC) Manual.⁴⁰ The following is a list from the Form EIA-867 of the main classifications and the category of primary business activity within each classification.

Agriculture, Forestry, and Fishing

- 01 Agriculture production-crops
- 02 Agriculture production, livestock and animal specialties
- 07 Agricultural services
- 08 Forestry
- 09 Fishing, hunting, and trapping

Mining

- 10 Metal mining
- 12 Coal mining
- 13 Oil and gas extraction
- 14 Mining and quarrying of nonmetallic minerals except fuels

15 to 17 Construction

Manufacturing

- 20 Food and kindred products
- 21 Tobacco products
- 22 Textile and mill products
- 23 Apparel and other finished products made from fabrics and similar materials
- 24 Lumber and wood products, except furniture
- 25 Furniture and fixtures
- 26 Paper and allied products (other than 2621 or 2631)

- 2621 Paper mills, except building paper
- 2631 Paperboard mills

- 27 Printing and publishing
- 28 Chemicals and allied products (other than 2819, 2821, 2869, or 2873)

- 2819 Industrial Inorganic Chemicals
- 2821 Plastics materials and resins
- 2869 Industrial organic chemicals
- 2873 Nitrogenous fertilizers

- 29 Petroleum refining and related industries (other than 2911)

- 2911 Petroleum refining

- 30 Rubber and miscellaneous plastic products
- 31 Leather and leather products
- 32 Stone, clay, glass, and concrete products (other than 3241)

⁴⁰Office of Management and Budget, *Standard Industrial Classification Manual*, 1972, (Washington, D.C. 1987).

- 3241 Cement, hydraulic
- 33 Primary metal industries (other than 3312 or 3334)
- 3312 Blast furnaces and steel mills
- 3334 Primary aluminum

- 34 Fabricated metal products, except machinery and transportation equipment
- 35 Industrial and commercial equipment and components except computer equipment
- 36 Electronic and other electrical equipment and components except computer equipment
- 37 Transportation equipment
- 38 Measuring, analyzing, and controlling instruments, photographic, medical, and optical goods, watches and clocks
- 39 Miscellaneous manufacturing industries

Transportation and Public Utilities

- 40 Railroad transportation
- 41 Local and suburban transit and interurban highway passenger transport
- 42 Motor freight transportation and warehousing
- 43 United States Postal Service
- 44 Water transportation
- 45 Transportation by air
- 46 Pipelines, except natural gas
- 47 Transportation services
- 48 Communications
- 49 Electric, gas, and sanitary services

50 to 51 Wholesale Trade

52 to 59 Retail Trade

Finance, Insurance, and Real Estate

- 60 Depository institutions
- 61 Nondepository credit institutions
- 62 Security and commodity brokers, dealers, exchanges, and services
- 63 Insurance carriers
- 64 Insurance agents, brokers, and services
- 65 Real estate
- 67 Holding and other investment offices

Services

- 70 Hotels
- 72 Personal services
- 73 Business services
- 75 Automotive repair, services, and parking
- 76 Miscellaneous repair services
- 78 Motion pictures
- 79 Amusement and recreation services
- 80 Health services
- 81 Legal services
- 82 Education services
- 83 Social services
- 84 Museums, art galleries, and botanical and zoological gardens
- 86 Membership organizations

- 87 Engineering, accounting, research, management, and related services
- 88 Private households
- 89 Miscellaneous services

91 to 97 Public Administration

Other (explain):

Historically, cogeneration facilities reported the Standard Classification Code (SIC) that identified the user of the electric and/or thermal energy. Beginning in 1993, the SIC code was broadened to include the SIC code(s) of the producing facility. This revision provides an alternative method of comparing power needs and utilization within the nonutility power industry. Tables C1 and C2 show the installed capacity and gross generation of electricity by the producing energy group, respectively.

Form PO-411

The Form PO-411 is filed annually as a voluntary report. The information reported includes: (1) actual energy and peak demand for the preceding year and 10 additional years; (2) existing and future generating capacity; (3) scheduled capacity transfers; (4) projections of capacity, demand, purchases, sales, and scheduled maintenance; (5) assessment of adequacy; (6) generating capacity unavailability; (7) bulk power system maps; (8) near term transmission adequacy; (9) future critical bulk power facilities that may not be in service when required; and, (10) system evaluation criteria. These data support queries from the executive branch, Congress, other public agencies, and the general public. These reports present various council aggregate totals for their member electric utilities, with some nonmember information included.

Instrument and Design History. The Form PO-411 program was initiated under the Federal Power Commission Docket R-362, reliability and adequacy of electric service, and Orders 383-2, 383-3, and 383-4. The Department of Energy, established in October 1977, assumed the responsibility for this activity. This form is considered voluntary under the authority of the Federal Power Act (Public Law 88-280), The Federal Energy Administration Act of 1974 (Public Law 93-275), and the Department of Energy Organization Act (Public Law 95-91). The responsibility for collecting these data has been delegated to the Office of Emergency Planning and Operations within the Department of Energy.

Data Processing. The Form PO-411 is filed annually on April 1 by the ten North American Electric Reliability Councils. The forms are compiled from data furnished by electric utilities within the council areas.

Electric utilities or other entities, subject to the provisions of Section 311 of the Federal Power Act (FPA), that are engaged in the generation, transmission, or distribution of electric energy for delivery and/or sale to the public are required to report expeditiously any 1) loss of firm system loads; 2) voltage reductions and public appeals; 3) vulnerabilities that could impact bulk electric power system adequacy or reliability; and, 4) fuel supply emergencies to the DOE.

In accordance with Section 202(a) of the Federal Power Act (FPA), the DOE is responsible for encouraging actions to assure an abundant supply of electric energy throughout the country. Under Section 311 of the FPA, the DOE is authorized and directed to collect information regarding the generation, transmission, and distribution of electric energy and to report the problems and developments of the electric utility industry to Congress. The Secretary of Energy has the Federal responsibility of receiving reports of major electric utility system emergencies. The Secretary has delegated that responsibility to the Office of Emergency Policy (PO) within the DOE.

Instrument and Design History. The collection of outage data was initiated by the FPC prior to the organization of the DOE. After Congress passed legislation creating the DOE, the collection of electric power system outage data became a function of the DOE. Currently the Office of Emergency Planning and Operations (OE) is the principal DOE office for this activity. Form OE-417 was activated after public comment on a rule-making procedure (FR 7/6/83). The form was revised to Form OE-417R after public comment under a later rule-making procedure (FR 10/31/86).

Data Processing. Reports of emergencies are usually received by the Alert Coordination Officer via telephone. The Director, Office of Emergency Operations, has the authority to require a full technical report (after notice in the *Federal Register*).

Form FE-781R

The Form FE-781R, "Annual Report of International Electrical Export/Import Data" is used to collect on an annual basis, monthly information on the gross amounts of electrical energy received and delivered and the costs and revenue associated with these transactions. The use of the format contained in Form FE-781R is optional for reporting purposes; however, submission of the data is mandatory.

Instrument and Design History. The authority to issue presidential permits pursuant to Executive Order Number 10485 was transferred to the Secretary of Energy by Executive Order Number 12038 (43 FR 4957 February 7, 1987). This responsibility was delegated by the Secretary to the Economic Regulatory Adminis-

tration (DOE Delegation Order Number 0204-04, October 1, 1977). The authority was redelegated (DOE Delegation Order Number 127) to the Office of Fuels Programs, Fossil Energy, (54 FR 11436 March 20, 1990). The survey universe is defined under Title 10 of the Code of Federal Regulations, Sections 205.308 and 205.325 to include all public utilities or other entities subject to the Department of Energy jurisdiction under Part II of the Federal Power Act engaged in the export of electric energy across the international borders of the United States with Canada and Mexico. It also includes those engaged in the transmission of electrical energy across these borders who hold a presidential permit.

Data Processing. The Form FE-781R is mailed to the respondents to collect annually, the monthly data for the preceding calendar year. The completed forms are to be returned to the DOE by February 15. The receipts are manually edited and the data used for the Presidential Permit Program are entered into a machine readable format.

Quality of Data

The Office of Coal, Nuclear, Electric and Alternate Fuels (CNEAF) is responsible for routine data improvement and quality assurance activities. All operations in this office are done in accordance with formal standards established by the EIA. These standards are the measuring rod necessary for quality statistics. Data improvement efforts include verification of data-keyed input by automatic computerized methods, editing by subject matter specialists, and follow up on nonrespondents. The CNEAF office supports the quality assurance efforts of the data collectors by providing advisory reviews of the structure of information requirements, and of proposed designs for new and revised data collection forms and systems. Once implemented, the actual performance of working data collection systems is also validated. Computerized respondent data files are checked to identify those who fail to respond to the survey. By law, nonrespondents may be fined or otherwise penalized for not filing a mandatory EIA data form. Before invoking the law, the EIA tries to obtain the required information by encouraging cooperation of nonrespondents.

Completed forms received by the CNEAF office are sorted, screened for completeness of reported information, and keyed onto computer tapes for storage and transfer to random access data bases for computer processing. The information coded on the computer tapes is manually spot-checked against the forms to certify accuracy of the tapes. To ensure the quality standards established by the EIA, formulas that use the past history of data values in the data base have been designed and implemented to check data input for errors automatically. Data values that fall outside the ranges pre-

scribed in the formulas are verified by telephoning respondents to resolve any discrepancies.

Conceptual problems affecting the quality of data are discussed in the report, *An Assessment of the Quality of Selected EIA Data Series: Electric Power Data*. This report is published by the Energy Information Administration (Office of Statistical Standards, see Appendix B).

Data Editing System

Data from the form surveys are edited using automated systems. The edit includes both deterministic checks, in which records are checked for the presence of required fields and their validity; and statistical checks, in which estimation techniques are used to validate data according to their behavior in the past and in comparison to other current fields.

Confidentiality of the Data

In general, the data collected on the forms used for input to this report are not confidential. However, data from the Form EIA-867, "Annual Nonutility Power Producer Report," are considered confidential and must adhere to EIA's "Policy on the Disclosure of Individually Identifiable Energy Information in the Possession of the EIA" (45 *Federal Register* 59812 (1980)). In order to protect the confidentiality of individual respondent's data, a procedure was developed to suppress the data for publication. The procedure is described as follows.

Disclosure of Data

Data reported on the Form EIA-867, "Annual Nonutility Power Producer Report," are confidential. In order to protect the confidentiality of data for an individual respondent, a policy was implemented to ensure that the reporting of survey data would not associate those data with a particular company. The final phase in the data quality assurance and control procedures is to determine which data must be suppressed (withheld) during publication to provide the necessary confidentiality for respondents that operate in small reporting areas. These procedures are performed as follows:

- **Primary Withholding Based on the Number of Respondents in a Cell**--All cells with three or fewer respondents are suppressed.
- **Residual Withholding Dominance Rule**--All cells containing four or more respondents are tested using a linear sensitivity rule.
- **Complementary Suppression**--All tables are reviewed to identify cells that should have data withheld to prevent disclosure of already sup-

pressed cells. An example of this concept, when U.S. totals are available, would be the complementary suppression of a second State in order to prevent the derivation of an initially suppressed State.

The withholding/suppression of data is performed as an adjunct to Quality Assurance (QA) procedures. The work is performed by survey editors and the QA staff and is reviewed by the survey manager before being submitted to the division level QA review.

All sensitive cells identified in the withholding analysis are denoted with the symbol/letter "W." The use of the symbol/letter applies to primary, complementary and inter-table suppressions as well as all withheld data.

Rounding Rules for Data

Given a number with r digits to the left of the decimal and $d+t$ digits in the fraction part, with d being the place to which the number is to be rounded and t being the remaining digits which will be truncated, this number is rounded to $r+d$ digits by adding 5 to the $(r+d+1)$ th digit when the number is positive or by subtracting 5 when the number is negative. The t digits are then truncated at the $(r+d+1)$ th digit. The symbol for a rounded number truncated to zero is (*).

CNEAF Data Revision and Policy

The Office of Coal, Nuclear, Electric and Alternate Fuels has adopted the following policy with respect to the revision and correction of recurrent data in energy publications:

1. Annual survey data collected by this office are published either as preliminary or final when first appearing in a data report. Data initially released as preliminary will be so noted in the report. These data will be revised, if necessary, and declared final in the next publication of the data.
2. All monthly and quarterly survey data collected by this office are published as preliminary. These data are revised only after the completion of the 12-month cycle of the data. No revisions are made to the published data before this unless approved by the Office Director.
3. The magnitude of changes due to revisions experienced in the past will be included in the data reports, so that the reader can assess the accuracy of the data.
4. After data are published as final, corrections will be made only in the event of a greater than one percent difference at the national level. Corrections for differences that are less than the before-mentioned threshold are left to the discretion of the Office Director.

The *Electric Power Annual* (EPA) presents the most current annual data available to the EIA. The statistics may differ from those published previously in EIA publications due to corrections, revisions, or other adjustments to the data subsequent to its original release. On a chapter basis, the status (preliminary versus final) of the data contained in the EPA follows:

- **Generating Capability at U.S. Electric Utilities**

Total net summer capability data for 1993 from the Form EIA-860 are final and unchanged from the preliminary data reported in the *Inventory of Power Plants in the United States 1993*, which was published in October 1994.

- **Net Generation at U.S. Electric Utilities**

All Form EIA-759 data are final. A comparison of preliminary versus final data for 1993 are provided in the Technical Notes of the *Electric Power Monthly* (EPM), July 1994.

- **U.S. Electric Utility Fossil-Fuel Statistics**

All FERC Form 423 data are final. A comparison of preliminary versus final data for 1993 from the FERC Form 423 is provided in the Technical Notes of the EPM, July 1994.

- **U.S. Electric Utility Retail Sales and Revenue**

Data on sales, revenue, and average revenue per kilowatthour from the Form EIA-861 for 1993 are preliminary. The data are revised and declared final in the *Electric Sales and Revenue 1993*. A comparison of preliminary versus final annual data at the national level for 1993 will be provided in the *Electric Power Annual* (EPA) 1994.

- **U.S. Electric Utility Financial Statistics**

Financial data from the Federal Energy Regula-

tory Commission Form 1 and the Form EIA-412 for 1993 are final.

- **U.S. Electric Utility Environmental Statistics**

Data from the Form EIA-767 for 1992 are final. The methodology for calculating emissions of sulfur dioxides, nitrogen oxides, and carbon dioxide has been revised. As a result, final data for 1992 at the national level differ from the preliminary by -2.0 percent for sulfur dioxide, -28.1 percent for nitrogen oxides, and 0.2 percent for carbon dioxide. Data for 1993 are preliminary. A comparison of preliminary versus final data at the national level for 1993 will be provided in the EPA 1994.

- **U.S. Electric Power Transactions**

All data from the Forms PO-411 and FE-718R are final. Data from the Form EIA-861 for 1993 are preliminary; Form EIA-861 data for prior years are final. Data from the Form EIA-860 are final.

- **U.S. Electric Utility Demand-Side Management**

Data on demand-side management from the Form EIA-861 for 1992 are final. Data for 1993 are preliminary. A comparison of preliminary versus final data at the national level for 1993 will be provided in the EPA 1994.

- **U.S. Nonutility Power Producers** Data from the Form EIA-867 for 1992 are final and unchanged from preliminary data. Data for 1993 are preliminary. A comparison of preliminary versus final annual data for 1993 will be provided in the EPA 1994.

- **Appendix A**

All data from the Form OE-417R are final.

Formulas and Calculations

Average Heat Content

In order to determine the Btu value per unit of consumption for each of the fossil fuels collected on the Form EIA-759, the heat content values contained on the FERC Form 423 were used. Data on the FERC Form 423 represent approximately 85 percent of the total generator nameplate capacity for all electric utilities.

Percent Difference

The following formula is used to calculate percent differences.

$$\text{Percent Difference} = \left(\frac{x(t_2) - x(t_1)}{x(t_1)} \right) \times 100,$$

where $x(t_1)$ and $x(t_2)$ denote the quantity at year t_1 and subsequent year t_2 .

Form EIA-759

Data for the Form EIA-759 are collected at the plant level. These data are then aggregated to provide geographic totals at the State, Census division, and U.S. level, or totals by type of plant. Consumption of fuel(s) is converted from quantities (in short tons, barrels, or thousand cubic feet) to Btu at the plant level. End-of-month fuel stocks for a single generating plant may not equal beginning-of-the-month stocks, plus receipts, less consumption, for many reasons, including the fact that several plants may share the same fuel stock.

FERC Form 423

Data for the FERC Form 423 are collected at the plant level. These data are then used in the following formulas to produce aggregates and averages for each fuel type at the State, Census division, and U.S. level. For these formulas, receipts and average heat content are at the plant level. For each geographic region, the summation Σ represents the sum of all plants in that geographic region. Additionally,

- For coal, units for receipts (R) are in tons, units for average heat content (A) are in Btu per pound, and the unit conversion (U) is 2,000 pounds per ton;
- For petroleum, units for receipts (R) are in barrels, units for average heat content (A) are in Btu

per gallon, and the unit conversion (U) is 42 gallons per barrel;

- For gas, units for receipts (R) are in thousand cubic feet (Mcf), average heat content (A) are in Btu per cubic foot, and the unit conversion (U) is 1,000 cubic feet per Mcf.

$$\text{Total Btu} = \sum_i (R_i \times A_i \times U),$$

where i denotes a plant; R_i = receipts for plant i ; A_i = average heat content for receipts at plant i ; and, U = unit conversion;

$$\text{Weighted Average Btu} = \frac{\sum_i (R_i \times A_i)}{\sum_i R_i},$$

where i denotes a plant; R_i = receipts for plant i ; and, A_i = average heat content for receipts at plant i .

The weighted average cost in cents (nominal dollars) per million Btu is calculated using the following formula:

$$\text{Weighted Average Cost} = \frac{\sum_i (R_i \times A_i \times U \times C_i)}{\sum_i (R_i \times A_i)},$$

where i denotes a plant; R_i = receipts for plant i ; A_i = average heat content for receipts at plant i ; and, C_i = cost in cents per million Btu for plant i .

The weighted average cost in dollars (nominal dollars) per unit is calculated using the following formula:

$$\text{Weighted Average Cost} = \frac{U \sum_i (R_i \times A_i \times C_i)}{(10^8 \frac{\text{cents}}{\text{dollar}}) \sum_i R_i}$$

where i denotes a plant; R_i = receipts for plant i ; A_i = average heat content for receipts at plant i ; U = unit conversion; and, C_i = cost in cents per million Btu for plant i .

Data on receipts of gas at combined-cycle gas turbines are not directly collected on the FERC Form 423. They are estimated at the plant level by prorating based on Form EIA-759 gas consumption data as follows: $(\text{CCGT}/(\text{CCGT} + \text{CCST} + \text{ST}))$ times total receipts, where CCGT = combined-cycle gas turbines, CCST = combined-cycle steam units, ST = steam units, and receipts = plant level gas receipts.

Form EIA-861

Data for the Form EIA-861 are collected at the utility level from all electric utilities in the United States, its territories, and Puerto Rico. Form EIA-861 data in this publication are for the United States only. These

data are then aggregated to provide geographic totals at the State, NERC region, Census division, and national level. Sources and disposition of data are also provided by utility class of ownership and retail consumer class of service. Average revenue (nominal dollars) per kilowatthour of electricity sold is calculated by dividing total annual retail revenue (nominal dollars) by the total annual retail sales of electricity.

Average revenue per kilowatthour is defined as the cost per unit of electricity sold and is calculated by dividing retail electric revenue by the corresponding sales of electricity. The average revenue per kilowatthour is calculated for all consumers and for each sector (residential, commercial, industrial, and other sales).

Electric utilities typically employ a number of rate schedules within a single sector. These alternative rate schedules reflect the varying consumption levels and patterns of these customers and their associated impact on the costs to the electric utility for providing electrical service. The average revenue per kilowatthour reported in this publication by sector represents a weighted average of customer revenue and sales within that sector and across sectors for all consumers.

The electric revenue used to derive the average revenue per kilowatthour is the operating revenue reported by the electric utility. Operating revenue includes energy charges, demand charges, consumer service charges, environmental surcharges, fuel adjustments, and other miscellaneous charges.

Electric utility operating revenues cover, among other costs of service, State and Federal income taxes and taxes other than income taxes paid by the utility. The Federal component of these taxes are, for the most part, "payroll" taxes. State and local authorities will tax the value of plant (property taxes), the amount of revenues (gross receipts taxes), purchases of materials and services (sales and use taxes), and a potentially long list of other taxes that vary extensively by taxing authority. Taxes deducted from an employee's pay (such as Federal income taxes and the employee's share of social security taxes) are not a part of the utility's "tax costs," but are paid to the taxing authorities in the name of the employees. These taxes are included in the utility's cost of service (for example, revenue requirements) and are included in the amounts recovered from the customer in rates and reported in operating revenues.

Electric utilities, like many other business enterprises, are required by various taxing authorities to collect

and remit taxes assessed on their customers. In this regard, the electric utility serves as an agent for the taxing authority. Taxes assessed on the consumer, such as a gross receipts tax or sales tax, are referred to as "pass through" taxes. These taxes do not represent a cost to the utility and are not recorded in the operating revenues of the utility. However, taxing authorities differ as to whether a specific tax is assessed on the utility or the consumer—which, in turn, determines whether or not the tax is included in the operating revenue of the electric utility.

Data for Demand-Side Management (DSM) activities are aggregated at the NERC region and consumer sector levels. EIA collects information on DSM activities from all utilities with DSM programs. Utilities with sales to ultimate consumers or sales for resale greater than or equal to 120,000 megawatthours report their incremental peakload reductions and energy savings for the reporting year (1993), annual peakload reductions and energy savings for the reporting year and first- and fifth-forecast years (1994 and 1998), and itemized direct and indirect utility costs and nonutility cost attributable to DSM programs for all 3 years. Annual and incremental effects for the reporting year are reported by consumer sector (residential, commercial, industrial, other) for each program category (energy efficiency, direct load control, interruptible load, other load management, other DSM programs, load building). Forecast peak reductions and energy savings are reported by program category with all consumer sectors combined. Utilities with sales to ultimate consumers and sales for resale less than 120,000 megawatthours report incremental peakload reductions and energy savings. They also report total utility cost, total nonutility cost, and total DSM cost for the reporting year and first and fifth forecast years. In years prior to 1992, utilities with sales less than 120,000 megawatthours did not report on DSM activities.

Form EIA-860

Data for the Form EIA-860 are submitted at the generating unit level and are then aggregated to provide totals by energy source and geographic area. In addition, at the national level, data are aggregated by prime mover.

Estimated values for net summer and net winter capability for nonnuclear⁴⁴ electric generating units were developed by use of a regression formula, using year-end 1992 data on net summer capability, net winter capability, and generator nameplate capacity of units in commercial operation during three intervals of time: 1940 or earlier, 1941 through 1980, and 1981 to present.

⁴⁴Respondents report summer and winter capability and nameplate for all nuclear units.

A heterogeneous, zero-intercept linear regression model with generator nameplate capacity as the regressor data was used since examination of the data shows that the intercepts are generally near zero.⁴⁵ In all formulas,

the symbol, *, is an operator meaning multiplied by.

For nonnuclear units,

Net Capability = $b \cdot (\text{Nameplate Capacity})$,

where

b , represents the slope or factor by which nameplate capacity has to be multiplied to obtain a capability estimate, using this model.

σ , represents the standard error for b .

Generator Nameplate Capacity is expressed in kilowatts.

Net Summer Capability

$b = .90$, $\sigma = .04$, 1940 or earlier; $b = .927$, $\sigma = .002$, 1941-1980; $b = .937$, $\sigma = .004$, 1981 through present, for coal steam units (Unit Types, ST, AB, PB)

$b = 1.00$, $\sigma = .03$, 1940 or earlier; $b = .961$, $\sigma = .002$, 1941 - 1980; $b = .93$, $\sigma = .01$, 1981 through present, for noncoal steam units (Unit Types, ST, AB, PB)

$b = .856$, $\sigma = .003$, 1980 or earlier; $b = .85$, $\sigma = .01$, 1981 through present, for gas-turbine units (Unit Types, GT, JE)

$b = .94$, $\sigma = .01$, 1940 or earlier; $b = .84$, $\sigma = .01$, 1941 - 1980; $b = .86$, $\sigma = .02$, 1981 through present, for combined-cycle units (Unit Types, CA, CS, CW, CT, IG)

$b = .884$, $\sigma = .009$, 1940 or earlier; $b = .925$, $\sigma = .002$, 1941 - 1980; $b = .976$, $\sigma = .003$, 1981 through present, for internal combustion units (Unit Type, IC)

$b = .975$, $\sigma = .005$, 1940 or earlier; $b = 1.034$, $\sigma = .004$, 1941 - 1980; $b = .950$, $\sigma = .008$, 1981 through present, for conventional and pipeline hydroelectric units (Unit Types, HC, HL)

$b = .93$, $\sigma = .03$, 1940 or earlier; $b = 1.03$, $\sigma = .01$, 1941 - 1980; $b = 1.01$, $\sigma = .006$, 1981 through present, for pumped-storage hydroelectric units (Unit Type, HR)

$b = 1$, for all other units (Including Unit Types, CG, FC, GE, OC, SP, SS, WT), where limited data are available.

Net Winter Capability

$b = .88$, $\sigma = .05$, 1940 or earlier; $b = .934$, $\sigma = .002$, 1941 - 1980; $b = .940$, $\sigma = .004$, 1981 through present, for coal steam units (Unit Types, ST, AB, PB)

$b = 1.02$, $\sigma = .03$, 1940 or earlier; $b = .965$, $\sigma = .002$, 1941 - 1980; $b = .94$, $\sigma = .01$, 1981 through present, for noncoal steam units (Unit Types, ST, AB, PB)

$b = 1.023$, $\sigma = .004$, 1980 or earlier; $b = .98$, $\sigma = .01$, 1981 through present, for gas-turbine units (Unit Types, GT, JE)

$b = 1.02$, $\sigma = .03$, 1940 or earlier; $b = .96$, $\sigma = .01$, 1941 - 1980; $b = .94$, $\sigma = .02$, 1981 through present, for combined-cycle units (Unit Types, CA, CS, CW, CT, IG)

$b = .893$, $\sigma = .008$, 1940 or earlier; $b = .940$, $\sigma = .002$, 1941 - 1980; $b = .987$, $\sigma = .002$, 1981 through present, for internal combustion units (Unit Type, IC)

$b = .979$, $\sigma = .005$, 1940 or earlier; $b = 1.026$, $\sigma = .004$, 1941 - 1980; $b = .92$, $\sigma = .01$, 1981 through present, for conventional and pipeline hydroelectric units (Unit Types, HC, HL)

$b = .96$, $\sigma = .05$, 1940 or earlier; $b = 1.02$, $\sigma = .01$, 1941 - 1980; $b = 1.03$, $\sigma = .01$, 1981 through present, for pumped-storage hydroelectric units (Unit Type, HR)

$b = 1$, for all other units (Unit Types, FC, GE, OC, SP, SS, WT, CG), where limited data are available.

FERC Form 1

Composite Financial Indicators for Major Investor-Owned Electric Utilities

All financial monetary data in this report are expressed in nominal terms. The following formulas are used to calculate composite financial indicators.

Electric Fixed Asset (Net Plant) Turnover =

$$\frac{\sum_i (EOR_i)}{\sum_i (U_i)} \quad (1)$$

where EOR_i is the Electric Operating Revenue for the i^{th} major utility, and U_i is the Electric Utility Plant -- Net for the i^{th} major utility.

⁴⁵This model is discussed in Knaib, J.R., Jr. (1994), "Relative Standard Error for a Ratio of Variables at an Aggregate Level Under Model Sampling," to appear in the *Proceedings of the Section on Survey Research Methods*, American Statistical Association.

Total Asset Turnover =

$$\frac{\sum_i (OR_i)}{\sum_i (A_i)} \quad (2)$$

where OR_i is the Operating Revenue for the i^{th} major utility, and A_i are the Total Assets for the i^{th} major utility.

Current Assets to Current Liabilities =

$$\frac{\sum_i (CAA_i)}{\sum_i (CAL_i)} \quad (3)$$

where CAA_i are the Current and Accrued Assets for the i^{th} major utility, and CAL_i are the Current and Accrued Liabilities for the i^{th} major utility.

Long-term Debt to Capitalization =

$$\frac{\sum_i (LTD_i)}{\sum_i (C_i)} \times 100, \quad (4)$$

where LTD_i is the Long-term Debt for the i^{th} major utility, and C_i is the Capitalization for the i^{th} major utility.

Preferred Stock to Capitalization =

$$\frac{\sum_i (PS_i)}{\sum_i (C_i)} \times 100, \quad (5)$$

where PS_i is the Preferred Stock for the i^{th} major utility, and C_i is the Capitalization for the i^{th} major utility.

Common Stock Equity to Capitalization =

$$\frac{\sum_i (CSE_i)}{\sum_i (C_i)} \times 100, \quad (6)$$

where CSE_i is the Common Stock Equity of the i^{th} major utility; and, C_i is the Capitalization for the i^{th} major utility.

Total Debt to Total Assets =

$$\frac{\sum_i (LTD_i + STD_i)}{\sum_i (TA_i)} \times 100, \quad (7)$$

where LTD_i is the Long-term Debt of the i^{th} major utility; STD_i is the Short-term Debt of the i^{th} major utility; and, TA_i are the Total Assets of the i^{th} major utility.

Common Stock Equity to Total Assets =

$$\frac{\sum_i (CSE_i)}{\sum_i (TA_i)} \times 100, \quad (8)$$

where CSE_i is the Common Stock Equity of the i^{th} major utility; and, TA_i are the Total Assets of the i^{th} major utility.

Interest Coverage Before Taxes Without AFUDC =

$$\frac{\sum_i (IBI_i + EIT_i + GIT_i + OUIT_i + TOID_i - AC_i)}{\sum_i (IE_i)} \quad (9)$$

where IBI_i is Total Income Before Interest Charges for the i^{th} major utility; EIT_i are the Electric Income Taxes for the i^{th} major utility; GIT_i are the Gas Income Taxes for the i^{th} major utility; $OUIT_i$ are the Other Utility Income Taxes for the i^{th} major utility; $TOID_i$ are the Taxes for Other Income and Deductions for the i^{th} major utility; AC_i is the Allowance for Other Funds Used During Construction for the i^{th} major utility; and, IE_i is the Interest Expense for the i^{th} major utility.

Profit Margin =

$$\frac{\sum_i (NI_i)}{\sum_i (OR_i)} \times 100, \quad (10)$$

where NI_i is the Net Income of the i^{th} major utility; and, OR_i is the Operating Revenue for the i^{th} major utility.

Return on Average Common Stock Equity =

$$\frac{\sum_i (NI_i)}{(\sum_i (CSEB_i) + \sum_i (CSEE_i)) / 2} \times 100,$$

where NI_i is the Net Income of the i^{th} major utility; $CSEB_i$ is the Common Stock Equity at Beginning of Year, for the i^{th} major utility, and $CSEE_i$ is the Common Stock Equity at End of Year

for the i^{th} major utility.

Return on Investment =

$$\frac{\sum_i (NI_i)}{\sum_i (TA_i)} \times 100, \quad (11)$$

where NI_i is the Net Income of the i^{th} major utility; and, TA_i are the Total Assets of the i^{th} major utility.

Composite Financial Indicators for Major Publicly Owned Electric Utilities

Electric Utility Plant per Dollar of Revenue =

$$\frac{\sum_i (EUP_i)}{\sum_i (EOR_i)}, \quad (12)$$

where EUP_i is the Electric Utility Plant for the i^{th} public utility; and, EOR_i is the Electric Operating Revenue for the i^{th} public utility.

Current Assets to Current Liabilities =

$$\frac{\sum_i (CA_i)}{\sum_i (CL_i)}, \quad (13)$$

where CA_i are the Current and Accrued Assets for the i^{th} public utility; and, CL_i are the Current and Accrued Liabilities for the i^{th} public utility.

Electric Utility Plant as a Percent of Total Assets =

$$\frac{\sum_i (EUP_i)}{\sum_i (TA_i)} \times 100, \quad (14)$$

where EUP_i is the Electric Utility Plant for the i^{th} public utility; and, TA_i are the Total Assets for the i^{th} public utility.

Net Electric Utility Plant as a Percent of Total Assets =

$$\frac{\sum_i (NEUP_i)}{\sum_i (TA_i)} \times 100, \quad (15)$$

where $NEUP_i$ is the Net Electric Utility Plant for the i^{th} public utility; and, TA_i is the Total Assets for the i^{th} public utility.

Debt as a Percent of Total Liabilities =

$$\frac{\sum_i (D_i)}{\sum_i (TL_i)} \times 100, \quad (16)$$

where D_i is the Debt for the i^{th} public utility; and, TL_i is the Total Liabilities for the i^{th} public utility.

Accumulated Provision for Depreciation as a Percent of Electric Utility Plant =

$$\frac{\sum_i (APD_i)}{\sum_i (EUP_i)} \times 100, \quad (17)$$

where APD_i is the Accumulated Provision for Depreciation for the i^{th} public utility; and, EUP_i is the Electric Utility Plant for the i^{th} public utility.

Electric Operation and Maintenance Expenses as a Percent of Electric Operating Revenue =

$$\frac{\sum_i (EOME_i)}{\sum_i (EOR_i)} \times 100, \quad (18)$$

where $EOME_i$ is the Electric Operation and Maintenance Expenses for the i^{th} public utility; and, EOR_i is the Electric Operating Revenue for the i^{th} public utility.

Electric Depreciation and Amortization as a Percent of Electric Operating Revenue =

$$\frac{\sum_i (EDA_i)}{\sum_i (EOR_i)} \times 100, \quad (19)$$

where EDA_i is Electric Depreciation and Amortization for the i^{th} public utility; and, EOR_i is the Electric Operating Revenue for the i^{th} public utility.

Taxes and Tax Equivalents as a Percent of Electric Operating Revenue =

$$\frac{\sum_i (TTE_i)}{\sum_i (EOR_i)} \times 100, \quad (20)$$

where TTE_i are the Taxes and Tax Equivalents for the i^{th} public utility; and, EOR_i is the Electric Operating Revenue for the i^{th} public utility.

Interest Expense as a Percent of Electric Operating Revenue =

$$\frac{\sum_i (IE_i)}{\sum_i (EOR_i)} \times 100, \quad (21)$$

where IE_i is the Interest Expense for the i^{th} public utility; and, EOR_i is the Electric Operating Revenue for the i^{th} public utility.

Net Income as a Percent of Electric Operating Revenues =

$$\frac{\sum_i (NI_i)}{\sum_i (EOR_i)} \times 100, \quad (22)$$

where NI_i is the Net Income of the i^{th} public utility; and, EOR_i is the Electric Operating Revenue for the i^{th} public utility.

Air Emissions

This section describes the methodology employed to calculate estimates of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon dioxide (CO_2) emissions from utility and nonutility electric generating plants.

Utility Air Emissions

The following describes the methodology employed to calculate estimates of SO_2 , NO_x , and CO_2 emissions from power plants operated by electric utilities. These air emissions are estimated using information contained on Form EIA-767, "Steam-Electric Plant Operation and Design Report." Form EIA-767 collects information annually for all U.S. power plants with a total existing or planned organic- or nuclear-fueled steam-electric generator nameplate rating of 10 megawatts (MW) or larger. Power plants with a total generator nameplate rating of 100 MW or more must complete the entire form, providing, among other things, information about fuel consumption and quality, legal air emission limits, and flue gas desulfurization (FGD) efficiency. Power plants with a total generator nameplate

rating from 10 MW to less than 100 MW complete only part of the form, including information on fuel consumption and FGD sulfur removal efficiency, if applicable.

Uncontrolled Air Pollutant Emissions. Uncontrolled air pollutant emissions are those emissions that would occur in the absence of any control equipment. Uncontrolled SO_2 , NO_x , and CO_2 emissions are determined by multiplying the quantity of fuel burned by an emission factor. An emission factor is the average quantity of a pollutant released from a boiler when a unit of fuel is burned.

The source of the SO_2 and NO_x emission factors, when available, is the Environmental Protection Agency report AP-42, "Compilation of Air Pollutant Emission Factors" (Table C3).⁴⁶ Environmental Protection Agency emission factors are based on boiler type, firing configuration, and fuel burned. The methodology for determining emissions of CO_2 has been revised since the 1991 publication. Emissions of carbon dioxide for 1992 and prior years have been revised using the set of factors shown in Tables C3 and C4.

In 1992, a special study of the relationship between the heat and carbon content of coal was completed by the Energy Information Administration's Analysis and Systems Division of the Office of Coal, Nuclear, Electric and Alternate Fuels. The hypothesis underlying this study was that the ratio of carbon-to-heat content varies not only by coal rank (i.e., anthracite, bituminous, subbituminous, and lignite), but also by geographic location of the coal. In this study, the hypothesis was tested and the results of the analysis supported the hypothesis. That is, it was concluded from the analysis that coal rank and location of the coal are significant factors in the variation of the ratio of carbon-to-heat content. After this determination, a set of conversion factors, by rank and State were derived on the basis of data contained in EIA's Coal Analysis File.⁴⁷

In editions prior to 1992 of this publication, separate conversion factors by coal rank were published and used to estimate emissions of CO_2 . The special study by EIA concluded that since geographic location of coal in addition to rank of coal is a significant factor in determining the carbon/heat content relationship, the use of emission factors that consider both of these elements may yield more accurate estimates of CO_2 emissions. The emission factors for coal were developed in the units of pounds of CO_2 per million Btu of coal.

The emission factors for CO_2 (Table C4) from coal are applied by power plant, based on the rank, amount of coal received, and the State from which the coal orig-

⁴⁶ "Supplement A to Compilation of Air Pollutant Emission Factors, Vol. 1: Stationary Point and Area Sources," Research Triangle Park, North Carolina, October 1986.

⁴⁷ For a description of EIA's Coal Analysis File, refer to "Analysis of the Relationship between the Heat and Carbon Content," EIA/CNEAF, September 1992.

inated, as reported in FERC Form 423, "Cost and Quality of Fuels for Electric Utility Plants." Thus, a weighted average emissions factor is obtained by plant and multiplied by the quantity of coal consumed by plant, as reported on Form EIA-767, "Steam-Electric Plant Operation and Design Report," to determine the emissions of CO₂. The emission factors for CO₂ assume 100-percent combustion of the carbon in the fuel. Since a small percentage of the carbon in the coal is not converted to CO₂, this publication assumes 99 percent combustion. The 1 percent of emissions is deducted at the State/National level. The emissions at the State level are based on the State in which the plant is located.

Uncontrolled emissions of SO₂ and NO_x do not always accurately depict the quantity of emissions released into the atmosphere because they fail to reflect reductions from control equipment and/or operating technologies. Consequently, controlled emissions are calculated to provide a more accurate estimate of actual utility air emission.

Controlled Sulfur Dioxide Emissions. Because of environmental regulations controlling SO₂ emissions, many utilities are required to install FGD units at their coal-fired plants.⁴⁸ FGD units typically remove between 70 to 90 percent of SO₂ from the boiler flue gas although higher removal efficiencies can be achieved. Electric utilities report both sulfur removal efficiency (percent) and their most stringent SO₂ emission limits on the Form EIA-767. To determine controlled SO₂ emissions, the uncontrolled emissions are reduced by the annual average removal efficiencies reported on the Form EIA-767. This emission is the controlled emission. As a check, the controlled emission is compared with the most stringent legal limit reported on the Form EIA-767. The controlled emission should be less than the legal limit because research indicates that utilities routinely remove more SO₂ than required to assure an operating margin of safety. If the controlled emission is not less than the most stringent legal limit, it implies that the utility is out of legal compliance and could be subject to fines and other penalties.

Utilities are permitted to take credit for sulfur that remains in bottom ash -- ash remaining in the bottom of the furnace after the coal is burned. For example, if a utility is required to remove 90 percent of the sulfur in the coal and 3 percent remains in the ash, it has to remove only 87 percent using scrubbers. This credit is included in emissions data in this report. It is likely, however, that in many cases the credit is not taken. In order to take the ash credit, utilities need to monitor the coal consumed on a daily basis; this is both time-consuming and costly. To the extent that utilities do not take the ash credit, emissions might be slightly overstated.

Controlled Nitrogen Oxide Emissions. The controlled NO_x emission is calculated by applying the appropriate reduction factor in Table C5. For utility boilers with regulated nitrogen oxide emission limits, the annual controlled estimate used is the lesser of the controlled estimate or the annual limitation. When more than one control technology is reported, the highest single reduction factor is used to estimate the annual controlled NO_x emission.

Carbon Dioxide Emissions. There are no Federal regulations that limit CO₂ emissions. Information pertinent to the estimation of controlled CO₂ emissions is not collected on the Form EIA-767; therefore, no estimates of controlled CO₂ emissions are made.

A degree of complexity is added to this approach, however, because air emission standards are not reported in consistent units. In some rare instances, emission standards are reported in units that cannot be directly compared with estimated uncontrolled emission rates. Examples of such standards are ones that specify the concentration of NO_x allowed in the flue gas or the ambient concentration of NO_x (parts per million). In cases where these types of standards are reported, the uncontrolled emission estimate is used. Such standards are uncommon, however, and do not significantly affect the results.

Air Emissions from Small Plants. The Form EIA-767 does not collect data for generators powered by internal combustion engines, gas turbines, combined cycle units (for example, gas turbines with waste heat boilers), and boilers at steam-electric plants with a total nameplate capacity of less than 10 MW. Accordingly, utility air emission from these generators are not estimated by the methodology. An estimate of air emissions from these generating units based on a similar methodology using 1991 fuel consumption data reported on the Form EIA-759, "Monthly Power Plant Report," was performed. Results of this effort indicate that emissions of SO₂, NO_x, and CO₂ from utility sources not included on the Form EIA-767, are less than 0.1, 1.2, and 1.1 percent, respectively, of total utility air emissions.

Nonutility Air Emissions

The following describes the methodology employed to calculate estimates of SO₂, NO_x, and CO₂ emissions from power plants operated by nonutilities. The emissions are estimated using information contained on Form EIA-867, "Annual Nonutility Power Producer Report." Form EIA-867 collects information annually from all nonutility power producers with a total generator nameplate rating of 1 megawatt (MW) or more, including cogenerators, small power producers, and other nonutility electricity generators. Facilities

⁴⁸Flocc gas desulfurization units may also reduce sulfur dioxide emissions from plants that burn oil and petroleum coke.

with a total generator nameplate rating of 1 MW or more must complete the entire form, providing, among other things, information about fuel consumption and quality. Facilities with a combined nameplate capacity of less than 25 megawatts are not required to complete Schedule V "Facility Environmental Information" of the Form EIA-867.

Uncontrolled Emissions. Uncontrolled air pollutant emissions are those emissions that would occur in the absence of any control equipment. Uncontrolled SO₂, NO_x, and CO₂ emissions are determined by multiplying the quantity of fuel burned by an emission factor. An emission factor is the average quantity of a pollutant released from a boiler when a unit of fuel is burned. As with electric utilities, the source of both the SO₂ and NO_x emission factors, when available, is the Environmental Protection Agency report AP-42, "Compilation of Air Pollutant Emission Factors."⁴⁹ However, the boiler type and firing configuration are not reported on the Form EIA-867 so all boilers are assumed to be large boilers⁵⁰ with pulverized coal firing and dry bottoms. For other types of prime movers (for example, gas turbines, combined cycle, and internal combustion engines) the same set of emission factors are used.

The methodology for determining emissions of CO₂ from nonutility electric power plants has been revised. The new methodology uses the results of the coal study discussed under "Utility Air Emissions." Based on the coal rank, the quality of coal received and its State of origin, weighted average emission factors are determined by State for electric utility plants. It is assumed that nonutility plants located in the same State as utility plants obtain coal from the same State. The weighted emission factors by State for utility coal-fired plants are multiplied by the coal consumption reported for nonutility plants in the respective State on Form EIA-867.

Uncontrolled emissions of SO₂ and NO_x do not always accurately depict the quantity of emissions released into the atmosphere because they fail to reflect reductions from control equipment and operating technologies. Consequently, controlled emissions are calculated to provide a more accurate estimate of actual nonutility air emissions.

Controlled Sulfur Dioxide Emissions. The Clean Air Act of 1971 established Federal emission limits for new fossil-fueled steam generators -- 1.2 pounds of SO₂ per million Btu of solid fossil fuel consumed and 0.8 pounds for liquid fossil fuels. The Clean Air Act of 1978 established even more stringent sulfur dioxide emission limits. The revised law mandates the installation of flue gas desulfurization (FGD) equipment at some new in-

dustrial and commercial facilities built after June 19, 1984, and requires that these facilities remove 90 percent of the SO₂ in the flue gases. Nonutilities report whether they have FGD equipment at their facilities and the date of first electrical generation on the Form EIA-867. Air emission limits are based on the date construction began. It is assumed that it takes two years from the start of construction to the date of first electrical generation as reported on the form.

Controlled SO₂ emissions are calculated for respondents reporting FGD equipment or fluidized bed combustion. For facilities reporting first electrical generation before August 1973, no reductions are assumed. For facilities reporting first electrical generation between August 1973 and June 1986, the controlled emission is estimated as the lesser of either: the uncontrolled emission, or a weighted average of 1.2 and 0.8 pounds of SO₂ per million Btu of solid and liquid fossil fuel consumed, respectively. For facilities reporting first electrical generation after June 1986, the controlled emission is estimated as the lesser of either: the uncontrolled emission reduced by 90 percent, or a weighted average of 1.2 and 0.8 pounds of SO₂ per million Btu of solid and liquid fossil fuel consumed, respectively.

Facilities with a total nameplate rating between 5 MW and 25 MW are not required to report whether they have FGD units. Controlled SO₂ emissions for these facilities are calculated based on the year electricity was first generated at the facility as reported on the Form EIA-867. For facilities reporting electrical generation before August 1973, no control equipment is assumed and the controlled SO₂ emission is equal to the uncontrolled emission as calculated above. For facilities reporting the date of their first electrical generation as between August 1973 and August 1980, the controlled SO₂ emission is estimated as the lesser of either: the uncontrolled SO₂ emission, or 1.2 pound of SO₂ per million Btu of fuel consumed. For facilities reporting their first electrical generation after August 1980, the controlled SO₂ emission is estimated as the lesser of either: the uncontrolled emission reduced by 80 percent, or 1.2 pounds of sulfur dioxide per million Btu of fuel consumed.

Controlled Nitrogen Oxide Emissions. Nonutilities with a total facility nameplate rating of 25 MW or more are required to report on the Form EIA-867 whether they have any NO_x control equipment and its type. Controlled NO_x emissions estimates are based on assumed removal efficiencies for the different types of NO_x control equipment. The percent removal efficiencies of the NO_x control equipment and/or operating technologies are shown in Table C4.

⁴⁹ "Supplement A to Compilation of Air Pollutant Emission Factors, Vol. I: Stationary Point and Area Sources," Research Triangle Park, North Carolina, October 1986.

⁵⁰ Boilers with a gross heat rate of 100 million Btu per hour or greater.

The controlled NO_x emission is calculated by reducing the uncontrolled emission by the appropriate reduction percentage based on the NO_x technology. In cases where more than one type of technology is reported, the highest single reduction percentage of the equipment reported is applied.

Facilities with a total nameplate rating between 5 MW and 25 MW are not required to report whether they have NO_x reduction equipment. However, the Clean Air Act limits NO_x emissions to 0.8 pounds per million Btu of fuel consumed. Controlled NO_x emissions for these facilities are calculated based on the year electricity was first generated at the facility as reported on the Form EIA-867. For facilities reporting electrical generation before August 1973, no control equipment is assumed and the controlled NO_x emission is estimated to be equal to the uncontrolled emission as calculated above. For facilities reporting the first date of electrical generation after August 1973, the controlled NO_x emission is estimated as the lesser of either: the uncontrolled NO_x emission, or 0.8 pounds of NO_x per million Btu of fuel consumed.

Controlled Carbon Dioxide Emissions. There are no Federal regulations that limit CO₂ emissions. Information pertinent to the estimation of controlled CO₂ emissions is not collected on the Form EIA-867; therefore, no estimates of controlled CO₂ emissions are provided.

General Information

Use of the Glossary

The terms in the glossary have been defined for general use. Restrictions on the definitions as used in these data collection systems are included in each definition when necessary to define the terms as they are used in this report.

Obtaining Copies of Data

These data are available on machine-readable tapes. Tapes may be purchased by using Visa, MasterCard, or American Express cards as well as money orders or checks payable to the National Technical Information Service (NTIS). Purchasers may also use NTIS and Government Printing Office depository accounts. To place an order, contact:

National Technical Information Service (NTIS)
Office of Data Base Services
U.S. Department of Commerce
5285 Port Royal Road
Springfield, Virginia 22161
(703) 487-4650

Table C1. Installed Capacity at U.S. Nonutility Generating Facilities by Producing Energy Group and Census Division, 1989 Through 1993
(Megawatts)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
1983 (1 Megawatt or More)							
New England	1,692	2,919	W	—	W	—	4,729
Middle Atlantic	2,845	5,408	295	—	W	W	8,730
East North Central	3,015	2,141	267	W	W	W	5,548
West North Central	702	184	185	W	W	W	1,261
South Atlantic	5,715	4,405	84	W	W	61	10,303
East South Central	1,878	18	W	W	W	—	1,734
West South Central	10,175	2,512	203	180	—	—	13,069
Mountain	431	969	77	245	—	278	2,020
Pacific	3,541	8,137	236	1,142	239	91	13,385
U.S. Total	29,992	26,714	1,444	1,990	287	571	60,778
1992 (1 Megawatt or More)							
New England	2,120	2,167	W	—	W	—	4,404
Middle Atlantic	5,112	1,395	410	W	W	162	7,379
East North Central	4,864	259	239	W	W	W	5,449
West North Central	695	W	138	W	W	W	1,224
South Atlantic	6,371	2,824	150	W	W	51	9,443
East South Central	1,487	W	W	W	W	—	1,535
West South Central	11,865	442	189	180	—	—	12,680
Mountain	748	474	157	197	—	278	1,852
Pacific	4,342	8,200	239	1,580	326	182	12,848
U.S. Total	37,612	15,961	1,642	2,413	483	713	56,814
1991 (5 Megawatts or More)							
New England	1,925	1,898	33	—	—	—	3,856
Middle Atlantic	3,328	884	184	W	W	162	4,940
East North Central	4,627	109	193	W	—	W	5,033
West North Central	607	W	130	W	—	—	1,103
South Atlantic	5,474	1,587	124	—	W	W	7,283
East South Central	1,468	W	—	—	W	—	1,469
West South Central	11,291	464	W	W	—	—	12,056
Mountain	483	318	W	W	—	258	1,292
Pacific	3,558	W	W	W	W	W	11,138
U.S. Total	32,767	10,948	1,111	2,129	466	693	48,171
1990 (5 Megawatts or More)							
New England	1,558	W	W	—	—	—	3,218
Middle Atlantic	2,387	727	132	W	W	162	3,595
East North Central	4,650	109	185	W	—	W	5,040
West North Central	551	W	W	W	—	—	889
South Atlantic	4,968	916	W	—	W	W	5,980
East South Central	1,250	W	—	—	W	—	1,273
West South Central	10,990	464	W	W	—	—	11,765
Mountain	249	254	W	W	—	258	978
Pacific	3,382	W	W	W	315	W	10,150
U.S. Total	29,946	8,937	889	1,985	462	670	42,869
1989 (5 Megawatts or More)							
New England	1,208	W	W	—	—	—	2,333
Middle Atlantic	2,082	531	76	W	W	W	2,874
East North Central	3,220	109	182	W	—	W	3,607
West North Central	554	W	W	W	—	—	872
South Atlantic	4,263	460	W	—	W	W	4,824
East South Central	1,100	W	—	—	W	—	1,129
West South Central	10,453	361	W	W	—	—	11,124
Mountain	240	194	W	W	—	W	829
Pacific	3,078	W	W	1,125	315	W	8,963
U.S. Total	26,190	7,698	777	1,716	462	452	38,845

W = Withheld to avoid disclosure of individual company data.

Notes: *Data shown in Table C1 are based on the facility's consumption. *Data for 1993 are preliminary; data for prior years are final. *See Technical Notes for Standard Industrial Classifications for these industry groups. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

Table C2. Gross Generation by U.S. Nonutility Power Producers by Producing Energy Group and Census Division, 1980 Through 1993
(Million Kilowatthours)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
1980 (1 Megawatt or More)							
New England	9,839	17,930	466	—	—	—	28,229
Middle Atlantic	16,468	30,513	W	—	—	W	46,706
East North Central	14,763	3,981	958	W	W	W	26,211
West North Central	2,989	341	403	W	W	W	4,675
South Atlantic	32,412	10,769	159	W	W	W	43,620
East South Central	10,531	72	W	W	W	—	10,741
West South Central	61,708	16,627	611	1,127	—	—	80,073
Mountain	2,449	5,701	W	623	—	W	9,672
Pacific	20,704	41,692	1,407	7,720	1,530	246	73,400
U.S. Total	171,845	133,627	5,541	10,689	1,767	1,757	325,226
1982 (1 Megawatt or More)							
New England	12,165	13,444	461	—	—	—	26,071
Middle Atlantic	27,682	7,930	2,329	W	W	1,124	40,880
East North Central	21,538	1,368	750	W	W	W	24,358
West North Central	2,758	W	W	W	W	W	4,371
South Atlantic	31,230	6,739	536	W	W	W	38,804
East South Central	9,772	W	W	W	W	—	9,962
West South Central	73,635	1,687	601	1,116	—	—	77,050
Mountain	3,564	2,156	837	W	—	W	7,455
Pacific	24,944	27,293	1,477	10,688	2,091	629	67,040
U.S. Total	207,769	66,415	7,389	14,923	3,193	2,922	296,001
1991 (5 Megawatts or More)							
New England	9,513	10,870	164	—	—	—	20,347
Middle Atlantic	16,413	4,376	844	W	W	1,158	24,886
East North Central	19,332	791	610	W	—	W	21,424
West North Central	2,587	W	W	W	—	—	3,316
South Atlantic	27,959	4,401	131	—	W	W	32,773
East South Central	6,683	W	—	—	W	—	9,013
West South Central	69,739	2,288	W	W	—	—	73,404
Mountain	2,280	1,705	W	W	—	515	5,442
Pacific	20,766	24,066	W	W	1,864	W	57,843
U.S. Total	177,472	48,562	4,597	12,369	2,966	2,499	245,448
1990 (5 Megawatts or More)							
New England	7,453	W	W	—	—	—	14,412
Middle Atlantic	12,078	3,907	354	W	W	433	17,425
East North Central	19,033	783	577	W	—	W	20,843
West North Central	2,225	W	W	—	—	—	2,641
South Atlantic	24,686	3,122	W	—	W	W	28,024
East South Central	7,947	W	—	—	W	—	8,065
West South Central	65,775	1,950	W	W	—	—	68,188
Mountain	1,517	1,331	W	W	—	545	4,313
Pacific	18,905	W	W	W	2,069	W	52,919
U.S. Total	159,522	39,635	3,489	11,040	2,847	1,706	217,241
1989 (5 Megawatts or More)							
New England	5,076	W	W	—	—	—	10,812
Middle Atlantic	10,023	2,314	292	W	W	W	13,634
East North Central	12,607	650	617	W	—	W	14,030
West North Central	1,728	W	W	—	—	—	1,939
South Atlantic	24,252	2,184	W	—	W	W	26,720
East South Central	7,014	W	—	—	W	—	7,100
West South Central	69,263	W	512	W	—	—	69,756
Mountain	1,534	886	W	W	—	W	3,548
Pacific	16,558	W	W	6,142	1,471	W	42,417
U.S. Total	142,058	31,088	3,046	6,197	1,876	1,867	167,856

W = Withheld to avoid disclosure of individual company data.

Notes: *Data shown in Table C2 are based on the facility's consumption. *Data for 1993 are preliminary; data for prior years are final. *See Technical Notes for Standard Industrial Classifications for these industry groups. *Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

Table C3. Sulfur Dioxide, Nitrogen Oxide, and Carbon Dioxide Emission Factors

Fuel	Boiler Type/ Firing Configuration	Emission Factors		
		Sulfur Dioxide ¹	Nitrogen Oxides ²	Carbon Dioxide ³
Utility				
Coal and Other Solid Fuels		lbs per ton	lbs per ton	lbs per ton
Bituminous ⁴	cyclone	38.00 x S	33.8	See Table C4
	fluidized bed ⁵	39.60 x S	9.6	See Table C4
	spreader stoker	39.00 x S	13.7	See Table C4
	tangential	38.00 x S	14.4	See Table C4
	all others	38.00 x S	21.7(34)	See Table C4
Subbituminous ⁴	cyclone	35.00 x S	33.8	See Table C4
	fluidized bed ⁵	39.60 x S	9.6	See Table C4
	spreader stoker	35.00 x S	13.7	See Table C4
	tangential	35.00 x S	14.4	See Table C4
	all others	35.00 x S	21.7(34)	See Table C4
Lignite ⁴	cyclone	30.00 x S	12.50	See Table C4
	fluidized bed ⁵	30.00 x S	9.60	See Table C4
	front/opposed	30.00 x S	11.10	See Table C4
	spreader stoker	30.00 x S	5.80	See Table C4
	tangential	30.00 x S	7.90	See Table C4
	all others	30.00 x S	11.10	See Table C4
Petroleum Coke ⁴	fluidized bed ⁵	39.00 x S	1.80	5,680
	all others	39.00 x S	16.00	5,680
Refuse	all types	3.48	2.89	2,344
Wood	all types	0.08	1.50	2,100
Petroleum and Other Liquid Fuels		lbs per 10 ³ gal	lbs per 10 ³ gal	lbs per 10 ³ gal
Residual Oil ⁷	tangential	162.7 x S	42.00	25,445
	vertical	162.7 x S	67.00	25,445
	all others	162.7 x S	67.00	25,445
Distillate Oil ⁷	all types	144.00 x S	20.00	22,572
Methanol	all types	0.05	12.40	7,603
Propane (liquid)	all types	0.05	19.00	12,500
Coal-Oil Mixture	all types	185.00 x S	50.00	22,388
Natural Gas and Other Gaseous Fuels		lbs per 10 ³ cf	lbs per 10 ³ cf	lbs per 10 ³ cf
Natural Gas	tangential	0.60	275.00	120,000
	all others	0.60	550.00	120,000
Blast Furnace Gas	all types	0.60	550.00	120,000
Modularity				
Coal and Other Solid Fuels		lbs per ton	lbs per ton	lbs per ton
Anthracite Culf	all types	39.00 x S	9.00	See Table C4
Bituminous ⁴	all types	38.00 x S	21.70	See Table C4
Bituminous Gob	all types	38.00 x S	21.70	See Table C4
Subbituminous	all types	35.00 x S	21.70	See Table C4
Lignite ⁴	all types	30.00 x S	11.10	See Table C4
Lignite Waste	all types	30.00 x S	11.10	See Table C4
Peat	all types	30.00 x S	11.10	See Table C4
Agricultural Waste	all types	0.08	1.20	1,560
Black Liquor	all types	7.00	1.50	2,725
Chemicals	all types	7.00	1.50	2,725
Closed Loop Biomass	all types	0.08	1.50	2,100
Internal	all types	0.08	1.50	2,100

See footnotes at end of table.

Table C3. Sulfur Dioxide, Nitrogen Oxide, and Carbon Dioxide Emission Factors—Continued

Fuel	Boiler Type/ Firing Configuration	Emission Factors		
		Sulfur Dioxide ¹	Nitrogen Oxides ²	Carbon Dioxide ³
Coal and Other Solid Fuels (Continued)		lbs per ton	lbs per ton	lbs per ton
Liquid Acetonitrile Waste	all types	7.00	1.50	2,725
Liquid Waste	all types	7.00	1.50	2,725
Municipal Solid Waste	all types	3.46	2.69	2,344
Petroleum Coke ⁴	all types	39.00 x S	18.00	5,680
Pitch	all types	30.00 x S	11.10	See Table C4
Railroad Ties	all types	0.08	1.50	2,100
Red Liquor	all types	7.00	1.50	2,725
Sludge	all types	2.80	8.60	2,100
Sludge Waste	all types	2.80	8.60	2,100
Sludge Wood	all types	2.80	8.60	2,100
Spent Sulfite Liquor	all types	7.00	1.50	2,725
Straw	all types	0.08	1.50	2,100
Sulfur	all types	7.00	0.00	0
Tar Coal	all types	30.00 x S	11.10	See Table C4
Tires	all types	38.00 x S	21.70	5,715
Waste Byproducts	all types	3.46	2.69	2,344
Waste Coal	all types	38.00 x S	21.70	See Table C4
Wood/Wood Waste	all types	0.08	1.50	2,100
Petroleum and Other Liquid Fuels		lbs per 10 ³ gal	lbs per 10 ³ gal	lbs per 10 ³ gal
Heavy Oil ⁵	all types	162.7 x S	67.00	25,445
Light Oil ⁶	all types	162.70 x S	20.00	22,572
Diesel	all types	162.70 x S	20.00	22,572
Kerosene	all types	162.70 x S	20.00	22,572
Butane (liquid)	all types	0.60	21.00	14,700
Fish Oil	all types	0.50	12.40	7,603
Methanol	all types	0.50	12.40	7,603
Oil Waste	all types	17.6 x S	2.30	20,000
Propene (liquid)	all types	0.50	19.00	12,500
Sludge Oil	all types	17.6 x S	2.30	20,000
Tar Oil	all types	162.70 x S	67.00	25,445
Waste Alcohol	all types	0.50	12.40	7,603
Natural Gas and Other Gaseous Fuels		lbs per 10 ³ cf	lbs per 10 ³ cf	lbs per 10 ³ cf
Natural Gas	all types	0.60	550.00	120,000
Butane (gas)	all types	0.60	550.00	479,450
Hydrogen	all types	0.00	550.00	0
Landfill Gas	all types	0.60	550.00	120,000
Methane	all types	0.60	550.00	116,438
Other Gas	all types	0.60	550.00	120,000
Propane (gas)	all types	0.60	550.00	358,333

¹ Uncontrolled sulfur dioxide emission factors. "x S" indicates that the constant must be multiplied by the percentage (by weight) of sulfur in the fuel. Sulfur dioxide emission estimates from facilities with flue gas desulfurization equipment are calculated by multiplying uncontrolled emission estimates by one minus the reported sulfur removal efficiencies. Sulfur dioxide emission factors also account for small quantities of sulfur trioxide and gaseous sulfates.

² Parenthetical values are for wet bottom boilers; otherwise dry bottom boilers. Emission factors are for boilers with a gross heat rate of 100 million Btu per hour or greater. See Table C5 for nitrogen oxide reduction factors used to calculate controlled nitrogen oxide emission estimates.

³ Uncontrolled carbon dioxide emission estimates are reduced by 1 percent to account for unburned carbon.

⁴ Coal types are categorized by Btu content as follows: bituminous (greater than or equal to 8,750 Btu per pound), subbituminous (equal to 7,500 to 8,750 Btu per pound), and lignite (less than 7,500 Btu per pound).

⁵ Sulfur dioxide emission estimates from fluidized bed boilers assume a sulfur removal efficiency of 90 percent.

⁶ Emission factors for petroleum coke are assumed to be the same as those for anthracite. If the sulfur content of petroleum coke is unknown, a 6 percent sulfur content is assumed.

⁷ Oil types are categorized by Btu content as follows: heavy (greater than or equal to 144,190 Btu per gallon), and light (less than 144,190 Btu per gallon).

cf = Cubic Feet.

gal = U.S. Gallons.

lbs = Pounds.

Sources: *For sulfur dioxide and nitrogen oxide factors: Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources*, Fourth Edition, Research Triangle Park, North Carolina, July 1993. *For carbon dioxide factors: Department of Energy, "Carbon Dioxide Emissions from Fossil Fuels: A Procedure for Estimation of Results, 1950-1981," June 1983.

Table C4. Carbon Dioxide Emission Factors For Coal by Rank and State of Origin

Rank	State of Origin	Factors (Pounds per Million Btu)
Anthracite	Pennsylvania	227.38
Bituminous	Alabama	205.48
Bituminous	Arizona	209.68
Bituminous	Arkansas	211.60
Bituminous	Colorado	206.21
Bituminous	Illinois	203.51
Bituminous	Indiana	203.64
Bituminous	Iowa	201.57
Bituminous	Kansas	202.79
Bituminous	Kentucky: East	204.60
Bituminous	Kentucky: West	203.23
Bituminous	Maryland	210.16
Bituminous	Missouri	201.31
Bituminous	Montana	209.62
Bituminous	New Mexico	206.71
Bituminous	Ohio	202.64
Bituminous	Oklahoma	205.93
Bituminous	Pennsylvania	206.72
Bituminous	Tennessee	204.79
Bituminous	Utah	204.08
Bituminous	Virginia	206.23
Bituminous	Washington	203.52
Bituminous	West Virginia	207.10
Bituminous	Wyoming	206.46
Bituminous	Texas	204.39
Subbituminous	Alaska	214.00
Subbituminous	Colorado	212.72
Subbituminous	Iowa	200.79
Subbituminous	Missouri	201.31
Subbituminous	Montana	213.42
Subbituminous	New Mexico	208.64
Subbituminous	Utah	207.09
Subbituminous	Washington	208.69
Subbituminous	Wyoming	212.71
Lignite	Arkansas	213.54
Lignite	California	216.31
Lignite	Louisiana	213.54
Lignite	Montana	220.59
Lignite	North Dakota	218.76
Lignite	South Dakota	216.97
Lignite	Texas	213.54
Lignite	Washington	211.68
Lignite	Wyoming	216.69

Source: Energy Information Administration, Office of Coal, Nuclear, Electric, and Alternate Fuels.

Table C5. Nitrogen Oxide Reduction Factors

Nitrogen Oxide Control Technology	EIA-767 Code(s)	EIA-867 Code(s)	Reduction Factor (Percent)
Advanced Overfire Air	AA	--	40
Alternate Burners	BF	--	20
Flue Gas Recirculation	FR	FG	40
Fluidized Bed Combustor	CF	-	20
Fuel Reburning	FU	--	30
Low Excess Air	LA	LE	20
Low Nitrogen Oxide Burners	LN	LN	40
Other (or Unspecified)	OT	OT	20
Overfire Air	OV	OA	30
Selective Catalytic Reduction	SR	CC	70
Selective Catalytic Reduction With Low Nitrogen Oxide Burners	SR and LN	CC and LN	90
Selective Noncatalytic Reduction	SN	-	30
Selective Noncatalytic Reduction With Low Nitrogen Oxide Burners	SN and LN	--	50
Stagging	SC	-	20
Steam or Water Injection	-	SW	20

Source: Babcock and Wilcox, *Steam Its Generation and Use*, 40th Edition, 1992

Table C6. Unit-of-Measure Equivalents

Unit	Equivalent		
Kilowatt (kW)	1,000	(One Thousand)	Watts
Megawatt (MW)	1,000,000	(One Million)	Watts
Gigawatt (GW)	1,000,000,000	(One Billion)	Watts
Terawatt (TW)	1,000,000,000,000	(One Trillion)	Watts
Gigawatt	1,000,000	(One Million)	Kilowatts
Thousand Gigawatts	1,000,000,000	(One Billion)	Kilowatts
Kilowatthours (kWh)	1,000	(One Thousand)	Watthours
Megawatthours (MWh)	1,000,000	(One Million)	Watthours
Gigawatthours (GWh)	1,000,000,000	(One Billion)	Watthours
Terawatthours (TWh)	1,000,000,000,000	(One Trillion)	Watthours
Gigawatthours	1,000,000	(One Million)	Kilowatthours
Thousand Gigawatthours	1,000,000,000	(One Billion)	Kilowatthours
U.S. Dollar	1,000	(One Thousand)	Mills
U.S. Cent	10	(Ten)	Mills

Source: Energy Information Administration, Survey Management Division

Glossary

Acid Rain: Also called acid precipitation or acid deposition, acid rain is precipitation containing harmful amounts of nitric and sulfuric acids formed primarily by nitrogen oxides and sulfur oxides released into the atmosphere when fossil fuels are burned. It can be wet precipitation (rain, snow, or fog) or dry precipitation (absorbed gaseous and particulate matter, aerosol particles or dust). Acid rain has a pH below 5.6. Normal rain has a pH of about 5.6, which is slightly acidic. The term pH is a measure of acidity or alkalinity and ranges from 0 to 14. A pH measurement of 7 is regarded as neutral. Measurements below 7 indicate increased acidity, while those above indicate increased alkalinity.

Actual Peak Reduction: The actual reduction in annual peak load (measured in kilowatts) achieved by consumers that participate in a utility DSM program. It reflects the changes in the demand for electricity resulting from a utility DSM program that is in effect at the same time the utility experiences its annual peak load, as opposed to the installed peak load reduction capability (i.e., Potential Peak Reduction). It should account for the regular cycling of energy efficient units during the period of annual peak load.

Allowance for Funds Used During Construction (AFUDC): A noncash item representing the estimated composite interest costs of debt and a return on equity funds used to finance construction. The allowance is capitalized in the property accounts and included in income.

Ampere: The unit of measurement of electrical current produced in a circuit by 1 volt acting through a resistance of 1 ohm.

Annual Effects: The total effects in energy use (measured in megawatthours) and peak load (measured in kilowatts) caused by all participants in the DSM programs that are in effect during a given year. It includes new and existing participants in existing programs (those implemented in prior years that are in place during the given year) and all participants in new

programs (those implemented during the given year). The effects of new participants in existing programs and all participants in new programs should be based on their start-up dates (i.e., if participants enter a program in July, only the effects from July to December should be reported). If start-up dates are unknown and cannot be reasonably estimated, the effects can be annualized (i.e., assume the participants were initiated into the program on January 1 of the given year). The Annual Effects should consider the useful life of efficiency measures, by accounting for building demolition, equipment degradation and attrition.

Anthracite: A hard, black lustrous coal, often referred to as hard coal, containing a high percentage of fixed carbon and a low percentage of volatile matter. Comprises three groups classified according to the following ASTM Specification D388-84, on a dry mineral-matter-free basis:

	Fixed Carbon Limits		Volatile Matter	
	GE	LT	GT	LE
Meta-Anthracite	98	-	-	2
Anthracite	92	98	2	8
Semianthracite	86	92	8	14

Appliances: Energy Efficiency program promotion of high efficiency appliances such as dishwashers, ranges, refrigerators, and freezers in the residential, commercial, and industrial sectors. Includes programs aimed at improving the efficiency of refrigeration equipment and electrical cooking equipment, including replacement. It also includes the promotion and identification of high efficiency appliances in retail stores using a labeling system different from the federally-mandated Energy Guide. Energy Efficiency program promotion of high efficiency cooling and heating appliances are included under Cooling System and Heating System, respectively.

Ash: Impurities consisting of silica, iron, alumina, and other noncombustible matter that are contained in coal. Ash increases the weight of coal, adds to the cost of handling, and can affect its burning characteristics. Ash content is measured as a percent by weight of coal on an "as received" or a "dry" (moisture-free, usually part of a laboratory analysis) basis.

Asset: An economic resource, tangible or intangible, which is expected to provide benefits to a business.

Available but not Needed Capability: Net capability of main generating units that are operable but not considered necessary to carry load, and cannot be connected to load within 30 minutes.

Average Revenue per Kilowatthour: The average revenue per kilowatthour of electricity sold by sector (residential, commercial, industrial, or other) and geographic area (State, Census division, and national), is calculated by dividing the total monthly revenue by the corresponding total monthly sales for each sector and geographic area.

Barrel: A volumetric unit of measure for crude oil and petroleum products equivalent to 42 U.S. gallons.

Base Bill: A charge calculated through multiplication of the rate from the appropriate electric rate schedule by the level of consumption.

Baseload: The minimum amount of electric power delivered or required over a given period of time at a steady rate.

Baseload Capacity: The generating equipment normally operated to serve loads on an around-the-clock basis.

Baseload Plant: A plant, usually housing high-efficiency steam-electric units, which is normally operated to take all or part of the minimum load of a system, and which consequently produces electricity at an essentially constant rate and runs continuously. These units are operated to maximize system mechanical and thermal efficiency and minimize system operating costs.

Bbl: The abbreviation for barrel.

Bcf: The abbreviation for 1 billion cubic feet.

Bituminous Coal: The most common coal. It is dense and black (often with well-defined bands of bright and dull material). Its moisture content usually is less than 20 percent. It is used for generating electricity, making coke, and space heating. Comprises five groups classified according to the following ASTM Specification D388-84, on a dry mineral-matter-free (mmf) basis for fixed-carbon and volatile matter and a moist mmf basis for calorific value.

	Fixed Carbon Limits		Volatile Matter Limits		Calorific Value Limits Btu/lb	
	GE	LT	GE	LT	GE	LE
LV	78	86	14	22	-	-
MV	69	78	22	31	-	-
HVA	-	69	31	-	14000	-
HVB	-	-	-	-	13000	14000
HVC	-	-	-	-	10500	13000

LV = Low-volatile bituminous coal
MV = Medium-volatile bituminous coal
HVA = High-volatile A bituminous coal
HVB = High-volatile B bituminous coal
HVC = High-volatile C bituminous coal

Boiler: A device for generating steam for power, processing, or heating purposes or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes in the boiler shell. This fluid is delivered to an end-use at a desired pressure, temperature, and quality.

Btu (British Thermal Unit): A standard unit for measuring the quantity of heat energy equal to the quantity of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit.

Capability: The maximum load that a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time without exceeding approved limits of temperature and stress.

Capacity: The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer.

Capacity (Purchased): The amount of energy and capacity available for purchase from outside the system.

Capacity Charge: An element in a two-part pricing method used in capacity transactions (energy charge is the other element). The capacity charge, sometimes called Demand Charge, is assessed on the amount of capacity being purchased.

Capital (Financial): The line items on the right side of a balance sheet, that include debt, preferred stock, and common equity. A net increase in assets must be financed by an increase in one or more forms of capital.

Census Divisions: The nine geographic divisions of the United States established by the Bureau of the Census, U.S. Department of Commerce, for the purpose of statistical analysis. The boundaries of Census divisions coincide with State boundaries. The Pacific Division is subdivided into the Pacific Contiguous and Pacific Noncontiguous areas.

Circuit: A conductor or a system of conductors through which electric current flows.

Coal: A black or brownish-black solid combustible substance formed by the partial decomposition of vegetable matter without access to air. The rank of coal, which includes anthracite, bituminous coal, subbituminous coal, and lignite, is based on fixed carbon, volatile matter, and heating value. Coal rank indicates the progressive alteration from lignite to anthracite. Lignite contains approximately 9 to 17 million Btu per ton. The contents of subbituminous and bituminous coal range from 16 to 24 million Btu per ton and from 19 to 30 million Btu per ton, respectively. Anthracite contains approximately 22 to 28 million Btu per ton.

Cogenerator: A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes. To receive status as a qualifying facility (QF) under the Public Utility Regulatory Policies Act (PURPA), the facility must produce electric energy and "another form of useful thermal energy through the sequential use of energy," and meet certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC). (See the Code of Federal Regulations, Title 18, Part 292.)

Coincidental Demand: The sum of two or more demands that occur in the same time interval.

Coincidental Peak Load: The sum of two or more peakloads that occur in the same time interval.

Coke (Petroleum): A residue high in carbon content and low in hydrogen that is the final product of thermal decomposition in the condensation process in cracking. This product is reported as marketable coke or catalyst coke. The conversion factor is 5 barrels (42 U.S. gallons each) per short ton.

Combined Cycle: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Combined Cycle Unit: An electric generating unit that consists of one or more combustion turbines and one or more boilers with a portion of the required energy input to the boiler(s) provided by the exhaust gas of the combustion turbine(s).

Combined Pumped-Storage Plant: A pumped-storage hydroelectric power plant that uses both pumped water and natural streamflow to produce electricity.

Commercial: The commercial sector is generally defined as nonmanufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, retail stores, and health, social, and educational institutions. The utility may classify commercial service as all consumers whose demand or annual use exceeds some specified limit. The limit may be set by the utility based on the rate schedule of the utility.

Commercial Operation: Commercial operation begins when control of the loading of the generator is turned over to the system dispatcher.

Connection: The physical connection (e.g. transmission lines, transformers, switch gear, etc.) between two electric systems permitting the transfer of electric energy in one or both directions.

Conservation and Other DSM: This Demand-Side Management category represents the amount of consumer load reduction at the time of system peak due to utility programs that reduce consumer load during many hours of the year. Examples include utility rebate and shared savings activities for the installation of energy efficient appliances, lighting and electrical machinery, and weatherization materials. In addition, this category includes all other Demand-Side Management activities, such as thermal storage, time-of-use rates, fuel substitution, measurement and evaluation, and any other utility-administered Demand-Side Management activity designed to reduce demand and/or electricity use.

Construction Work In Progress (CWIP): The balance shown on a utility's balance sheet for construction work not yet completed but in process. This balance line item may or may not be included in the rate base.

Consumption (Fuel): The amount of fuel used for gross generation, providing standby service, start-up and/or flame stabilization.

Contract Price: Price of fuels marketed on a contract basis covering a period of 1 or more years. Contract prices reflect market conditions at the time the contract was negotiated and therefore remain constant throughout the life of the contract or are adjusted through escalation clauses. Generally, contract prices do not fluctuate widely.

Contract Receipts: Purchases based on a negotiated agreement that generally covers a period of 1 or more years.

Cooling System: Energy Efficiency program promotion aimed at improving the efficiency of the cooling delivery system, including replacement, in the residential, commercial, or industrial sectors.

Cooperative Electric Utility: An electric utility legally established to be owned by and operated for the benefit of those using its service. The utility company will generate, transmit, and/or distribute supplies of electric energy to a specified area not being serviced by another utility. Such ventures are generally exempt from Federal income tax laws. Most electric cooperatives have been initially financed by the Rural Electrification Administration, U.S. Department of Agriculture.

Cost: The amount paid to acquire resources, such as plant and equipment, fuel, or labor services.

Current (Electric): A flow of electrons in an electrical conductor. The strength or rate of movement of the electricity is measured in amperes.

Demand (Electric): The rate at which electric energy is delivered to or by a system, part of a system, or piece of equipment, at a given instant or averaged over any designated period of time.

Demand-Side Management: The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. It refers only to energy and load-shape modifying activities that are undertaken in response to utility-administered programs. It does not refer to energy and load-shape changes arising from the normal operation of the marketplace or from government-mandated energy-efficiency standards. Demand-Side Management (DSM) covers the complete range of load-shape objectives, including strategic conservation and load management, as well as strategic load growth.

Demand-Side Management Expenditures: The expenditures incurred by the utility to achieve the capacity and energy savings from the Demand-Side Management Program. Expenditures incurred by consumers or third parties are to be excluded. The expenditures are to be reported in nominal dollars in the year in which they are incurred, regardless of when the savings occur. Program expenditures include expensed items incurred to implement the program, incentive payments provided to consumers to install Demand-Side Management measures, and annual operation and maintenance expenses incurred during the year. Utility expenditures that are general, administrative, or not specific to a particular Demand-Side Management category are to be excluded.

Direct Load Control: Refers to program activities that can interrupt consumer load at the time of annual peak load by direct control of the utility system operator by interrupting power supply to individual appliances or equipment on consumer premises. This type of control usually involves residential consumers. Direct Load Control excludes Interruptible Load and Other Load Management effects. (Direct Load Control, as defined here, is synonymous with Direct Load Control Management reported to the North American Electric Reliability Council on the voluntary Office

of Energy Emergency Operations Form OE-411, "Coordinated Regional Bulk Power Supply Program Report," with the exception that annual peakload effects are reported here and seasonal (i.e., summer and winter) peakload effects are reported on the OE-411.)

Direct Utility Cost: A utility cost that is identified with one of the DSM program categories (i.e. Energy Efficiency, Direct Load Control, Interruptible Load, Other Load Management, Other DSM Programs, Load Building).

Distillate Fuel Oil: A general classification for one of the petroleum fractions produced in conventional distillation operations. It is used primarily for space heating, on-and-off-highway diesel engine fuel (including railroad engine fuel and fuel for agriculture machinery), and electric power generation. Included are Fuel Oils No. 1, No. 2, and No. 4; and Diesel Fuels No. 1, No. 2, and No. 4.

Distribution System: The portion of an electric system that is dedicated to delivering electric energy to an end user.

Diversity Exchange: An exchange of capacity or energy, or both, between systems whose peakloads occur at different times.

Electric Plant (Physical): A facility containing prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or fission energy into electric energy.

Electric Rate Schedule: A statement of the electric rate and the terms and conditions governing its application, including attendant contract terms and conditions that have been accepted by a regulatory body with appropriate oversight authority.

Electric Utility: A corporation, person, agency, authority, or other legal entity or instrumentality that owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public and files forms listed in the Code of Federal Regulations, Title 18, Part 141. Facilities that qualify as cogenerators or small power producers under the Public Utility Regulatory Policies Act (PURPA) are not considered electric utilities.

Energy: The capacity for doing work as measured by the capability of doing work (potential energy) or the conversion of this capability to motion (kinetic energy). Energy has several forms, some of which are easily convertible and can be changed to another form useful for work. Most of the world's convertible energy comes from fossil fuels that are burned to produce heat that is then used as a transfer medium to mechanical or other means in order to accomplish tasks. Electrical energy is usually measured in kilowatthours, while heat energy is usually measured in British thermal units.

Energy Charge: That portion of the charge for electric service based upon the electric energy (kWh) consumed or billed.

Energy Deliveries: Energy generated by one electric utility system and delivered to another system through one or more transmission lines.

Energy Effects: The changes in aggregate electricity use (measured in megawatthours) for customers that participate in a utility DSM program. Energy Effects should represent changes at the consumer meter (i.e. exclude transmission and distribution effects) and reflect only activities that are undertaken specifically in response to utility-administered programs, including those activities implemented by third parties under contract to the utility. To the extent possible, Energy Effects should exclude non-program related effects such as changes in energy usage attributable to non-participants, government-mandated energy-efficiency standards that legislate improvements in building and appliance energy usage, changes in consumer behavior that result in greater energy use after initiation in a DSM program, the natural operations of the marketplace, and weather and business-cycle adjustments.

Energy Efficiency: Refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption (reported in megawatthours), often without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems.

Energy Receipts: Energy generated by one electric utility system and received by another system through one or more transmission lines.

Energy Source: The primary source that provides the power that is converted to electricity through chemical, mechanical, or other means. Energy sources include coal, petroleum and petroleum products, gas, water, uranium, wind, sunlight, geothermal, and other sources.

Equity Capital: The sum of capital from retained earnings and the issuance of stocks.

Expenditure: The incurrence of a liability to obtain an asset or service.

Facility: An existing or planned location or site at which prime movers, electric generators, and/or equipment for converting mechanical, chemical, and/or nuclear energy into electric energy are situated, or will be situated. A facility may contain more than one generator of either the same or different prime mover type. For a cogenerator, the facility includes the industrial or commercial process.

Federal Energy Regulatory Commission (FERC): A quasi-independent regulatory agency within the Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification.

Federal Power Act: Enacted in 1920, and amended in 1935, the Act consists of three parts. The first part incorporated the Federal Water Power Act administered by the former Federal Power Commission, whose activities were confined almost entirely to licensing non-Federal hydroelectric projects. Parts II and III were added with the passage of the Public Utility Act. These parts extended the Act's jurisdiction to include regulating the interstate transmission of electrical energy and rates for its sale as wholesale in interstate commerce. The Federal Energy Regulatory Commission is now charged with the administration of this law.

Federal Power Commission: The predecessor agency of the Federal Energy Regulatory Commission. The Federal Power Commission (FPC) was created by an Act of Congress under the Federal Water Power Act

on June 10, 1920. It was charged originally with regulating the electric power and natural gas industries. The FPC was abolished on September 20, 1977, when the Department of Energy was created. The functions of the FPC were divided between the Department of Energy and the Federal Energy Regulatory Commission.

FERC: The Federal Energy Regulatory Commission.

Firm Gas: Gas sold on a continuous and generally long-term contract.

Firm Power: Power or power-producing capacity intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions.

Flue Gas Desulfurization Unit (Scrubber): Equipment used to remove sulfur oxides from the combustion gases of a boiler plant before discharge to the atmosphere. Chemicals, such as lime, are used as the scrubbing media.

Flue Gas Particulate Collectors: Equipment used to remove fly ash from the combustion gases of a boiler plant before discharge to the atmosphere. Particulate collectors include electrostatic precipitators, mechanical collectors (cyclones), fabric filters (baghouses), and wet scrubbers.

Fly Ash: Particulate matter from coal ash in which the particle diameter is less than 1×10^{-4} meter. This is removed from the flue gas using flue gas particulate collectors such as fabric filters and electrostatic precipitators.

Forced Outage: The shutdown of a generating unit, transmission line or other facility, for emergency reasons or a condition in which the generating equipment is unavailable for load due to unanticipated breakdown.

Fossil Fuel: Any naturally occurring organic fuel, such as petroleum, coal, and natural gas.

Fossil-Fuel Plant: A plant using coal, petroleum, or gas as its source of energy.

Fuel: Any substance that can be burned to produce heat; also, materials that can be fissioned in a chain reaction to produce heat.

Fuel Expenses: These costs include the fuel used in the production of steam or driving another prime mover for the generation of electricity. Other associated expenses include unloading the shipped fuel and all handling of the fuel up to the point where it enters the first bunker, hopper, bucket, tank, or holder in the boiler-house structure.

Full-Forced Outage: The net capability of main generating units that is unavailable for load for emergency reasons.

Gas: A fuel burned under boilers and by internal combustion engines for electric generation. These include natural, manufactured and waste gas.

Gas Turbine Plant: A plant in which the prime mover is a gas turbine. A gas turbine consists typically of an axial-flow air compressor, one or more combustion chambers, where liquid or gaseous fuel is burned and the hot gases are passed to the turbine and where the hot gases expand to drive the generator and are then used to run the compressor.

Generating Unit: Any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

Generation (Electricity): The process of producing electric energy by transforming other forms of energy; also, the amount of electric energy produced, expressed in watthours (Wh).

Gross Generation: The total amount of electric energy produced by the generating units at a generating station or stations, measured at the generator terminals.

Net Generation: Gross generation less the electric energy consumed at the generating station for station use.

Generator: A machine that converts mechanical energy into electrical energy.

Generator Nameplate Capacity: The full-load continuous rating of a generator, prime mover, or other electric power production equipment under specific

conditions as designated by the manufacturer. Installed generator nameplate rating is usually indicated on a nameplate physically attached to the generator.

Geothermal Plant: A plant in which the prime mover is a steam turbine. The turbine is driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the earth. The energy is extracted by drilling and/or pumping.

Gigawatt (GW): One billion watts.

Gigawatthour (GWh): One billion watthours.

Greenhouse Effect: The increasing mean global surface temperature of the earth caused by gases in the atmosphere (including carbon dioxide, methane, nitrous oxide, ozone, and chlorofluorocarbon). The greenhouse effect allows solar radiation to penetrate but absorbs the infrared radiation returning to space.

Grid: The layout of an electrical distribution system.

Gross Generation: The total amount of electric energy produced by a generating facility, as measured at the generator terminals.

Heating System: Energy Efficiency program promotion aimed at improving the efficiency of the heating delivery system, including replacement, in the residential, commercial, or industrial sectors.

Heavy Oil: The fuel oils remaining after the lighter oils have been distilled off during the refining process. Except for start-up and flame stabilization, virtually all petroleum used in steam plants is heavy oil.

Hydroelectric Plant: A plant in which the turbine generators are driven by falling water.

Incremental Effects: The annual effects in energy use (measured in megawatthours) and peakload (measured in kilowatts) caused by new participants in existing DSM programs and all participants in new DSM programs during a given year. Reported Incremental Effects should be annualized to indicate the program

effects that would have occurred had these participants been initiated into the program on January 1 of the given year. Incremental effects are not simply the Annual Effects of a given year minus the Annual Effects of the prior year, since these net effects would fail to account for program attrition, degradation, demolition, and participant dropouts.

Indirect Utility Cost: A utility cost that may not be meaningfully identified with any particular DSM program category. Indirect costs could be attributable to one of several accounting cost categories (i.e., Administrative, Marketing, Monitoring & Evaluation, Utility-Earned Incentives, Other). Accounting costs that are known DSM program costs should not be reported under Indirect Utility Cost, rather those costs should be reported as Direct Utility Costs under the appropriate DSM program category.

Industrial: The industrial sector is generally defined as manufacturing, construction, mining agriculture, fishing and forestry establishments Standard Industrial Classification (SIC) codes 01-39. The utility may classify industrial service using the SIC codes, or based on demand or annual usage exceeding some specified limit. The limit may be set by the utility based on the rate schedule of the utility.

Interdepartmental Service (Electric): Interdepartmental service includes amounts charged by the electric department at tariff or other specified rates for electricity supplied by it to other utility departments.

Intermediate Load (Electric System): The range from base load to a point between base load and peak. This point may be the midpoint, a percent of the peakload, or the load over a specified time period.

Internal Combustion Plant: A plant in which the prime mover is an internal combustion engine. An internal combustion engine has one or more cylinders in which the process of combustion takes place, converting energy released from the rapid burning of a fuel-air mixture into mechanical energy. Diesel or gas-fired engines are the principal types used in electric plants. The plant is usually operated during periods of high demand for electricity.

Interruptible Gas: Gas sold to customers with a provision that permits curtailment or cessation of service at the discretion of the distributing company under

certain circumstances, as specified in the service contract.

Interruptible Load: Refers to program activities that, in accordance with contractual arrangements, can interrupt consumer load at times of seasonal peak load by direct control of the utility system operator or by action of the consumer at the direct request of the system operator. It usually involves commercial and industrial consumers. In some instances the load reduction may be affected by direct action of the system operator (remote tripping) after notice to the consumer in accordance with contractual provisions. For example, loads that can be interrupted to fulfill planning or operation reserve requirements should be reported as Interruptible Load. Interruptible Load as defined here excludes Direct Load Control and Other Load Management. (Interruptible Load, as reported here, is synonymous with Interruptible Demand reported to the North American Electric Reliability Council on the voluntary Office of Energy Emergency Operations Form OE-411, "Coordinated Regional Bulk Power Supply Program Report," with the exception that annual peakload effects are reported on the Form EIA-861 and seasonal (i.e., summer and winter) peakload effects are reported on the OE-411).

Kilowatt (kW): One thousand watts.

Kilowatthour (kWh): One thousand watthours.

Leverage Ratio: A measure that indicates the financial ability to meet debt service requirements and increase the value of the investment to the stockholders. (i.e. the ratio of total debt to total assets).

Liability: An amount payable in dollars or by future services to be rendered.

Light Oil: Lighter fuel oils distilled off during the refining process. Virtually all petroleum used in internal combustion and gas-turbine engines is light oil.

Lignite: A brownish-black coal of low rank with high inherent moisture and volatile matter (used almost exclusively for electric power generation). It is also referred to as brown coal. Comprises two groups classified according to the following ASTM Specification D388-84 for calorific values on a moist material-matter-free basis:

Limits Btu/lb.

	GE	LT
Lignite A	6300	8300
Lignite B	-	6300

Load (Electric): The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers.

Load Building: Refers to programs that are aimed at increasing the usage of existing electric equipment or the addition of electric equipment. Examples include industrial technologies such as induction heating and melting, direct arc furnaces and infrared drying; cooking for commercial establishments; and heat pumps for residences. Load Building should include programs that promote electric fuel substitution. Load Building effects should be reported as a negative number, shown with a minus sign.

Marketing Cost: Expenses directly associated with the preparation and implementation of the strategies designed to encourage participation in a DSM program. The category excludes general market and load research costs.

Monitoring & Evaluation Cost: Expenditures associated with the planning, collection, and analysis of data used to assess program operation and effects. It includes the activities such as load metering, customer surveys, new technology testing, and program evaluations that are intended to establish or improve the ability to monitor and evaluate the impacts of DSM programs, collectively or individually.

Maximum Demand: The greatest of all demands of the load that has occurred within a specified period of time.

Mcf: One thousand cubic feet.

Megawatt (MW): One million watts.

Megawatthour (MWh): One million watthours.

MMcf: One million cubic feet.

Natural Gas: A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in porous geological formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane.

Net Capability: The maximum load-carrying ability of the equipment, exclusive of station use, under specified conditions for a given time interval, independent of the characteristics of the load. (Capability is determined by design characteristics, physical conditions, adequacy of prime mover, energy supply, and operating limitations such as cooling and circulating water supply and temperature, headwater and tailwater elevations, and electrical use.)

Net Generation: Gross generation minus plant use from all electric utility owned plants. The energy required for pumping at a pumped-storage plant is regarded as plant use and must be deducted from the gross generation.

Net Summer Capability: The steady hourly output, which generating equipment is expected to supply to system load exclusive of auxiliary power, as demonstrated by tests at the time of summer peak demand.

Net Winter Capability: The steady hourly output which generating equipment is expected to supply to system load exclusive of auxiliary power, as demonstrated by tests at the time of winter peak demand.

New Construction: Energy-efficiency program promotion to encourage the building of new homes, buildings, and plants to exceed standard government-mandated energy efficiency codes; it may include major renovations of existing facilities.

Noncoincident Peak Load: The sum of two or more peakloads on individual systems that do not occur in the same time interval. Meaningful only when considering loads within a limited period of time, such as a day, week, month, a heating or cooling season, and usually for not more than 1 year.

Non-Firm Power: Power or power-producing capacity supplied or available under a commitment having limited or no assured availability.

Nonutility Power Producer: A corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not an electric utility. Nonutility power producers include qualifying cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers) without a designated franchised service area, and which do not file forms listed in the Code of Federal Regulations, Title 18, Part 141.

North American Electric Reliability Council (NERC): A council formed in 1968 by the electric utility industry to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America. NERC consists of ten regional reliability councils and encompasses essentially all the power regional of the contiguous United States, Canada, and Mexico. The NERC Regions are:

ASCC - Alaskan System Coordination Council

ECAR - East Central Area Reliability Coordination Agreement

ERCOT - Electric Reliability Council of Texas

MAIN - Mid-America Interconnected Network

MAAC - Mid-Atlantic Area Council

MAPP - Mid-Continent Area Power Pool

NPCC - Northeast Power Coordinating Council

SERC - Southeastern Electric Reliability Council

SPP - Southwest Power Pool

WSCC - Western Systems Coordinating Council

Nuclear Fuel: Fissionable materials that have been enriched to such a composition that, when placed in a nuclear reactor, will support a self-sustaining fission chain reaction, producing heat in a controlled manner for process use.

Nuclear Power Plant: A facility in which heat produced in a reactor by the fissioning of nuclear fuel is used to drive a steam turbine.

Off-Peak Gas: Gas that is to be delivered and taken on demand when demand is not at its peak.

Ohm: The unit of measurement of electrical resistance. The resistance of a circuit in which a potential difference of 1 volt produces a current of 1 ampere.

Operable Nuclear Unit: A nuclear unit is "operable" after it completes low-power testing and is granted authorization to operate at full power. This occurs when it receives its full power amendment to its operating license from the Nuclear Regulatory Commission.

Other Cost: A residual category to capture the Indirect Costs of DSM programs that cannot be meaningfully included in any of the other cost categories listed and defined herein. Included are costs such as those incurred in the research and development of DSM technologies.

Other DSM Programs: A residual category to capture the effects of DSM programs that cannot be meaningfully included in any of the program categories listed and defined herein. The energy effects attributable to this category should be the net effects of all the residual programs. Programs that promote consumer's substitution of electricity by other energy types should be included in Other DSM Programs. Also, self-generation should be included in Other DSM Programs to the extent that it is not accounted for as backup generation in Other Load Management or Interruptible Load categories.

Other Incentives: Energy Efficiency programs that offer cash or noncash awards to electric energy efficiency deliverers, such as appliance and equipment dealers, building contractors, and architectural and engineering firms, that encourage consumer participation in a DSM program and adoption of recommended measures.

Other Load Management: Refers to programs other than Direct Load Control and Interruptible Load that limit or shift peak load from on-peak to off-peak time periods. It includes technologies that primarily shift all or part of a load from one time-of-day to another and secondarily may have an impact on energy consumption. Examples include space heating and water heating storage systems, cool storage systems, and load limiting devices in energy management systems. This category also includes programs that aggressively promote time-of-use (TOU) rates and other innovative rates such as real time pricing. These rates are intended to reduce consumer bills and shift hours of operation

of equipment from on-peak to off-peak periods through the application of time-differentiated rates.

Outage: The period during which a generating unit, transmission line, or other facility is out of service.

Peak Demand: The maximum load during a specified period of time.

Peak Load Plant: A plant usually housing old, low-efficiency steam units; gas turbines; diesels; or pumped-storage hydroelectric equipment normally used during the peak-load periods.

Peaking Capacity: Capacity of generating equipment normally reserved for operation during the hours of highest daily, weekly, or seasonal loads. Some generating equipment may be operated at certain times as peaking capacity and at other times to serve loads on an around-the-clock basis.

Percent Difference: The relative change in a quantity over a specified time period. It is calculated as follows: the current value has the previous value subtracted from it; this new number is divided by the absolute value of the previous value; then this new number is multiplied by 100.

Petroleum: A mixture of hydrocarbons existing in the liquid state found in natural underground reservoirs, often associated with gas. Petroleum includes fuel oil No. 2, No. 4, No. 5, No. 6; topped crude; Kerosene; and jet fuel.

Petroleum Coke: See Coke (Petroleum).

Petroleum (Crude Oil): A naturally occurring, oily, flammable liquid composed principally of hydrocarbons. Crude oil is occasionally found in springs or pools but usually is drilled from wells beneath the earth's surface.

Planned Generator: A proposal by a company to install electric generating equipment at an existing or planned facility or site. The proposal is based on the owner having obtained (1) all environmental and regulatory approvals, (2) a signed contract for the electric energy, or (3) financial closure for the facility.

Plant: A facility at which are located prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or nuclear energy into electric energy. A plant may contain more than one type of prime mover. Electric utility plants exclude facilities that satisfy the definition of a qualifying facility under the Public Utility Regulatory Policies Act of 1978.

Plant Use: The electric energy used in the operation of a plant. Included in this definition is the energy required for pumping at pumped-storage plants.

Plant-Use Electricity: The electric energy used in the operation of a plant. This energy total is subtracted from the gross energy production of the plant; for reporting purposes the plant energy production is then reported as a net figure. The energy required for pumping at pumped-storage plants is, by definition, subtracted, and the energy production for these plants is then reported as a net figure.

Potential Peak Reduction: The potential annual peak load reduction (measured in kilowatts) that can be deployed from Direct Load Control, Interruptible Load, Other Load Management, and Other DSM Program activities. It represents the load that can be reduced either by the direct control of the utility system operator or by the consumer in response to a utility request to curtail load. It reflects the installed load reduction capability, as opposed to the Actual Peak Reduction achieved by participants, during the time of annual system peak load.

Power: The rate at which energy is transferred. Electrical energy is usually measured in watts. Also used for a measurement of capacity.

Power Pool: An association of two or more interconnected electric systems having an agreement to coordinate operations and planning for improved reliability and efficiencies.

Price: The amount of money or consideration-in-kind for which a service is bought, sold, or offered for sale.

Prime Mover: The engine, turbine, water wheel, or similar machine that drives an electric generator, or, for reporting purposes, a device that converts energy to electricity directly (e.g., photovoltaic solar and fuel cell(s)).

Process Heating: Energy Efficiency program promotion of increased electric energy efficiency applications in industrial process heating.

Profit: The income remaining after all business expenses are paid.

Public Authority Service to Public Authorities: Public authority service includes electricity supplied and services rendered to municipalities or divisions or agencies of State or Federal governments, under special contracts or agreements or service classifications applicable only to public authorities.

Public Street and Highway Lighting: Public street and highway lighting includes electricity supplied and services rendered for the purposes of lighting streets, highways, parks, and other public places; or for traffic or other signal system service, for municipalities, or other divisions or agencies of State or Federal governments.

Pumped-Storage Hydroelectric Plant: A plant that usually generates electric energy during peak-load periods by using water previously pumped into an elevated storage reservoir during off-peak periods when excess generating capacity is available to do so. When additional generating capacity is needed, the water can be released from the reservoir through a conduit to turbine generators located in a power plant at a lower level.

Purchased Power Adjustment: A clause in a rate schedule that provides for adjustments to the bill when energy from another electric system is acquired and it varies from a specified unit base amount.

Pure Pumped-Storage Hydroelectric Plant: A plant that produces power only from water that has previously been pumped to an upper reservoir.

Qualifying Facility (QF): A cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC) pursuant to the Public Utility Regulatory Policies Act (PURPA). (See the Code of Federal Regulations, Title 18, Part 292.) Part 292.

Railroad and Railway Services: Railroad and railway services include electricity supplied and services rendered to railroads and interurban and street railways, for general railroad use, including the propulsion of cars or locomotives, where such electricity is supplied under separate and distinct rate schedules.

Rate Base: The value of property upon which a utility is permitted to earn a specified rate of return as established by a regulatory authority. The rate base generally represents the value of property used by the utility in providing service and may be calculated by any one or a combination of the following accounting methods: fair value, prudent investment, reproduction cost, or original cost. Depending on which method is used, the rate base includes cash, working capital, materials and supplies, and deductions for accumulated provisions for depreciation, contributions in aid of construction, customer advances for construction, accumulated deferred income taxes, and accumulated deferred investment tax credits.

Rate-making Authority: A utility commission's legal authority to fix, modify, approve, or disapprove rates, as determined by the powers given the commission by a State or Federal legislature.

Receipts: Purchases of fuel.

Regulation: The governmental function of controlling or directing economic entities through the process of rulemaking and adjudication.

Reserve Margin (Operating): The amount of unused available capability of an electric power system at peakload for a utility system as a percentage of total capability.

Residential: The residential sector is defined as private household establishments which consume energy primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking and clothes drying. The classification of an individual consumer's account, where the use is both residential and commercial, is based on principal use. For the residential class, do not duplicate consumer accounts due to multiple metering for special services (water, heating, etc.). Apartment houses are also included.

Residual Fuel Oil: The topped crude of refinery operation, includes No. 5 and No. 6 fuel oils as defined

in ASTM Specification D396 and Federal Specification VV-F-815C; Navy Special fuel oil as defined in Military Specification MIL-F-859E including Amendment 2 (NATO Symbol F-77); and Bunker C fuel oil. Residual fuel oil is used for the production of electric power, space heating, vessel bunkering, and various industrial purposes. Imports of residual fuel oil include imported crude oil burned as fuel.

Restricted-Universe Census: This is the complete enumeration of data from a specifically defined subset of entities including, for example, those that exceed a given level of sales or generator nameplate capacity.

Retail: Sales covering electrical energy supplied for residential, commercial, and industrial end-use purposes. Other small classes, such as agriculture and street lighting, also are included in this category.

Revenue: The total amount of money received by a firm from sales of its products and/or services, gains from the sales or exchange of assets, interest and dividends earned on investments, and other increases in the owner's equity except those arising from capital adjustments.

Running and Quick-Start Capability: The net capability of generating units that carry load or have quick-start capability. In general, quick-start capability refers to generating units that can be available for load within a 30-minute period.

Sales: The amount of kilowatthours sold in a given period of time; usually grouped by classes of service, such as residential, commercial, industrial, and other. Other sales include public street and highway lighting, other sales to public authorities and railways, and interdepartmental sales.

Sales for Resale: Energy supplied to other electric utilities, cooperatives, municipalities, and Federal and State electric agencies for resale to ultimate consumers.

Scheduled Outage: The shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule.

Short Ton: A unit of weight equal to 2,000 pounds.

Small Power Producer (SPP): Under the Public Utility Regulatory Policies Act (PURPA), a small power production facility (or small power producer) generates electricity using waste, renewable (water, wind and solar), or geothermal energy as a primary energy source. Fossil fuels can be used, but renewable resource must provide at least 75 percent of the total energy input. (See Code of Federal Regulations, Title 18, Part 292.)

Spinning Reserve: That reserve generating capacity running at a zero load and synchronized to the electric system.

Spot Purchases: A single shipment of fuel or volumes of fuel, purchased for delivery within 1 year. Spot purchases are often made by a user to fulfill a certain portion of energy requirements, to meet unanticipated energy needs, or to take advantage of low-fuel prices.

Stability: The property of a system or element by virtue of which its output will ultimately attain a steady state. The amount of power that can be transferred from one machine to another following a disturbance. The stability of a power system is its ability to develop restoring forces equal to or greater than the disturbing forces so as to maintain a state of equilibrium.

Standard Industrial Classification (SIC): A set of codes developed by the Office of Management and Budget, which categorizes business into groups with similar economic activities.

Standby Facility: A facility that supports a utility system and is generally running under no-load. It is available to replace or supplement a facility normally in service.

Standby Service: Support service that is available, as needed, to supplement a consumer, a utility system, or to another utility if a schedule or an agreement authorizes the transaction. The service is not regularly used.

Steam-Electric Plant (Conventional): A plant in which the prime mover is a steam turbine. The steam used to drive the turbine is produced in a boiler where fossil fuels are burned.

Stocks: A supply of fuel accumulated for future use. This includes coal and fuel oil stocks at the plant site, in coal cars, tanks, or barges at the plant site, or at separate storage sites.

Subbituminous Coal: Subbituminous coal, or black lignite, is dull black and generally contains 20 to 30 percent moisture. The heat content of subbituminous coal ranges from 16 to 24 million Btu per ton as received and averages about 18 million Btu per ton. Subbituminous coal, mined in the western coal fields, is used for generating electricity and space heating.

Substation: Facility equipment that switches, changes, or regulates electric voltage.

Sulfur: One of the elements present in varying quantities in coal which contributes to environmental degradation when coal is burned. In terms of sulfur content by weight, coal is generally classified as low (less than or equal to 1 percent), medium (greater than 1 percent and less than or equal to 3 percent), and high (greater than 3 percent). Sulfur content is measured as a percent by weight of coal on an "as received" or a "dry" (moisture-free, usually part of a laboratory analysis) basis.

Switching Station: Facility equipment used to tie together two or more electric circuits through switches. The switches are selectively arranged to permit a circuit to be disconnected, or to change the electric connection between the circuits.

System (Electric): Physically connected generation, transmission, and distribution facilities operated as an integrated unit under one central management, or operating supervision.

Total DSM Cost: Refers to the sum of total utility cost and nonutility cost.

Total DSM Programs: Refers to the total net effects of all the utility's DSM programs. For the purpose of this survey, it is the sum of the effects for Energy Efficiency, Direct Load Control, Interruptible Load, Other Load Management, Other DSM Programs, and Load Building. Net growth in energy or load effects should be reported as a negative number, shown with a minus sign.

Total Nonutility Cost: Refers to total cash expenditures incurred by consumers and trade allies that are associated with participation in a DSM program, but that are not reimbursed by the utility. The nonutility expenditures should include only those additional costs necessary to purchase or install an efficient measure relative to a less efficient one. Costs are to be reported in nominal dollars in the year in which they are incurred, regardless of when the actual effects occur. To the extent possible, provide the best estimate of nonutility costs if actual costs are unavailable.

Total Utility Cost: Refers to the sum of the total Direct and Indirect Utility Costs for the year. Utility costs should reflect the total cash expenditures for the year, reported in nominal dollars, that flowed out to support DSM programs. They should be reported in the year they are incurred, regardless of when the actual effects occur.

Transformer: An electrical device for changing the voltage of alternating current.

Transmission: The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

Transmission System (Electric): An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers, or is delivered to other electric systems.

Turbine: A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam, or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction, or a mixture of the two.

Uniform System of Accounts: Prescribed financial rules and regulations established by the Federal Energy Regulatory Commission for utilities subject to its jurisdiction under the authority granted by the Federal Power Act.

Useful Thermal Output: The thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical generation.

Utility-Earned Incentives: Costs in the form of incentives paid to the utility for achievement in consumer participation in DSM programs. These financial incentives are intended to influence the utility's consideration of DSM as a resource option by addressing cost recovery, lost revenue, and profitability.

Voltage Reduction: Any intentional reduction of system voltage by 3 percent or greater for reasons of maintaining the continuity of service of the bulk electric power supply system.

Water Heating: Energy Efficiency program promotion to increase efficiency in water heating, including low-flow shower heads and water heater insulation

wraps. Could be applicable to residential, commercial, or industrial consumer sectors.

Watt: The electrical unit of power. The rate of energy transfer equivalent to 1 ampere flowing under a pressure of 1 volt at unity power factor.

Watt-hour (Wh): An electrical energy unit of measure equal to 1 watt of power supplied to, or taken from, an electric circuit steadily for 1 hour.

Wheeling Service: The movement of electricity from one system to another over transmission facilities of intervening systems. Wheeling service contracts can be established between two or more systems.

Wholesale Sales: Energy supplied to other electric utilities, cooperatives, municipals, and Federal and State electric agencies for resale to ultimate consumers.