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Electric Power Annual 1992

January 1994

Energy Information Administration
Office of Coal, Nuclear, Electric and Alternate Fuels
U.S. Department of Energy
Washington, DC 20585

1992

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Preface

The *Electric Power Annual* presents a summary of electric utility 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 Planning and Operations Form OE-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 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 750 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 OE-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 Planning and Operations 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 Planning and Operations 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*.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 Reclamation, the International Water and Boundary Commission, and the U.S. Department of Energy. Electric-

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.

ity 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 PURPA (these facilities are generally referred to as qualifying facilities (QF's)), and other nonutility generators (including independent power producers) without a designated franchise service area. QF's 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 (such as 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 Commission (FERC). The FERC is responsible for the implementation of PURPA. Under PURPA, a small power producer generates 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.

Independent power producers (IPP) in the United States are wholesale electricity producers, other than QF's under PURPA, that are unaffiliated with franchised utilities in the area in which the IPP's are selling power and that lack significant marketing power. Unlike traditional electric utilities, IPP's do not possess transmission facilities and do not sell power in any retail service territory where they have a franchise. An IPP is an entity that is not a QF.

A new class of IPP's--exempt wholesale generators (EWGs)--was established by the Energy Policy Act of 1992. 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

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.

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.

Figure 1. Generating Capability at U.S. Electric Utilities by Class of Ownership, 1992

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, 1992

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, 1992

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, 1992

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, 1992

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, 1992

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, 1992

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, 1992

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 1992

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, 1992 and 1991," represents the information required by Section 171 of the Act. More disaggregated information may be found in other tables in this publication.

In 1992, generation from renewable energy sources³ accounted for about 11 percent (329,230 million kilowatthours) of the electric power industry's production of electricity (Table 1).⁴ Conventional hydroelectric generation accounts for the greatest share (96 percent) of the electric utilities' generation from renewable sources. Generation from biomass accounts for the greatest share (71 percent) of nonutility generation from renewable sources.

Electric Utilities. Exclusive of conventional hydroelectric power, generation from renewable sources accounted for 0.4 percent of total electric utility generation in 1992. Electric utilities generated 8,104 million kilowatthours from geothermal steam; 2,093 million kilowatthours from biomass; and 3 million kilowatthours from photovoltaic. The capacity factors for electric utility geothermal and biomass plants were

53 percent and 51 percent, respectively, in 1992.⁵ 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 2,207 megawatts, as of year-end 1992. This represents 0.3 percent of total electric utility generating capacity. In contrast, nonutility capacity that used renewable energy sources was 13,249 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 1992, nonutilities generated 53,607 million kilowatthours from biomass; 9,446 million kilowatthours from water (conventional hydroelectric); 8,578 million kilowatthours from geothermal steam; 2,916 million kilowatthours from wind; 743 million kilowatthours from solar thermal plants and 4 million kilowatthours from photovoltaic plants. The capacity factor for geothermal plants averaged 78 percent in 1992; 62 percent for biomass plants; 40 percent for conventional hydroelectric plants; 23 percent for solar thermal plants; 18 percent for wind-powered plants; and 7 percent for photovoltaic plants. The average efficiency of all biomass plants operated by nonutilities was approximately 11 percent or 30,000 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 17 percent or 20,000 Btu per kilowatthour.

The total installed capacity of nonutility power producers' plants that used renewable sources was 15,933 megawatts (including 2,684 megawatts of conventional hydroelectric capacity) as of year-end 1992.

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.

⁴All electric utilities' net generation and gross generation of nonutility power producers with an installed capacity of 1 or more megawatts. The ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full-power operation during the same period.

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 1992 reached 2,763 billion kilowatthours, nearly unchanged from 1991 sales of 2,762 billion kilowatthours (Table 1). Sales of electricity were higher than in 1991 in the industrial sector by 3 percent. Sales were less in other end-use sectors--residential by 2 percent, commercial and other sales by 1 percent. Average revenue per kilowatthour of electricity sold to ultimate consumers in 1992 was 6.8 cents, an increase of 0.1 cents from the 1991 level.

Generation. In 1992, total U.S. generation by electric utilities (2,797 billion kilowatthours) was 1 percent lower than in 1991. This was the first time in 10 years that a decline from the previous year for net generation

levels was reported. Nonetheless, generation of electricity from nuclear power achieved a record level of 619 billion kilowatthours, an increase of 1 percent from 1991. A slightly improved capacity factor of 70.9 percent, compared with 70.2 percent in 1991, contributed to this growth in nuclear-powered generation.⁹

The sharpest decline (20 percent) in generation in 1992 occurred for petroleum-fired units. During the year, petroleum-fired plants generated 89 billion kilowatthours, 23 billion kilowatthours below the amount reported during 1991. The second largest decline in generation (13 percent) was reported for hydroelectric plants. Hydroelectric generation fell to the second lowest level in 10 years. Drought conditions over the past several years, primarily in the Pacific Northwest and in California, contributed to this decline.

James A. FitzPatrick is a nuclear power plant operated by New York State Power Authority.

⁹Energy Information Administration, *Monthly Energy Review* (MER), August 1993, DOE/EIA-0035(93/08), Table 8.1, p. 113

The reduction in 1992 electric utility net generation from the 1991 level represents the first national drop since 1982.¹⁰ However, electricity sales did not decline in 1992 from 1991 sales as was the case in 1982. The level of electric utility generation in 1992 was substituted by nonutility power production and demand-side management initiatives.

Fossil-Fuel Receipts and Costs. A number of factors appear to have had a notable effect on the volume of receipts and the cost of fossil fuels delivered to electric utilities during 1992. Variations in annual weather conditions had substantial effects on electric utility fuel purchases. In 1992, a drought in the western United States, Hurricane Andrew in the South, and mild winter and summer temperatures throughout much of the Nation played a major role in determining electric utility fuel requirements for 1992.

The average cost of all fossil fuels delivered to electric utilities¹¹ in 1992 was \$1.59 per million Btu, the lowest average annual cost since 1978.¹² Fuel oil was the most expensive at \$2.55 per million Btu; natural gas was second at \$2.33 per million Btu; and coal was the least expensive at \$1.41 per million Btu. The average cost of coal decreased \$0.04 per million Btu in 1992; fuel oil was unchanged; and natural gas increased \$0.18 per million Btu. However, since coal accounted for 82 percent of the total Btu content of fossil fuels delivered to electric utilities in 1992, the overall average cost decreased \$0.01 per million Btu.

- **Coal.** Abundant supplies of coal, which were available to electric utilities in 1992, contributed to depressed coal prices. The average delivered cost of coal to electric utilities in 1992 was \$29.36 per short ton. This was a 2-percent decrease from the \$30.02 per short ton reported in 1991 and the lowest average cost of coal delivered to electric utilities since 1980.¹³ The average cost of both contract and spot-market coal delivered to electric utilities decreased in 1992. The average cost of contract coal decreased by \$0.66 per short ton to \$29.89 per short ton. The average cost of spot-market coal dropped \$0.38 per short ton to a level of \$26.64 per short ton. This is the lowest average annual cost for coal purchased in the spot-market and delivered to electric utilities since 1977.¹⁴ As has been the case since 1985, the average delivered cost of coal purchased under contract was higher than that for coal purchased in the spot-market (\$29.89 versus \$26.64 per short ton). This indicates an excess supply of coal and an expectation of a continued decline in the cost of coal. Aiding a decline in the average cost of coal is the fact that

electric utilities follow strategies that will reduce their fuel costs. With spot-market costs \$3.25 per short ton less, on average, than the average cost of contract coal, electric utilities will often minimize their contract receipts and opt for spot-market purchases. 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 coal-related indices, while some contracts are periodically open for renegotiation. Since the overall cost 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. In addition, several electric utilities have been able to reduce the cost of transporting the coal to the plant either by renegotiation of contracts or by increasing competition among the carriers.

In the western United States a continuing drought reduced hydroelectric generation. An increase in coal-fired generation in the region appears to have made up for the shortfall. This was most significant in contributing to an annual increase in coal receipts of 6 million short tons to 776 million short tons.

- **Petroleum.** The petroleum market was relatively stable during 1992. No after-effects of the Persian Gulf Conflict of 1991 are readily apparent in the data submitted for electric utility fuel purchases during 1992. The average cost of petroleum products (fuel oil) delivered to electric utilities was \$16.15 per barrel (\$2.55 per million Btu), an increase of only \$0.06 per barrel from 1991. However, the cost of fuel oil delivered to electric utilities did increase rather sharply mid-year, in tandem with the cost of natural gas. Receipts of fuel oil at electric utilities totaled 144 million barrels, a decrease of 26 million barrels from 1991. This is the lowest annual total reported since data collection was begun in 1972. Fuel oil accounted for only 5 percent of the total Btu content of fossil fuels delivered in 1992. Receipts of fuel oil to electric utilities peaked at 636 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, are heavily dependent on the fuel for electric generation.
- **Gas.** The natural gas markets appeared to be somewhat less stable than the petroleum markets during 1992. The average cost of natural gas delivered to electric utilities was \$2.38 per thousand cubic

¹⁰The 1982 decline was the first drop in net utility generation since before 1949.

¹¹The delivered cost of fossil fuels includes all costs (including transportation, taxes, etc.) incurred by the electric utility for delivery of the fuel to the plant.

¹²Energy Information Administration, *Electric Power Monthly (EPM)*, DOE/EIA-0226(93-06), Table 33.

¹³Energy Information Administration, *Historical Monthly Energy Review (HMER)*, DOE/EIA-0035(73-88), Table 9-10.

¹⁴Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1993*, DOE/EIA-0191(92) and prior issues.

feet (\$2.33 per million Btu), an increase of 8 percent from 1991. The lowest average monthly cost of natural gas delivered to electric utilities was \$2.01 per thousand cubic feet (Mcf) reported in March. However, by October the average cost of natural gas had increased to \$3.05 per Mcf.¹⁵ 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, Organization of Petroleum Exporting Countries (OPEC'S) reduction in production of heavier crudes, which compete with natural gas, and Hurricane Andrew, which "blew away" an estimated 5 percent of the gas-producing wells in the Gulf of Mexico.¹⁶

Receipts of natural gas at electric utilities totaled 2,638 billion cubic feet (Bcf), nearly unchanged from the 2,631 Bcf reported in 1991. Monthly receipts of natural gas peaked in July at 316 Bcf as electric utilities increased purchases of natural gas under interruptible contracts. Receipts were lowest in January and February, 160 Bcf each.¹⁷

Capability. At the end of 1992, electric utility generating capability in the United States totaled 695,059 megawatts. This capability included 3,341 megawatts of newly added capability. The newly added capability in 1992 was 8 percent less than the newly added capability in 1991.¹⁸ Gas-fired capability accounted for 53 percent of the capability that entered service in 1992. Hydroelectric capability additions represented 19 percent; coal-fired capability additions accounted for 15 percent; and petroleum-fired capability additions represented 14 percent. No new nuclear units started operation in 1992.

U.S. electric utilities, at the end of 1992, included 27,898 megawatts of gas-fired capability additions in their 10-year plans.¹⁹ Of this 27,898 megawatts of planned gas-fired capability additions, 2,185 megawatts is combined-cycle steam capability using waste heat produced from gas-fired gas turbines. Gas-fired capability additions during the next 10 years will be primarily in simple-cycle gas turbines and gas turbines operating as combined-cycle units. Gas turbines have relatively short construction times, and can be brought on line quickly, at a relatively low cost. These planned gas-fired units are expected to serve the peak and intermediate loads of electric utilities.

Emissions. In 1992, emissions from electric utilities' fossil-fueled steam plants used for the generation of electricity in the United States were estimated to be:

sulfur dioxide (SO₂), 15 million tons; nitrogen oxides (NO_x), 8 million tons; and carbon dioxide, (CO₂), 1,859 million tons.²⁰

Financial Status. In 1992, electric utility operating revenues (\$169.5 billion) for major U.S. investor-owned electric utilities were up a modest 1.6 percent; however, net income (\$18.4 billion) showed a gain of 8.5 percent from 1991. Operating income decreased \$0.3 billion due to increases in other operating and maintenance expenses, depreciation, and taxes other than income taxes. This decrease in operating income, however, was offset by a decline in fuel expenses and income taxes. Electric operating expenses (\$139.0 billion) increased by 2.3 percent.

Other income and expenses, as well 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 increased by \$1.3 billion or 8.9 percent. Dividends paid to owners of common stock declined to 91.1 percent in 1992, compared with 96.2 percent in 1991, based on dividends declared during the year. Earnings available per average common share were \$2.61, reversing the 1991 decline of \$.13 to \$2.53.

In 1992, investment in the major U.S. investor-owned segment of the industry increased by \$18.8 billion. Of that increase, net utility plant accounted for \$10.1 billion. Construction work in progress (CWIP) was \$20.6 billion, an increase of 14.2 percent. This reversed the downward trend that resulted from a number of remaining nuclear plants being completed and, therefore, reclassified from CWIP into plant in service. The total asset turnover ratio (operating revenues divided by total assets) remained steady at 0.37.

Total capitalization of \$356.0 billion increased by 2.1 percent from 1991. The ratio of long-term debt to total capitalization stood at 48.9, essentially unchanged from the previous year.

In 1992, electric utility operating revenue (\$21.7 billion) for the major publicly owned generator electric utilities grew by 2.9 percent. Generator electric utility operating expenses increased by 1.8 percent, resulting in an increase in net income (\$1.0 billion) of 28.0 percent. Total assets for generator electric utilities increased 3.8 percent to \$106.9 billion. For the major publicly owned nongenerator electric utilities, electric utility operating revenue (\$7.2 billion) grew by 1.8 percent. Nongenerator electric utility operating expenses decreased less than \$1 billion to end the year at \$6.8

¹⁵Energy Information Administration, *Electric Power Monthly (EPM)*, DOE/EIA-0226(93/06), Table 33.

¹⁶Standard & Poor's Industry Survey, *Natural Gas*, Vol. 160, No. 47, November 19, 1992.

¹⁷Energy Information Administration, *Electric Power Monthly (EPM)*, DOE/EIA-0226(93/06), Table 33.

¹⁸Energy Information Administration (EIA), *Electric Power Annual 1991*, DOE/EIA-0348(91), p. 21.

¹⁹Energy Information Administration (EIA), *Inventory of Power Plants in the United States 1992*, DOE/EIA-0095(92), p. 14.

²⁰Emissions 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.

billion. Net income for nongenerators was \$0.3 billion, up 34.5 percent. Total assets for nongenerator electric utilities increased by 4.3 percent to end the year at \$9.4 billion.

Demand-Side Management. In 1992, energy savings and peakload reductions resulting from demand-side management programs were reported by 905 electric utilities. Of these, 504 were classified as large utilities, an increase of 41 utilities over 1991.²¹ These large utilities estimated that they achieved reductions in their annual peak loads of 17,657 megawatts in 1992, compared to 16,739 megawatts in 1991. In 1992, their potential, contractually available peakload reduction was 25,005 megawatts. Energy efficiency programs accounted for 45 percent of actual peakload reduction in 1992. Direct load control and interruptible load programs accounted for 42 percent of actual peakload reductions and 89 percent of potential peakload reductions. Energy savings increased from 23,343 million kilowatthours in 1991 to 31,767 million kilowatthours in 1992. Eighty percent of energy savings resulted from energy efficiency programs. Total utility cost increased 28 percent from 1.7 billion dollars to 2.2 billion dollars.²²

Large utilities in the Southeastern and Western United States again led all DSM program activities by a wide margin. Among the North American Electric Reliability Council (NERC) regions, the Southwestern Electric Reliability Council (SERC) and the Western Systems Coordinating Council (WSCC) accounted for 56 percent of total actual peakload reductions, and 67 percent of total energy savings. SERC's large amount of energy savings was due to the inclusion of Tennessee Valley Authority, whose large energy efficiency program accounted for 24 percent of the region's energy savings, and has the largest amount of total actual peakload reductions due to Carolina Power and Light, which considers cogeneration a part of their DSM program. The WSCC and Northeast Power Coordinating Council (NPCC) accounted for 50 percent of total DSM expenditures.

The residential sector accounted for 41 percent of energy savings, and 43 percent of actual peakload reductions. The industrial sector accounted for the largest percent of the potential peakload reductions (51 percent). Of the 905 electric utilities with DSM programs, 412 reported energy efficiency programs in the resi-

dential sector, 268 in the commercial sector, and 189 in the industrial sector (Table 73).

In 1993, energy savings are expected to increase 28 percent over 1992 levels to 40,816 million kilowatthours, potential peakload reductions are projected to increase nearly 10 percent to 27,478 megawatts, and total utility cost is projected to increase 25 percent to 2.8 billion dollars. Between 1993 and 1997, DSM savings and cost are expected to continue to grow. Energy savings are projected to increase at an annual rate of 16 percent to 72,783 million kilowatthours, potential peakload reductions are expected to increase at an annual rate of 5 percent to 33,344 megawatts and utility costs are projected to increase to 3.8 billion dollars in 1997.

U.S. Nonutility Power Producer Statistics

Generation. In 1992, U.S. nonutility power producers with facilities having an installed capacity of 1 or more megawatts (previously the cutoff was 5 or more megawatts) generated 296 billion kilowatthours of electricity. Receipts from electric utilities and nonutilities totaled 83 billion kilowatthours. Nonutility power producers delivered 175 billion kilowatthours or approximately 60 percent of their gross generation and used 204 billion kilowatthours at these facilities for operating power plants and for industrial processing. The highest level of nonutility production of electricity occurred in California and Texas, with 59 and 52 billion kilowatthours, respectively. For California (comparing facilities of 5 or more megawatts), this was a 9-percent increase over 1991.

Gross generation for nonutility power producers (with an installed capacity of 5 or more megawatts) in 1992 was 17 percent higher than 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 18 percent of the total. Of the total nonutility generation, 241 billion kilowatthours were from qualifying facilities, 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

²¹Large utilities are those reporting sales to ultimate consumers or sales for resale larger than or equal to 120,000 megawatthours. These utilities are required to report incremental and annual peakload reductions and energy savings for the reporting year (1992), and annual peakload reductions and energy savings for the first and fifth forecast years (1993 and 1997), and itemized direct and indirect utility costs for all three years (1992, 1993, and 1997). Small utilities with sales to ultimate consumers or sales for resale of less than 120,000 megawatthours are only required to report incremental energy savings and peakload reductions, and direct and indirect utility costs for the reporting year and first and fifth forecast years.

²²It 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.

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 56,814 megawatts at the end of 1992. The installed capacity for facilities of 5 or more megawatts increased by 15 percent from 1991. Nonutility capacity for facilities of 1 megawatt and less than 5 megawatts was 1,651 megawatts. These facilities became operational prior to 1992, but due to the volatility of this industry and lack of standardized naming conventions, they were not identified prior to 1992. Nonutility capacity in 1992 was equivalent to 8 percent of the traditional U.S. electric utility installed capacity.²³

Natural gas was the fuel most used by nonutilities. Of all energy sources, gas accounted for the largest amount (21,542 megawatts) of nonutility capacity. The West South Central Census Division accounted for 44 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 (2,971 megawatts) was located in the Middle Atlantic Census Division. Cogeneration accounts for 73 percent of nonutility capacity (62 percent qualifying facility capacity and 11 percent nonqualifying facility capacity). Small power producers and independent power producers account for 15 and 12 percent, respectively, of nonutility capacity.

The greatest number (558) of nonutility generating facilities was in the Pacific Census Division, and most of the capacity (12,848 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 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 collocated.

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 electric utilities' requirements make a 10-year period more appropriate. Capacity additions planned through 1995 by U.S. nonutilities total 17,686 megawatts, compared with 15,198 megawatts (generator nameplate capacity) planned for the same period by U.S. electric utilities. However, electric utilities have planned 52,774 megawatts (generator nameplate capacity) in capacity additions for the 10-year period, 1993-2002. Of the nonutility planned capacity, 60 percent is petroleum and/or gas-fired. Coal-fired capacity represents approximately 21 percent of the total planned nonutility additions.

Emissions. Air emissions from nonutility facilities of 1 megawatt or more were 1,219 thousand tons of SO₂, 1,259 thousand tons of NO_x, and 549,832 thousand tons of CO₂. For facilities of 5 or more megawatts, estimated SO₂ emissions were 1,201 thousand short tons, an 8-percent increase from 1990. The estimates of 1992 emissions in the United States for NO_x and CO₂ were 1,234 thousand short tons and 540,189 thousand short tons, respectively. 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. Low-sulfur fuels, flue gas desulfurization, and fluidized bed combustion are the most commonly used methods to reduce SO₂ emissions.

Figure 9. U.S. Electric Utility Sales to Ultimate Consumers by Sector, 1992

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."

²³Energy Information Administration (EIA), *Inventory of Power Plants in the United States 1992* (DOE/EIA-009592), p. 12.

Figure 10. U.S. Electric Utility Average Revenue per Kilowatthour by Sector, 1992

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, 1992

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

Figure 12. Monthly U.S. Electric Utility Net Generation, 1992 and 1991

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, 1992

Notes: •The total generating capability value includes 2 gigawatts of other generating capability (geothermal, biomass, 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, 1992

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

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, 1992

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 the "Nonutility Power Producers" chapter. •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, 1992 and 1991

Item	1992	1991	Percent Change
Electric Utilities			
Generating Capability (megawatts)¹	695,059	693,016	0.3
Coal	300,547	299,611	.3
Petroleum	71,852	72,878	-1.4
Gas	128,092	126,877	1.0
Nuclear	98,985	99,589	-.6
Renewable			
Hydroelectric (conventional)	74,345	73,617	1.0
Geothermal	1,739	1,563	11.3
Biomass ²	464	464	0
Wind	.	.	0
Solar Thermal	0	0	0
Photovoltaic	3	3	0
Hydroelectric Pumped Storage	19,030	18,414	3.3
Net Generation (million kilowatthours)	2,797,219	2,825,023	-1.0
Coal	1,575,895	1,551,167	1.6
Petroleum ³	88,916	111,463	-20.2
Gas	263,872	264,172	-.1
Nuclear	618,776	612,565	1.0
Renewable			
Hydroelectric (conventional)	243,736	280,061	-13.0
Geothermal	8,104	8,087	.2
Biomass ²	2,093	2,046	2.3
Wind	0	0	0
Solar Thermal	0	0	0
Photovoltaic	3	3	0
Hydroelectric Pumped Storage ⁴	-4,177	-4,541	-8.0
Consumption			
Coal (million short tons)	780	772	1.0
Petroleum (million barrels) ⁵	147	185	-20.5
Gas (billion cubic feet)	2,766	2,789	-.8
Stocks (Year End)			
Coal (million short tons)	154	158	-2.5
Petroleum (million barrels) ⁶	72	75	-4.0
Receipts			
Coal (million short tons)	776	770	.8
Petroleum (million barrels) ⁷	144	170	-15.3
Gas (billion cubic feet) ⁸	2,638	2,631	.3
Cost (cents per million Btu)⁹			
Coal	141.2	144.7	-2.4
Petroleum ¹⁰	255.1	254.8	.1
Gas	232.8	215.3	8.1
Sales To Ultimate Consumers			
(million kilowatthours)	2,763,343	2,762,003	0
Residential	935,940	955,417	-2.0
Commercial	761,269	765,664	-.6
Industrial	972,691	946,583	2.8
Other ¹¹	93,443	94,339	-.9
Revenue From Sales to Ultimate Consumers			
(billion dollars)	188	186	1.1
Residential	77	77	0
Commercial	58	58	0
Industrial	47	46	2.2
Other ¹¹	6	6	0
Average Revenue per Kilowatthour (cents)			
Residential	6.8	6.7	1.5
Commercial	8.2	8.0	2.5
Industrial	7.7	7.5	2.7
Other ¹¹	4.8	4.8	0
	6.7	6.5	3.1
Emissions (thousand short tons)¹²			
Sulfur Dioxide (SO ₂)	14,981	15,336	-2.3
Nitrogen Oxides (NO _x)	7,889	7,892	0
Carbon Dioxide (CO ₂)	1,858,772	1,871,561	-.7
Noncoincident Summer Peak Load (megawatts)	549,211	551,106	-.3
DSM Actual Peak Load Reductions (megawatts)	17,657	16,739	5.5
DSM Energy Savings (million kilowatthours)	31,767	23,343	36.1
DSM Cost (million dollars)	2,243	1,748	28.3

**Table 1. Electric Power Industry Summary Statistics for the United States, 1992 and 1991
(Continued)**

Item	1992 1MW or >	1992 5MW or >	1991 5MW or >	Percent Change
Nonutility Power Producers				
Installed Capacity (megawatts)	56,814	55,163	48,171	14.5
Coal ¹³	8,503	8,443	7,291	15.8
Petroleum Only ¹⁴	1,730	1,579	1,207	30.8
Gas Only ¹⁵	21,542	21,104	20,259	4.2
Petroleum/Natural Gas (combined)	8,478	8,354	5,049	65.5
Nuclear ¹⁶	20	20	20	.0
Renewable				
Hydroelectric (conventional)	2,684	2,133	1,587	34.4
Geothermal	1,254	1,243	1,048	18.6
Biomass ²	9,812	9,540	9,207	3.6
Wind	1,822	1,786	1,652	8.1
Solar Thermal	354	354	354	.0
Photovoltaic	7	7	7	.0
Other ¹⁷	611	602	491	22.6
Gross Generation (million kilowatthours)	296,001	289,856	248,448	16.7
Coal ¹³	47,363	47,160	40,587	16.2
Petroleum ¹⁴	10,963	10,692	7,814	36.8
Gas ¹⁵	158,798	156,317	131,340	19.0
Nuclear ¹⁶	67	67	80	-16.3
Renewable				
Hydroelectric (conventional)	9,446	7,611	6,243	21.9
Geothermal	8,578	8,533	7,651	11.5
Biomass ²	53,607	52,354	47,741	9.7
Wind	2,916	2,872	2,606	10.2
Solar Thermal	743	743	774	-4.0
Photovoltaic	4	4	5	-20.0
Other ¹⁷	3,516	3,504	3,609	-2.9
Supply and Disposition (million kilowatthours)				
Gross Generation	296,001	289,856	248,448	16.7
Receipts ¹⁸	83,421	76,198	68,264	11.6
Deliveries ¹⁹	175,160	171,836	140,537	22.3
Facility Use	204,261	194,218	176,175	10.2
Emissions (thousand short tons)²⁰				
Sulfur Dioxide (SO ₂)	1,219	1,201	1,112	8.0
Nitrogen Oxides (NO _x)	1,259	1,234	1,101	12.1
Carbon Dioxide (CO ₂)	549,832	540,189	487,963	10.7

¹ 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.

² 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.

³ Includes petroleum coke.

⁴ Represents total pumped storage facility production minus energy used for pumping.

⁵ Does not include petroleum coke consumption of 780 thousand short tons in 1992 and 722 thousand short tons in 1991.

⁶ Does not include petroleum coke stocks of 65 thousand short tons at year end 1992 and 70 thousand short tons at year end 1991.

⁷ Does not include petroleum coke receipts of 687 thousand short tons in 1992 and 485 thousand short tons in 1991.

⁸ Includes small amounts of coke-oven, refinery, and blast furnace gas.

⁹ 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.

¹⁰ Does not include petroleum coke cost of 75.0 cents per million Btu in 1992 and 81.0 cents per million Btu in 1991.

¹¹ Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

¹² Includes only those power plants with a fossil-fueled steam-electric nameplate capacity (existing or planned) of 10 or more megawatts. As of 1992, 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.

¹³ Includes coal, anthracite culm and coal waste.

¹⁴ Includes petroleum coke, diesel, kerosene, and petroleum sludge and tar.

¹⁵ Includes natural gas, butane, ethane, propane, waste heat and waste gases.

¹⁶ 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.

¹⁷ Includes hydrogen, sulfur, batteries, chemicals, and spent sulfite liquor.

¹⁸ Includes purchases, interchanges, and exchanges of electric energy with utilities and other nonutilities.

¹⁹ 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.

²⁰ As of 1992, 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.

²¹ DSM = Demand-Side Management.

Notes: •Data for nonutility power producers, demand-side management, emissions, sales to ultimate consumers, revenue from sales, and average revenue per kilowatthour are preliminary for 1992; 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.

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.²⁴ 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, as well as, providing 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.²⁵ 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.

²⁴Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(93/10), pp. 11 and 35.

²⁵As of the year-end 1992, about 3 percent of the operable capability was inactive. Energy Information Administration, *Inventory of Power Plants in the United States 1992*, DOE/EIA-0095(92), 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.²⁶ 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*,

²⁶A 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, magma²⁷ 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

²⁷Magma 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 1988 through 1992, as well as capability additions planned by electric utilities for 1993 through 2002.

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 retrofiting 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 1984. 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 870 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 capability additions are published in the *Inventory of Power Plants in the United States*.²⁸

Table 2. Generating Capability at U.S. Electric Utilities by Prime Mover and Primary Energy Source, End of Year, 1988 Through 1992 (Megawatts)

Prime Mover/Primary Energy Source	1992	1991	1990	1989	1988
Fossil Steam	446,201	^a 446,575	446,985	443,866	441,947
Coal-Fired	300,547	299,611	299,876	296,614	294,685
Petroleum-Fired	44,472	45,711	49,789	51,340	51,137
Gas-Fired	101,182	101,253	97,320	95,912	96,124
Gas Turbine/Internal Combustion	54,291	52,790	50,861	50,022	48,604
Petroleum-Fired	27,381	27,235	27,275	27,018	26,352
Gas-Fired	26,910	25,555	23,516	23,004	22,252
Hydroelectric	93,375	92,031	90,885	90,467	90,284
Nuclear	98,985	99,589	99,624	98,161	94,695
Other^c	2,207	2,031	2,111	2,103	2,124
U.S. Total	695,059	693,016	690,465	684,619	677,654

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

^b R Revised to correct total value.

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."

²⁸Energy Information Administration, *Inventory of Power Plants in the United States 1992*, DOE/EIA-0095(92)(Washington, DC, October 1993).

Table 3. Summary of Capability Additions, Retirements, and Total Operable Capability at U.S. Electric Utilities by Energy Source, End of Year, 1992

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	1	498	5	254	1,238	300,547
Petroleum	40	460	42	529	3,239	71,852
Gas	17	1,758	16	1,061	2,115	128,092
Hydroelectric	23	624	0	0	3,497	93,375
Nuclear	0	0	2	603	109	98,985
Other ²	0	0	3	67	70	2,207
U.S. Total	81	3,341	68	2,514	10,268	695,059

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. •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, 1993 Through 2002

Year	Total		Petroleum & Gas		Coal	
	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)
1993	60	3,757	48	2,538	0	0
1994	58	4,271	40	2,369	1	540
1995	58	4,948	43	3,575	1	391
1996	62	3,938	35	2,412	5	1,312
1997	40	2,978	31	2,729	1	93
1998	45	4,250	36	3,708	2	483
1999	46	6,197	32	3,046	5	1,830
2000	43	4,989	37	2,941	4	2,025
2001	48	4,514	45	4,283	1	220
2002	43	5,021	41	3,841	2	1,180
1993-2002	503	44,863	388	31,443	22	8,074

	Nuclear		Hydroelectric		Other ²	
	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)
1993	1	1,150	10	68	1	•
1994	1	1,170	16	193	0	0
1995	0	0	13	981	1	1
1996	0	0	22	214	0	0
1997	0	0	8	156	0	0
1998	0	0	6	55	1	4
1999	1	1,170	8	151	0	0
2000	0	0	2	22	0	0
2001	0	0	0	0	2	10
2002	0	0	0	0	0	0
1993-2002	3	3,490	85	1,840	5	16

¹ Net summer capability.

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

• 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 5. Generating Capability at Electric Utilities by Census Division and State, End of Year, 1992 and 1991

Census Division State	1992		1991	
	Number of Generators	Capability ¹ (megawatts)	Number of Generators	Capability ¹ (megawatts)
New England	670	22,644	680	23,209
Connecticut	87	6,988	90	7,060
Maine	188	2,405	189	2,417
Massachusetts	196	9,494	201	9,771
New Hampshire	43	2,507	44	2,609
Rhode Island	21	156	24	261
Vermont	135	1,094	132	1,091
Middle Atlantic	967	78,378	976	78,411
New Jersey	119	13,824	119	13,725
New York	614	31,108	623	31,349
Pennsylvania	234	33,446	234	33,337
East North Central	1,679	113,499	1,682	113,735
Illinois	333	32,636	334	32,643
Indiana	155	20,821	152	20,773
Michigan	559	22,374	557	22,275
Ohio	241	27,130	250	27,540
Wisconsin	391	10,537	389	10,504
West North Central	1,865	54,722	1,875	54,597
Iowa	406	8,092	404	8,090
Kansas	425	9,693	429	9,609
Minnesota	328	8,880	328	8,884
Missouri	342	15,385	342	15,308
Nebraska	247	5,453	249	5,450
North Dakota	45	4,476	48	4,546
South Dakota	72	2,744	75	2,710
South Atlantic	1,340	133,242	1,332	131,530
Delaware	27	2,082	31	2,162
District of Columbia	4	806	4	806
Florida	365	33,411	357	32,708
Georgia	206	21,399	202	20,752
Maryland	111	10,862	110	10,723
North Carolina	200	20,148	200	20,131
South Carolina	216	16,314	216	16,162
Virginia	155	13,772	156	13,652
West Virginia	56	14,448	56	14,435
East South Central	474	58,557	474	58,520
Alabama	147	19,930	147	19,902
Kentucky	110	15,300	110	15,333
Mississippi	52	7,032	52	7,016
Tennessee	165	16,294	165	16,269
West South Central	807	101,890	806	101,458
Arkansas	102	9,639	100	9,634
Louisiana	109	16,699	111	16,795
Oklahoma	153	12,881	153	12,848
Texas	443	62,671	442	62,180
Mountain	814	49,674	800	49,411
Arizona	122	14,973	119	14,910
Colorado	167	6,642	167	6,610
Idaho	115	2,357	112	2,282
Montana	95	4,871	100	4,828
Nevada	65	5,119	65	5,125
New Mexico	54	5,062	52	5,045
Utah	140	4,802	133	4,785
Wyoming	56	5,847	52	5,826
Pacific Contiguous	1,119	79,221	1,116	79,078
California	653	43,763	651	43,599
Oregon	189	11,237	189	11,236
Washington	277	24,221	276	24,243
Pacific Noncontiguous	533	3,232	519	3,068
Alaska	438	1,672	426	1,547
Hawaii	95	1,560	93	1,521
U.S. Total	10,268	695,059	10,260	693,016

¹ Net 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, 1992

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	2,646	8	6,393	369	3,132	5	111
Connecticut	1	385	4	3,212	35	135	2	64
Maine	0	0	1	870	133	420	0	0
Massachusetts	9	1,684	1	665	64	1,855	0	0
New Hampshire	5	578	1	1,150	31	290	0	0
Rhode Island	0	0	0	0	1	1	0	0
Vermont	0	0	1	496	105	430	3	47
Middle Atlantic	99	23,041	19	17,415	379	7,357	0	0
New Jersey	8	1,629	4	3,853	3	360	0	0
New York	32	3,897	6	4,831	331	5,085	0	0
Pennsylvania	59	17,515	9	8,731	45	1,912	0	0
East North Central	391	76,763	23	20,103	482	2,844	10	196
Illinois	58	14,947	13	12,609	14	10	0	0
Indiana	80	19,562	0	0	21	69	0	0
Michigan	80	11,976	5	3,942	232	2,198	0	0
Ohio	120	23,164	2	2,046	9	125	3	90
Wisconsin	53	7,114	3	1,506	206	443	7	106
West North Central	204	35,032	8	5,600	161	3,913	12	88
Iowa	50	5,909	1	515	25	125	0	0
Kansas	20	5,149	1	1,159	0	0	2	*
Minnesota	53	5,771	3	1,547	54	143	10	88
Missouri	48	10,782	1	1,125	29	1,112	0	0
Nebraska	15	3,066	2	1,254	20	168	0	0
North Dakota	12	3,856	0	0	5	545	0	0
South Dakota	6	499	0	0	28	1,821	0	0
South Atlantic	216	64,541	27	23,543	457	11,952	3	*
Delaware	5	931	0	0	0	0	0	0
District of Columbia	0	0	0	0	0	0	0	0
Florida	29	10,034	5	3,830	7	47	0	0
Georgia	39	13,104	4	3,741	118	2,815	0	0
Maryland	15	4,617	2	1,650	13	428	0	0
North Carolina	47	12,500	5	4,639	104	1,962	0	0
South Carolina	24	4,812	7	6,364	125	3,485	0	0
Virginia	24	4,215	4	3,319	68	3,108	3	*
West Virginia	33	14,328	0	0	22	108	0	0
East South Central	143	36,605	8	8,275	205	7,477	0	0
Alabama	42	11,599	5	4,836	89	2,934	0	0
Kentucky	58	14,096	0	0	30	795	0	0
Mississippi	6	2,227	1	1,143	0	0	0	0
Tennessee	37	8,683	2	2,296	86	3,747	0	0
West South Central	57	31,305	7	7,332	124	2,946	1	*
Arkansas	5	3,817	2	1,694	40	1,293	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	19,271	3	3,632	47	644	1	*
Mountain	103	28,693	3	3,810	418	10,266	9	39
Arizona	14	5,070	3	3,810	41	2,779	0	0
Colorado	31	4,954	0	0	47	1,078	0	0
Idaho	0	0	0	0	112	2,302	0	0
Montana	6	2,260	0	0	84	2,478	2	13
Nevada	8	2,692	0	0	17	1,031	0	0
New Mexico	13	3,901	0	0	6	59	0	0
Utah	12	4,271	0	0	82	251	7	27
Wyoming	19	5,545	0	0	29	287	0	0
Pacific Contiguous	5	1,868	6	6,514	846	43,132	27	1,772
California	0	0	4	4,310	417	13,169	25	1,715
Oregon	1	508	1	1,104	175	9,011	1	11
Washington	4	1,360	1	1,100	254	20,952	1	46
Pacific Noncontiguous	5	54	0	0	56	356	3	*
Alaska	5	54	0	0	52	352	3	*
Hawaii	0	0	0	0	4	3	0	0
U.S. Total	1,238	300,547	109	98,985	3,497	93,375	70	2,207

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, 1992

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	44	5,533	2	105	22	3,088	68	8,726
Connecticut	19	2,288	0	0	2	528	21	2,816
Maine	13	1,042	0	0	0	0	13	1,042
Massachusetts	12	2,203	2	105	16	2,026	30	4,334
New Hampshire	0	0	0	0	1	406	1	406
Rhode Island	0	0	0	0	3	128	3	128
Vermont	0	0	0	0	0	0	0	0
Middle Atlantic	46	9,238	43	8,827	11	2,303	100	20,168
New Jersey	15	1,286	14	1,916	3	117	32	3,319
New York	18	4,692	28	6,510	8	2,186	54	13,388
Pennsylvania	13	3,260	1	201	0	0	14	3,461
East North Central	24	5,071	20	702	9	1,069	53	6,842
Illinois	13	3,116	8	180	6	166	27	3,461
Indiana	5	193	2	120	0	0	7	313
Michigan	5	1,699	3	294	3	903	11	2,895
Ohio	1	64	1	17	0	0	2	81
Wisconsin	0	0	6	92	0	0	6	92
West North Central	5	72	77	2,509	5	58	87	2,639
Iowa	3	22	6	121	0	0	9	142
Kansas	0	0	45	1,890	3	22	48	1,912
Minnesota	2	50	9	86	0	0	11	136
Missouri	0	0	5	90	2	36	7	126
Nebraska	0	0	11	259	0	0	11	259
North Dakota	0	0	0	0	0	0	0	0
South Dakota	0	0	1	64	0	0	1	64
South Atlantic	50	6,643	63	5,809	40	8,248	153	20,700
Delaware	1	84	0	0	4	576	5	660
District of Columbia	2	550	0	0	0	0	2	550
Florida	26	3,833	51	5,314	24	5,109	101	14,257
Georgia	2	115	5	98	5	352	12	565
Maryland	12	1,012	1	137	3	1,302	16	2,451
North Carolina	2	28	1	68	0	0	3	96
South Carolina	2	92	3	69	3	91	8	252
Virginia	3	929	2	122	1	818	6	1,869
West Virginia	0	0	0	0	0	0	0	0
East South Central	2	58	31	2,727	3	863	36	3,649
Alabama	0	0	1	50	0	0	1	50
Kentucky	2	58	1	115	0	0	3	173
Mississippi	0	0	29	2,562	3	863	32	3,426
Tennessee	0	0	0	0	0	0	0	0
West South Central	3	298	321	55,843	0	0	324	55,941
Arkansas	0	0	16	2,515	0	0	16	2,515
Louisiana	2	212	74	10,948	0	0	76	11,160
Oklahoma	0	0	33	6,127	0	0	33	6,127
Texas	1	86	198	36,054	0	0	199	36,140
Mountain	0	0	72	3,698	0	0	72	3,698
Arizona	0	0	21	1,509	0	0	21	1,509
Colorado	0	0	15	263	0	0	15	263
Idaho	0	0	0	0	0	0	0	0
Montana	0	0	1	70	0	0	1	70
Nevada	0	0	9	725	0	0	9	725
New Mexico	0	0	24	966	0	0	24	966
Utah	0	0	2	166	0	0	2	166
Wyoming	0	0	0	0	0	0	0	0
Pacific Contiguous	2	86	111	20,712	13	1,256	126	22,053
California	0	0	110	20,563	13	1,256	123	21,819
Oregon	0	0	1	148	0	0	1	148
Washington	2	86	0	0	0	0	2	86
Pacific Noncontiguous	25	1,152	2	85	0	0	27	1,237
Alaska	0	0	2	85	0	0	2	85
Hawaii	25	1,152	0	0	0	0	25	1,152
U.S. Total	201	28,151	742	100,618	103	16,885	1,046	145,654

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-860, "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, 1992

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	1,127	9	114	14	395	205	1,636
Connecticut	24	375	0	0	0	0	24	375
Maine	41	73	0	0	0	0	41	73
Massachusetts	70	465	9	114	13	378	92	957
New Hampshire	4	66	0	0	1	17	5	83
Rhode Island	17	27	0	0	0	0	17	27
Vermont	26	120	0	0	0	0	26	120
Middle Atlantic	236	5,672	124	4,674	10	52	370	10,397
New Jersey	28	2,002	43	2,838	1	23	72	4,663
New York	112	2,085	70	1,794	9	29	191	3,908
Pennsylvania	96	1,585	11	242	0	0	107	1,827
East North Central	393	3,003	248	3,026	79	722	720	6,751
Illinois	78	591	115	964	28	56	221	1,610
Indiana	26	287	16	580	5	11	47	878
Michigan	143	530	70	780	18	53	231	1,362
Ohio	62	809	30	396	13	419	105	1,625
Wisconsin	84	787	17	307	15	183	116	1,277
West North Central	600	3,682	409	2,966	384	802	1,393	7,450
Iowa	161	479	53	686	107	235	321	1,400
Kansas	58	317	133	882	163	275	354	1,473
Minnesota	112	839	46	219	39	136	197	1,195
Missouri	137	1,390	69	730	51	120	257	2,240
Nebraska	81	300	98	372	20	34	199	706
North Dakota	26	65	2	10	0	0	28	75
South Dakota	25	291	8	68	4	2	37	361
South Atlantic	249	5,783	148	4,475	87	2,247	484	12,505
Delaware	13	122	3	336	1	33	17	491
District of Columbia	2	256	0	0	0	0	2	256
Florida	117	3,033	97	2,020	9	190	223	5,242
Georgia	22	942	1	5	10	227	33	1,174
Maryland	43	719	20	990	2	7	65	1,716
North Carolina	16	273	8	178	17	500	41	951
South Carolina	8	182	14	692	30	529	52	1,402
Virginia	27	245	5	255	18	761	50	1,261
West Virginia	1	12	0	0	0	0	1	12
East South Central	31	1,205	48	1,298	3	50	82	2,552
Alabama	1	18	9	494	0	0	10	512
Kentucky	8	76	8	110	3	50	19	236
Mississippi	2	31	11	206	0	0	13	237
Tennessee	20	1,080	20	488	0	0	40	1,568
West South Central	60	293	201	4,021	33	51	294	4,365
Arkansas	19	204	9	105	11	11	39	320
Louisiana	1	16	24	174	0	0	25	190
Oklahoma	11	30	46	814	16	28	73	871
Texas	29	42	122	2,929	6	12	157	2,983
Mountain	96	384	93	2,488	20	295	209	3,167
Arizona	2	75	37	1,727	4	3	43	1,805
Colorado	42	141	20	125	12	80	74	346
Idaho	3	56	0	0	0	0	3	56
Montana	0	0	2	50	0	0	2	50
Nevada	20	48	7	411	4	212	31	671
New Mexico	6	24	5	113	0	0	11	137
Utah	15	26	22	62	0	0	37	88
Wyoming	8	15	0	0	0	0	8	15
Pacific Contiguous	42	636	59	2,781	8	465	109	3,881
California	32	542	46	1,846	6	362	84	2,750
Oregon	2	6	6	345	2	103	10	454
Washington	8	88	7	590	0	0	15	678
Pacific Noncontiguous	415	866	26	681	1	38	442	1,585
Alaska	349	462	26	681	1	38	376	1,181
Hawaii	66	404	0	0	0	0	66	404
U.S. Total	2,304	22,649	1,365	26,525	639	5,116	4,308	54,291

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-860, "Annual Electric Generator Report."

Table 9. Planned Capability Additions at Electric Utilities by Energy Source, North American Electric Reliability Council Region, and Hawaii, 1993 Through 2002

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	38	3,317	32	2,641	1	600
ERCOT	42	7,195	39	4,545	2	1,500
MAAC	37	4,115	36	3,815	1	300
MAIN	62	5,779	54	5,169	4	593
MAPP(U.S.)	20	1,208	18	767	2	441
NPCC(U.S.)	18	552	6	433	0	0
SERC	145	15,941	135	10,585	5	2,145
SPP	35	2,792	26	1,173	4	1,540
WSCC(U.S.)	101	3,931	37	2,283	3	955
Contiguous U.S.	498	44,630	383	31,410	22	8,074
ASCC	3	1	3	1	0	0
Hawaii	2	32	2	32	0	0
U.S. Total	503	44,663	388	31,443	22	8,074

	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	77	0	0
ERCOT	1	1,150	0	0	0	0
MAAC	0	0	0	0	0	0
MAIN	0	0	1	2	3	14
MAPP(U.S.)	0	0	0	0	0	0
NPCC(U.S.)	0	0	12	119	0	0
SERC	2	2,340	3	870	0	0
SPP	0	0	5	80	0	0
WSCC(U.S.)	0	0	59	692	2	1
Contiguous U.S.	3	3,490	85	1,840	5	16
ASCC	0	0	0	0	0	0
Hawaii	0	0	0	0	0	0
U.S. Total	3	3,490	85	1,840	5	16

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 1989. •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, 1993 Through 2002

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	10	340	3	291	0	0
Connecticut	0	0	0	0	0	0
Maine	5	47	0	0	0	0
Massachusetts	0	0	0	0	0	0
New Hampshire	0	0	0	0	0	0
Rhode Island	3	291	3	291	0	0
Vermont	2	2	0	0	0	0
Middle Atlantic	22	2,276	17	2,206	0	0
New Jersey	14	2,064	14	2,064	0	0
New York	8	212	3	142	0	0
Pennsylvania	0	0	0	0	0	0
East North Central	81	7,199	71	6,588	4	593
Illinois	26	3,239	26	3,239	0	0
Indiana	12	961	12	961	0	0
Michigan	1	1	1	1	0	0
Ohio	12	647	10	645	0	0
Wisconsin	30	2,351	22	1,742	4	593
West North Central	52	3,734	46	1,753	6	1,981
Iowa	10	326	9	308	1	18
Kansas	13	712	12	32	1	680
Minnesota	4	174	4	174	0	0
Missouri	19	1,814	16	954	3	860
Nebraska	5	285	5	285	0	0
North Dakota	1	423	0	0	1	423
South Dakota	0	0	0	0	0	0
South Atlantic	138	13,686	129	10,371	6	2,445
Delaware	3	131	3	131	0	0
District of Columbia	0	0	0	0	0	0
Florida	38	3,914	37	3,476	1	438
Georgia	42	3,718	39	2,848	0	0
Maryland	20	1,919	19	1,619	1	300
North Carolina	16	1,266	16	1,266	0	0
South Carolina	11	1,723	9	798	2	925
Virginia	8	1,013	6	231	2	782
West Virginia	0	0	0	0	0	0
East South Central	43	6,014	37	2,999	1	600
Alabama	23	1,638	23	1,638	0	0
Kentucky	13	1,709	9	1,034	1	600
Mississippi	5	328	5	328	0	0
Tennessee	2	2,340	0	0	0	0
West South Central	53	7,764	45	5,035	2	1,500
Arkansas	4	115	1	82	0	0
Louisiana	0	0	0	0	0	0
Oklahoma	3	220	1	174	0	0
Texas	46	7,429	43	4,779	2	1,500
Mountain	55	2,621	21	1,292	3	955
Arizona	8	538	2	131	1	360
Colorado	4	609	1	66	1	515
Idaho	6	99	0	0	0	0
Montana	8	191	0	0	0	0
Nevada	14	1,064	14	1,064	0	0
New Mexico	2	28	2	28	0	0
Utah	12	10	2	2	0	0
Wyoming	1	80	0	0	1	80
Pacific Contiguous	44	1,195	14	876	0	0
California	28	624	10	400	0	0
Oregon	3	408	3	408	0	0
Washington	13	163	1	67	0	0
Pacific Noncontiguous	5	33	5	33	0	0
Alaska	3	1	3	1	0	0
Hawaii	2	32	2	32	0	0
U.S. Total	503	44,863	388	31,443	22	8,074

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-860, "Annual Electric Generator Report."

Table 10. Planned Capability Additions at Electric Utilities by Energy Source, Census Division, and State, 1993 Through 2002 (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	49	0	0
Connecticut	0	0	0	0	0	0
Maine	0	0	5	47	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	0	0
Middle Atlantic	0	0	5	70	0	0
New Jersey	0	0	0	0	0	0
New York	0	0	5	70	0	0
Pennsylvania	0	0	0	0	0	0
East North Central	0	0	3	4	3	14
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	1	2	3	14
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	870	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	870	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	75	0	0
Alabama	0	0	0	0	0	0
Kentucky	0	0	3	75	0	0
Mississippi	0	0	0	0	0	0
Tennessee	2	2,340	0	0	0	0
West South Central	1	1,150	5	80	0	0
Arkansas	0	0	3	34	0	0
Louisiana	0	0	0	0	0	0
Oklahoma	0	0	2	46	0	0
Texas	1	1,150	0	0	0	0
Mountain	0	0	31	375	0	0
Arizona	0	0	5	47	0	0
Colorado	0	0	2	29	0	0
Idaho	0	0	6	99	0	0
Montana	0	0	8	191	0	0
Nevada	0	0	0	0	0	0
New Mexico	0	0	0	0	0	0
Utah	0	0	10	8	0	0
Wyoming	0	0	0	0	0	0
Pacific Contiguous	0	0	28	317	2	1
California	0	0	16	222	2	1
Oregon	0	0	0	0	0	0
Washington	0	0	12	96	0	0
Pacific Noncontiguous	0	0	0	0	0	0
Alaska	0	0	0	0	0	0
Hawaii	0	0	0	0	0	0
U.S. Total	3	3,490	85	1,840	5	16

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 1988 through 1992. 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 750) in the United States. More detailed statistics from the Form EIA-759 are published in the *Electric Power Monthly*.²⁹

Table 11. Net Generation from U.S. Electric Utilities by Energy Source, 1988 Through 1992
(Million Kilowatthours)

Energy Source	1992	1991	1990	1989	1988
Coal	1,575,895	1,551,167	1,559,606	1,553,661	1,540,653
Petroleum ¹	88,916	111,463	117,017	158,318	148,900
Steam	86,046	108,176	113,402	151,111	143,801
Gas Turbine/Internal Combustion	2,871	3,287	3,615	7,207	5,099
Gas	263,872	264,172	264,089	266,598	252,801
Steam	245,612	245,880	245,901	245,057	236,280
Gas Turbine/Internal Combustion	18,260	18,291	18,189	21,542	16,521
Hydroelectric	239,559	275,519	279,926	265,063	222,940
Nuclear	618,776	612,565	576,862	529,355	526,973
Other ²	10,200	10,137	10,651	11,309	11,984
U.S. Total	2,797,219	2,825,023	2,808,151	2,784,304	2,704,250

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."

²⁹Energy 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, 1992 and 1991
(Million Kilowatthours)

Census Division State	Total		Fossil Steam		Gas Turbine/Internal Combustion	
	1992	1991	1992	1991	1992	1991
New England	84,585	87,008	41,111	46,912	575	988
Connecticut	25,154	23,552	7,638	10,452	11	24
Maine	8,335	9,519	1,261	1,267	*	2
Massachusetts	32,838	35,802	27,429	30,207	553	946
New Hampshire	13,451	12,705	4,618	4,728	*	1
Rhode Island	109	171	101	162	8	10
Vermont	4,698	5,259	64	96	2	4
Middle Atlantic	309,430	325,473	175,750	187,169	1,126	2,167
New Jersey	31,167	37,029	8,961	11,004	749	1,373
New York	112,229	126,077	62,172	72,080	309	643
Pennsylvania	166,034	162,367	104,617	104,085	68	150
East North Central	487,563	500,461	364,313	371,104	321	469
Illinois	124,824	127,851	50,998	55,879	24	54
Indiana	97,300	98,200	96,716	97,731	21	70
Michigan	82,679	94,567	62,726	66,444	228	247
Ohio	136,297	132,694	120,907	117,390	30	28
Wisconsin	46,464	47,149	32,967	33,660	17	71
West North Central	212,828	221,171	162,584	170,532	345	754
Iowa	29,427	31,228	24,994	26,049	32	130
Kansas	31,764	32,315	23,076	26,056	197	391
Minnesota	37,784	40,428	25,420	27,139	32	50
Missouri	56,627	60,121	47,043	48,931	51	139
Nebraska	22,387	22,972	12,527	13,842	30	38
North Dakota	28,592	27,535	26,893	25,778	*	*
South Dakota	6,246	6,573	2,631	2,738	3	6
South Atlantic	547,468	541,105	371,854	369,455	3,489	3,622
Delaware	6,267	7,604	5,999	7,125	269	479
District of Columbia	74	180	61	171	13	9
Florida	133,977	130,744	107,129	108,495	1,497	1,478
Georgia	91,779	90,809	58,401	60,123	40	31
Maryland	39,587	38,215	26,825	27,481	273	291
North Carolina	83,007	83,520	54,204	46,993	214	191
South Carolina	71,479	69,838	23,180	24,199	52	34
Virginia	48,964	48,941	24,144	23,969	1,132	1,111
West Virginia	72,334	71,254	71,911	70,898	*	*
East South Central	264,028	257,793	196,417	190,558	769	729
Alabama	90,792	85,051	61,074	58,386	61	33
Kentucky	77,351	75,505	73,582	71,845	2	2
Mississippi	20,488	23,305	11,676	13,532	638	640
Tennessee	75,396	73,932	50,085	46,794	68	54
West South Central	378,465	378,717	316,574	318,229	6,204	6,151
Arkansas	37,370	38,365	22,664	22,139	*	3
Louisiana	55,188	57,158	44,237	42,567	595	634
Oklahoma	45,943	44,850	39,981	39,981	2,752	3,013
Texas	239,964	238,343	209,692	213,541	2,857	2,501
Mountain	257,180	249,057	203,779	189,910	1,175	900
Arizona	70,109	66,767	36,721	33,966	868	608
Colorado	31,899	31,038	30,343	29,364	52	12
Idaho	6,260	8,282	--	--	*	*
Montana	25,468	28,157	17,157	16,159	8	15
Nevada	20,963	20,922	18,887	18,444	94	117
New Mexico	27,708	25,065	27,428	24,765	25	62
Utah	32,921	30,158	32,027	29,277	128	91
Wyoming	41,852	38,667	41,217	37,936	*	-4
Pacific Contiguous	244,645	252,619	68,647	54,146	3,549	2,305
California	119,310	104,968	55,324	43,414	1,611	1,124
Oregon	41,220	46,298	3,688	2,820	1,478	1,169
Washington	84,115	101,353	9,635	7,911	460	12
Pacific Noncontiguous	11,028	11,620	6,523	7,209	3,578	3,494
Alaska	4,167	4,286	722	791	2,527	2,600
Hawaii	6,861	7,333	5,801	6,419	1,051	894
U.S. Total	2,797,219	2,825,023	1,907,553	1,905,223	21,131	21,579

* 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 13. Net Generation from Electric Utilities by Energy Source, Census Division, and State, 1992 and 1991
(Million Kilowatthours)

Census Division State	Coal		Petroleum ¹		Gas	
	1992	1991	1992	1991	1992	1991
New England	16,284	17,147	21,293	26,393	4,109	4,360
Connecticut	2,148	2,118	5,297	7,890	203	468
Maine	--	--	1,262	1,269	--	--
Massachusetts	10,949	11,861	13,282	15,612	3,751	3,679
New Hampshire	3,187	3,168	1,374	1,561	57	*
Rhode Island	0	0	75	54	35	117
Vermont	--	--	3	5	63	95
Middle Atlantic	132,529	130,534	21,023	33,266	23,324	25,535
New Jersey	5,409	5,237	1,016	1,799	3,285	5,342
New York	24,921	24,938	17,786	27,754	19,774	20,031
Pennsylvania	102,199	100,359	2,221	3,714	265	163
East North Central	360,265	365,923	1,469	2,245	2,900	3,405
Illinois	49,815	53,955	434	906	773	1,072
Indiana	95,746	96,527	287	354	704	920
Michigan	61,435	65,138	498	554	1,022	998
Ohio	120,529	116,813	195	369	213	235
Wisconsin	32,741	33,489	54	62	189	180
West North Central	160,162	165,439	846	844	1,922	5,003
Iowa	24,844	25,870	36	47	146	262
Kansas	22,153	23,435	45	53	1,076	2,959
Minnesota	24,443	26,186	639	576	370	426
Missouri	46,830	47,908	81	119	183	1,044
Nebraska	12,402	13,563	9	13	145	303
North Dakota	26,865	25,751	29	28	*	*
South Dakota	2,626	2,727	7	8	1	9
South Atlantic	318,715	310,846	34,641	38,763	21,987	23,468
Delaware	3,814	4,588	1,830	1,899	624	1,106
District of Columbia	--	--	74	180	--	--
Florida	61,631	61,123	28,176	30,116	18,818	18,735
Georgia	58,235	59,985	128	108	77	61
Maryland	23,625	22,623	2,612	3,935	861	1,214
North Carolina	54,011	46,762	147	174	259	247
South Carolina	23,014	23,166	68	83	150	984
Virginia	22,676	21,939	1,423	2,036	1,177	1,104
West Virginia	71,708	70,649	182	232	21	17
East South Central	191,958	185,032	665	746	4,563	5,508
Alabama	60,690	57,897	82	104	363	417
Kentucky	73,476	71,714	84	112	24	22
Mississippi	7,796	8,750	372	370	4,147	5,052
Tennessee	49,996	46,671	127	160	30	17
West South Central	186,166	182,599	801	347	135,811	141,434
Arkansas	20,030	19,574	50	64	2,584	2,504
Louisiana	19,796	18,912	483	45	24,554	24,245
Oklahoma	27,666	26,028	15	19	15,051	16,947
Texas	118,673	118,085	254	219	93,621	97,739
Mountain	196,219	182,602	580	524	8,155	7,684
Arizona	34,602	32,306	73	89	2,914	2,178
Colorado	30,002	28,923	39	38	353	415
Idaho	--	--	*	*	--	--
Montana	17,126	16,132	16	18	23	24
Nevada	16,443	16,366	328	238	2,210	1,957
New Mexico	25,348	22,129	36	32	2,068	2,666
Utah	31,543	28,884	34	48	578	436
Wyoming	41,154	37,863	55	61	8	8
Pacific Contiguous	13,308	10,718	340	615	58,540	45,117
California	--	--	325	598	56,610	43,940
Oregon	3,683	2,814	9	10	1,474	1,164
Washington	9,625	7,904	6	7	464	12
Pacific Noncontiguous	290	326	7,258	7,720	2,552	2,657
Alaska	290	326	407	407	2,552	2,657
Hawaii	--	--	6,851	7,313	--	--
U.S. Total	1,575,895	1,551,167	88,916	111,463	263,872	264,172

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 13. Net Generation from Electric Utilities by Energy Source, Census Division, and State, 1992 and 1991 (Continued)
(Million Kilowatthours)

Census Division State	Nuclear		Hydroelectric ¹		Other ²	
	1992	1991	1992	1991	1992	1991
New England	38,474	33,820	3,959	4,740	466	549
Connecticut	16,771	12,243	360	394	374	439
Maine	5,358	6,264	1,715	1,985	--	--
Massachusetts	4,742	4,417	114	233	--	--
New Hampshire	7,869	6,788	964	1,188	--	--
Rhode Island	--	--	0	0	--	--
Vermont	3,735	4,108	806	941	92	109
Middle Atlantic	105,883	110,731	26,671	25,406	0	--
New Jersey	21,595	24,807	-138	-155	--	--
New York	24,155	28,448	25,593	24,906	0	--
Pennsylvania	60,133	57,476	1,217	656	--	--
East North Central	118,604	124,712	3,858	3,723	468	455
Illinois	73,742	71,866	52	53	8	--
Indiana	--	--	562	399	--	--
Michigan	18,849	27,021	876	856	--	--
Ohio	14,805	14,833	244	145	310	298
Wisconsin	11,207	10,991	2,123	2,270	150	157
West North Central	39,895	40,092	9,575	9,370	428	422
Iowa	3,405	4,147	981	883	14	20
Kansas	8,491	5,859	--	9	*	*
Minnesota	11,166	12,059	758	778	407	403
Missouri	8,084	9,979	1,450	1,072	--	--
Nebraska	8,748	8,048	1,075	1,045	6	--
North Dakota	--	--	1,699	1,757	--	--
South Dakota	--	--	3,612	3,828	--	--
South Atlantic	155,401	152,866	16,724	15,161	*	*
Delaware	--	--	--	--	--	--
District of Columbia	--	--	--	--	--	--
Florida	25,116	20,508	236	263	--	--
Georgia	27,996	26,016	5,342	4,639	--	--
Maryland	10,664	9,036	1,825	1,407	0	0
North Carolina	22,754	30,312	5,835	6,024	--	--
South Carolina	45,537	43,108	2,710	2,497	--	--
Virginia	23,334	23,886	353	-26	*	*
West Virginia	--	--	423	356	--	--
East South Central	43,225	41,594	23,617	24,912	--	--
Alabama	19,397	15,875	10,260	10,758	--	--
Kentucky	--	--	3,767	3,658	--	--
Mississippi	8,174	9,133	--	--	--	--
Tennessee	15,654	16,587	9,590	10,497	--	--
West South Central	46,178	46,418	9,228	7,642	281	276
Arkansas	11,326	12,662	3,380	3,561	--	--
Louisiana	10,356	13,956	--	--	--	--
Oklahoma	--	--	3,210	1,857	--	--
Texas	24,496	19,800	2,638	2,225	281	276
Mountain	25,609	25,096	26,352	32,903	265	249
Arizona	25,609	25,096	6,911	7,098	--	--
Colorado	--	--	1,505	1,663	0	*
Idaho	--	--	6,260	8,281	--	--
Montana	--	--	8,223	11,921	79	62
Nevada	--	--	1,982	2,362	--	--
New Mexico	--	--	255	237	--	--
Utah	--	--	580	604	186	186
Wyoming	--	--	636	736	--	--
Pacific Contiguous	45,509	37,237	118,648	150,745	8,292	8,186
California	35,244	31,542	19,205	20,975	7,925	7,912
Oregon	4,573	1,465	31,476	40,844	6	*
Washington	5,692	4,230	67,967	88,926	361	274
Pacific Noncontiguous	--	--	928	917	0	0
Alaska	--	--	918	896	0	0
Hawaii	--	--	10	20	0	0
U.S. Total	618,776	612,565	239,559	275,519	10,200	10,137

¹ Station losses include energy used for pumped storage. Energy used in 1992 for pumping was 23,249 million kilowatthours and in 1991 was 24,394 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, 1992 and 1991
(Million Kilowatthours)

Census Division State	Total ¹		Steam		Gas Turbine/Internal Combustion	
	1992	1991	1992	1991	1992	1991
New England	21,293	26,393	21,081	26,124	212	268
Connecticut	5,297	7,890	5,287	7,866	11	24
Maine	1,262	1,269	1,261	1,267	*	2
Massachusetts	13,282	15,612	13,091	15,386	191	226
New Hampshire	1,374	1,561	1,374	1,560	*	1
Rhode Island	75	54	67	45	8	10
Vermont	3	5	1	1	2	4
Middle Atlantic	21,023	33,266	20,766	32,689	257	577
New Jersey	1,016	1,799	913	1,619	103	179
New York	17,786	27,754	17,678	27,462	108	292
Pennsylvania	2,221	3,714	2,175	3,608	46	105
East North Central	1,469	2,245	1,447	2,176	23	69
Illinois	434	906	428	885	6	21
Indiana	287	354	286	347	1	7
Michigan	498	554	492	545	6	9
Ohio	195	369	188	360	7	9
Wisconsin	54	62	53	39	2	23
West North Central	846	844	809	762	38	82
Iowa	36	47	30	33	6	14
Kansas	45	53	27	30	17	23
Minnesota	639	576	636	566	3	10
Missouri	81	119	76	96	4	22
Nebraska	9	13	6	7	3	6
North Dakota	29	28	29	28	*	*
South Dakota	7	8	4	2	3	6
South Atlantic	34,641	38,763	33,896	37,914	745	850
Delaware	1,830	1,899	1,821	1,879	8	20
District of Columbia	74	180	61	171	13	9
Florida	28,176	30,116	27,630	29,487	546	629
Georgia	128	108	94	88	34	20
Maryland	2,612	3,935	2,570	3,848	42	87
North Carolina	147	174	124	161	23	13
South Carolina	68	83	58	78	10	5
Virginia	1,423	2,036	1,355	1,970	68	66
West Virginia	182	232	182	232	*	*
East South Central	665	746	615	699	50	47
Alabama	82	104	71	96	12	8
Kentucky	84	112	84	111	*	1
Mississippi	372	370	371	370	*	*
Tennessee	127	160	89	123	38	37
West South Central	801	347	787	324	14	23
Arkansas	50	64	49	61	*	3
Louisiana	483	45	486	45	-3	*
Oklahoma	15	19	14	16	1	3
Texas	254	219	237	201	16	18
Mountain	580	524	559	502	21	21
Arizona	73	89	67	87	5	2
Colorado	39	38	35	35	4	3
Idaho	*	*	---	---	*	*
Montana	16	18	15	17	*	1
Nevada	328	238	321	221	6	17
New Mexico	36	32	35	32	*	*
Utah	34	48	30	45	4	2
Wyoming	55	61	55	65	*	-4
Pacific Contiguous	340	615	285	566	55	49
California	325	598	275	555	50	43
Oregon	9	10	6	6	4	4
Washington	6	7	5	6	1	1
Pacific Noncontiguous	7,258	7,720	5,802	6,419	1,456	1,301
Alaska	407	407	1	*	406	407
Hawaii	6,851	7,313	5,801	6,419	1,051	894
U.S. Total	88,916	111,463	86,046	108,176	2,871	3,287

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, 1992 and 1991
(Million Kilowatthours)

Census Division State	Total		Steam		Gas Turbine/Internal Combustion	
	1992	1991	1992	1991	1992	1991
New England	4,109	4,360	3,746	3,640	363	720
Connecticut	203	468	203	468	--	--
Maine	--	--	--	--	--	--
Massachusetts	3,751	3,679	3,388	2,960	363	720
New Hampshire	57	*	57	--	0	*
Rhode Island	35	117	35	117	--	--
Vermont	63	95	63	95	--	--
Middle Atlantic	23,324	25,535	22,455	23,945	869	1,590
New Jersey	3,285	5,342	2,639	4,148	646	1,194
New York	19,774	20,031	19,573	19,680	201	351
Pennsylvania	265	163	243	118	22	45
East North Central	2,900	3,405	2,602	3,005	298	400
Illinois	773	1,072	755	1,039	18	33
Indiana	704	920	684	857	20	62
Michigan	1,022	998	800	760	222	238
Ohio	213	235	189	217	23	18
Wisconsin	189	180	173	131	15	48
West North Central	1,922	5,003	1,614	4,331	308	672
Iowa	146	262	120	146	26	116
Kansas	1,076	2,959	896	2,591	180	368
Minnesota	370	426	341	386	30	40
Missouri	183	1,044	137	927	47	117
Nebraska	145	303	119	272	26	32
North Dakota	*	*	*	*	*	*
South Dakota	1	9	1	9	*	*
South Atlantic	21,987	23,468	19,243	20,696	2,744	2,773
Delaware	624	1,106	364	648	260	458
District of Columbia	--	--	--	--	--	--
Florida	18,818	18,735	17,867	17,885	951	850
Georgia	77	61	71	49	6	12
Maryland	861	1,214	630	1,010	230	203
North Carolina	259	247	69	70	191	178
South Carolina	150	984	108	956	42	28
Virginia	1,177	1,104	113	60	1,064	1,044
West Virginia	21	17	21	17	--	--
East South Central	4,563	5,508	3,844	4,826	719	682
Alabama	363	417	313	393	49	24
Kentucky	24	22	22	21	1	1
Mississippi	4,147	5,052	3,508	4,412	638	640
Tennessee	30	17	0	0	30	17
West South Central	135,811	141,434	129,622	135,306	6,190	6,128
Arkansas	2,584	2,504	2,584	2,504	0	0
Louisiana	24,554	24,245	23,956	23,610	599	635
Oklahoma	15,051	16,947	12,301	13,937	2,751	3,010
Texas	93,621	97,739	90,781	95,255	2,840	2,483
Mountain	8,155	7,684	7,001	6,805	1,154	879
Arizona	2,914	2,178	2,052	1,573	862	605
Colorado	353	415	306	406	48	9
Idaho	--	--	--	--	--	--
Montana	23	24	15	10	8	14
Nevada	2,210	1,957	2,122	1,856	88	100
New Mexico	2,068	2,666	2,044	2,604	25	62
Utah	578	436	454	348	124	88
Wyoming	8	8	8	8	--	--
Pacific Contiguous	58,548	45,117	55,054	42,861	3,494	2,256
California	56,610	43,940	55,049	42,859	1,561	1,081
Oregon	1,474	1,164	0	--	1,474	1,164
Washington	464	12	5	2	459	10
Pacific Noncontiguous	2,552	2,657	431	464	2,121	2,193
Alaska	2,552	2,657	431	464	2,121	2,193
Hawaii	--	--	--	--	--	--
U.S. Total	263,872	264,172	245,612	245,880	18,260	18,291

* 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.⁴⁰ 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

⁴⁰Other fossil fuels include petroleum coke, refinery gas, coke oven gas, blast furnace gas, and liquified 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 750) in the United States. More detailed statistics on stocks and consumption are published in the *Electric Power Monthly*.³¹ 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*.³²

³¹Energy Information Administration, *Electric Power Monthly*, DOE/EIA-0226(93/1-12)(Washington, DC)

³²Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1992* DOE/EIA-0191(92)(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, 1988 Through 1992

Item	1992	1991	1990	1989	1988
Consumption					
Coal (thousand short tons)	779,860	772,268	773,549	766,888	758,372
Petroleum (thousand barrels) ¹	147,335	184,886	196,054	267,451	248,096
Gas (million cubic feet)	2,765,608	2,789,014	2,787,332	2,787,012	2,635,613
Stocks					
Coal (thousand short tons)	154,130	157,876	156,166	135,860	146,507
Petroleum (thousand barrels) ¹	71,849	74,993	83,501	61,270	69,285

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-759, "Monthly Power Plant Report."

Table 17. Receipts and Average Delivered Cost of Fossil Fuels at U.S. Electric Utilities, 1988 Through 1992

Item	1992	1991	1990	1989	1988
Receipts					
Coal (thousand short tons)	¹ 775,963	¹ 769,923	786,627	753,217	727,775
Petroleum (thousand barrels) ²	144,390	169,625	209,350	246,422	236,923
Gas (million cubic feet)	³ 2,637,678	³ 2,630,818	2,490,979	2,472,506	2,362,721
Cost (dollars)					
Coal (per short ton)	29.36	30.02	30.45	30.15	30.64
Contract	29.89	30.55	30.74	30.38	30.86
Spot	26.64	27.02	29.11	29.07	29.30
Petroleum (per barrel) ²	16.15	16.09	21.28	18.17	15.33
Contract	16.17	16.12	21.27	18.17	15.36
Spot	16.07	16.04	21.30	18.17	15.25
Gas (per thousand cubic feet)	2.38	2.20	2.38	2.42	2.33
Firm	2.37	2.19	2.27	2.34	2.22
Interruptible ⁴	2.40	2.22	2.48	2.50	2.47

¹ Data for 1991 and 1992 include approximately 2.9 million and 3 million short tons, respectively, of lignite delivered to Unit 4 of the Sandow Plant at the Texas Utilities Electric Company.

² Does not include petroleum coke

³ Data for 1991 and 1992 include an estimated 125 and 120 billion cubic feet of gas, respectively, received at combined-cycle gas turbines

⁴ Includes off-peak gas

Notes: •Data are final •As of 1991, data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts •Data for 1988-1990 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, 1992 and 1991

Census Division State	Coal (thousand short tons)		Petroleum ¹ (thousand barrels)		Gas (million cubic feet)	
	1992	1991	1992	1991	1992	1991
New England	6,112	6,421	34,982	42,791	42,343	46,564
Connecticut	817	840	8,788	13,029	2,100	4,702
Maine	--	--	2,237	2,307	--	--
Massachusetts	4,044	4,339	21,455	24,594	38,341	39,133
New Hampshire	1,251	1,242	2,315	2,704	633	0
Rhode Island	0	0	178	142	469	1,638
Vermont	--	--	8	15	801	1,091
Middle Atlantic	52,488	52,617	34,832	54,668	250,602	275,551
New Jersey	2,118	2,081	2,092	3,293	38,772	61,874
New York	9,963	9,874	29,201	45,315	208,731	211,640
Pennsylvania	40,407	40,662	3,538	6,060	3,100	2,037
East North Central	169,029	173,718	4,231	5,525	47,513	52,588
Illinois	25,264	27,754	2,271	3,044	9,293	12,865
Indiana	46,937	47,720	264	351	7,771	10,043
Michigan	28,238	29,896	1,125	1,230	24,908	23,736
Ohio	50,358	49,577	489	753	2,956	3,237
Wisconsin	18,231	18,771	82	147	2,584	2,706
West North Central	102,557	104,246	568	778	25,456	62,239
Iowa	15,357	15,846	90	109	2,265	3,671
Kansas	14,068	14,732	104	156	13,981	36,122
Minnesota	15,841	16,114	63	92	4,906	5,870
Missouri	23,815	24,286	209	287	2,351	12,709
Nebraska	7,881	8,524	25	30	1,903	3,689
North Dakota	23,192	22,174	58	69	1	1
South Dakota	2,402	2,570	19	35	48	177
South Atlantic	126,093	123,729	56,369	63,529	239,787	255,024
Delaware	1,628	1,958	2,708	2,808	8,384	14,354
District of Columbia	--	--	250	497	--	--
Florida	25,016	24,870	44,940	48,430	202,576	201,319
Georgia	23,656	24,848	268	213	1,162	838
Maryland	8,993	8,632	5,111	7,637	11,575	16,059
North Carolina	21,011	18,078	314	349	3,159	3,020
South Carolina	9,078	9,218	159	144	1,795	9,823
Virginia	8,661	8,568	2,310	3,112	10,936	9,471
West Virginia	28,050	27,557	307	340	201	140
East South Central	80,203	77,917	1,212	1,344	58,109	66,928
Alabama	24,988	23,700	141	163	3,368	4,081
Kentucky	31,715	31,432	195	228	269	227
Mississippi	3,237	3,570	651	681	54,180	62,409
Tennessee	20,263	19,216	225	272	291	211
West South Central	129,351	127,908	689	707	1,399,083	1,454,413
Arkansas	12,241	11,978	95	129	27,015	27,903
Louisiana	13,077	12,406	93	89	254,922	254,245
Oklahoma	16,699	15,668	28	38	148,980	167,214
Texas	87,333	87,856	473	452	968,165	1,005,051
Mountain	105,609	98,400	1,073	1,001	89,679	84,369
Arizona	17,280	16,116	135	159	30,939	23,282
Colorado	15,902	15,416	84	82	5,019	5,715
Idaho	--	--	1	1	--	--
Montana	10,768	10,223	35	41	220	268
Nevada	7,914	7,892	584	447	24,355	21,738
New Mexico	14,775	12,809	73	67	22,486	28,100
Utah	13,857	12,829	62	82	6,576	5,190
Wyoming	25,114	23,115	100	122	83	76
Pacific Contiguous	8,142	7,015	637	1,076	584,082	460,009
California	--	--	605	1,037	564,432	449,014
Oregon	1,994	1,831	19	23	14,264	10,856
Washington	6,148	5,184	13	16	5,385	139
Pacific Noncontiguous	277	298	12,743	13,465	28,953	31,330
Alaska	277	298	755	769	28,953	31,330
Hawaii	--	--	11,989	12,696	--	--
U.S. Total	779,660	772,268	147,335	184,886	2,765,608	2,789,014

¹ Does not include petroleum coke. Petroleum coke consumption in 1992 was 999 thousand short tons and in 1991 was 722 thousand short tons.

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 19. Petroleum Consumption at Electric Utilities by Selected Prime Mover,
Census Division, and State, 1992 and 1991
(Thousand Barrels)**

Census Division State	Total		Steam		Gas Turbine/Internal Combustion	
	1992	1991	1992	1991	1992	1991
New England	34,982	42,791	34,550	42,239	432	552
Connecticut	8,788	13,029	8,758	12,960	31	69
Maine	2,237	2,307	2,233	2,299	4	8
Massachusetts	21,455	24,594	21,083	24,156	372	439
New Hampshire	2,315	2,704	2,314	2,700	2	5
Rhode Island	178	142	162	123	17	19
Vermont	8	15	2	2	7	13
Middle Atlantic	34,832	54,668	34,116	53,115	716	1,553
New Jersey	2,092	3,293	1,827	2,794	266	499
New York	29,201	45,315	28,908	44,557	293	759
Pennsylvania	3,538	6,060	3,381	5,765	157	295
East North Central	4,231	5,525	4,105	5,259	126	267
Illinois	2,271	3,044	2,249	2,975	22	70
Indiana	264	351	255	327	8	24
Michigan	1,125	1,230	1,087	1,184	38	46
Ohio	489	753	451	698	38	55
Wisconsin	82	147	63	74	19	72
West North Central	568	778	408	496	160	282
Iowa	90	109	61	64	29	45
Kansas	104	156	64	93	41	63
Minnesota	63	92	39	51	24	41
Missouri	209	287	167	202	41	85
Nebraska	25	30	13	13	12	18
North Dakota	58	69	56	67	1	2
South Dakota	19	35	8	6	12	28
South Atlantic	56,369	63,529	54,653	61,408	1,716	2,121
Delaware	2,708	2,808	2,684	2,760	24	48
District of Columbia	250	497	204	464	46	33
Florida	44,940	48,430	43,769	46,921	1,172	1,509
Georgia	268	213	182	150	86	64
Maryland	5,111	7,637	5,008	7,440	103	197
North Carolina	314	349	214	264	101	86
South Carolina	159	144	103	116	56	28
Virginia	2,310	3,112	2,182	2,956	128	157
West Virginia	307	340	307	339	*	1
East South Central	1,212	1,344	1,121	1,226	91	117
Alabama	141	163	124	145	17	17
Kentucky	195	228	193	224	2	4
Mississippi	651	681	650	673	*	8
Tennessee	225	272	153	184	71	88
West South Central	689	707	648	651	41	56
Arkansas	95	129	94	120	1	9
Louisiana	93	89	92	87	1	1
Oklahoma	28	38	25	34	2	4
Texas	473	452	437	410	36	42
Mountain	1,073	1,001	1,018	940	55	61
Arizona	135	159	121	153	14	5
Colorado	84	82	72	72	12	10
Idaho	1	1	--	--	1	1
Montana	35	41	34	39	1	1
Nevada	584	447	565	409	19	38
New Mexico	73	67	72	67	1	1
Utah	62	82	54	77	8	5
Wyoming	100	122	100	122	0	0
Pacific Contiguous	637	1,076	501	963	136	112
California	605	1,037	482	933	124	104
Oregon	19	23	9	18	9	5
Washington	13	16	10	12	3	4
Pacific Noncontiguous	12,743	13,465	10,043	10,988	2,701	2,478
Alaska	755	769	4	1	751	768
Hawaii	11,989	12,696	10,039	10,986	1,950	1,710
U.S. Total	147,335	184,886	141,163	177,286	6,172	7,600

* Value less than 0.5.

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •Does not include petroleum coke. Petroleum coke consumption in 1992 was 999 thousand short tons and in 1991 was 722 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, 1992 and 1991**
(Million Cubic Feet)

Census Division State	Total		Steam		Gas Turbine/Internal Combustion	
	1992	1991	1992	1991	1992	1991
New England	42,343	46,564	38,657	37,703	3,686	8,861
Connecticut	2,100	4,702	2,100	4,702	--	--
Maine	--	--	--	--	--	--
Massachusetts	38,341	39,133	34,655	30,273	3,686	8,861
New Hampshire	633	0	633	--	0	0
Rhode Island	469	1,638	469	1,638	--	--
Vermont	801	1,091	801	1,091	--	--
Middle Atlantic	250,602	275,551	238,639	253,424	11,963	22,126
New Jersey	38,772	61,874	30,221	46,027	8,551	17,846
New York	208,731	211,640	205,618	206,077	3,113	5,564
Pennsylvania	3,100	2,037	2,801	1,320	299	717
East North Central	47,513	52,588	43,700	47,121	3,813	5,467
Illinois	9,293	12,865	9,002	12,407	291	458
Indiana	7,771	10,043	7,470	9,069	302	974
Michigan	24,908	23,736	22,470	20,964	2,438	2,772
Ohio	2,956	3,237	2,450	2,787	506	450
Wisconsin	2,584	2,706	2,308	1,894	276	813
West North Central	25,456	62,239	21,160	52,685	4,296	9,553
Iowa	2,265	3,671	1,735	2,003	531	1,668
Kansas	13,981	36,122	11,692	31,005	2,289	5,117
Minnesota	4,906	5,870	4,557	5,339	349	532
Missouri	2,351	12,709	1,602	10,902	750	1,807
Nebraska	1,903	3,689	1,530	3,278	372	411
North Dakota	1	1	1	*	*	*
South Dakota	48	177	43	158	5	19
South Atlantic	239,787	255,024	206,641	221,583	33,146	33,441
Delaware	8,384	14,354	5,818	8,784	2,566	5,570
District of Columbia	--	--	--	--	--	--
Florida	202,576	201,319	188,669	188,847	13,907	12,473
Georgia	1,162	838	1,065	676	97	162
Maryland	11,575	16,059	8,725	13,290	2,850	2,770
North Carolina	3,159	3,020	0	0	3,159	3,020
South Carolina	1,795	9,823	1,065	9,297	730	526
Virginia	10,936	9,471	1,098	549	9,838	8,922
West Virginia	201	140	201	140	--	--
East South Central	58,109	66,928	42,485	51,483	15,623	15,445
Alabama	3,368	4,081	3,030	3,843	338	238
Kentucky	269	227	240	205	29	22
Mississippi	54,180	62,409	39,215	47,436	14,965	14,973
Tennessee	291	211	0	0	291	211
West South Central	1,399,083	1,454,413	1,328,391	1,383,729	70,692	70,685
Arkansas	27,015	27,903	27,015	27,903	0	0
Louisiana	254,922	254,245	247,797	245,926	7,125	8,319
Oklahoma	148,980	167,214	119,089	135,876	29,892	31,338
Texas	968,165	1,005,051	934,490	974,024	33,675	31,028
Mountain	89,679	84,369	75,941	73,773	13,738	10,596
Arizona	30,939	23,282	21,545	16,761	9,394	6,521
Colorado	5,019	5,715	4,318	5,571	701	144
Idaho	--	--	--	--	--	--
Montana	220	268	116	80	104	188
Nevada	24,355	21,738	22,822	20,158	1,534	1,580
New Mexico	22,486	28,100	22,172	27,279	315	821
Utah	6,576	5,190	4,886	3,848	1,690	1,343
Wyoming	83	76	83	76	--	--
Pacific Contiguous	584,082	460,009	547,658	436,416	36,424	23,593
California	564,432	449,014	547,614	436,395	16,819	12,619
Oregon	14,264	10,856	0	--	14,264	10,856
Washington	5,385	139	44	20	5,340	119
Pacific Noncontiguous	28,953	31,330	0	0	28,953	31,330
Alaska	28,953	31,330	0	0	28,953	31,330
Hawaii	--	--	--	--	--	--
U.S. Total	2,765,608	2,789,014	2,543,273	2,557,917	222,335	231,097

* 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 21. Coal and Petroleum Stocks at Electric Utilities by Census Division and State,
as of December 31, 1992 and 1991**

Census Division State	Coal (thousand short tons)		Petroleum ¹ (thousand barrels)	
	1992	1991	1992	1991
New England	1,237	1,128	6,073	5,289
Connecticut	150	173	2,162	1,775
Maine	--	--	681	784
Massachusetts	727	583	2,563	2,411
New Hampshire	361	373	528	178
Rhode Island	0	0	104	111
Vermont	--	--	36	30
Middle Atlantic	17,743	16,638	15,536	15,628
New Jersey	771	681	1,822	2,190
New York	2,106	1,546	11,855	11,666
Pennsylvania	14,866	14,412	1,859	1,772
East North Central	40,250	39,394	2,798	2,757
Illinois	7,399	6,977	1,226	1,092
Indiana	11,294	9,953	180	183
Michigan	7,402	8,099	727	826
Ohio	10,395	10,213	467	462
Wisconsin	3,760	4,151	197	194
West North Central	19,712	20,169	1,694	1,782
Iowa	4,301	4,499	187	196
Kansas	2,747	3,310	655	688
Minnesota	2,175	2,616	167	159
Missouri	6,211	5,458	374	412
Nebraska	1,798	1,976	205	213
North Dakota	2,194	1,999	46	49
South Dakota	285	312	60	66
South Atlantic	27,977	28,746	14,357	15,039
Delaware	361	458	302	605
District of Columbia	--	--	118	119
Florida	4,021	4,781	8,221	8,689
Georgia	4,692	5,251	523	555
Maryland	2,400	2,220	1,610	1,879
North Carolina	4,512	4,657	231	257
South Carolina	2,206	1,988	343	378
Virginia	1,922	1,685	2,833	2,398
West Virginia	7,863	7,707	175	158
East South Central	13,401	14,210	1,651	1,622
Alabama	4,071	4,247	168	139
Kentucky	5,415	5,881	119	102
Mississippi	899	933	904	968
Tennessee	3,016	3,148	461	413
West South Central	16,483	17,694	8,297	7,943
Arkansas	1,572	2,150	269	259
Louisiana	1,701	2,235	1,743	1,295
Oklahoma	3,066	2,835	617	521
Texas	10,143	10,474	5,668	5,868
Mountain	16,009	18,086	1,383	1,892
Arizona	3,543	4,177	745	767
Colorado	3,410	3,466	185	221
Idaho	--	--	14	15
Montana	735	741	14	18
Nevada	1,447	1,412	253	689
New Mexico	1,570	1,399	103	120
Utah	3,153	4,123	28	30
Wyoming	2,153	2,767	42	32
Pacific Contiguous	1,312	1,804	18,841	21,672
California	--	--	18,211	21,022
Oregon	615	660	269	286
Washington	697	1,145	360	363
Pacific Noncontiguous	6	8	1,219	1,369
Alaska	6	8	306	241
Hawaii	--	--	914	1,128
U.S. Total	154,130	157,876	71,849	74,993

¹ Does not include petroleum coke. Petroleum coke stocks at the end of 1992 were 67 thousand short tons and in 1991 were 70 thousand short tons.

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,
1992 and 1991**

Census Division State	Coal (thousand short tons)		Petroleum ¹ (thousand barrels)		Gas (million cubic feet)	
	1992	1991	1992	1991	1992	1991
New England	6,213	6,433	35,861	39,568	42,087	45,852
Connecticut	793	871	9,108	11,724	2,000	4,690
Maine	---	---	2,198	2,235	---	---
Massachusetts	4,194	4,278	21,871	23,310	37,913	38,248
New Hampshire	1,226	1,284	2,605	2,132	916	---
Rhode Island	---	---	80	167	458	1,821
Vermont	---	---	---	---	800	1,093
Middle Atlantic	53,680	52,066	38,740	53,535	229,709	246,863
New Jersey	2,205	2,027	2,438	2,907	32,305	51,744
New York	10,393	9,235	32,680	45,887	195,476	194,870
Pennsylvania	41,082	40,804	3,622	4,741	1,929	249
East North Central	169,346	170,575	3,920	4,432	43,401	45,531
Illinois	25,449	26,813	2,299	2,341	8,952	11,126
Indiana	47,838	46,292	270	360	7,467	9,026
Michigan	27,875	28,866	929	1,024	22,222	20,720
Ohio	50,596	49,517	369	624	2,458	2,966
Wisconsin	17,589	19,087	54	83	2,700	1,693
West North Central	101,643	105,054	496	585	18,213	48,575
Iowa	15,037	16,344	60	70	1,816	2,083
Kansas	13,634	14,401	51	90	10,437	28,979
Minnesota	15,154	16,187	36	37	3,008	3,354
Missouri	24,502	25,204	288	314	1,592	10,820
Nebraska	7,759	8,908	8	8	1,310	3,166
North Dakota	23,427	21,683	53	62	*	*
South Dakota	2,130	2,326	---	4	39	172
South Atlantic	125,181	124,355	54,488	57,679	217,976	231,677
Delaware	1,532	2,002	2,214	2,448	2,188	5,087
District of Columbia	---	---	231	454	---	---
Florida	24,377	24,461	43,311	44,855	191,121	191,825
Georgia	22,851	24,694	217	217	1,199	790
Maryland	9,284	8,668	5,076	6,875	8,584	13,234
North Carolina	20,660	18,167	193	226	2,917	2,932
South Carolina	9,255	9,215	84	114	1,315	9,518
Virginia	8,915	8,599	2,801	2,158	10,433	8,096
West Virginia	28,307	28,549	361	333	219	196
East South Central	80,758	77,397	1,108	1,241	41,671	51,819
Alabama	24,886	24,350	131	153	2,923	3,434
Kentucky	32,292	30,591	221	248	240	205
Mississippi	3,208	3,727	607	657	38,508	48,180
Tennessee	20,372	18,730	149	183	---	---
West South Central	128,757	127,713	627	617	1,365,720	1,404,965
Arkansas	11,630	12,443	97	118	27,137	27,672
Louisiana	12,675	12,212	93	89	237,653	223,528
Oklahoma	16,840	15,868	115	21	145,415	163,914
Texas	87,613	87,189	324	389	955,515	989,850
Mountain	102,617	99,693	790	825	80,491	76,185
Arizona	16,315	17,020	140	133	29,420	22,575
Colorado	15,597	15,500	27	17	1,521	2,680
Idaho	---	---	---	---	---	---
Montana	10,860	10,398	16	22	118	83
Nevada	7,894	8,084	390	417	22,804	19,916
New Mexico	14,929	12,888	74	78	21,661	26,895
Utah	12,840	13,254	29	46	4,884	3,960
Wyoming	24,181	22,549	114	110	83	76
Pacific Contiguous	7,768	6,636	35	2,145	580,334	460,628
California	---	---	1	2,045	565,619	449,661
Oregon	1,932	1,719	19	84	14,684	10,940
Washington	5,836	4,917	15	15	30	27
Pacific Noncontiguous	---	---	8,324	8,998	18,086	18,722
Alaska	---	---	---	---	18,086	18,722
Hawaii	---	---	8,324	8,998	---	---
U. S. Total	775,963	769,923	144,390	169,625	2,637,678	2,630,818

¹ Does not include petroleum coke. Petroleum coke receipts in 1992 were 687 thousand short tons and in 1991 were 485 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, 1992 and 1991

Census Division State	Coal			Petroleum ¹			Gas		
	1992		1991	1992		1991	1992		1991
	(\$ 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	45.14	172.0	178.9	14.85	233.2	225.9	2.65	256.9	215.6
Connecticut	51.30	194.8	216.6	15.27	241.0	247.4	2.74	265.9	209.0
Maine	--	--	--	14.48	228.8	208.5	--	--	--
Massachusetts	44.11	168.7	172.5	15.03	236.3	221.0	2.68	259.3	218.4
New Hampshire	44.69	168.5	174.4	12.23	185.8	179.6	2.10	205.9	--
Rhode Island	--	--	--	12.50	195.0	241.1	2.20	213.4	198.0
Vermont	--	--	--	--	--	--	2.00	202.4	174.0
Middle Atlantic	37.56	149.6	156.5	16.92	267.3	273.6	2.45	237.4	217.2
New Jersey	46.62	173.1	178.2	18.96	303.3	302.1	2.18	210.9	195.7
New York	38.62	148.8	159.4	16.72	263.8	271.9	2.48	241.2	222.8
Pennsylvania	36.81	148.4	154.7	17.34	275.2	272.8	3.06	297.2	295.3
East North Central	32.05	145.6	148.7	20.23	326.9	336.3	1.56	221.2	218.1
Illinois	37.06	173.7	171.4	19.27	305.1	308.8	2.24	220.1	210.4
Indiana	27.89	131.2	134.4	25.57	443.3	493.9	2.48	247.7	237.7
Michigan	34.23	155.6	159.2	18.34	296.8	285.5	.81	195.4	195.9
Ohio	34.40	143.5	147.9	26.09	451.4	428.7	2.31	223.8	217.9
Wisconsin	25.92	133.3	135.8	27.19	463.7	445.8	2.42	240.0	270.3
West North Central	18.92	110.0	112.2	19.32	318.5	335.8	2.06	209.8	171.7
Iowa	19.58	110.4	110.4	24.57	424.0	437.7	3.08	306.8	268.5
Kansas	20.99	117.9	122.6	25.58	437.8	431.6	1.94	199.9	170.7
Minnesota	20.96	118.6	126.0	26.24	450.9	382.9	1.85	183.7	170.2
Missouri	27.57	133.6	134.2	14.67	234.9	261.9	1.89	187.2	149.1
Nebraska	12.77	74.6	74.5	26.87	464.9	457.3	2.28	238.2	196.8
North Dakota	9.45	72.1	70.9	26.72	457.7	426.1	4.18	403.3	433.9
South Dakota	13.68	113.3	113.3	--	--	487.9	2.88	282.7	175.8
South Atlantic	41.28	165.6	169.7	15.51	244.5	230.0	2.34	230.5	212.0
Delaware	45.31	173.4	178.2	15.31	241.8	237.9	2.70	260.0	236.9
District of Columbia	--	--	--	21.03	350.4	318.6	--	--	--
Florida	45.03	182.0	185.7	15.38	241.7	224.8	2.30	227.7	213.5
Georgia	43.36	180.1	179.9	25.64	434.4	473.8	2.89	282.2	276.3
Maryland	40.68	159.5	163.4	14.56	230.3	226.1	2.66	255.0	225.8
North Carolina	43.00	172.6	177.9	25.65	441.1	473.5	2.96	286.0	267.5
South Carolina	39.13	152.7	162.6	26.79	461.7	475.1	1.73	169.0	148.9
Virginia	37.81	147.3	152.2	15.45	247.1	222.7	2.48	237.2	182.2
West Virginia	36.88	147.2	151.7	28.35	483.8	537.4	3.53	352.5	363.3
East South Central	33.05	138.5	142.3	19.49	317.5	345.4	1.88	183.2	159.6
Alabama	41.67	172.7	181.0	26.49	459.8	511.8	2.28	222.9	187.1
Kentucky	27.01	116.2	117.7	27.99	479.4	505.1	2.77	271.5	259.7
Mississippi	39.94	159.7	166.9	12.82	200.0	215.7	1.85	179.7	157.3
Tennessee	31.01	127.3	125.2	27.93	480.2	498.3	--	--	--
West South Central	22.55	147.4	149.9	24.42	416.4	477.3	2.28	221.3	199.7
Arkansas	28.84	165.3	159.7	27.71	480.8	560.7	1.57	153.2	140.9
Louisiana	24.93	153.5	164.7	23.12	387.9	413.4	1.91	182.8	153.1
Oklahoma	21.47	123.4	131.8	25.33	435.6	408.7	3.20	308.2	286.5
Texas	21.58	149.1	149.9	23.49	399.0	471.0	2.25	219.5	197.4
Mountain	21.64	111.3	113.6	24.41	405.7	445.6	2.07	201.8	181.5
Arizona	28.31	137.4	140.8	27.51	466.5	499.0	2.28	221.3	200.5
Colorado	21.67	109.2	108.7	27.25	479.3	512.6	2.14	214.0	214.9
Idaho	--	--	--	--	--	--	--	--	--
Montana	12.14	70.8	67.1	30.15	509.1	471.7	4.12	341.9	393.5
Nevada	32.32	146.2	140.6	20.56	331.3	393.3	1.91	186.7	173.4
New Mexico	23.83	132.2	137.6	29.38	515.5	535.3	1.99	195.4	170.1
Utah	27.54	120.9	119.4	28.47	484.1	490.3	1.87	174.5	161.5
Wyoming	13.42	75.9	83.1	28.01	479.3	494.3	3.33	320.1	333.6
Pacific Contiguous	22.17	129.6	142.6	26.42	448.7	314.4	2.79	269.9	283.9
California	--	--	--	13.26	217.9	306.2	2.81	271.8	286.9
Oregon	21.23	110.1	108.4	26.44	449.2	475.3	1.96	193.7	157.0
Washington	22.48	137.3	155.1	27.39	466.0	572.9	3.31	315.5	383.0
Pacific Noncontiguous	--	--	--	18.32	292.1	330.6	1.18	117.6	115.6
Alaska	--	--	--	--	--	--	1.18	117.6	115.6
Hawaii	--	--	--	18.32	292.1	330.6	--	--	--
U. S. Total	29.36	141.2	144.7	16.15	255.1	254.8	2.38	232.8	215.3

¹ Does not include petroleum coke. Petroleum coke cost in 1992 was 75.0 cents per million Btu and in 1991 was 81.0 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. 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 kilowatthour differs across U.S. Census divisions. The New England and Middle Atlantic Census Divisions tend to have an average revenue per kilowatthour 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 kilowatthour 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 kilowatthour.

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 kilowatthour are published in the *Electric Sales and Revenue*.³³

³³Energy Information Administration, *Electric Sales and Revenue 1991*, DOE/EIA-0540(91)(Washington, DC, April 1993).

Table 24. U.S. Electric Utility Sales to Ultimate Consumers and Associated Revenue by Sector, 1988 Through 1992

Item	1992	1991	1990	1989	1988
Sales (million kilowatthours)					
Residential	935,940	955,417	924,019	905,525	892,866
Commercial	761,269	765,664	751,027	725,861	699,100
Industrial	972,691	946,583	945,522	925,659	896,498
Other ¹	93,443	94,339	91,988	89,765	89,598
U.S. Total	2,763,343	2,762,003	2,712,555	2,646,809	2,578,062
Revenue (million dollars)					
Residential	76,848	76,828	72,378	69,240	66,790
Commercial	58,342	57,655	55,117	52,228	49,224
Industrial	46,992	45,737	44,857	43,719	42,145
Other ¹	6,296	6,138	5,891	5,609	5,551
U.S. Total	188,480	186,359	178,243	170,797	163,710

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

Notes: •Data for 1992 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 Kilowatthour for U.S. Electric Utilities by Sector, 1988 Through 1992 (Cents)

Sector	1992	1991	1990	1989	1988
Residential	8.2	8.0	7.8	7.6	7.5
Commercial	7.7	7.5	7.3	7.2	7.0
Industrial	4.8	4.8	4.7	4.7	4.7
Other ¹	6.7	6.5	6.4	6.2	6.2
All Sectors	6.8	6.7	6.6	6.5	6.4

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

Notes: •Data for 1992 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."

Table 26. Electric Utility Sales to Ultimate Consumers by Sector, Census Division, and State, 1992 and 1991
(Million Kilowatthours)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other ¹	
	1992	1991	1992	1991	1992	1991	1992	1991	1992	1991
New England	103,896	103,220	37,604	37,146	37,929	37,741	26,328	26,343	2,035	1,990
Connecticut	27,127	27,171	10,496	10,441	10,485	10,544	5,780	5,822	367	364
Maine	11,483	11,383	3,830	3,817	2,730	2,685	4,753	4,709	171	171
Massachusetts	44,998	44,797	15,560	15,379	18,629	18,517	9,663	9,794	1,146	1,107
New Hampshire	8,954	8,762	3,428	3,357	2,077	2,029	3,333	3,265	116	111
Rhode Island	6,393	6,403	2,363	2,369	2,481	2,474	1,359	1,363	190	197
Vermont	4,941	4,704	1,927	1,783	1,527	1,491	1,440	1,390	47	40
Middle Atlantic	307,880	310,431	98,512	100,314	104,773	105,162	90,585	90,871	14,010	14,084
New Jersey	63,122	64,683	20,547	21,539	27,403	27,627	14,687	15,031	485	485
New York	128,470	129,411	38,720	39,177	46,591	46,982	31,028	31,112	12,132	12,140
Pennsylvania	116,288	116,337	39,245	39,598	30,779	30,553	44,869	44,728	1,394	1,459
East North Central	469,279	475,111	136,630	145,235	113,809	116,589	204,049	198,047	14,791	15,239
Illinois	112,521	116,869	32,367	35,964	31,457	33,119	40,898	39,712	7,798	8,074
Indiana	76,977	77,034	22,837	24,220	16,083	16,381	37,439	35,787	619	645
Michigan	83,840	84,519	25,671	26,760	21,208	21,455	35,657	35,007	1,304	1,298
Ohio	145,016	145,658	39,141	40,942	31,818	32,325	69,674	67,856	4,383	4,534
Wisconsin	50,925	51,032	16,615	17,349	13,243	13,309	20,382	19,686	686	688
West North Central	190,506	196,748	67,729	73,408	52,038	52,892	65,947	65,198	4,793	5,250
Iowa	30,208	30,781	10,290	11,159	7,019	7,123	12,134	11,684	765	815
Kansas	27,069	28,152	8,873	9,933	9,400	9,551	8,450	8,284	346	384
Minnesota	47,412	48,755	14,848	15,655	8,291	8,417	23,557	23,938	716	745
Missouri	54,411	56,514	21,294	23,386	18,792	19,112	13,440	13,114	885	902
Nebraska	17,784	18,605	6,561	7,138	5,266	5,291	4,752	4,690	1,204	1,486
North Dakota	7,128	7,255	3,020	3,096	1,752	1,876	1,835	1,762	521	521
South Dakota	6,494	6,685	2,843	3,040	1,518	1,522	1,777	1,726	356	397
South Atlantic	552,841	545,836	219,372	218,512	159,131	157,340	156,608	152,527	17,730	17,457
Delaware	8,532	8,536	2,786	2,824	2,445	2,420	3,248	3,241	53	51
District of Columbia	10,043	10,195	1,488	1,580	5,227	5,238	2,987	3,053	341	324
Florida	147,010	146,336	73,189	72,814	52,620	52,441	16,497	16,482	4,704	4,599
Georgia	83,391	81,539	30,528	30,187	23,715	23,241	28,197	27,193	952	919
Maryland	50,989	51,108	19,762	20,295	10,770	10,667	19,768	19,448	689	697
North Carolina	94,195	92,316	34,761	34,391	25,142	24,676	32,522	31,514	1,770	1,736
South Carolina	58,401	57,069	18,940	18,707	12,375	12,209	26,305	25,361	781	793
Virginia	76,448	75,111	29,780	29,607	21,610	21,230	16,714	16,029	8,345	8,245
West Virginia	23,831	23,625	8,138	8,106	5,228	5,219	10,370	10,206	95	94
East South Central	241,036	236,831	80,844	82,061	33,694	40,178	121,722	109,616	4,776	4,976
Alabama	62,162	61,227	21,137	21,293	10,917	11,349	29,471	27,985	637	599
Kentucky	67,065	64,194	17,787	18,644	9,576	9,900	37,081	32,939	2,622	2,711
Mississippi	33,238	33,019	12,422	12,518	6,732	6,832	13,487	13,024	596	646
Tennessee	78,572	78,390	29,498	29,605	6,470	12,097	41,683	35,667	922	1,021
West South Central	371,249	372,901	127,816	131,990	92,049	92,305	135,738	132,639	15,646	15,967
Arkansas	28,451	28,440	10,440	11,001	6,177	6,300	11,251	10,518	583	622
Louisiana	65,098	64,704	21,188	21,577	13,839	13,970	27,466	26,584	2,605	2,573
Oklahoma	38,268	39,404	14,255	15,325	10,338	10,587	11,599	11,415	2,077	2,078
Texas	239,431	240,352	81,934	84,088	61,696	61,447	85,421	84,122	10,381	10,694
Mountain	167,973	163,131	51,595	50,897	52,675	50,972	56,855	54,777	6,848	6,485
Arizona	43,651	41,848	16,230	15,641	14,468	13,982	11,055	10,405	1,898	1,820
Colorado	31,822	31,457	10,216	10,099	13,898	13,742	6,849	6,748	860	868
Idaho	19,008	18,046	5,739	5,971	5,340	4,865	7,551	6,909	379	301
Montana	13,096	13,407	3,286	3,459	2,859	2,819	6,414	6,622	536	507
Nevada	17,696	16,625	6,064	5,782	4,175	3,987	6,723	6,173	734	684
New Mexico	14,431	14,084	3,791	3,665	4,630	4,533	4,609	4,546	1,401	1,340
Utah	16,567	15,907	4,505	4,460	4,956	4,734	6,212	5,876	894	837
Wyoming	11,700	11,757	1,763	1,819	2,350	2,310	7,442	7,498	146	129
Pacific	345,677	345,015	111,759	111,855	110,780	108,182	110,544	112,327	12,593	12,651
California	213,447	208,650	68,121	66,017	80,235	78,425	57,090	56,191	8,002	8,018
Oregon	42,910	43,651	15,202	15,949	11,818	11,614	15,123	15,297	766	791
Washington	89,319	92,714	28,436	29,889	18,727	18,143	38,332	40,839	3,825	3,842
Pacific Noncontiguous	13,006	12,780	4,079	3,998	4,391	4,303	4,316	4,239	221	239
Alaska	4,339	4,256	1,640	1,603	2,035	2,005	504	466	160	182
Hawaii	8,667	8,524	2,438	2,396	2,356	2,298	3,811	3,773	61	58
U. S. Total	2,763,343	2,762,003	935,940	955,417	761,269	765,664	972,691	946,583	93,443	94,339

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

Notes: *Data for 1992 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, 1992 and 1991
(Thousands)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other ¹	
	1992	1991	1992	1991	1992	1991	1992	1991	1992	1991
New England	6,108	6,058	5,397	5,354	637	631	26	25	49	48
Connecticut	1,446	1,441	1,311	1,306	125	125	5	5	5	5
Maine	675	667	585	577	70	70	1	1	19	19
Massachusetts	2,665	2,648	2,350	2,337	285	282	14	14	16	15
New Hampshire	579	569	496	488	75	73	2	2	6	6
Rhode Island	440	437	391	389	45	45	3	3	1	1
Vermont	304	297	263	258	36	36	1	1	3	3
Middle Atlantic	15,833	15,741	13,998	13,895	1,732	1,744	55	53	49	48
New Jersey	3,327	3,323	2,931	2,911	372	389	14	13	10	10
New York	7,216	7,171	6,355	6,309	818	820	12	12	31	30
Pennsylvania	5,290	5,247	4,711	4,674	542	536	29	29	8	8
East North Central	18,727	18,562	16,773	16,630	1,796	1,782	76	72	83	79
Illinois	4,910	4,878	4,434	4,405	448	449	3	5	21	20
Indiana	2,524	2,492	2,247	2,218	248	246	16	16	12	13
Michigan	4,175	4,140	3,745	3,716	397	392	15	14	18	18
Ohio	4,810	4,761	4,294	4,252	465	460	32	31	19	18
Wisconsin	2,307	2,292	2,053	2,040	237	235	5	6	12	10
West North Central	8,556	8,515	7,408	7,367	983	979	48	47	117	121
Iowa	1,327	1,318	1,152	1,145	160	158	4	4	11	12
Kansas	1,224	1,267	1,038	1,069	161	172	13	13	11	12
Minnesota	2,050	2,016	1,812	1,781	203	199	11	10	24	26
Missouri	2,474	2,449	2,184	2,164	264	259	11	11	15	15
Nebraska	819	808	666	656	108	106	5	5	39	40
North Dakota	318	317	266	265	44	44	3	3	5	5
South Dakota	345	340	289	286	42	42	2	2	11	11
South Atlantic	21,216	20,817	18,663	18,318	2,264	2,217	80	81	208	201
Delaware	327	321	293	288	33	31	1	1	1	1
District of Columbia	220	220	193	193	27	27				
Florida	6,930	6,803	6,082	5,975	733	717	21	22	94	89
Georgia	3,095	3,026	2,750	2,691	306	299	14	14	25	22
Maryland	1,988	1,957	1,787	1,759	190	186	11	11	1	1
North Carolina	3,363	3,302	2,917	2,860	402	396	14	15	30	31
South Carolina	1,712	1,680	1,476	1,449	213	210	4	4	19	17
Virginia	2,702	2,640	2,401	2,346	261	254	5	4	36	36
West Virginia	877	868	764	757	99	97	11	11	3	4
East South Central	7,247	7,186	6,288	6,205	858	861	58	40	42	81
Alabama	1,952	1,918	1,693	1,666	240	235	12	9	7	8
Kentucky	1,748	1,745	1,528	1,525	192	192	10	9	18	18
Mississippi	1,186	1,183	1,021	1,006	149	147	7	6	9	24
Tennessee	2,360	2,340	2,046	2,007	277	286	29	16	8	30
West South Central	12,386	12,194	10,757	10,586	1,368	1,345	113	113	148	150
Arkansas	1,174	1,158	1,021	1,004	115	114	23	22	15	17
Louisiana	1,881	1,864	1,656	1,642	191	189	15	14	20	19
Oklahoma	1,592	1,574	1,374	1,359	188	187	17	16	14	13
Texas	7,739	7,598	6,706	6,582	874	855	59	61	100	101
Mountain	6,494	6,422	5,621	5,558	766	760	35	34	72	70
Arizona	1,687	1,646	1,496	1,457	164	161	5	5	22	22
Colorado	1,658	1,700	1,438	1,475	203	209	2	2	15	13
Idaho	502	489	420	409	74	72	4	4	4	3
Montana	425	420	349	346	59	57	4	5	13	12
Nevada	616	594	536	515	78	76	1	1	2	2
New Mexico	698	687	597	588	86	85	5	5	9	9
Utah	664	645	588	572	62	60	10	9	4	4
Wyoming	245	242	199	196	39	39	3	3	4	4
Pacific Contiguous	16,094	15,906	14,075	13,975	1,881	1,800	55	52	83	79
California	12,316	12,205	10,761	10,728	1,469	1,398	38	34	48	46
Oregon	1,415	1,388	1,224	1,201	173	169	7	7	12	11
Washington	2,363	2,313	2,090	2,047	239	233	11	10	23	23
Pacific Noncontiguous	620	615	531	521	83	82	1	1	6	11
Alaska	237	237	199	196	33	32			4	9
Hawaii	384	378	331	326	50	50	1	1	2	2
U. S. Average	113,282	112,016	99,510	98,409	12,367	12,201	548	518	658	688

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 1992 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 28. Revenue from Electric Utility Sales to Ultimate Consumers by Sector, Census Division, and State, 1992 and 1991
(Million Dollars)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other ¹	
	1992	1991	1992	1991	1992	1991	1992	1991	1992	1991
New England	10,096	9,715	4,087	3,874	3,628	3,524	2,137	2,078	243	238
Connecticut	2,723	2,609	1,162	1,097	1,034	1,001	475	461	51	49
Maine	1,039	979	436	399	253	243	328	316	22	21
Massachusetts	4,347	4,270	1,652	1,599	1,735	1,708	831	835	129	129
New Hampshire	893	800	389	348	216	195	272	243	16	14
Rhode Island	658	651	264	260	249	244	125	126	19	20
Vermont	436	406	184	170	141	133	105	98	6	5
Middle Atlantic	28,442	28,095	10,839	10,814	10,368	10,197	5,937	5,883	1,298	1,200
New Jersey	6,004	6,120	2,233	2,329	2,558	2,559	1,132	1,152	81	79
New York	13,092	12,664	4,813	4,690	5,204	5,099	2,017	1,918	1,057	958
Pennsylvania	9,347	9,311	3,793	3,795	2,606	2,539	2,788	2,813	159	163
East North Central	30,383	30,790	11,353	11,845	8,456	8,571	9,540	9,329	1,034	1,044
Illinois	8,655	8,913	3,332	3,549	2,545	2,632	2,238	2,180	541	552
Indiana	4,081	4,100	1,567	1,630	964	974	1,499	1,445	51	51
Michigan	6,063	6,095	2,082	2,158	1,756	1,757	2,104	2,061	121	119
Ohio	8,792	8,900	3,225	3,340	2,409	2,435	2,885	2,850	273	276
Wisconsin	2,793	2,782	1,148	1,168	782	774	815	793	48	46
West North Central	11,491	11,843	4,954	5,292	3,295	3,326	2,932	2,900	309	324
Iowa	1,807	1,829	825	866	446	444	487	469	49	50
Kansas	1,775	1,851	701	777	627	632	417	410	31	31
Minnesota	2,618	2,664	1,041	1,083	508	511	1,020	1,019	50	52
Missouri	3,489	3,653	1,584	1,728	1,200	1,221	643	643	62	62
Nebraska	983	1,019	411	435	297	297	193	195	81	92
North Dakota	414	418	191	192	114	120	89	86	20	20
South Dakota	404	410	202	210	103	102	83	80	16	17
South Atlantic	35,981	35,428	16,903	16,709	10,606	10,453	7,337	7,170	1,134	1,096
Delaware	571	572	241	243	172	170	153	153	6	6
District of Columbia	650	638	98	104	361	348	170	166	21	20
Florida	10,261	10,479	5,671	5,759	3,461	3,549	828	856	320	315
Georgia	5,563	5,353	2,361	2,264	1,778	1,710	1,342	1,300	83	78
Maryland	3,469	3,482	1,575	1,603	764	750	1,068	1,069	61	61
North Carolina	6,213	5,973	2,820	2,733	1,666	1,600	1,602	1,518	125	122
South Carolina	3,231	3,211	1,361	1,351	763	760	1,061	1,056	45	45
Virginia	4,800	4,576	2,273	2,173	1,347	1,284	715	678	465	441
West Virginia	1,203	1,144	502	479	295	282	398	374	8	8
East South Central	12,370	12,356	4,980	5,017	2,164	2,527	4,948	4,531	278	282
Alabama	3,462	3,456	1,413	1,425	748	773	1,264	1,223	37	35
Kentucky	2,812	2,830	1,013	1,059	506	528	1,170	1,116	122	126
Mississippi	2,006	1,988	871	861	489	491	595	585	50	51
Tennessee	4,090	4,083	1,682	1,671	420	735	1,919	1,607	68	70
West South Central	22,782	22,579	9,822	9,926	6,217	6,104	5,759	5,561	984	986
Arkansas	1,908	1,903	865	892	439	438	565	531	39	42
Louisiana	3,914	3,844	1,592	1,596	995	982	1,160	1,102	168	164
Oklahoma	2,219	2,278	1,022	1,078	631	643	448	440	118	117
Texas	14,740	14,554	6,343	6,361	4,152	4,041	3,587	3,489	658	663
Mountain	10,162	9,710	3,905	3,735	3,493	3,329	2,385	2,276	378	369
Arizona	3,551	3,283	1,555	1,430	1,250	1,161	637	580	109	112
Colorado	1,917	1,873	736	714	801	787	314	308	65	64
Idaho	735	694	283	292	230	206	206	181	17	15
Montana	549	555	192	199	148	141	186	193	24	22
Nevada	1,006	932	375	341	264	252	331	306	35	33
New Mexico	1,027	1,005	344	333	383	373	221	220	79	79
Utah	878	869	314	317	296	288	229	226	39	37
Wyoming	500	499	107	109	121	120	262	262	9	9
Pacific Contiguous	25,522	24,640	9,561	9,192	9,674	9,200	5,678	5,678	609	570
California	20,612	19,661	7,544	7,120	8,291	7,876	4,333	4,260	443	405
Oregon	1,850	1,854	750	768	576	563	486	482	38	42
Washington	3,061	3,124	1,268	1,304	807	760	858	937	128	123
Pacific Noncontiguous	1,250	1,203	443	423	441	423	338	329	29	28
Alaska	432	417	178	171	192	186	39	38	23	22
Hawaii	819	786	266	252	248	237	299	291	6	6
U. S. Total	188,480	186,359	76,848	76,828	58,342	57,655	46,992	45,737	6,296	6,138

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

Notes: •Data for 1992 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, 1992 and 1991
(Cents)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other ¹	
	1992	1991	1992	1991	1992	1991	1992	1991	1992	1991
New England	9.7	9.4	10.9	10.4	9.6	9.3	8.1	7.9	12.0	12.0
Connecticut	10.0	9.6	11.1	10.5	9.9	9.5	8.2	7.9	13.9	13.4
Maine	9.0	8.6	11.4	10.5	9.3	9.1	6.9	6.7	12.9	12.2
Massachusetts	9.7	9.5	10.6	10.4	9.3	9.2	8.6	8.5	11.3	11.7
New Hampshire	10.0	9.1	11.4	10.4	10.4	9.6	8.2	7.4	13.4	12.8
Rhode Island	10.3	10.2	11.2	11.0	10.1	9.9	9.2	9.3	10.3	10.1
Vermont	8.8	8.6	9.6	9.5	9.2	8.9	7.3	7.0	12.9	13.4
Middle Atlantic	9.2	9.1	11.0	10.8	9.9	9.7	6.6	6.5	9.3	8.5
New Jersey	9.5	9.5	10.9	10.8	9.3	9.3	7.7	7.7	16.7	16.3
New York	10.2	9.8	12.4	12.0	11.2	10.9	6.5	6.2	8.7	7.9
Pennsylvania	8.0	8.0	9.7	9.6	8.5	8.3	6.2	6.3	11.4	11.2
East North Central	6.5	6.5	8.3	8.2	7.4	7.4	4.7	4.7	7.0	6.9
Illinois	7.7	7.6	10.3	9.9	8.1	7.9	5.5	5.5	6.9	6.8
Indiana	5.3	5.3	6.9	6.7	6.0	5.9	4.0	4.0	8.2	7.9
Michigan	7.2	7.2	8.1	8.1	8.3	8.2	5.9	5.9	9.3	9.2
Ohio	6.1	6.1	8.2	8.2	7.6	7.5	4.1	4.2	6.2	6.1
Wisconsin	5.5	5.5	6.9	6.7	5.9	5.8	4.0	4.0	7.0	6.7
West North Central	6.0	6.0	7.3	7.2	6.3	6.3	4.4	4.4	6.5	6.2
Iowa	6.0	5.9	8.0	7.8	6.4	6.2	4.0	4.0	6.4	6.1
Kansas	6.6	6.6	7.9	7.8	6.7	6.6	4.9	4.9	8.9	8.1
Minnesota	5.5	5.5	7.0	6.9	6.1	6.1	4.3	4.3	6.9	6.9
Missouri	6.4	6.5	7.4	7.4	6.4	6.4	4.8	4.9	7.1	6.9
Nebraska	5.5	5.5	6.3	6.1	5.6	5.6	4.1	4.2	6.8	6.2
North Dakota	5.8	5.8	6.3	6.2	6.5	6.4	4.9	4.9	3.8	3.7
South Dakota	6.2	6.1	7.1	6.9	6.8	6.7	4.7	4.6	4.6	4.3
South Atlantic	6.5	6.5	7.7	7.6	6.7	6.6	4.7	4.7	6.4	6.3
Delaware	6.7	6.7	8.7	8.6	7.0	7.0	4.7	4.7	10.8	11.0
District of Columbia	6.5	6.3	6.6	6.6	6.9	6.6	5.7	5.4	6.2	6.1
Florida	7.0	7.2	7.7	7.9	6.6	6.8	5.0	5.2	6.8	6.9
Georgia	6.7	6.6	7.7	7.5	7.5	7.4	4.8	4.8	8.7	8.5
Maryland	6.8	6.8	8.0	7.9	7.1	7.0	5.4	5.5	8.9	8.7
North Carolina	6.6	6.5	8.1	7.9	6.6	6.5	4.9	4.8	7.1	7.0
South Carolina	5.5	5.6	7.2	7.2	6.2	6.2	4.0	4.2	5.7	5.7
Virginia	6.3	6.1	7.6	7.3	6.2	6.0	4.3	4.2	5.6	5.3
West Virginia	5.0	4.8	6.2	5.9	5.6	5.4	3.8	3.7	8.6	8.6
East South Central	5.1	5.2	6.2	6.1	6.4	6.3	4.1	4.1	5.8	5.7
Alabama	5.6	5.6	6.7	6.7	6.9	6.8	4.3	4.4	5.8	5.8
Kentucky	4.2	4.4	5.7	5.7	5.3	5.3	3.2	3.4	4.7	4.7
Mississippi	6.0	6.0	7.0	6.9	7.3	7.2	4.4	4.5	8.5	7.9
Tennessee	5.2	5.2	5.7	5.6	6.5	6.1	4.6	4.5	7.4	6.9
West South Central	6.1	6.1	7.7	7.5	6.8	6.6	4.2	4.2	6.3	6.2
Arkansas	6.7	6.7	8.3	8.1	7.1	7.0	5.0	5.0	6.8	6.8
Louisiana	6.0	5.9	7.5	7.4	7.2	7.0	4.2	4.1	6.4	6.4
Oklahoma	5.8	5.8	7.2	7.0	6.1	6.1	3.9	3.9	5.7	5.6
Texas	6.2	6.1	7.7	7.6	6.7	6.6	4.2	4.1	6.3	6.2
Mountain	6.0	6.0	7.6	7.3	6.6	6.5	4.2	4.2	5.5	5.7
Arizona	8.1	7.8	9.6	9.1	8.6	8.3	5.8	5.6	5.7	6.1
Colorado	6.0	6.0	7.2	7.1	5.8	5.7	4.6	4.6	7.6	7.3
Idaho	3.9	3.8	4.9	4.9	4.3	4.2	2.7	2.6	4.4	4.8
Montana	4.2	4.1	5.8	5.8	5.2	5.0	2.9	2.9	4.5	4.3
Nevada	5.7	5.6	6.2	5.9	6.3	6.3	4.9	4.9	4.8	4.9
New Mexico	7.1	7.1	9.1	9.1	8.3	8.2	4.8	4.8	5.7	5.9
Utah	5.3	5.5	7.0	7.1	6.0	6.1	3.7	3.8	4.4	4.4
Wyoming	4.3	4.2	6.1	6.0	5.2	5.2	3.5	3.5	6.4	6.6
Pacific Contiguous	7.4	7.1	8.6	8.2	8.7	8.5	5.1	5.1	4.8	4.5
California	9.7	9.4	11.1	10.8	10.3	10.0	7.6	7.6	5.5	5.0
Oregon	4.3	4.2	4.9	4.8	4.9	4.8	3.2	3.1	5.0	5.3
Washington	3.4	3.4	4.5	4.4	4.3	4.2	2.2	2.3	3.3	3.2
Pacific Noncontiguous	9.6	9.4	10.9	10.6	10.0	9.8	7.8	7.8	13.0	11.5
Alaska	9.9	9.8	10.8	10.7	9.5	9.3	7.7	8.2	14.2	12.1
Hawaii	9.4	9.2	10.9	10.5	10.5	10.3	7.8	7.7	9.7	9.6
U. S. Average	6.8	6.7	8.2	8.0	7.7	7.5	4.8	4.8	6.7	6.5

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 1992 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 electric utilities and for a 4-year period on major 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. The prior publications 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 1992. 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.

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 transported 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 1992. 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 1988 through 1992 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*.¹⁴

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 450 publicly owned electric utilities are required to submit the Form EIA-412. These major 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*.¹⁵

¹⁴Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*, DOE/EIA-0437(92)-1 (Washington, DC), 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, data for 1988 are published in the *Financial Statistics of Selected Electric Utilities*, DOE/EIA-0437.

¹⁵Energy Information Administration (EIA), *Financial Statistics of Major U.S. 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, data for 1988 are published in the *Financial Statistics of Selected Electric Utilities*, DOE/EIA-0437.

**Table 30. Composite Statement of Income for Major U.S. Investor-Owned Electric Utilities,
1988 Through 1992**
(Thousand Dollars)

Description	1992 ¹	1991 ¹	1990	1989	1988
Operating Revenue	185,493,458	182,450,728	172,999,954	167,067,596	159,488,265
Electric	169,488,035	166,803,843	157,278,537	150,903,317	143,930,420
Gas	14,937,370	14,560,221	14,611,056	15,119,408	14,580,945
Other Utility	1,068,053	1,086,663	1,110,362	1,044,871	976,899
Operating Expenses	153,682,429	150,361,969	142,471,369	136,500,226	129,730,357
Electric	139,009,093	135,947,991	127,900,634	121,552,060	115,347,626
Fuel	30,254,398	31,312,220	32,634,846	32,937,516	31,903,430
Other Operating and Maintenance	69,212,541	66,645,950	60,231,131	54,785,240	51,752,113
Depreciation ²	17,091,753	16,127,176	14,888,584	15,032,961	13,469,355
Taxes Other Than Income Taxes	12,760,152	12,270,379	11,433,264	10,796,423	10,319,912
Income Taxes	7,197,682	7,690,521	7,146,859	6,848,369	6,080,204
Deferred Income Tax	3,017,335	2,294,676	1,855,377	1,479,626	2,078,160
Investment Tax Credit (Net)	-524,768	-392,931	-289,428	-328,075	-255,548
Gas	13,691,253	13,406,370	13,523,155	13,972,207	13,473,072
Income Taxes	279,618	308,656	428,107	336,660	330,991
Other	13,411,635	13,097,714	13,095,048	13,635,547	13,142,081
Other Utility	982,083	1,007,609	1,047,580	975,958	909,659
Income Taxes	26,956	3,530	7,805	16,480	15,921
Other	955,127	1,004,079	1,039,775	959,478	893,738
Operating Income	31,811,029	32,088,758	30,528,585	30,567,370	29,757,908
Electric	30,478,942	30,855,852	29,377,903	29,351,256	28,582,794
Gas	1,246,117	1,153,852	1,087,901	1,147,200	1,107,873
Other	85,970	79,055	62,782	68,913	67,240
Other Income and Deductions	1,689,045	523,325	1,830,496	2,560,660	2,039,670
Allowance for Other Funds Used During Construction	611,514	706,102	1,080,217	1,202,004	1,615,721
Less Taxes	379,461	852,579	389,448	943,175	1,070,681
Deferred Earnings (Misc.) (acct 421)	1,341,354	1,271,525	1,477,520	1,073,178	1,898,737
Less Other Income and Expenses ³	-115,638	601,723	337,793	-1,228,653	404,107
Total Income Before Interest Charges	33,500,074	32,612,083	32,359,081	33,128,030	31,797,578
Net Interest Charges	15,223,174	15,736,248	15,735,630	14,852,295	14,386,924
Interest Expense	15,307,441	16,010,348	16,186,426	15,648,011	15,333,123
Less Allowance for Borrowed Funds Used During Construction	558,348	635,525	814,229	1,142,007	1,261,283
Other Charges--Net	474,080	361,424	363,433	346,291	315,084
Net Income Before Extraordinary Charges	18,276,900	16,875,836	16,623,451	18,275,735	17,410,653
Less Extraordinary Items After Taxes⁴	-107,544	-73,829	-273,715	962,974	1,368,946
Net Income	18,384,444	16,949,664	16,897,166	17,312,761	16,041,707
Preferred Stock Dividend Requirements	2,039,449	1,945,213	2,025,157	2,417,239	2,264,454
Earnings Available for Common Stocks	16,344,995	15,004,451	14,872,009	14,895,522	13,777,253
Common Stocks Dividends	14,897,608	14,427,570	14,189,677	14,030,562	13,517,681
Additions to Retained Earnings	2,184,266	254,189	424,940	705,327	-13,385
Average Shares of Common Stock Outstanding	6,261,284	5,932,492	5,596,535	5,824,221	5,400,881
Earnings Available Per Average Common Share (Dollars)	2.61	2.53	2.66	2.56	2.55

¹ Excluded are the independent power producers jurisdictional to the Federal Energy Regulatory Commission

² 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. Excluded are the independent power producers jurisdictional to the Federal Energy Regulatory Commission

³ Includes amortization and depletion

⁴ 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,
1988 Through 1992**
(Thousand Dollars)

Description	1992 ¹	1991 ²	1990	1989	1988
Assets					
Utility Plant - Net	386,864,738	376,771,703	371,310,063	363,223,395	361,838,256
Electric Utility Plant - Net	358,300,259	349,611,025	344,912,770	337,460,182	335,866,884
Electric Utility Plant	498,118,599	479,822,229	458,081,342	428,700,561	409,092,233
Construction Work in Progress	20,648,234	18,077,211	22,558,726	33,714,555	40,298,296
Less Accumulated Depreciation	160,466,573	148,288,414	135,727,298	124,954,934	113,523,644
Nuclear Fuel - Net	6,836,719	6,911,645	7,812,038	8,700,644	9,642,680
Other Utility Plant - Net	21,727,760	20,249,033	18,585,255	17,062,569	16,128,692
Other Property and Investments	18,045,977	17,385,415	17,703,929	16,136,757	15,200,883
Current and Accrued Assets	43,447,871	43,357,785	41,534,862	41,516,163	39,122,286
Deferred Debits	57,993,875	50,024,920	47,322,374	44,846,622	38,335,664
Total Assets	506,352,461	487,539,823	477,871,029	465,722,937	454,296,889
Capitalization and Liabilities					
Capitalization	356,026,762	348,828,405	340,983,205	334,068,968	329,813,736
Common Stock Equity (End of Year)	156,346,650	151,671,304	147,424,082	145,175,878	142,715,825
Common Stock	103,963,697	99,723,170	96,502,507	94,602,732	93,158,701
Retained Earnings (Adjusted)	52,382,953	51,948,134	50,921,575	50,573,146	49,557,124
Preferred Stock	25,539,216	25,262,285	25,621,039	25,944,650	26,371,225
Long-term Debt	174,140,896	171,894,816	167,938,084	162,948,440	160,726,686
Current and Other Liabilities	150,325,698	138,711,418	136,887,824	131,653,970	124,483,152
Other Noncurrent Liabilities	8,627,882	6,931,193	7,224,872	7,803,119	7,711,888
Current and Accrued Liabilities	45,557,601	43,357,436	44,283,442	42,023,659	38,412,073
Deferred Credits	96,140,215	88,422,789	85,379,510	81,827,192	78,359,191
Accumulated Deferred Income Taxes	65,020,984	59,188,298	56,529,757	53,328,188	50,247,264
Accumulated Deferred Investment Tax Credit	14,046,840	14,689,786	15,290,316	15,886,418	16,792,695
Other Deferred Credits (Adjusted)	17,072,392	14,544,705	13,559,436	12,612,586	11,319,232
Total Capitalization and Liabilities	506,352,461	487,539,823	477,871,029	465,722,937	454,296,889

¹ Excluded are the independent power producers jurisdictional to the Federal Energy Regulatory Commission.

² 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. Excluded are the independent power producers jurisdictional to the Federal Energy Regulatory Commission.

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, 1992

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, 1988 Through 1992

Description ¹	1992 ²	1991 ³	1990	1989	1988
Activity					
1 Electric Fixed Asset (Net Plant) Turnover	0.47	0.48	0.46	0.45	0.43
2 Total Asset Turnover	.37	.37	.36	.36	.35
Leverage					
3 Current Assets to Current Liabilities	95	100	94	99	102
4 Long-term Debt to Capitalization	48.91	49.28	49.25	48.78	48.73
5 Preferred Stock to Capitalization	7.17	7.24	7.51	7.77	8.00
6 Common Stock Equity to Capitalization	43.91	43.48	43.24	43.46	43.27
7 Total Debt to Total Assets ⁴	36.13	36.69	36.79	36.26	36.67
8 Common Stock Equity to Total Assets	30.88	31.11	30.85	31.17	31.42
9 Interest Coverage Before Taxes without AFUDC	2.62	2.49	2.38	2.46	2.35
Profitability					
10 Profit Margin	9.91	9.29	9.77	10.36	10.06
11 Return on Average Common Stock Equity ⁵	11.94	11.33	11.55	12.03	11.23
12 Return on Investment	3.63	3.48	3.54	3.72	3.53

¹ Indicators 1, 2, 3, and 9 are ratios. Indicators 4 through 8 and 10 through 12 are percentages.

² Excluded are the independent power producers jurisdictional to the Federal Energy Regulatory Commission.

³ 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. Excluded are the independent power producers jurisdictional to the Federal Energy Regulatory Commission.

⁴ 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 \$8,791,477 for 1992, \$6,986,960 for 1991, \$7,874,293 for 1990, \$5,928,421 for 1989, and \$5,843,202 for 1988.

⁵ The Average Common Stock Equity is the average of the beginning and ending year balances. The values for the beginning of each year were \$156,346,650 for 1992, \$151,671,304 for 1991, \$147,424,082 for 1990, \$145,175,878 for 1989, and \$142,715,825 for 1988.

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, 1992

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. Percents in the figure are percentage of utility operating expenses.

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, 1988 Through 1992
(Thousand Dollars)

Description	1992 ¹	1991 ²	1990	1989	1988
Utility Operating Revenue	185,493,458	182,450,728	172,999,954	167,067,596	159,488,265
Electric Utility	169,488,035	166,803,843	157,278,537	150,903,317	143,930,420
Other Utility	16,005,423	15,646,884	15,721,418	16,164,279	15,557,844
Utility Operating Expenses	153,682,429	150,361,969	142,471,369	136,500,226	129,730,357
Electric Utility	139,009,093	135,947,991	127,900,634	121,552,060	115,347,626
Operation	87,272,134	85,933,743	81,086,488	76,451,124	72,742,004
Production	66,979,805	66,101,528	62,501,048	59,235,893	56,186,332
Cost of Fuel	30,254,398	31,312,220	32,634,846	32,937,516	31,903,430
Purchased Power	26,212,238	24,169,252	20,340,504	17,959,051	16,061,339
Other	10,513,169	10,620,056	9,525,698	8,339,326	8,221,563
Transmission	1,308,101	1,247,286	1,130,272	1,113,547	1,026,861
Distribution	2,498,514	2,530,490	2,443,859	2,393,944	2,331,160
Customer Accounts	3,347,124	3,203,212	3,247,245	2,992,829	2,894,179
Customer Service	1,531,369	1,451,507	1,180,636	959,473	887,963
Sales	198,647	203,230	212,233	208,655	177,006
Administrative and General	11,408,575	11,196,490	10,371,195	9,546,783	9,238,502
Maintenance	12,194,805	12,024,427	11,779,489	11,271,632	10,913,539
Depreciation	17,091,753	16,127,176	14,888,584	15,032,961	13,469,355
Taxes and Other	22,450,401	21,862,645	20,146,073	18,796,343	18,222,728
Other Utility	14,673,336	14,413,979	14,570,735	14,948,165	14,382,731
Income From Utility Operations	31,811,029	32,088,758	30,528,585	30,567,370	29,757,908

¹ Excluded are the independent power producers jurisdictional to the Federal Energy Regulatory Commission.

² 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. Excluded are the independent power producers jurisdictional to the Federal Energy Regulatory Commission.

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, 1988 Through 1992

Description	1992 ¹	1991 ²	1990	1989	1988
Utility Operating Revenue	100.0	100.0	100.0	100.0	100.0
Electric Utility	91.4	91.4	90.9	90.3	90.2
Other Utility	8.6	8.6	9.1	9.7	9.8
Utility Operating Expenses	82.9	82.4	82.4	81.7	81.3
Electric Utility	74.9	74.5	73.9	72.8	72.3
Operation	47.0	47.1	46.9	45.8	45.6
Production	36.1	36.2	36.1	35.5	35.2
Cost of Fuel	16.3	17.2	18.9	19.7	20.0
Purchased Power	14.1	13.2	11.8	10.7	10.1
Other	5.7	5.8	5.5	5.0	5.2
Transmission	.7	.7	.7	.7	.6
Distribution	1.3	1.4	1.4	1.4	1.5
Customer Accounts	1.8	1.8	1.9	1.8	1.8
Customer Service	.8	.8	.7	.6	.6
Sales	.1	.1	.1	.1	.1
Administrative and General	6.2	6.1	6.0	5.7	5.8
Maintenance	6.6	6.6	6.8	6.7	6.8
Depreciation	9.2	8.8	8.6	9.0	8.4
Taxes and Other	12.1	12.0	11.6	11.3	11.4
Other Utility	7.9	7.9	8.4	8.9	9.0
Income From Utility Operations	17.1	17.6	17.6	18.3	18.7

¹ Excluded are the independent power producers jurisdictional to the Federal Energy Regulatory Commission.

² 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. Excluded are the independent power producers jurisdictional to the Federal Energy Regulatory Commission.

Notes: •Data are final. •Percents 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, 1988 Through 1992
(Mills per Kilowatthour)

Plant Type	1992 ¹	1991 ²	1990	1989	1988
Operation					
Nuclear	10.43	10.49	10.04	10.29	9.50
Fossil Steam	2.38	2.29	2.21	1.99	1.98
Hydroelectric ³	4.33	3.88	3.35	3.27	4.45
Gas Turbine and Small Scale ⁴	10.18	9.61	8.76	5.66	6.61
Maintenance					
Nuclear	5.93	5.50	5.68	5.87	5.17
Fossil Steam	2.95	2.98	2.97	2.78	2.87
Hydroelectric ³	3.30	2.89	2.58	2.39	3.05
Gas Turbine and Small Scale ⁴	12.15	12.93	12.23	8.60	10.11
Fuel					
Nuclear	6.12	6.71	7.18	7.45	7.88
Fossil Steam	17.49	17.91	18.55	18.28	17.98
Hydroelectric ³	--	--	--	--	--
Gas Turbine and Small Scale ⁴	28.59	30.96	32.57	34.77	32.06
Total⁵					
Nuclear	22.48	22.70	22.91	23.61	22.50
Fossil Steam	22.83	23.17	23.72	23.05	22.70
Hydroelectric ³	7.63	6.76	5.33	5.66	7.50
Gas Turbine and Small Scale ⁴	50.92	53.51	53.56	49.03	48.78

¹ Excluded are the independent power producers jurisdictional to the Federal Energy Regulatory Commission.

² 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. Excluded are the independent power producers jurisdictional to the Federal Energy Regulatory Commission.

³ Includes Pumped Storage.

⁴ Includes gas turbine, internal combustion, photovoltaic, and wind plants.

⁵ 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."

Figure 18. Average Operating Expenses of Fossil-Fueled and Nuclear Steam-Electric Plants for Major U.S. Investor-Owned Electric Utilities, 1992

Notes: •Totals may not equal sum of components because of independent rounding. •Data are final. Percents in the figure are percentage of utility operating expenses.

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 1992
(Thousand Dollars)

Description	1992	1991	1990	1989
Operating Revenue - Electric	21,686,349	21,082,870	20,470,371	19,261,832
Operating Expenses - Electric	17,190,647	16,886,921	16,460,700	15,721,118
Operation Excluding Fuel	9,591,495	9,082,917	9,198,194	8,723,046
Fuel	2,935,940	3,072,158	2,749,890	2,587,003
Maintenance	1,564,792	1,446,295	1,455,786	1,486,423
Depreciation and Amortization	2,417,279	2,300,532	2,075,595	2,051,058
Taxes and Tax Equivalents	681,140	595,719	550,042	500,424
Net Contributions and Services	--	389,300	431,193	373,165
Operating Income - Electric	4,495,703	4,195,949	4,009,671	3,540,714
Other Income and Deductions	1,628,944	1,843,761	1,869,720	1,977,538
Income from Electric Plant Leased to Others	15,129	5,942	11,330	5,325
Allowance for Funds Used During Construction	24,183	71,025	123,282	231,996
Other Income Net	1,839,484	1,890,138	1,735,107	1,740,217
Less Other Electric Deductions	249,852	123,345	--	--
Total Income Before Interest Charges	6,124,646	6,039,710	5,879,390	5,518,252
Net Interest Charges	5,025,758	5,205,799	5,064,936	4,740,190
Interest Expenses	4,757,583	4,775,003	4,663,114	4,337,962
Other Income Deductions	268,175	430,796	401,822	402,229
Net Income Before Extraordinary Charges	1,098,889	833,911	814,455	778,062
Less Extraordinary Items	115,275	65,544	108,958	653,861
Net Income	983,613	768,367	705,497	124,201

¹ 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 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 1992
(Thousand Dollars)

Description	1992	1991	1990	1989
Assets				
Electric Utility Plant-Net Inc Nuclear Fuel	61,710,753	60,737,416	59,596,453	58,324,873
Electric Utility Plant Inc Nuclear Fuel	85,359,878	81,535,543	78,244,146	74,665,136
Accumulated Provision for Depreciation and Amortization	23,649,125	20,798,127	18,647,693	16,340,263
Other Property and Investments	18,228,937	17,332,581	15,801,311	15,037,749
Current and Accrued Assets	14,990,707	14,084,691	13,867,162	12,965,449
Deferred Debits	12,017,041	10,890,161	9,926,695	8,729,005
Total Assets	106,947,439	103,044,849	99,191,621	95,057,077
Liabilities and Other Credits				
Investment of Municipality - Surplus	22,823,226	22,222,042	21,681,128	21,049,561
Long-Term Debt	72,004,391	68,871,516	66,510,223	63,101,457
Other Noncurrent Liabilities	698,351	622,507	435,670	401,397
Current and Accrued Liabilities	8,080,777	7,844,671	7,283,479	7,213,148
Deferred Credits	3,340,694	3,484,113	3,281,121	3,291,514
Total Liabilities and Other Credits	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 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 1992

Description	1992	1991	1990	1989
Electric Utility Plant per Dollar of Revenue	3.9	3.9	3.8	3.9
Current Assets to Current Liabilities	1.9	1.8	1.9	1.8
Electric Utility Plant as a Percent of Total Assets	79.8	79.1	78.9	78.5
Net Electric Utility Plant as a Percent of Total Assets	57.7	58.9	60.1	61.4
Debt as a Percent of Total Liabilities	74.9	74.4	74.4	74.0
Accumulated Provision for Depreciation as a Percent of Electric Utility Plant	27.7	25.5	23.8	21.9
Electric Operation and Maintenance Expenses as a Percent of Electric Operating Revenues	65.0	64.5	65.5	66.4
Electric Depreciation and Amortization as a Percent of Electric Operating Revenues	10.5	10.9	10.1	10.6
Taxes and Tax Equivalents as a Percent of Electric Operating Revenues	3.1	2.8	2.7	2.6
Interest Expenses as a Percent of Electric Operating Revenues	21.9	22.6	22.8	22.5
Net Income as a Percent of Electric Operating Revenues	4.5	3.6	3.4	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 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 1992
(Thousand Dollars)

Description	1992	1991	1990	1989
Operating Revenue - Electric	21,686,349	21,082,870	20,470,371	19,261,832
Operating Expenses - Electric	17,190,647	16,886,921	16,460,700	15,721,118
Operation including Fuel	12,527,435	12,155,075	11,948,084	11,310,048
Production	9,712,324	9,465,070	9,525,315	8,976,237
Transmission	534,512	508,711	471,887	440,256
Distribution	388,703	362,654	328,897	314,678
Customer Accounts	299,209	289,398	272,849	248,501
Customer Service	82,731	73,901	60,411	62,431
Sales	17,545	18,077	18,043	11,927
Administrative and General	1,492,411	1,437,265	1,270,683	1,256,018
Maintenance	1,564,792	1,446,295	1,455,786	1,486,423
Depreciation and Amortization	2,285,807	2,300,532	2,075,595	2,051,058
Taxes and Tax Equivalents	681,140	595,719	550,042	500,424
Net Contributions and Services	--	389,300	431,193	373,165
Income from Electric Utility Operations	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 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 1992
(Thousand Dollars)

Description	1992	1991	1990	1989
Operating Revenue - Electric	7,247,407	7,119,875	6,978,752	6,552,712
Operating Expenses - Electric	6,843,539	6,859,619	6,740,926	6,354,593
Operation Excluding Fuel	6,244,812	6,119,381	6,030,028	5,693,914
Fuel	19	4	*	--
Maintenance	192,635	186,267	191,621	182,509
Depreciation and Amortization	251,079	246,594	231,197	200,580
Taxes and Tax Equivalents	154,994	138,491	133,125	124,160
Net Contributions and Services	--	168,882	154,956	153,431
Operating Income - Electric	403,868	260,255	237,826	198,118
Other Income and Deductions	74,486	138,039	156,148	170,943
Income from Electric Plant Leased to Others	1,773	3,264	2,121	1,727
Allowance for Funds Used During Construction	39	1,606	-213	-302
Other Income Net	172,938	147,117	154,240	169,518
Less Other Electric Deductions	100,264	13,949	--	--
Total Income Before Interest Charges	478,354	398,294	393,975	369,062
Net Interest Charges	140,861	139,806	137,311	122,403
Interest Expenses	109,378	112,031	109,972	101,469
Other Income Deductions	31,483	27,775	27,340	20,934
Net Income Before Extraordinary Charges	337,493	258,488	256,663	246,658
Less Extraordinary Items	2,156	9,252	11,315	-14,950
Net Income	335,338	249,236	245,348	261,608

* 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 258 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 1992
(Thousand Dollars)

Description	1992	1991	1990	1989
Assets				
Electric Utility Plant-Net Inc Nuclear Fuel	4,881,003	4,662,421	4,407,579	4,112,690
Electric Utility Plant Inc Nuclear Fuel	7,733,037	7,318,688	6,861,881	6,344,572
Accumulated Provision for Depreciation and Amortization	2,852,034	2,656,267	2,454,302	2,231,882
Other Property and Investments	1,890,451	1,849,607	1,770,583	1,710,066
Current and Accrued Assets	2,227,084	2,162,131	2,063,931	1,934,281
Deferred Debits	386,263	324,440	271,452	249,834
Total Assets	9,384,801	8,998,600	8,513,545	8,006,871
Liabilities and Other Credits				
Investment of Municipality - Surplus	5,522,242	5,244,951	4,994,123	4,675,254
Long-Term Debt	2,713,721	2,542,435	2,348,676	2,216,899
Other Noncurrent Liabilities	10,284	55,488	38,157	40,842
Current and Accrued Liabilities	983,865	968,924	949,345	887,078
Deferred Credits	154,689	186,803	183,244	186,799
Total Liabilities and Other Credits	9,384,801	8,998,600	8,513,545	8,006,871

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 258 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 1992

Description	1992	1991	1990	1989
Electric Utility Plant per Dollar of Revenue	1.1	1.0	1.0	1.0
Current Assets to Current Liabilities	2.3	2.2	2.2	2.2
Electric Utility Plant as a Percent of Total Assets	82.4	81.3	80.6	79.2
Net Electric Utility Plant as a Percent of Total Assets	52.0	51.8	51.8	51.4
Debt as a Percent of Total Liabilities	39.4	39.0	38.7	38.8
Accumulated Provision for Depreciation as a Percent of Electric Utility Plant	36.9	36.3	35.8	35.2
Electric Operation and Maintenance Expenses as a Percent of Electric Operating Revenues	38.8	88.6	89.2	89.7
Electric Depreciation and Amortization as a Percent of Electric Operating Revenues	3.4	3.5	3.3	3.1
Taxes and Tax Equivalents as a Percent of Electric Operating Revenues	2.1	1.9	1.9	1.9
Interest Expenses as a Percent of Electric Operating Revenues	1.5	1.6	1.6	1.5
Net Income as a Percent of Electric Operating Revenues	4.6	3.5	3.5	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 258 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 1992
(Thousand Dollars)

Description	1992	1991	1990	1989
Operating Revenue - Electric	7,247,407	7,119,875	6,978,752	6,552,712
Operating Expenses - Electric	6,843,539	6,859,619	6,740,926	6,354,593
Operation Including Fuel	6,244,831	6,119,385	6,030,028	5,693,914
Production	5,617,261	5,523,601	5,478,840	5,052,577
Transmission	32,956	32,264	30,119	26,459
Distribution	176,188	164,147	144,962	233,363
Customer Accounts	109,196	102,488	99,305	93,509
Customer Service	15,629	15,536	13,967	13,583
Sales	11,646	11,587	11,222	5,065
Administrative and General	281,954	269,762	251,614	269,357
Maintenance	192,635	186,267	191,621	182,509
Depreciation and Amortization	248,040	246,594	231,197	200,580
Taxes and Tax Equivalents	154,994	138,491	133,125	124,160
Net Contributions and Services	--	168,882	154,956	153,431
Income from Electric Utility Operations	403,868	260,255	237,826	198,118

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 258 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

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*.³⁶ 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 kilowatthour 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.

³⁶Energy Information Administration, *Annual Energy Outlook* DOE/EIA-0383(93)(Washington, DC, 1993).

Table 44. Estimated Emissions from Fossil-Fueled Steam-Electric Generating Units at U.S. Electric Utilities, 1988 Through 1992
(Thousand Short Tons)

Emission	1992	1991	1990	1989	1988
Sulfur Dioxide (SO ₂)	14,981	15,336	15,666	16,060	15,923
Nitrogen Oxides (NO _x) ¹	7,889	7,892	7,893	7,944	7,822
Carbon Dioxide (CO ₂) ²	1,858,772	1,871,561	1,866,408	1,906,568	1,891,049

¹ As of 1992 data, reductions from NO_x control technologies have been changed--historical data were revised to reflect that change--see the Technical Notes for more information

² As of 1992 data, emission factors for the calculation of CO₂ have been changed--historical data were revised to reflect that change--see the Technical Notes for more information. SO₂, NO_x, and CO₂ emissions are only for steam-electric plants 10 megawatts and larger based on fuel consumption data reported on Form EIA-767. Total emissions of CO₂ using Form EIA-759 fuel consumption data are published in *Emissions of Greenhouse Gases in the United States 1985-1990* (DOE/EIA-0573)

Notes: •Estimates for 1992 are preliminary, estimates for prior years are final. •Estimates are derived from the Form EIA-767, "Steam-Electric Plant Operation and Design Report." (See Technical Notes for methodology)

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, 1988 Through 1992

Environmental Equipment	Scrubbers		Particulate Collectors	
	Number of Generators	Capacity ¹ (megawatts)	Number of Generators	Capacity ¹ (megawatts)
1992	154	71,351	1,169	353,525
1991	154	70,554	1,173	352,990
1990	153	69,122	1,177	349,319
1989	150	67,571	1,173	347,683
1988	149	67,221	1,181	345,839
	Cooling Towers		Total ¹	
	Number of Generators	Capacity ¹ (megawatts)	Number of Generators	Capacity ¹ (megawatts)
1992	485	165,306	1,346	379,194
1991	486	165,337	1,353	378,963
1990	478	162,557	1,360	376,894
1989	466	160,083	1,357	375,285
1988	458	156,800	1,363	372,555

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 1992 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."

Table 46. Estimated Emissions from Fossil-Fueled Steam-Electric Generating Units at Electric Utilities by Census Division and State, 1992 and 1991
(Thousand Short Tons)

Census Division State	1992			1991		
	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide ¹	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide ¹
New England	302	117	35,950	338	127	40,548
Connecticut	34	16	6,582	44	20	8,864
Maine	7	3	1,047	11	3	1,071
Massachusetts	203	75	23,343	235	79	25,395
New Hampshire	57	23	4,570	48	24	4,706
Rhode Island	.	.	100	.	1	155
Vermont	.	.	308	.	1	357
Middle Atlantic	1,599	558	188,851	1,671	585	179,062
New Jersey	61	45	9,427	64	51	11,060
New York	342	154	55,302	388	174	62,715
Pennsylvania	1,197	358	104,122	1,218	361	105,287
East North Central	4,869	1,868	379,080	5,175	1,913	387,092
Illinois	842	306	53,965	853	340	59,307
Indiana	1,182	539	105,641	1,403	546	107,096
Michigan	353	313	65,462	386	327	68,362
Ohio	2,228	552	123,125	2,242	536	120,939
Wisconsin	264	158	30,867	292	164	31,388
West North Central	1,215	913	183,106	1,317	953	189,158
Iowa	175	155	24,785	184	158	25,789
Kansas	67	129	27,053	77	144	29,753
Minnesota	78	151	30,595	80	160	31,070
Missouri	681	284	50,477	745	289	52,035
Nebraska	52	82	14,417	53	89	15,685
North Dakota	130	94	32,930	145	93	31,769
South Dakota	32	18	2,648	33	20	3,056
South Atlantic	3,456	1,345	347,799	3,435	1,329	356,300
Delaware	40	19	5,845	51	28	8,750
District of Columbia	1	.	98	1	.	222
Florida	745	394	84,806	724	392	96,273
Georgia	787	194	55,886	795	201	56,817
Maryland	259	96	26,713	263	92	27,143
North Carolina	378	195	53,972	331	170	46,854
South Carolina	154	80	23,752	163	35	24,603
Virginia	177	72	23,908	177	71	23,951
West Virginia	916	295	72,819	930	291	71,687
East South Central	2,210	820	197,904	2,135	806	193,451
Alabama	537	229	62,044	533	223	59,589
Kentucky	767	358	74,661	741	356	73,535
Mississippi	102	42	10,920	105	47	12,498
Tennessee	803	192	50,279	755	180	47,828
West South Central	756	1,264	292,103	732	1,248	293,635
Arkansas	66	102	23,995	66	101	23,795
Louisiana	110	189	38,364	103	178	36,468
Oklahoma	108	168	38,300	103	165	37,696
Texas	473	804	191,444	459	804	195,677
Mountain	464	786	199,360	436	746	186,604
Arizona	128	144	27,942	122	134	24,809
Colorado	87	136	32,372	84	139	32,012
Idaho	--	--	--	--	--	--
Montana	22	80	19,708	20	77	18,755
Nevada	59	71	21,184	56	70	20,957
New Mexico	59	152	19,469	51	135	17,485
Utah	31	77	32,773	29	74	30,559
Wyoming	78	126	45,911	75	118	42,029
Pacific Contiguous	85	205	49,838	72	171	40,456
California	1	137	34,204	1	113	27,639
Oregon	14	21	4,014	11	19	3,257
Washington	70	47	11,620	59	39	9,560
Pacific Noncontiguous	23	12	4,802	25	14	5,257
Alaska	1	.	2	1	.	1
Hawaii	23	12	4,800	24	14	5,256
U.S. Total	14,981	7,889	1,858,772	15,336	7,892	1,871,561

¹ As of 1992 data, 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.

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Notes: *Estimates for 1992 are preliminary; estimates for prior years are final. *Totals may not equal sum of components because of independent rounding. *Estimates are derived from the Form EIA-767, "Steam-Electric Plant Operation and Design Report." (See Technical Notes for methodology).

Source: Energy Information Administration, Form EIA-767, "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, 1992 (Thousand Short Tons)

Census Division State	Coal			Petroleum			Gas			Other ¹		
	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide ²	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide ²	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide ²	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide ²
New England	143	66	16,526	158	41	16,630	*	10	2,440	1	1	354
Connecticut	9	6	2,205	24	8	4,179	*	*	132	*	*	66
Maine	0	0	0	7	3	1,047	0	0	0	0	0	0
Massachusetts	90	38	10,926	113	27	10,234	*	9	2,172	*	*	11
New Hampshire	44	21	3,395	13	2	1,099	0	*	58	*	*	18
Rhode Island	0	0	0	*	*	70	0	*	29	0	0	0
Vermont	0	0	0	0	0	0	0	*	49	*	*	259
Middle Atlantic	1,506	473	134,822	93	39	18,282	*	45	15,766	1	*	191
New Jersey	57	34	6,250	4	4	1,303	*	8	1,872	*	*	2
New York	259	84	26,096	82	33	15,381	*	37	13,667	*	*	159
Pennsylvania	1,190	355	102,276	7	3	1,598	*	1	217	*	*	30
East North Central	4,661	1,852	373,554	8	4	1,977	*	7	2,105	1	5	1,424
Illinois	837	302	52,323	4	3	1,044	*	1	591	*	*	6
Indiana	1,181	538	105,018	*	*	141	*	2	482	0	0	0
Michigan	351	305	63,294	3	1	537	*	3	731	*	4	900
Ohio	2,228	550	122,699	*	*	221	*	*	158	1	1	48
Wisconsin	264	157	30,219	*	*	35	*	1	143	*	*	470
West North Central	1,213	905	180,703	2	*	328	*	6	1,444	*	1	631
Iowa	175	154	24,612	*	*	31	*	1	139	*	*	3
Kansas	67	126	26,207	*	*	35	*	3	812	0	0	0
Minnesota	77	148	29,665	*	*	19	*	1	283	*	1	628
Missouri	680	283	50,199	2	*	166	*	*	112	0	*	*
Nebraska	52	82	14,315	*	*	7	0	*	96	0	0	0
North Dakota	130	94	32,865	*	*	66	0	0	*	0	0	0
South Dakota	32	18	2,841	*	*	4	0	*	3	0	0	0
South Atlantic	3,216	1,223	307,981	239	66	26,128	*	56	13,386	1	*	305
Delaware	32	15	4,327	8	3	1,206	*	1	133	1	*	179
District of Columbia	0	0	0	1	*	93	0	0	0	*	*	5
Florida	547	285	51,313	197	56	20,958	*	53	12,501	*	*	34
Georgia	786	193	55,732	1	*	92	0	*	62	0	0	0
Maryland	234	90	23,724	25	4	2,360	*	2	544	*	*	86
North Carolina	378	195	53,833	*	*	138	0	0	0	0	0	0
South Carolina	154	80	23,627	*	*	58	0	*	66	*	0	*
Virginia	169	70	22,788	8	2	1,053	0	*	68	0	0	0
West Virginia	915	295	72,637	*	*	169	0	*	12	0	0	0
East South Central	2,204	809	194,727	6	1	567	*	11	2,610	0	0	0
Alabama	537	228	61,786	*	*	71	*	1	187	0	0	0
Kentucky	767	358	74,549	*	*	99	0	*	13	0	0	0
Mississippi	96	31	8,201	6	1	309	*	10	2,410	0	0	0
Tennessee	803	191	50,191	*	*	88	0	0	0	0	0	0
West South Central	755	950	208,986	1	*	345	*	313	82,773	0	0	0
Arkansas	66	97	22,161	*	*	59	*	5	1,775	0	0	0
Louisiana	110	134	22,959	*	*	52	*	55	15,354	0	0	0
Oklahoma	107	136	30,937	*	*	13	*	32	7,350	0	0	0
Texas	472	583	132,929	*	*	221	*	221	58,294	0	0	0
Mountain	462	768	194,127	2	1	511	*	17	4,721	0	*	*
Arizona	128	139	26,537	*	*	70	*	5	1,335	0	0	0
Colorado	87	134	32,055	*	*	44	*	1	272	0	*	*
Idaho	--	--	--	--	--	--	--	--	--	--	--	--
Montana	22	80	19,692	*	*	9	0	*	7	0	0	0
Nevada	58	64	19,501	1	1	265	*	6	1,418	0	0	0
New Mexico	59	149	18,047	*	*	40	*	4	1,381	0	0	0
Utah	31	76	32,441	*	*	29	*	1	303	0	0	0
Wyoming	78	126	45,853	*	*	53	0	*	5	0	0	0
Pacific Contiguous	84	67	14,562	1	1	234	*	136	33,986	*	1	1,055
California	0	0	0	1	1	222	*	136	33,982	0	0	0
Oregon	14	21	4,007	*	*	7	0	0	0	0	0	0
Washington	70	46	10,555	*	*	5	0	*	4	*	1	1,055
Pacific Noncontiguous	1	0	0	23	12	4,802	0	0	0	0	0	0
Alaska	1	0	0	*	*	2	0	0	0	0	0	0
Hawaii	0	0	0	23	12	4,800	0	0	0	0	0	0
U.S. Total	14,445	7,113	1,625,788	531	167	69,803	1	601	159,221	3	9	3,960

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

² As of 1992 data, 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

Notes: *Totals may not equal sum of components because of independent rounding *Estimates are preliminary *Estimates are derived from the Form EIA-767, "Steam-Electric Plant Operation and Design Report" (See Technical Notes for methodology). * Value less than 0.5

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, 1992

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	2,773	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	24,153	9	4,727	85	24,153	17	11,931
New Jersey	8	1,732	0	0	8	1,732	0	0
New York	25	3,758	1	691	25	3,758	0	0
Pennsylvania	52	18,664	8	4,035	52	18,664	17	11,931
East North Central	303	82,381	17	8,220	303	82,381	41	20,485
Illinois	55	17,123	4	1,439	55	17,123	2	562
Indiana	68	21,565	10	4,468	68	21,565	23	9,395
Michigan	49	12,116	0	0	49	12,116	2	195
Ohio	93	24,544	3	2,314	93	24,544	11	8,854
Wisconsin	38	7,033	0	0	38	7,033	3	1,479
West North Central	136	35,675	26	11,372	136	35,675	36	11,345
Iowa	27	5,645	1	176	27	5,645	6	1,681
Kansas	20	5,644	8	3,930	20	5,644	7	2,854
Minnesota	25	5,417	8	3,333	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	3,994	6	2,809	12	3,994	4	1,826
South Dakota	1	456	0	0	1	456	0	0
South Atlantic	214	68,654	14	6,968	212	68,591	64	35,400
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	38	14,537	1	123	38	14,537	12	9,774
Maryland	15	4,943	0	0	15	4,943	2	1,370
North Carolina	47	12,556	0	0	45	12,494	8	3,188
South Carolina	24	5,324	4	1,501	24	5,324	14	3,923
Virginia	24	4,549	0	0	24	4,549	3	713
West Virginia	33	14,958	2	1,368	33	14,958	13	9,822
East South Central	132	40,471	23	8,622	132	40,471	28	12,893
Alabama	39	12,586	4	1,597	39	12,586	4	2,599
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	30,488	48	20,701	87	30,488	75	25,993
Arizona	13	5,554	8	2,683	13	5,554	11	5,152
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	8	2,769	5	879	8	2,769	7	1,951
New Mexico	10	4,282	10	4,282	10	4,282	5	2,012
Utah	10	4,604	7	3,969	10	4,604	10	4,604
Wyoming	15	5,838	9	4,641	15	5,838	14	5,476
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	1,032	320,078	153	71,157	1,030	320,016	293	136,542

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 49. Number and Capacity of Petroleum- and Gas-Fired Steam-Electric Generators for Electric Utility Plants with Environmental Equipment by Census Division and State, 1992

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	1,683	1	415
Maine	4	846	0	0	4	846	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	48	12,829	0	0	45	10,993	4	2,012
New Jersey	10	1,737	0	0	9	1,602	2	311
New York	28	7,726	0	0	28	7,726	0	0
Pennsylvania	10	3,365	0	0	8	1,664	2	1,701
East North Central	15	2,461	0	0	10	928	5	1,533
Illinois	1	210	0	0	0	0	1	210
Indiana	5	370	0	0	3	278	2	92
Michigan	6	1,743	0	0	4	512	2	1,231
Ohio	1	51	0	0	1	51	0	0
Wisconsin	2	88	0	0	2	88	0	0
West North Central	18	1,484	0	0	5	168	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	82	0	0	1	82	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	15,588	0	0	40	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	31	9,975	0	0	22	8,625	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	882
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	87	13,721	0	0	4	2,258	85	12,562
Arkansas	2	183	0	0	0	0	2	183
Louisiana	14	2,535	0	0	2	1,184	13	1,943
Oklahoma	16	3,915	0	0	1	567	15	3,348
Texas	55	7,088	0	0	1	507	55	7,088
Mountain	33	2,982	1	195	5	478	33	2,982
Arizona	14	1,577	1	195	1	195	14	1,577
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	153	3	252
Wyoming	0	0	0	0	0	0	0	0
Pacific Contiguous	30	3,379	0	0	5	368	29	3,216
California	30	3,379	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	314	59,116	1	195	139	33,509	192	28,764

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 50. Average Quality of Fossil Fuels Burned at Electric Utilities by Census Division and State, 1992 and 1991

Census Division State	Coal						Petroleum				Gas	
	1992			1991			1992		1991		1992	1991
	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	Average Btu per Cubic Foot
New England	13,109	1.24	7.5	13,128	1.18	7.1	151,320	1.40	151,003			1,041
Connecticut	13,212	.57	6.3	13,217	.57	6.1	151,145	.91	151,145			1,033
Maine	--	--	--	--	--	--	150,768	1.03	150,768			--
Massachusetts	13,071	1.20	8.2	13,078	1.25	7.5	150,994	1.61	150,58		.031	1,044
New Hampshire	13,159	1.80	6.4	13,237	1.40	6.3	155,755	1.74	155,475	1.50	1,019	--
Rhode Island	--	--	--	--	--	--	148,327	1.00	146,666	1.00	1,031	1,032
Vermont	--	--	--	--	--	--	--	--	140,000	.30	1,000	1,000
Middle Atlantic	12,549	1.93	11.2	12,506	1.99	11.7	150,246	.74	150,163	.80	1,031	1,031
New Jersey	13,105	1.26	8.2	13,087	1.32	8.2	149,048	.42	148,626	.40	1,034	1,032
New York	12,880	1.63	8.3	12,847	1.75	9.0	150,435	.78	150,289	.84	1,031	1,031
Pennsylvania	12,436	2.05	12.1	12,391	2.08	12.5	149,388	.62	150,247	.72	1,031	1,030
East North Central	10,889	1.79	8.8	10,873	1.81	8.9	146,168	.60	146,832	.61	1,016	1,010
Illinois	10,601	2.02	8.5	10,560	1.87	8.5	149,623	.62	149,806	.62	1,016	1,020
Indiana	10,497	1.87	8.5	10,512	2.03	8.6	137,137	.35	137,378	.30	1,020	1,024
Michigan	10,792	.67	6.8	10,846	.70	6.7	145,058	.73	146,186	.72	1,016	986
Ohio	11,937	2.60	11.4	11,914	2.60	11.6	137,711	.36	140,406	.57	1,034	1,026
Wisconsin	9,589	.77	6.2	9,583	.82	6.3	139,188	.30	138,779	.39	982	1,007
West North Central	8,523	.88	1.2	8,591	.93	7.2	143,439	1.06	143,123	.97	989	985
Iowa	8,797	.69	5.8	8,838	.68	6.0	138,026	.45	138,029	.38	1,003	1,006
Kansas	8,827	.48	5.7	8,943	.57	5.7	140,329	.50	138,968	.47	982	974
Minnesota	8,774	.52	6.6	8,751	.53	7.1	139,070	.42	138,715	.42	1,006	1,006
Missouri	10,197	1.77	7.6	10,233	1.88	7.8	147,201	1.60	146,894	1.43	1,002	1,013
Nebraska	8,524	.38	5.1	8,518	.36	5.0	139,080	.22	142,312	.51	956	944
North Dakota	6,489	.75	9.6	6,560	.82	9.2	139,463	.50	138,632	.46	1,022	998
South Dakota	6,245	.88	9.0	6,238	.84	8.8	138,041	.36	137,542	.35	1,011	1,007
South Atlantic	12,379	1.52	10.0	12,366	1.52	9.9	151,074	1.36	150,867	1.35	1,012	1,020
Delaware	12,953	1.01	8.9	13,183	1.00	8.8	150,159	1.07	150,759	1.19	1,037	1,140
District of Columbia	--	--	--	--	--	--	143,643	.92	143,214	.93	--	--
Florida	12,203	1.73	8.4	12,215	1.72	8.4	151,548	1.38	151,416	1.26	1,010	1,012
Georgia	11,937	1.67	10.3	11,816	1.64	10.0	142,504	1.13	140,030	.73	1,024	1,024
Maryland	12,745	1.34	10.6	12,788		10.7	150,042	1.56	149,927	1.36	1,045	1,046
North Carolina	12,470	.92	10.1	12,551		9.8	138,198	.20	139,011	.20	--	--
South Carolina	12,743	1.13	8.9	12,641		9.1	140,089	.44	138,039	.15	1,022	1,025
Virginia	12,814	1.02	9.5	12,761		9.7	149,847	1.08	149,551	1.14	1,037	1,042
West Virginia	12,447	2.01	11.4	12,465		11.3	139,824	.33	139,213	.36	1,000	1,000
East South Central	11,971	1.90	10.1	11,985	1.91	10.2	146,572	1.71	145,458	1.55	1,028	1,025
Alabama	12,046	1.43	11.8	12,103	1.39	11.7	137,086	.33	137,254	.31	1,022	1,024
Kentucky	11,776	2.21	10.1	11,717	2.27	10.3	138,933	.30	138,829	.27	1,022	1,020
Mississippi	12,349	1.70	8.2	12,564	1.58	8.3	152,579	2.73	151,798	2.69	1,029	1,025
Tennessee	12,126	2.03	8.4	12,168	2.02	8.6	138,688	.31	138,880	.28	--	--
West South Central	7,576	.65	10.3	7,599	.65	10.5	138,550	.44	140,750	.49	1,028	1,031
Arkansas	8,526	.31	5.0	8,615	.31	5.0	139,050	.62	140,082	.43	1,024	1,028
Louisiana	7,960	.50	7.1	7,954	.51	7.3	142,976	.49	140,888	.44	1,037	1,035
Oklahoma	8,710	.41	5.2	8,741	.43	5.3	140,615	.62	140,711	.62	1,031	1,041
Texas	7,169	.77	12.5	7,206	.75	12.6	137,290	.38	140,985	.51	1,025	1,029
Mountain	9,805	.54	11.0	9,843	.54	10.8	145,386	.59	142,750	.48	1,026	1,021
Arizona	10,322	.51	12.4	10,382	.53	12.5	140,141	.35	139,571	.24	1,032	1,027
Colorado	9,916	.38	7.0	9,906	.37	6.8	146,780	.63	143,234	.53	962	970
Idaho	--	--	--	--	--	--	--	--	--	--	--	--
Montana	8,577	.66	8.9	8,524	.65	8.8	136,865	.50	136,865	.50	1,206	1,194
Nevada	11,861	.48	9.7	11,955	.49	9.6	147,734	.73	146,673	.69	1,025	1,024
New Mexico	9,150	.80	21.5	9,230	.78	21.2	134,864	.11	135,193	.14	1,021	1,019
Utah	11,470	.47	11.4	11,552	.46	10.9	139,175	.33	139,585	.29	1,074	1,067
Wyoming	8,725	.53	7.5	8,689	.52	7.7	140,502	.34	140,599	.35	1,039	1,051
Pacific Contiguous	8,476	.59	11.1	8,115	.57	11.9	147,407	.50	146,484	.42	1,032	1,027
California	--	--	--	--	--	--	147,759	.50	146,705	.42	1,032	1,027
Oregon	9,416	.40	4.3	8,349	.34	4.8	138,800	.50	138,800	.50	--	--
Washington	8,172	.65	13.3	8,033	.65	14.4	140,903	.31	140,897	.31	1,027	1,037
Pacific Noncontiguous	7,906	.16	8.4	7,864	.19	8.7	149,521	.68	149,083	.67	--	--
Alaska	7,906	.16	8.4	7,864	.19	8.7	134,360	.39	134,360	.29	--	--
Hawaii	--	--	--	--	--	--	149,527	.68	149,084	.67	--	--
U.S. Average	10,338	1.27	9.6	10,347	1.30	9.7	150,473	1.12	150,289	1.07	1,027	1,028

Notes: •Data for 1992 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-767, "Steam-Electric Plant Operation and Design Report."

Table 51. Average Flue Gas Desulfurization Costs at Electric Utilities by Census Division and State, 1988 Through 1992

Census Division State	Average O&M Costs (mills per kilowatthour)					Average Installed Costs (dollars per kilowatt)				
	1992	1991	1990	1989	1988	1992	1991	1990	1989	1988
New England	--	--	--	--	--	--	--	--	--	--
Connecticut	--	--	--	--	--	--	--	--	--	--
Maine	--	--	--	--	--	--	--	--	--	--
Massachusetts	--	--	--	--	--	--	--	--	--	--
New Hampshire	--	--	--	--	--	--	--	--	--	--
Rhode Island	--	--	--	--	--	--	--	--	--	--
Vermont	--	--	--	--	--	--	--	--	--	--
Middle Atlantic	4.91	5.01	5.15	4.92	4.15	183	178	157	174	175
New Jersey	NM	--	--	--	--	398	--	--	--	--
New York	1.03	1.07	1.22	1.24	1.23	319	319	212	212	212
Pennsylvania	6.04	6.20	6.25	5.90	4.83	157	149	149	168	170
East North Central	1.83	2.16	2.41	2.41	2.36	147	139	138	137	137
Illinois	2.47	2.53	2.35	2.69	2.64	197 ¹	197	147	146	146
Indiana	1.58	2.12	2.41	2.26	2.26	149	133	154	153	153
Michigan	--	--	--	--	--	--	--	--	--	--
Ohio	2.06	2.03	2.52	2.76	2.39	83	83	47	47	47
Wisconsin	--	--	--	--	--	--	--	--	--	--
West North Central	.75	.72	.74	.73	.80	83	75	75	74	72
Iowa	2.42	2.83	2.33	2.30	2.03	202	202	202	202	202
Kansas	.66	.53	.61	.59	.59	72	71	71	71	71
Minnesota	.40	.40	.27	.26	.30	73	73	73	73	73
Missouri	2.12	1.89	2.02	2.05	1.78	87	87	87	87	87
Nebraska	--	--	--	--	--	--	--	--	--	--
North Dakota	.74	.81	.92	.91	1.13	101	71	71	65	59
South Dakota	--	--	--	--	--	--	--	--	--	--
South Atlantic	1.28	1.63	1.58	1.47	1.95	143	144	85	92	92
Delaware ¹	NM	29.62	36.60	30.80	35.81	1,385	1,385	1,385	1,385	1,385
District of Columbia	--	--	--	--	--	--	--	--	--	--
Florida	1.15	1.23	1.07	.94	1.58	69	69	80	80	80
Georgia	--	--	--	--	--	--	--	--	--	--
Maryland	--	--	--	--	--	--	--	--	--	--
North Carolina	--	--	--	--	--	--	--	--	--	--
South Carolina	.64	.60	.54	.61	.59	43	43	34	46	46
Virginia	--	--	--	--	--	--	--	--	--	--
West Virginia	2.23	2.55	2.41	2.11	2.14	260	259	113	111	111
East South Central	1.65	1.51	1.49	1.48	1.69	140	153	131	120	120
Alabama	1.00	.94	.91	.76	1.58	80	82	82	82	82
Kentucky	1.91	1.70	1.70	1.73	1.80	135	155	146	133	133
Mississippi	.30	.41	.34	.33	.29	70	70	70	70	70
Tennessee	NM	NM	--	--	--	202	202	--	--	--
West South Central	1.22	1.17	.93	.99	.93	73	69	69	69	69
Arkansas	--	--	--	--	--	--	--	--	--	--
Louisiana	NM	NM	NM	NM	13	75	75	75	75	75
Oklahoma	.55	.57	.66	.54	.57	92	92	92	92	92
Texas	1.26	1.20	.95	1.03	1.03	72	67	67	67	67
Mountain	.69	.79	.74	.70	.75	148	149	154	149	151
Arizona	.68	.63	.77	.71	1.05	175	175	175	138	138
Colorado	.57	.63	.45	.43	.49	69	69	69	69	83
Idaho	--	--	--	--	--	--	--	--	--	--
Montana	.90	.94	1.19	1.04	.80	274	274	274	274	274
Nevada	.93	3.80	1.11	1.51	1.80	126	126	126	126	126
New Mexico	1.03	1.14	.95	.91	1.04	165	167	192	192	192
Utah	.48	.56	.43	.52	.51	97	97	97	97	97
Wyoming	.55	.67	.72	.56	.62	137	137	137	137	137
Pacific Contiguous	--	--	--	--	--	--	--	--	--	--
California	--	--	--	--	--	--	--	--	--	--
Oregon	--	--	--	--	--	--	--	--	--	--
Washington	--	--	--	--	--	--	--	--	--	--
Pacific Noncontiguous	--	--	--	--	--	--	--	--	--	--
Alaska	--	--	--	--	--	--	--	--	--	--
Hawaii	--	--	--	--	--	--	--	--	--	--
U.S. Average	1.32	1.40	1.35	1.33	1.36	132	130	118	117	118

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 1992 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 52. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1992

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 SO2 Removal (Percent Efficiency)
	by Plant	by Unit with FGD System					
Alabama Electric Coop Inc							
Charles R Lowman 2	538	236	7903	1.90	Spray	Limestone	85.0
Charles R Lowman 3	-	236	8005	1.90	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	8106	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	8501	.80	Tray	Lime	72.0
Four Corners 5	-	818	8501	.80	Tray	Lime	72.0
Associated Electric Coop Inc							
Thomas Hill FGD3	1,135	670	8207	4.80	Spray	Limestone	91.1
Basin Electric Power Coop							
Antelope Valley FGD1	870	435	8307	1.20	Spray Dry	Lime/Alkaline Fly Ash	81.0
Antelope Valley FGD2	-	435	8511	1.20	Spray Dry	Lime/Alkaline Fly Ash	81.0
Laramie River 1	1,710	570	8007	.80	Spray	Limestone	90.0
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	509	509	8611	3.80	Spray	Limestone	90.0
R D Green G1	527	264	7912	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	3.40	Venturi	Limestone	86.0
Central Illinois Pub Serv Co							
Newton 1	1,235	617	7912	4.00	Spray	Sodium Carbonate	90.0
Central Louisiana Elec Co Inc							
Dolet 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	99.0
W H Zimmer 1	1,426	1,426	9103	4.50	Spray	Lime	99.0
Columbus Southern Power Co							
Conesville 5	2,175	444	7705	7.90	Spray	Lime	89.7
Conesville 6	-	444	7708	7.90	Spray	Lime	89.7
Coop Power Assn							
Coal Creek 1	1,012	506	7908	1.00	Spray	Lime	90.0
Coal Creek 2	-	506	8107	1.00	Spray	Lime	90.0
Deseret Generation & Tran Coop							
Bonanza 1-1	400	400	8605	.50	Spray	Limestone	95.0
Duquesne Light Co							
Elrama SCRB	510	510	7609	2.50	Venturi	Lime	83.0
F R Phillips SCRB	411	411	7406	2.50	Venturi	Lime	83.0
East Kentucky Power Coop Inc							
H L Spurlock 2	814	508	8306	3.60	Spray Dry	Lime	90.0
Georgia Power Co							
Yates Y1FG	1,488	123	9210	2.50		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 1992—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	58	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 C Inc Merom 1FGD	1,080	540	8309	3.00	Spray	Limestone	90.0
Merom 2FGD	-	540	8202	3.00	Spray	Limestone	90.0
Houston Lighting & Power Co Limestone FGD1	1,627	813	8511	3.10	Spray	Limestone	90.0
Limestone FGD2	-	813	8611	3.10	Spray	Limestone	90.0
W A Parish FGD8	3,953	615	8212	.50	Spray	Limestone	85.0
Illinois Power Co Baldwin 1	1,892	623	9501	3.20	Spray	Limestone	95.0
Baldwin 2	-	635	9504	3.20	Spray	Limestone	95.0
Indianapolis Power & Light Co Petersburg 3	1,873	574	7711	-	Tray	Limestone	85.0
Petersburg 4	-	574	8604	-	Spray	Limestone	95.0
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	893	7306	5.40	Venturi	Limestone	80.0
Kentucky Utilities Co Green River 1	264	75	7510	3.80	Venturi	Lime	80.0
Lakeland City of C D McIntosh Jr 3	593	364	8209	1.80	Spray	Limestone	85.0
Los Angeles City of Intermountain 1CCC	1,784	892	8607	.30	Spray	Limestone	90.0
Intermountain 2CCC	-	892	8707	.90	Spray	Limestone	90.0
Louisville Gas & Electric Co Cane Run 4	792	163	7612	3.50	Packed	Other	85.0
Cane Run 5	-	209	7805	3.50	Spray	Other	85.0
Cane Run 6	-	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	9012	4.50	Spray	Limestone	90.7
Lower Colorado River Authority Sam Seymour 3	1,690	460	8804	1.70	Spray	Limestone	90.0
Marquette City of Shiras 3	40	40	8307	.50	Spray Dry	Limestone	80.0
Michigan South Central Pwr Agcy Endicott Generating 1	55	50	8305	4.30	Spray	Limestone	90.0
Minnesota Power & Light Co Clay Boswell AQCS2	1,073	558	8004	1.00	Spray	Alkaline Fly Ash	83.2
Clay Boswell SCR3	-	365	7302	1.00	Spray	Alkaline Fly Ash	25.4
Syl Laskin SCR1	116	58	7105	1.00	Spray	Alkaline Fly Ash	-
Syl Laskin SCR2	-	58	7105	1.00	Spray	Alkaline Fly Ash	-

See footnotes at end of table.

Table 52. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1992—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					
Minnkota Power Coop Inc Milton R Young FGD2	734	477	7806	1.20	Spray	Lime/Alkaline Fly Ash	77.9
Monongahela Power Co Pleasants 1	1,368	684	7903	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	58.8
Colstrip 2	-	358	7608	.80	Venturi	Lime/Alkaline Fly Ash	58.8
Colstrip 3	-	778	8401	.80	Venturi	Lime/Alkaline Fly Ash	95.0
Colstrip 4	-	778	8604	.80	Venturi	Lime/Alkaline Fly Ash	95.0
Montana-Dakota Utilities Co Coyote FGD1	450	450	8105	.80	Spray Dry	Lime/Alkaline Fly Ash	70.0
Muscatine City of Muscatine 9	276	176	8306	3.20	Spray	Limestone	96.0
Nevada Power Co Reid Gardner 1	612	114	7404	.50	Spray	Sodium Carbonate	90.5
Reid Gardner 2	-	114	7404	.50	Spray	Sodium Carbonate	90.5
Reid Gardner 3	-	114	7607	.50	Spray	Sodium Carbonate	90.5
Reid Gardner 4	-	270	8307	.90	Spray	Sodium Carbonate	85.0
New York State Elec & Gas Corp Kintigh 1	691	691	8408	3.60	Spray	Limestone	90.0
Northern Indiana Pub Serv Co Bailey 78	616	616	9206	-	Packed	Limestone	90.0
R M Schahfer 17	1,943	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	660	7605	.90	Venturi	Limestone/Alk Fly Ash	50.0
Sherburne County 2	-	660	7704	.90	Spray	Limestone/Alk Fly Ash	50.0
Sherburne County 3	-	809	8711	.90	Spray Dry	Lime/Alkaline Fly Ash	72.3
Orlando Utilities Comm Stanton Energy 1	929	465	8707	3.50	Spray	Limestone	90.0
PacifiCorp Hunter (Emery) 1	1,339	446	7806	.60	Spray	Lime	80.0
Hunter (Emery) 2	-	446	8006	.60	Spray	Lime	80.0
Hunter (Emery) 3	-	446	8306	.60	Spray	Limestone	90.0
Huntington 1	893	446	7802	.60	Spray	Lime	80.0
Jim Bridger SC71	2,242	561	9009	1.00	Tray	Soda Liquor Waste	86.4
Jim Bridger SC72	-	561	8609	1.00	Tray	Soda Liquor Waste	86.4
Jim Bridger SC73	-	561	8809	1.00	Tray	Soda Liquor Waste	86.4
Jim Bridger SC74	-	561	7911	1.00	Tray	Soda Liquor Waste	91.0
Naughton 3	707	326	8110	.80	Tray	Sodium Carbonate	70.0
Wyodak SC91	362	362	8612	.80	Spray Dry	Lime	75.2
Pennsylvania Power Co Bruce Mansfield 1	2,741	914	7604	4.80	Venturi	Lime	92.1
Bruce Mansfield 2	-	914	7710	4.80	Venturi	Lime	92.1
Bruce Mansfield 3	-	914	8009	4.80	Spray	Lime	92.1
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

See footnotes at end of table.

Table 52. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1992—Continued

Utility Plant and FGD No.	Nameplate Capacity (megawatts)		Initial Start up Date of FGD System	Design Coal Sulfur (Percent by WT)	FGD Type	Sorber	Designed SO ₂ Removal (Percent Efficiency)
	by Plant	by Unit with FGD System					
Plains Elec Gen&Trans Coop Inc							
Escalante 1	233	233	8412	0.80	Spray	Limestone	95.0
Platte River Power Authority							
Rawhide 101	285	285	8404	.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	86.0
Richmond City of							
Whitewater Valley LFC	-	-	9410	2.30	Spray Dry	Limestone	75.0
Salt River Proj Ag I & P Dist							
Coronado FGD1	822	411	7912	1.00	Spray	Limestone	82.5
Coronado FGD2	-	411	8011	1.00	Spray	Limestone	82.5
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	86.0
Seminole Electric Coop Inc							
Seminole 1	1,304	652	8402	3.00	Spray	Limestone	86.0
Seminole 2	-	652	8412	3.00	Spray	Limestone	86.0
Sierra Pacific Power Co							
North Valmy 2	521	267	8507	.50	Spray Dry	Lime	70.0
Sikeston City of							
Sikeston 1	261	261	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	8006	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	7906	1.50	Spray	Limestone	85.0
Southern Illinois Power Coop							
Marion 4	272	173	7904	4.40	Venturi	Limestone	89.4
Southern Indiana Gas & Elec Co							
A B Brown 1	530	265	7904	4.50	Spray		85.0
A B Brown 2	-	265	8602	4.50	Spray		90.0
Southwestern Electric Power Co							
Pirkey 1	721	721	8501	1.50	Spray	Limestone	85.0
Soyland Power Coop Inc							
Pearl Station 1A	22	22	7611	3.40	Venturi	Other	11.8

See footnotes at end of table.

Table 52. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1992—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 SO2 Removal (Percent Efficiency)
		by Plant	by Unit with FGD System					
Springfield City of								
Dallman	33	388	207	8012	3.30	Packed	Limestone	95.0
Southwest	1	194	194	7704	3.20	Tray	Limestone	87.0
Sunflower Electric Power Corp								
Holcomb	SDA1	349	349	8308	1.00	Spray Dry	Lime/Alkaline Fly Ash	80.0
Holcomb	SDA2	-	349	8308	1.00	Spray Dry	Lime/Alkaline Fly Ash	80.0
Holcomb	SDA3	-	349	8308	1.00	Spray Dry	Lime/Alkaline Fly Ash	80.0
Tampa Electric Co								
Big Bend	FGD4	1,823	486	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	1,969	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	1,980	793	7808	1.50	Spray	Limestone	74.0
Sandow	4	591	591	8105	1.60	Spray	Limestone	73.9
Tri-State G & T Assn Inc								
Craig	C1	1,339	446	8010	.40	Spray	Limestone	85.0
Craig	C2	-	446	8005	.40	Spray	Limestone	85.0
Craig	C3	-	446	8410	.40	Spray Dry	Lime	85.0
Tucson Electric Power Co								
Springerville	1	850	425	8506	.70	Spray Dry	Lime/Alkaline Fly Ash	61.3
Springerville	2	-	425	9006	.70	Spray Dry	Lime/Alkaline Fly Ash	61.3
United Power Assn								
Elk River	1	46	46	8903	-	Spray Dry	Lime	90.0
Stanton	10	172	172	8206	.70	Spray Dry	Lime	70.0
West Penn Power Co								
Mitchell	33	449	299	8208	4.00	Spray	Lime	95.0
West Texas Utilities Co								
Oklauion	1	720	720	8612	.40	Spray	Limestone	86.8
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	60.0
Lawrence	4N	614	114	6906	.90	Venturi	Limestone	73.0
Lawrence	4S	-	114	6906	.90	Venturi	Limestone	73.0
Lawrence	5N	-	413	7105	.90	Venturi	Limestone	52.0
Lawrence	5S	-	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 1991 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 Planning and Operations, Form OE-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*.³⁷

³⁷Energy Information Administration, *Electric Trade in the United States*, DOE/EIA-0531(90) (Washington, DC, 1992).

Table 53. Sources and Disposition of Electricity in the United States, 1988 Through 1992
(Million Kilowatthours)

Item	1992	1991	1990	1989	1988
Source					
Net Generation	2,805,092	2,835,377	2,821,493	2,811,398	2,730,774
Purchases from Utilities	1,146,323	1,127,669	998,525	959,375	922,038
Purchases from Nonutilities	166,283	139,436	116,065	89,813	68,030
Net Exchange	-3,504	1,172	-1,130	2,369	32,955
Net Wheeling	5,756	4,963	6,077	3,525	2,262
Disposition					
Sales to Ultimate Consumers	2,763,343	2,762,003	2,712,555	2,646,809	2,578,062
Requirements and Nonrequirements Sales for Resale	1,119,948	1,116,655	999,268	975,676	945,993
Energy Furnished Without Charge	4,409	4,210	5,896	5,647	5,525
Energy Used by Utility Electric Department	15,651	15,154	18,974	19,501	16,962
Energy Losses ²	216,599	210,596	204,339	218,846	209,516

¹ 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 1988.

² 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 1992 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, 1988 Through 1992
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1992	1991	1990	1989	1988
ECAR	483,530	488,102	485,128	487,659	487,040
ERCOT	190,442	192,000	188,586	185,011	179,442
MAAC	193,330	197,235	193,393	193,889	191,874
MAIN	200,288	206,906	201,653	200,660	198,666
MAPP(U.S.)	120,053	122,991	120,750	116,410	118,238
NPCC(U.S.)	202,978	218,053	227,866	233,624	223,996
SERC	637,803	630,562	611,708	612,643	571,541
SPP	242,514	244,415	244,762	239,032	233,396
WSCC(U.S.)	522,863	523,468	535,242	530,205	514,622
Contiguous U.S.	2,793,802	2,823,732	2,809,087	2,799,130	2,718,815
ASCC	4,735	4,654	4,660	4,575	4,460
Hawaii	6,555	6,991	7,746	7,692	7,499
U.S. Total	2,805,092	2,835,377	2,821,493	2,811,398	2,730,774

Notes: •Data for 1992 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 Alaska Systems Coordinating Council (ASCC) became a NERC Region member in 1989.

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, 1988 Through 1992
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	All Sectors	Residential	Commercial	Industrial	Other ¹
1992					
ECAR	429,591	129,847	97,007	192,916	9,820
ERCOT	203,206	71,802	53,342	69,306	8,755
MAAC	210,799	72,221	65,971	69,797	2,810
MAIN	200,571	56,685	54,013	81,314	8,558
MAPP(U.S.)	117,282	41,724	25,510	46,877	3,171
NPCC(U.S.)	233,394	76,774	84,839	57,553	14,228
SERC	609,116	239,899	153,232	198,418	17,567
SPP	235,321	80,252	59,964	87,121	7,985
WSCC(U.S.)	511,395	162,773	163,083	165,208	20,331
Contiguous U.S.	2,750,673	931,977	756,961	968,511	93,224
ASCC	4,338	1,640	2,034	504	160
Hawaii	8,332	2,323	2,274	3,676	59
U.S. Total	2,763,343	935,940	761,269	972,691	93,443
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	65,821	70,044	2,861
MAIN	201,815	61,856	55,904	75,196	8,859
MAPP(U.S.)	120,522	44,449	25,873	46,699	3,502
NPCC(U.S.)	233,643	76,755	85,036	57,668	14,185
SERC	601,988	239,154	157,981	187,386	17,467
SPP	238,328	84,615	60,682	84,701	8,330
WSCC(U.S.)	505,936	162,191	158,783	164,919	20,044
Contiguous U.S.	2,749,594	951,544	761,453	942,495	94,101
ASCC	4,255	1,603	2,005	466	182
Hawaii	8,154	2,270	2,205	3,623	55
U.S. Total	2,762,003	955,417	765,664	946,583	94,339
1990					
ECAR	418,732	125,258	93,318	190,495	9,661
ERCOT	202,090	72,451	54,140	68,791	6,708
MAAC	207,770	70,571	63,605	70,795	2,799
MAIN	193,068	57,050	53,600	73,936	8,481
MAPP(U.S.)	115,912	42,156	24,751	45,692	3,313
NPCC(U.S.)	234,542	76,496	84,787	59,281	13,979
SERC	588,223	232,383	153,914	184,980	16,946
SPP	236,253	84,325	60,574	83,012	8,343
WSCC(U.S.)	503,744	159,464	158,260	164,479	21,541
Contiguous U.S.	2,700,334	920,153	746,949	941,461	91,770
ASCC	4,253	1,661	1,972	459	161
Hawaii	7,968	2,204	2,106	3,601	56
U.S. Total	2,712,555	924,019	751,027	945,522	91,988

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

Notes: •Data for 1992 are preliminary; data for prior years 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 1989.

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, 1988 Through 1992 (Continued)
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	All Sectors	Residential	Commercial	Industrial	Other ¹
1989					
ECAR	414,977	126,538	91,610	187,166	9,663
ERCOT	195,648	70,005	52,988	67,783	4,872
MAAC	207,325	70,756	62,117	71,649	2,803
MAIN	188,425	56,318	52,258	71,518	8,330
MAPP(U.S.)	113,692	42,050	23,584	44,531	3,528
NPCC(U.S.)	233,573	76,090	84,682	58,986	13,815
SERC	571,569	225,987	146,375	182,469	16,739
SPP	223,134	77,907	57,480	79,450	8,298
WSCC(U.S.)	486,675	156,102	150,856	158,203	21,515
Contiguous U.S.	2,635,019	901,752	721,950	921,754	89,562
ASCC	4,142	1,643	1,897	450	151
Hawaii	7,649	2,129	2,014	3,454	52
U.S. Total	2,646,809	905,525	725,861	925,659	89,765
1988					
ECAR	408,171	128,073	89,404	181,082	9,611
ERCOT	192,367	68,708	51,723	67,182	4,755
MAAC	202,705	69,794	60,669	69,511	2,730
MAIN	185,430	58,202	51,470	67,344	8,414
MAPP(U.S.)	113,136	42,616	23,479	43,596	3,445
NPCC(U.S.)	228,883	74,897	83,030	57,527	13,429
SERC	545,250	217,201	135,410	176,737	15,901
SPP	218,281	76,942	56,183	76,625	8,530
WSCC(U.S.)	472,386	152,798	144,022	152,975	22,592
Contiguous U.S.	2,566,607	889,231	695,390	892,579	89,407
ASCC	4,045	1,590	1,778	542	136
Hawaii	7,411	2,045	1,932	3,378	56
U.S. Total	2,578,062	892,866	699,100	896,498	89,598

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

Notes: •Data for 1992 are preliminary, data for prior years 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 1989

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 1988 Through 1992
(Megawatts)

North American Electric Reliability Council Region and Hawaii	1992	1991	1990	1989	1988
ECAR	104,661	104,925	102,379	102,545	101,257
ERCOT	51,688	51,213	51,016	49,733	48,928
MAAC	51,553	51,331	50,323	50,071	48,766
MAIN	49,730	49,544	49,475	49,511	49,631
MAPP(U.S.)	30,968	31,057	30,772	30,376	30,348
NPCC(U.S.)	54,637	55,443	55,587	54,460	54,067
SERC	148,127	146,447	146,286	145,129	142,404
SPP	70,771	70,642	70,519	70,468	70,311
WSCC(U.S.)	129,694	129,346	129,280	129,296	128,986
Contiguous U.S.	691,828	689,948	685,637	681,581	674,697
ASCC	1,672	1,547	1,542	1,541	1,504
Hawaii	1,560	1,521	1,487	1,483	1,453
U.S. Total	695,059	693,016	690,465	684,619	677,654

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 1989.

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

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Table 57. Noncoincidental Peak Load at Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1988 Through 1992
(Megawatts)

North American Electric Reliability Council Region and Hawaii	1992	1991	1990	1989	1988
Summer					
ECAR	78,550	81,539	79,258	75,442	79,149
ERCOT	42,619	41,870	42,737	40,402	40,843
MAAC	43,658	45,937	42,613	41,614	43,110
MAIN	38,819	41,598	40,740	39,460	41,139
MAPP(U.S.)	22,638	25,498	24,994	23,531	24,899
NPCC(U.S.)	43,658	45,594	44,116	45,031	45,245
SERC	128,236	124,688	121,149	117,051	115,168
SPP	51,324	51,885	52,541	49,439	49,356
WSCC(U.S.)	99,205	92,096	97,389	90,657	90,551
Contiguous U.S.	548,707	550,635	545,537	522,627	529,460
ASCC	504	471	463	455	1
Hawaii	1	1	1	1	1
U.S. Total	549,211	551,106	546,000	523,082	529,460
Winter					
ECAR	72,885	71,181	67,097	73,080	67,771
ERCOT	35,055	35,448	35,815	38,388	34,621
MAAC	37,915	37,983	36,551	38,161	36,363
MAIN	31,289	33,420	32,461	33,770	30,631
MAPP(U.S.)	21,856	21,432	21,113	20,699	20,162
NPCC(U.S.)	41,125	41,866	40,545	42,588	42,951
SERC	121,250	119,575	117,231	121,995	108,649
SPP	39,912	38,759	38,949	42,268	35,649
WSCC(U.S.)	91,686	86,097	94,252	84,768	82,937
Contiguous U.S.	492,983	484,813	484,014	495,717	459,734
ASCC	635	622	613	626	1
Hawaii	1	1	1	1	1
U.S. Total	493,618	485,435	484,627	496,343	459,734

¹ Data for Alaska were first submitted in 1989; data for Hawaii are not submitted for this form.

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 1989.

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

Table 58. Electric Utility Receipts by North American Electric Reliability Council Region and Hawaii, 1988 Through 1992
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Receipts ¹	Purchased Power	Exchange Received	Wheeling Received
1992				
ECAR	190,220	155,564	2,853	31,803
ERCOT	130,049	59,661	46,311	24,077
MAAC	92,676	71,675	11,134	9,868
MAIN	55,810	52,108	213	3,489
MAPP(U.S.)	125,334	81,610	32,062	11,661
NPCC(U.S.)	227,569	163,418	3,464	60,687
SERC	378,689	325,039	26,439	27,211
SPP	150,336	123,644	4,943	21,749
WSCC(U.S.)	478,769	275,031	76,224	127,514
Contiguous U.S.	1,829,452	1,307,750	203,643	318,060
ASCC	3,021	2,531	12	478
Hawaii	2,328	2,324	4	0
U.S. Total	1,834,801	1,312,605	203,658	318,538
1991				
ECAR	195,606	151,284	14,030	30,293
ERCOT	127,343	57,805	48,603	20,934
MAAC	84,589	61,395	17,352	5,842
MAIN	58,405	48,165	6,420	3,819
MAPP(U.S.)	114,659	78,176	26,999	9,484
NPCC(U.S.)	211,379	140,964	13,242	57,173
SERC	381,671	321,277	31,937	28,457
SPP	150,048	122,420	5,477	22,150
WSCC(U.S.)	503,361	281,676	77,218	144,466
Contiguous U.S.	1,827,060	1,263,162	241,278	322,620
ASCC	2,876	2,343	20	514
Hawaii	1,605	1,601	4	0
U.S. Total	1,831,541	1,267,106	241,302	323,133
1990				
ECAR	243,163	106,892	103,430	32,841
ERCOT	111,413	58,788	36,144	16,481
MAAC	79,405	52,639	20,992	5,774
MAIN	69,759	35,701	32,607	1,451
MAPP(U.S.)	115,894	70,621	36,795	8,477
NPCC(U.S.)	190,396	123,171	18,613	48,613
SERC	385,587	290,825	65,471	29,291
SPP	147,674	108,909	11,674	27,091
WSCC(U.S.)	517,074	263,989	100,988	152,097
Contiguous U.S.	1,860,364	1,111,535	426,714	322,115
ASCC	2,900	2,345	2	552
Hawaii	714	710	4	0
U.S. Total	1,863,977	1,114,590	426,720	322,667

¹ Equals purchased power plus exchange received plus wheeling received.

Notes: •Data for 1992 are preliminary; data for prior years 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 1989. •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 58. Electric Utility Receipts by North American Electric Reliability Council Region and Hawaii, 1988 Through 1992 (Continued)
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Receipts ¹	Purchased Power	Exchange Received	Wheeling Received
1989				
ECAR	206,000	90,953	93,949	21,098
ERCOT	102,501	58,354	34,733	9,414
MAAC	86,267	46,371	31,511	8,385
MAIN	63,790	33,699	28,877	1,215
MAPP(U.S.)	114,246	68,948	36,090	9,208
NPCC(U.S.)	183,999	125,993	15,109	42,897
SERC	383,664	278,755	82,183	22,726
SPP	140,237	107,120	13,526	19,591
WSCC(U.S.)	485,872	236,294	84,754	164,824
Contiguous U.S.	1,766,575	1,046,488	420,730	299,356
ASCC	2,746	2,253	28	465
Hawaii	452	446	6	0
U.S. Total	1,769,773	1,049,187	420,764	299,822
1988				
ECAR	186,112	95,143	75,848	15,121
ERCOT	101,642	58,629	35,153	7,861
MAAC	76,386	41,173	27,731	7,482
MAIN	58,756	29,756	27,086	1,915
MAPP(U.S.)	114,754	68,937	38,014	7,804
NPCC(U.S.)	178,664	122,867	17,432	38,365
SERC	348,524	256,746	79,424	12,354
SPP	130,316	102,211	8,015	20,089
WSCC(U.S.)	443,345	211,960	73,630	157,755
Contiguous U.S.	1,638,499	987,422	382,332	268,746
ASCC	2,607	2,154	28	424
Hawaii	497	492	5	0
U.S. Total	1,641,604	990,068	382,365	269,170

¹ Equals purchased power plus exchange received plus wheeling received.

Notes: •Data for 1992 are preliminary; data for prior years 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 1989 •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 59. Electric Utility Deliveries by North American Electric Reliability Council Region and Hawaii, 1988 Through 1992
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Deliveries ¹	Requirements and Nonrequirements Sales for Resale	Exchange Delivered	Wheeling Delivered
1992				
ECAR	212,729	178,224	2,887	31,618
ERCOT	102,966	32,299	46,577	24,090
MAAC	59,416	48,364	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.)	178,603	116,451	1,657	60,495
SERC	357,147	300,686	31,053	25,408
SPP	137,540	109,595	6,306	21,639
WSCC(U.S.)	431,563	223,114	83,426	125,023
Contiguous U.S.	1,636,870	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	51,289	31,670	13,776	5,842
MAIN	48,267	38,135	6,392	3,739
MAPP(U.S.)	106,020	68,849	29,235	7,935
NPCC(U.S.)	177,038	112,478	7,635	56,925
SERC	364,167	306,718	30,001	27,447
SPP	136,561	107,884	6,600	22,078
WSCC(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	1,674,954	1,116,655	240,130	318,170
1990				
ECAR	278,650	153,283	92,614	32,753
ERCOT	85,076	32,153	36,428	16,496
MAAC	49,621	20,683	23,164	5,774
MAIN	63,588	24,191	37,983	1,414
MAPP(U.S.)	109,484	64,005	37,824	7,656
NPCC(U.S.)	166,593	98,972	19,222	48,399
SERC	367,232	279,722	59,336	28,174
SPP	136,099	95,289	13,824	26,985
WSCC(U.S.)	484,479	228,643	107,448	148,388
Contiguous U.S.	1,740,822	996,941	427,843	316,038
ASCC	2,883	2,327	3	552
Hawaii	5	0	5	0
U.S. Total	1,743,709	999,268	427,850	316,591

¹ Equals sales for resale plus exchange delivered plus wheeling delivered

Notes •Data for 1992 are preliminary; data for prior years 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 1989 •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 59. Electric Utility Deliveries by North American Electric Reliability Council Region and Hawaii, 1988 Through 1992 (Continued)
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Deliveries ¹	Requirements and Nonrequirements Sales for Resale	Exchange Delivered	Wheeling Delivered
1989				
ECAR	245,874	152,703	72,177	20,994
ERCOT	76,668	32,355	35,017	9,297
MAAC	55,290	17,940	28,990	8,360
MAIN	60,612	23,746	35,661	1,205
MAPP(U.S.)	105,500	59,451	37,852	8,197
NPCC(U.S.)	164,638	99,653	22,634	42,351
SERC	375,248	277,693	75,670	21,885
SPP	134,684	96,202	18,558	19,924
WSCC(U.S.)	469,146	213,689	91,833	163,623
Contiguous U.S.	1,687,660	973,432	418,392	295,836
ASCC	2,705	2,244	-	461
Hawaii	3	0	3	0
U.S. Total	1,690,368	975,676	418,395	296,297
1988				
ECAR	232,759	159,063	58,661	15,036
ERCOT	75,182	31,905	35,364	7,913
MAAC	47,606	16,628	23,513	7,465
MAIN	56,863	21,291	33,666	1,906
MAPP(U.S.)	108,391	62,928	38,757	6,705
NPCC(U.S.)	154,736	97,267	19,380	38,089
SERC	330,155	261,562	56,850	11,743
SPP	125,734	94,034	11,743	19,956
WSCC(U.S.)	428,207	199,053	71,472	157,682
Contiguous U.S.	1,559,633	943,731	349,406	266,496
ASCC	2,590	2,177	0	413
Hawaii	89	85	4	0
U.S. Total	1,562,312	945,993	349,410	266,909

¹ Equals sales for resale plus exchange delivered plus wheeling delivered.

* Value less than 0.5.

Notes: •Data for 1992 are preliminary; data for prior years 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 1989. •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 60. Electric Utility Net Energy Flow by North American Electric Reliability Council Region and Hawaii, 1988 Through 1992
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Net Energy Flow ¹	Receipts ²	Deliveries ³
1992			
ECAR	-22,509	190,220	212,729
ERCOT	27,082	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.)	48,966	227,569	178,603
SERC	21,542	378,689	357,147
SPP	12,796	150,336	137,540
WSCC(U.S.)	47,206	478,769	431,563
Contiguous U.S.	192,583	1,829,452	1,636,870
ASCC	1	3,021	3,020
Hawaii	2,325	2,328	3
U.S. Total	194,909	1,834,801	1,639,893
1991			
ECAR	-25,829	195,606	221,435
ERCOT	25,553	127,343	101,790
MAAC	33,300	84,589	51,289
MAIN	10,138	58,405	48,267
MAPP(U.S.)	8,640	114,659	106,020
NPCC(U.S.)	34,340	211,379	177,038
SERC	17,505	381,671	364,167
SPP	13,487	150,048	136,561
WSCC(U.S.)	37,826	503,361	465,535
Contiguous U.S.	154,960	1,827,060	1,672,100
ASCC	27	2,876	2,849
Hawaii	1,600	1,605	5
U.S. Total	156,586	1,831,541	1,674,954
1990			
ECAR	-35,487	243,163	278,650
ERCOT	26,337	111,413	85,076
MAAC	29,784	79,405	49,621
MAIN	6,171	69,759	63,588
MAPP(U.S.)	6,409	115,894	109,484
NPCC(U.S.)	23,803	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.	119,542	1,860,364	1,740,822
ASCC	17	2,900	2,883
Hawaii	709	714	5
U.S. Total	120,268	1,863,977	1,743,709

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 1992 are preliminary; data for prior years 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 1989. •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 60. Electric Utility Net Energy Flow by North American Electric Reliability Council Region and Hawaii, 1988 Through 1992 (Continued)
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Net Energy Flow ¹	Receipts ²	Deliveries ³
1989			
ECAR	-39,874	206,000	245,874
ERCOT	25,833	102,501	76,668
MAAC	30,977	86,267	55,290
MAIN	3,178	63,790	60,612
MAPP(U.S.)	8,746	114,246	105,500
NPCC(U.S.)	19,361	183,999	164,638
SERC	8,416	393,664	375,248
SPP	5,552	140,237	134,684
WSCC(U.S.)	16,726	485,872	469,146
Contiguous U.S.	78,915	1,766,575	1,687,660
ASCC	41	2,746	2,705
Hawaii	449	452	3
U.S. Total	79,405	1,769,773	1,690,368
1988			
ECAR	-46,647	186,112	232,759
ERCOT	26,460	101,642	75,182
MAAC	28,780	76,386	47,606
MAIN	1,894	58,756	56,863
MAPP(U.S.)	6,363	114,754	108,391
NPCC(U.S.)	23,927	178,664	154,736
SERC	18,369	348,524	330,155
SPP	4,582	130,316	125,734
WSCC(U.S.)	15,138	443,345	428,207
Contiguous U.S.	78,866	1,638,499	1,559,633
ASCC	17	2,607	2,590
Hawaii	408	497	89
U.S. Total	79,292	1,641,604	1,562,312

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 1992 are preliminary; data for prior years 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 1989. •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, 1988 Through 1992
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1992	1991	1990	1989	1988
ECAR	10,420	8,649	7,878	2,024	1,214
ERCOT	23,666	23,036	23,570	22,694	22,170
MAAC	16,433	12,721	8,007	5,479	2,550
MAIN	347	273	283	179	103
MAPP(U.S.)	576	1,563	348	148	97
NPCC(U.S.)	36,116	23,220	15,037	10,182	6,316
SERC	15,304	12,914	10,928	8,914	8,103
SPP	5,457	5,705	3,514	2,811	1,319
WSCC(U.S.)	55,637	49,951	45,978	37,145	25,939
Contiguous U.S.	163,957	138,033	115,542	89,576	67,810
ASCC	1	1	1	1	•
Hawaii	2,324	1,402	522	235	220
U.S. Total	166,283	139,436	116,065	89,813	68,030

• Value less than 0.5 thousand.

Notes: •Data for 1992 are preliminary; data for prior years 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 1989.

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, 1988 Through 1992
(Thousand Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1992	1991	1990	1989	1988
ECAR	-231,967	-446,412	-10,918,913	-5,426,212	* 164,437
ERCOT	-169,142	-195,548	-8,744	-10,315	-11,762
MAAC	--	--	--	--	--
MAIN	--	--	--	--	--
MAPP(U.S.)	6,921,800	3,307,714	742,954	-373,343	-1,279,546
NPCC(U.S.)	12,053,907	10,989,137	6,562,311	11,147,862	23,349,907
SERC	--	--	--	--	--
SPP	--	--	--	--	--
WSCC(U.S.)	9,773,701	8,617,259	5,602,571	5,637,853	9,546,828
Contiguous U.S.	28,348,299	22,272,150	1,980,179	10,975,843	31,769,864
ASCC	--	--	--	--	--
Hawaii	--	--	--	--	--
U.S. Total	28,348,299	22,272,150	1,980,179	10,975,843	31,769,864

* Value less than 0.5.

R = Revised data.

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. •The Alaska Systems Coordinating Council (ASCC) became a NERC Region member in 1989.

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, 1988 Through 1992
(Thousand Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1992	1991	1990	1989	1988
ECAR	82,151	106,606	38,234	13,451	381,621
ERCOT	--	14	1,121	1,333	--
MAAC	--	--	--	--	--
MAIN	--	--	--	--	--
MAPP(U.S.)	8,573,652	4,708,775	3,072,170	2,260,790	2,361,083
NPCC(U.S.)	14,699,638	13,051,823	9,272,554	13,707,688	24,319,405
SERC	--	--	--	--	--
SPP	--	--	--	--	--
WSCC(U.S.)	13,848,735	12,945,048	10,122,141	10,127,191	11,774,401
Contiguous U.S.	37,204,176	30,812,266	22,506,220	26,110,432	38,836,510
ASCC	--	--	--	--	--
Hawaii	--	--	--	--	--
U.S. Total	37,204,176	30,812,266	22,506,220	26,110,432	38,836,510

* 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. •The Alaska Systems Coordinating Council (ASCC) became a NERC Region member in 1989.

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, 1988 Through 1992
(Thousand Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1992	1991	1990	1989	1988
ECAR	314,118	553,018	10,957,147	5,439,663	^a 217,184
ERCOT	169,142	195,562	9,865	1,648	11,762
MAAC	--	--	--	--	--
MAIN	--	--	--	--	--
MAPP(U.S.)	1,651,852	1,401,061	2,329,216	2,634,133	3,640,629
NPCC(U.S.)	2,645,731	2,062,686	2,710,243	2,559,806	969,498
SERC	--	--	--	--	--
SPP	--	--	--	--	--
WSCC(U.S.)	4,075,034	4,327,789	4,519,570	4,489,338	2,227,573
Contiguous U.S.	8,855,877	8,540,116	20,526,041	15,134,589	7,066,646
ASCC	.	.	.	.	.
Hawaii	--	--	--	--	--
U.S. Total	8,855,877	8,540,116	20,526,041	15,134,589	7,066,646

* Value less than 0.5.

R = Revised data.

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. •The Alaska Systems Coordinating Council (ASCC) became a NERC Region member in 1989.

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

In recent years, 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, cost-effectively meet customer energy service requirements, selectively expand customer services, and 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 regula-

tory 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. By 1992, 41 States had begun implementing integrated resource planning.³⁸ 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 kilowatthours) 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-

³⁸Mitchell, Cynthia, "Integrated Resource Planning Survey: Where the States Stand," *The Electricity Journal* (May 1992), pp. 10-15.

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.³⁹

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 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 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.⁴⁰

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 usu-

³⁹Growth 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.

⁴⁰Self-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.

ally 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 four benefit/cost tests that are widely used in planning to identify cost effective DSM programs.⁴¹ 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 moving 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.⁴² 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.⁴³

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 con-

⁴¹California Public Utilities Commission and California Energy Commission, *Standard Practice Manual: Economic Analysis of Demand-Side Management Programs*, (Sacramento, California, December 1987).

⁴²Baumol, William J. and Wallace E. Oates, *The Theory of Environmental Policy*, 2nd Ed., (Cambridge University Press, New York, 1989) p. 17.

⁴³The Consumer Energy Council of America Research Foundation, *Incorporating Environmental Externalities into Utility Planning* (Consumer Energy Council of American Research Foundation, Washington, D.C., 1993)

sumer 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 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, heat pump, 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 first began to broaden their DSM approach to include incentive and financing programs for industrial lighting, thermal storage, electrotechnology, and advanced motors and drive systems, which have the potential to meet energy-efficiency and load-management objectives. Recently, 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.

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 purchased-power reductions, 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.⁴⁴

As utility DSM budgets have grown, exceeding \$2.2 billion in 1992, it has become increasingly important to know what DSM programs have accomplished. This

⁴⁴General Accounting Office, *Electricity Supply: Utility Demand-Side Management Programs Can Reduce Electricity Use*, GAO/RCED-92-13 (Washington, DC, October 1991).

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. In 1994, EIA intends to examine DSM data quality and verification practices. The study will summarize the state-of-the-art with respect to DSM program evaluation, describe the relationship between evaluation and verification, introduce typical evaluation and verification methodologies, and discuss the factors which influence the extent to which it is reasonable to reach broad conclusions about the quality of savings estimates. The results of the study will be presented in a feature article of EIA's *Electric Power Monthly*.

Data Sources

The data in the following tables were collected on the revised Schedule V of the 1992 Form EIA-861, "Annual Electric Utility Report." In 1991, the rapid growth in DSM, the widening range of activities, and the increasing demand for more detailed program performance and cost data led the EIA to conclude that its 3-year DSM data collection form needed revision. The current Schedule V includes reporting of actual and potential peakload 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). The prior schedule collected actual and potential peakload reductions for Direct Load Control, Interruptible Load, and Energy Efficiency combined with all other DSM programs. En-

ergy savings were reported for all program categories combined. Data were not reported by consumer sector. The years to be reported have also been changed. On the current schedule, utilities provide information for the reporting year (1992) and the first- and fifth-forecast years (1993 and 1997). The prior version of the schedule collected data for the reporting year and each of the following 10 years.

Other additions to the current schedule include the collection of incremental and annual peakload reductions and energy savings 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 in 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.

On the current schedule, costs are reported in one of three categories. If the cost can be tracked to a specific program category, 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. In prior years, cost was reported as an aggregate figure for all DSM programs for the reporting year and each of the 10 forecast years.

A final addition to the revised schedule is a checkbox 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 the utility promotes. The checkbox provides program-specific information on the end uses and program types used by utilities to increase energy efficiency.

Table 65. Annual Demand-Side Management Peakload Reductions, Energy Savings, and Cost at U.S. Electric Utilities, 1989 Through 1992

Item	1992	1991	1990	1989
Actual Peakload Reductions (megawatts)^{1 2}	17,657	16,739	14,772	12,463
Energy Savings (million kilowatthours)¹	31,767	23,343	18,671	16,268
Cost (thousand dollars)³	2,243,270	1,747,933	1,177,457	872,935

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 Referred to in the *Electric Power Annual, 1991* 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 1992 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. •Data for 1992 for peakload growth (386,729 megawatts), energy sales (1,738,450 megawatt-hours), and cost (\$24,585 (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 1992 (Megawatts)

North American Electric Reliability Council Region and Hawaii	1992					
	Actual Peakload Reduction ¹	Direct Load Control	Interruptible Load	Energy Efficiency	Other Load Management	Other Demand-Side Management
ECAR	661	128	49	379	101	4
ERCOT	592	22	131	369	68	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
NPCC(U.S.)	1,796	169	323	1,257	48	•
SERC	6,012	1,582	684	2,638	487	621
SPP	624	370	117	85	6	46
WSCC(U.S.)	3,902	188	1,074	2,351	237	52
Contiguous U.S.	17,647	3,777	3,579	7,889	1,669	734
ASCC	7	2	0	•	4	0
Hawaii	4	0	0	1	3	0
U.S. Total	17,657	3,779	3,579	7,890	1,676	734

	1991			
	Actual Peakload Reduction ¹	Direct Load Control	Interruptible Load	Energy Efficiency and Other Programs
ECAR	1,401	319	615	467
ERCOT	311	68	30	213
MAAC	1,484	573	667	244
MAIN	762	64	369	329
MAPP(U.S.)	1,424	902	305	217
NPCC(U.S.)	1,493	215	343	935
SERC	5,996	2,030	602	3,364
SPP	1,155	506	428	221
WSCC(U.S.)	2,668	414	287	1,967
Contiguous U.S.	16,694	5,091	3,646	7,957
ASCC	5	2	3	0
Hawaii	40	0	25	15
U.S. Total	16,739	5,093	3,674	7,972

	1990			
	Actual Peakload Reduction ¹	Direct Load Control	Interruptible Load	Energy Efficiency and Other Programs
ECAR	1,087	169	589	329
ERCOT	333	40	173	120
MAAC	1,083	263	569	251
MAIN	549	85	197	267
MAPP(U.S.)	1,116	629	261	226
NPCC(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	8
U.S. Total	14,772	3,692	4,219	6,861

¹ Represents the sum of the achieved reductions in the annual peak load attributable to direct load control, interruptible load, energy efficiency, other load management, and other demand-side management; whereas, in the *Electric Power Annual*, 1991, 1991 and 1990 peakload reductions attributable to energy efficiency, other load management, and other demand-side management were reported together under conservation and other programs.

• Value less than 0.5.

Notes: •Data for 1992 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. •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). •The Alaska Systems Coordinating Council (ASCC) became a NERC Region member in 1989.

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

Table 67. Annual and Incremental Effects at Electric Utilities by Demand-Side Management Program, 1992

Program	Potential Peakload Reduction ¹ (megawatts)	Actual Peakload Reduction ² (megawatts)	Energy Savings (million kilowatthours)
Annual Effects³			
Large Electric Utilities⁴			
Energy Efficiency ⁵	--	7,890	25,565
Direct Load Control	7,626	3,779	289
Interruptible Load	14,566	3,579	1,994
Other Load Management ⁶	1,899	1,676	419
Other Demand-Side Management ⁷	914	734	3,500
Total Electric Utilities	25,005	17,657	31,767
Incremental Effects⁸			
Large Electric Utilities⁴			
Energy Efficiency ⁵	--	1,501	5,338
Direct Load Control	1,395	554	40
Interruptible Load	4,204	1,537	130
Other Load Management ⁶	387	293	106
Other Demand-Side Management ⁷	91	53	171
Small Electric Utilities⁹			
Energy Efficiency ⁵	--	17	12
Direct Load Control	433	183	30
Interruptible Load	88	27	3
Other Load Management ⁶	120	92	2
Other Demand-Side Management ⁷	16	13	2
Total Electric Utilities	6,734	4,271	5,833

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 megawatts.

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 demand-side management programs during the year. Incremental effects are annualized to indicate the program effects that would have occurred 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 megawatts.

Note: Data are preliminary.

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

Table 68. Annual and Incremental Effects at Electric Utilities by Sector, 1992

Sector	Potential Peakload Reduction ¹ (megawatts)	Actual Peakload Reduction ² (megawatts)	Energy Savings (million kilowatthours)
Annual Effects³			
Large Electric Utilities⁴			
Residential	7,027	7,606	13,107
Commercial	4,235	4,598	9,617
Industrial ⁵	12,858	4,920	8,417
Other ⁶	885	532	626
Total Electric Utilities	25,005	17,657	31,767
Incremental Effects⁷			
Large Electric Utilities⁴			
Residential	1,229	1,112	1,818
Commercial	793	1,251	2,953
Industrial ⁵	3,826	1,468	882
Other ⁶	229	108	132
Small Electric Utilities⁸			
Residential	330	139	14
Commercial	54	32	5
Industrial ⁵	133	113	26
Other ⁶	140	48	3
Total Electric Utilities	6,734	4,271	5,833

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 1992. Included are new and existing participants in existing programs (those implemented in prior years that were in place during 1992) and all participants in new programs (those implemented during 1992).

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

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 Reflects the total effects caused by new participants in existing demand-side management programs and all participants in new programs during 1992. The effects are annualized to indicate program effects that would have resulted had participants been initiated into the program on January 1, 1992.

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

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	
	1992	1991	1990	1993	1997
Direct Load Control					
ECAR	222	337	218	264	488
ERCOT	121	68	40	154	304
MAAC	933	756	422	1,069	1,519
MAIN	147	64	86	160	388
MAPP(U.S.)	1,054	1,020	780	1,129	1,475
NPCC(U.S.)	188	222	135	183	233
SERC	3,814	3,271	2,383	4,335	5,673
SPP	533	569	460	621	739
WSCC(U.S.)	612	731	682	703	933
Contiguous U.S.	7,624	7,038	5,206	8,618	11,752
ASCC	2	2	1	2	0
Hawaii	0	0	0	0	10
U.S. Total	7,626	7,040	5,207	8,620	11,762
Interruptible Load					
ECAR	1,214	1,036	853	1,164	1,235
ERCOT	1,736	1,293	1,624	1,930	1,265
MAAC	838	724	760	1,065	1,307
MAIN	867	735	786	910	1,256
MAPP(U.S.)	789	682	674	924	1,188
NPCC(U.S.)	371	379	572	366	291
SERC	4,204	2,759	2,331	4,411	4,816
SPP	1,181	813	705	1,164	1,427
WSCC(U.S.)	3,353	3,038	2,646	3,571	3,992
Contiguous U.S.	14,553	11,459	10,951	15,504	16,777
ASCC	0	3	3	0	0
Hawaii	13	25	31	4	19
U.S. Total	14,566	11,487	10,985	15,508	16,796

Notes: •Data for 1992, 1993, and 1997 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	
	1992	1991	1990	1989	1993	1997
ECAR	1,129	1,072	636	557	1,663	4,652
ERCOT	1,013	393	227	191	1,158	1,473
MAAC	954	549	450	439	1,621	5,756
MAIN	1,212	1,081	721	409	1,627	2,997
MAPP(U.S.)	940	494	465	326	1,254	3,306
NPCC(U.S.)	5,049	3,657	2,065	1,373	6,687	14,116
SERC	13,302	11,900	10,812	10,153	13,888	17,770
SPP	273	156	146	105	307	408
WSCC(U.S.)	7,885	3,877	2,993	2,569	12,590	22,119
Contiguous U.S.	31,758	23,179	18,515	16,122	40,795	72,596
ASCC	0	0	0	4	7	22
Hawaii	9	164	156	142	14	165
U.S. Total	31,767	23,343	18,671	16,268	40,816	72,783

* Value less than 0.5

Notes: •Data for 1992, 1993, and 1997 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) •The Alaska Systems Coordinating Council (ASCC) became a NERC Region member in 1989

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	
	1992	1991	1990	1989	1993	1997
ECAR	130,903	36,534	15,355	11,177	228,565	335,685
ERCOT	55,675	52,701	33,147	31,184	63,669	67,356
MAAC	178,420	131,103	116,565	93,322	295,347	534,793
MAIN	133,610	93,316	89,651	77,068	136,394	186,744
MAPP(U.S.)	85,021	56,082	33,612	20,897	102,354	152,639
NPCC(U.S.)	542,222	511,632	317,640	168,570	585,457	706,455
SERC	510,489	331,751	258,695	243,686	560,658	722,289
SPP	30,927	24,652	22,648	13,667	33,080	48,129
WSCC(U.S.)	574,928	510,158	289,964	213,158	794,602	1,068,104
Contiguous U.S.	2,242,195	1,747,929	1,177,277	872,729	2,800,126	3,822,194
ASCC	315	0	177	197	887	1,041
Hawaii	760	4	3	9	9,421	26,203
U.S. Total	2,243,270	1,747,933	1,177,457	872,935	2,810,434	3,849,438

Notes •Data for 1992, 1993, and 1997 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 (\$20,398 (thousands) in 1992) is excluded •The Alaska Systems Coordinating Council (ASCC) became a NERC Region member in 1989

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

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

Program	Existing		Projected	
	1992	1993	1997	
Total Direct Cost¹	1,847,182	2,404,720	3,399,457	
Energy Efficiency	1,204,661	1,644,993	2,438,689	
Direct Load Control	322,127	376,193	476,514	
Interruptible Load	178,031	215,400	252,619	
Other Load Management	78,676	92,721	137,708	
Other Demand Side Management	63,687	75,413	93,927	
Total Indirect Cost²	396,088	405,714	449,981	
Administrative	158,494	176,409	192,770	
Marketing	56,225	72,192	83,671	
Monitoring and Evaluation	71,610	104,085	119,979	
Other ³	109,759	53,028	53,561	
Total Utility Cost⁴	2,243,270	2,810,434	3,849,438	

¹ Reflects electric utility cost incurred during the year that are identified with one of the demand-side program categories—Load building cost (\$24,858 (thousands) for 1992, \$31,207 (thousands) for 1993, and \$34,960 (thousands) for 1997) 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 1992, 1993, and 1997 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 (\$477,959 (thousands) by 85 utilities in 1992, \$455,930 (thousands) by 95 utilities in 1993, and \$553,323 (thousands) by 94 utilities in 1997) are excluded

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

Table 73. Number of Electric Utilities Having Different Energy End Uses and Program Types by Sector, 1992

Item	Residential	Commercial	Industrial
End Uses			
Heating System	359	224	130
Cooling System	360	264	162
Water Heating	412	215	129
Lighting	229	268	190
Building Shell	210	136	97
New Construction	238	148	100
Appliances	168	80	46
Motors	--	150	159
Process Heating	--	47	87
Electrolytics	--	5	26
Other System	44	52	36
Program Types			
Energy Audits	383	298	205
Rebates	347	234	155
Loaning	189	91	58
Other Incentives ¹	145	102	82
Other	143	102	82

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-861, "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 1992. 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 ownership⁴⁵, 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.

⁴⁵FERC 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 1992 are preliminary; data for 1989 through 1991 are final.⁴⁶ 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, 1992, 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 1992 includes operational facilities in 1991 and new facilities or planned facilities that became operational during that year.

The total capacity for 1989 through 1992 (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 1992.

⁴⁶Preliminary 1989 and 1990 statistics were provided in the Energy Information Administration (EIA), "Nonutility Power Producers," *Electric Power Monthly*, DOE/EIA-922(692-04), pp. 1-15.

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*, 1985.

Table 74. Summary Statistics for U.S. Nonutility Power Producers, 1989 Through 1992

Item	1 Megawatt or More 1992	5 Megawatts or More			
		1992	1991	1990	1989
Installed Capacity (megawatts)	56,814	55,163	48,171	42,869	36,645
Coal ¹	8,503	8,443	7,291	6,712	6,229
Petroleum ²	1,730	1,579	1,207	811	917
Natural Gas ³	21,542	21,104	20,259	16,682	13,999
Petroleum/Natural Gas (Combined)	8,478	8,354	5,049	6,167	4,439
Hydroelectric	2,684	2,133	1,587	1,477	1,386
Geothermal	1,254	1,243	1,048	1,031	944
Solar	360	360	360	360	200
Wind	1,822	1,786	1,652	1,405	1,339
Wood ⁴	6,805	6,735	6,580	5,786	5,254
Waste ⁵	3,006	2,805	2,627	2,230	1,742
Nuclear ⁶	20	20	20	20	20
Other ⁷	611	602	491	187	176
Gross Generation (million kilowatthours)	296,001	289,856	248,448	217,241	187,356
Coal ¹	47,363	47,160	40,587	32,131	31,511
Petroleum ²	10,963	10,692	7,814	7,330	5,742
Natural Gas ³	158,798	156,317	131,340	116,706	98,875
Hydroelectric	9,446	7,611	6,243	6,235	5,931
Geothermal	8,578	8,533	7,651	6,872	5,046
Solar	746	746	779	663	489
Wind	2,916	2,872	2,606	2,251	1,833
Wood ⁴	36,255	36,024	33,785	30,812	27,835
Waste ⁵	17,352	16,330	13,956	11,415	8,296
Nuclear ⁶	67	67	80	116	49
Other ⁷	3,516	3,504	3,609	2,710	1,750
Supply and Disposition (million kilowatthours)					
Gross Generation	296,001	289,856	248,448	217,241	187,356
Receipts ⁸	83,421	76,198	68,264	63,743	61,479
Deliveries ⁹	175,160	171,836	^R 140,537	^R 126,048	^R 98,916
Facility Use	204,261	194,218	^R 176,175	^R 154,936	^R 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, tires, 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.

^R R = Revised data.

Notes: •Data for 1992 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 Nonutility Generating Facilities by Fossil Fuels, Renewable Energy Sources, and Census Division, 1989 Through 1992 (Megawatts)

Census Division	Fossil Fuels ¹	Renewables/ Other/ Nuclear ²	Fossil Fuels and Renewables/ Other/ Nuclear
1992 (1 Megawatt or More)			
New England	2,115	1,429	861
Middle Atlantic	5,883	1,081	415
East North Central	4,024	387	1,038
West North Central	956	141	127
South Atlantic	5,413	1,388	2,642
East South Central	486	188	862
West South Central	10,239	266	2,176
Mountain	966	601	285
Pacific	6,941	5,239	668
U.S. Total	37,022	10,719	9,074
1992 (5 Megawatts or More)			
New England	2,060	1,292	848
Middle Atlantic	5,788	916	405
East North Central	3,877	310	1,030
West North Central	902	118	127
South Atlantic	5,328	1,299	2,628
East South Central	463	180	862
West South Central	10,154	254	2,166
Mountain	933	508	293
Pacific	6,772	5,004	655
U.S. Total	36,278	9,880	9,005
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	116
South Atlantic	3,597	1,250	2,416
East South Central	455	162	872
West South Central	10,019	41	1,996
Mountain	564	445	283
Pacific	6,044	4,508	587
U.S. Total	30,925	8,754	8,492
1990 (5 Megawatts or More)			
New England	1,238	891	1,089
Middle Atlantic	2,568	592	435
East North Central	3,986	106	949
West North Central	629	55	185
South Atlantic	2,933	682	2,365
East South Central	249	W	W
West South Central	7,857	38	3,870
Mountain	450	W	W
Pacific	5,394	3,792	964
U.S. Total	25,304	6,579	10,986
1989 (5 Megawatts or More)			
New England	582	871	881
Middle Atlantic	2,137	402	435
East North Central	2,609	106	693
West North Central	632	55	185
South Atlantic	1,999	480	2,346
East South Central	196	W	W
West South Central	7,268	38	3,818
Mountain	324	W	W
Pacific	4,599	3,462	903
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 sulfite liquors), and/or nuclear as energy sources.

W = Withheld to avoid disclosure of individual company data.

Notes: •See Technical Notes for a description of allocating capacity. •Data for 1992 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 967, "Annual Nonutility Power Producer Report."

Table 76. Installed Capacity at Nonutility Generating Facilities by Energy Source and Census Division, 1989 Through 1992 (Megawatts)

Census Division	Coal ¹	Natural Gas ¹	Petroleum and ² Petroleum/ Natural Gas (Combined) ³	Hydroelectric/ Geothermal/ Solar/ Wind	Wood ⁴ / Waste ⁵	Other ⁶ / Nuclear	Total
1992 (1 Megawatt or More)							
New England	261	413	1,702	579	1,448	--	4,404
Middle Atlantic	1,582	1,570	2,971	W	787	W	7,379
East North Central	1,240	2,845	619	W	626	W	5,449
West North Central	737	146	146	73	122	--	1,224
South Atlantic	2,649	825	2,474	205	2,870	420	9,443
East South Central	288	255	W	--	889	W	1,535
West South Central	828	9,521	1,020	W	1,095	W	12,680
Mountain	175	790	W	514	166	W	1,852
Pacific	743	5,176	W	4,037	1,808	W	12,848
U.S. Total	8,503	21,542	10,207	6,120	9,812	630	56,814
1992 (5 Megawatts or More)							
New England	W	W	1,660	463	1,418	--	4,200
Middle Atlantic	1,572	1,541	2,906	W	735	W	7,108
East North Central	1,221	2,751	577	W	591	W	5,217
West North Central	733	W	111	W	116	--	1,147
South Atlantic	2,632	797	2,433	155	2,822	415	9,255
East South Central	285	239	W	--	880	W	1,505
West South Central	W	9,453	996	W	1,084	W	12,574
Mountain	175	764	W	426	159	W	1,724
Pacific	741	5,024	W	3,868	1,734	W	12,431
U.S. Total	8,443	21,104	9,933	5,522	9,540	622	55,163
1991 (5 Megawatts or More)							
New England	353	793	1,086	432	1,192	--	3,856
Middle Atlantic	1,328	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	2,809	388	7,263
East South Central	276	239	W	--	874	W	1,489
West South Central	W	9,244	806	--	1,157	W	12,056
Mountain	162	489	W	363	159	W	1,292
Pacific	W	W	824	3,343	1,652	13	11,130
U.S. Total	7,291	20,259	6,256	4,647	9,207	510	48,171
1990 (5 Megawatts or More)							
New England	358	218	1,052	418	1,171	--	3,218
Middle Atlantic	1,053	409	1,386	239	507	--	3,595
East North Central	1,181	2,673	736	50	401	--	5,040
West North Central	640	W	W	55	122	--	869
South Atlantic	1,733	621	953	W	2,392	W	5,980
East South Central	256	W	--	--	817	W	1,273
West South Central	892	8,771	1,261	--	841	--	11,765
Mountain	W	347	W	308	94	W	978
Pacific	W	W	1,489	W	1,670	--	10,150
U.S. Total	6,712	16,682	6,978	4,274	8,016	206	42,869
1989 (5 Megawatts or More)							
New England	W	W	571	398	1,109	--	2,333
Middle Atlantic	997	356	1,044	191	386	--	2,974
East North Central	1,087	1,287	721	50	463	--	3,607
West North Central	643	W	W	55	122	--	872
South Atlantic	1,805	328	425	W	1,996	W	4,824
East South Central	298	W	--	--	661	W	1,123
West South Central	726	8,625	1,002	--	771	--	11,124
Mountain	W	263	W	283	91	W	823
Pacific	W	3,001	1,490	W	1,397	--	8,963
U.S. Total	6,229	13,999	5,356	3,870	6,997	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, tires, landfill gases, fish oils, and other waste.

⁷ Includes hydrogen, sulfur, batteries, chemicals, and spent sulfite liquor. Data previously published for other energy sources have been reclassified and are included in the category that best reflects its characteristics.

W = Withheld to avoid disclosure of individual company data.

Notes: *Data for 1992 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 77. Installed Capacity at Nonutility Generating Facilities by Qualifying Facility Status and Census Division, 1989 Through 1992 (Megawatts)

Census Division	QF Capacity		Non-QF Capacity		Total Capacity	
	No. of Facilities	Capacity (megawatts)	No. of Facilities	Capacity (megawatts)	No. of Facilities	Capacity (megawatts)
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	2,108	194	5,449
West North Central	23	505	44	720	67	1,224
South Atlantic	127	6,256	95	3,187	222	9,443
East South Central	23	822	23	713	46	1,535
West South Central	107	10,551	59	2,128	166	12,680
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
1992 (5 Megawatts or More)						
New England	79	2,989	22	1,211	101	4,200
Middle Atlantic	132	6,729	14	380	146	7,108
East North Central	43	3,220	56	1,998	99	5,217
West North Central	14	475	27	672	41	1,147
South Atlantic	96	6,163	50	3,092	146	9,255
East South Central	18	811	16	694	34	1,505
West South Central	93	10,508	33	2,066	126	12,574
Mountain	41	1,235	17	489	58	1,724
Pacific	300	10,718	83	1,714	383	12,431
U.S. Total	816	42,848	318	12,315	1,134	55,163
1991 (5 Megawatts or More)						
New England	69	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	625	36	1,103
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	10,016	30	2,040	117	12,056
Mountain	28	843	15	449	43	1,292
Pacific	276	9,458	86	1,681	362	11,138
U.S. Total	719	36,969	308	11,202	1,027	48,171
1990 (5 Megawatts or More)						
New England	66	2,352	18	866	84	3,218
Middle Atlantic	90	3,142	15	453	105	3,595
East North Central	37	3,072	50	1,969	87	5,040
West North Central	14	478	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	978
Pacific	248	8,592	77	1,558	325	10,150
U.S. Total	658	33,323	256	9,546	914	42,869
1989 (5 Megawatts or More)						
New England	59	1,766	15	568	74	2,333
Middle Atlantic	73	2,513	16	461	89	2,974
East North Central	34	1,637	48	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	576	27,429	249	9,216	825	36,645

QF = Nonutility generating facilities that have obtained status as qualifying facilities under the Public Utility Regulatory Policies Act of 1978.

Notes: •Data for 1992 are preliminary; data for prior years are final. •The shift between the number of facilities previously published as qualifying and non-qualifying in 1989 and 1990 is due to changes in facility status. The number of facilities shown for 1992 includes operational facilities in 1991 and new facilities or planned facilities that became operational during that year. •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 Nonutility Generating Facilities by Major Industry Group and Census Division, 1989 Through 1992 (Megawatts)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
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	695	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	11,865	442	193	180	--	--	12,680
Mountain	746	474	157	197	--	278	1,852
Pacific	4,342	6,200	239	1,560	326	182	12,848
U.S. Total	37,612	13,951	1,643	2,413	483	713	56,814
1992 (5 Megawatts or More)							
New England	2,061	2,036	103	--	--	--	4,200
Middle Atlantic	5,041	1,227	382	W	W	162	7,108
East North Central	4,749	185	197	W	--	W	5,217
West North Central	650	W	131	W	--	--	1,147
South Atlantic	6,292	2,752	130	--	W	W	9,255
East South Central	1,481	W	--	--	W	--	1,505
West South Central	11,803	431	174	166	--	--	12,574
Mountain	734	379	144	188	--	278	1,724
Pacific	4,251	5,975	173	1,546	318	168	12,431
U.S. Total	37,066	13,163	1,434	2,361	455	685	55,163
1991 (5 Megawatts or More)							
New England	1,925	1,898	33	--	--	--	3,856
Middle Atlantic	3,326	984	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	1,517	124	--	W	W	7,263
East South Central	1,466	W	--	--	W	--	1,489
West South Central	11,291	464	W	W	--	--	12,056
Mountain	493	316	W	W	--	268	1,292
Pacific	3,558	W	W	W	W	W	11,138
U.S. Total	32,767	10,946	1,111	2,199	455	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	--	--	869
South Atlantic	4,968	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	978
Pacific	3,382	W	W	W	315	W	10,150
U.S. Total	29,985	8,937	869	1,955	452	670	42,869
1989 (5 Megawatts or More)							
New England	1,203	W	W	--	--	--	2,333
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	452	452	36,645

W = Withheld to avoid disclosure of individual company data

Notes: •Data for 1992 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 Nonutility Power Producers by Energy Source and Census Division, 1989 Through 1992
(Million Kilowatthours)

Census Division	Coal ¹	Petroleum ²	Natural Gas ³	Hydroelectric	Geothermal/ Solar/ Wind	Wood ⁴ / Waste ⁵	Other ⁶ / Nuclear	Total
1992 (1 Megawatt or More)								
New England	2,397	1,506	11,056	2,694	--	8,418	--	26,071
Middle Atlantic	9,747	W	22,504	1,916	--	5,244	W	40,890
East North Central	6,569	510	13,549	W	--	3,166	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	--	--	5,163	W	9,962
West South Central	5,354	2,129	62,469	W	--	5,586	W	77,050
Mountain	1,131	40	3,450	600	1,214	816	204	7,455
Pacific	4,327	3,017	37,354	W	11,026	9,607	W	67,040
U.S. Total	47,383	10,963	158,798	9,448	12,241	53,607	3,583	296,001
1992 (5 Megawatts or More)								
New England	2,397	1,432	10,913	2,296	--	8,250	--	25,289
Middle Atlantic	9,703	W	22,144	1,460	--	4,994	W	39,691
East North Central	6,492	500	13,145	W	--	3,007	W	23,505
West North Central	2,561	41	637	247	--	645	--	4,130
South Atlantic	13,066	2,327	5,146	905	--	14,785	2,023	38,253
East South Central	2,144	W	2,349	--	--	5,127	W	9,859
West South Central	5,354	2,120	62,086	W	--	5,550	W	76,623
Mountain	1,131	15	3,309	395	1,179	776	204	7,009
Pacific	4,313	2,994	36,568	W	10,973	9,220	W	65,498
U.S. Total	47,160	10,692	156,317	7,611	12,152	52,354	3,571	289,856
1991 (5 Megawatts or More)								
New England	2,527	1,232	6,710	2,264	--	7,553	--	20,347
Middle Atlantic	7,741	W	11,050	877	--	3,933	W	24,806
East North Central	5,456	W	12,173	266	W	3,084	--	21,424
West North Central	1,641	36	745	227	--	466	--	3,316
South Atlantic	11,504	1,563	3,706	760	--	12,991	2,249	32,773
East South Central	2,065	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	40,587	7,814	131,340	6,243	11,035	47,741	3,688	248,448
1990 (5 Megawatts or More)								
New England	1,922	1,592	1,618	2,374	--	6,905	--	14,412
Middle Atlantic	5,242	1,173	7,186	969	--	2,856	--	17,425
East North Central	5,473	478	11,906	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	--	--	4,360	W	8,065
West South Central	W	W	57,938	--	--	4,924	W	69,199
Mountain	769	W	1,453	402	844	639	W	4,313
Pacific	1,946	W	W	W	8,942	8,209	W	52,319
U.S. Total	32,131	7,330	116,706	6,235	9,786	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	4,636	1,039	5,190	742	--	1,828	--	13,634
East North Central	5,722	402	5,415	199	--	2,293	--	14,030
West North Central	W	W	449	165	--	306	--	1,939
South Atlantic	10,895	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	56,039	--	--	5,014	843	66,755
Mountain	W	W	1,322	443	W	642	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 sulfite liquor. Data previously published for other energy sources have been reclassified and are included in the category that best reflects its characteristics

W = Withheld to avoid disclosure of individual company data

Notes: •Data for 1992 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 80. Gross Generation at Nonutility Generating Facilities by Qualifying Facility Status and Census Division, 1989 Through 1992
(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)
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	99	8,675	194	24,358
West North Central	23	2,073	44	2,298	67	4,371
South Atlantic	127	28,916	95	9,888	222	38,804
East South Central	23	5,413	23	4,549	46	9,962
West South Central	107	65,080	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
1992 (5 Megawatts or More)						
New England	79	18,352	22	6,937	101	25,289
Middle Atlantic	132	37,900	14	1,791	146	39,691
East North Central	43	15,122	56	8,383	99	23,505
West North Central	14	1,949	27	2,180	41	4,130
South Atlantic	96	28,621	50	9,632	146	38,253
East South Central	18	5,367	16	4,492	34	9,859
West South Central	93	64,927	33	11,696	126	76,623
Mountain	41	5,223	17	1,785	58	7,009
Pacific	300	59,933	83	5,565	383	65,498
U.S. Total	816	237,394	318	52,461	1,134	289,856
1991 (5 Megawatts or More)						
New England	69	15,448	22	4,899	91	20,347
Middle Atlantic	105	23,202	17	1,684	122	24,886
East North Central	38	13,169	52	8,255	90	21,424
West North Central	14	1,984	22	1,331	36	3,316
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	61,661	30	11,743	117	73,404
Mountain	28	3,673	15	1,769	43	5,442
Pacific	276	51,570	86	6,273	362	57,843
U.S. Total	719	199,599	308	48,849	1,027	248,448
1990 (5 Megawatts or More)						
New England	66	11,776	18	2,636	84	14,412
Middle Atlantic	90	15,748	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	35	6,895	114	28,024
East South Central	14	3,713	15	4,352	29	8,065
West South Central	84	58,348	25	10,850	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	658	174,866	256	42,374	914	217,241
1989 (5 Megawatts or More)						
New England	59	8,364	15	2,548	74	10,912
Middle Atlantic	73	11,788	16	1,847	89	13,634
East North Central	34	5,338	48	8,692	82	14,030
West North Central	14	1,290	11	649	25	1,939
South Atlantic	68	19,924	38	6,796	106	26,720
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	36,608	74	5,809	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: •Data for 1992 are preliminary; data for prior years are final. •The shift between the number of facilities previously published as qualifying and non-qualifying in 1989 and 1990 is due to changes in facility status. The number of facilities shown for 1992 includes operational facilities in 1991 and new facilities or planned facilities that became operational during that year. •Totals may not equal sum of components because of independent rounding.

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

Table 81. Gross Generation by Nonutility Power Producers by Major Industry Group and Census Division, 1989 Through 1992
(Million Kilowatthours)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
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	24,358
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	1,697	601	1,116	--	--	77,050
Mountain	3,564	2,156	837	W	--	W	7,455
Pacific	24,944	27,233	1,477	10,666	2,091	629	67,040
U.S. Total	207,789	60,415	7,389	14,923	3,163	2,322	296,001
1992 (5 Megawatts or More)							
New England	11,838	12,950	440	--	--	--	25,289
Middle Atlantic	27,553	6,617	2,174	W	W	1,124	39,691
East North Central	21,459	1,073	587	W	--	W	23,505
West North Central	2,618	W	W	W	--	--	4,130
South Atlantic	31,008	6,490	501	--	W	W	38,253
East South Central	9,728	W	--	--	W	--	9,859
West South Central	73,435	1,648	520	1,020	--	--	76,623
Mountain	3,507	1,870	W	487	--	W	7,009
Pacific	24,591	26,576	1,145	10,563	2,067	557	65,498
U.S. Total	205,798	57,584	6,502	14,667	3,080	2,225	289,856
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	24,886
East North Central	19,332	791	810	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	8,883	W	--	--	W	--	9,013
West South Central	69,739	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	48,552	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	19,033	793	577	W	--	W	20,843
West North Central	2,225	W	W	--	--	--	2,641
South Atlantic	24,589	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	--	--	69,199
Mountain	1,517	1,331	W	W	--	545	4,313
Pacific	19,905	W	W	W	2,069	W	52,319
U.S. Total	159,522	38,635	3,489	11,040	2,847	1,708	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	12,607	550	517	W	--	W	14,070
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	63,263	W	512	W	--	--	66,755
Mountain	1,534	986	W	W	--	W	3,848
Pacific	16,558	W	W	6,142	1,471	W	42,417
U.S. Total	142,055	31,086	3,046	8,197	1,875	1,097	187,356

W = Withheld to avoid disclosure of individual company data

Notes: •Data for 1992 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 82. Nonutility Electricity Supply and Disposition for Facilities by Census Division and State, 1992
(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	26,071	25,289	2,878	2,503	20,687	20,095	8,262	7,696
Connecticut	4,267	4,152	W	W	3,724	3,638	W	W
Maine	7,634	7,501	1,947	1,916	4,419	4,312	5,163	5,135
Massachusetts	7,496	7,320	409	273	6,509	6,419	1,396	1,144
New Hampshire	1,711	1,407	233	95	1,350	1,031	593	470
Rhode Island	4,788	4,751	83	W	4,556	4,551	315	W
Vermont	175	158	W	W	130	113	W	W
Middle Atlantic	40,890	39,691	6,805	6,089	32,706	31,844	14,989	13,936
New Jersey	12,818	12,618	571	355	11,513	11,429	1,876	1,541
New York	14,138	13,353	3,788	3,643	11,487	10,809	6,439	6,186
Pennsylvania	13,934	13,720	2,445	2,091	9,705	9,605	6,674	6,206
East North Central	24,358	23,505	15,623	13,772	10,632	10,300	29,350	26,977
Illinois	3,539	3,227	4,463	3,816	298	197	7,704	6,867
Indiana	W	W	4,416	4,098	W	W	8,275	7,932
Michigan	13,045	12,729	1,474	998	9,360	9,221	5,159	4,505
Ohio	1,433	W	2,773	2,744	104	W	4,102	4,048
Wisconsin	W	W	2,196	2,106	W	W	4,160	3,725
West North Central	4,371	4,130	4,395	4,149	1,096	1,009	7,670	7,270
Iowa	W	W	991	939	W	W	1,728	1,666
Kansas	322	W	W	W	W	W	W	W
Minnesota	2,580	2,486	2,445	2,323	729	671	4,295	4,138
Missouri	W	W	187	177	W	W	363	322
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	38,804	38,253	15,833	14,331	16,315	16,102	38,321	36,482
Delaware	761	W	W	W	W	W	W	W
District of Columbia	W	W	W	W	W	W	W	W
Florida	10,273	10,137	2,266	1,977	3,835	3,829	8,704	8,285
Georgia	5,829	5,751	2,599	1,967	106	86	8,322	7,633
Maryland	1,647	W	W	W	W	W	W	W
North Carolina	6,832	6,753	2,905	2,508	4,422	4,401	5,315	4,857
South Carolina	2,800	2,738	1,354	1,338	751	716	3,402	3,360
Virginia	7,725	7,695	3,497	3,395	5,815	5,754	5,377	5,247
West Virginia	2,937	2,911	1,666	1,666	845	845	3,759	3,732
East South Central	9,962	9,859	5,990	5,907	419	395	15,534	15,371
Alabama	4,741	4,716	2,393	W	175	W	6,959	6,906
Kentucky	W	W	W	W	W	W	W	W
Mississippi	2,746	2,704	523	W	98	W	3,172	3,127
Tennessee	2,475	2,479	3,073	3,025	146	125	5,402	5,339
West South Central	77,050	76,623	18,584	16,956	32,924	32,903	62,710	60,676
Arkansas	2,490	2,484	784	W	66	W	3,208	3,127
Louisiana	18,703	18,610	6,532	5,801	3,594	3,594	21,612	20,918
Oklahoma	4,205	4,126	852	W	3,102	W	1,956	1,875
Texas	51,852	51,352	10,116	9,644	26,162	26,142	35,905	34,855
Mountain	7,455	7,009	3,643	3,491	5,009	4,668	6,089	5,831
Arizona	W	W	121	W	W	W	W	W
Colorado	1,471	1,289	258	184	1,091	969	596	504
Idaho	1,304	1,218	936	936	1,138	1,051	1,102	1,102
Montana	458	W	W	W	W	W	W	W
Nevada	W	2,410	W	(*)	2,201	2,228	190	182
New Mexico	371	W	W	W	W	W	1,252	1,198
Utah	328	W	W	W	45	W	W	W
Wyoming	640	627	W	W	W	W	W	W
Pacific	67,040	65,498	9,670	8,999	55,373	54,520	21,337	19,978
Alaska	1,033	965	W	W	W	W	1,042	972
California	59,296	58,112	4,391	3,868	50,516	49,942	13,142	12,038
Hawaii	3,102	3,029	44	42	2,429	2,363	717	703
Oregon	1,159	1,056	W	W	W	W	1,179	1,159
Washington	2,450	2,336	4,427	4,298	1,620	1,529	5,257	5,106
U.S. Total	296,001	289,856	83,421	76,198	175,160	171,836	204,261	194,218

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.

(*) Denotes less than one-half the unit of measure.

W = Withheld to avoid disclosure of individual company data.

Notes: •Data for 1992 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 83. Estimated Emissions from Nonutility Power Producers Facilities by Census Division, 1989 Through 1992 (Thousand Short Tons)

Census Division	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide ¹
1992 (1 Megawatt or More)			
New England	37	52	38,685
Middle Atlantic	90	173	51,663
East North Central	206	274	88,094
West North Central	83	37	14,084
South Atlantic	387	234	122,916
East South Central	121	73	46,182
West South Central	238	263	111,284
Mountain	22	29	10,485
Pacific Contiguous	44	107	59,453
Pacific Noncontiguous	11	17	6,986
U.S. Total	1,219	1,259	549,832
1992 (5 Megawatts or More)			
New England	36	50	37,617
Middle Atlantic	87	169	50,310
East North Central	201	270	86,745
West North Central	61	36	13,535
South Atlantic	384	231	121,834
East South Central	120	73	45,845
West South Central	236	259	109,937
Mountain	22	29	10,268
Pacific Contiguous	43	102	57,669
Pacific Noncontiguous	11	15	6,429
U.S. Total	1,201	1,234	540,189
1991 (5 Megawatts or More)			
New England	45	42	32,316
Middle Atlantic	94	118	38,572
East North Central	197	258	81,675
West North Central	70	31	12,200
South Atlantic	347	205	110,306
East South Central	113	64	41,459
West South Central	176	248	102,126
Mountain	21	26	10,752
Pacific Contiguous	43	99	54,031
Pacific Noncontiguous	6	10	4,526
U.S. Total	1,112	1,101	487,963
1990 (5 Megawatts or More)			
New England	47	36	26,648
Middle Atlantic	120	117	35,708
East North Central	183	291	84,621
West North Central	46	22	7,627
South Atlantic	303	170	94,697
East South Central	105	62	37,684
West South Central	177	242	91,509
Mountain	15	22	9,069
Pacific Contiguous	28	103	49,869
Pacific Noncontiguous	8	11	4,757
U.S. Total	1,032	1,076	442,189
1989 (5 Megawatts or More)			
New England	41	30	26,275
Middle Atlantic	108	88	27,367
East North Central	177	286	77,411
West North Central	40	21	7,186
South Atlantic	257	181	101,014
East South Central	70	64	36,865
West South Central	81	228	94,134
Mountain	7	29	11,843
Pacific Contiguous	17	86	42,525
Pacific Noncontiguous	7	10	4,245
U.S. Total	805	1,023	428,865

¹ As of 1992 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 1992 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-867, "Annual Nonutility Power Producer Report."

Appendix A

Major Disturbances and Unusual Occurrences in U.S. Electric Power Systems

Appendix A

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 Planning and Operations.

Table A1. Major Disturbances and Unusual Occurrences in U.S. Electric Power Systems, 1992

Date	Time	Area	Utility/Power Pool (NERC Council)	Type of Disturbance	Loss (megawatt)	Number of Customers Affected	Restoration Time
1/06/92	5:04 PM	Washington, DC Downtown area	Potomac Electric Power Company (MAAC)	¹ Equipment	300	18,000	7:34 PM Same Day
1/21/92	2:30 AM	Oklahoma City Oklahoma	Oklahoma Gas and Electric Company (SPP)	² Rifle Fire	None		Not Applicable
1/22/92	Morning	Stillwater, Oklahoma	Stillwater Municipal Electric Department (SPP)	² Rifle Fire	None		Not Applicable
1/23/92	Morning	Stillwater, Oklahoma	Stillwater Municipal Electric Department (SPP)	² Rifle Fire	None		Not Applicable
1/23/92	2:25 PM	Livermore, California	Western Area Power Administration (WSCC)	⁴ Fog and Ice	50	One	2:47 PM Same Day
1/30/92	3:33 PM	Miami, Florida	Florida Power and Light Company (SERC)	⁵ Relaying Error	None		Not Applicable
2/10/92	Evening	Noble County Oklahoma	Oklahoma Gas and Electric Company (SPP)	⁶ Rifle Fire	5	NA	4 hours
2/11/92	Evening	Noble County Oklahoma	Oklahoma Gas and Electric Company (SPP)	⁶ Rifle Fire	5	NA	4 hours
2/20/92	3:31 PM	Noble County Oklahoma	Oklahoma Gas and Electric Company (SPP)	⁷ Rifle Fire	None		5:15 AM 2/21/92
2/27/92	3:08 PM	East Central Oklahoma	Oklahoma Gas and Electric Public Service of Oklahoma (SPP)	⁸ Rifle Fire	None		Two days
3/08/92	7:00 PM	Colorado	Public Service Company of Colorado (WSCC)	⁹ Storm 1	Minor	NA	Two days
3/26/92	6:35 AM	Town of Windsor, NC	Windsor Municipal Electric System (SERC)	¹⁰ Lightning	NA	1,560	10:58 AM Same Day
4/13/92	6:00 AM	Chicago, Illinois Business Area	Commonwealth Edison Company (MAIN)	¹¹ Flood	NA		5/4/92 80% 5/19/92 100%
4/27/92	1:27 PM	Northern Utah	Pacificorp (WSCC)	¹² Equipment Failure	418	NA	1:38 PM Same Day
4/29/92	8:33 AM	Los Angeles California	Los Angeles Department of Water and Power (WSCC)	¹³ Riots	46	51,800	4:48 PM 5/4/92
5/07/92	10:40 AM	New York City	Consolidated Edison Company (NPCC)	¹⁴ Test	NA		11:49 AM Same Day
5/18/92	6:29 PM	Town of Windsor, NC	Windsor Municipal Electric System (SERC)	¹⁵ Lightning	NA	1,560	9:52 PM Same Day
6/17/92	11:00 AM	Chicago, Illinois	Commonwealth Edison Company (MAIN)	¹⁶ Storm	NA	230,000	Midnight 6/19/92

See endnotes on the next page.

Table A1. Major Disturbances and Unusual Occurrences in U.S. Electric Power Systems, 1992—Continued

Date	Time	Area	Utility/Power Pool (NERC Council)	Type of Disturbance	Loss (megawatt)	Number of Customers Affected	Restoration Time
6/17/92	11:00 AM	Northern Michigan	Consumers Power Company (ECAR)	¹⁷ Storm	175	350,000	Noon 6/22/92
6/17/92	1:00 PM	Southern Michigan Northern Indiana	Indiana-Michigan Power Company (ECAR)	¹⁸ Storm	NA	93,000	3:32 PM 6/21/92
6/17/92	7:00 PM	Detroit Michigan	Detroit Edison Company (ECAR)	¹⁸ Storm	NA	100,000	Noon 6/18/92
6/17/92	11:00 PM	Indianapolis Indiana	Indianapolis Power and Light Company (ECAR)	²⁰ Storm	268	155,000	Midnight 6/22/92
6/19/92	3:12 PM	Eastern and S.W. Oklahoma	Public Service Company of Oklahoma (SPP)	²¹ Storm	75	100,000	5:00 PM 6/23/92
6/24/92	8:14 PM	Town of Windsor, NC	Windsor Municipal Electric System (SERC)	²² Lightning	NA	1,560	9:44 PM Same Day
7/01/92	6:02 PM	Corpus Christi Rio Grande, Texas	Central Power & Light Company (ERCOT)	²² Equipment Failure	664	64,000	7:40 PM Same Day
7/02/92	3:00 PM	Chicago, Illinois	Commonwealth Edison Company (MAIN)	²⁴ Storm	700	210,000	3:00 AM 7/04/92
7/08/92	1:00 AM	Concordia, Kansas	Centel Electric-Kansas (SPP)	²⁵ Storm	NA	7,800	3:00 PM 7/09/92
7/14/92	3:17 AM	Allegheny Power System	Allegheny Power Company (ECAR)	²⁶ VR--High loads	NA	1,271,000	11:00 PM Same Day
7/22/92	5:16 PM	West Point Jackson, Mississippi	Tennessee Valley Authority (SERC)	²⁷ Equipment Failure	568	150,000	5:48 PM Same Day
8/10/92	8:49 AM PAST	Vancouver British Columbia Canada	British Columbia Hydro and Power Authority (WSCC)	²⁸ Line Fault	380	50,000	9:19 AM PAST Same Day
8/20/92	5:50 PM PAST	Calif-Oregon	Many systems (WSCC)	²⁹ Forest Fire	520	NA	2:00 AM PAST 8/21/92
8/21/92	3:44 PM PAST	Calif-Oregon	Many systems (WSCC)	³⁰ Forest Fire	400	165	5:25 PM PAST Same Day
8/24/92	4:55 AM	East Coast of South Florida	Florida Power & Light Company (SERC)	³¹ Hurricane Andrew	1,262	1,400,000	10:00 AM 9/27/92
8/24/92	8:00 AM	Gulf Coast of South Florida	Lee County Electric Cooperative (SERC)	³² Hurricane Andrew	NA	37,938	7:00 PM 8/27/92
8/24/92	4:55 AM	Key West Florida	Key West Utilities Board (SERC)	³³ Hurricane Andrew	92	22,754	11:00 PM Same Day
8/24/92	4:55 AM	Florida Keys Florida	Florida Keys Electric Cooperative (SERC)	³⁴ Hurricane Andrew	45	26,844	10:00 PM 9/04/92

See endnotes on the next page.

Table A1. Major Disturbances and Unusual Occurrences in U.S. Electric Power Systems, 1992—Continued

Date	Time	Area	Utility/Power Pool (NERC Council)	Type of Disturbance	Loss (megawatt)	Number of Customers Affected	Restoration Time
8/25/92	Midnight	St. Tammany and other parishes	Washington-St. Tammany Electric Coop., LA. (SPP)	³⁶ Hurricane Andrew	NA	22,000	4:00 PM 8/29/92
8/25/92	7:15 PM	Area around E. Baton Rouge	Dixie Elec. Membership Corp., La. (SPP)	³⁶ Hurricane Andrew	225	57,018	Noon 9/03/92
8/25/92	9:00 PM	St. Mary and other parishes	So. LA. Electric Coop Association (SPP)	³⁷ Hurricane Andrew	58	15,205	10:00 AM 8/29/92
8/25/92	9:00 PM	Southwest, MS	Mississippi Power & Light Co (SPP)	³⁸ Hurricane Andrew	806	40,000	4:00 PM 8/29/92
8/25/92	11:00 PM	City of Morgan City, LA	Morgan City, LA, Muni. Power Plant (SPP)	³⁹ Hurricane Andrew	NA	6,170	8:00 AM 9/09/92
8/25/92	11:00 PM	St. Mary and other parishes	Teche Electric Coop., Inc. LA (SPP)	⁴⁰ Hurricane Andrew	40	9,000	5:00 PM 9/09/92
8/25/92	9:00 AM	Copiah & 10 other counties	Southern Pine Electric Pwr. Assoc., MS (SPP)	⁴¹ Hurricane Andrew	NA	26,500	2:00 PM 8/29/92
8/25/92	2:27 PM	East Central Mississippi	Mississippi Power Co. (SERC)	⁴² Hurricane Andrew		12,000	11:00 AM 8/31/92
8/26/92	Midnight	Attala and 12 other counties	Delta Electric Power Association, MS (SPP)	⁴³ Hurricane Andrew	NA	1,500	7:00 PM 8/28/92
8/26/92	Midnight	George and 4 other counties	Singing River Electric Pwr. Assoc., MS (SPP)	⁴⁴ Hurricane Andrew	NA	500	8:00 AM 8/27/92
8/26/92	12:10 AM	South Louisiana	LA. P&L & New Orleans Public Service (SPP)	⁴⁵ Hurricane Andrew	400	200,000	8:00 AM 9/01/92
8/26/92	1:25 AM	Southwest Louisiana	Gulf States Utilities Co. (SPP)	⁴⁶ Hurricane Andrew	NA	170,000	5:00 PM 9/02/92
8/26/92	1:30 AM	City of Houma, LA	Houma, LA, Light & Water Dept. (SPP)	⁴⁷ Hurricane Andrew	20	6,000	9:00 AM 8/28/92
8/26/92	2:00 AM	Acadia and other parishes	Southwest. LA Elec. Mem. Corp. (SPP)	⁴⁸ Hurricane Andrew	60	42,000	11:00 AM 9/02/92
8/26/92	2:00 AM	City of St. Martinville	St. Martinville, LA, Muni. Elec. Dept (SPP)	⁴⁹ Hurricane Andrew	NA	2,746	5:00 PM 8/30/92
8/26/92	2:00 AM	South Central Louisiana	Central Louisiana Electric Co. (SPP)	⁵⁰ Hurricane Andrew	250 to 350	36,264	9:00 AM 9/05/92
8/26/92	2:15 AM	City of Lafayette, LA	Lafayette, LA, Utilities System (SPP)	⁵¹ Hurricane Andrew	167	26,000	Morning 8/29/92
8/26/92	2:20 AM	City of Abbeyville, LA	Abbeyville, LA, Water & Light Plant (SPP)	⁵² Hurricane Andrew	8	4,767	9:00 PM 8/29/92

See endnotes on the next page.

Table A1. Major Disturbances and Unusual Occurrences in U.S. Electric Power Systems, 1992—Continued

Date	Time	Area	Utility/Power Pool (NERC Council)	Type of Disturbance	Loss (megawatt)	Number of Customers Affected	Restoration Time
8/26/92	3:00 AM	Area around W. Baton Rouge	Pointe Coupee Electric Mem. Corp., LA (SPP)	⁵³ Hurricane Andrew	35	8,650	9:00 PM 8/30/92
8/26/92	9:15 AM	City of New Roads, LA	New Roads, LA, Muni. Power Plant (SPP)	⁵⁴ Hurricane Andrew	NA	1,959	10:00 AM 8/31/92
8/26/92	4:00 AM	Pike and 5 other counties	Magnolia Elec. Power Association, MS (SPP)	⁵⁵ Hurricane Andrew	40	16,000	8:00 PM 8/29/92
8/26/92	4:00 PM	Alcorn and other counties	Alcorn County, MS Elec Pwr. Assoc. (SPP)	⁵⁶ Hurricane Andrew	NA	1,000	8:30 PM Same Day
8/26/92	6:00 PM	Clarke and 9 other counties	E. Miss. Elec. Power Association, MS (SPP)	⁵⁷ Hurricane Andrew	NA	12,500	2:30 AM 8/28/92
8/26/92	7:00 PM	Yazoo and 5 other counties	Yazoo Valley Elec. Pwr Association, MS (SPP)	⁵⁸ Hurricane Andrew	20	4,000	9:00 PM 8/27/92
8/26/92	8:00 PM	Covington & 11 other counties	Pearl River Valley El. Pwr. Assoc. MS (SPP)	⁵⁹ Hurricane Andrew	NA	5,000 to 6,000	Noon 8/27/92
8/26/92	9:30 PM	Adams and 8 other counties	Southwest MS Electric Pwr. Assoc., MS (SPP)	⁶⁰ Hurricane Andrew	65	19,500	7:30 PM 9/02/92
8/26/92	11:00 PM	Washington & 6 other counties	Twin County Elect. Pwr Association, MS (SPP)	⁶¹ Hurricane Andrew	1.5	800	5:00 PM 8/27/92
8/26/92	11:00 PM	Jones & 6 other counties	Dixie Electric Power Association, MS (SPP)	⁶² Hurricane Andrew	24	5,000	7:00 PM 8/28/92
8/26/92	2:05 PM	City of Plaquemine, LA	Plaquemine City, LA, Lt. & Wtr. Dept. (SPP)	⁶³ Hurricane Andrew	16	4,120	11:00 PM 8/30/92
8/27/92	Morning	5 towns and 8 counties	Tombigbee Electric Pwr Association, MS (SPP)	⁶⁴ Hurricane Andrew	NA	300	Afternoon Same Day
8/27/92	12:30 AM	Leake and other counties	Central Electric Power Association, MS (SPP)	⁶⁵ Hurricane Andrew	15	6,900	4:00 AM 8/28/92
8/27/92	2:00 AM	8 counties & 10 towns	Four County Elec. Pwr. Association, MS (SPP)	⁶⁶ Hurricane Andrew	15	10,000	2:00 AM 8/28/92
8/27/92	5:00 AM	11 towns and 7 counties	Natchez Trace El. Pwr. Association, MS (SPP)	⁶⁷ Hurricane Andrew	NA	5,000	10:00 PM Same Day
8/27/92	7:00 PM	Rural areas around Panola	Tallahatchie Valley El. Pwr. Assoc. (SPP)	⁶⁸ Hurricane Andrew	NA	6,000	4:00 AM 8/28/92
8/27/92	8:00 AM	Lafayette & 3 other counties	North East MS Elec. Pwr. Assoc., MS (SPP)	⁶⁹ Hurricane Andrew	NA	2,500	Midnight Same Day
8/27/92	8:00 AM	3 towns and 5 counties	Pontotoc Elect. Power Association, MS (SPP)	⁷⁰ Hurricane Andrew	7	2,000	10:00 PM Same Day

See endnotes on the next page

Table A1. Major Disturbances and Unusual Occurrences in U.S. Electric Power Systems, 1992—Continued

Date	Time	Area	Utility/Power Pool (NERC Council)	Type of Disturbance	Loss (megawatt)	Number of Customers Affected	Restoration Time
8/27/92	8:00 AM	Monroe, Lowndes & Itawamba	Monroe County Elec.Pwr Association, MS (SPP)	⁷¹ Hurricane Andrew	NA	1,300	5:00 PM Same Day
8/27/92	10:00 AM	Rural areas in Miss. & Tenn.	Tippah Electric Power Association, MS (SPP)	⁷² Hurricane Andrew	NA	150	5:00 PM Same Day
8/27/92	12:30 PM	Central Alabama	Alabama Power Co. (SERC)	⁷³ Hurricane Andrew	200	58,000	1:58 PM 8/28/92
8/28/92	5:00 PM PAST	Los Angeles, Burbank, CA	Los Angeles Dept. of Water & Power (WSCC)	⁷⁴ Line Fault	738	232,800	5:37 PM Same Day
9/11/92	1:40 PM	Island of Kauai, HI	Citizens Utilities Company Kauai Division	⁷⁵ Hurricane Iniki	NA	24,700	Estimate 2 months
10/03/92	6:30 AM	Chiefland, FL West Central, FL	Central Florida Electric Cooperative (SERC)	⁷⁶ Tornado	NA	32	1:00 PM Same Day
10/03/92	10:30 AM	St. Petersburg, West Central, FL	Florida Power Corporation (SERC)	⁷⁷ Tornado	NA	30,000	2:00 AM 10/5/92
10/03/92	12:30 PM	Dade City, FL West Central, FL	Withlacoochee River Electric Cooperative (SERC)	⁷⁸ Tornado	NA	3,600	2:30 PM Same Day
10/21/92	5:00 PM	Guam	Guam Power Authority	⁷⁹ Typhoon	NA		NA
10/28/92	1:29 PM CST	New Mexico West Texas	Southwestern Public Service Company (SPP)	⁸⁰ Misoperate	236	17,199	2:24 PM Same Day
11/01/92	11:40 PM	Kewaunee Cty. WI	Wisconsin Public Service Corporation (MAIN)	⁸¹ Seaweed	None		10:40 AM 11/3/92
11/14/92	10:12 AM	OR, CA, CO, NV, UT, NM, AZ	Several systems in (WSCC)	⁸² Line Fault	None		11:49 AM Same Day
11/21/92	3:35 PM	Houston, TX	Houston Lightning & Power Company (ERCOT)	⁸³ Tornado	525	118,900	Midnight 11/24/92
11/23/92	6:29 AM	Town of Windsor, NC	Windsor Municipal Electric System (SERC)	⁸⁴ Tornado	NA	1,560	10:42 AM Same Day
11/25/92	9:55 AM	Marin, Sonoma Napa Counties	Pacific Gas & Electric Co. California (WSCC)	⁸⁵ Misoperate	530	312,000	10:30 AM Same Day
12/11/92	6:00 AM	Long Island, NY	Long Island Lighting Company (NPCC)	⁸⁶ Storm	90	94,000	10:00 AM 12/13/92
12/12/92	9:04 AM	MA, RI, CT	New England Power Pool (NPCC)	⁸⁷ Storm	300	181,000	5:00 PM 12/14/92
12/14/92	NA	Near Santa Rosa, CA	Pacific Gas & Electric Company (WSCC)	⁸⁸ Sabotage	None		NA

See endnotes on the next page.

Table A1. Major Disturbances and Unusual Occurrences in U.S. Electric Power Systems, 1992—Continued

Date	Time	Area	Utility/Power Pool (NERC Council)	Type of Disturbance	Loss (megawatt)	Number of Customers Affected	Restoration Time
12/16/92	4:47 AM	Southern, MD	Southern Maryland Electric Coop. (MAAC)	¹ Misoperate	85	41,000	6:02 AM Same Day
12/18/92	5:46 AM	Las Vegas, NV	Western Area Power Administration (WSPC)	² Sabotage	30	NA	1:14 PM Same Day
12/21/92	3:15 PM	Near Seattle Washington	Bonneville Power Administration (WSPC)	³ Sabotage	None		NA
12/28/92	2:40 AM	Portola, CA	Plumas-Sierra Rural Electric Coop. (WSPC)	⁴ Line Fault	16	5,492	4:01 AM Same Day
12/28/92	11:16 AM	Portola, CA	Plumas-Sierra Rural Electric Coop. (WSPC)	⁵ Line Fault	16	5,492	11:39 AM Same Day
12/28/92	9:54 AM	Portola, CA	Plumas-Sierra Rural Electric Coop. (WSPC)	⁶ Line Fault	16	5,492	10:18 AM Same Day
12/30/92	3:16 AM	Portola, CA	Plumas-Sierra Rural Electric Coop. (WSPC)	⁷ Line Fault	16	5,492	9:51 AM Same Day
12/31/92	9:26 AM	Portola, CA	Plumas-Sierra Rural Electric Coop. (WSPC)	⁸ Line Fault	16	5,492	11:27 AM Same Day
12/31/92	7:03 PM	Portola, CA	Plumas-Sierra Rural Electric Coop. (WSPC)	⁹ Line Fault	16	5,492	10:10 AM Same Day
12/31/92	8:51 PM	Sequoyah Nuclear	Tennessee Valley Authority (SERC)	¹⁰ Circ. Bkr.	None		8:62 PM Same Day

¹ During a normal switching operation, the switching device malfunctioned, initiating an arc between two 230-kilovolt cables that connect PEPCO's Station C to the system. The station was thereby disconnected from the system, and its five generating units tripped, causing loss of all load supplied from that station. An emergency tie with Virginia Electric and Power Company was established to allow restoration of service to begin.

² One distribution transformer in each of the two different substations was damaged by rifle fire, one at 2:30 AM and the other at an earlier time which could not be ascertained. Customer service was not affected.

³ Two substation transformers (69-kilovolt/12.47-kilovolt) were damaged by rifle fire on 1/22 and two more (69-kilovolt/12.47-kilovolt) were damaged by rifle fire on 1/23. All four transformers were repaired and were re-energized by the morning of 1/25. Customer service was not affected.

⁴ The 230-kilovolt transmission line from Western Area Power Administration's Tracy substation to its Livermore substation tripped, causing loss of power to the DOE Lawrence Livermore National Laboratory Site No. 2 and the National Laboratory at Livermore, California. One of the two emergency generators at the Sandia facility did not start; it was later discovered that a battery charger had been connected incorrectly. The other generator did start and provided power for critical loads. The cause of the 230-kilovolt line trip is believed to have been fog and icing in the Altamont Pass area. Service was restored via a 230-kilovolt line from Pacific Gas and Electric Company.

⁵ During test of a relaying system change, a tripping relay at Midway Substation was inadvertently operated, causing bus circuit breakers to open. At the same time a circuit breaker that should not have tripped did trip. Opening of the circuit breakers resulted in the opening of two of the three 230-kilovolt lines from St. Lucie nuclear plant. This left the two St. Lucie units feeding about 1,700 megawatts into one 230-kilovolt line, which became overloaded by about 65 percent. The overload was removed in 4 minutes, 54 seconds. Customer service was not affected.

⁶ Rifle fire damaged insulators on one 138-kilovolt line and one 345-kilovolt line on February 10 and on two 138-kilovolt lines on February 11. The lines were tripped and locked out by protective relays. Three of the lines originate at the company's Sooner Generating Plant; dispatchers limited output from that plant until repairs were completed.

⁷ Two 345-kilovolt lines were tripped by protective relays after being damaged by rifle fire. The lines originate at the company's Sooner Generating Plant, one going to the Northwest substation, one going to the Woodring substation. Power output at Sooner Unit 2 was reduced from 500 megawatts to 400 megawatts until repairs were completed and the lines were restored for service.

⁸ Five 345-kilovolt lines tripped and were locked out by protective relays after insulators were damaged by rifle fire over a period of 2 hours and 54 minutes.

⁹ A blizzard traversed the service area of Public Service of Colorado from about 7:00 PM on 3/08/92 to about 2:00 PM on 3/09/92. The PSC system temporarily lost ten 230-kilovolt lines, nine 115-kilovolt lines, a section of 44-kilovolt line and two 345-kilovolt interconnections with Tri-State Generation & Transmission Cooperative and Western Power Administration of Department of Energy. All lines except the 44-kilovolt were restored to service by 5:00 PM on 3/09/92; repairs were in progress on twelve wood pole structures of the 44-kilovolt line that had been damaged. The Fort St. Vrain substation lost one 230-kilovolt bus for a time due to tripping of a circuit breaker when a bushing flashed over. The Rocky Flats installation of DOE lost one of the two 115-kilovolt lines supplying utility power and used its emergency power facilities as backup.

¹⁰ Lightning burned a pole on US 13 bypass near Peanut Company. Power is purchased from North Carolina Power Company.

¹¹ Construction workers accidentally pierced the roof of a tunnel system under Chicago, allowing the Chicago River to flood the tunnels and the lower levels of buildings in the central business area. The presence of water in the buildings made it necessary to cut off power where there was danger of short circuits and damage to equipment. Restoration of service was dependent upon removal of water and debris, and restoration of safe condi-

tions on customer premises that had been flooded.

¹² An overhead static wire failed on a double-circuit transmission structure supporting the Gadsby-Terminal 138-kilovolt line and the Gadsby-Terminal 46-kilovolt line, causing a phase-to-ground fault on both lines and then a multi-phase fault. Fault duration was about 20 cycles, during which the 138-kilovolt bus voltage at Terminal dipped to 0.5 per unit. During the disturbance frequency fell to 59.987 cycles and then rose to 60.065 cycles before returning to normal. The 138-kilovolt line was restored to service in about 16 minutes, the 46-kilovolt line was left out of service pending repair of the static wire. The disturbance caused tripping of one 29 megawatt generating unit at a Kennecott Copper Company facility (restored within 17 minutes) and 5 megawatts of small hydro units. The load lost was 383 megawatts of firm load and 35 megawatts of interruptible.

¹³ Riots following the verdict in the Rodney King police brutality trial led to tripping of 37 5-kilovolt distribution circuits in the City of Los Angeles. Restoration of service of delayed until the safety of utility personnel could be assured. There was no damage to distribution or transmission substations or the bulk power system generally. The maximum number of customers without power at any one time was 24,300, the total number of customers affected was 51,800.

¹⁴ Test of the voltage reduction procedures. At 10:40 AM a voltage reduction of 8% was initiated, a 5% reduction was initiated at 10:58 AM and a 3% reduction at 11:17 AM. Reset was begun at 11:24 AM, all voltages were normal by 11:49 AM.

¹⁵ Lightning broke an insulator on the Roanoke 115-kilovolt tap. Power is purchased from North Carolina Power Company.

¹⁶ A storm caused distribution circuit damage. Generating plants and transmission lines were not damaged.

¹⁷ A storm caused extensive distribution circuit damage. Sixty-five line crews were requested from out-of-state utilities and contractor crews were reassigned from other duties, to restore service.

¹⁸ The storm caused many distribution circuit outages.

¹⁹ The storm caused many distribution circuit outages.

²⁰ High winds toppled trees, damaging distribution conductors and breaking poles, lightning caused damage to distribution transformers. Three 138-kilovolt lines tripped when two steel towers fell and conductor support arms on other structures were damaged. Two of the lines were returned to service on June 22. Seventy-six line crews were sent in by other utilities, and 60 tree-trimming crews were also utilized.

²¹ Winds in the 100 mile per hour range traversed the company's service area, causing distribution circuit damage and tripping three 138-kilovolt lines, two 345-kilovolt lines and one 345/138 kilovolt transformer.

²² Lightning struck a switch in the Everett substations.

²³ A 138-kilovolt lightning arrester on Lon Hill Unit 3 (150 megawatt) main power transformer failed, causing a 3-phase on the CPL transmission system. Unit 3 tripped. Voltage levels in the Corpus Christi and Rio Grande areas dropped to 70%-85% or normal, and current in some distribution feeders rose to 170% to 300% of pre-fault values as motors stalled because of the low voltage. Over current relays tripped loads and voltage rose to 114% of nominal until capacitors could be removed. Unit No. 7 (48 megawatts) at La Palma Power Plant then tripped on loss-of-excitation, and Bates Unit 2 (107 megawatts) was tripped about 8 minutes later by operator control because of a high-combustible boiler alarm. Load loss was as follows: 380 megawatts industrial and 84 megawatts residential/commercial in the Corpus Christi area, 200 megawatts residential/commercial in the Rio Grande area 120 miles from the location of the fault, and 42 megawatts tripped by under voltage relaying on the CFE system in Mexico.

²⁴ Falling trees damaged distribution circuits as a severe storm with high winds and lightning moved through the company's service area.

²⁵ Falling trees damaged distribution circuits as a storm with high winds and hail hit the service area.

²⁶ High loads on the Allegheny Power System and neighboring utilities caused loads on the bulk power transmission system in the area to approach voltage stability limits. Transfer of power from west to east through the Allegheny Power System were curtailed beginning at 8:00 AM on July 17 but power flow remained high as cuts in contracted flows were replaced by other power flows looping through the APS system towards the PJM service area. A 5% voltage reduction was initiated at 3:17 PM to reduce bulk transmission loading. APS also purchased energy so that some generators could be unloaded in order to reduce loading on critical lines.

²⁷ A 1,200 MVA 500/161 kilovolt 3-phase transformer bank was tripped by a sudden-pressure relay during a tap-changing-under-load operation under supervisory control. The bank is located in a substation at West Point, Mississippi. Under-voltage relays shed 568 megawatts interrupting 150,000 customers in the West Point-Jackson area of Mississippi. There was no damage evident to the transformer structures, and differential relays did not operate. After preliminary inspection, the bank was returned to service at 6:53 PM the same day. Lost load had been previously restored by switching operations.

²⁸ A single-line-to-ground fault occurred on the 138-kilovolt line between the Dunsuir and John Hart substations on Vancouver Island in British Columbia. As operators attempted to adjust generation to relieve loads on parallel lines, other lines tripped. Some load was shed by under frequency relaying, some by low-voltage relaying. Some loads were restored within 15 minutes, some within 30 minutes. The 190 megawatt of pulp mill load that was shed required about 6 and 7 hours to clear the processing systems and return to full load even though electric service was available within half an hour. The U.S. portion of the WSCC system was not affected. Note: This event is included here because it occurred on the WSCC system, which extends across the U.S.-Canadian border.

²⁹ A forest fire caused tripping of the 500-kilovolt Malin-Round Mountain transmission line No. 2. The line reclosed and tripped again, the No. 1 line of that circuit also tripped. This caused operation of the WSCC Islanding Scheme, separating the WSCC system into a North Island and a South Island and initiating operation of the Remedial Action Scheme, tripping some Northwest generating capacity. In addition 225 megawatt of generation in Southern California tripped on under frequency. The fire also caused the loss of some 230-kilovolt transmission, resulting in the tripping of 450 megawatt of generation in the Pit River watershed.

³⁰ At 3:45 PM PAST a forest fire caused tripping of Malin-Round Mountain 500-kilovolt transmission lines No. 1 and No. 2. The WSCC Islanding Scheme then separated the system into North and South Islands. South frequency dropped to 59.67 Hz and North frequency rose to 60.292 Hz. Remedial Action Scheme (RAS) tripped 400 megawatt of generation in the Northwest, Co. (in the South Island) lost 400 megawatt of interruptible load, which tripped on under frequency. Both Malin-Round Mountain lines were reclosed, and were again tripped by the fire at 4:03 PM PAST. No further remedial actions took place because loading on the two lines was low. The WSCC Open Loop procedure was implemented at 4:21 PM.

³¹ Hurricane Andrew interrupted service to 1,400,000 customers of Florida Power and Light Company, damaging the Cutler Power Plant (two fossil units) and the Turkey Point Power Plant (two nuclear and two fossil units). All eight transmission lines connected to the Turkey Point Plant sustained some damage, as did the switchyard and the two fossil units at Turkey Point. The transmission line to Florida Keys Cooperative/Key West Utilities Board was blown down. There was much destruction of distribution facilities. Restoration of service began shortly after the hurricane left the area. By September 23 service had been restored to all customers except 25,000, whose premises required major repairs before electric power could be safely reconnected. Cutler Unit 5 was returned to service on September 8, Cutler Unit 6 returned to service on September 21. At the Turkey Point Plant, Unit 1 (fossil) may be back in service by April 1993 if rebuilding of the demolished stack has been completed, Unit 2 (fossil) was returned to service at full power on September 16, Unit 3 (nuclear) is out for refueling and may be returned to service at full power on September 16, Unit 3 (nuclear) is out for refueling and may be returned to service in early December 1992, Unit 4 (nuclear) was re-started during the weekend of October 24/25 and as of October 26 was operating at half power. All radial lines to substations had been repaired by September 3 and six of the eight 230-kilovolt lines at Turkey Point were back in service as of September 4. The other 2 Turkey Point lines have not been reconnected because the system configuration will be changed. Many other lines that were re-established to temporary standards because of the need to restore service will be upgraded during 1993.

³² Distribution lines were knocked down by the hurricane.

³³ The hurricane destroyed about 13 miles of the 138-kilovolt interconnection between Key West Utilities Board, Florida Keys Electric Cooperative and Florida Power and Light Corporation, interrupting all customers on the Key West Utilities Board system. The Key West System supplied limited power to its customers from its own generating facilities and requested customers to reduce loads until the interconnection was re-established. The Key West system also supplied some power to the Florida Keys Cooperative while the 138-kilovolt line to Florida Power and Light was being rebuilt. Full service was restored to both systems when the line was completed on September 8, 1992.

³⁴ Florida Keys Electric Cooperative lost all customers when the hurricane destroyed the interconnection to Florida Power and Light. Partial service to customers was restored by use of its own generation and power from the Key West Utilities Board. Customers were requested to reduce their use of power and restrictions on unessential use were enforced. Full power was restored when the interconnection to Florida Power and Light was restored to service on September 8, 1992.

³⁵ The hurricane knocked out many distribution circuits and service drops to customers. All supply lines from Cajun Electric Cooperative were tripped. Some customers were without service for 2.5 hours, some for 7 hours, others for longer.

³⁸ Distribution circuit damage was extensive. All power supply was lost when the seven supply lines from Cajun Electric Power Cooperative tripped. Dixie has no generating plant; all power is purchased from Cajun. Dixie estimates that the cost of restoring service after the hurricane was about \$2.5 million.

³⁹ Distribution circuit damage was extensive. Temporary repairs were made initially to restore service as soon as possible, bringing all work up to system standards may take another six months. All power is purchased from Cajun Electric Power Cooperative and is delivered over 7 transmission lines and one small 13.8-kilovolt distribution circuit. Of the 7 transmission lines two (115-kilovolt) are owned by South Louisiana Cooperative, one (138-kilovolt) is owned by Central Louisiana Electric Company, and four (115-kilovolt) are owned by Louisiana Power and Light Company. Early during the hurricane all supply lines were out of service for a time.

⁴⁰ The approximate cost of restoration work after the hurricane was \$2.5 million. Three 115-kilovolt and one 230-kilovolt transmission lines were down and much distribution circuit work was needed.

⁴¹ The storm interrupted service to all customers. About 70% of the customers had service restored by 5:00 PM on 9/1/92, drawing some 20 megawatts. The normally expected summer peak demand is 38 megawatts. Load was being supplied by the interconnection with Louisiana Power and Light Company, pending reconstruction of the Central Louisiana Electric Company 138-kilovolt line which had 300 structures destroyed. At the Morgan City Steam Plant, Units 1, 2, and 3 are expected to be in service on the evening of September 1. Drying of Unit 4 switchgear is expected to take several days.

⁴² All power is purchased from Cajun Electric Power Cooperative, over 9 delivery points, 3 at 138-kilovolt and 6 at 34.5-kilovolt. All 9 delivery points tripped during the storm.

⁴³ The Southern Pine Cooperative purchases its power from the South Mississippi Electric Power Association, over 26 delivery points, five of these tripped. Many of the customers affected had service restored before the final restoration time in the table above. About 2,000 customers were out for the full duration of the incident. There is no record of the megawatt load lost, but the system has computed the energy loss as being 1948.92 megawatt-hours.

⁴⁴ The hurricane brushed the southern end of the company's area on 8/25 with minimal damage, and returned on 8/26; it was over by 8/27. No damage was done to generating plants. Distribution circuits, 44-kilovolt lines and 115-kilovolt lines were down on 8/25 and 8/26.

⁴⁵ Hurricane Andrew interrupted part of the purchased power supply to the system, which does not have a generating plant of its own. Some distribution circuits in the system were damaged.

⁴⁶ Power is purchased from South Mississippi Electric Power Association, none of the supply lines tripped. Outages were caused by wind-driven contacts between trees and distribution circuits.

⁴⁷ High winds and tornadoes resulting from Hurricane Andrew caused tripping of nine 115-kilovolt and four 230-kilovolt transmission lines, causing outages of 15 major substations on the combined interconnected systems of Louisiana Power and Light Company and New Orleans Public Service Company. Distribution facilities were also damaged. No generation was lost during the storm.

⁴⁸ The hurricane caused tripping of transmission lines as follows: 24 138-kilovolt, 9 230-kilovolt and 2 500-kilovolt. Some lines reclosed after tripping. As of 4:30 PM on 8/26, 7 of the 230-kilovolt and 6 of the 138-kilovolt lines were back in service. By 2:00 PM on 8/28, only 1 230-kilovolt line, 5 138-kilovolt lines and one 500-kilovolt line were still out of service. The 500-kilovolt line, from Webber to Willow Glen power plant, had 12 supporting structures down. It was expected that all the 138-kilovolt lines would be back in service by Sep 10, with the 500-kilovolt line being restored by Sep 18. Many distribution circuits were down.

⁴⁹ High winds caused many distribution circuit failures.

⁵⁰ The system purchases its power from Cajun Electric Power Cooperative. Delivery is made over 28 delivery points; sixteen point lost power during the hurricane beginning at 2:23 AM on 8/26/92 and continuing through 6:39 PM on the same day. Outage times for the 16 points ranged from 2 minutes to 59 hours 27 minutes. The last restoration of service to a delivery point was made at 5:03 PM on 8/28/92. Distribution circuit damage within the system caused interruptions to begin before delivery point service was lost and continue after all delivery point power was restored.

⁵¹ The entire city lost its power supply. About 75% of the customers had power restored by 11:00 AM on 8/28. The remainder had service restored by 5:00 PM on 8/30. The city's consulting engineer estimates that the total revenue lost due to the hurricane was about \$43,650.

⁵² Transmission and distribution lines were damaged by the hurricane but the company did not report that any generating plants were damaged. All 138-kilovolt lines south of Lafayette and New Iberia were out of service, and 300 H-frame structures on 230-kilovolt lines were down. As of September 3 service had been restored to about 20,800 customers.

⁵³ High winds caused faults that tripped 39 distribution circuit breakers (mostly at the 13.8 level) of the 63 on the system. About 13,000 customers had service restored within 24 hours. By 8/26 midday less than 500 customers were without service. About 35 crews including tree-trimmers worked on service restoration. The system used its own supplies for repairs, insulators, conductors, transformers. Not many poles were broken.

⁵⁴ Some outages were reported about midnight on 8/25; additional outages were reported continuously after that time; the load at 2:20 AM was about 7.5 megawatts. The system was shut down at 3:30 AM when load had dropped to 5 megawatts to prevent damage by the many short circuits that occurred as falling tree branches and poles caused distribution lines to break. Normal load at that time would have been about 12.5 megawatts.

⁵⁵ The 35 megawatts load loss endured for about an hour. Power supply from Cajun Electric Cooperative was interrupted at all seven delivery points; 3 points were restored the same day. Service was restored to about 70% of the customers lost within 48 hours.

⁵⁶ The city's generating plant was not damaged but the line over which purchased power is supplied by the Louisiana Energy and Power Authority tripped. Distribution circuits were damaged.

⁵⁷ Power is purchased from South Mississippi Electric Power Association and is delivered over the system of Mississippi Power & Light Co. Two of the supply lines tripped; in addition, distribution circuits within the system were damaged by the storm.

⁵⁸ Several distribution circuit poles were down, damage was minor. Most customers had service restored within 2 hours.

⁵⁹ Power is supplied to the system by Southeastern Power Administration over transmission lines Mississippi Power Company, TVA and Mississippi Power Company. One Mississippi Power Company line tripped.

⁶⁰ The Yazoo system has 8 delivery points, at which it receives all its power. The supplier is the South Mississippi Electric Power Association. None of the delivery points lost power supply. All customer outages were due to effects of the hurricane on distribution circuits.

⁶¹ All power is purchased from South Mississippi Electric Power Association (SMEPA), and is delivered over several SMEPA 69-kilovolt lines. One of the lines tripped during the storm; it was out of service for about 30 minutes. Customer outages were due to windblown tree limbs contacting distribution circuits.

⁶² Almost the entire system was down due to distribution circuit faults and loss of three delivery points for 4 or 5 hours during the hurricane. Power is purchased for the cooperative by South Mississippi Electric Power Association and is delivered over the transmission system of Mississippi Power and Light Co. at 11 delivery points. Transmission to the points that were interrupted was at 115-kilovolt.

⁶³ The effect of the hurricane was minor. None of the 10 delivery points over which power is received from South Mississippi Electric Power Association tripped.

⁶⁴ Power is purchased from South Mississippi Electric Power Association. There are 20 delivery points, nine of which tripped during the hurricane.

⁶⁵ No details available.

⁶⁶ Outages were minor, caused by windblown tree limbs contacting distribution circuits. Power is purchased from South Mississippi Electric Power Association; there are eight delivery points, none of which tripped during the storm.

⁶⁷ Distribution circuits were out of service as 27 poles went down. The total cost of restoring the system to normal was about \$65,000.

⁶⁸ Power supply, purchased from TVA, was not lost. Outages were due to distribution system damage caused by the hurricane. Service was restored to many customers within 12 hours, but complete restoration was not accomplished until 2 AM on 8/28.

⁶⁹ Power is purchased from TVA. There was some intermittent tripping of the supply as tree limbs shorted transmission lines temporarily. Customer outages were due to tree limbs being blown into distribution circuits. The 5000 customer outages is the total that occurred during the storm, not the number out simultaneously.

⁷⁰ Customer outages were due to the hurricane bringing trees into contact with distribution circuits and breaking some distribution circuit poles. About a dozen poles had to be replaced. Power is supplied to the cooperative from TVA at 8 delivery points; none of these tripped.

⁷¹ Power is purchased from TVA over 4 delivery points. None of the delivery points tripped. Damage was confined to distribution circuits.

⁷² All power is purchased from TVA over 5 transmission lines: 1 at 46-kilovolt, 1 at 69-kilovolt and three at 161-kilovolt; none of the lines tripped during the hurricane. Customer outages were due mainly to wind-blown tree limbs contacting distribution circuits.

¹¹ Power supply, purchased from TVA, was not lost. Outages were due to distribution circuit damage caused by the storm.

¹² The hurricane had little effect on the system. Power is purchased from TVA, delivered over one 161 kilovolt line and one 46 kilovolt line. The power supply lines did not trip. Customer outages were due to the effects of high winds on trees and distribution circuits.

¹³ Hurricane Andrew caused tornadoes, high winds and lightning across central Alabama, damaging the subtransmission system and distribution circuits. There were no outages of the bulk power network.

¹⁴ A fault on an internal 230-kilovolt of Los Angeles Dept. of Water and Power caused mis-operation of relays, opening circuits to two 230 kilovolt busses and cutting off power to the two 230/69-kilovolt transformer banks that supply the City of Burbank. There was no damage to system facilities.

¹⁵ Hurricane Iniki destroyed much of the transmission and distribution system.

¹⁶ A tornado passed over Central Florida, damaging distribution circuits.

¹⁷ The tornado in Central Florida caused tripping of feeders.

¹⁸ The tornado in Central Florida, caused falling trees and windblown debris to trip eleven distribution feeders and one 69-kilovolt line. Generating plants were not damaged. The premises of some customers were damaged to the extent that service could not be restored until the premises were rebuilt.

¹⁹ Typhoon Brian crossed the southern tip of Guam about 5 PM Guam time (3 AM EST). The eye of the typhoon was some 8 to 9 miles wide, winds were about 90 MPH, gusting to 110 MPH. The north end of the island received sustained winds of 45 MPH with gusts to 62 MPH. There were limited pockets of power outages but no transmission lines failed. Military bases have power. No additional data were reported.

²⁰ Protective relays at Jones Station operated to disconnect the plant from the system as a 345 kilovolt transmission line was being returned to service from a maintenance outage. Under frequency relays then operated, shedding 150 megawatts of the company's firm load (mostly service to rural substations and Rural Electric Cooperatives). In addition, 86 megawatts of firm power sales over the DC tie at Artesia, NM, to El Paso Electric Company and Texas-New Mexico Power Company was interrupted. Interruptible sales to Public Service Company of New Mexico and El Paso Electric Company were also interrupted. The areas affected were around Roswell, NM and the Texas communities of Hereford, Lubbock, Levelland and Tulia.

²¹ The Kewaunee nuclear generating unit was shut down for about 35 hours when seaweed from Lake Michigan clogged the screens which filter the condenser cooling water. No load was lost.

²² A fault on the 500-kilovolt line from Malin substation in Oregon to Round Mountain substation in northern California caused protective relays to trip the line. The Pacific Intero (PACI) remedial action scheme then operated to send a separation signal to the Four Corners power plant. Transmission lines tripped to separate WSCC into a Southern Island and a Northern Island, and the frequency in the Northern Island rose to 60.17 hertz (cycles per second). No generating plants tripped and no customers were affected; 13 lines, operating at voltage levels from 55-kilovolt to 500-kilovolt tripped.

²³ A cold front moving through the Houston area caused tornadoes that disrupted service in all four zones of the company's service area. Some 57 distribution feeders were tripped and locked out due to broken poles, downed conductors and windblown trees and debris. In addition, five 69-kilovolt and eight 138-kilovolt transmission lines suffered outages as high winds damaged steel towers, wood poles, crossarms and insulators.

²⁴ Tornado broke a pole supporting the supply line from North Carolina Power Company.

²⁵ The No. 1 and No. 2 230-kilovolt busses at Ignacio Substation in Marin County were tripped by differential and breaker backup protective relays while a DC ground problem was being investigated. Other lines and the Fulton Substation also tripped, by action of under voltage and under frequency relays. Unit No. 11 at the Geysers Geothermal Power Plant, generating 89 megawatts, was tripped by under frequency and breaker backup over current relays. The CCCPA No. 2 unit, generating 70 megawatts, was tripped by under voltage relays. All the 115-kilovolt lines serving Marin, Sonoma and Napa counties tripped.

²⁶ The entire service area was affected by a storm with winds ranging between 50 and 75 miles per hour. Several lines at 33-kilovolt and 69-kilovolt were tripped by storm effects. Lines at 115-kilovolt and higher voltages were not affected.

²⁷ Storm caused tripping of three 345-kilovolt transmission lines and eight 115-kilovolt lines.

²⁸ One leg of a tower supporting a double-circuit 115-kilovolt transmission line appeared to have been blown off by a bomb. The incident was discovered during inspection after a customer noticed that the tower was tilted. There was no interruption to service.

²⁹ While one of two 69-kilovolt lines supplying power to the cooperative was being switched improper operation of a protective relay caused the other line to trip, cutting off service to the cooperative. The relaying arrangements have been corrected.

³⁰ DOE's Nevada Test Site is supplied by two 138-kilovolt transmission lines, one from Nevada Power Company (NPC) and one from Valley Electric Power Association (VEA). At 1:00 AM the NPC line tripped. It was later discovered that a line support structure (wishbone pole) had toppled after being sawed through at the base. In falling, the pole down an adjacent 3-pole H-frame structure. At 12:25 PM the VEA line tripped due to failure of a splice in one conductor and resulting single-phase operation. It is assumed that the splice failed because of the stress caused by the fallen structures. Tripping of the lines disrupted power supply from the Amargosa Substation of Western Area Power Administration to loads of NPC, VEA and the Test Site. Emergency diesel generators at the Test Site started and supplied their loads until commercial was restored.

³¹ The Bonneville Power Administration Covington Substation operator found what appeared to be an explosive device adjacent to the substation fence. The device was removed, the power system was not affected.

³² Outage on Plumas-Sierra system because of high winds in the area which caused an outage of the only supply line from Pacific Gas and Electric Company.

³³ Outage of the Pacific Gas and Electric supply line caused loss of power to Plumas-Sierra.

³⁴ Outage due to Pacific Gas and Electric transmission trouble.

³⁵ Conductor down on Pacific Gas and Electric line to Plumas-Sierra.

³⁶ Fault (short circuit) on Pacific Gas and Electric line Plumas-Sierra.

³⁷ Tree fell into Pacific Gas and Electric line to Plumas-Sierra.

³⁸ A 500-kilovolt circuit breaker in the Sequoyah nuclear power plant switchyard was replaced by a new breaker. Twelve minutes after the new breaker was energized, a short circuit developed in Phase C. Protective relays tripped the faulty circuit breaker and all the 500 kilovolt breakers in the switchyard, as well as several 161-kilovolt circuit breakers. Both generating units tripped, resulting in a voltage dip and a decline in frequency. The Raccoon Mountain pumped storage was brought on line to supply the generation deficit and the situation was stabilized in 11 minutes. There was no loss of customers and the only of load was due to the short-term drop in voltage and frequency, this loss could not be measured.

Notes: •Under the Code of Federal Regulations (10 CFR Part 205) and published in the **Federal Register** of October 31, 1986, 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, EDT: Eastern Daylight Time, EST: Eastern Standard Time.

MAST: Mountain Advanced Standard Time, CST: Central 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.

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: International Affairs and Energy Emergencies, Form OE-417R, "Electric Power System Emergency Report."

Appendix B

References

Appendix B

References

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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, Emergency Planning and Operations Form OE-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 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.

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 93-275) 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 hydro-electric 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 1992 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.
- For generating units using a combination of fossil energy and renewable energy sources, capacity is characterized as fossil or renewable and allo-

cated based on the greatest percentage of Btu consumed when summed for each.

- In addition, for capacity within the fossil energy and renewable energy sources, the single fuel within that energy source with the greatest percentage of Btu consumed is used to further allocate capacity.

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.
- 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.

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.⁴⁷ 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

⁴⁷Office of Management and Budget, *Standard Industrial Classification Manual*, 1972, (Washington, D.C. 1987).

- 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)

- 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):

Form OE-411

The Form OE-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 OE-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 OE-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. Data from the Form OE-411 are also summarized in the staff report *Electric Power Supply and Demand for the Contiguous United States* (DOE/OE-0013).

Form OE-417R

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 Planning and Operations (OE) 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 Administration (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 re-

vised 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 prescribed 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 suppressed 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.
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 1992 from the Form EIA-860 are final and unchanged from the preliminary data reported in the *Inventory of Power Plants in the United States 1992*, which was published in October 1993.
- **Net Generation at U.S. Electric Utilities**
All Form EIA-759 data are final. A comparison of preliminary versus final data for 1992 are provided in the Technical Notes of the *Electric Power Monthly* (EPM), July 1993.
- **U.S. Electric Utility Fossil-Fuel Statistics**
All FERC Form 423 data are final. A comparison of preliminary versus final data for 1992 from the FERC Form 423 is provided in the Technical Notes of the EPM, July 1993.
- **U.S. Electric Utility Retail Sales and Revenue**
Data on sales, revenue, and average revenue per

kilowatthour from the Form EIA-861 for 1992 are preliminary. The data are revised and declared final in the *Electric Sales and Revenue 1992*. A comparison of preliminary versus final annual data at the national level for 1992 will be provided in the *Electric Power Annual* (EPA) 1993.

- **U.S. Electric Utility Financial Statistics**
Financial data from the Federal Energy Regulatory Commission Form 1 and the Form EIA-412 for 1992 are final.
- **U.S. Electric Utility Environmental Statistics**
Data from the Form EIA-767 for 1991 are final. The methodology for calculating emissions of sulfur dioxides, nitrogen oxides, and carbon dioxide has been revised. As a result, final data for 1991 at the national level differ from the preliminary by 3.7 percent for sulfur dioxide, 2.6 percent for nitrogen oxides, and 6.6 percent for carbon dioxide. Data for 1992 are preliminary. A comparison of preliminary versus final data at the national level for 1992 will be provided in the EPA 1993.
- **U.S. Electric Power Transactions**
All data from the Forms OE-411 and FE-718R are final. Data from the Form EIA-861 for 1992 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 1991 are final and unchanged from preliminary values. Data for 1992 are preliminary. A comparison of preliminary versus final data at the national level for 1992 will be provided in the EPA 1993.
- **U.S. Nonutility Power Producers** Data from the Form EIA-867 for 1991 are final and unchanged from preliminary data, with the exception of deliveries and facility use. Refinement of definitions for deliveries and facility use resulted in the reallocation of preliminary data between these two categories. The difference between preliminary and final values for both categories was a 9-percent change. Data for 1992 are preliminary. A comparison of preliminary versus final annual data for 1992 will be provided in the EPA 1993.
- **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.

Data for Demand-Side Management (DSM) activities are aggregated at the NERC region and consumer sector levels. In 1992, for the first time, EIA collected 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 (1992), annual peakload reductions and energy savings for the reporting year and first- and fifth-forecast years (1993 and 1997), 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 and total direct and indirect utility cost for the reporting year. 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 electric generating units were developed by use of a regression formula. Estimates of net summer capability and net winter capability are made for operable nonnuclear electric generating units with no reported capability and for all electric generating units that are under construction or in the planning stage that are not nuclear-powered or coal-fired. The formula is based on reported values in the 1984 data file. The formula is used to estimate values for existing units where data are missing and for projected units. (When data are reported for existing units, the estimation formulas are not used. When data for existing units are not reported, the estimation formulas are used in all cases. The estimation formulas are not used for planned coal-fired or nuclear-powered units. However, the estimation formulas are used in all cases for all other

planned units.) In all formulas, the symbol, *, is an operator meaning multiplied by; the symbol, **, is an operator meaning raised to the specified power (exponent).

For nonnuclear units,

Net Summer Capability equals $e^{**}(i \text{ plus } (\ln(\text{generator Nameplate Capacity}) * c))$, rounded to nearest megawatt,

where

- e , the base of natural logarithms ($\ln$), is approximately 2.71828,
- Generator Nameplate Capacity is expressed in megawatts,
- i is the intercept, and c is the regression coefficient,
- i equals 0.02564, c equals 0.98423, for steam units (Unit Type is Steam Turbine (ST), Atmospheric Fluidized Bed Combustion (AB), Pressurized Fluidized Bed Combustion (PB)),
- i equals -0.10255, c equals 0.97841, for gas-turbine units (Unit Types are Gas Turbine (GT) and Jet Engine (JE)),
- i equals -0.00397, c equals 0.95914, for combined-cycle units (Unit Types are Combined Cycle Steam Turbine with Supplemental Firing (CA), Combined Cycle - Single Shaft (CS), Combined Cycle Steam Turbine with Only Waste Heat Capability (CW), Combined Cycle Combustion Turbine (CT), and Integrated Coal Gasification Combined-Cycle (IG)),
- i equals -0.08865, c equals 1.00966, for internal combustion units (Unit Type is Internal Combustion (diesel) (IC)),
- i equals -0.04963, c equals 1.03738 for conventional and pipeline hydroelectric units (Unit Types are Hydraulic Turbine - Conventional (HC) and Hydraulic Turbine - Pipeline (HL)),
- i equals -0.00922, c equals 1.00630, for pumped storage hydroelectric units (Unit Type is Hydraulic Turbine - Reversible (pumped storage) (HR)),
- i equals -0.02604, c equals 0.98289, for all other units (Unit Types are Fuel Cell (FC), Steam Turbine - Geothermal (GE), Ocean Thermal Turbine (OC), Photovoltaic (SP), Steam Turbine - Solar (SS), and Wind Turbine (WT)).

Net Winter Capability equals $(e^{**}i) * (\text{Generator Nameplate Capacity}^{**}c)$,

where

- e , the base of natural logarithms ($\ln$), is approximately 2.71828,

- Generator Nameplate Capacity is expressed in megawatts for conventional hydroelectric and pipeline hydroelectric units, and in kilowatts for all other unit types,
- i is the intercept, and c is the regression coefficient,
- i equals 0.1614, c equals 0.98373, for steam units (Unit Type is ST, AB, and PB),
- i equals 0.2249, c equals 0.97881, for gas-turbine units (Unit Types are GT and JE),
- i equals 0.9626, c equals 0.90413, for combined-cycle units (Unit Types are CA, CS, CW, CT, and IG),
- i equals -0.1378, c equals 1.02501, for internal combustion units (Unit Type is IC),
- i equals -0.0608, c equals 1.02560, for conventional and pipeline hydroelectric units (Unit Types are HC and HL),
- i equals -0.1167, c equals 1.08540, for pumped storage hydroelectric units (Unit Type is HR),
- i equals 0.2859, c equals 0.9867, for all other units (Unit Types are FC, GF, JC, SP, SS, and WT).

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.

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 =**

$$\frac{\sum_i \left(\frac{IBI_i + EIT_i + GIT_i}{+ OUIT_i + TOID_i - AC_i} \right)}{\sum_i (IE_i)} \quad (9)$$

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 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 C1).⁴⁸ Environmental Protection Agency emission factors are based on boiler type, fir-

ing configuration, and fuel burned. The methodology for determining emissions of CO₂ has been revised since the 1991 publication. Emissions of carbon dioxide for prior years have been revised using the set of factors shown in Tables C1 and C2.

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.⁴⁸

In previous editions of this publication, separate conversion factors by coal rank were published and used to estimate emissions of CO₂. 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 CO₂ emissions. The emission factors for coal were developed in the units of pounds of CO₂ per million Btu of coal.

The emission factors for CO₂ (Table C2) from coal are applied by power plant, based on the rank, amount of coal received, and the State from which the coal originated, 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 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 cal-

culated 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.⁴⁹ 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 C3. 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.

⁴⁸ "Supplement A to Compilation of Air Pollutant Emission Factors, Vol. 1 Stationary Point and Area Sources," Research Triangle Park, North Carolina, October 1986.

⁴⁹ 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.

⁵⁰ Flue gas desulfurization units may also reduce sulfur dioxide emissions from plants that burn oil and petroleum coke.

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 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."⁵¹ However, the boiler type and firing configuration are not reported on the Form EIA-867 so all boilers are assumed to be large boilers⁵² 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 industrial 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.

⁵¹ "Supplement A to *Compilation of Air Pollutant Emission Factors*, Vol. I: Stationary Point and Area Sources," Research Triangle Park, North Carolina, October 1986.

⁵² Boilers with a gross heat rate of 100 million Btu per hour or greater.

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.

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. 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	39.00 x S	37 (37)	See Table C2
	fluidized bed ⁴	39.00 x S	21 (34)	See Table C2
	spreader stoker	39.00 x S	14 (14)	See Table C2
	tangential	39.00 x S	15 (15)	See Table C2
	all others	39.00 x S	21 (34)	See Table C2
Subbituminous ⁴	cyclone	35.00 x S	37 (37)	See Table C2
	fluidized bed ⁴	35.00 x S	21 (34)	See Table C2
	spreader stoker	35.00 x S	14 (14)	See Table C2
	tangential	35.00 x S	15 (15)	See Table C2
	all others	35.00 x S	21 (34)	See Table C2
Lignite ⁴	cyclone	30.00 x S	17.00	See Table C2
	fluidized bed ⁴	30.00 x S	12.00	See Table C2
	front/opposed	30.00 x S	14.00	See Table C2
	spreader stoker	30.00 x S	6.00	See Table C2
	tangential	30.00 x S	8.00	See Table C2
	all others	30.00 x S	12.00	See Table C2
Petroleum Coke ⁴	fluidized bed ⁴	39.00 x S	18.00	6,693
	all others	39.00 x S	18.00	6,693
Refuse	all types	2.50	3.00	2,344
Wood	all types	0.15	2.80	3,788
Petroleum and Other Liquid Fuels		lbs per 10 ³ gal	lbs per 10 ³ gal	lbs per 10 ³ gal
Residual Oil ⁷	tangential	159.90 x S	42.00	26,199
	vertical	159.90 x S	105.00	26,199
	all others	159.90 x S	67.00	26,199
Distillate Oil ⁷	all types	144.00 x S	20.00	22,763
Methanol	all types	0.05	12.40	7,603
Propane (liquid)	all types	0.05	12.40	12,617
Coal-Oil Mixture	all types	185.00 x S	50.00	22,368
Natural Gas and Other Gaseous Fuels		lbs per 10 ⁶ cf	lbs per 10 ⁶ cf	lbs per 10 ⁶ cf
Natural Gas	tangential	0.60	275.00	124,127
	all others	0.60	550.00	124,127
Blast Furnace Gas	all types	0.60	550.00	124,127
Nonutility				
Coal and Other Solid Fuels		lbs per ton	lbs per ton	lbs per ton
Anthracite Culm	all types	39.00 x S	18.00	See Table C2
Bituminous ⁴	all types	39.00 x S	21.00	See Table C2
Bituminous Gob	all types	39.00 x S	21.00	See Table C2
Subbituminous	all types	35.00 x S	21.00	See Table C2
Lignite ⁴	all types	30.00 x S	12.00	See Table C2
Lignite Waste	all types	30.00 x S	12.00	See Table C2
Peat	all types	30.00 x S	12.00	See Table C2
Agricultural Waste	all types	0.15	2.80	1,714
Black Liquor	all types	7.00	1.50	2,725
Chemicals	all types	7.00	1.50	2,725
Closed Loop Biomass	all types	0.15	2.80	3,788
Internal	all types	0.15	2.80	3,788

See footnotes at end of table.

Table C1. 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
		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	2.50	3.00	2,344
Petroleum Coke ⁴	all types	39.00 x S	18.00	6,693
Pitch	all types	30.00 x S	12.00	See Table C2
Railroad Ties	all types	0.15	2.80	3,788
Red Liquor	all types	7.00	1.50	2,725
Sludge	all types	1.00	6.00	3,788
Sludge Waste	all types	1.00	6.00	3,788
Sludge Wood	all types	1.00	6.00	3,788
Spent Sulfite Liquor	all types	7.00	1.50	2,725
Straw	all types	0.15	2.80	3,788
Sulfur	all types	7.00	0.00	0
Tar Coal	all types	30.00 x S	12.00	See Table C2
Tires	all types	39.00 x S	21.00	5,715
Waste Byproducts	all types	2.50	3.00	2,344
Waste Coal	all types	39.00 x S	21.00	See Table C2
Wood/Wood Waste	all types	0.15	2.80	3,788
Petroleum and Other Liquid Fuels		lbs per 10³ gal	lbs per 10³ gal	lbs per 10³ gal
Heavy Oil ⁵	all types	159.90 x S	67.00	26,199
Light Oil ⁵	all types	144.00 x S	20.00	22,763
Diesel	all types	144.00 x S	20.00	22,763
Kerosene	all types	144.00 x S	20.00	22,763
Butane (liquid)	all types	0.60	13.20	14,628
Fish Oil	all types	0.50	12.40	7,603
Methanol	all types	0.50	12.40	7,603
Oil Waste	all types	151.50 x S	37.50	24,481
Propane (liquid)	all types	0.50	12.40	12,617
Sludge Oil	all types	151.50 x S	37.50	24,481
Tar Oil	all types	159.00 x S	55.00	26,199
Waste Alcohol	all types	0.50	12.40	7,603
Natural Gas and Other Gaseous Fuels		lbs per 10⁶ cf	lbs per 10⁶ cf	lbs per 10⁶ cf
Natural Gas	all types	0.60	550.00	121,900
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	121,900
Methane	all types	0.60	550.00	116,436
Other Gas	all types	0.60	550.00	121,900
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 Parenthetic 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 C3 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 9,750 Btu per pound), subbituminous (equal to 7,500 to 9,750 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," Research Triangle Park, North Carolina, October 1986. •For carbon dioxide factors: Department of Energy, "Carbon Dioxide Emissions from Fossil Fuels: A Procedure for Estimation of Results, 1950-1981," June 1983.

Table C2. 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	205.46
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	204.80
Bituminous	Kentucky: West	203.23
Bituminous	Maryland	210.16
Bituminous	Missouri	201.31
Bituminous	Montana	209.62
Bituminous	New Mexico	205.71
Bituminous	Ohio	202.84
Bituminous	Oklahoma	205.93
Bituminous	Pennsylvania	205.72
Bituminous	Tennessee	204.79
Bituminous	Utah	204.08
Bituminous	Virginia	206.23
Bituminous	Washington	203.62
Bituminous	West Virginia	207.10
Bituminous	Wyoming	206.48
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	208.84
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	215.59

Source: Energy Information Administration.

Table C3. 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
Slagging	SC	--	20
Steam or Water Injection	--	SW	20

Source: Babcock and Wilcox, *Steam: Its Generation and Use*, 40th Edition, 1992.

Table C4. 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	GT	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 watt-hours (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 capacity 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 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.

Noncoincidental 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 nine 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.

Ratemaking 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.

Watthour (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, municipalities, and Federal and State electric agencies for resale to ultimate consumers.

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