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Preface

Two-Volume Approach to the Electric Power Annual

This year, the *Electric Power Annual* is published in two volumes. Volume I, released July 1995, focused on U.S. electric utilities and contained final 1994 data on net generation, fossil fuel consumption, stocks, receipts, and cost. Volume I also contained preliminary 1994 data on generating unit capability and planned additions, as well as estimated retail sales of electricity, associated revenue, and average revenue per kilowatthour of electricity sold. These estimates were based on a monthly sample (Form EIA-826, "Monthly Electric Utility Sales and Revenue Report with State Distributions"). Also included in Volume I was the information on net generation and associated generating capability from renewable energy sources and the estimates for national-level nonutility data.

Volume II presents annual 1994 summary statistics for the electric power industry, including information on both electric utilities and nonutility power producers. Included are the preliminary data for electric utility retail sales of electricity, associated revenue, and average revenue per kilowatthour of electricity sold (based on the annual census--Form EIA-861, "Annual Electric Utility Report") and for electric utility financial statistics, environmental statistics, power transactions, and demand-side management. Final 1994 data for U.S. nonutility power producers on installed capacity and gross generation, as well as supply and disposition information, are provided in Volume II.

The *Electric Power Annual 1994, Volume II* presents a summary of electric power industry statistics at national, regional, and State levels. The objective of the publication is to provide industry decisionmakers, government policymakers, analysts, and the general public with historical data that may be used in understanding U.S. electricity markets. The *Electric Power Annual, Volume II* is prepared by the Coal and Electric Data and Renewables Division; Office of Coal, Nuclear, Electric and Alternate Fuels; Energy Information Administration (EIA); U.S. Department of Energy.

In the private sector, the majority of the users of the *Electric Power Annual, Volume II* are researchers and analysts and, ultimately, individuals with policymaking and decisionmaking responsibilities in electric utility companies. Other users include financial and investment institutions, economic development organizations interested in new power plant construction, special interest groups, lobbyists, electric power associations, and the news media.

In the public sector, users include analysts, researchers, statisticians, and other professionals with regulatory, policy, and program responsibilities for Federal, State, and local governments. The Congress and other legislative bodies are also interested in general trends related to electricity at State and national levels. 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.

In Volume II, the section titled "The U.S. Electric Power Industry at a Glance" highlights key statistics for the year. Subsequent sections present data on electric utility retail sales and revenue, electric utility financial statistics, electric utility environmental statistics, electric power transactions, electric utility demand-side management, and nonutility power producers. 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.

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

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The U.S. Electric Power Industry at a Glance

The first section of this chapter provides a 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 and includes a graphic presentation.

Industry Profile

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

Investor-Owned Electric Utilities. Investor-owned electric utilities currently account for more than 75 percent of all U.S. electric utility generating capability, generation, sales, and revenue. Like all private businesses, investor-owned electric utilities have the objective of producing a return for their investors. Investor-owned utilities either distribute their profits to stockholders as dividends or reinvest these profits. They are granted service monopolies in certain geographic areas and obliged to serve all consumers. As franchised monopolies, these electric utilities are regulated and required to charge reasonable and 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 reduced 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 large 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.

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 Utilities Service (formerly the Rural Electrification Administration) in the 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 fewer than 1,500 consumers) and farms where it was relatively expensive to provide service. Cooperatives are incorporated under State law and are usually directed by an elected board of directors, which in turn selects a manager. 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

[1] In this report, the following definitions are used to distinguish 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.

electric utilities do not operate in Connecticut, Hawaii, Rhode Island, or in the District of Columbia.

Federal Electric Utilities. Power produced by the 10 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. Wholesale Federal producers include the U.S. Army Corps of Engineers, the U.S. Bureau of Reclamation, and the International Water and Boundary Commission. Electricity generated by these wholesale producers is marketed by Federal power marketing administrations in the U.S. Department of Energy: Bonneville, Southeastern, Southwestern, and Western Area. The Federal power marketing administrations operate in all areas except 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 markets electricity in both the wholesale and retail markets.

Nonutility Power Producers. U.S. nonutility power producers are comprised of cogenerators and small power producers, that meet the criteria for being classified as qualifying facilities (QF's) under PURPA 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 (usually heat or steam) for industrial, commercial, heating, or cooling purposes. To receive status as a QF under PURPA, the facility must produce electric energy and another form of useful thermal energy through the sequential use of energy, and must meet certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC), which is responsible for the implementation of PURPA. To qualify under PURPA, a small power producer must generate electricity using biomass (waste), renewable resources (water, wind, and solar), or geothermal energy as a primary energy source. Fossil fuels can be used, but renewable resources must provide at least 75 percent of the total energy input.

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

A new class of IPP's called exempt wholesale generators (EWG's) was established by the Energy Policy Act of 1992 (EPACT). This 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 interest in IPP facilities and can form corporate subsidiaries to develop and operate independent power projects anywhere in the world.[2]

Wholesale Transmission Services, Energy Brokers, and Power Marketers. Under EPACT, which also amended the Federal Power Act (FPA), any electric utility can apply to the FERC for an order requiring another electric utility to provide transmission services (wheeling). Prior to EPACT, the FERC could not mandate an electric utility to provide wheeling services for wholesale electric trade. This change in the law permits operators of electric generating equipment to sell wholesale power (sales for resale) to noncontiguous electric utilities.

The amendment to the FPA also affects power marketers, a relatively new group under FERC's jurisdiction. Power marketers are business entities that engage in buying and selling electricity, but have no generating or transmission facilities. Power marketers take ownership of the electricity and are involved in interstate trade. A number of power marketers that may be involved in interstate electricity trade have filed with FERC and have had their rates authorized. Energy brokers do not take ownership of the electricity traded, so their transactions are not regulated.

Open Access to the Transmission Grid. To foster increased competition in wholesale electricity markets and take full advantage of changing economics in this market, the FERC released early in 1995 a notice of proposed rulemaking (NOPR) regarding open access and transmission pricing (FERC Docket No. RM95-08-000). Recognizing the potential problems of a sudden move to competitive bulk power markets, the FERC simultaneously released an update to its NOPR regarding the treatment of stranded assets (Supplement to FERC Docket No. RM94-08-000). In proposing to require open access to the transmission grid, the FERC recognized that transmission "is the vital link between sellers and buyers. To achieve the benefits of robust, competitive bulk power markets, all wholesale buyers and sellers must have equal access to the transmission grid. . . .Thus, market power through control of transmission is the single greatest impediment to competition. Unquestionably, this market power is still being used today, or can be used, discriminatorily to block transmission."[3] The FERC acknowledged, "With the advent of competition, even prudent investments may become stranded. Reliance on past contractual and regulatory practices must be recognized and past investments must be protected to assure an orderly, fair transition to competition."

[2] EWG's are not considered electric utilities under PUHCA; they can only sell their output at wholesale to electric utilities and municipalities. For this report, EWG's are classified as nonutilities. However, EWG's are considered to be electric utilities under the Federal Power Act.
[3] FERC Docket No. RM95-08-000 and Docket No. RM94-07-001, pages 4 and 5, March 29, 1995.

A Review of 1994

This year, renewable energy resources information follows the electric utility and nonutility discussions. A graphic presentation (Figures 1 through 10) on the U.S. electric utility industry includes: retail sales of electricity, associated revenue, and average per kilowatthour sold by class of ownership; number of ultimate consumers served and number of electric utilities by class of ownership; sales for resale and associated revenue by class of ownership; net sales and average revenue per kilowatthour by sector; and nonutility installed and planned capacity. These data are collected and compiled from various sources, as indicated in the Preface.

U.S. Electric Utility Statistics

Retail Sales and Revenue. In 1994, sales of electricity to ultimate consumers increased to 2,935 billion kilowatthours, approximately 2.6 percent more than the 2,861 billion kilowatthours recorded in 1993. Revenue from retail sales increased from $198 billion in 1993 to $203 billion in 1994, a 2.3-percent increase (Table 1). Average revenue per kilowatthour decreased slightly, from 6.93 cents in 1993 to 6.91 cents in 1994.

By sector, 1994 sales increased from 1993 sales by 1.4 percent to 1,008 billion kilowatthours in the residential sector; 3.2 percent to 821 billion kilowatthours in the commercial sector; 3.2 percent to 1,008 billion kilowatthours in the industrial sector; and 3.0 percent to 98 billion kilowatthours in the other sector. Revenue increased 2.1 percent to $85 billion in the residential sector; 3.0 percent to $63 billion in the commercial sector; and 1.5 percent to $48 billion in the industrial sector; while revenue remained steady at $7 billion in the other sector. Average revenue per kilowatthour was 8.38 cents in the residential sector, 7.73 cents in the commercial sector, 4.77 cents in the industrial sector, and 6.84 cents in the other sector. Average revenue for the residential sector is generally higher than for the other sectors, due in part to the relatively small consumption level per consumer and the relatively low load factor. The load factor is average load expressed as a percentage of the peak load. Generally, a consumer whose average load is low relative to its maximum demand is more costly to serve than a consumer whose load factor is high. Residential consumers typically have a lower load factor than industrial consumers.

Among the ownership classes, investor-owned electric utilities account for more than 75 percent of all retail sales and revenue, with publicly owned and cooperative electric utilities providing the remainder. Federal electric utilities are primarily wholesalers of electricity. Sales to ultimate consumers increased in 1994 for electric utilities in all ownership categories: investor-owned, by 2.3 percent to 2,238 billion kilowatthours; publicly owned, by 3.6 percent to 422 billion kilowatthours; cooperatives, by 3.3 percent to 229 billion kilowatthours; and Federal, by 0.7 percent to 47 billion kilowatthours. Revenue likewise increased for all categories: investor-owned, by 1.9 percent to $160 billion; publicly owned, by 3.7 percent to $26 billion; cooperatives, by 3.4 percent to $16 billion; and Federal, by 0.5 percent to $1 billion.

Average revenue per kilowatthour for investor-owned electric utilities decreased slightly in 1994 to 7.14 cents from 7.16 cents in 1993. For publicly owned electric utilities, the average revenue per kilowatthour was stable at 6.09 cents; for cooperatives, it increased slightly to 7.01 cents in 1994 from 7.00 in 1993. Average revenue per kilowatthour decreased for Federal electric utilities to 2.76 cents from 2.77 cents in 1993.

Federal electric utilities generally have the lowest average revenue per kilowatthour because they have access to relatively low-cost financing and generally utilize facilities that are relatively inexpensive to operate. 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 publicly owned electric utilities, they generally serve sparsely populated areas and provide service to a higher percentage of rural residential customers than other classes of electric utilities. As a consequence, cooperative electric utilities generally have a higher average revenue per kilowatthour than do publicly owned electric utilities.

Financial. In 1994, the major investor-owned electric utilities had electric utility operating revenues of $179.3 billion, up a modest 1.7 percent from 1993; however, net income ($19.9 billion) showed an increase of 11.2 percent from 1993, following a 2.7-percent decline from 1992 to 1993. Operating income increased $0.4 billion in 1994. Electric operating expenses ($148.7 billion) increased by 1.7 percent. Earnings available to common stock increased by $2.2 billion or a substantial 13.5 percent. Dividends paid to owners of common stock decreased to 86.5 percent in 1994, compared with 95.1 percent in 1993, based on dividends declared during the year. Earnings available per average common share were $2.94, up for the third consecutive year.

In 1994, investment in the major investor-owned segment of the industry was $574.5 billion, an increase of $7.9 billion from 1993. Electric utility construction work in progress (CWIP) was $17.1 billion, a decrease of 5.0 percent from 1993 and a decrease of 24.0 percent from 1990. The total asset turnover ratio (operating revenues divided by total assets) remained the same at 0.34. Total capitalization of $365.6 billion increased by 1.4 percent from that in 1993. The ratio of long-term debt to total capitalization stood at 48.2, marginally down from the ratio in the previous year.

In 1994, the major publicly owned generator electric utilities had electric utility operating revenue of $23.3 up by 3.5 percent. Generator electric utility operating expenses increased by 2.9 percent, resulting in an increase in net income ($0.2 billion) of 35.2 percent. Total assets for publicly owned generator electric utilities increased 1.8 percent to $114.2 billion. The Electric Utility Plant per Dollar of Revenue ratio was 4.0 in 1994.

In 1994, the major publicly owned nongenerator electric utilities had electric utility operating revenue of $8.0 billion, a 5.3-percent growth over 1993. Nongenerator electric utility operating expenses increased by 6.2 percent to end the year at $7.5 billion. Net income for nongenerators was $0.4 billion, down 1.0 percent. Total assets for nongenerator electric utilities increased by 1.0 percent to end the year at $10.3 billion. The Electric Utility Plant per Dollar of Revenue ratio was 1.1 in 1994.

Environmental. In 1994, air emissions from electric utility fossil-fueled steam plants used for the generation of electricity in the United States were estimated to include: 13 million short tons of sulfur dioxide (SO_2), 6 million short tons of nitrogen oxides (NO_x); and 1,910 million short tons of carbon dioxide (CO_2). There was a decrease in these emissions for 1994 from the previous year; the most significant was a decrease of 9.2 percent in SO_2 emissions. The electric utilities chose to use certain kinds of coal and add emission abatement equipment to reduce SO_2 emissions and thus comply with Phase I of the Clean Air Act Amendments of 1990 (CAAA90), which began January 1, 1995. Switching to low-sulfur coal is one of the major strategies chosen by electric utilities. Production and distribution of low-sulfur coal has increased in the last few years, as a result. In 1994, U.S. electric utility plants received more than 157 million short tons of low- to medium-sulfur coal (less than or equal to 2.5 pounds of SO_2 per million Btu) from the Central Appalachian Coal Region (east Kentucky, southern West Virginia and Virginia) and more than 286 million short tons of low- to medium-sulfur coal from the Mountain Region (Wyoming, Montana and Colorado). This is an increase of 52.0 percent over combined receipts from these regions in 1985. The Phase I plants that switched to low-sulfur coal reduced the average sulfur content by weight of coal as received to 1.8 percent in 1994, 27.4 percent lower than in 1985. The average delivered cost of the coal received by those plants fell 14.5 percent to $32.68 per short ton from $38.23 per short ton in 1985.

Another reason SO_2 emissions from electric utility power plants are decreasing is the operation of flue gas desulfurization (FGD) units in the United States. FGD's (or scrubbers) use chemicals, such as lime, to remove sulfur oxides from the combustion gases of boilers before the gases are discharged to the atmosphere. In 1994, there were 168 generators connected to scrubbers in U.S. power plants, compared with 153 in 1993 and 137 in 1985, a 9.8- and 22.6-percent increase, respectively.

Power Transactions. On a national level, wholesale power receipts (purchased power plus exchanges received and wheeling received) increased from 1,864 billion kilowatthours in 1990 to 1,927 billion kilowatthours in 1994. Each year, however, even as these numbers increased, the exchange-received component dropped. This pattern reflects a structural change in the wholesale trade sector of the electric power industry. From a national total of 241 billion kilowatthours in 1991 to 155 billion kilowatthours in 1994, exchanges received fell nearly 100 billion kilowatthours as the use of exchange transactions dropped. The electric power industry has shifted away from in-kind exchanges of electricity to purchased power transactions as increases price competition has become apparent among traditional electric utilities.[4]

In 1994, the noncoincidental peak load at electric utilities showed a very moderate increase of nearly 5 billion kilowatts for the summer period. However, it dropped almost 4 billion kilowatts, to 519 billion kilowatts, for the winter peak load. Energy losses on the electrical system in 1994 were estimated to be 221 billion kilowatthours. This number is within the recent high and low range from 226 billion kilowatthours (in 1990 and 1993) to 211 billion kilowatthours in 1991.

In 1994, the United States imported more than 52 billion kilowatthours of electricity from Canada and Mexico and exported nearly 8 billion kilowatthours. More than 25 billion kilowatthours entered the United States at the northeastern border, while 10 billion kilowatthours entered through Washington State and Minnesota/North Dakota. Almost two-thirds of the electricity exported was transmitted from the Western Systems Coordinating Council (WSCC).

[4] In 1990, the Federal Energy Regulatory Commission (FERC) changed its treatment of one wholesale trade account. The definition for Summary of Interchange was clarified and the term replaced with the terms, Exchanges Received and Exchanges Delivered. The FERC reemphasized "in-kind exchanges of electricity" as the meaning of the term. When this clarification of the definition was implemented, the quantity of electricity reported traded in this category dropped nearly in half, from 427 billion kilowatthours in 1990 to 241 billion kilowatthours in 1991.

Demand-Side Management. Because of the changes that are occurring within the electric utility industry as it restructures, some utilities are reluctant to announce future plans for Demand-Side Management (DSM) funding and program implementation. There were 29 utilities in the reporting year 1994 unable to provide forecasts. For these electric utilities, 1999 DSM effects and costs were set equal to their 1995 effects and costs unless otherwise specified.

In 1994, energy savings and peak load reduction, resulting from DSM programs, were reported by 1,028 electric utilities. Of these, 578 were classified as large utilities,[5] an increase of 39 utilities. Nine of these utilities had been previously classified as small utilities, and 30 reported having DSM programs for the first time. The large utilities estimated that they reduced their annual peak loads by 25,001 megawatts in 1994, compared with 23,069 megawatts in 1993. In 1994, their potential, contractually available peak load reduction was 42,917 megawatts. Energy efficiency programs accounted for 46.6 percent of actual peak load reduction in 1994. Direct load control and interruptible load programs accounted for 43.7 percent of actual peak load reduction and 66.1 percent of potential peak load reduction. Energy savings increased from 45,294 million kilowatthours in 1993 to 52,483 million kilowatthours in 1994. Energy savings from energy efficiency programs represented 94.7 percent of total energy savings. Total utility cost decreased 1.0 percent from $2.74 billion in 1993 to $2.72 billion in 1994.[6]

Due to an unusually cold winter in 1994, many electric utilities in the Eastern United States experienced their annual peak in the winter as opposed to the summer. For this reason, many electric utilities, particularly in South Carolina, reported a decrease in actual and potential peak load reduction in 1994. However, for forecast years these electric utilities continue to assume that their system peak will be in the summer.

The Southeast and Northwest regions of the United States had the largest DSM programs in terms of energy effects, peak load reductions, and cost. Of the ten North American Electric Reliability Council (NERC) regions, the Southeastern Electric Reliability Council (SERC) and the Western Systems Coordinating Council (WSCC) Regions accounted for 52.6 percent of actual peak load reduction, 59.8 percent of energy savings, and 54.4 percent of utility cost. Adding the Northeast Power Coordinating Council Region (NPCC) to the SERC and WSCC Regions increased their share of energy savings to 75.9 percent and utility cost to 71.4 percent of the total DSM cost.

The residential sector accounted for 40.0 percent of energy saving, while the commercial sector accounted for 41.5 percent. The industrial sector accounted for 42.6 percent of potential peak load reduction, but only 31.9 percent of actual peak load reduction. The residential sector led in actual peak load reduction with 38.6 percent.

In 1995, energy savings are expected to increase by 0.7 percent over 1994 levels to 52,831 million kilowatthours, while potential peak load reductions are projected to remain relatively constant. Total utility cost is projected to decrease 4.5 percent, falling to 2.6 billion dollars. Between 1995 and 1999, DSM savings are expected to grow, albeit at a decreased rate, while DSM costs are expected to decrease slightly. Energy savings are projected to increase at an annual rate of 8.0 percent to 71,883 million kilowatthours, and potential peak load reductions are expected to increase at an annual rate of 5.4 percent to 51,487 megawatts. Utility costs are projected to stay constant at approximately $2.5 billion in 1999.

[5] Large utilities are those reporting sales to ultimate consumers or sales for resale greater than or equal to 120,000 megawatthours. These utilities are required to report incremental and annual peak load reduction and energy savings for the reporting year (1994), annual peak load reduction and energy savings for the first and fifth forecast years (1995 and 1999), and itemized direct and indirect utility costs for all three years (1994, 1995, and 1999). Small utilities with sales to ultimate consumers and sales for resale of less than 120,000 megawatthours are only required to report incremental energy savings and peak load reduction, and total utility, total nonutility, and total DSM costs for the reporting year and for the first and fifth forecast years.

[6] It 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.

U.S. Nonutility Power Producer Statistics

Generation. In 1994, U.S. nonutility power producers with facilities having an installed capacity of 1 megawatt or more (before 1992, the cutoff was 5 megawatt or more) generated 355 billion kilowatthours of electricity. U.S. nonutility power producers received 94 billion kilowatthours from and delivered 220 billion kilowatthours to electric utilities and other nonutilities. Nonutility power producers delivered approximately 62.6 percent of their gross generation to electric utilities and other nonutilities and used 227 billion kilowatthours for power plant operation and for industrial processes. The highest level of nonutility production of electricity occurred in California and Texas, with 63 and 54 billion kilowatthours, respectively.

Gross generation for nonutility power producers (with an installed capacity of 1 megawatt or more) was 9.1 percent higher in 1994 than a year earlier. Slightly more than half of the generation by nonutility power producers was gas-fired, with generation from coal accounting for 16.6 percent of the total. Of the total nonutility generation, 292 billion kilowatthours were from qualifying facilities, more than four times the quantity from nonqualifying facilities. (See the Chapter titled "Nonutility Power Producers" for a definition of these facilities.) The largest share of gross generation was produced by facilities in the West South Central Census Division, followed by the Pacific Census Division. The manufacturing sector dominates electricity generation and is concentrated in the West South Central and South Atlantic Census Divisions, where there is a large potential for cogeneration in both the refining and the paper and pulp industries.

Capacity. The total installed capacity of nonutility power producers with an installed capacity of 1 megawatt or more in the United States was 68,445 megawatts at the end of 1994. The installed capacity for facilities of 1 megawatt or more increased by 12.6 percent from 1993. Nonutility capacity in 1994 was equivalent to 9.2 percent of the traditional U.S. electric utility installed capacity.[7]

Natural gas was the fuel most used by nonutilities. Of all energy sources, gas accounted for the largest amount (28,055 megawatts) of nonutility capacity. The West South Central Census Division accounted for 37.6 percent of that gas-fired capacity. The second largest share of nonutility capacity was provided by petroleum, followed by wood and waste. The largest volume of petroleum capacity (3,562 megawatts) was located in the Middle Atlantic Census Division. Cogeneration accounts for 77.6 percent of nonutility capacity (66.4 percent qualifying facility capacity and 11.2 percent nonqualifying facility capacity). Small power producers and independent power producers account for 13.9 and 8.3 percent, respectively, of nonutility capacity.

The greatest number (552) of nonutility generating facilities was in the Pacific Census Division, and most of the capacity (13,764 megawatts) was in the West South Central 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 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 co-located.

Nonutilities face the same regulation requirements as an electric utility with the sole exception of the "economic" regulations regarding recovery of the investments. As a result of this exception, nonutilities require considerably less lead time than electric utilities to finance and build facilities. Nonutilities generally plan for 3 years while requirements of electric utilities make a 10-year period more appropriate. Capacity additions planned through 1997 by U.S. nonutilities total 10,014 megawatts, compared with 13,125 megawatts (generator nameplate capacity) planned for the same period by U.S. electric utilities. Electric utilities have planned 49,236 megawatts (generator nameplate capacity) in capacity additions for the 10-year period, 1995 through 2004. Of the nonutility planned capacity, 49.1 percent is petroleum and/or gas-fired. Coal-fired capacity represents 24.3 percent of the total planned nonutility additions.

Consumption. In 1994, consumption by nonutilities of 1 megawatt or more included 2,149 billion cubic feet of natural gas, 52 million short tons of coal, and 40 million barrels of petroleum. Compared to 1993, consumption increased 10.0 percent for petroleum, 8.1 percent for coal, and 6.8 percent of gas.

Emissions. In 1994, estimated air emissions from nonutility facilities of 1 megawatt or more were 1,424 thousand short tons of SO_2, 1,335 thousand short tons of NO_x, and 567,282 thousand short tons of CO_2. This is a 12.3-percent increase of SO_2 emissions from the previous year. Emissions of SO_2 should not increase at the same rate as NO_x and CO_2 emissions, because nonutility control of emissions is more widespread for SO_2 than for other air pollutants.

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

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 of various renewable energy resources. The information described in this section on "Renewable Energy Resources" and in Table 1, "Electric Power Industry Summary Statistics for the United States, 1993 and 1994," represents the information required by Section 171 of the Act aggregated at the U.S. level. More detailed information is included in other tables in this publication.

In 1994, net generation from renewable energy sources[8] accounted for about 10.4 percent (338,213 million kilowatthours) of the electric power industry's production of electricity (Table 1).[9] Conventional hydroelectric generation accounts for the greatest share (96.5 percent) of electric utility net generation from renewable sources. Generation from biomass accounts for the greatest share (67.5 percent) of nonutility gross generation from renewable sources.

Electric Utilities. Exclusive of conventional hydroelectric power, generation from renewable sources accounted for 0.3 percent of total electric utility generation in 1994. Electric utilities generated 6,941 million kilowatthours from geothermal steam; 1,988 million kilowatthours from biomass; and 3 million kilowatthours from photovoltaic. The capacity factors for electric utility geothermal and biomass plants were 45.4 percent and 44.1 percent, respectively, in 1994.[10] Photovoltaic plants had a capacity factor of about 9.7 percent. The efficiency[11] of biomass plants averaged 23 percent, or about 15,000 Btu per kilowatthour.[12] 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 2,274 megawatts as of year-end 1994. This represents 0.3 percent of total electric utility generating capacity. In contrast, nonutility capacity that used renewable energy sources totaled 13,992 megawatts (excluding conventional hydroelectric plants) or 20.4 percent of total nonutility generating capacity.

Nonutility. Nonutility generation from renewable sources accounted for 23.9 percent of total nonutility generation.[13] In 1994, nonutilities generated 57,392 million kilowatthours from biomass; 13,227 million kilowatthours from water (conventional hydroelectric); 10,122 million kilowatthours from geothermal steam; 3,482 million kilowatthours from wind; 824 million kilowatthours from solar thermal plants. In 1994, the capacity factor for geothermal plants averaged 86.5 percent; 62.0 percent for biomass plants; 44.8 percent for conventional hydroelectric plants; 26.5 percent for solar thermal plants; and 22.8 percent for wind-powered plants. The average efficiency of all biomass plants operated by nonutilities was approximately 12.5 percent or 26,148 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 22.0 percent or 15,363 Btu per kilowatthour.

The total installed capacity of nonutility power producer plants that used renewable sources was 17,340 megawatts (including 3,364 megawatts of conventional hydroelectric capacity) as of year-end 1994.

[8] Renewable 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.

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

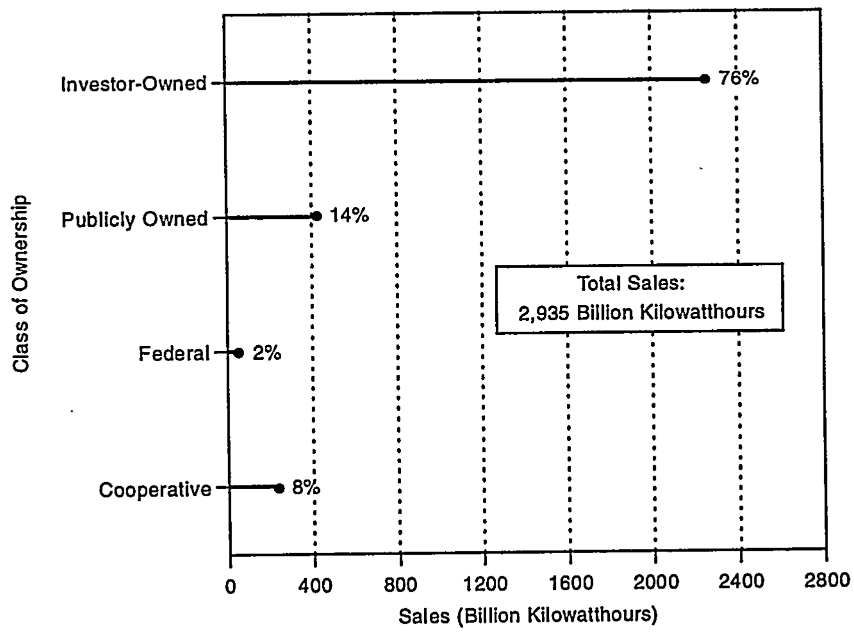
[10] The capacity factor is the ratio of the average load on the plant(s) for a considered period of time to the aggregate capacity of the plant(s).

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

[12] Plants that consumed 50 or more percent biomass fuels based on Btu input.

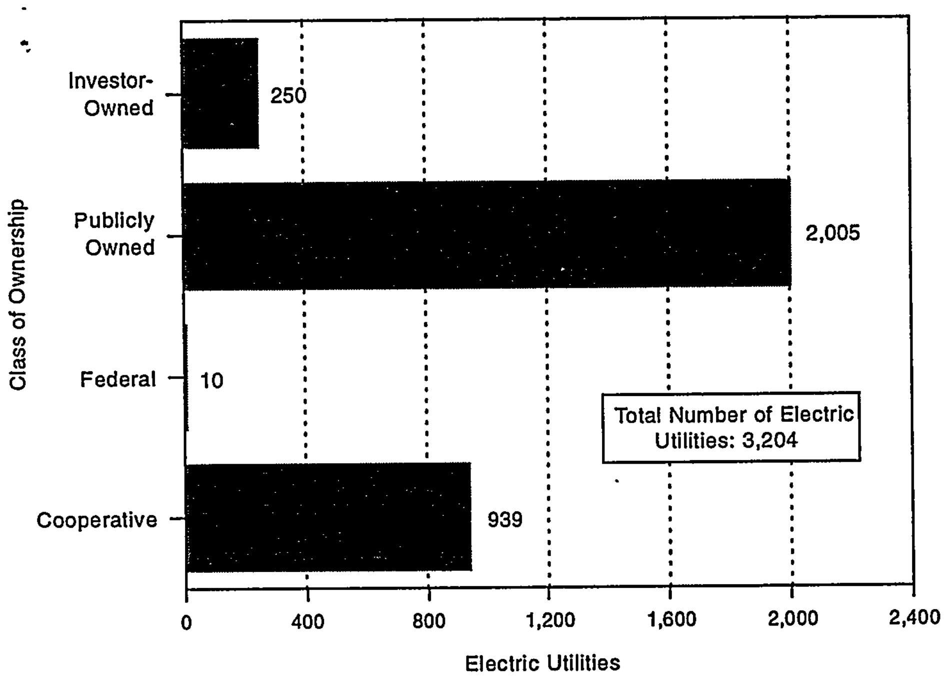
[13] Nonutility power producers with an installed electric generating capacity of 1 or more megawatts.

Figure 1. U.S. Electric Utility Sales to Ultimate Consumers by Class of Ownership, 1994



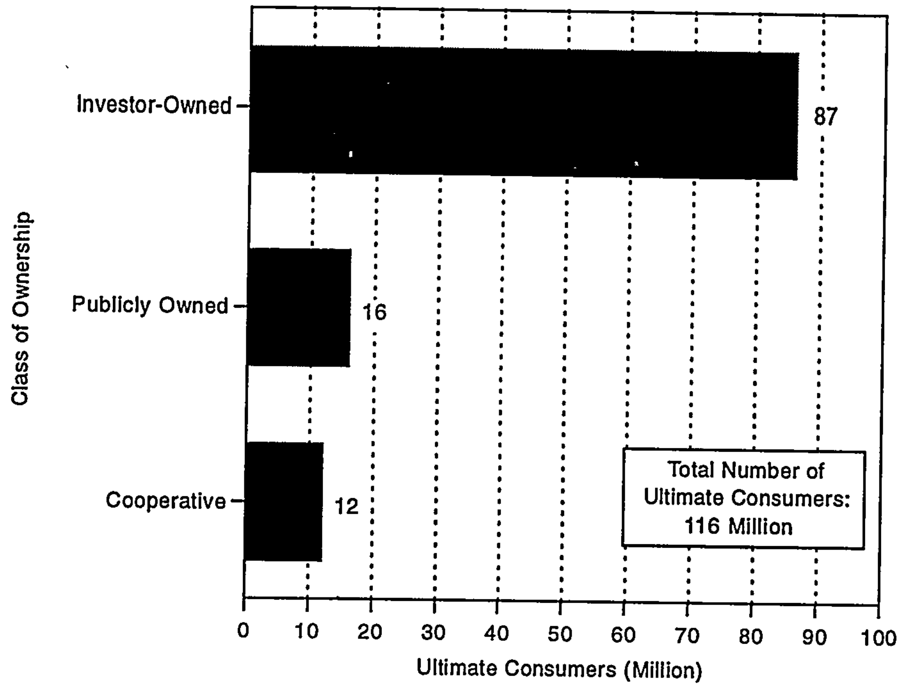
Notes: •Data are preliminary. •Totals may not equal sum of components because of independent rounding.
Sources: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 2. Number of U.S. Electric Utilities by Class of Ownership, 1994



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

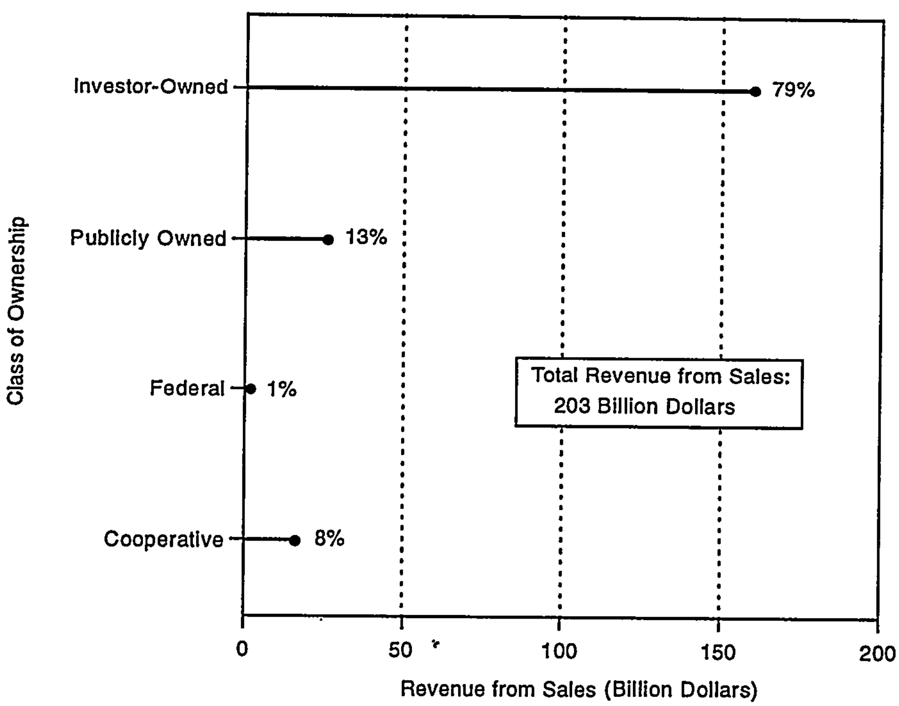
Figure 3. Number of Ultimate Consumers Served by U.S. Electric Utilities by Class of Ownership, 1994



Notes: •Data are preliminary. •The number of ultimate consumers served by Federal electric utilities not shown because it 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."

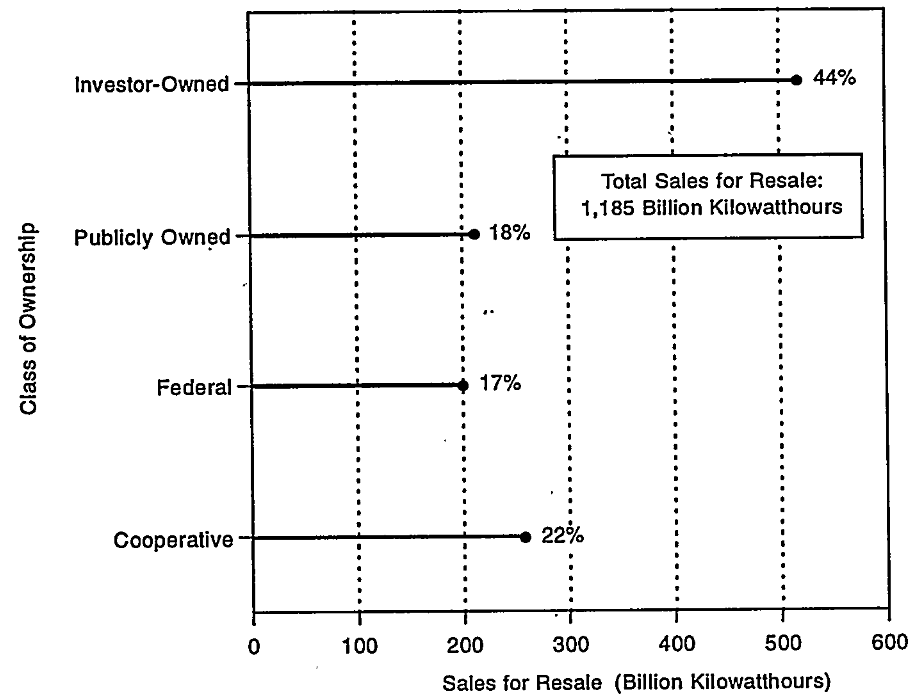
Figure 4. Revenue from U.S. Electric Utility Sales to Ultimate Consumers by Class of Ownership, 1994



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

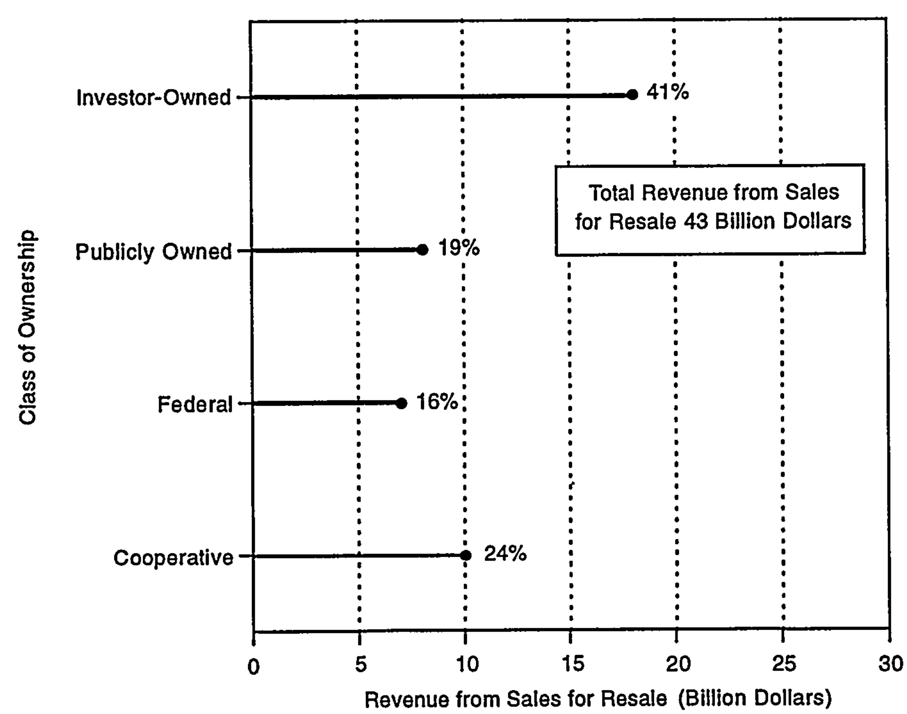
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 5. U.S. Electric Utility Sales for Resale by Class of Ownership, 1994



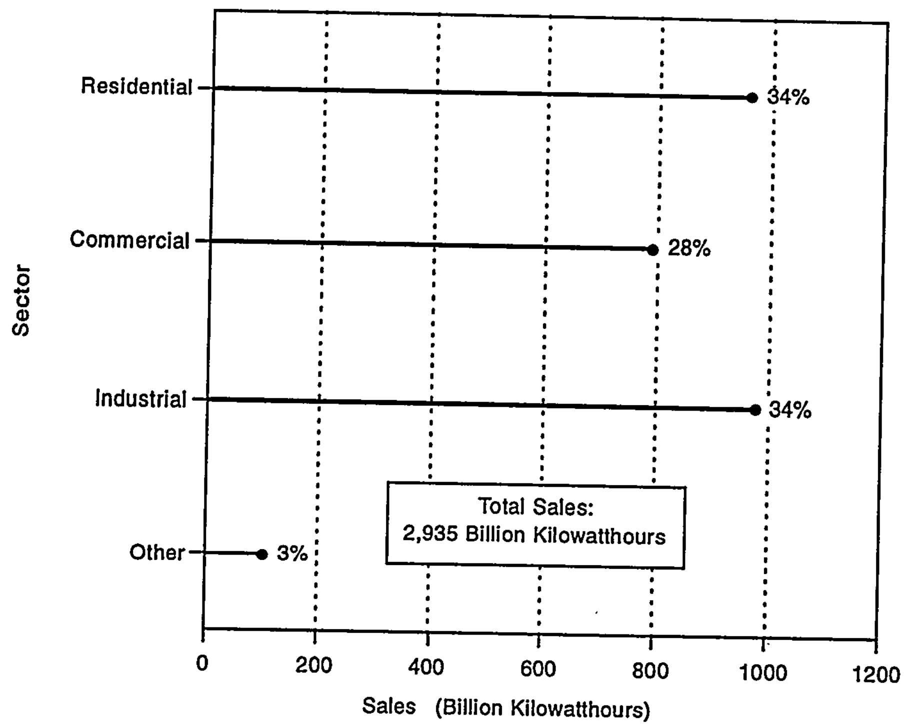
Notes: •Data are preliminary. •Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 6. Revenue from U.S. Electric Utility Sales for Resale by Class of Ownership, 1994



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."

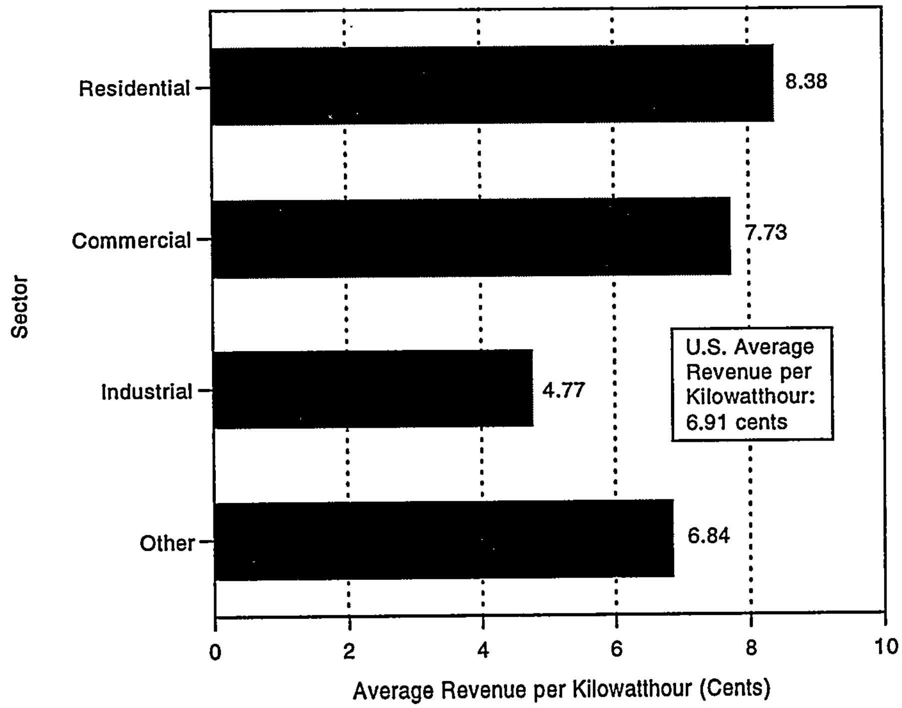
Figure 7. U.S. Electric Utility Sales to Ultimate Consumers by Sector, 1994



Notes: •Other includes sales for public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales. •Data are preliminary. •Totals may not equal sum of components because of independent rounding.

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

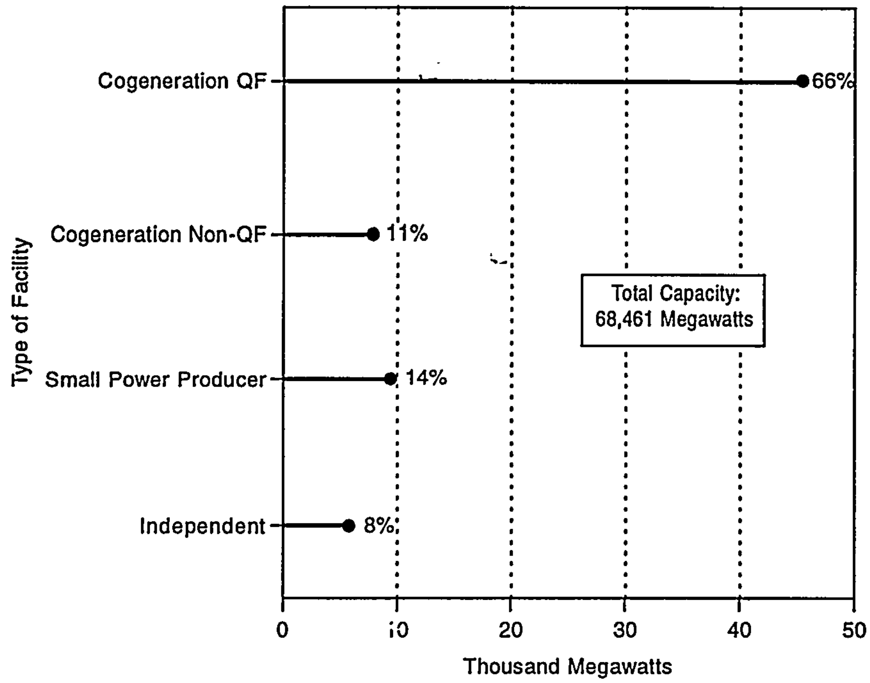
Figure 8. U.S. Electric Utility Average Revenue per Kilowatthour by Sector, 1994



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

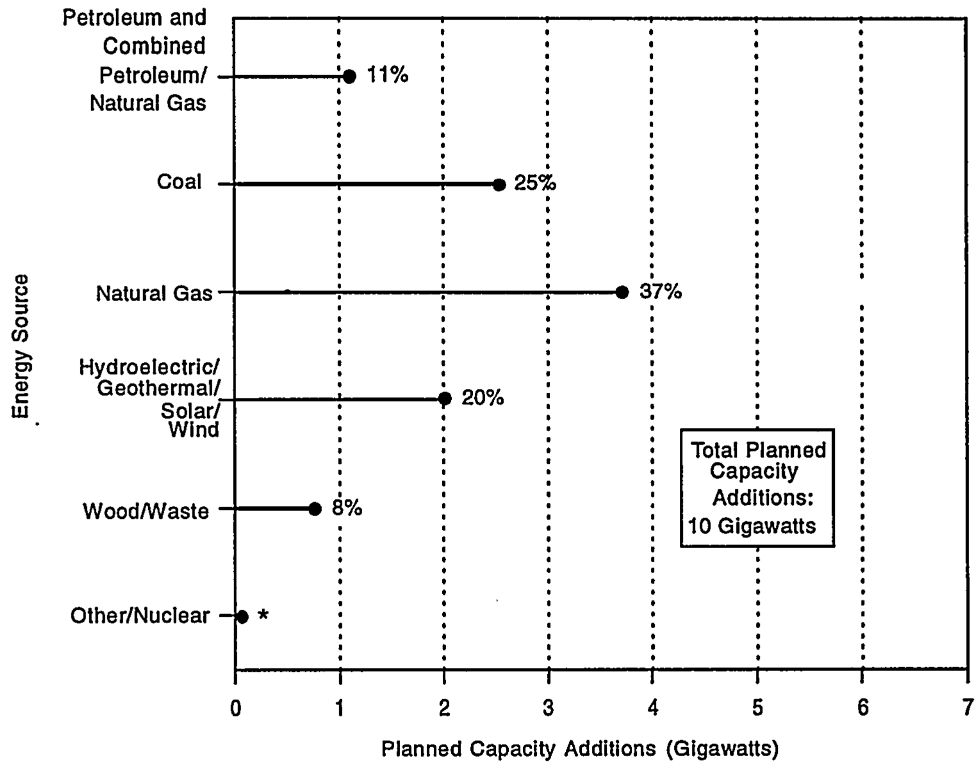
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 9. Installed Capacity at U.S. Nonutility Generating Facilities by Type of Facility, 1994



QF = Qualifying Facility.
Notes: •Data are preliminary. •Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

Figure 10. Planned Capacity Additions for U.S. Nonutility Generating Facilities by Energy Source, as of December 31, 1994



* = Value rounds to less than 1 percent.

Notes: •Totals may not equal sum of components because of independent rounding. •Other includes hydrogen, sulfur, batteries, chemicals, and spent sulfite liquor. •Data for planned capacity additions represent all planned generating facilities that meet one or more of three criteria presented in Chapter 6, "Nonutility Power Producers." •Data are preliminary.

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

Table 1. Electric Power Industry Summary Statistics for the United States, 1993 and 1994

Item	1993	1994	Percent Change
Electric Power Industry[1]			
Generating Capability (megawatts)	754,955	764,443	1.3
Net Generation (million kilowatthours)	3,196,924	3,253,799	1.8
Emissions (thousand short tons)			
Sulfur Dioxide (SO2)	15,208	14,018	-7.8
Nitrogen Oxides (NOX)	6,895	6,801	-1.4
Carbon Dioxide (CO2)	2,322,747	2,329,666	.3
Electric Utilities			
Generating Capability (megawatts)[2]	699,971	702,658	.4
Coal	300,795	301,098	.1
Petroleum	69,519	69,919	.6
Gas	132,495	133,854	1.0
Nuclear	99,041	99,148	.1
Renewable			
Hydroelectric (conventional)	74,763	75,196	.6
Geothermal	1,747	1,747	—
Biomass[3]	459	515	12.2
Wind	1	8	NM
Solar Thermal	—	—	—
Photovoltaic	4	4	—
Hydroelectric Pumped Storage	21,146	21,168	.1
Net Generation (million kilowatthours)	2,882,525	2,910,712	1.0
Coal	1,639,151	1,635,493	-.2
Petroleum[4]	99,539	91,039	-8.5
Gas	258,915	291,115	12.4
Nuclear	610,291	640,440	4.9
Renewable			
Hydroelectric (conventional)	269,098	247,071	-8.2
Geothermal	7,571	6,941	-8.3
Biomass[3]	1,990	1,988	-.1
Wind	—	—	—
Solar Thermal	—	—	—
Photovoltaic	4	3	-25.0
Hydroelectric Pumped Storage[5]	-4,036	-3,378	-16.3
Consumption			
Coal (million short tons)	814	817	.4
Petroleum (million barrels)[6]	162	151	-6.8
Gas (billion cubic feet)	2,682	2,987	11.4
Stocks (Year End)			
Coal (million short tons)	111	127	14.4
Petroleum (million barrels)[7]	62	63	1.6
Receipts			
Coal (million short tons)	769	832	8.2
Petroleum (million barrels)[8]	148	143	-3.4
Gas (billion cubic feet)[9]	2,575	2,864	11.2
Cost (cents per million Btu)[10]			
Coal	138.5	135.5	-2.2
Petroleum[11]	243.3	248.8	2.3
Gas	256.0	223.0	-12.9
Sales To Ultimate Consumers (million kilowatthours)	2,861,462	2,934,517	2.6
Residential	994,781	1,008,440	1.4
Commercial	794,573	820,252	3.2
Industrial	977,164	1,007,997	3.2
Other[12]	94,944	97,827	3.0
Revenue From Ultimate Consumers (million dollars)	198,220	202,702	2.3
Residential	82,814	84,548	2.1
Commercial	61,521	63,393	3.0
Industrial	47,357	48,071	1.5
Other[12]	6,528	6,689	2.5
Average Revenue per Kilowatthour (cents)	6.93	6.91	-.3
Residential	8.32	8.38	.7
Commercial	7.74	7.73	-.1
Industrial	4.85	4.77	-1.6
Other[12]	6.88	6.84	-.6
Net Electric Plant Inc Fuel (million dollars)			
Major Investor Owned	369,794	372,593	.8
Major Publicly Owned Generator/Nongenerator	67,726	69,057	2.0
Emissions (thousand short tons)[13]			
Sulfur Dioxide (SO2)	14,432	13,104	-9.2
Nitrogen Oxides (NOX)	5,852	5,719	-2.3
Carbon Dioxide (CO2)	1,926,803	1,909,510	-.9
Noncoincidental Summer Peak Load (megawatts)	R 581,264	585,844	4.1
DSM Actual Peak Load Reductions (megawatts)	23,069	25,001	8.4
DSM Energy Savings (million kilowatthours)	45,294	52,483	15.9
DSM Cost (million dollars)	2,744	2,716	-1.0

Table 1. Electric Power Industry Summary Statistics for the United States, 1993 and 1994 (Continued)

Item	1993	1994	Percent Change
Nonutility Power Producers			
Installed Capacity (megawatts)	60,778	68,461	12.6
Coal[14]	9,772	10,372	6.1
Petroleum Only[15]	2,043	2,262	10.7
Gas Only[16]	23,463	26,925	14.8
Petroleum/Natural Gas (combined)	8,505	9,820	15.5
Nuclear[17]	20	—	—
Renewable			
Hydroelectric (conventional)	2,741	3,364	22.7
Geothermal	1,318	1,335	1.3
Biomass[3]	10,177	10,566	3.8
Wind	1,813	1,737	-4.2
Solar Thermal	354	354	—
Photovoltaic	7	*	—
Other[18]	566	597	5.5
Gross Generation (million kilowatthours)	325,226	354,925	9.1
Coal[14]	53,367	59,035	10.6
Petroleum[15]	13,364	15,069	12.8
Gas[16]	174,282	179,735	3.1
Nuclear[17]	78	54	-30.8
Renewable			
Hydroelectric (conventional)	11,511	13,227	14.9
Geothermal	9,749	10,122	3.8
Biomass[3]	55,746	57,392	3.0
Wind	3,052	3,482	14.1
Solar Thermal	895	824	-7.9
Photovoltaic	2	**	-85.0
Other[18]	3,181	3,507	10.2
Consumption			
Coal (Thousand short tons)	48,343	52,261	8.1
Petroleum (Thousand barrels)[19]	36,768	40,460	10.0
Natural Gas (Million cubic feet)	2,013,788	2,149,246	6.7
Other Gas (Million cubic feet)[20]	1,678,166	1,586,185	-5.5
Supply and Disposition (million kilowatthours)			
Gross Generation	325,226	354,925	9.1
Receipts[21]	85,323	94,166	10.4
Deliveries[22]	203,035	222,315	9.5
Facility Use	207,514	226,777	9.3
Emissions (thousand short tons)[23]			
Sulfur Dioxide (SO2)	1,267	1,424	12.4
Nitrogen Oxides (NOX)	1,300	1,335	2.7
Carbon Dioxide (CO2)	535,999	567,281	5.8

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

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

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

[4] Includes petroleum coke.

[5] Represents total pumped storage facility production minus energy used for pumping. Negative generation denotes that electric power consumed for plant use exceeds gross generation.

[6] Does not include petroleum coke consumption of 1,220 thousand short tons in 1993 and 999 thousand short tons in 1994.

[7] Does not include petroleum coke stocks of 89 thousand short tons at year end 1993 and .03 thousand shorts tons at year end 1994.

[8] Does not include petroleum coke receipts of 1,248 thousand short tons in 1993 and 1,263 thousand short tons in 1994.

[9] Includes small amounts of coke-oven, refinery, and blast furnance gas.

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

[11] Does not include petroleum coke cost of 70.3 cents per million Btu in 1993 and 68.9 cents per million Btu in 1994.

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

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

[14] Includes coal, anthracite culm and coal waste.

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

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

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

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

[19] Does not include petroleum coke consumption of 4,740 thousand short tons for 1994.

[20] Includes butane, ethane, propane, and other gases.

[21] Includes purchases, interchanges, and exchanges of electric energy with utilities and other nonutilities.

[22] 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.

[23] As of 1993, emission factors for the calculation of carbon dioxide emissions and reductions from nitrogen oxide control technologies have been

changed--historical data were revised to reflect that change--see Technical Notes for more information.
R = Revised data.
NM = Calculation not meaningful.
* = Less than 0.5 megawatts.
** = Less than 0.5 million kilowatthours.

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 1994; other data in this table are final. •See Technical Notes for estimation methodology. •Totals may not equal sum of components because of independent rounding. •Percent change is calculated before rounding. • * = less than 0.5 megawatts. •DSM = Demand-Side Management.

Sources: •Energy Information Administration, Form EIA-759, "Monthly Power Plant Report"; Form EIA-860, "Annual Electric Generator Report"; Form EIA-861, "Annual Electric Utility Report"; Form EIA-767, "Steam-Electric Plant Operation and Design Report"; Form EIA-867, "Annual Nonutility Power Producer Report." •Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." •Office of the Assistant Secretary for Emergency Planning and Operations, Form OE-411, "Coordinated Bulk Power Supply Program."

U.S. Electric Utility Retail Sales and Revenue

This chapter provides summary statistics on the sale of electricity to ultimate consumers, associated revenue, and average revenue per kilowatthour sold at the national, Census division, 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: generating plants (stations) to 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. Electric utilities design, build, and operate power systems. Some companies may operate only 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 generally has many different classifications of consumers. Electric utilities determine consumer classification by various 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 (e.g. load growth and 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 grouped into end-use sectors: residential, commercial, industrial, and other. The electric utility determines the criteria for end-use sector classification 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, such as hotels, motels, restaurants, wholesale businesses, and retail stores, and health, social, and educational institutions. The industrial sector includes manufacturing, construction, mining, agriculture, fishing, and forestry establishments (SIC codes 1 through 39). However, utilities may classify their commercial and industrial service based on demand or annual usage falling within a specified range, such as classifying a light manufacturer as commercial. The electric utility sets the range for classifying its consumers. The other sector includes public street and highway lighting, the transportation sector, 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. Revenue requirements are the anticipated costs of providing services for some period of time in the future, usually one year. Revenue requirements are based on operating expenses, depreciation expenses, taxes, and return on the rate base (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 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 for different sectors vary based on the 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 the annual revenue from retail sales by the annual retail sales for each sector and State. The resulting measurement is the cost (per kilowatthour of electricity sold) for providing service to a sector, given the rate schedule of the electric utility for that particular sector. The average revenue per kilowatthour is calculated for all consumers and for each sector (residential, commercial, industrial, and other sales). Utilities typically employ a number of rate schedules within a single sector. These alternative rate schedules reflect the varying consumption levels and patterns of different consumers and the associated impacts on the cost to the electric utility for providing electrical service. The average revenue per kilowatthour by sector reported in this publication represents a weighted average of revenue and sales from ultimate consumers within that sector and across sectors for all consumers.

The electric revenue used to derive the average revenue per kilowatthour is the operating revenue reported by the electric utility. Operating revenue includes energy charges, demand charges, consumer service charges, environmental surcharges, fuel adjustments, and other miscellaneous charges.

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

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

Average revenue per kilowatthour for the residential sector is generally higher than for other sectors. This is primarily due 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 generally has the lowest average revenue per kilowatthour 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 among the ownership classes because they have access to relatively low-cost financing and mostly utilize inexpensive 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 publicly owned electric utilities, cooperatives generally serve sparsely populated areas; as a consequence, cooperatives generally have higher average revenue per kilowatthour than publicly 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 the national 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 inexpensive 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 low average revenue per kilowatthour.

Source of Data

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 an annual census of electric utilities (approximately 3,200) that own and/or operate facilities within the United States, its territories, and Puerto Rico.[14] Data collected include the generation, transmission, distribution, sales, and associated revenue of electric energy, primarily used by the public. More detailed statistics on sales, average revenue, and revenue per kilowatthour are published annually in the *Electric Sales and Revenue*[15]

Table 2. U.S. Electric Utility Sales to Ultimate Consumers and Associated Revenue by Sector, 1990 Through 1994

Item	1990	1991	1992	1993	1994
Sales (million kilowatthours)					
Residential	924,019	955,417	935,939	994,781	1,008,440
Commercial	751,027	765,664	761,271	794,573	820,252
Industrial	945,522	946,583	972,714	977,164	1,007,997
Other[1]	91,988	94,339	93,442	94,944	97,827
U.S. Total	**2,712,555**	**2,762,003**	**2,763,365**	**2,861,462**	**2,934,517**
Revenue (million dollars)					
Residential	72,378	76,828	76,848	82,814	84,548
Commercial	55,117	57,655	58,343	61,521	63,393
Industrial	44,857	45,737	46,993	47,357	48,071
Other[1]	5,891	6,138	6,296	6,528	6,689
U.S. Total	**178,243**	**186,359**	**188,480**	**198,220**	**202,702**

[1] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.
Notes: •Data for 1994 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 3. Average Revenue per Kilowatthour for U.S. Electric Utilities by Sector, 1990 Through 1994
(Cents)

Sector	1990	1991	1992	1993	1994
Residential	7.83	8.04	8.21	8.32	8.38
Commercial	7.34	7.53	7.66	7.74	7.73
Industrial	4.74	4.83	4.83	4.85	4.77
Other[1]	6.40	6.51	6.74	6.88	6.84
All Sectors	**6.57**	**6.75**	**6.82**	**6.93**	**6.91**

[1] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.
Notes: •Data for 1994 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."

[14] Summary data in this publication are for the United States only and do not include Puerto Rico and the U.S. territories.
[15] For detailed data, including data for the power authorities of Guam, Puerto Rico, American Samoa, and the Virgin Islands, see the *Electric Sales and Revenue*, DOE/EIA-0540, published annually by the Energy Information Administration.

Table 4. U.S. Electric Utility Sales to Ultimate Consumers by Sector, Census Division, and State, 1993 and 1994
(Million Kilowatthours)

Census Division State	All Sectors 1993	All Sectors 1994	Residential 1993	Residential 1994	Commercial 1993	Commercial 1994	Industrial 1993	Industrial 1994	Other[1] 1993	Other[1] 1994
New England	**104,797**	**106,317**	**38,057**	**38,536**	**38,667**	**40,398**	**26,191**	**25,575**	**1,882**	**1,809**
Connecticut	27,238	28,026	10,597	10,898	10,677	10,845	5,597	5,917	368	366
Maine	11,952	11,606	3,872	3,692	2,868	2,812	5,040	4,952	172	151
Massachusetts	45,281	46,091	15,785	16,049	18,897	19,371	9,605	9,710	994	961
New Hampshire	8,761	8,956	3,420	3,431	2,123	3,221	3,100	2,182	118	122
Rhode Island	6,548	6,572	2,412	2,457	2,532	2,563	1,419	1,378	186	174
Vermont	5,016	5,067	1,971	2,009	1,570	1,586	1,431	1,435	44	36
Middle Atlantic	**315,772**	**320,481**	**103,395**	**104,499**	**108,473**	**111,580**	**89,732**	**89,793**	**14,172**	**14,608**
New Jersey	65,621	66,261	22,042	22,156	28,493	29,359	14,596	14,251	490	495
New York	130,170	131,174	39,897	40,103	47,728	48,827	30,187	29,467	12,357	12,777
Pennsylvania	119,981	123,045	41,455	42,239	32,252	33,395	44,949	46,076	1,325	1,336
East North Central	**489,034**	**506,239**	**146,298**	**147,377**	**127,309**	**131,966**	**200,478**	**211,966**	**14,948**	**14,930**
Illinois	117,786	121,489	35,226	35,705	34,355	35,663	40,249	41,765	7,956	8,356
Indiana	81,931	83,808	24,978	25,048	17,015	17,462	39,415	40,763	523	534
Michigan	87,589	91,160	26,770	27,174	28,930	30,412	30,572	32,717	1,316	857
Ohio	148,571	154,370	41,951	41,789	33,299	34,052	68,831	74,007	4,491	4,522
Wisconsin	53,156	55,413	17,373	17,661	13,710	14,378	21,410	22,714	662	659
West North Central	**201,831**	**208,179**	**74,413**	**74,983**	**54,394**	**56,811**	**67,884**	**70,894**	**5,140**	**5,491**
Iowa	32,104	33,039	11,103	11,062	7,269	7,477	12,465	13,224	1,267	1,277
Kansas	28,808	29,614	9,986	10,131	9,753	10,111	8,702	9,001	367	371
Minnesota	49,211	51,155	15,597	16,006	8,535	8,997	24,384	25,450	694	701
Missouri	58,622	59,697	24,182	24,057	19,914	20,617	13,618	14,106	908	916
Nebraska	18,749	19,820	7,226	7,338	5,471	5,805	4,963	5,339	1,089	1,338
North Dakota	7,432	7,681	3,209	3,243	1,831	1,884	1,905	2,011	487	542
South Dakota	6,905	7,174	3,109	3,147	1,621	1,919	1,847	1,762	327	346
South Atlantic	**582,431**	**592,436**	**236,503**	**237,790**	**167,515**	**176,978**	**159,908**	**158,909**	**18,505**	**18,758**
Delaware	9,121	9,299	3,044	3,107	2,605	2,685	3,417	3,447	56	60
District of Columbia	10,375	10,295	1,635	1,572	5,418	8,093	2,976	267	346	363
Florida	152,748	159,544	76,827	80,595	54,876	57,447	16,298	16,513	4,747	4,989
Georgia	89,191	89,913	33,867	32,735	25,169	26,161	29,084	29,942	1,071	1,075
Maryland	53,872	54,752	21,546	21,666	11,317	13,254	20,201	19,037	809	794
North Carolina	99,778	99,789	37,742	37,207	26,747	27,458	33,488	33,307	1,800	1,817
South Carolina	61,533	61,858	20,687	19,903	13,177	13,393	26,867	27,760	802	802
Virginia	81,372	82,210	32,472	32,343	22,727	22,948	17,390	18,154	8,783	8,766
West Virginia	24,442	24,776	8,682	8,663	5,480	5,539	10,187	10,482	92	92
East South Central	**247,788**	**259,226**	**85,250**	**89,078**	**32,943**	**34,186**	**124,603**	**130,838**	**4,992**	**5,124**
Alabama	65,058	67,581	22,628	23,159	11,254	11,844	30,524	31,919	652	659
Kentucky	68,149	72,485	19,223	19,481	9,829	10,095	36,320	40,049	2,777	2,861
Mississippi	34,749	36,627	13,200	13,642	6,685	7,094	14,229	15,256	635	635
Tennessee	79,832	82,533	30,199	32,797	5,175	5,154	43,530	43,614	928	968
West South Central	**390,034**	**402,084**	**137,779**	**140,192**	**96,252**	**99,478**	**139,680**	**145,473**	**16,324**	**16,941**
Arkansas	31,663	32,619	11,762	11,642	6,698	6,866	12,609	13,526	594	585
Louisiana	67,756	70,144	22,430	22,631	14,398	15,024	28,439	29,896	2,488	2,593
Oklahoma	40,531	41,142	15,901	16,127	10,824	11,120	11,699	11,721	2,107	2,173
Texas	250,084	258,179	87,686	89,792	64,331	66,468	86,933	90,329	11,134	11,589
Mountain	**171,193**	**180,285**	**54,001**	**56,738**	**53,801**	**54,821**	**56,653**	**61,247**	**6,738**	**7,479**
Arizona	44,408	47,282	16,705	18,212	14,813	15,625	10,989	11,303	1,901	2,142
Colorado	32,958	34,502	10,656	10,939	14,422	12,953	7,024	9,620	856	990
Idaho	18,720	19,879	6,245	6,222	4,969	5,638	7,222	7,647	284	373
Montana	12,929	13,184	3,598	3,567	3,026	3,096	5,837	5,961	469	561
Nevada	18,499	20,036	6,281	6,845	4,298	4,612	7,181	7,775	740	805
New Mexico	14,927	15,859	3,884	4,080	4,759	4,970	4,816	5,184	1,467	1,625
Utah	16,867	17,846	4,726	5,008	5,020	5,500	6,221	6,498	900	840
Wyoming	11,885	11,696	1,906	1,865	2,493	2,428	7,363	7,260	122	144
Pacific	**345,550**	**345,788**	**114,987**	**115,001**	**110,794**	**109,337**	**107,764**	**109,001**	**12,005**	**12,450**
California	210,500	213,684	67,359	68,866	79,058	76,925	56,189	59,864	7,894	8,030
Oregon	44,578	44,971	16,696	16,462	12,205	12,660	15,012	15,072	664	777
Washington	90,473	87,133	30,932	29,673	19,531	19,752	36,563	34,065	3,447	3,643
Pacific Noncontiguous	**13,033**	**13,482**	**4,098**	**4,245**	**4,426**	**4,698**	**4,271**	**4,302**	**238**	**237**
Alaska	4,375	4,533	1,629	1,688	2,062	2,155	501	511	182	179
Hawaii	8,658	8,948	2,469	2,557	2,363	2,543	3,770	3,791	56	58
U. S. Total	**2,861,462**	**2,934,517**	**994,781**	**1,008,440**	**794,573**	**820,252**	**977,164**	**1,007,997**	**94,944**	**97,827**

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

Notes: •Data for 1994 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 5. Number of Ultimate Consumers Served by U.S. Electric Utilities by Sector, Census Division, and State, 1993 and 1994
(Thousands)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other[1]	
	1993	1994	1993	1994	1993	1994	1993	1994	1993	1994
New England	6,148	6,202	5,431	5,477	646	649	27	29	44	47
Connecticut	1,448	1,457	1,312	1,321	125	125	5	6	5	5
Maine	681	687	591	595	70	71	3	3	18	18
Massachusetts	2,693	2,719	2,371	2,395	294	296	14	14	14	14
New Hampshire	579	586	498	502	76	75	2	3	3	5
Rhode Island	442	444	394	396	45	45	2	3	1	1
Vermont	306	309	265	268	37	37	1	1	3	3
Middle Atlantic	15,949	16,060	14,103	14,199	1,742	1,759	55	54	49	48
New Jersey	3,354	3,381	2,954	2,976	377	381	14	14	10	10
New York	7,259	7,296	6,398	6,432	818	822	12	12	31	30
Pennsylvania	5,336	5,383	4,751	4,791	548	556	29	29	8	8
East North Central	18,925	19,146	16,957	17,149	1,822	1,847	72	72	74	77
Illinois	4,953	5,002	4,477	4,516	454	458	5	5	17	23
Indiana	2,556	2,592	2,278	2,311	251	255	17	18	10	8
Michigan	4,216	4,258	3,781	3,818	405	411	12	13	18	16
Ohio	4,858	4,911	4,338	4,385	470	477	32	31	18	18
Wisconsin	2,342	2,383	2,083	2,118	242	246	5	6	12	12
West North Central	8,642	8,754	7,488	7,585	989	1,005	48	48	117	116
Iowa	1,335	1,348	1,159	1,169	158	160	4	4	14	15
Kansas	1,236	1,252	1,050	1,063	162	167	13	14	11	9
Minnesota	2,072	2,110	1,834	1,866	204	209	10	10	24	24
Missouri	2,507	2,541	2,212	2,244	269	273	12	11	14	13
Nebraska	823	830	670	674	108	110	4	5	40	41
North Dakota	322	323	270	273	44	43	3	2	5	5
South Dakota	347	351	294	297	43	43	2	2	8	8
South Atlantic	21,566	22,037	19,019	19,423	2,311	2,377	81	82	156	156
Delaware	332	340	298	305	33	33	1	1	1	1
District of Columbia	221	220	193	193	27	27	*	*	*	*
Florida	7,022	7,179	6,200	6,340	750	768	22	23	50	48
Georgia	3,162	3,253	2,810	2,878	313	335	14	14	25	26
Maryland	2,017	2,059	1,813	1,852	192	195	11	11	1	1
North Carolina	3,437	3,518	2,984	3,055	412	424	13	13	28	26
South Carolina	1,739	1,776	1,505	1,536	218	222	4	4	12	12
Virginia	2,747	2,795	2,442	2,484	264	269	5	5	36	38
West Virginia	888	897	773	780	101	103	11	11	3	3
East South Central	7,374	7,528	6,395	6,517	873	897	64	70	42	45
Alabama	1,989	2,028	1,723	1,752	247	256	12	13	7	7
Kentucky	1,779	1,813	1,555	1,584	195	200	11	11	17	18
Mississippi	1,203	1,229	1,036	1,056	152	155	8	9	8	9
Tennessee	2,404	2,458	2,082	2,125	279	286	33	37	10	10
West South Central	12,584	12,811	10,946	11,133	1,390	1,420	113	129	135	129
Arkansas	1,194	1,220	1,040	1,062	118	122	23	25	13	11
Louisiana	1,918	1,925	1,687	1,691	197	200	15	15	19	18
Oklahoma	1,609	1,630	1,390	1,408	190	192	16	16	13	13
Texas	7,863	8,037	6,829	6,971	886	906	58	73	91	87
Mountain	6,675	6,918	5,762	5,936	784	800	35	38	94	144
Arizona	1,725	1,762	1,536	1,571	168	171	5	5	16	16
Colorado	1,710	1,796	1,459	1,493	205	208	2	2	45	93
Idaho	516	535	434	449	76	78	4	4	3	4
Montana	432	442	355	364	60	62	4	4	13	13
Nevada	641	673	557	586	81	84	1	1	2	2
New Mexico	716	751	615	645	88	92	5	6	8	8
Utah	687	706	606	623	66	66	11	12	5	5
Wyoming	248	253	201	205	40	40	3	4	4	4
Pacific Contiguous	16,240	16,383	14,220	14,349	1,886	1,893	57	60	78	81
California	12,390	12,455	10,841	10,897	1,464	1,471	39	39	45	49
Oregon	1,439	1,472	1,243	1,271	176	181	7	7	13	13
Washington	2,412	2,456	2,135	2,181	245	242	11	14	20	19
Pacific Noncontiguous	630	646	539	552	84	85	1	1	5	8
Alaska	240	245	202	206	33	34	*	*	4	4
Hawaii	390	402	337	346	51	51	1	1	2	4
U. S. Average	114,735	116,486	100,860	102,318	12,526	12,733	553	584	795	851

[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 1994 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 6. Revenue from U.S. Electric Utility Sales to Ultimate Consumers by Sector, Census Division, and State, 1993 and 1994
(Million Dollars)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other[1]	
	1993	1994	1993	1994	1993	1994	1993	1994	1993	1994
New England	10,486	10,731	4,277	4,403	3,808	4,015	2,163	2,078	238	236
Connecticut	2,795	2,853	1,207	1,250	1,072	1,084	464	467	52	51
Maine	1,087	1,118	443	455	271	286	351	356	23	22
Massachusetts	4,518	4,611	1,737	1,779	1,828	1,889	832	822	121	121
New Hampshire	951	1,014	421	443	234	351	280	203	16	16
Rhode Island	681	673	275	277	258	255	128	122	21	20
Vermont	453	462	194	200	146	149	107	108	6	5
Middle Atlantic	30,014	30,670	11,729	12,026	11,012	11,353	5,905	5,862	1,368	1,429
New Jersey	6,554	6,664	2,514	2,556	2,774	2,889	1,180	1,132	86	88
New York	13,960	14,320	5,256	5,435	5,564	5,700	2,012	1,996	1,129	1,189
Pennsylvania	9,499	9,686	3,959	4,035	2,674	2,765	2,713	2,733	153	153
East North Central	31,790	32,447	12,202	12,337	9,403	9,654	9,132	9,443	1,053	1,013
Illinois	9,123	9,008	3,622	3,564	2,749	2,739	2,193	2,164	559	541
Indiana	4,235	4,397	1,666	1,697	991	1,033	1,530	1,619	47	48
Michigan	6,256	6,467	2,185	2,249	2,319	2,411	1,632	1,716	120	90
Ohio	9,240	9,553	3,508	3,576	2,528	2,628	2,924	3,061	280	288
Wisconsin	2,936	3,023	1,222	1,250	815	844	853	883	46	46
West North Central	12,183	12,519	5,410	5,486	3,430	3,558	3,011	3,118	332	356
Iowa	1,916	1,957	890	895	462	473	489	513	74	76
Kansas	1,902	1,957	785	799	654	674	430	444	33	41
Minnesota	2,756	2,880	1,105	1,146	529	562	1,072	1,121	50	51
Missouri	3,710	3,749	1,757	1,754	1,247	1,278	642	652	64	65
Nebraska	1,039	1,087	452	463	311	324	200	213	76	87
North Dakota	433	444	203	207	119	122	92	95	19	21
South Dakota	428	444	219	222	109	127	85	79	15	16
South Atlantic	38,503	38,735	18,547	18,600	11,226	11,604	7,543	7,328	1,187	1,203
Delaware	637	631	274	277	189	188	167	159	7	7
District of Columbia	703	733	117	117	387	578	176	12	22	24
Florida	10,994	11,103	6,137	6,271	3,669	3,649	858	848	330	335
Georgia	5,983	5,907	2,640	2,527	1,873	1,918	1,379	1,368	91	94
Maryland	3,748	3,847	1,770	1,817	812	953	1,100	1,008	67	68
North Carolina	6,619	6,611	3,086	3,041	1,764	1,802	1,642	1,642	127	126
South Carolina	3,472	3,509	1,516	1,492	820	853	1,090	1,118	45	47
Virginia	5,072	5,095	2,459	2,507	1,395	1,339	729	755	489	493
West Virginia	1,276	1,300	547	551	317	323	404	417	8	9
East South Central	12,947	13,327	5,319	5,566	2,144	2,188	5,187	5,268	297	305
Alabama	3,687	3,707	1,544	1,550	780	800	1,324	1,315	38	41
Kentucky	2,943	3,091	1,096	1,125	519	534	1,198	1,299	130	134
Mississippi	2,147	2,215	940	964	498	512	653	684	55	55
Tennessee	4,169	4,314	1,738	1,928	346	342	2,012	1,970	73	75
West South Central	24,738	25,291	10,867	11,049	6,672	6,908	6,114	6,218	1,085	1,116
Arkansas	2,096	2,072	973	940	471	472	611	622	41	38
Louisiana	4,242	4,241	1,741	1,722	1,062	1,081	1,262	1,262	177	177
Oklahoma	2,415	2,402	1,136	1,134	672	677	484	477	124	115
Texas	15,984	16,576	7,017	7,254	4,467	4,678	3,757	3,858	743	786
Mountain	10,521	11,092	4,105	4,349	3,604	3,663	2,428	2,659	383	421
Arizona	3,645	3,747	1,611	1,694	1,288	1,301	638	636	107	117
Colorado	1,994	2,096	771	805	839	777	318	440	66	74
Idaho	749	796	312	317	219	246	203	216	14	17
Montana	564	594	208	213	154	160	181	196	21	25
Nevada	1,087	1,277	409	490	280	322	362	423	36	42
New Mexico	1,079	1,127	357	373	398	413	234	243	90	98
Utah	898	956	324	346	299	323	235	249	40	38
Wyoming	505	499	114	113	126	122	258	255	8	9
Pacific Contiguous	25,674	26,468	9,873	10,221	9,749	9,945	5,496	5,720	556	582
California	20,401	20,900	7,613	7,869	8,269	8,383	4,121	4,246	398	401
Oregon	1,974	2,070	838	877	601	629	499	523	35	41
Washington	3,298	3,499	1,422	1,476	879	932	876	951	122	140
Pacific Noncontiguous	1,366	1,421	485	509	473	505	378	377	30	29
Alaska	443	465	182	191	197	208	41	43	23	22
Hawaii	923	956	303	318	276	297	337	334	6	6
U. S. Total	198,220	202,702	82,814	84,548	61,521	63,393	47,357	48,071	6,528	6,689

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

Notes: •Data for 1994 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 7. Average Revenue per Kilowatthour for U.S. Electric Utilities by Sector, Census Division, and State, 1993 and 1994
(Cents)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other[1]	
	1993	1994	1993	1994	1993	1994	1993	1994	1993	1994
New England	**10.01**	**10.09**	**11.24**	**11.43**	**9.85**	**9.94**	**8.26**	**8.12**	**12.66**	**13.02**
Connecticut	10.26	10.18	11.39	11.47	10.04	9.99	8.29	7.90	14.08	14.00
Maine	9.10	9.63	11.43	12.32	9.45	10.16	6.96	7.18	13.22	14.63
Massachusetts	9.98	10.00	11.00	11.09	9.67	9.75	8.66	8.46	12.21	12.60
New Hampshire	10.85	11.32	12.31	12.91	11.01	10.91	9.04	9.32	13.30	13.36
Rhode Island	10.40	10.24	11.38	11.26	10.17	9.95	9.03	8.86	11.14	11.23
Vermont	9.04	9.13	9.84	9.96	9.31	9.42	7.50	7.50	13.50	14.88
Middle Atlantic	**9.50**	**9.57**	**11.34**	**11.51**	**10.15**	**10.17**	**6.58**	**6.53**	**9.65**	**9.79**
New Jersey	9.99	10.06	11.41	11.54	9.73	9.84	8.09	7.94	17.54	17.70
New York	10.72	10.92	13.17	13.55	11.66	11.67	6.66	6.78	9.14	9.31
Pennsylvania	7.92	7.87	9.55	9.55	8.29	8.28	6.04	5.93	11.56	11.43
East North Central	**6.50**	**6.41**	**8.34**	**8.37**	**7.39**	**7.32**	**4.56**	**4.45**	**7.04**	**6.79**
Illinois	7.75	7.41	10.28	9.98	8.00	7.68	5.45	5.18	7.03	6.47
Indiana	5.17	5.25	6.67	6.78	5.83	5.91	3.88	3.97	9.00	9.02
Michigan	7.14	7.09	8.16	8.28	8.02	7.93	5.34	5.25	9.15	10.54
Ohio	6.22	6.19	8.36	8.56	7.59	7.72	4.25	4.14	6.23	6.36
Wisconsin	5.52	5.46	7.03	7.08	5.95	5.87	3.98	3.89	6.98	7.00
West North Central	**6.04**	**6.01**	**7.27**	**7.32**	**6.31**	**6.26**	**4.44**	**4.40**	**6.45**	**6.49**
Iowa	5.97	5.92	8.02	8.09	6.36	6.32	3.92	3.88	5.85	5.96
Kansas	6.60	6.61	7.86	7.89	6.70	6.66	4.94	4.93	8.91	10.94
Minnesota	5.60	5.63	7.09	7.16	6.19	6.24	4.40	4.41	7.17	7.21
Missouri	6.33	6.28	7.26	7.29	6.26	6.20	4.71	4.62	7.10	7.07
Nebraska	5.54	5.49	6.25	6.31	5.68	5.58	4.04	3.99	6.99	6.54
North Dakota	5.83	5.77	6.31	6.37	6.48	6.45	4.85	4.71	3.99	3.82
South Dakota	6.20	6.19	7.04	7.06	6.75	6.60	4.60	4.51	4.55	4.62
South Atlantic	**6.61**	**6.54**	**7.84**	**7.82**	**6.70**	**6.56**	**4.72**	**4.61**	**6.41**	**6.41**
Delaware	6.98	6.78	9.01	8.91	7.25	7.00	4.88	4.62	11.78	11.17
District of Columbia	6.78	7.12	7.18	7.47	7.15	7.15	5.91	4.63	6.47	6.72
Florida	7.20	6.96	7.99	7.78	6.69	6.35	5.26	5.13	6.96	6.72
Georgia	6.71	6.57	7.79	7.72	7.44	7.33	4.74	4.57	8.50	8.71
Maryland	6.96	7.03	8.21	8.39	7.17	7.19	5.45	5.30	8.28	8.58
North Carolina	6.63	6.62	8.18	8.17	6.59	6.56	4.90	4.93	7.07	6.91
South Carolina	5.64	5.67	7.33	7.49	6.22	6.37	4.06	4.03	5.67	5.84
Virginia	6.23	6.20	7.57	7.75	6.14	5.84	4.19	4.16	5.56	5.63
West Virginia	5.22	5.25	6.30	6.36	5.78	5.83	3.96	3.98	9.22	9.44
East South Central	**5.22**	**5.14**	**6.24**	**6.25**	**6.51**	**6.40**	**4.16**	**4.03**	**5.95**	**5.95**
Alabama	5.67	5.48	6.82	6.69	6.93	6.76	4.34	4.12	5.89	6.28
Kentucky	4.32	4.26	5.70	5.77	5.29	5.29	3.30	3.24	4.68	4.67
Mississippi	6.18	6.05	7.12	7.06	7.45	7.22	4.59	4.48	8.70	8.60
Tennessee	5.22	5.23	5.76	5.88	6.68	6.63	4.62	4.52	7.91	7.74
West South Central	**6.34**	**6.29**	**7.89**	**7.88**	**6.93**	**6.94**	**4.38**	**4.27**	**6.65**	**6.59**
Arkansas	6.62	6.35	8.27	8.07	7.04	6.88	4.85	4.60	6.93	6.46
Louisiana	6.26	6.05	7.76	7.61	7.38	7.20	4.44	4.22	7.11	6.81
Oklahoma	5.96	5.84	7.14	7.03	6.21	6.09	4.14	4.07	5.87	5.29
Texas	6.39	6.42	8.00	8.08	6.94	7.04	4.32	4.27	6.68	6.79
Mountain	**6.15**	**6.15**	**7.60**	**7.66**	**6.70**	**6.68**	**4.29**	**4.34**	**5.68**	**5.62**
Arizona	8.21	7.93	9.65	9.30	8.70	8.32	5.80	5.63	5.64	5.47
Colorado	6.05	6.07	7.24	7.36	5.82	6.00	4.52	4.58	7.72	7.43
Idaho	4.00	4.00	4.99	5.09	4.42	4.37	2.81	2.82	4.99	4.64
Montana	4.36	4.51	5.77	5.96	5.10	5.17	3.10	3.30	4.51	4.49
Nevada	5.87	6.37	6.51	7.16	6.51	6.97	5.04	5.45	4.87	5.19
New Mexico	7.23	7.11	9.18	9.13	8.37	8.30	4.86	4.70	6.13	6.05
Utah	5.33	5.36	6.85	6.91	5.96	5.87	3.78	3.83	4.49	4.51
Wyoming	4.25	4.26	5.96	6.04	5.04	5.02	3.50	3.51	6.62	6.45
Pacific Contiguous	**7.43**	**7.65**	**8.59**	**8.89**	**8.80**	**9.10**	**5.10**	**5.25**	**4.63**	**4.67**
California	9.69	9.78	11.30	11.43	10.46	10.90	7.33	7.09	5.05	5.00
Oregon	4.43	4.60	5.02	5.33	4.93	4.97	3.33	3.47	5.33	5.27
Washington	3.65	4.02	4.60	4.97	4.50	4.72	2.40	2.79	3.53	3.83
Pacific Noncontiguous	**10.48**	**10.54**	**11.83**	**12.00**	**10.69**	**10.75**	**8.86**	**8.76**	**12.41**	**12.24**
Alaska	10.12	10.25	11.15	11.32	9.55	9.66	8.19	8.37	12.77	12.57
Hawaii	10.66	10.68	12.28	12.45	11.68	11.67	8.95	8.82	11.26	11.21
U. S. Average	**6.93**	**6.91**	**8.32**	**8.38**	**7.74**	**7.73**	**4.85**	**4.77**	**6.88**	**6.84**

[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 1994 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, Composite Financial Indicators, and Revenue and Expense Statistics. Historical data are provided for a 5-year period on major U.S. investor-owned and U.S. publicly owned electric utilities. Statistics on the average operating expenses for all plants owned by major U.S. investor-owned electric utilities are also provided.

Background

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

A component of any economic regulatory activity is the determination of financing and accounting rules. As a consequence of regulatory jurisdiction, regulations for financing and accounting are more critical to the electric power industry than to most other non-regulated 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 (which 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.

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 1994. 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 that exists between the assets and the 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 stockholders' investment. The financial soundness of an industry is directly related to the ability of the industry to raise capital and to provide a reasonable return on the capital invested. 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) that 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 widely used ratio 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. *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. Five ratios are calculated from the balance sheet. 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.

Because a number of initiatives are being considered to promote increased competition in the electric power industry, three new operating ratios that measure specific costs associated with the sale of each kilowatthour of electricity were added to this, and the prior, issue of this report. *Purchase Power Cents Per Kilowatthour* is the ratio of the cost of purchased power to the number of kilowatthours purchased. This ratio measures the purchased power component of power supply cost. *Generated Cents Per Kilowatthour* is the ratio of the cost of labor, materials used and expenses incurred in the production of electric generation. This ratio measures the generation component of production expenses. *Total Power Supply Per Kilowatthour Sold* is the ratio of the total cost of power supply to total sales to both ultimate and resale consumers. This ratio measures all power supply costs, including generation and purchase power, associated with the sale of each kilowatthour of electricity.

Revenue and Expense Statistics

Summary revenue and expense statistics are basic to any analysis of the operating soundness of an electric utility. 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

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

Operating expenses include recurring expenses to operate and maintain the physical condition or operating efficiency of the plant. These expenses include wages and benefits of the operators, plant maintenance, security, supervision, materials (such as spare parts), and supplies (except fuel consumed during plant operation and maintenance). 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 sources of total electricity generation, accounting for about 80 percent of total utility generation in the United States in 1994. Publicly owned electric utilities were responsible for 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 1990 through 1994 are provided grouped into 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). Detailed financial statistics on investor-owned electric utilities are published in the *Financial Statistics of Major U.S. Investor-Owned Electric Utilities.*[16]

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 either of the following:

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

Approximately 500 publicly owned electric utilities are required to submit the Form EIA-412. These major publicly owned electric utilities represent about one-fourth of all publicly owned electric utilities and more than 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. 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.*[17]

[16] Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities,* DOE/EIA-0437(94)/1 (Washington, DC); data for 1992 and 1993 are published in the *Financial Statistics of Major U.S. Investor-Owned Electric Utilities,* DOE/EIA-0431/1; data for 1991 are published in the *Financial Statistics of Major Investor-Owned Electric Utilities,* DOE/EIA-0437(91)/1; and data for 1990 are published in the *Financial Statistics of Selected Investor-Owned Electric Utilities*, DOE/EIA-0437(90)/1.

[17] Energy Information Administration (EIA), *Financial Statistics of Major U.S. Publicly Owned Electric Utilities,* DOE/EIA-0437(94)/2; data for 1992 and 1993 are published in the *Financial Statistics of Major U.S. Publicly Owned Electric Utilities,* DOE/EIA-0437/2; data for 1991 are published in the *Financial Statistics of Major Publicly Owned Electric Utilities,* DOE/EIA-0437(91)/2; and data for 1990 are published in the *Financial Statistics of Selected Publicly Owned Electric Utilities,* DOE/EIA-0437(90)/2.

Table 8. Composite Statement of Income for Major U.S. Investor-Owned Electric Utilities, 1990 Through 1994
(Thousand Dollars)

Description	1990	1991[1]	1992	1993	1994
Operating Revenue	172,999,954	182,450,728	185,493,458	193,637,843	196,281,500
Electric	157,278,537	166,803,843	169,488,035	176,354,365	179,307,260
Gas	14,611,056	14,560,221	14,937,370	16,686,912	16,221,506
Other Utility	1,110,362	1,086,663	1,068,053	596,567	752,734
Operating Expenses	142,471,369	150,361,969	153,682,429	161,908,147	164,207,153
Electric	127,900,634	135,947,991	139,009,093	146,118,013	148,662,734
Fuel	32,634,846	31,312,220	30,254,398	31,214,057	30,107,888
Other Operating and Maintenance	60,231,131	66,645,950	69,212,541	72,561,087	75,021,900
Depreciation[2]	14,888,584	16,127,176	17,091,753	18,098,736	18,679,022
Taxes Other Than Income Taxes	11,433,264	12,270,379	12,760,152	13,040,400	13,275,354
Income Taxes	7,146,859	7,690,521	7,197,682	8,296,900	9,625,569
Deferred Income Tax	1,855,377	2,294,676	3,017,335	2,993,143	1,831,593
Investment Tax Credit (Net)	-289,428	-392,931	-524,768	-515,791	-584,701
Gas	13,523,155	13,406,370	13,691,253	15,234,557	14,877,836
Income Taxes	428,107	308,656	279,618	251,533	465,076
Other	13,095,048	13,097,714	13,411,635	14,983,024	14,412,760
Other Utility	1,047,580	1,007,609	982,083	555,577	666,584
Income Taxes	7,805	3,530	26,956	10,763	14,963
Other	1,039,775	1,004,079	955,127	544,814	651,621
Operating Income	30,528,585	32,088,758	31,811,029	31,729,696	32,074,346
Electric	29,377,903	30,855,852	30,478,942	30,236,352	30,644,526
Gas	1,087,901	1,153,852	1,246,117	1,452,354	1,343,670
Other	62,782	79,055	85,970	40,990	86,150
Other Income and Deductions	1,830,496	523,325	1,689,045	1,346,398	1,809,553
Allowance for Other Funds Used During Construction	1,080,217	706,102	611,514	591,445	402,569
Less Taxes	389,448	852,579	379,461	1,119,581	477,529
Deferred Earnings (Misc.) (acct 421)	1,477,520	1,271,525	1,341,354	677,360	802,120
Less Other Income and Expenses[3]	337,793	601,723	-115,638	-1,197,174	-1,082,393
Total Income Before Interest Charges	32,359,081	32,612,083	33,500,074	33,076,094	33,883,899
Net Interest Charges	15,735,630	15,736,248	15,223,174	14,700,488	14,161,602
Interest Expense	16,186,426	16,010,348	15,307,441	14,566,753	13,915,384
Less Allowance for Borrowed Funds Used During Construction	814,229	635,525	558,348	555,021	420,828
Other Charges--Net	363,433	361,424	474,080	688,756	667,046
Net Income Before Extraordinary Charges	16,623,451	16,875,836	18,276,900	18,375,606	19,722,298
***Less* Extraordinary Items After Taxes[3]**	-273,715	-73,829	-107,544	484,409	-165,288
Net Income	16,897,166	16,949,664	18,384,444	17,891,198	19,887,586
Preferred Stock Dividend Requirements	2,025,157	1,945,213	2,039,449	1,765,286	1,581,940
Earnings Available for Common Stocks	14,872,009	15,004,451	16,344,995	16,125,912	18,305,646
Common Stocks Dividends	14,189,677	14,427,570	14,897,608	15,334,377	15,875,659
Additions to Retained Earnings	424,940	254,189	2,184,266	296,171	2,063,432
Average Shares of Common Stock Outstanding	5,950,933	5,932,492	6,261,284	6,129,888	6,223,816
Earnings Available Per Average Common Share (Dollars)	2.50	2.53	2.61	2.63	2.94

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

[2] Includes amortization and depletion.

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

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

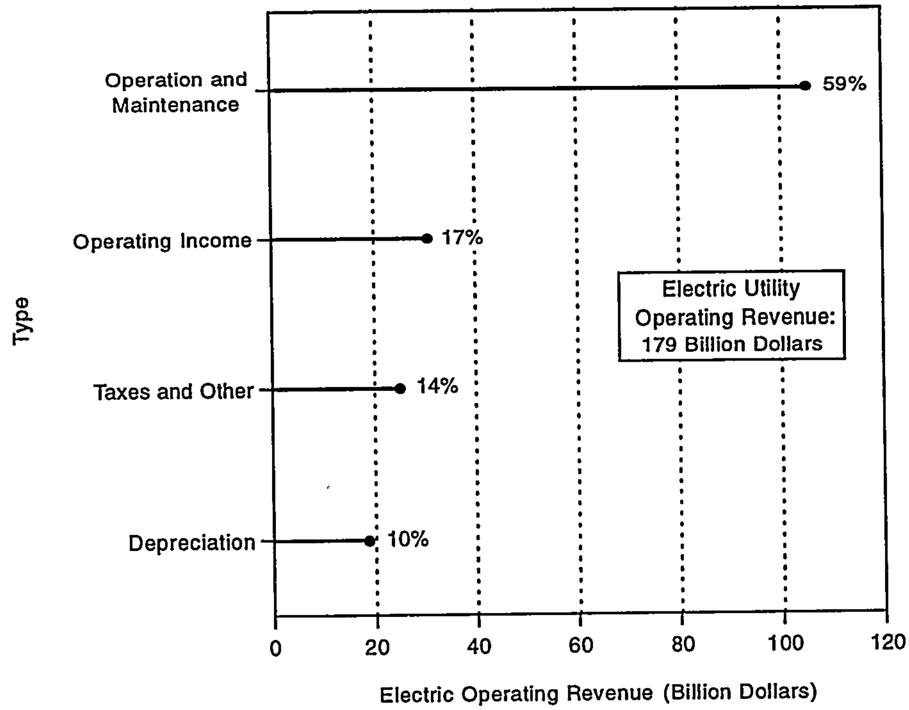
Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." See Appendix A for a detailed description of this restricted-universe census.

Table 9. Composite Balance Sheet for Major U.S. Investor-Owned Electric Utilities, 1990 Through 1994
(Thousand Dollars)

Description	1990	1991[1]	1992	1993	1994
Assets					
Utility Plant - Net	371,310,063	376,771,703	386,864,738	393,829,243	397,812,254
Electric Utility Plant - Net	344,912,770	349,611,025	358,300,259	363,829,459	366,936,417
Electric Utility Plant	458,081,342	479,822,229	498,118,599	519,207,367	535,928,383
Construction Work in Progress	22,558,726	18,077,211	20,648,234	18,048,849	17,148,353
Less Accumulated Depreciation	135,727,298	148,288,414	160,466,573	173,426,756	186,140,318
Nuclear Fuel - Net	7,812,038	6,911,645	6,836,719	5,964,178	5,656,878
Other Utility Plant - Net	18,585,255	20,249,033	21,727,759	24,035,606	25,218,959
Other Property and Investments	17,703,929	17,385,415	18,045,977	20,063,695	23,479,360
Current and Accrued Assets	41,534,662	43,357,785	43,447,871	42,409,989	41,262,977
Deferred Debits	47,322,374	50,024,920	57,993,875	[2] 110,338,355	111,957,082
Total Assets	477,871,029	487,539,823	506,352,461	566,641,282	574,511,673
Capitalization and Liabilities					
Capitalization	340,983,205	348,828,405	356,026,762	360,455,273	364,724,736
Common Stock Equity (End of Year)	147,424,082	151,671,304	156,346,650	160,296,897	164,482,824
Common Stock	96,502,507	99,723,170	103,963,697	107,470,838	109,522,096
Retained Earnings (Adjusted)	50,921,575	51,948,134	52,382,953	52,826,059	54,960,728
Preferred Stock	25,621,039	25,262,285	25,539,216	25,304,294	24,859,833
Long-term Debt	167,938,084	171,894,816	174,140,896	174,854,082	175,382,079
Current and Other Liabilities	136,887,824	138,711,418	150,325,698	206,186,010	209,786,937
Other Noncurrent Liabilities	7,224,872	6,931,193	8,627,882	11,478,303	13,452,636
Current and Accrued Liabilities	44,283,442	43,357,436	45,557,601	48,878,976	48,035,058
Deferred Credits	85,379,510	88,422,789	96,140,215	145,828,731	148,299,243
Accumulated Deferred Income Taxes	56,529,757	59,188,298	65,020,984	104,964,188	107,054,667
Accumulated Deferred Investment Tax Credit	15,290,316	14,689,786	14,046,840	13,428,995	12,784,415
Other Deferred Credits (Adjusted)	13,559,436	14,544,705	17,072,392	27,435,549	28,460,160
Total Capitalization and Liabilities	477,871,029	487,539,823	506,352,461	566,641,282	574,511,673

[1] Due to its emergence from bankruptcy, the 1991 financial statements for the Public Service Company of New Hampshire are from May 16 through December 31.
[2] In 1993, Other Regulatory Assets (a new line item) was added to the Balance Sheet and accounts for the large increase in Deferred Debits from 1992.
Notes: •Data are final. •Totals may not equal sum of components because of independent rounding.
Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." See Appendix A for a detailed description of this restricted-universe census.

Figure 11. Allocation of the Revenue Dollar from Electric Operations for Major U.S. Investor - Owned Electric Utilities, 1994



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 A for a detailed description of this restricted-universe census.

Table 10. Composite Financial Indicators for Major U.S. Investor-Owned Electric Utilities, 1990 Through 1994

Description[1]	1990	1991[2]	1992	1993	1994
Activity					
1. Electric Fixed Asset (Net Plant) Turnover	0.46	0.48	0.47	0.48	0.49
2. Total Asset Turnover	.36	.37	.37	.34	.34
Leverage					
3. Current Assets to Current Liabilities	.94	1.00	.95	.87	.86
4. Long-term Debt to Capitalization	49.25	49.28	48.91	48.51	48.09
5. Preferred Stock to Capitalization	7.51	7.24	7.17	7.02	6.82
6. Common Stock Equity to Capitalization	43.24	43.48	43.91	44.47	45.10
7. Total Debt to Total Assets[3]	36.79	36.69	36.13	32.48	32.35
8. Common Stock Equity to Total Assets	30.85	31.11	30.88	28.29	28.63
9. Interest Coverage Before Taxes without AFUDC	2.38	2.49	2.62	2.78	3.10
Profitability					
10. Profit Margin	9.77	9.29	9.91	9.24	10.13
11. Return on Average Common Stock Equity[4]	11.55	11.33	11.94	11.30	12.24
12. Return on Investment	3.54	3.48	3.63	3.16	3.46

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

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

[3] Total debt is the sum of Long-term Debt and Short-term Debt. The values for Short-term Debt included in Current and Accrued Liabilities (Notes Payable) were $10,448,573 for 1994; $9,210,845 for 1993; $8,791,477 for 1992; $6,986,960 for 1991; and $7,874,293 for 1990.

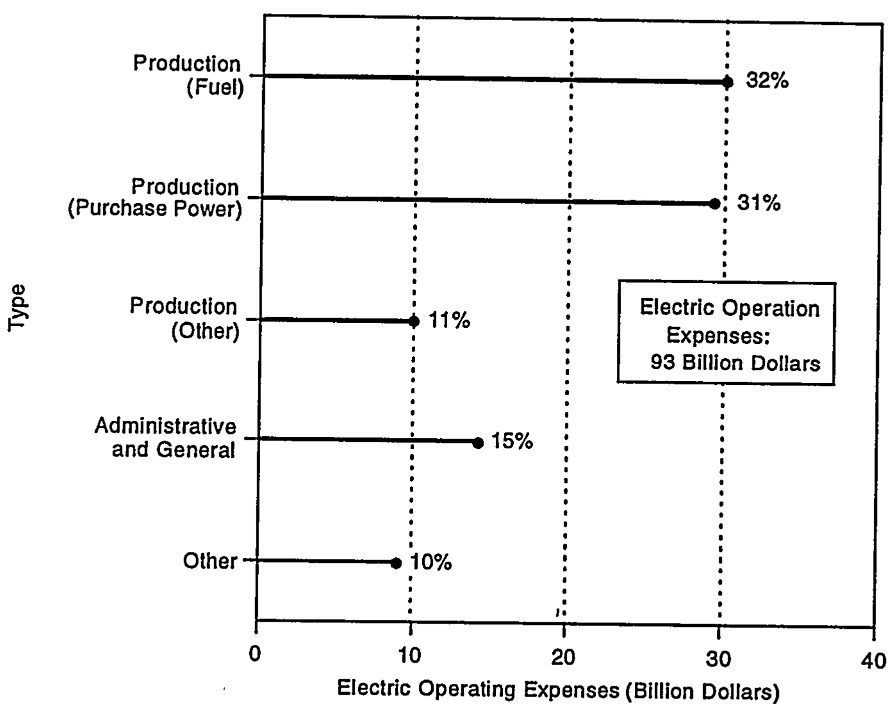
[4] The Average Common Stock Equity is the average of the beginning and ending year balances. The value for the beginning of 1990 was $145,175,878.

AFUDC=Allowance for Funds Used During Construction.

Notes: •Data are final. •Formulas for computing the financial indicators are in Appendix A. •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 A for a detailed description of this restricted-universe census.

Figure 12. Electric Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 1994



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

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

Table 11. Revenue and Expense Statistics for Major U.S. Investor-Owned Electric Utilities, 1990 Through 1994

(Thousand Dollars)

Description	1990	1991[1]	1992	1993	1994
Utility Operating Revenue	172,999,954	182,450,728	185,493,458	193,637,843	196,281,500
Electric Utility	157,278,537	166,803,843	169,488,035	176,354,365	179,307,260
Other Utility	15,721,418	15,646,884	16,005,423	17,283,479	16,974,240
Utility Operating Expenses	142,471,369	150,361,969	153,682,429	161,908,147	164,207,153
Electric Utility	127,900,634	135,947,991	139,009,093	146,118,013	148,662,734
Operation	81,086,488	85,933,743	87,272,134	91,328,230	93,107,998
Production	62,501,048	66,101,528	66,979,805	68,780,803	69,268,652
Cost of Fuel	32,634,846	31,312,220	30,254,398	31,214,057	30,107,888
Purchased Power	20,340,504	24,169,252	26,212,238	27,715,512	29,213,084
Other	9,525,698	10,620,056	10,513,169	9,851,234	9,947,680
Transmission	1,130,272	1,247,286	1,308,101	1,354,058	1,361,080
Distribution	2,443,859	2,530,490	2,498,514	2,595,023	2,581,409
Customer Accounts	3,247,245	3,203,212	3,347,124	3,418,487	3,546,489
Customer Service	1,180,636	1,451,507	1,531,369	1,852,267	1,955,991
Sales	212,233	203,230	198,647	203,291	231,589
Administrative and General	10,371,195	11,196,490	11,408,575	13,124,300	14,162,788
Maintenance	11,779,489	12,024,427	12,194,805	12,446,914	12,021,790
Depreciation	14,888,584	16,127,176	17,091,753	18,098,736	18,679,022
Taxes and Other	20,146,073	21,862,645	22,450,401	24,244,133	24,853,924
Other Utility	14,570,735	14,413,979	14,673,336	15,790,134	15,544,420
Income From Utility Operations	30,528,585	32,088,758	31,811,029	31,729,696	32,074,346

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

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

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

Table 12. Revenue and Expense Percentages for Major U.S. Investor-Owned Electric Utilities, 1990 Through 1994

Description	1990	1991[1]	1992	1993	1994
Utility Operating Revenue	100.0	100.0	100.0	100.0	100.0
Electric Utility	90.9	91.4	91.4	91.1	91.4
Other Utility	9.1	8.6	8.6	8.9	8.6
Utility Operating Expenses	82.4	82.4	82.9	83.6	83.7
Electric Utility	73.9	74.5	74.9	75.5	75.7
Operation	46.9	47.1	47.0	47.2	47.4
Production	36.1	36.2	36.1	35.5	35.3
Cost of Fuel	18.9	17.2	16.3	16.1	15.3
Purchased Power	11.8	13.2	14.1	14.3	14.9
Other	5.5	5.8	5.7	5.1	5.1
Transmission	.7	.7	.7	.7	.7
Distribution	1.4	1.4	1.3	1.3	1.3
Customer Accounts	1.9	1.8	1.8	1.8	1.8
Customer Service	.7	.8	.8	1.0	1.0
Sales	.1	.1	.1	.1	.1
Administrative and General	6.0	6.1	6.2	6.8	7.2
Maintenance	6.8	6.6	6.6	6.4	6.1
Depreciation	8.6	8.8	9.2	9.3	9.5
Taxes and Other	11.6	12.0	12.1	12.5	12.7
Other Utility	8.4	7.9	7.9	8.2	7.9
Income From Utility Operations	17.6	17.6	17.1	16.4	16.3

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

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

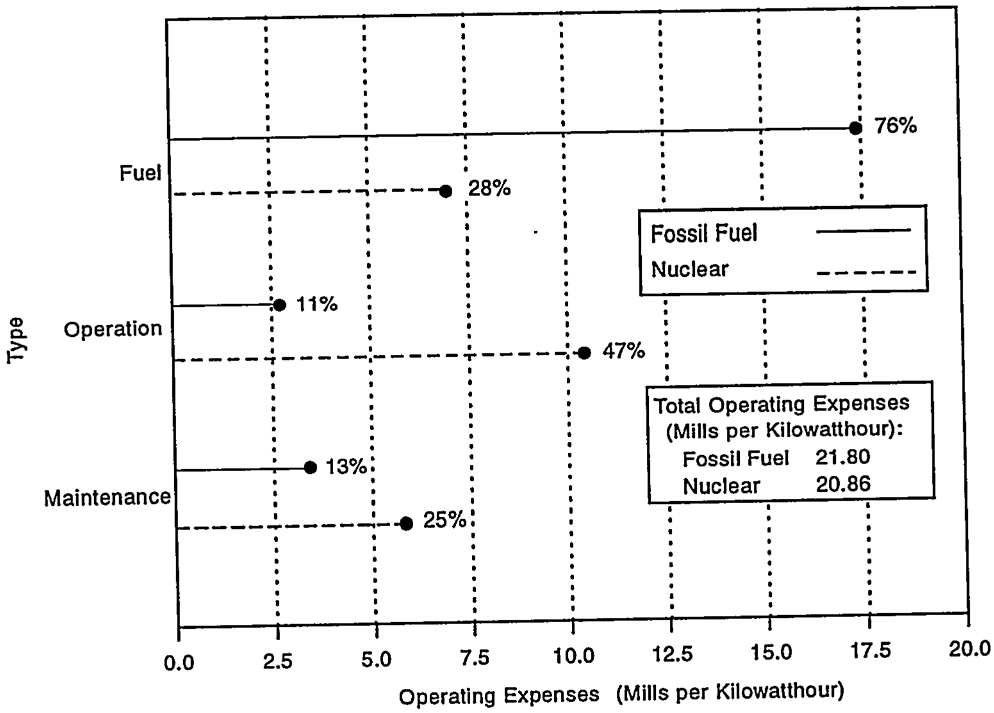
Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." See Appendix A for a detailed description of this restricted-universe census.

Table 13. Average Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 1990 Through 1994
(Mills per Kilowatthour)

Plant Type	1990	1991[1]	1992	1993	1994
			Operation		
Nuclear	10.04	10.49	10.43	10.20	9.79
Fossil Steam	2.21	2.29	2.38	2.37	2.32
Hydroelectric[2]	3.35	3.88	4.33	3.82	4.53
Gas Turbine and Small Scale[3]	8.76	9.61	10.18	6.47	4.58
			Maintenance		
Nuclear	5.68	5.50	5.93	5.73	5.20
Fossil Steam	2.97	2.98	2.95	2.96	2.82
Hydroelectric[2]	2.58	2.89	3.30	2.65	2.90
Gas Turbine and Small Scale[3]	12.23	12.93	12.15	7.52	5.39
			Fuel		
Nuclear	7.18	6.71	6.12	5.88	5.87
Fossil Steam	18.55	17.91	17.49	17.65	16.67
Hydroelectric[2]	—	—	—	—	—
Gas Turbine and Small Scale[3]	32.57	30.96	28.59	26.39	22.19
			Total[4]		
Nuclear	22.91	22.70	22.48	21.80	20.86
Fossil Steam	23.72	23.17	22.83	22.97	21.80
Hydroelectric[2]	5.93	6.76	7.63	6.47	7.43
Gas Turbine and Small Scale[3]	53.56	53.51	50.92	40.38	32.16

[1] Due to its emergence from bankruptcy, the 1991 financial statements for the Public Service Company of New Hampshire are from May 16 through December 31.
[2] Includes Pumped Storage.
[3] Includes gas turbine, internal combustion, photovoltaic, and wind plants.
[4] Totals may not equal sum of components because of independent rounding.
Notes: •Data are final. •Expenses are average expenses weighted by net generation. •A mill is a monetary cost and billing unit equal to 1/1000 of the U.S. dollar (equivalent to 1/10 of 1 cent).
Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." See Appendix A for a detailed description of this restricted-universe census.

Figure 13. Average Operating Expenses of Fossil - Fueled and Nuclear Steam - Electric Plants for Major U.S. Investor - Owned Electric Utilities, 1994



Notes: •Data are final. •Totals may not equal sum of components because of independent rounding.
Source: Federal Energy Regulatory Commission, FERC Form1, "Annual Report of Major Electric Utilities, Licensees and Others." See Appendix A for a detailed description of this restricted-universe census.

Table 14. Composite Statement of Income for Major U.S. Publicly Owned Generator Electric Utilities, 1990 Through 1994
(Thousand Dollars)

Description	1990	1991	1992	1993	1994
Operating Revenue - Electric	20,470,371	21,082,870	21,686,349	22,521,847	23,266,686
Operating Expenses - Electric	16,460,700	16,886,921	17,190,647	18,162,164	18,648,687
Operation Excluding Fuel	9,198,194	9,082,917	9,408,002	9,803,647	10,191,897
Fuel	2,749,890	3,072,158	3,119,433	3,437,920	3,385,718
Maintenance	1,455,786	1,446,295	1,564,792	1,565,293	1,584,444
Depreciation and Amortization[1]	2,075,595	2,300,532	2,417,279	2,596,099	2,720,560
Taxes and Tax Equivalents	550,042	595,719	681,140	759,205	766,068
Net Contributions and Services	431,193	389,300	—	—	—
Operating Income - Electric	4,009,671	4,195,949	4,495,703	4,359,683	4,617,999
Other Income and Deductions	1,869,720	1,843,761	1,628,944	1,219,709	1,098,922
Income from Electric Plant Leased to Others	11,330	5,942	15,129	23,576	30,242
Allowance for Funds Used During Construction	123,282	71,025	24,183	28,476	7,872
Other Income Net	1,735,107	1,890,138	1,839,484	1,455,984	1,237,067
Less Other Electric Deductions	—	123,345	249,852	288,325	176,259
Total Income Before Interest Charges	5,879,390	6,039,710	6,124,646	5,579,392	5,716,920
Net Interest Charges	5,064,936	5,205,799	5,025,758	4,682,023	4,681,141
Interest Expenses	4,663,114	4,775,003	4,757,583	4,433,067	4,332,296
Other Income Deductions	401,822	430,796	268,175	248,956	348,845
Net Income Before Extraordinary Charges	814,455	833,911	1,098,889	897,369	1,035,779
Less **Extraordinary Items**	108,958	65,544	115,275	214,227	124,211
Net Income	705,497	768,367	983,613	683,142	911,568

[1] Nuclear fuel included in 1992, 1993, and 1994 data.

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 227 for 1994, 222 for 1993, 225 for 1992, 218 for 1991, and 216 for 1990.

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

Table 15. Composite Balance Sheet for Major U.S. Publicly Owned Generator Electric Utilities, 1990 Through 1994
(Thousand Dollars)

Description	1990	1991	1992	1993	1994
Assets					
Electric Utility Plant-Net Inc Nuclear Fuel	59,596,453	60,737,416	61,710,753	62,477,584	63,576,104
Electric Utility Plant Inc Nuclear Fuel	78,244,146	81,535,543	85,359,878	88,353,146	92,044,086
Accumulated Provision for Depreciation and Amortization	18,647,693	20,798,127	23,649,125	25,875,562	28,467,982
Other Property and Investments	15,801,311	17,332,581	18,228,937	20,487,402	20,973,996
Current and Accrued Assets	13,867,162	14,084,691	14,990,707	15,357,112	15,782,291
Deferred Debits	9,926,695	10,890,161	12,017,041	13,987,324	13,913,754
Total Assets	99,191,621	103,044,849	106,947,439	112,309,422	114,246,146
Liabilities and Other Credits					
Investment of Municipality - Surplus	21,681,128	22,222,042	22,823,226	23,527,598	24,518,851
Long-Term Debt	66,510,223	68,871,516	72,004,391	76,168,783	76,815,309
Other Noncurrent Liabilities	435,670	622,507	698,351	590,789	701,406
Current and Accrued Liabilities	7,283,479	7,844,671	8,080,777	8,594,053	8,913,155
Deferred Credits	3,281,121	3,484,113	3,340,694	3,428,200	3,297,425
Total Liabilities and Other Credits	99,191,621	103,044,849	106,947,439	112,309,422	114,246,146

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 227 for 1994, 222 for 1993, 225 for 1992, 218 for 1991, and 216 for 1990.

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

Table 16. Composite Financial Indicators for Major U.S. Publicly Owned Generator Electric Utilities, 1990 Through 1994

Description	1990	1991	1992	1993	1994
Electric Utility Plant per Dollar of Revenue	3.8	3.9	3.9	3.9	4.0
Current Assets to Current Liabilities	1.9	1.8	1.9	1.8	1.8
Electric Utility Plant as a Percent of Total Assets	78.9	79.1	79.8	78.7	80.6
Net Electric Utility Plant as a Percent of Total Assets	60.1	58.9	57.7	55.6	55.6
Debt as a Percent of Total Liabilities	74.4	74.4	74.9	75.5	75.0
Accumulated Provision for Depreciation as a Percent of Electric Utility Plant	23.8	25.5	27.7	29.3	30.9
Electric Operation and Maintenance Expenses as a Percent of Electric Operating Revenues	65.5	64.5	65.0	65.7	65.2
Electric Depreciation and Amortization as a Percent of Electric Operating Revenues	10.1	10.9	10.5	10.8	11.1
Taxes and Tax Equivalents as a Percent of Electric Operating Revenues	2.7	2.8	3.1	3.4	3.3
Interest Expenses as a Percent of Electric Operating Revenues	22.8	22.6	21.9	19.7	18.6
Net Income as a Percent of Electric Operating Revenues	3.4	3.6	4.5	3.0	3.9
Purchase Power Cents Per Kilowatthour	3.8	3.8	3.7	3.6	3.6
Generated Cents Per Kilowatthour	1.8	1.8	1.9	1.9	1.9
Total Power Supply Per Kilowatthour Sold	2.6	2.6	2.6	2.6	2.6

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The number of publicly owned generating electric utilities that reported were 227 for 1994, 222 for 1993, 225 for 1992, 218 for 1991, and 216 for 1990.
Source: Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities."

Table 17. Revenue and Expense Statistics for Major U.S. Publicly Owned Generator Electric Utilities, 1990 Through 1994
(Thousand Dollars)

Description	1990	1991	1992	1993	1994
Operating Revenue - Electric	20,470,371	21,082,870	21,686,349	22,521,847	23,266,686
Operating Expenses - Electric	16,460,700	16,886,921	17,190,647	18,162,164	18,648,687
Operation Including Fuel	11,948,084	12,155,075	12,527,435	13,241,567	13,577,615
Production	9,525,315	9,465,070	9,712,324	10,254,301	10,444,534
Transmission	471,887	508,711	534,512	579,635	609,612
Distribution	328,897	362,654	388,703	408,335	429,535
Customer Accounts	272,849	289,398	299,209	314,992	316,794
Customer Service	60,411	73,901	82,731	94,089	104,101
Sales	18,043	18,077	17,545	17,210	22,436
Administrative and General	1,270,683	1,437,265	1,492,411	1,573,005	1,650,603
Maintenance	1,455,786	1,446,295	1,564,792	1,565,293	1,584,444
Depreciation and Amortization Excluding Nuclear Fuel	2,075,595	2,300,532	2,285,807	2,441,927	2,591,423
Taxes and Tax Equivalents	550,042	595,719	681,140	759,205	766,068
Net Contributions and Services	431,193	389,300	—	—	—
Income from Electric Utility Operations	4,009,671	4,195,949	4,495,703	4,359,683	4,617,999

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 227 for 1994, 222 for 1993, 225 for 1992, 218 for 1991, and 216 for 1990.
Source: Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities."

Table 18. Composite Statement of Income for Major U.S. Publicly Owned Nongenerator Electric Utilities, 1990 Through 1994
(Thousand Dollars)

Description	1990	1991	1992	1993	1994
Operating Revenue - Electric	6,978,752	7,119,875	7,247,407	7,523,453	7,995,632
Operating Expenses - Electric	6,740,926	6,859,619	6,843,539	7,063,260	7,566,745
Operation Excluding Fuel	6,030,028	6,119,381	6,244,812	6,424,783	6,857,958
Fuel	*	4	19	15	13
Maintenance	191,621	186,267	192,635	207,046	233,967
Depreciation and Amortization[1]	231,197	246,594	251,079	256,736	273,770
Taxes and Tax Equivalents	133,125	138,491	154,994	174,681	201,038
Net Contributions and Services	154,956	168,882	—	—	—
Operating Income - Electric	237,826	260,255	403,868	460,193	428,887
Other Income and Deductions	156,148	138,039	74,486	98,822	97,664
Income from Electric Plant Leased to Others	2,121	3,264	1,773	2,405	2,185
Allowance for Funds Used During Construction	-213	1,606	39	106	51
Other Income Net	154,240	147,117	172,938	172,569	178,515
Less Other Electric Deductions	—	13,949	100,264	76,258	83,086
Total Income Before Interest Charges	393,975	398,294	478,354	559,015	526,551
Net Interest Charges	137,311	139,806	140,861	172,792	156,433
Interest Expenses	109,972	112,031	109,378	114,527	108,647
Other Income Deductions	27,340	27,775	31,483	58,264	47,786
Net Income Before Extraordinary Charges	256,663	258,488	337,493	386,223	370,118
Less **Extraordinary Items**	11,315	9,252	2,156	25,600	3,821
Net Income	245,348	249,236	335,338	360,624	366,297

[1] Nuclear fuel included in 1992, 1993, and 1994 data.

* =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 275 for 1994, 273 for 1993, 258 for 1992, 252 for 1991, and 251 for 1990.

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

Table 19. Composite Balance Sheet for Major U.S. Publicly Owned Nongenerator Electric Utilities, 1990 Through 1994
(Thousand Dollars)

Description	1990	1991	1992	1993	1994
Assets					
Electric Utility Plant-Net Inc Nuclear Fuel	4,407,579	4,662,421	4,881,003	5,268,229	5,496,059
Electric Utility Plant Inc Nuclear Fuel	6,861,881	7,318,688	7,733,037	8,317,096	8,759,850
Accumulated Provision for Depreciation and Amortization	2,454,302	2,656,267	2,852,034	3,048,867	3,263,791
Other Property and Investments	1,770,583	1,849,607	1,890,451	1,911,724	1,904,194
Current and Accrued Assets	2,063,931	2,162,131	2,227,084	2,495,760	2,497,816
Deferred Debits	271,452	324,440	386,263	423,907	400,447
Total Assets	8,513,545	8,998,600	9,384,801	10,099,620	10,298,517
Liabilities and Other Credits					
Investment of Municipality - Surplus	4,994,123	5,244,951	5,522,242	5,983,376	6,281,647
Long-Term Debt	2,348,676	2,542,435	2,713,721	2,898,817	2,723,507
Other Noncurrent Liabilities	38,157	55,488	10,284	10,749	11,414
Current and Accrued Liabilities	949,345	968,924	982,587	1,039,867	1,098,941
Deferred Credits	183,244	186,803	154,689	166,812	183,009
Total Liabilities and Other Credits	8,513,545	8,998,600	9,384,801	10,099,620	10,298,517

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 275 for 1994, 273 for 1993, 258 for 1992, 252 for 1991, and 251 for 1990.

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

Table 20. Composite Financial Indicators for Major U.S. Publicly Owned Nongenerator Electric Utilities, 1990 Through 1994

Description	1990	1991	1992	1993	1994
Electric Utility Plant per Dollar of Revenue	1.0	1.0	1.1	1.1	1.1
Current Assets to Current Liabilities	2.2	2.2	2.3	2.4	2.3
Electric Utility Plant as a Percent of Total Assets	80.6	81.3	82.4	82.4	85.1
Net Electric Utility Plant as a Percent of Total Assets	51.8	51.8	52.0	52.2	53.4
Debt as a Percent of Total Liabilities	38.7	39.0	39.4	39.0	37.1
Accumulated Provision for Depreciation as a Percent of Electric Utility Plant	35.8	36.3	36.9	36.7	37.3
Electric Operation and Maintenance Expenses as a Percent of Electric Operating Revenues	89.2	88.6	88.8	88.1	88.7
Electric Depreciation and Amortization as a Percent of Electric Operating Revenues	3.3	3.5	3.4	3.4	3.4
Taxes and Tax Equivalents as a Percent of Electric Operating Revenues	1.9	1.9	2.1	2.3	2.5
Interest Expenses as a Percent of Electric Operating Revenues	1.6	1.6	1.5	1.5	1.4
Net Income as a Percent of Electric Operating Revenues	3.5	3.5	4.6	4.8	4.6
Purchase Power Cents Per Kilowatthour	4.0	4.1	4.1	4.1	4.1

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 275 for 1994, 273 for 1993, 258 for 1992, 252 for 1991, and 251 for 1990.
Source: Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities."

Table 21. Revenue and Expense Statistics for Major U.S. Publicly Owned Nongenerator Electric Utilities, 1990 Through 1994
(Thousand Dollars)

Description	1990	1991	1992	1993	1994
Operating Revenue - Electric	**6,978,752**	**7,119,875**	**7,247,407**	**7,523,453**	**7,995,632**
Operating Expenses - Electric	6,740,926	6,859,619	6,843,539	7,063,260	7,566,745
Operation Including Fuel	6,030,028	6,119,385	6,244,831	6,424,798	6,857,970
Production	5,478,840	5,523,601	5,617,261	5,760,626	6,185,035
Transmission	30,119	32,264	32,956	33,755	34,045
Distribution	144,962	164,147	176,188	189,023	190,181
Customer Accounts	99,305	102,488	109,196	117,353	119,019
Customer Service	13,967	15,536	15,629	17,166	16,941
Sales	11,222	11,587	11,646	8,704	9,845
Administrative and General	251,614	269,762	281,954	298,171	302,904
Maintenance	191,621	186,267	192,635	207,046	233,967
Depreciation and Amortization Excluding Nuclear Fuel	231,197	246,594	248,040	252,850	268,790
Taxes and Tax Equivalents	133,125	138,491	154,994	174,681	201,038
Net Contributions and Services	154,956	168,882	—	—	—
Income from Electric Utility Operations	**237,826**	**260,255**	**403,868**	**460,193**	**428,887**

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 275 for 1994, 273 for 1993, 258 for 1992, 252 for 1991, and 251 for 1990.
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. More than 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 ranges from containing 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 called 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 but discharging the 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 average global temperature. It is called the "greenhouse" effect because it is similar to the trapping of the sun energy in a greenhouse. These potential increases in temperatures are of concern because they could cause significant 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 CO_2 from power plants. Tail gas cleanup (CO_2 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, CO_2 emissions are reduced.

Emission Standards

To respond to concerns about emissions of SO_2 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 SO_2 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 SO_2 per million Btu of heat input, but require SO_2 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 affect generators of electricity are a 10-million-ton reduction in SO_2 emissions and a 2-million-ton reduction in NO_x emissions from 1980 levels. The reduction in SO_2 is to occur in two phases that begin in 1995 and 2000, respectively. The CAAA established an innovative marketable emission allowance program. It also 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 SO_2 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 SO_2 from the gas (flue gas) released through the flues of the plant. Additional methods for reducing emissions of SO_2, 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 what type of fuel is 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 SO_2. 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 as a household vacuum cleaner does) 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 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 represent a significant part of the cost of a power plant. This 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 for SO_2, NO_x, and CO_2 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.*[18] 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 more than 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.

[18] Energy Information Administration, *Annual Energy Outlook* DOE/EIA-0383(94)(Washington, DC, 1994).

Table 22. Estimated Emissions from Fossil-Fueled Steam-Electric Generating Units at U.S. Electric Utilities, 1990 Through 1994
(Thousand Short Tons)

Emission	1990	1991	1992	1993	1994
Sulfur Dioxide (SO2)	15,369	15,012	14,680	14,432	13,104
Nitrogen Oxides (NOx)[1]	5,801	5,801	5,674	5,852	5,719
Carbon Dioxide (CO2)[1]	1,855,411	1,860,050	1,844,728	1,926,803	1,909,510

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

Notes: •Estimates for 1994 are preliminary; estimates for prior years are final. •Emissions of CO2, NOx, and SO2 have been revised from the updated (January 1995) Air Pollutant Emissions Factors (AP-42 release V) of the Environmental Protection Agency (see Technical Notes). •Estimates are for steam-electric plants 10 megawatts and larger, based on fuel consumption data.

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

Table 23. Number and Capacity of Fossil-Fueled Steam-Electric Generators for U.S. Electric Utility Plants with Environmental Equipment, 1990 Through 1994

Environmental Equipment	Scrubbers		Particulate Collectors	
	Number of Generators	Capacity[1] (megawatts)	Number of Generators	Capacity[1] (megawatts)
1990	153	69,122	1,177	349,319
1991	154	70,554	1,173	352,990
1992	154	71,351	1,169	353,525
1993	153	70,890	1,155	351,451
1994	168	80,617	1,134	351,004

Environmental Equipment	Cooling Towers		Total[2]	
	Number of Generators	Capacity[1] (megawatts)	Number of Generators	Capacity[1] (megawatts)
1990	478	162,557	1,360	376,894
1991	486	165,337	1,353	378,963
1992	485	165,306	1,346	379,194
1993	486	164,951	1,334	377,473
1994	480	165,452	1,308	376,723

[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 1994 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 24. Estimated Emissions from Fossil-Fueled Steam-Electric Generating Units at U.S. Electric Utilities by Census Division and State, 1993 and 1994
(Thousand Short Tons)

Census Division State	1993 Sulfur Dioxide	1993 Nitrogen Oxides[1]	1993 Carbon Dioxide[1]	1994 Sulfur Dioxide	1994 Nitrogen Oxides[1]	1994 Carbon Dioxide[1]
New England	227	74	31,173	198	69	29,573
Connecticut	28	11	6,527	25	10	5,702
Maine	6	1	733	5	1	677
Massachusetts	142	44	19,050	118	40	18,225
New Hampshire	51	18	4,690	50	18	4,756
Rhode Island	*	*	49	*	*	67
Vermont	*	*	123	*	*	146
Middle Atlantic	1,471	406	161,211	1,404	351	152,607
New Jersey	60	34	8,660	53	31	8,563
New York	281	99	47,740	244	90	43,948
Pennsylvania	1,130	273	104,811	1,107	230	100,096
East North Central	4,670	1,463	393,607	4,356	1,456	401,276
Illinois	794	275	63,616	779	280	65,886
Indiana	1,205	409	107,982	1,172	411	111,347
Michigan	358	237	65,741	397	243	70,850
Ohio	2,132	425	125,562	1,819	403	120,433
Wisconsin	182	117	30,705	189	119	32,759
West North Central	1,019	657	190,012	1,072	675	193,712
Iowa	175	116	26,333	172	114	25,928
Kansas	70	111	32,464	71	112	31,761
Minnesota	88	117	33,665	88	115	33,621
Missouri	464	179	44,999	506	201	50,380
Nebraska	58	66	16,727	54	64	16,034
North Dakota	131	57	32,992	148	56	32,909
South Dakota	31	11	2,832	33	12	3,078
South Atlantic	3,348	1,038	378,576	2,943	995	363,790
Delaware	50	20	7,792	43	18	6,989
District of Columbia	1	*	216	2	*	283
Florida	700	281	100,091	694	261	84,301
Georgia	689	147	58,853	553	145	61,354
Maryland	269	76	28,948	249	74	29,631
North Carolina	421	166	58,520	362	145	52,180
South Carolina	178	69	26,850	188	71	27,501
Virginia	189	61	26,455	172	57	24,323
West Virginia	850	217	70,849	680	224	77,227
East South Central	2,350	689	222,665	1,796	625	210,528
Alabama	548	188	67,495	512	165	63,616
Kentucky	827	287	82,310	685	270	80,694
Mississippi	141	37	13,945	92	38	13,806
Tennessee	834	176	58,915	507	152	52,412
West South Central	786	877	298,605	753	853	294,327
Arkansas	62	59	21,257	68	64	23,618
Louisiana	119	122	37,991	121	118	39,574
Oklahoma	104	121	39,292	92	120	38,459
Texas	501	575	200,065	471	551	192,677
Mountain	453	520	203,778	477	542	207,750
Arizona	130	104	31,507	137	108	27,020
Colorado	83	100	32,483	88	102	34,147
Idaho	—	—	—	—	—	—
Montana	20	42	15,766	21	51	18,876
Nevada	53	49	19,886	53	51	20,363
New Mexico	58	98	29,782	63	101	30,534
Utah	31	43	32,850	29	44	33,367
Wyoming	78	84	41,504	85	86	43,443
Pacific Contiguous	87	120	42,471	86	144	51,383
California	5	74	28,462	4	94	36,097
Oregon	13	13	3,654	14	14	4,084
Washington	70	33	10,356	67	35	11,202
Pacific Noncontiguous	21	9	4,706	19	8	4,564
Alaska	1	*	1	1	*	1
Hawaii	20	9	4,705	18	8	4,563
U.S. Total	14,432	5,852	1,926,803	13,104	5,719	1,909,510

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

* =Value less than 0.5.

Notes: •Estimates for 1994 are preliminary; estimates for prior years are final. •Emissions of CO2, NOx, and SO2 have been revised from the updated (January 1995) Air Pollutant Emissions Factors (AP-42 release V) of the Environmental Protection Agency (see Technical Notes). •Estimates are for steam-electric plants 10 megawatts and larger, based on fuel consumption data.

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

Table 25. Estimated Emissions from Fossil-Fueled Steam-Electric Generating Units at U.S. Electric Utilities by Fossil Fuel, Census Division, and State, 1994
(Thousand Short Tons)

Census Division State	Coal			Petroleum			Gas			Other[1]		
	Sulfur Dioxide	Nitrogen Oxides[2]	Carbon Dioxide[2]	Sulfur Dioxide	Nitrogen Oxides[2]	Carbon Dioxide[2]	Sulfur Dioxide	Nitrogen Oxides[2]	Carbon Dioxide[2]	Sulfur Dioxide	Nitrogen Oxides[2]	Carbon Dioxide[2]
New England	111	44	15,566	87	17	11,030	*	8	2,804	*	*	173
Connecticut	8	5	2,155	17	4	3,063	*	1	469	*	*	15
Maine	0	0	0	5	1	677	0	0	0	0	0	0
Massachusetts	64	23	10,001	54	10	5,994	*	7	2,218	*	*	12
New Hampshire	38	16	3,410	12	2	1,258	0	*	76	*	*	12
Rhode Island	0	0	0	*	*	36	0	*	32	0	0	0
Vermont	0	0	0	*	*	3	0	*	9	*	*	134
Middle Atlantic	1,338	296	121,875	66	24	17,227	*	31	13,461	*	*	44
New Jersey	48	23	5,268	4	3	1,470	*	6	1,824	*	*	1
New York	200	51	21,710	45	16	11,367	*	24	10,871	0	0	0
Pennsylvania	1,090	222	94,897	17	6	4,391	*	1	765	*	*	43
East North Central	4,346	1,444	395,205	10	3	2,416	*	8	2,942	1	1	713
Illinois	774	273	62,586	6	2	1,281	*	5	2,018	0	0	1
Indiana	1,172	409	110,718	*	*	171	*	1	458	0	0	0
Michigan	393	241	69,847	3	1	697	*	1	307	0	*	*
Ohio	1,818	402	119,722	*	*	237	0	*	37	1	1	438
Wisconsin	189	119	32,332	*	*	30	*	*	121	*	*	275
West North Central	1,070	665	190,174	1	*	259	*	8	2,258	1	1	1,021
Iowa	172	114	25,749	*	*	35	*	*	104	*	*	39
Kansas	71	107	30,249	*	*	46	*	5	1,465	*	*	1
Minnesota	87	112	32,270	*	*	21	*	1	357	1	1	973
Missouri	505	201	50,084	1	*	110	*	1	187	0	*	*
Nebraska	54	64	15,884	*	*	7	*	*	143	0	*	*
North Dakota	148	56	32,872	*	*	37	0	0	*	0	0	0
South Dakota	33	12	3,065	*	*	3	0	*	2	*	*	8
South Atlantic	2,638	913	320,605	305	60	36,306	*	21	6,706	*	*	173
Delaware	35	14	5,281	8	2	1,431	*	1	272	*	*	5
District of Columbia	0	0	0	2	*	266	0	0	0	*	*	17
Florida	444	192	50,051	250	50	28,545	*	19	5,663	*	*	43
Georgia	553	144	61,202	1	*	94	0	*	52	*	*	7
Maryland	218	68	25,376	31	5	3,638	*	1	515	*	*	101
North Carolina	362	145	52,023	*	*	157	0	0	0	0	0	0
South Carolina	187	71	27,266	*	*	87	*	*	148	0	0	*
Virginia	159	55	22,388	13	2	1,900	0	*	35	0	0	0
West Virginia	679	224	77,019	*	*	187	0	*	21	0	0	0
East South Central	1,779	611	205,393	16	2	1,221	*	12	3,906	*	*	8
Alabama	512	164	63,341	*	*	75	*	1	201	0	0	0
Kentucky	685	270	80,561	*	*	119	0	*	15	0	*	*
Mississippi	76	24	9,174	16	2	933	*	12	3,691	*	*	8
Tennessee	507	152	52,317	*	*	95	0	0	0	0	0	0
West South Central	750	597	208,799	2	1	593	*	255	84,936	0	0	0
Arkansas	68	60	22,051	*	*	76	*	4	1,491	0	0	0
Louisiana	121	72	24,173	1	*	217	*	45	15,184	0	0	0
Oklahoma	92	93	30,474	*	*	31	*	27	7,954	0	0	0
Texas	470	372	132,101	1	*	269	*	179	60,307	0	0	0
Mountain	476	529	202,739	1	1	352	*	13	4,659	0	*	*
Arizona	137	106	26,198	*	*	113	*	2	709	0	0	0
Colorado	88	101	33,863	*	*	5	*	1	279	0	*	*
Idaho	—	—	—	—	—	—	—	—	—	—	—	—
Montana	21	51	18,836	*	*	9	0	*	31	0	*	*
Nevada	53	46	18,822	1	*	142	*	5	1,399	0	0	0
New Mexico	63	97	28,721	*	*	21	*	4	1,792	0	0	0
Utah	29	43	32,902	*	*	23	*	1	442	0	0	0
Wyoming	85	86	43,397	*	*	39	0	*	7	0	0	0
Pacific Contiguous	82	49	14,651	4	2	1,555	*	92	34,551	*	*	626
California	0	0	0	4	2	1,546	*	92	34,550	0	0	0
Oregon	14	14	4,079	*	*	5	0	0	0	0	0	0
Washington	67	35	10,572	*	*	4	0	*	*	*	*	626
Pacific Noncontiguous	1	0	0	18	8	4,564	0	0	0	0	0	0
Alaska	1	0	0	*	*	1	0	0	0	0	0	0
Hawaii	0	0	0	18	8	4,563	0	0	0	0	0	0
U.S. Total	12,590	5,148	1,675,006	510	118	75,523	1	450	156,222	2	3	2,758

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

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

Notes: •Estimates for 1994 are preliminary; estimates for prior years are final. •Emissions of CO2, NOx, and SO2 have been revised from the updated (January 1995) Air Pollutant Emissions Factors (AP-42 release V) of the Environmental Protection Agency (see Technical Notes). •Estimates are for steam-electric plants 10 megawatts and larger, based on fuel consumption data. •*=Value less than 0.5.

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

Table 26. Number and Capacity of Coal-Fired Steam-Electric Generators for U.S. Electric Utility Plants with Environmental Equipment by Census Division and State, 1994

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	14	2,699	0	0	14	2,699	0	0
Connecticut	1	400	0	0	1	400	0	0
Maine	0	0	0	0	0	0	0	0
Massachusetts	8	1,690	0	0	8	1,690	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	83	23,763	10	5,626	83	23,763	16	11,366
New Jersey	6	1,379	0	0	6	1,379	0	0
New York	25	3,721	1	655	25	3,721	0	0
Pennsylvania	52	18,664	9	4,971	52	18,664	16	11,366
East North Central	293	81,327	22	10,452	293	81,327	41	20,489
Illinois	55	17,123	4	1,439	55	17,123	2	562
Indiana	67	21,069	12	5,240	67	21,069	23	9,395
Michigan	49	12,124	0	0	49	12,124	2	199
Ohio	85	24,057	4	3,614	85	24,057	11	8,854
Wisconsin	37	6,953	2	160	37	6,953	3	1,479
West North Central	136	35,702	24	10,692	136	35,702	38	11,770
Iowa	27	5,645	1	176	27	5,645	6	1,681
Kansas	19	5,634	7	3,920	19	5,634	8	3,258
Minnesota	25	5,417	8	3,333	25	5,417	9	3,787
Missouri	38	11,448	2	455	38	11,448	7	789
Nebraska	14	3,092	0	0	14	3,092	4	430
North Dakota	12	4,009	6	2,809	12	4,009	4	1,826
South Dakota	1	456	0	0	1	456	0	0
South Atlantic	214	69,324	19	10,258	214	69,324	62	35,918
Delaware	6	1,034	0	0	6	1,034	1	442
District of Columbia	0	0	0	0	0	0	0	0
Florida	28	10,894	7	4,102	28	10,894	11	6,293
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	45	12,494	0	0	45	12,494	6	3,126
South Carolina	25	5,915	5	2,092	25	5,915	14	4,378
Virginia	24	4,549	0	0	24	4,549	3	713
West Virginia	33	14,958	6	3,942	33	14,958	13	9,822
East South Central	132	40,471	27	11,930	132	40,471	28	12,893
Alabama	39	12,586	4	1,597	39	12,586	4	2,599
Kentucky	54	15,956	19	7,333	54	15,956	21	9,394
Mississippi	6	2,150	2	400	6	2,150	3	900
Tennessee	33	9,780	2	2,600	33	9,780	0	0
West South Central	59	33,690	16	10,547	57	33,463	32	17,262
Arkansas	5	3,958	0	0	5	3,958	4	3,400
Louisiana	8	3,799	1	721	6	3,572	6	2,681
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	88	30,539	50	21,112	88	30,539	76	26,044
Arizona	14	5,749	9	2,877	14	5,749	12	5,347
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	4,461	7	3,826	10	4,461	10	4,461
Wyoming	15	5,838	10	5,001	15	5,838	14	5,476
Pacific Contiguous	5	2,084	0	0	3	2,020	4	1,524
California	2	64	0	0	0	0	2	64
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	1,024	319,600	168	80,617	1,020	319,309	297	137,266

[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 27. Number and Capacity of Petroleum- and Gas-Fired Steam-Electric Generators for U.S. Electric Utility Plants with Environmental Equipment by Census Division and State, 1994

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	22	6,204	0	0	21	5,789	1	415
Connecticut	11	2,098	0	0	10	1,683	1	415
Maine	4	846	0	0	4	846	0	0
Massachusetts	6	2,846	0	0	6	2,846	0	0
New Hampshire	1	414	0	0	1	414	0	0
Rhode Island	0	0	0	0	0	0	0	0
Vermont	0	0	0	0	0	0	0	0
Middle Atlantic	39	12,041	0	0	36	10,205	4	2,012
New Jersey	12	2,091	0	0	11	1,956	2	311
New York	19	6,735	0	0	19	6,735	0	0
Pennsylvania	8	3,216	0	0	6	1,515	2	1,701
East North Central	13	2,384	0	0	8	851	5	1,533
Illinois	1	210	0	0	0	0	1	210
Indiana	3	230	0	0	1	138	2	92
Michigan	6	1,743	0	0	4	512	2	1,231
Ohio	1	114	0	0	1	114	0	0
Wisconsin	2	88	0	0	2	88	0	0
West North Central	17	1,462	0	0	4	146	13	1,315
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	3	61	0	0	0	0	3	61
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	47	15,241	0	0	34	11,993	17	4,425
Delaware	4	597	0	0	4	597	2	132
District of Columbia	2	580	0	0	0	0	2	580
Florida	30	9,959	0	0	21	8,608	9	1,351
Georgia	0	0	0	0	0	0	0	0
Maryland	7	2,203	0	0	5	885	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	4	353	0	0	1	147	3	206
Alabama	0	0	0	0	0	0	0	0
Kentucky	1	147	0	0	1	147	0	0
Mississippi	3	206	0	0	0	0	3	206
Tennessee	0	0	0	0	0	0	0	0
West South Central	86	13,733	0	0	4	2,258	84	12,574
Arkansas	2	183	0	0	0	0	2	183
Louisiana	12	2,308	0	0	2	1,184	11	1,716
Oklahoma	19	4,350	0	0	1	567	18	3,783
Texas	53	6,892	0	0	1	507	53	6,892
Mountain	32	2,787	0	0	2	101	32	2,787
Arizona	13	1,382	0	0	0	0	13	1,382
Colorado	3	111	0	0	2	101	3	111
Idaho	—	—	—	—	—	—	—	—
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	0	0	3	252
Wyoming	0	0	0	0	0	0	0	0
Pacific Contiguous	24	2,918	0	0	4	205	24	2,918
California	24	2,918	0	0	4	205	24	2,918
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	284	57,123	0	0	114	31,695	183	28,186

[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 28. Average Quality of Fossil Fuels Burned at U.S. Electric Utilities by Census Division and State, 1993 and 1994

Census Division State	Coal 1993 Average Btu per Pound	Coal 1993 Sulfur Percent by Weight	Coal 1993 Ash Percent by Weight	Coal 1994 Average Btu per Pound	Coal 1994 Sulfur Percent by Weight	Coal 1994 Ash Percent by Weight	Petroleum 1993 Average Btu per Gallon	Petroleum 1993 Sulfur Percent by Weight	Petroleum 1994 Average Btu per Gallon	Petroleum 1994 Sulfur Percent by Weight	Gas 1993 Average Btu per Cubic Foot	Gas 1994 Average Btu per Gallon
New England	12,972	1.14	7.7	12,821	1.02	7.5	151,209	1.34	150,611	1.31	1,033	1,031
Connecticut	13,053	.56	6.9	12,974	.54	7.4	151,667	.91	151,066	.90	1,029	1,018
Maine	—	—	—	—	—	—	150,791	1.26	150,257	1.11	—	—
Massachusetts	12,908	1.10	8.1	12,737	.95	7.8	150,591	1.50	150,175	1.48	1,034	1,035
New Hampshire	13,104	1.58	6.8	12,973	1.54	6.5	154,164	1.72	151,801	1.59	1,016	1,013
Rhode Island	—	—	—	—	—	—	151,508	1.00	—	—	1,032	—
Vermont	—	—	—	—	—	—	140,000	.30	140,000	.30	1,000	1,000
Middle Atlantic	12,519	1.89	11.0	12,495	1.97	11.0	150,405	.75	148,813	.64	1,031	1,032
New Jersey	13,076	1.29	8.2	13,175	1.32	7.9	148,931	.56	148,410	.47	1,033	1,036
New York	12,850	1.59	8.3	12,876	1.69	8.1	150,629	.81	149,305	.65	1,031	1,031
Pennsylvania	12,416	1.99	11.7	12,379	2.07	11.8	149,980	.61	147,684	.65	1,033	1,032
East North Central	10,770	1.64	8.6	10,758	1.59	8.5	145,580	.59	145,806	.72	999	1,018
Illinois	10,138	1.57	7.6	10,082	1.50	7.5	149,684	.60	149,147	.84	1,016	1,018
Indiana	10,470	1.84	8.5	10,450	1.82	8.3	136,991	.35	137,422	.33	1,017	1,018
Michigan	10,692	.67	6.9	10,821	.69	7.1	144,440	.73	145,424	.78	954	1,020
Ohio	12,009	2.44	11.1	11,992	2.42	11.0	137,845	.37	137,677	.28	1,029	1,027
Wisconsin	9,392	.51	6.2	9,503	.51	6.3	139,432	.39	139,615	.41	1,012	1,008
West North Central	8,417	.71	6.9	8,368	.70	6.9	142,192	.84	141,714	.79	990	983
Iowa	8,686	.60	5.6	8,704	.56	5.7	137,833	.50	137,853	.43	1,005	1,007
Kansas	8,673	.46	5.4	8,538	.47	5.7	143,489	.73	140,429	.40	980	974
Minnesota	8,795	.52	6.4	8,772	.53	6.7	138,462	.33	138,682	.31	1,008	1,005
Missouri	9,903	1.27	7.0	9,564	1.11	6.5	144,128	1.15	145,393	1.34	1,007	999
Nebraska	8,505	.36	5.1	8,500	.35	5.2	138,969	.21	139,313	.26	975	986
North Dakota	6,539	.73	9.8	6,527	.75	9.8	138,562	.39	139,070	.46	1,092	1,063
South Dakota	6,245	.86	8.5	6,230	.86	8.4	136,757	.34	139,167	.38	1,020	1,005
South Atlantic	12,401	1.42	9.9	12,267	1.34	9.8	151,176	1.40	150,891	1.38	1,010	1,017
Delaware	12,858	.95	9.0	12,843	.93	9.1	150,164	.95	150,018	.91	1,033	1,037
District of Columbia	—	—	—	—	—	—	143,546	.94	143,642	.91	—	—
Florida	12,209	1.59	8.2	12,184	1.58	8.2	151,683	1.47	151,315	1.45	1,008	1,014
Georgia	12,094	1.45	10.2	11,551	1.09	9.0	141,352	1.33	141,491	.87	1,023	1,024
Maryland	12,730	1.31	10.4	12,753	1.18	10.2	150,763	1.40	150,352	1.42	1,041	1,043
North Carolina	12,456	.96	10.0	12,417	.92	10.3	138,433	.20	139,075	.20	—	—
South Carolina	12,717	1.17	9.0	12,685	1.20	9.0	143,725	1.09	141,333	.57	1,022	1,023
Virginia	12,805	1.00	9.6	12,767	.98	9.8	149,361	1.05	150,843	1.11	1,014	1,010
West Virginia	12,405	1.93	11.7	12,394	1.89	11.7	139,344	.31	139,398	.33	1,000	1,015
East South Central	12,021	1.80	10.3	11,920	1.80	10.3	152,231	2.67	149,032	2.12	1,022	1,027
Alabama	12,055	1.32	11.7	12,041	1.35	11.6	137,081	.33	137,587	.25	1,024	1,012
Kentucky	11,841	2.18	10.2	11,746	2.14	10.2	138,965	.31	138,735	.27	1,020	1,019
Mississippi	12,321	1.44	8.7	11,349	1.07	7.9	153,455	2.87	152,882	2.78	1,022	1,028
Tennessee	12,201	1.84	9.1	12,164	1.95	9.4	138,314	.31	138,262	.26	—	—
West South Central	7,607	.63	9.8	7,616	.63	9.6	148,493	.67	144,410	.45	1,026	1,028
Arkansas	8,525	.32	5.1	8,549	.32	4.9	137,856	.30	141,806	.54	1,027	1,024
Louisiana	7,936	.53	7.1	7,899	.56	7.4	152,306	1.11	149,091	.47	1,036	1,043
Oklahoma	8,604	.38	5.1	8,555	.35	5.1	139,864	.50	138,518	.36	1,030	1,034
Texas	7,261	.73	11.6	7,265	.74	11.4	146,124	.19	142,359	.42	1,023	1,023
Mountain	9,813	.54	11.1	9,812	.55	11.2	144,215	.52	144,850	.57	1,023	1,027
Arizona	10,251	.51	12.3	10,323	.51	12.0	142,030	.44	146,526	.70	1,028	1,023
Colorado	9,917	.39	7.1	10,030	.41	7.2	137,093	.26	136,086	.19	975	982
Idaho	—	—	—	—	—	—	—	—	—	—	—	—
Montana	8,493	.65	9.0	8,480	.66	9.1	141,000	.50	141,000	.50	1,165	1,055
Nevada	11,840	.48	9.7	11,786	.48	9.6	148,485	.70	148,511	.69	1,029	1,035
New Mexico	9,114	.80	21.8	9,056	.82	22.5	134,793	.10	136,000	.10	1,018	1,023
Utah	11,506	.48	11.1	11,588	.48	10.6	138,428	.34	138,745	.34	1,063	1,044
Wyoming	8,702	.51	7.6	8,711	.54	8.1	139,143	.30	139,213	.30	1,045	1,034
Pacific Contiguous	8,361	.62	11.0	8,520	.57	12.0	146,361	.43	145,585	.42	1,030	1,026
California	—	—	—	—	—	—	146,416	.43	145,627	.42	1,030	1,026
Oregon	8,836	.37	5.1	8,808	.37	5.8	138,800	.50	138,800	.50	—	—
Washington	8,198	.70	13.0	8,416	.64	14.2	140,979	.30	140,000	.30	1,040	1,035
Pacific Noncontiguous	7,858	.16	8.6	7,784	.17	9.2	149,251	.69	149,809	.66	—	—
Alaska	7,858	.16	8.6	7,784	.17	9.2	134,356	.38	134,356	.23	—	—
Hawaii	—	—	—	—	—	—	149,255	.69	149,814	.67	—	—
U.S. Average	10,319	1.19	9.5	10,265	1.17	9.4	150,585	1.20	149,882	1.12	1,025	1,027

Notes: •Data for 1994 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 29. Average Flue Gas Desulfurization Costs at U.S. Electric Utilities by Census Division and State, 1990 Through 1994

Census Division State	Average O&M Costs (mills per kilowatthour)					Average Installed Costs (dollars per kilowatt)				
	1990	1991	1992	1993	1994	1990	1991	1992	1993	1994
New England	—	—	—	—	—	—	—	—	—	—
Connecticut	—	—	—	—	—	—	—	—	—	—
Maine	—	—	—	—	—	—	—	—	—	—
Massachusetts	—	—	—	—	—	—	—	—	—	—
New Hampshire	—	—	—	—	—	—	—	—	—	—
Rhode Island	—	—	—	—	—	—	—	—	—	—
Vermont	—	—	—	—	—	—	—	—	—	—
Middle Atlantic	**5.15**	**5.01**	**4.91**	**3.96**	**2.68**	**157**	**178**	**183**	**184**	**184**
New Jersey	—	—	NM	NM	NM	—	—	398	398	398
New York	1.22	1.07	1.03	1.09	1.03	212	319	319	331	331
Pennsylvania	6.25	6.20	6.04	4.65	2.96	149	149	157	157	157
East North Central	**2.41**	**2.16**	**1.83**	**1.90**	**2.05**	**138**	**139**	**147**	**130**	**127**
Illinois	2.35	2.53	2.47	2.52	2.71	147	197	197	147	147
Indiana	2.41	2.12	1.58	1.58	1.53	154	133	149	143	142
Michigan	—	—	—	—	—	—	—	—	—	—
Ohio	2.52	2.03	2.06	2.25	2.92	47	83	83	83	88
Wisconsin	—	—	—	—	2.86	—	—	—	—	16
West North Central	**.74**	**.72**	**.75**	**.66**	**.60**	**75**	**75**	**83**	**84**	**84**
Iowa	2.33	2.83	2.42	1.87	1.53	202	202	202	202	202
Kansas	.61	.53	.66	.49	.46	71	71	72	72	73
Minnesota	.27	.40	.40	.43	.39	73	73	73	73	73
Missouri	2.02	1.89	2.12	1.86	1.35	87	87	87	87	87
Nebraska	—	—	—	—	—	—	—	—	—	—
North Dakota	.92	.81	.74	.81	.79	71	71	101	102	102
South Dakota	—	—	—	—	—	—	—	—	—	—
South Atlantic	**1.58**	**1.63**	**1.28**	**.98**	**1.16**	**85**	**144**	**143**	**119**	**115**
Delaware[1]	36.60	29.62	NM	—	—	1,385	1,385	1,385	—	—
District of Columbia	—	—	—	—	—	—	—	—	—	—
Florida	1.07	1.23	1.15	.78	1.01	80	69	69	69	67
Georgia	—	—	—	—	—	—	—	—	—	—
Maryland	—	—	—	—	—	—	—	—	—	—
North Carolina	—	—	—	—	—	—	—	—	—	—
South Carolina	.54	:60	.64	.59	.60	34	43	43	43	43
Virginia	—	—	—	—	—	—	—	—	—	—
West Virginia	2.41	2.55	2.23	2.09	2.33	113	259	260	217	209
East South Central	**1.49**	**1.51**	**1.65**	**1.45**	**1.06**	**131**	**153**	**140**	**137**	**143**
Alabama	.91	.94	1.00	.69	.82	82	82	80	80	80
Kentucky	1.70	1.70	1.91	1.76	1.60	146	155	135	132	140
Mississippi	.34	.41	.30	.27	.27	70	70	70	70	70
Tennessee	—	NM	NM	NM	.05	—	202	202	196	204
West South Central	**.93**	**1.17**	**1.22**	**1.01**	**1.08**	**69**	**69**	**73**	**74**	**76**
Arkansas	—	—	—	—	—	—	—	—	—	—
Louisiana	NM	NM	NM	NM	NM	75	75	75	75	75
Oklahoma	.66	.57	.55	.54	.50	92	92	92	92	92
Texas	.95	1.20	1.26	1.03	1.11	67	67	72	72	75
Mountain	**.74**	**.79**	**.69**	**.68**	**.73**	**154**	**149**	**148**	**146**	**150**
Arizona	.77	.63	.68	.42	.77	175	175	175	160	175
Colorado	.45	.63	.57	.67	.52	69	69	69	69	69
Idaho	—	—	—	—	—	—	—	—	—	—
Montana	1.19	.94	.90	1.10	1.11	274	274	274	274	274
Nevada	1.11	3.80	.93	.99	.74	126	126	126	126	126
New Mexico	.95	1.14	1.03	1.07	1.07	192	167	165	165	165
Utah	.43	.56	.48	.37	.41	97	97	97	97	101
Wyoming	.72	.67	.55	.54	.62	137	137	137	137	137
Pacific Contiguous	—	—	—	—	—	—	—	—	—	—
California	—	—	—	—	—	—	—	—	—	—
Oregon	—	—	—	—	—	—	—	—	—	—
Washington	—	—	—	—	—	—	—	—	—	—
Pacific Noncontiguous	—	—	—	—	—	—	—	—	—	—
Alaska	—	—	—	—	—	—	—	—	—	—
Hawaii	—	—	—	—	—	—	—	—	—	—
U.S. Average	**1.35**	**1.40**	**1.32**	**1.19**	**1.14**	**118**	**130**	**132**	**125**	**127**

[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 1994 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 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1994

Utility Plant and FGD No.		Nameplate Capacity (megawatts) by Plant	Nameplate Capacity (megawatts) by Unit with FGD System	Initial Start up Date of FGD System	Design Coal Sulfur (Percent by WT)	FGD Type	Sorbent	Designed SO2 Removal (Percent Efficiency)
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	Lime	50.7
Cholla	2	-	289	7806	1.20	Venturi	Lime	85.0
Cholla	4	-	414	8106	1.20	Packed	Lime	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	Bubbling Reactor	Limestone	90.0

See footnotes at end of table.

Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1994 (Continued)

Utility Plant and FGD No.	Nameplate Capacity (megawatts) by Plant	Nameplate Capacity (megawatts) by Unit with FGD System	Initial Start up Date of FGD System	Design Coal Sulfur (Percent by WT)	FGD Type	Sorbent	Designed SO2 Removal (Percent Efficiency)
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
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							
Ghent 1	2,226	557	9501	3.50	Spray	Limestone	95.0
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	1,640	820	8607	.90	Spray	Limestone	90.0
Intermountain 2CCC	-	820	8707	.30	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 Agy							
Endicott Generating 1	55	50	8305	4.30	Spray	Limestone	90.0
Minnesota Power & Light Co							
Boswell Energy Cente AQCS2	1,073	558	8004	1.00	Spray	Alkaline Fly Ash	83.2
Boswell Energy Cente SCR3	-	365	7302	1.00	Spray	Alkaline Fly Ash	25.4
Laskin Energy Center SCR1	116	58	7105	1.00	Spray	Alkaline Fly Ash	-
Laskin Energy Center SCR2	-	58	7105	1.00	Spray	Alkaline Fly Ash	-
Minnkota Power Coop Inc							
Milton R Young FGD2	734	477	7806	1.20	Spray	Lime/Alkaline Fly Ash	77.9

See footnotes at end of table.

Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1994 (Continued)

Utility Plant and FGD No.		Nameplate Capacity (megawatts) by Plant	Nameplate Capacity (megawatts) by Unit with FGD System	Initial Start up Date of FGD System	Design Coal Sulfur (Percent by WT)	FGD Type	Sorbent	Designed SO2 Removal (Percent Efficiency)
Monongahela Power Co								
Harrison	1	2,052	684	9411	4.00	Spray	Lime	98.0
Harrison	2	-	684	9411	4.00	Spray	Lime	98.0
Harrison	3	-	684	9411	4.00	Spray	Lime	98.0
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	655	655	8408	3.60	Spray	Limestone	90.0
Northern Indiana Pub Serv Co								
Bailly	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
Ohio Power Co								
Gen J M Gavin	1	2,600	1,300	9412	3.50	Spray	Lime	95.0
Orlando Utilities Comm								
Stanton Energy	1	929	465	8707	3.50	Spray	Limestone	90.0
Owensboro City of								
Elmer Smith	FGD	416	416	9411	3.50	Spray	Limestone	96.0
PacifiCorp								
Dave Johnston	SC44	817	360	7202	.40	Venturi	Lime	-
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 Electric Co								
Conemaugh	1	1,872	936	9412	1.70	Spray	Limestone	95.0

See footnotes at end of table.

Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1994 (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					
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
Plains Elec Gen&Trans Coop Inc								
Escalante	1	233	233	8412	.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	4	3,340	668	9501	3.50	Spray	Limestone	92.0
Gibson	5	-	668	8210	4.40	Spray	Limestone	86.0
Richmond City of								
Whitewater Valley	LFC	-	-	9410	2.10	Spray Dry	Limestone	72.5
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	1,429	715	8402	3.00	Spray	Limestone	86.0
Seminole	2	-	715	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	1	1,147	591	9505	1.10	Spray	Limestone	90.0
Cross	2	-	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	52.7
R D Morrow	2	-	200	7906	1.50	Spray	Limestone	52.7
Southern Illinois Power Coop								
Marion	4	272	173	7904	4.40	Venturi	Limestone	89.4

See footnotes at end of table.

Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1994 (Continued)

Utility Plant and FGD No.		Nameplate Capacity (megawatts) by Plant	by Unit with FGD System	Initial Start up Date of FGD System	Design Coal Sulfur (Percent by WT)	FGD Type	Sorbent	Designed SO2 Removal (Percent Efficiency)
Southern Indiana Gas & Elec Co								
A B Brown	1	530	265	7904	4.50	Spray	Sodium Ash	85.0
A B Brown	2	–	265	8602	4.50	Spray	Sodium Ash	90.0
F B Culley	2-3	415	369	9501	3.80	Spray	Limestone	95.0
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
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								
Cumberland	1	2,600	1,300	9501	4.00	Spray	Limestone	95.0
Cumberland	2	–	1,300	9501	4.00	Spray	Limestone	95.0
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
Virginia Electric & Power Co								
Mt Storm	3	1,662	522	9501	2.00	Spray	Limestone	90.0
West Penn Power Co								
Mitchell	33	449	299	8208	4.00	Spray	Lime	95.0
West Texas Utilities Co								
Oklaunion	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

See footnotes at end of table.

Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1994 (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					
Western Resources, Inc							
Jeffrey Energy Centr 3	–	720	8305	0.30	Spray	Limestone	60.0
Lawrence 4N	604	114	6906	.90	Venturi	Limestone	73.0
Lawrence 4S	–	114	6906	.90	Venturi	Limestone	73.0
Lawrence 5N	–	403	7105	.90	Venturi	Limestone	52.0
Lawrence 5S	–	403	7105	.90	Venturi	Limestone	52.0
Wisconsin Electric Power Co							
Port Washington 1	320	80	9308	1.20	Spray	Sodium Carbonate	50.0
Port Washington 4	–	80	9408	1.20	Spray	Sodium Carbonate	50.0

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 power industry on its operations and wholesale electricity trade at the international (Canada and Mexico), national, and North American Electric Reliability Council (NERC) region levels.[19] Generating capability, generation from utility and nonutility sources, and end-user consumption are also presented.

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 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 planned and 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.) These agreements include transaction categories for purchases, sales for resale, exchanges, and wheeling of energy.

Purchase transactions involve buying power from 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 availability of excess generating capacity or 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 one or more intervening utilities.

Electric Utility Transactions

Electric power transactions *(wholesale electricity trade)* allow electric utilities to acquire power, to share resources, and to provide mutual assistance in times 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.

[19] The NERC is an organization established by the electric utility industry for maintaining, coordinating, and promoting reliability among the interconnected systems of North America.

Electric utilities originally became interested in energy transactions because of the savings gained from reduced or avoided production costs. They avoided building expensive additional capacity by obtaining power from other sources. Purchasing power from other utilities helped utilities meet peak load without using expensive oil- or gas-fired turbines. Similarly, utilities benefited 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 common coverage of facility outages. This coordination also provides the opportunity to achieve short-term saving, largely 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 they may just share the benefits of planned or hourly wholesale sales of power and energy among the member utilities. Power pools may also 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 for the reliability and stability of 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 14).

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 (power marketers file only for transactions). Transmission filings cover the allocation of electric power flows on the transmission line systems. Other categories described in the filings usually include 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 its 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 a given season, for an off-peak time of the day, or from a generator fired by a particular fuel that is currently not fully utilized. 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 include a demand or capacity charge 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, for example, by avoiding the use of more expensive fuels, or by 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 increasing 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-way and projected line construction are also being affected because of concerns linked to generated electromagnetic forces surrounding the transmission lines.

Legislative and regulatory initiatives have been implemented to address emissions at power plants. For example, the Clean Air Act Amendments of 1990 established emission allowances for nitrogen oxides, sulfur dioxide, and carbon dioxide for power plants based on historical levels. (The implementation occurs in two phases: 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 future availability of power from power plants emitting high levels of these gases 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 by changing costs and availability of electrical energy.

International Transactions

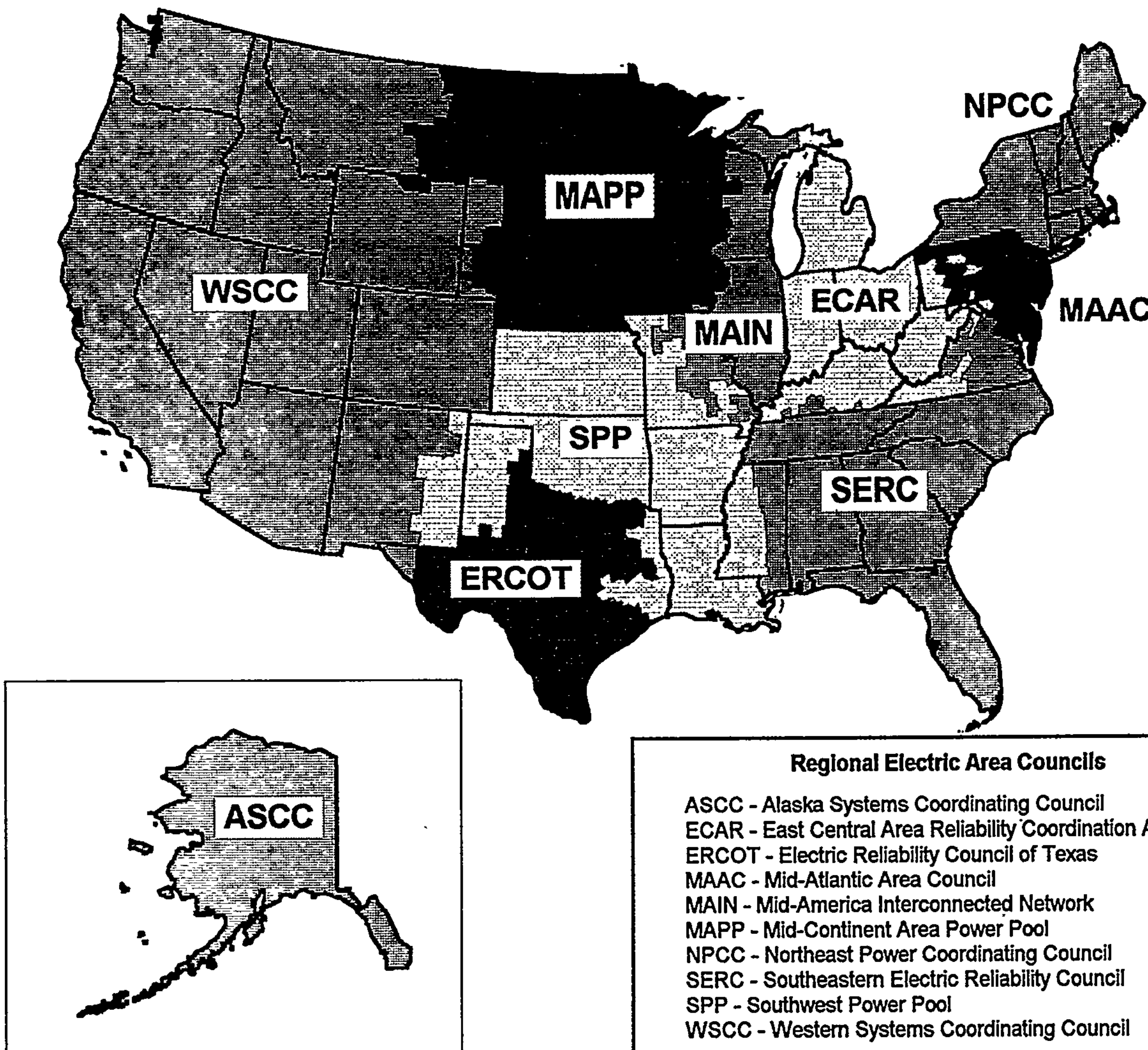
U.S. electric utilities have taken advantage of being able to enter into international trade agreements to acquire energy from Canada and Mexico. These trade agreements between utilities cover a variety of transaction options. The options include purchasing nonfirm energy from relatively inexpensive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

Data Sources

Statistics on electricity transactions among U.S. electric utilities and on international electricity trade (including the United States, Canada, and Mexico) are presented in the following tables. These data were obtained from the Form EIA-861, "The Annual Electric Utility Report"; the Form EIA-860, "Annual Electric Generator Report"; the Department of Energy, Office of the Assistant Secretary for Emergency Policy, Form PO-411, "Coordinated Regional 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." Detailed information on U.S. electric power transactions is published in the *Electric Trade in the United States*.[20]

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

Figure 14. North American Electric Reliability Council Regions for the Contiguous United States and Alaska



Regional Electric Area Councils

ASCC - Alaska Systems Coordinating Council
ECAR - East Central Area Reliability Coordination Agreement
ERCOT - Electric Reliability Council of Texas
MAAC - Mid-Atlantic Area Council
MAIN - Mid-America Interconnected Network
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

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

Table 31. Sources and Disposition of Electricity at U.S. Electric Utilities, 1990 Through 1994
(Million Kilowatthours)

Item	1990	1991	1992	1993	1994
Source					
Net Generation	2,821,493	2,835,377	2,805,092	2,897,815	2,924,960
Purchases from Utilities	998,525	1,127,669	1,146,323	1,218,882	1,226,773
Purchases from Nonutilities	116,065	139,436	166,283	188,537	208,779
Net Exchange	-1,130	1,172	-3,504	[1] -2,725	-3,651
Net Wheeling	6,077	4,963	5,756	4,668	4,210
Disposition					
Sales to Ultimate Consumers	2,712,555	2,762,003	2,763,365	2,861,462	2,934,517
Requirements and Nonrequirements Sales for Resale	999,268	1,116,655	1,119,948	1,200,047	1,185,352
Energy Furnished Without Charge	5,896	4,210	4,409	5,003	4,762
Energy Used by Utility Electric Department	18,974	15,154	15,651	14,245	15,495
Energy Losses[2]	204,339	210,596	216,592	226,415	220,944

[1] The shift in magnitude for net exchange reflects a change in accounting procedures by electric utilities because of reclassificatiion 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 1994 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 32. Net Generation from U.S. Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1990 Through 1994
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1990	1991	1992	1993	1994
ECAR	485,128	488,102	483,530	494,602	492,074
ERCOT	188,586	192,000	190,442	198,187	204,256
MAAC	193,393	197,235	193,330	205,552	206,221
MAIN	201,653	206,906	200,288	217,284	221,770
MAPP(U.S.)	120,750	122,991	120,053	124,808	124,607
NPCC(U.S.)	227,866	218,053	202,978	195,140	189,546
SERC	611,708	630,562	637,803	667,464	678,423
SPP	244,762	244,415	242,514	256,901	260,024
WSCC(U.S.)	535,242	523,468	522,863	527,428	537,398
Contiguous U.S.	**2,809,087**	**2,823,732**	**2,793,801**	**2,887,366**	**2,914,319**
ASCC	4,660	4,654	4,735	4,660	4,914
Hawaii	7,746	6,991	6,555	5,790	5,728
U.S. Total	**2,821,493**	**2,835,377**	**2,805,092**	**2,897,815**	**2,924,960**

Notes: •Data for 1994 are preliminary; data for prior years are final. •Annual net generation data shown here should only be used in comparison with other Form EIA-861 data. Differences in this net generation data and net generation reported on the Form EIA-759, "Monthly Power Plant Report," (Table 1) occur due to the time frame in reporting. Since the components of net generation are provided monthly by the Form EIA-759 by prime mover and energy source, the Form EIA-759 is used as the official Energy Information Administration source for net generation. •Totals may not equal sum of components because of independent rounding.

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

Table 33. U.S. Electric Utility Sales to Ultimate Consumers by Sector, North American Electric Reliability Council Region, and Hawaii, 1990 Through 1994
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	All Sectors	Residential	Commercial	Industrial	Other[1]
			1990		
ECAR	418,732	125,258	93,318	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**
			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**
			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.)	117,283	41,724	25,510	46,877	3,171
NPCC(U.S.)	233,393	76,773	84,839	57,553	14,228
SERC	609,139	239,899	153,232	198,441	17,567
SPP	235,320	80,251	59,964	87,121	7,984
WSCC(U.S.)	511,395	162,773	163,083	165,208	20,331
Contiguous U.S.	**2,750,695**	**931,976**	**756,962**	**968,534**	**93,223**
ASCC	4,338	1,640	2,034	504	160
Hawaii	8,332	2,323	2,274	3,676	59
U.S. Total	**2,763,365**	**935,939**	**761,271**	**972,714**	**93,442**

See footnotes at end of table.

Table 33. U.S. Electric Utility Sales to Ultimate Consumers by Sector, North American Electric Reliability Council Region, and Hawaii, 1990 Through 1994 (Continued)
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	All Sectors	Residential	Commercial	Industrial	Other[1]
			1993		
ECAR	447,062	139,068	108,441	189,527	10,026
ERCOT	212,182	76,887	55,602	70,508	9,185
MAAC	220,037	77,450	69,026	70,687	2,873
MAIN	207,004	61,610	57,843	78,858	8,693
MAPP(U.S.)	124,143	44,718	26,568	49,353	3,504
NPCC(U.S.)	236,012	78,417	86,723	56,570	14,302
SERC	638,223	256,275	158,893	204,832	18,223
SPP	249,888	88,012	62,962	90,606	8,308
WSCC(U.S.)	514,212	168,376	164,167	162,076	19,593
Contiguous U.S.	**2,848,766**	**990,812**	**790,229**	**973,017**	**94,708**
ASCC	4,374	1,629	2,062	501	182
Hawaii	8,325	2,340	2,285	3,646	54
U.S. Total	**2,861,462**	**994,781**	**794,573**	**977,164**	**94,944**
			1994		
ECAR	459,740	139,519	111,730	198,790	9,701
ERCOT	218,781	78,709	57,209	73,248	9,615
MAAC	223,639	78,267	75,476	66,999	2,897
MAIN	214,308	62,094	60,090	83,056	9,068
MAPP(U.S.)	128,881	45,330	28,012	51,769	3,770
NPCC(U.S.)	238,677	79,176	89,590	55,255	14,656
SERC	656,478	261,240	164,290	212,424	18,524
SPP	257,193	88,909	65,469	94,329	8,487
WSCC(U.S.)	523,695	171,081	163,782	167,957	20,875
Contiguous U.S.	**2,921,391**	**1,004,324**	**815,647**	**1,003,827**	**97,593**
ASCC	4,533	1,688	2,155	511	179
Hawaii	8,593	2,428	2,451	3,659	56
U.S. Total	**2,934,517**	**1,008,440**	**820,252**	**1,007,997**	**97,827**

[1] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.
Notes: •Data for 1994 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 34. Generating Capability at U.S. Electric Utilities by North American Electric Reliability Council Region and Hawaii, as of December 1990 Through 1994
(Megawatts)

North American Electric Reliability Council Region and Hawaii	1990	1991	1992	1993	1994
ECAR	102,379	104,925	104,661	104,818	104,812
ERCOT	51,016	51,213	51,688	52,889	53,110
MAAC	50,323	51,331	51,553	51,589	51,494
MAIN	49,475	49,544	49,730	50,314	50,863
MAPP(U.S.)	30,772	31,057	30,968	30,915	31,357
NPCC(U.S.)	55,587	55,443	54,637	56,043	55,958
SERC	146,286	146,447	148,127	149,748	151,729
SPP	70,519	70,642	70,771	71,009	71,099
WSCC(U.S.)	129,280	129,346	129,694	129,334	128,897
Contiguous U.S.	**685,637**	**689,948**	**691,828**	**696,659**	**699,319**
ASCC	1,542	1,547	1,672	1,711	1,737
Hawaii	1,487	1,521	1,560	1,602	1,602
U.S. Total	**690,465**	**693,016**	**695,059**	**699,971**	**702,658**

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 35. Noncoincidental Peak Load at U.S. Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1990 Through 1994
(Megawatts)

North American Electric Reliability Council Region and Hawaii	1990	1991	1992	1993	1994
			Summer		
ECAR	79,258	81,539	78,550	R 85,930	87,165
ERCOT	42,737	41,870	42,619	44,255	44,162
MAAC	42,613	45,937	43,658	46,494	46,019
MAIN	40,740	41,598	38,819	41,956	42,562
MAPP(U.S.)	24,994	25,498	22,638	24,396	27,000
NPCC(U.S.)	44,116	46,594	43,658	46,706	47,581
SERC	121,149	124,688	128,236	136,101	132,584
SPP	52,541	51,885	51,324	57,106	56,035
WSCC(U.S.)	97,389	92,096	99,205	97,809	102,212
Contiguous U.S.	**545,537**	**551,705**	**548,707**	**R 580,753**	**585,320**
ASCC	463	471	504	511	524
Hawaii	[1]	[1]	[1]	[1]	[1]
U.S. Total	**546,000**	**551,176**	**549,211**	**R 581,264**	**585,844**
			Winter		
ECAR	67,097	71,181	72,885	81,846	75,638
ERCOT	35,815	35,448	35,055	35,407	36,180
MAAC	36,551	37,983	37,915	41,406	40,653
MAIN	32,461	33,420	31,289	34,966	33,999
MAPP(U.S.)	21,113	21,432	21,866	21,955	23,033
NPCC(U.S.)	40,545	41,786	41,125	42,063	42,547
SERC	117,231	119,575	121,250	133,635	132,661
SPP	38,949	38,759	39,912	41,644	42,505
WSCC(U.S.)	94,252	86,097	91,686	88,811	91,037
Contiguous U.S.	**484,014**	**485,681**	**492,983**	**521,733**	**518,253**
ASCC	613	622	635	632	641
Hawaii	[1]	[1]	[1]	[1]	[1]
U.S. Total	**484,627**	**486;303**	**493,618**	**522,365**	**518,894**

[1] Data for Hawaii are not submitted for this form.

R = Revised data.

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

Sources: **Data for 1994:** North American Reliability Council, *Electricity Supply and Demand 1995-2004;* **Data for prior years:** Department of Energy, Office of Emergency Policy, Form PO-411, "Coordinated Region Bulk Power Supply Program."

Table 36. U.S. Electric Utility Receipts by North American Electric Reliability Council Region and Hawaii, 1990 Through 1994
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Receipts[1]	Purchased Power	Exchange Received	Wheeling Received
			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**
			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**
			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.)	227,570	163,419	3,464	60,687
SERC	378,689	325,039	26,439	27,211
SPP	150,335	123,644	4,943	21,749
WSCC(U.S.)	478,769	275,031	76,224	127,514
Contiguous U.S.	**1,829,453**	**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**

See footnotes at end of table.

Table 36. U.S. Electric Utility Receipts by North American Electric Reliability Council Region and Hawaii, 1990 Through 1994 (Continued)
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Receipts[1]	Purchased Power	Exchange Received	Wheeling Received
		1993		
ECAR	201,396	167,278	2,927	31,191
ERCOT	144,491	63,523	54,253	26,716
MAAC	93,051	76,663	3,256	13,132
MAIN	67,930	62,511	400	5,018
MAPP(U.S.)	109,222	89,875	2,567	16,781
NPCC(U.S.)	249,585	178,147	3,622	67,815
SERC	398,660	341,136	30,391	27,132
SPP	166,846	135,037	6,282	25,528
WSCC(U.S.)	485,155	287,564	59,660	137,931
Contiguous U.S.	**1,916,336**	**1,401,733**	**163,359**	**351,244**
ASCC	3,039	2,582	0	456
Hawaii	3,106	3,103	3	0
U.S. Total	**1,922,481**	**1,407,419**	**163,361**	**351,701**
		1994		
ECAR	199,010	166,167	1,982	30,861
ERCOT	141,092	61,900	55,122	24,069
MAAC	94,914	79,911	3,214	11,789
MAIN	66,539	61,161	502	4,877
MAPP(U.S.)	109,000	87,548	2,414	19,038
NPCC(U.S.)	267,637	194,500	4,105	69,032
SERC	397,661	340,918	31,609	25,134
SPP	172,132	142,632	5,955	23,545
WSCC(U.S.)	472,025	294,190	49,919	127,915
Contiguous U.S.	**1,920,009**	**1,428,926**	**154,822**	**336,260**
ASCC	3,951	3,183	73	695
Hawaii	3,444	3,442	3	0
U.S. Total	**1,927,404**	**1,435,551**	**154,898**	**336,955**

[1] Equals purchased power plus exchange received plus wheeling received.

Notes: •Data for 1994 are preliminary; data for prior years are final. •Totals may not equal sum of components because of independent rounding. •This is a summation of utility trade for utilities that operate within the NERC Region. •Due to the complexity of electric power transactions that involve specifics of contracts, simultaneous energy transactions, the unintended receipt and delivery of energy (inadvertent flow), and losses, uniformity in reporting the classification and quantity of each transaction among utilities may not exist. •Includes utility, import, export, and nonutility transactions.

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

Table 37. U.S. Electric Utility Deliveries by North American Electric Reliability Council Region and Hawaii, 1990 Through 1994

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Deliveries[1]	Requirements and Nonrequirements Sales for Resale	Exchange Delivered	Wheeling Delivered
		1990		
ECAR	278,650	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**
		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**
		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**

See footnotes at end of table.

Table 37. U.S. Electric Utility Deliveries by North American Electric Reliability Council Region and Hawaii, 1990 Through 1994 (Continued)
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Deliveries[1]	Requirements and Nonrequirements Sales for Resale	Exchange Delivered	Wheeling Delivered
		1993		
ECAR	216,294	182,147	3,153	30,994
ERCOT	114,854	33,760	54,409	26,686
MAAC	60,556	47,525	1	13,030
MAIN	62,541	57,410	180	4,951
MAPP(U.S.)	98,325	77,943	4,251	16,130
NPCC(U.S.)	189,109	119,632	1,923	67,553
SERC	374,073	321,445	27,304	25,324
SPP	151,816	119,353	7,044	25,419
WSCC(U.S.)	442,657	238,351	67,816	136,489
Contiguous U.S.	**1,710,224**	**1,197,567**	**166,081**	**346,576**
ASCC	2,936	2,480	0	456
Hawaii	5	0	5	0
U.S. Total	**1,713,165**	**1,200,047**	**166,086**	**347,032**
		1994		
ECAR	199,205	166,045	2,513	30,647
ERCOT	112,985	33,536	55,360	24,088
MAAC	60,205	48,483	2	11,720
MAIN	58,584	53,490	284	4,810
MAPP(U.S.)	92,834	70,181	4,236	18,417
NPCC(U.S.)	198,778	128,171	1,871	68,735
SERC	367,081	312,497	31,071	23,514
SPP	153,989	124,902	5,638	23,448
WSCC(U.S.)	429,034	244,874	57,489	126,672
Contiguous U.S.	**1,672,694**	**1,182,180**	**158,465**	**332,050**
ASCC	3,945	3,172	78	695
Hawaii	6	0	6	0
U.S. Total	**1,676,646**	**1,185,352**	**158,549**	**332,745**

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

Notes: •Data for 1994 are preliminary; data for prior years are final. •Totals may not equal sum of components because of independent rounding. •This is a summation of utility trade for utilities that operate within the NERC Region. •Due to the complexity of electric power transactions that involve specifics of contracts, simultaneous energy transactions, the unintended receipt and delivery of energy (inadvertent flow), and losses, uniformity in reporting the classification and quantity of each transaction among utilities may not exist. •Includes utility, import, export, and nonutility transactions.

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

Table 38. U.S. Electric Utility Net Energy Flow by North American Electric Reliability Council Region and Hawaii, 1990 Through 1994
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Net Energy Flow[1]	Receipts[2]	Deliveries[3]
		1990	
ECAR	-35,487	243,163	278,650
ERCOT	26,337	111,413	85,076
MAAC	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**
		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**
		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.)	48,967	227,570	178,603
SERC	21,542	378,689	357,147
SPP	12,795	150,335	137,540
WSCC(U.S.)	47,206	478,769	431,563
Contiguous U.S.	**192,583**	**1,829,453**	**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**

See footnotes at end of table.

Table 38. U.S. Electric Utility Net Energy Flow by North American Electric Reliability Council Region and Hawaii, 1990 Through 1994 (Continued)

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Net Energy Flow[1]	Receipts[2]	Deliveries[3]
		1993	
ECAR	-14,898	201,396	216,294
ERCOT	29,637	144,491	114,854
MAAC	32,495	93,051	60,556
MAIN	5,388	67,930	62,541
MAPP(U.S.)	10,898	109,222	98,325
NPCC(U.S.)	60,476	249,585	189,109
SERC	24,587	398,660	374,073
SPP	15,031	166,846	151,816
WSCC(U.S.)	42,498	485,155	442,657
Contiguous U.S.	**206,112**	**1,916,336**	**1,710,224**
ASCC	103	3,039	2,936
Hawaii	3,101	3,106	5
U.S. Total	**209,316**	**1,922,481**	**1,713,165**
		1994	
ECAR	-195	199,010	199,205
ERCOT	28,107	141,092	112,985
MAAC	34,709	94,914	60,205
MAIN	7,956	66,539	58,584
MAPP(U.S.)	16,165	109,000	92,834
NPCC(U.S.)	68,859	267,637	198,778
SERC	30,580	397,661	367,081
SPP	18,143	172,132	153,989
WSCC(U.S.)	42,990	472,025	429,034
Contiguous U.S.	**247,314**	**1,920,009**	**1,672,694**
ASCC	6	3,951	3,945
Hawaii	3,438	3,444	6
U.S. Total	**250,758**	**1,927,404**	**1,676,646**

[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 1994 are preliminary; data for prior years are final. •Totals may not equal sum of components because of independent rounding. •This is a summation of utility trade for utilities that operate within the NERC Region. •Due to the complexity of electric power transactions that involve specifics of contracts, simultaneous energy transactions, the unintended receipt and delivery of energy (inadvertent flow), and losses, uniformity in reporting the classification and quantity of each transaction among utilities may not exist. •Includes utility, import, export, and nonutility transactions.

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

Table 39. U.S. Electric Utility Purchases of Nonutility Generated Electricity by North American Electric Reliability Council Region and Hawaii, 1990 Through 1994

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1990	1991	1992	1993	1994
ECAR	7,878	8,649	10,420	11,962	12,659
ERCOT	23,570	23,036	23,666	24,267	23,264
MAAC	8,007	12,721	16,433	18,083	20,911
MAIN	283	273	347	401	392
MAPP(U.S.)	348	1,563	576	582	585
NPCC(U.S.)	15,037	23,220	36,116	42,724	49,348
SERC	10,928	12,914	15,304	19,021	24,020
SPP	3,514	5,705	5,457	6,809	6,857
WSCC(U.S.)	45,978	49,951	55,637	61,580	67,297
Contiguous U.S.	**115,542**	**138,033**	**163,957**	**185,429**	**205,333**
ASCC	1	1	1	4	4
Hawaii	522	1,402	2,324	3,103	3,442
U.S. Total	**116,065**	**139,436**	**166,283**	**188,537**	**208,779**

Notes: •Data for 1994 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 40. Net Imports at U.S. Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1990 Through 1994
(Thousand Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1990	1991	1992	1993	1994
ECAR	-10,918,913	-446,412	-231,967	931,679	6,906,673
ERCOT	-8,744	-195,548	-169,142	-7,760	-25,191
MAAC	–	–	–	–	–
MAIN	–	–	–	–	–
MAPP(U.S.)	742,954	3,307,714	6,921,800	7,808,685	9,380,144
NPCC(U.S.)	6,562,311	10,989,137	12,053,907	16,756,045	23,535,934
SERC	–	–	–	–	–
SPP	–	–	–	–	–
WSCC(U.S.)	5,602,571	8,617,259	9,773,701	2,938,533	4,840,154
Contiguous U.S.	**1,980,179**	**22,272,150**	**28,348,299**	**28,427,182**	**44,637,717**
ASCC	*	*	*	*	*
Hawaii	–	–	–	–	–
U.S. Total	**1,980,179**	**22,272,150**	**28,348,299**	**28,427,182**	**44,637,717**
Net Canada	619,353	20,773,039	31,927,468	27,283,021	43,695,066
Net Mexico	1,360,826	1,499,111	1,032,552	1,144,160	942,651

* =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 trade with Canada and Mexico. •Net imports data represent gross imports minus gross exports.

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

Table 41. Imports to U.S. Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1990 Through 1994
(Thousand Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1990	1991	1992	1993	1994
ECAR	38,234	106,606	82,151	959,746	6,909.598
ERCOT	1,121	14	–	14	70
MAAC	–	–	–	–	–
MAIN	–	–	–	–	–
MAPP(U.S.)	3,072,170	4,708,775	8,573,652	10,767,276	10,130,216
NPCC(U.S.)	9,272,554	13,051,823	14,699,638	18,741,212	25,080,505
SERC	–	–	–	–	–
SPP	–	–	–	–	–
WSCC(U.S.)	10,122,141	12,945,048	13,848,735	8,613,566	10,109,276
Contiguous U.S.	**22,506,220**	**30,812,266**	**37,204,176**	**39,081,814**	**52,229,668**
ASCC	*	*	*	*	*
Hawaii	–	–	–	–	–
U.S. Total	**22,506,220**	**30,812,266**	**37,204,176**	**39,081,814**	**52,229,668**
From Canada	20,554,932	28,696,527	35,181,757	37,088,486	50,218,349
From Mexico	1,951,288	2,115,739	2,022,419	1,993,327	2,011,319

* =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 exported to Canada and Mexico.

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

Table 42. Exports from U.S. Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1990 Through 1994
(Thousand Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1990	1991	1992	1993	1994
ECAR	10,957,147	553,018	314,118	28,067	2,925
ERCOT	9,865	195,562	169,142	7,774	25,261
MAAC	—	—	—	—	—
MAIN	—	—	—	—	—
MAPP(U.S.)	2,329,216	1,401,061	1,651,852	2,958,591	750,072
NPCC(U.S.)	2,710,243	2,062,686	2,645,731	1,985,167	1,544,571
SERC	—	—	—	—	—
SPP	—	—	—	—	—
WSCC(U.S.)	4,519,570	4,327,789	4,075,034	5,675,033	5,269,122
Contiguous U.S.	**20,526,041**	**8,540,116**	**8,855,877**	**10,654,632**	**7,591,951**
ASCC	*	*	*	*	*
Hawaii	—	—	—	—	—
U.S. Total	**20,526,041**	**8,540,116**	**8,855,877**	**10,654,632**	**7,591,951**
To Canada	19,935,579	7,923,488	3,254,289	9,805,465	6,523,283
To Mexico	590,462	616,628	989,867	849,167	1,068,668

* =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 exported to Canada and Mexico.

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

U.S. Electric Utility Demand-Side Management

U.S. electric utilities have come to realize that a flexible and diverse management strategy provides the greatest opportunity for success in the competitive and uncertain environment in which they operate. An important component of this strategy has been the increasing reliance on demand-side management (DSM) programs to modify the growth in demand for energy use, to cost-effectively meet customer energy service requirements, to selectively expand customer services, and to improve and optimize 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 electric utilities planning, implementing, and monitoring of activities that are designed to encourage consumers to modify their level and pattern of electricity usage. 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 (IRP) 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, resource prices, new technologies, and changes in regulatory and tax policy. Regulatory review of utility resource planning along with requirements that utilities follow an IRP process evolved from the forecasting and citing 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. More than 40 States have implemented integrated resource planning. In addition to balanced consideration of supply- and demand-side options, the IRP process includes consideration of risk and diversity of supply, maintenance of system reliability, and in some instances the application of specific values to reflect environmental and other external 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 affect on the amount of annual electricity consumption. For example, residential and commercial air conditioners or water heaters may be allowed to operate unimpeded during off-hour peak demand hours, but are cycled on and off by direct control of the utility during a few peak-demand hours. Third, flexible load shape programs provide consumers a price signal or incentive to modify their consumption in response to changes in the utility's cost of providing power. Real time pricing is an example of this type of program. Fourth, strategic load growth or electrification programs are designed to increase electricity consumption typically by building usage during valleys of low consumption or introducing new, efficient electrotechnologies. Such programs may facilitate the efficient operation of baseload generating units, reduce rates, and help customers meet environmental requirements, enhance product quality, or lower costs by replacing less efficient energy sources.

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

Energy Efficiency - Energy efficiency programs 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 often target high-use seasons or times of day. While they reduce overall electricity consumption over many hours during the year, the largest impacts of cost-effective programs often coincide with periods of peak usage. 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 primarily 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 peak loads, 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. The category 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.[21]

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.[22]

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

To compare DSM programs to other demand- and supply-side resources, regulators have developed standardized benefit/cost tests. Five benefit-cost tests are widely used in planning to identify cost-effective DSM programs. 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, should be implemented.

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

21 Self-generation of electricity for consumers' use is included in the Other DSM category only to the extent that it is not accounted for as backup generation in Other Load Management or Interruptible Load categories. Also, self-generation in the Other DSM category 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.

22 Load building, although collected on the Form EIA-861, Schedule V, is not included in the discussion of data in this publication.

The Participant Test measures the quantifiable benefits and costs to consumers who participate in the DSM program. It attempts to determine to answer whether or not the participant is better off with the DSM technology and likely to participate in future 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 or 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 participant and utility costs (the Societal Cost Test is a variant of this test that incorporates externalities and excludes tax credits). The Total Resources Cost Test 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 takes 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.[23] 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.[24]

Program Implementation

Another component of DSM program development is the marketing plan to implement a package of cost-effective programs through customer education, direct contact, cooperation with trade ally (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 services such as appliance and equipment dealers, building contractors, and architectural and engineering firms, or directly to consumers to encourage consumer participation in a DSM program and adoption of recommended measures. Appliance rebates and zero- or low-interest loans are common examples of incentive programs. Lastly, utilities offer alternative-rate programs, such as discounts or refunds on monthly electric bills, in return for consumer participation in 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 significantly alter the load curve of the utility system.

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

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

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

sector have increased significantly, with program activities focusing on energy-management assistance, cool storage, lighting, heating and air conditioning, and water heating improvements.

DSM program development in the industrial sector has been slow compared to its development in the residential and commercial sectors. The wide variety of industrial process uses initially hindered the design of DSM programs tailored to the industrial sector. Utilities traditionally relied on alternative rate-design approaches, such as interruptible service and time-of-use rates to achieve DSM objectives in the industrial sector. Utilities have broadened their DSM approach to include incentive and financing programs for industrial lighting, thermal storage, electrotechnology, advanced motors and drive systems, compressed-air systems, and other process-energy uses that have the potential to meet energy-efficiency and load-management objectives. A number of utilities have also developed flexible custom measure programs that 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 by verifying DSM results, assessing the effectiveness of the program, providing 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 peak load reduction or its reduction per consumer. Utilities interested in reducing overall energy consumption measure both peak load reduction and total energy savings. When evaluating program success, utilities typically determine the level of load-and-energy reductions, program costs per unit of energy and/or demand savings, and program participation rates.

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

The analytical procedures applied to estimate electricity and load changes involve a variety of techniques. These techniques include using engineering estimates to derive the energy-saving effect per installation of each 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 way 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.[25]

As utility DSM budgets have grown, exceeding $2.7 billion in 1994, it has become increasingly important to know what DSM programs have accomplished. This has led to more sophisticated efforts to measure and evaluate an increased number of programs. Nevertheless, detailed impact and process evaluations have been completed on only a small fraction of all DSM programs. These evaluations vary with respect to the methodologies employed, the issues and types of programs studied, and the purposes for which evaluations were conducted. Because practices 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.[26]

Data Sources

The data in the following tables were collected on Schedule V, "Demand-Side Management Information," of the 1994 Form EIA-861, "Annual Electric Utility Report." Schedule V collects utility information on actual and potential peak load reductions and energy savings for six program categories (Energy Efficiency, Direct Load Control, Interruptible Load, Other Load Management, Other DSM Programs, and Load Building) by four major consumer sectors (residential, commercial, industrial, and other). Utilities provide information for the reporting year (1994) and the first and fifth forecast years (1995 and 1999).

Both annual and incremental energy savings and peak load reductions are collected for the reporting year. Annual effects are the total effects in energy use and peak load caused by all new and prior-year participants in the DSM programs that are in place during a

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

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

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

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

Table 43. U.S. Electric Utility Demand Side Management Program Energy Savings, Actual and Potential Peak Load Reductions, and Cost, 1990 Through 1994

Item	1990	1991	1992	1993	1994
Energy Savings (million kilowatthours)[1]	20,458	24,848	35,563	45,294	52,483
Actual Peak Load Reductions (megawatts)[1 2]	13,704	15,619	17,204	23,069	25,001
Potential Peak Load Reductions (megawatts)[1 2]	NA	NA	32,442	39,508	42,917
Cost (thousand dollars)[3]	1,177,457	1,803,773	2,348,094	2,743,533	2,715,700

[1] Represents the total annual 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 peak load reduction capability (i.e., Potential Peak Reduction).

[3] 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. Nonutility costs are excluded.

NA=Data not available.

Notes: •Data for 1994 are preliminary; data for prior years are final. •Data are provided for electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 120,000 megawatthours. •Data for 1994 for peak load growth (1,324,865 megawatts), energy sales (4,011,227 megawatthours), and cost ($42,106 (thousands)) attributable to Load Building programs are excluded. •Due to data corrections by several large utilities totals may not equal those previously published in the Electric Power Annual, 1993.

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

Table 44. U.S. Electric Utility Actual Peak Load Reductions by North American Electric Reliability Council Region and Hawaii, by Demand-Side Management Program Category, 1990 Through 1994 (Megawatts)

North American Electric Reliability Council Region and Hawaii	Total Actual Peak Load Reduction	Direct Load Control	Interruptible Load	Energy Efficiency, Other Load Management, and Other Demand-Side Management
		1990		
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	6,231	1,577	1,473	2,070
SPP	761	429	203	129
WSCC(U.S.)	2,308	370	275	1,663
Contiguous U.S.	**13,661**	**3,691**	**4,185**	**5,785**
ASCC	4	1	3	0
Hawaii	39	0	31	8
U.S. Total	**13,704**	**3,692**	**4,219**	**5,793**
		1991		
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	4,876	2,030	602	2,244
SPP	1,155	506	428	221
WSCC(U.S.)	2,668	414	287	1,967
Contiguous U.S.	**15,574**	**5,091**	**3,646**	**6,837**
ASCC	5	2	3	0
Hawaii	40	0	25	15
U.S. Total	**15,619**	**5,093**	**3,674**	**6,852**

See footnotes at end of table.

Table 44. U.S. Electric Utility Actual Peak Load Reductions by North American Electric Reliability Council Region and Hawaii, by Demand-Side Management Program Category, 1990 Through 1994 (Continued) (Megawatts)

	Total Actual Peak Load Reduction	Direct Load Control	Interruptible Load	Energy Efficiency	Other Load Management	Other Demand-Side Management
			1992			
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	5,559	1,582	684	2,638	487	168
SPP	624	370	117	85	6	46
WSCC(U.S.)	3,902	188	1,074	2,351	237	52
Contiguous U.S.	**17,194**	**3,777**	**3,579**	**7,889**	**1,669**	**281**
ASCC	7	2	0	*	4	0
Hawaii	4	0	0	1	3	0
U.S. Total	**17,204**	**3,779**	**3,579**	**7,890**	**1,676**	**281**
			1993			
ECAR	1,671	179	773	573	115	31
ERCOT	1,414	42	114	949	291	17
MAAC	1,493	329	516	301	340	7
MAIN	844	60	247	494	39	4
MAPP(U.S.)	2,121	793	632	413	270	12
NPCC(U.S.)	1,968	201	228	1,520	18	*
SERC	8,447	1,770	2,792	3,329	439	115
SPP	889	395	323	111	36	23
WSCC(U.S.)	4,210	183	1,003	2,671	250	104
Contiguous U.S.	**23,597**	**3,953**	**6,628**	**10,363**	**1,799**	**315**
ASCC	7	2	0	*	4	0
Hawaii	5	0	0	5	0	0
U.S. Total	**23,069**	**3,955**	**6,628**	**10,368**	**1,803**	**315**
			1994			
ECAR	1,583	200	634	631	103	15
ERCOT	1,838	20	77	1,420	301	19
MAAC	1,803	353	676	414	356	4
MAIN	1,177	26	523	576	46	6
MAPP(U.S.)	2,319	933	656	505	211	14
NPCC(U.S.)	2,261	90	194	1,959	16	1
SERC	8,562	2,118	2,736	3,023	494	192
SPP	855	232	249	177	185	13
WSCC(U.S.)	4,584	203	998	2,950	376	57
Contiguous U.S.	**24,983**	**4,176**	**6,743**	**11,655**	**2,088**	**321**
ASCC	8	2	0	1	0	4
Hawaii	10	0	0	6	4	0
U.S. Total	**25,001**	**4,179**	**6,743**	**11,662**	**2,092**	**326**

Notes: •Data for 1994 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 peak load 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).

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

Table 45. U.S. Electric Utility Demand-Side Management Program Annual and Incremental Effects by Program Category, 1994

Program	Actual Peak Load Reduction[1] (megawatts)	Potential Peak Load Reduction[2] (megawatts)	Energy Savings (million kilowatthours)
	Annual Effects[3]		
Large Utilities[4]			
Energy Efficiency[5]	11,662	11,662	49,720
Direct Load Control	4,179	8,890	170
Interruptible Load	6,743	19,384	969
Other Load Management[6]	2,092	2,468	190
Other Demand-Side Management[7]	326	513	1,434
U.S. Total	25,001	42,917	52,483
	Incremental Effects[8]		
Large Utilities[4]			
Energy Efficiency[5]	1,751	1,751	8,054
Direct Load Control	457	884	15
Interruptible Load	704	2,822	12
Other Load Management[6]	224	282	7
Other Demand-Side Management[7]	33	165	141
Small Utilities[9]			
Energy Efficiency[5]	9	9	11
Direct Load Control	27	41	4
Interruptible Load	21	30	*
Other Load Management[6]	6	8	2
Other Demand-Side Management[7]	2	2	1
U.S. Total	3,234	5,994	8,247

[1] Represents the sum of the actual peak load reductions attributable to direct load control, interruptible load, energy efficiency, other load management, and other demand-side management.

[2] Represents the sum of the potential peak load reductions attributable to direct load control, interruptible load, other load management, other demand-side management, including the actual peak load reduction achieved by energy efficiency programs.

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

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

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

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

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

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

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

* =Value less than 0.5.

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."

Table 46. U.S. Electric Utility Demand-Side Management Program Annual and Incremental Effects by Sector, 1994

Sector	Actual Peak Load Reduction[1] (megawatts)	Potential Peak Load Reduction[2] (megawatts)	Energy Savings (million kilowatthours)
	Annual Effects[3]		
Large Utilities[4]			
Residential	9,638	13,851	21,028
Commercial	6,927	9,915	21,773
Industrial[5]	7,977	18,271	8,568
Other[6]	460	881	1,114
U.S. Total	25,001	42,917	52,483
	Incremental Effects[7]		
Large Utilities[4]			
Residential	1,083	1,467	2,194
Commercial	1,244	2,115	4,449
Industrial[5]	785	1,997	1,325
Other[6]	57	326	262
Small Utilities[8]			
Residential	27	38	13
Commercial	7	12	3
Industrial[5]	24	31	1
Other[6]	6	8	1
U.S. Total	3,234	5,994	8,247

[1] Represents the sum of the actual peak load reductions attributable to direct load control, interruptible load, energy efficiency, other load management, and other demand-side management.

[2] Represents the sum of the potential peak load reductions attributable to direct load control, interruptible load, other load management, other demand-side management, including the actual peak load reduction achieved by energy efficiency programs.

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

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

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

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

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

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

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."

Table 47. U.S. Electric Utility Potential Peak Load Reduction by Direct Load Control and Interruptible Load and by North American Electric Reliability Council Region and Hawaii, Selected Years
(Megawatts)

North American Electric Reliability Council Region and Hawaii	Historical Reductions					Projected Reductions	
	1990	1991	1992	1993	1994	1995	1999
	Direct Load Control						
ECAR	218	337	222	227	247	242	430
ERCOT	40	68	121	164	202	225	287
MAAC	422	756	933	1,033	1,260	1,154	1,447
MAIN	86	64	147	190	211	257	497
MAPP(U.S.)	780	1,020	1,054	1,252	1,368	1,483	1,837
NPCC(U.S.)	135	222	188	219	104	103	141
SERC	2,383	3,271	3,814	3,950	4,339	4,159	5,108
SPP	460	569	533	615	434	444	454
WSCC(U.S.)	682	731	612	612	724	569	719
Contiguous U.S.	**5,206**	**7,038**	**7,624**	**8,263**	**8,888**	**8,635**	**10,921**
ASCC	1	2	2	2	2	3	3
Hawaii	0	0	0	0	0	0	0
U.S. Total	**5,207**	**7,040**	**7,626**	**8,266**	**8,890**	**8,637**	**10,923**
	Interruptible Load						
ECAR	853	1,036	1,214	1,456	1,643	1,389	1,777
ERCOT	1,624	1,293	1,736	1,968	1,803	1,028	1,008
MAAC	760	724	838	1,152	1,614	1,413	1,708
MAIN	786	735	867	803	1,116	1,116	1,249
MAPP(U.S.)	674	682	789	823	973	1,147	1,335
NPCC(U.S.)	572	379	371	358	245	232	211
SERC	2,331	2,759	4,204	6,624	6,816	7,074	7,518
SPP	705	813	1,181	2,041	2,004	2,395	2,661
WSCC(U.S.)	2,646	3,038	3,353	2,997	3,167	2,847	2,701
Contiguous U.S.	**10,951**	**11,459**	**14,553**	**18,222**	**19,380**	**18,641**	**20,169**
ASCC	3	3	0	0	0	0	0
Hawaii	31	25	13	12	4	4	4
U.S. Total	**10,985**	**11,487**	**14,566**	**18,235**	**19,384**	**18,645**	**20,173**

Notes: •Data for 1994, 1995, and 1999 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 megawatthours. •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 48. U.S. Electric Utility Demand-Side Management Energy Savings by North American Electric Reliability Council Region and Hawaii, Selected Years
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Historical Savings					Projected Savings	
	1990	1991	1992	1993	1994	1995	1999
ECAR	636	1,072	1,129	1,779	2,237	2,908	5,177
ERCOT	227	393	1,013	2,288	3,739	1,310	2,099
MAAC	450	549	954	1,150	1,820	2,414	5,030
MAIN	721	1,081	1,212	2,125	2,453	2,731	4,454
MAPP(U.S.)	465	494	940	1,581	1,883	2,545	4,480
NPCC(U.S.)	2,065	3,657	5,049	6,769	8,422	9,118	13,303
SERC	7,232	7,481	10,492	11,264	11,768	12,339	15,036
SPP	146	156	273	365	492	528	691
WSCC(U.S.)	8,360	9,801	14,491	17,954	19,634	18,893	21,267
Contiguous U.S.	**20,302**	**24,684**	**35,554**	**45,275**	**52,449**	**52,783**	**71,536**
ASCC	0	0	*	2	3	5	11
Hawaii	156	164	9	17	31	42	336
U.S. Total	**20,458**	**24,848**	**35,563**	**45,294**	**52,483**	**52,831**	**71,883**

* =Value less than 0.5.

Notes: •Data for 1994, 1995, and 1999 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 megawatthours.

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

Table 49. U.S. Electric Utility Demand-Side Management Cost by North American Electric Reliability Council Region and Hawaii, Selected Years
(Thousand Dollars)

North American Electric Reliability Council Region and Hawaii	Existing					Projected	
	1990	1991	1992	1993	1994	1995	1999
ECAR	15,355	36,534	130,903	187,137	137,118	138,101	129,950
ERCOT	33,147	52,701	55,675	62,533	69,538	74,710	67,121
MAAC	116,565	131,103	178,420	262,111	305,190	295,640	325,647
MAIN	89,651	93,316	133,610	128,607	96,253	107,026	138,907
MAPP(U.S.)	33,612	56,082	85,021	103,185	138,256	140,862	133,325
NPCC(U.S.)	317,640	511,632	542,222	565,145	462,668	408,361	409,050
SERC	258,695	643,081	510,489	643,081	684,690	696,424	739,310
SPP	22,648	24,652	30,927	33,376	28,626	32,717	33,273
WSCC(U.S.)	289,964	565,998	679,752	756,947	792,387	694,687	476,438
Contiguous U.S.	**1,177,277**	**1,803,769**	**2,347,019**	**2,741,832**	**2,714,726**	**2,588,528**	**2,453,021**
ASCC	177	0	315	419	386	851	1,161
Hawaii	3	4	760	1,282	588	2,865	38,034
Total Cost[1]	**1,177,457**	**1,803,773**	**2,348,094**	**2,743,533**	**2,715,700**	**2,592,244**	**2,492,216**

[1] 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. Nonutility costs are excluded.

Notes: •Data for 1994, 1995, and 1999 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 megawatthours. •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 ($42,106 (thousands) in 1994) is excluded.

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

Table 50. U.S. Electric Utility Demand-Side Management Direct and Indirect Cost, Selected Years
(Thousand Dollars)

Program	Historical Cost	Projected Costs	
	1994	1995	1999
Total Direct Cost[1]	2,254,036	2,172,170	2,054,701
Energy Efficiency	1,592,125	1,498,531	1,286,453
Direct Load Control	374,008	354,207	403,999
Interruptible Load	201,613	226,891	226,834
Other Load Management	54,017	52,459	49,313
Other Demand-Side Management	32,273	40,082	88,102
Total Indirect Cost[2]	461,598	418,028	434,722
Administrative	199,950	157,531	165,392
Marketing	66,188	82,208	79,405
Monitoring and Evaluation	78,839	66,218	58,433
Other[3]	116,621	112,071	131,492
Total Cost[4]	2,715,700	2,592,244	2,492,216

[1] Reflects electric utility cost incurred during the year that are identified with one of the demand-side program categories. Load building cost ($42,106 (thousands) for 1994, $48,025 (thousands) for 1995, and $69,711 (thousands) for 1999) 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. Nonutility costs are excluded.

Notes: •Data for 1994, 1995, and 1999 are preliminary. •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 megawatthours. •Nonutility cost ($397,424 (thousands) in 1994, $330,508 (thousands) in 1995, and $393,109 (thousands) in 1999) are excluded.

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

Table 51. Number of U.S. Electric Utilities with Demand-Side Management Energy Efficiency Programs by End Uses and Program Types by Sector, 1994

Item	Residential	Commercial	Industrial
End Uses			
Heating System	385	241	140
Cooling System	391	284	174
Water Heating	437	219	136
Lighting	246	275	212
Building Shell	222	139	101
New Construction	244	156	107
Appliances	170	85	51
Motors	—	174	176
Process Heating	—	57	101
Electrolytics	—	12	26
Other System	66	36	38
Program Types			
Energy Audits	410	337	248
Rebates	405	295	206
Loaning	187	105	68
Other Incentives[1]	126	98	74
Other	121	97	74

[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

This chapter provides an overview of U.S. nonutility power producers, and their generating technologies, together with statistical data on capacity, generation, sales, consumption and emissions for 1990 through 1994. These data are aggregated at the U.S. Census division level. Since nonutility data are confidential, the EIA implemented information disclosure rules. See "Nondisclosure of Data" in Appendix A. In 1989, the Energy Information Administration (EIA) began collecting nonutility electricity generation data on the Form EIA-867, "Annual Nonutility Power Producers Report." This survey enables 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 the 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 A.

Background

Early in the 20th century, more than half of all electricity produced in the United States came from industrial firms. However, during the first half of the 20th century, major changes occurred in the industry: economies of scale in generation, 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.

In the late 1970's, changing economic conditions and legislation made nonutility generation attractive again for many industrial facilities and power project developers. In addition, oil-price shocks in the 1970's led to a dramatic rise in energy prices, while high interest rates and stricter Federal air quality regulations increased the cost of building power plants. 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 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 prompted the passage of the Public Utility Regulatory Policies Act (PURPA) of 1978. 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 if they meet specific ownership,[27] 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.

The Energy Policy Act of 1992 (EPACT) amended the Public Utility Holding Company Act (PUHCA) of 1935. PUHCA was designed to discourage holding companies from structuring their operations in ways that would prevent effective State regulation. The following are provisions of EPACT potentially affecting the nonutility industry:

- The creation of exempt wholesale generators (EWG's), corporate entities that are engaged exclusively in the business of wholesale electric generation and that are exempt from corporate organizational restrictions under PUHCA. Entities that are currently subject to PUHCA (registered holding companies and exempt utility holding companies) and entities that are not currently subject to PUHCA (nonutilities and non-holding company utilities) are permitted to own EWG's without limitation. Registered holding companies, must obtain approval from the Securities Exchange Commission to finance EWG's and service sales and construction contracts involving EWG's. The EPACT removes obstacles to wholesale power competition in the PUHCA by allowing both utilities and nonutilities to form EWG's without triggering the restrictions of PUHCA.

- Allowing FERC to order upon application the 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. It also expands the program to promote the export of these renewable energy technologies to emerging markets in developing countries.

Recent Legislative and Regulatory Activities

Recent government activity that will affect nonutility power producers are largely motivated by the EPACT electricity provisions, the FERC and several States have been working to develop open-access transmission systems, restructure the wholesale power generation market, and reform the ratemaking process. However, regulators are moving cautiously until the competitive effects of changes in utility cost structure and business practices are thoroughly studied. For example, the pricing provisions in wholesale power supply and transmission service contracts are undergoing review as the electricity industry moves closer to a market-based pricing regime. Artificial market support mechanisms, such as PURPA's avoided cost and guaranteed market provisions, are being reviewed as well.

One notable Federal action to foster competition was the issuance of a proposed rulemaking in March 1995, *Open Access Non-discriminatory Transmission Services by Public Utilities* (Docket No. RM95-8-000). The proposed rule would require that all utilities file open-access transmission tariffs for wholesale electricity transmission services. These services would have to be nondiscriminatory in the sense that terms and conditions for service were comparable to those available to utilities. A number of States are considering complementary wheeling proposals. At least nine States currently have retail wheeling proposals under consideration. Nevada has already passed a retail wheeliing law, while Michigan recently set rates for a five-year experimental retail wheeling program for certain industrial customers. Other FERC actions include the issuance of a policy statement on flexible transmission pricing (Docket No. RM93-19-000), and an inquiry into the adequacy of current FERC power pool arrangement policies (Docket No. RM94-20-000).

PURPA is under review for streamlining or repeal of certain key provisions. The FERC issued a Final Rule in January 1995 that modified requirements for QF determination.[28] Key modifications included (1) allowing facilities to meet operating and efficiency standards on a 12-month basis (rather than calendar-year basis) to account for startup difficulties, (2) clarifying the "sequential-use-of energy" requirement[29], (3) removing the 80-megawatt size limitation for qualifying Small Power Producers (a temporary removal of the limitation was instituted by Congress in 1991), and (4) streamlining the QF determination process for facilities that use waste energy inputs. At the legislative level, a bill was introduced before the U.S. Senate in April 1995 that repeals Section 210 of PURPA. Known as the *Electric Utility Ratepayer Act* (S.708), the bill would eliminate the requirement that utilities must offer to purchase power from QF's. Proponents of the bill argue that the QF power purchase

27 FERC rules require that QF's be less than 50 percent owned by electric utilities.

28 Federal Energy Regulatory Commission, Order 575, "Streamlining of Regulations Pertaining to Parts II and III of the Federal Power Act and the Public Utility Regulatory Policies Act of 1978," January 13, 1995.

29 To meet FERC's "sequential energy" requirement, at least a portion of the waste heat from bottoming cycle cogenerators must be used to generate electricity. For topping cycle cogenerators, at least a portion of the waste heat from electricity production must be employed for a useful thermal purpose.

mandate is anticompetitive and costly. Opponents of the bill maintain that the mandate is a necessary check against utility monopoly power.

State public service commissions (PUC's) are coping with new regulatory responsibilities resulting from various EPACT provisions. New standards have been established, or are now being considered, for addressing jurisdictional responsibility for wholesale power market transactions. For the nonutility power market, an issue has been whether PUC's should intervene in disputes involving negotiated wholesale power purchases. Other new regulatory responsibilities include oversight of EWG's and the reevaluation of power purchase, supply, and demand-side management practices.

Regulators are also investigating ways to mitigate the adverse financial impacts on utilities' regulated assets caused by competition, while at the same time providing consumers with lower-cost power purchase alternatives. Among the options advanced by PUC's are incentive rates for deferring cogeneration or bypass by industrial customers, performance-based rates (price-cap and other flexible pricing plans), approval of utility-operated, on-site industrial power generation projects, and allowing independent power producers to repower existing utility generating plants.

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. The unused energy from the first process is 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 by producing 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 15), 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 15 represent most topping-cycle facilities.

In a bottoming-cycle system (Figure 16), 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.

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, unlike some technologies, boiler warmup time is not necessary.

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 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 sources. 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 form of biomass energy most commonly used by nonutilities. When economic to do so, 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 A.

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. The manufacturing sector uses the most energy (i.e. is the most energy intensive) because it creates new products using mechanical or chemical processes. It is therefore more cost-effective to produce one's own energy in this sector than in sectors that only require energy for space conditioning and lighting, such as the nonmanufacturing sectors.

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 using 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 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. All data are final. These data were obtained from the Form EIA-867, "Annual Nonutility Power Producer Report." The Form EIA-867 is a mandatory survey of all existing and planned nonutility electric generating facilities in the United States with a total generator nameplate capacity of 1 or more megawatts. In 1992, the reporting threshold of the Form EIA-867 was lowered to include all facilities with a combined nameplate capacity of 1 or more megawatts. Previously, data were collected every 3 years from facilities with a nameplate capacity between 1 and 5 megawatts. Planned generators are defined as a proposal by a company to install electric generating equipment at an existing or planned facility. The proposal is based on the owner having obtained (1) all environmental and regulatory approvals, (2) a signed contract for the electric energy, or (3) financial closure of the facility. Nonutilities generally install small, turn-key packaged generating facilities with minimal regulatory requirements which result in considerably less lead time to finance and build, as compared to traditional electric utility facilities. Data on planned nonutility capacity additions as of December 31, 1994, are presented by energy source in Figure 10. 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 A).

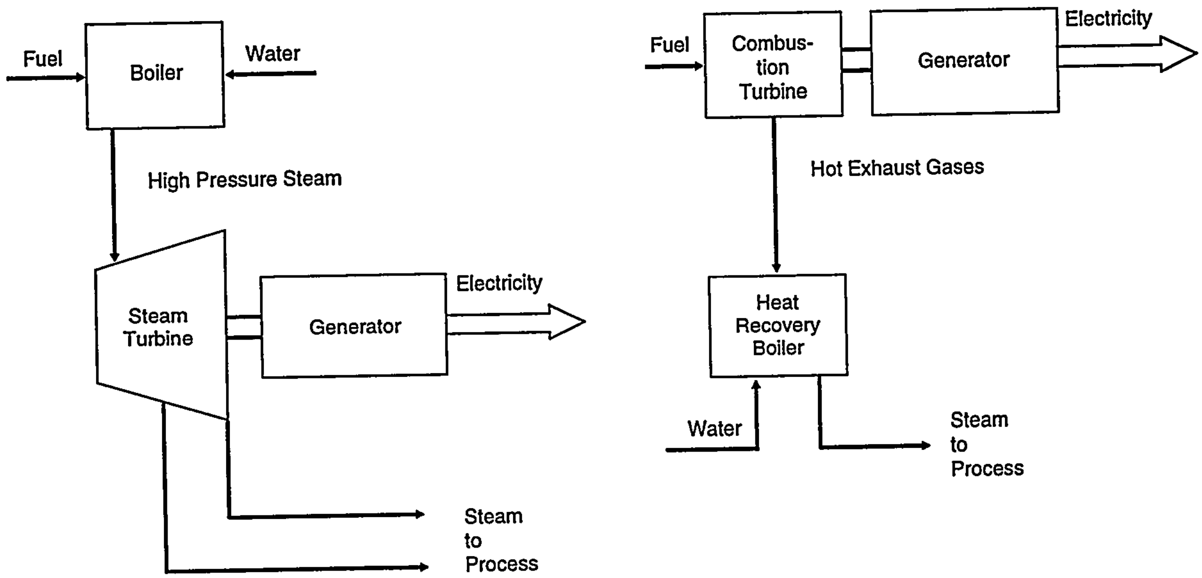
The other energy sources in Tables 52, 54, and 57 include hydrogen, sulfur, batteries, chemicals, fish oil and spent sulfite liquor. Data previously published for other energy sources in 1990 have been reclassified and are included in the category that best reflects its characteristics.

The change in data previously published in 1990 for major industry groups in Tables 56 and 59 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 55 and 58 in 1990, is due to changes in facility status. The number of facilities shown for 1994 includes operational facilities in 1993 and new facilities or planned facilities that became operational during that year.

The total capacity for 1990 through 1994 (Table 52) 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 7 percent of the total nonutility generating capacity in 1994.

Figure 15. Two Topping-Cycle Plant Configurations

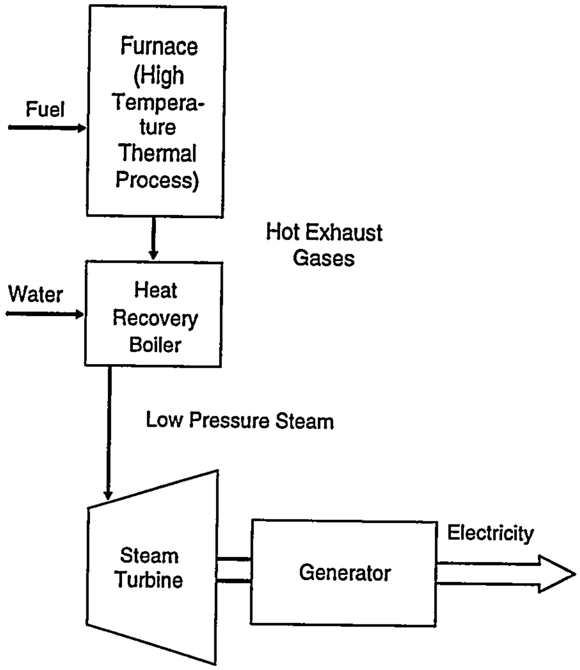


1. A boiler produces steam to power a turbine-generator to produce electricity. The turbine steam leaving the turbine is used in thermal applications such as space heating or food preparation.

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 16. 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 52. Summary Statistics for U.S. Nonutility Power Producers, 1990 Through 1994

Item	1990	1991	1992	1993		1994	
	5 Megawatts or More			1 Megawatt or More	5 Megawatts or More	1 Megawatt or More	5 Megawatts or More
Installed Capacity (megawatts)	42,869	48,171	56,814	60,778	59,055	68,461	66,633
Coal[1]	6,712	7,291	8,503	9,772	9,712	10,372	10,322
Petroleum[2]	811	1,207	1,730	2,043	1,869	2,262	2,061
Natural Gas[3]	16,682	20,259	21,542	23,463	23,009	26,925	26,454
Other Gas[4]	—	—	—	—	—	1,130	1,122
Petroleum/Natural Gas (Combined)	6,167	5,049	8,478	8,505	8,377	9,820	9,667
Hydroelectric	1,477	1,587	2,684	2,741	2,173	3,364	2,783
Geothermal	1,031	1,048	1,254	1,318	1,307	1,335	1,324
Solar	360	360	360	360	360	354	354
Wind	1,405	1,652	1,822	1,813	1,775	1,737	1,700
Wood[5]	5,786	6,580	6,805	7,046	6,983	7,416	7,354
Waste[6]	2,230	2,627	3,006	3,131	2,910	3,150	2,900
Nuclear[7]	20	20	20	20	20	—	—
Other[8]	187	491	611	566	562	597	593
Gross Generation (million kilowatthours)	217,241	248,448	296,001	325,226	318,843	354,925	348,189
Coal[1]	32,131	40,587	47,363	53,367	53,166	59,035	58,839
Petroleum[2]	7,330	7,814	10,963	13,364	13,089	15,069	14,751
Natural Gas[3]	116,706	131,340	158,798	174,282	171,765	179,735	177,058
Other Gas[4]	—	—	—	—	—	12,480	12,441
Hydroelectric	6,235	6,243	9,446	11,511	9,583	13,227	11,293
Geothermal	6,872	7,651	8,578	9,749	9,704	10,122	10,080
Solar	663	779	746	897	897	824	824
Wind	2,251	2,606	2,916	3,052	2,999	3,482	3,424
Wood[5]	30,812	33,785	36,255	37,421	37,206	38,595	38,395
Waste[6]	11,415	13,956	17,352	18,325	17,187	18,797	17,532
Nuclear[7]	116	80	67	78	78	54	54
Other[8]	2,710	3,609	3,516	3,181	3,169	3,507	3,496
Consumption							
Coal (Thousand short tons)	NA	38,113	44,132	48,343	47,827	52,261	51,731
Petroleum (Thousand barrels)[9]	NA	27,274	30,219	36,768	35,390	40,460	38,521
Natural Gas (Million cubic feet)	NA	1,569,713	1,791,576	2,013,788	1,968,875	2,149,246	2,094,964
Other Gas (Million cubic feet)[10]	NA	1,364,353	1,581,870	1,678,166	1,672,852	1,586,185	1,583,190
Supply and Disposition (million kilowatthours)							
Gross Generation	217,241	248,448	296,001	325,226	318,843	354,925	348,189
Receipts[11]	63,743	68,264	83,421	85,323	77,378	94,166	83,476
Deliveries to Utilities[12]	106,224	129,118	164,374	187,466	184,266	204,688	201,398
Deliveries to Other End Users[13]	19,824	11,419	10,786	15,569	15,176	17,626	17,033
Facility Use	154,936	176,175	204,261	207,514	196,780	226,777	213,235

[1] Includes coal, anthracite culm and coal waste.
[2] Includes petroleum, petroleum coke, diesel, kerosene, petroleum sludge and tar.
[3] Includes butane, ethane, propane, waste heat, and waste gases for years 1990-1993. Includes waste heat and waste gases for year 1994.
[4] Includes butane, ethane, propane, and other gases. Data not available for years 1990-1993.
[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 and other waste.
[7] 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.
[8] Includes hydrogen, sulfur, batteries, chemicals, and spent sulfite liquor. Data previously published for other energy sources in 1990 have been reclassified and are included in the category that best reflects its characteristics.
[9] Does not include petroleum coke consumption of 4,740 thousand short tons for 1994.
[10] Includes butane, ethane, propane, and other gases.
[11] Includes purchases, interchanges, and exchanges of electric energy with utilities and other nonutilities.
[12] Includes sales, interchanges, and exchanges of electric energy with utilities.
[13] Includes sales, interchanges, and exchanges of electric energy with 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.

NA = Not available.

Notes: •Data for the above 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 53. Installed Capacity at U.S. Nonutility Generating Facilities by Fossil Fuels, Renewable Energy Sources, and Census Division, 1990 Through 1994
(Megawatts)

Census Division	Fossil Fuels[1]	Renewables/ Other/ Nuclear[2]	Both Fossil Fuels and Renewables/ Other/ Nuclear
	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**
	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**
	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**
	1993 (1 Megawatt or More)		
New England	2,369	1,479	882
Middle Atlantic	7,107	1,089	535
East North Central	4,079	421	1,046
West North Central	972	143	146
South Atlantic	6,357	1,358	2,587
East South Central	444	253	1,037
West South Central	10,673	255	2,142
Mountain	1,042	635	344
Pacific	7,420	5,205	760
U.S. Total	**40,463**	**10,836**	**9,478**
	1994 (1 Megawatt or More)		
New England	2,532	1,486	877
Middle Atlantic	9,956	1,215	581
East North Central	4,476	341	1,130
West North Central	959	178	159
South Atlantic	7,778	1,799	2,806
East South Central	426	245	1,418
West South Central	11,339	255	2,170
Mountain	1,819	610	253
Pacific	7,700	5,092	861
U.S. Total	**46,986**	**11,221**	**10,254**

[1] Includes petroleum, natural gas, and/or coal as energy sources.
[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: •For a summary of 1993 and 1994 data for 5 megawatts or more, see Table 52. •See Technical Notes for a description of allocating capacity. •Data for above 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 54. Installed Capacity at U.S. Nonutility Generating Facilities by Energy Source and Census Division, 1990 Through 1994 (Megawatts)

Census Division	Coal[1]	Natural Gas[2]	Petroleum[3] only / and Natural Gas[4]	Hydroelectric/ Geothermal/ Solar / Wind	Wood[5] / Waste[6]	Other[7] / Nuclear	Total
			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**
			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	11,138
U.S. Total	**7,291**	**20,259**	**6,256**	**4,647**	**9,207**	**510**	**48,171**
			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**
			1993 (1 Megawatt or More)				
New England	363	587	1,780	587	1,412	—	4,729
Middle Atlantic	2,049	1,860	3,494	W	856	W	8,730
East North Central	1,733	2,523	525	W	646	W	5,546
West North Central	758	118	157	73	156	—	1,261
South Atlantic	2,770	1,664	2,332	209	2,953	375	10,303
East South Central	289	222	W	—	1,099	W	1,734
West South Central	828	9,915	1,022	W	1,089	W	13,069
Mountain	233	808	W	548	166	W	2,020
Pacific	749	5,768	W	4,099	1,801	W	13,385
U.S. Total	**9,772**	**23,463**	**10,548**	**6,232**	**10,177**	**585**	**60,778**
			1994 (1 Megawatt or More)				
New England	353	1,028	1,512	586	1,416	—	4,895
Middle Atlantic	2,302	4,533	W	441	888	W	11,752
East North Central	2,057	2,544	572	115	658	—	5,947
West North Central	729	122	182	95	168	—	1,296
South Atlantic	2,771	2,033	3,436	568	3,197	379	12,384
East South Central	323	224	W	W	1,265	W	2,088
West South Central	828	10,652	943	W	1,125	W	13,764
Mountain	238	1,289	W	551	157	W	2,682
Pacific	771	5,630	W	4,069	1,692	W	13,654
U.S. Total	**10,372**	**28,055**	**12,081**	**6,790**	**10,566**	**597**	**68,461**

[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: •For a summary of 1993 and 1994 data for 5 megawatts or more, see Table 52. •Data for above years are final. •Totals may not equal sum of components because of independent rounding.

Table 55. Installed Capacity at U.S. Nonutility Generating Facilities by Qualifying Facility Status and Census Division, 1990 Through 1994
(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)
	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**
	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**
	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**
	1993 (1 Megawatt or More)					
New England	116	3,404	73	1,325	189	4,729
Middle Atlantic	230	8,351	44	379	274	8,730
East North Central	98	3,403	101	2,143	199	5,546
West North Central	25	512	49	749	74	1,261
South Atlantic	139	7,011	97	3,291	236	10,303
East South Central	24	881	30	853	54	1,734
West South Central	107	11,159	60	1,910	167	13,069
Mountain	81	1,446	38	574	119	2,020
Pacific	412	11,606	142	1,779	554	13,385
U.S. Total	**1,232**	**47,774**	**634**	**13,004**	**1,866**	**60,778**
	1994 (1 Megawatt or More)					
New England	117	3,420	75	1,475	192	4,895
Middle Atlantic	248	11,350	48	402	296	11,752
East North Central	101	3,448	118	2,498	219	5,947
West North Central	26	535	51	760	77	1,296
South Atlantic	151	8,300	129	4,083	280	12,384
East South Central	24	930	35	1,159	59	2,088
West South Central	107	11,846	61	1,917	168	13,764
Mountain	85	1,905	38	776	123	2,682
Pacific	408	11,826	146	1,828	554	13,654
U.S. Total	**1,267**	**53,562**	**701**	**14,900**	**1,968**	**68,461**

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

Notes: •For summary statistics of 1993 and 1994 for 5 megawatts or more, see Table 52. •Data for above years are final. •The number of facilities shown includes operational, new, and planned facilities. •Totals may not equal sum of components because of independent rounding.

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

Table 56. Installed Capacity at U.S. Nonutilities Attributed to Major Industry Groups and Census Divisions, 1990 Through 1994
(Megawatts)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
				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**
				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	1,587	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**
				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**
				1993 (1 Megawatt or More)			
New England	2,248	2,363	W	—	W	—	4,729
Middle Atlantic	5,807	1,989	511	W	W	225	8,730
East North Central	4,851	301	271	W	W	W	5,546
West North Central	702	184	165	W	W	W	1,261
South Atlantic	6,925	2,914	158	W	W	269	10,303
East South Central	1,676	18	W	W	W	—	1,734
West South Central	12,245	442	203	180	—	—	13,069
Mountain	772	566	158	245	—	278	2,020
Pacific	4,678	5,532	324	2,439	239	173	13,385
U.S. Total	**39,904**	**14,309**	**1,908**	**3,246**	**406**	**1,005**	**60,778**
				1994 (1 Megawatt or More)			
New England	2,267	2,499	W	—	—	W	4,895
Middle Atlantic	8,509	2,168	546	W	W	225	11,752
East North Central	5,129	373	287	W	W	90	5,947
West North Central	706	213	166	W	W	W	1,296
South Atlantic	8,180	3,887	176	W	W	67	12,384
East South Central	2,029	18	W	27	W	—	2,088
West South Central	12,940	442	202	180	—	—	13,764
Mountain	833	779	139	245	—	686	2,682
Pacific	5,086	5,307	433	2,438	239	151	13,654
U.S. Total	**45,678**	**15,686**	**2,070**	**3,252**	**542**	**1,234**	**68,461**

W = Withheld to avoid disclosure of individual company data.

Notes: •Data shown in this table are nonutility generating capacity attributed to major industry groups and census divisions of the users of the electrical energy. •Data for above 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 57. Gross Generation for U.S. Nonutility Power Producers by Energy Source and Census Division, 1990 Through 1994

(Million Kilowatthours)

Census Division	Coal[1]	Petroleum[2]	Natural Gas[3]	Hydroelectric	Geothermal/ Solar/Wind	Wood[4] / Waste[5]	Other[6] / Nuclear	Total
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	1,459	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**
1991 (5 Megawatts or More)								
New England	2,527	1,292	6,710	2,264	—	7,553	—	20,347
Middle Atlantic	7,741	W	11,050	877	—	3,933	W	24,886
East North Central	5,456	W	12,173	266	W	3,084	—	21,424
West North Central	1,841	36	745	227	—	466	—	3,316
South Atlantic	11,504	1,563	3,706	760	—	12,991	2,249	32,773
East South Central	2,005	W	2,132	—	—	4,735	W	9,013
West South Central	5,459	W	60,095	—	—	5,404	W	73,404
Mountain	1,044	15	1,932	511	991	755	193	5,442
Pacific	3,009	W	32,796	1,337	W	8,820	W	57,843
U.S. Total	**40,587**	**7,814**	**131,340**	**6,243**	**11,035**	**47,741**	**3,688**	**248,448**
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	336	—	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	**47,363**	**10,963**	**158,798**	**9,446**	**12,241**	**53,607**	**3,583**	**296,001**
1993 (1 Megawatt or More)								
New England	2,417	1,764	12,460	2,526	—	9,062	—	28,229
Middle Atlantic	10,950	W	28,381	1,724	—	5,714	W	48,705
East North Central	7,138	627	14,274	W	—	3,602	W	26,211
West North Central	2,852	63	687	336	—	737	—	4,675
South Atlantic	15,466	2,774	7,886	963	—	14,821	1,710	43,620
East South Central	2,289	W	2,170	—	—	6,019	W	10,741
West South Central	5,798	3,239	63,077	W	—	5,804	W	80,073
Mountain	1,317	112	4,638	948	1,588	767	201	9,572
Pacific	5,140	2,905	40,708	W	12,110	9,220	W	73,400
U.S. Total	**53,367**	**13,364**	**174,282**	**11,511**	**13,698**	**55,746**	**3,259**	**325,226**
1994 (1 Megawatt or More)								
New England	2,575	1,937	13,917	2,709	—	8,787	—	29,925
Middle Atlantic	12,169	2,213	34,178	1,877	—	5,824	197	56,457
East North Central	8,652	717	15,139	533	—	3,952	—	28,993
West North Central	3,111	W	726	339	W	789	—	5,077
South Atlantic	17,122	3,369	11,348	2,983	—	15,328	2,002	52,152
East South Central	2,325	174	2,246	W	—	6,874	W	12,786
West South Central	6,227	W	64,768	W	—	5,882	W	81,989
Mountain	1,567	115	6,131	837	W	768	W	11,273
Pacific	5,285	3,114	43,762	1,918	12,752	9,188	252	76,271
U.S. Total	**59,035**	**15,069**	**192,214**	**13,227**	**14,428**	**57,392**	**3,560**	**354,925**

[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: •For a summary of 1993 and 1994 data for 5 megawatts or more, see Table 52. •Data for above years are final. •Totals may not equal sum of components because of independent rounding.

Table 58. Gross Generation at U.S. Nonutility Generating Facilities by Qualifying Facility Status and Census Division, 1990 Through 1994
(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)
	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**
	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**
	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**
	1993 (1 Megawatt or More)					
New England	116	20,936	73	7,293	189	28,229
Middle Atlantic	230	46,602	44	2,102	274	48,705
East North Central	98	17,238	101	8,973	199	26,211
West North Central	25	2,257	49	2,418	74	4,675
South Atlantic	139	32,132	97	11,488	236	43,620
East South Central	24	5,383	30	5,358	54	10,741
West South Central	107	68,884	60	11,190	167	80,073
Mountain	81	7,391	38	2,181	119	9,572
Pacific	412	66,820	142	6,580	554	73,400
U.S. Total	**1,232**	**267,641**	**634**	**57,584**	**1,866**	**325,226**
	1994 (1 Megawatt or More)					
New England	117	21,832	75	8,093	192	29,925
Middle Atlantic	248	54,274	48	2,183	296	56,457
East North Central	101	17,961	118	11,033	219	28,993
West North Central	26	2,480	51	2,597	77	5,077
South Atlantic	151	39,312	129	12,840	280	52,152
East South Central	24	5,702	35	7,085	59	12,786
West South Central	107	70,773	61	11,217	168	81,989
Mountain	85	9,089	38	2,183	123	11,273
Pacific	407	70,659	145	5,612	554	76,271
U.S. Total	**1,267**	**292,082**	**701**	**62,843**	**1,968**	**354,925**

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

Notes: •For a summary of 1993 and 1994 data for 5 megawatts or more, see Table 52. •Data for above years are final. •The number of facilities shown includes operational, new, and planned facilities. •Totals may not equal sum of components because of independent rounding.

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

Table 59. Gross Generation of U.S. Nonutilities Attributed to Major Industry Groups and Census Divisions, 1990 Through 1994
(Million Kilowatthours)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
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	18,905	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**
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**
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**
1993 (1 Megawatt or More)							
New England	12,644	15,120	466	—	—	—	28,229
Middle Atlantic	31,368	11,669	2,809	W	W	1,273	48,705
East North Central	23,015	1,698	987	W	W	W	26,211
West North Central	2,983	341	W	W	W	W	4,675
South Atlantic	33,179	8,461	657	W	W	1,184	43,620
East South Central	10,531	72	W	W	W	—	10,741
West South Central	76,103	2,232	611	1,127	—	—	80,073
Mountain	4,622	2,899	975	W	—	W	9,572
Pacific	26,889	25,056	2,038	17,228	1,530	659	73,400
U.S. Total	**221,334**	**67,549**	**8,970**	**20,877**	**2,671**	**3,826**	**325,226**
1994 (1 Megawatt or More)							
New England	13,641	15,743	W	—	—	W	29,925
Middle Atlantic	37,382	12,009	3,385	W	1,452	W	56,457
East North Central	24,909	2,415	1,067	W	W	254	28,993
West North Central	3,150	434	421	W	W	W	5,077
South Atlantic	41,152	10,142	635	W	W	W	52,152
East South Central	12,478	81	W	148	W	—	12,786
West South Central	78,974	2,013	539	464	—	—	81,989
Mountain	5,096	3,173	954	563	—	1,486	11,273
Pacific	31,053	22,971	2,406	17,757	1,523	561	76,271
U.S. Total	**247,836**	**68,982**	**9,900**	**21,024'**	**3,172**	**4,011**	**354,925**

W = Withheld to avoid disclosure of individual company data.
Notes: •Data shown in this table are nonutility gross generation by industry groups and census divisions. •Data for above 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 60. U.S. Nonutility Electricity Supply and Disposition for Facilities by Census Division and State, 1994
(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	**29,925**	**29,130**	**4,127**	**3,768**	**24,502**	**23,898**	**9,550**	**9,000**
Connecticut	4,253	4,160	291	283	3,604	3,523	941	920
Maine	8,019	7,893	2,888	2,887	4,967	4,866	5,940	5,914
Massachusetts	10,836	10,635	610	459	9,756	9,674	1,690	1,421
New Hampshire	1,681	1,361	233	W	1,299	981	615	W
Rhode Island	4,780	4,741	W	40	4,581	4,576	W	206
Vermont	356	340	W	W	295	279	W	W
Middle Atlantic	**56,457**	**55,197**	**7,180**	**5,024**	**47,303**	**46,371**	**16,334**	**13,850**
New Jersey	17,171	16,912	2,225	645	15,417	15,254	3,979	2,303
New York	23,315	22,538	1,406	1,238	20,257	19,592	4,465	4,184
Pennsylvania	15,970	15,746	3,549	3,141	11,629	11,524	7,890	7,363
East North Central	**28,993**	**27,909**	**19,368**	**17,168**	**14,785**	**14,225**	**33,576**	**30,853**
Illinois	3,958	3,524	5,531	4,861	390	276	9,099	8,109
Indiana	W	W	5,315	4,898	W	W	9,100	8,616
Michigan	15,189	14,752	1,786	1,248	11,943	11,701	5,033	4,300
Ohio	W	W	3,424	3,385	W	W	4,382	4,328
Wisconsin	3,086	2,963	3,313	2,776	437	238	5,962	5,500
West North Central	**5,077**	**4,837**	**5,114**	**4,769**	**1,532**	**1,437**	**8,660**	**8,169**
Iowa	1,039	W	1,494	1,442	213	W	2,320	2,250
Kansas	343	W	W	W	W	—	1,137	W
Minnesota	3,111	3,045	2,473	2,366	1,115	1,078	4,469	4,333
Missouri	372	344	W	W	W	W	433	393
Nebraska	W	W	W	W	—	—	W	W
North Dakota	W	W	W	W	W	W	W	W
South Dakota	—	—	—	—	—	—	—	—
South Atlantic	**52,152**	**51,433**	**17,252**	**15,434**	**28,536**	**28,167**	**40,868**	**38,700**
Delaware	772	W	W	W	W	W	W	W
District of Columbia	—	—	—	—	—	—	—	—
Florida	17,518	17,371	1,786	1,411	9,937	9,930	9,367	8,853
Georgia	5,967	5,877	3,055	2,232	161	119	8,861	7,990
Maryland	1,632	1,598	W	W	W	W	W	W
North Carolina	9,762	9,661	3,157	2,802	7,103	7,080	5,816	5,384
South Carolina	2,878	W	2,271	W	738	W	4,411	4,287
Virginia	9,723	9,478	3,056	2,956	7,858	7,645	4,921	4,789
West Virginia	3,900	3,881	1,569	1,569	1,624	1,624	3,845	3,827
East South Central	**12,786**	**12,592**	**8,234**	**7,262**	**1,566**	**1,456**	**19,454**	**18,398**
Alabama	6,445	6,335	3,110	W	135	W	9,420	8,883
Kentucky	—	—	—	—	—	—	—	—
Mississippi	2,697	2,659	1,819	W	70	W	4,446	4,377
Tennessee	3,644	3,598	3,305	W	1,360	W	5,589	5,139
West South Central	**81,989**	**81,611**	**20,329**	**18,563**	**32,304**	**32,282**	**70,014**	**67,892**
Arkansas	2,622	2,599	W	W	W	W	3,298	3,255
Louisiana	20,140	20,057	6,890	6,040	4,389	4,389	22,641	21,708
Oklahoma	5,043	5,020	W	W	W	W	2,428	2,374
Texas	54,184	53,935	11,658	10,794	24,195	24,174	41,647	40,555
Mountain	**11,273**	**10,750**	**4,117**	**3,758**	**8,280**	**7,927**	**7,110**	**6,580**
Arizona	767	W	W	W	W	W	672	W
Colorado	2,451	2,305	160	75	1,989	1,863	622	517
Idaho	1,517	1,381	1,074	1,074	1,376	1,240	1,215	1,214
Montana	474	W	W	W	W	W	W	W
Nevada	4,197	4,152	W	W	3,866	3,828	W	W
New Mexico	383	313	1,226	1,219	W	—	W	1,533
Utah	782	W	W	W	W	W	W	W
Wyoming	701	680	W	W	W	W	1,257	W
Pacific	**76,271**	**74,730**	**8,446**	**7,731**	**63,507**	**62,669**	**21,210**	**19,792**
Alaska	1,123	1,055	102	W	75	W	1,150	1,075
California	63,156	61,996	3,481	2,924	53,190	52,606	13,447	12,314
Hawaii	4,281	4,215	51	49	3,525	3,492	807	772
Oregon	1,034	902	666	W	890	W	810	788
Washington	6,677	6,561	4,147	4,012	5,828	5,730	4,996	4,843
U.S. Total	**354,925**	**348,189**	**94,166**	**83,476**	**222,315**	**218,431**	**226,777**	**213,235**

[1] Includes purchases, interchanges, and exchanges of electric energy with utilities and other nonutilities.

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

W = Withheld to avoid disclosure of individual company data.

Notes: •Data for the above 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 61. Estimated Emissions from U.S. Nonutility Power Producers Facilities by Census Division, 1990 Through 1994 (Thousand Short Tons)

Census Division	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide[1]
	1990 (5 Megawatts or More)		
New England	49	32	21,764
Middle Atlantic	121	111	34,222
East North Central	180	290	81,154
West North Central	45	22	6,932
South Atlantic	303	164	85,636
East South Central	103	59	32,953
West South Central	176	236	84,424
Mountain	15	21	8,072
Pacific Contiguous	28	97	41,487
Pacific Noncontiguous	8	10	4,507
U.S. Total	**1,028**	**1,042**	**401,151**
	1991 (5 Megawatts or More)		
New England	46	38	26,464
Middle Atlantic	95	108	37,252
East North Central	193	258	78,122
West North Central	69	32	11,290
South Atlantic	343	199	100,603
East South Central	112	62	36,647
West South Central	174	245	94,953
Mountain	20	26	9,777
Pacific Contiguous	42	94	46,466
Pacific Noncontiguous	7	9	4,277
U.S. Total	**1,101**	**1,071**	**445,851**
	1992 (1 Megawatt or More)		
New England	39	46	32,105
Middle Atlantic	89	156	49,970
East North Central	201	275	84,494
West North Central	60	37	13,045
South Atlantic	384	231	112,364
East South Central	119	70	41,064
West South Central	237	258	103,095
Mountain	21	29	9,683
Pacific Contiguous	45	102	51,545
Pacific Noncontiguous	13	15	6,709
U.S. Total	**1,208**	**1,219**	**504,074**
	1993 (1 Megawatt or More)		
New England	45	49	33,616
Middle Atlantic	127	168	56,669
East North Central	205	307	92,877
West North Central	83	42	14,235
South Atlantic	374	250	118,221
East South Central	130	75	45,715
West South Central	227	250	102,544
Mountain	20	33	10,318
Pacific Contiguous	44	111	55,062
Pacific Noncontiguous	12	15	6,742
U.S. Total	**1,267**	**1,300**	**535,999**
	1994 (1 Megawatt or More)		
New England	48	48	33,809
Middle Atlantic	124	172	59,731
East North Central	291	325	101,517
West North Central	68	45	14,790
South Atlantic	404	273	130,675
East South Central	138	78	51,625
West South Central	263	233	100,721
Mountain	22	37	12,015
Pacific Contiguous	52	109	55,089
Pacific Noncontiguous	14	15	7,309
U.S. Total	**1,424**	**1,335**	**567,281**

[1] As of 1993 data, emission factors for the calculation of carbon dioxide emissions and reductions from nitrogen oxide control technologies have been changed--historical estimates were revised to reflect that change--See Technical Notes for more information.

Notes: •Estimates for 1994 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 A, "Technical Notes," for methodology.

Source: Estimated using data from the Form EIA-867, "Annual Nonutility Power Producer Report."

Appendix A

Technical Notes

Appendix A

Technical Notes

Sources of Data

The *Electric Power Annual Volume II* is prepared by the Coal and Electric Data and Renewables 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 Volume II* are compiled from six forms filed annually by electric utilities and one form filed annually by nonutility power producers. Those forms are: the Form EIA-861, "Annual Electric Utility Report"; the Federal Energy Regulatory Commission (FERC) Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others"; the Form EIA-412, "Annual Report of Public Electric Utilities"; the Form EIA-767, "Steam-Electric Plant Operation and Design Report"; the Form EIA-867, "Annual Nonutility Power Producer Report"; the Department of Energy, Office of Emergency Planning Form PO-411, "Coordinated Regional 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." Each form is summarized below.

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 and demand-side management information from approximately 3,200 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 *Electric Power Monthly;* the *Electric Sales and Revenue;* the *Financial Statistics of Major U.S. Investor-Owned Electric Utilities;* the *Financial Statistics of Major U.S. Publicly Owned Electric Utilities;* the *Annual Energy Outlook;* the *U.S. Electric Utility Demand-Side Management;* and the *Electric Trade in the United States.* These reports present aggregate totals for electric utilities on national, State, and regional levels by ownership type.

Demand-side management data collected on the Form EIA-861 are estimated by electric utilities based on engineering data or statistical analysis. The utilities also use a variety of verification methodologies for these estimates. The Energy Policy Act (EPACT) of 1992, Section 171(a), mandated that EIA verify DSM data estimates and the methodologies used for estimation and verification. In response to this mandate, EIA conducted a study of DSM estimation methodologies and DSM verification methodologies. The report describes typical estimation methodologies and DSM verification methodologies, as well as the difficulties in reaching broad conclusions concerning the quality of savings estimates reported to EIA. The report is featured in the EIA publication, *U.S. Electric Utility Demand-Side Management 1993*, released in July 1995.

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 to collect data as of the end of the calendar year. The completed forms are to be returned to the EIA by April 30. The data are 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. These are utility-level checks. Respondents are telephoned to obtain clarification of reported data and to obtain missing data.

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 seven independent power producers (IPP's): Catalyst Old River Hydroelectric Limited Partnership, Entergy Power Incorporated, Hardee Power Partners Limited, 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. The FERC has also determined that Golden Spread Electric Cooperative, Old Dominion Electric Cooperative, People's Electric Cooperative, and Rayburn Country Electric Cooperative Incorporated should file a FERC Form 1 under Section 201 of the Federal Power Act. Data from these four entities were not included since they are classified as cooperative electric utilities on the Form EIA-861.

The FERC Form 1 is used to collect data on income and earnings, taxes, depreciation and amortization, distribution of salaries and wages, electric operating revenues, electric maintenance expenses, generating plant statistics, planned construction data, year-end balance sheets, and general corporate information. Respondents are required to report data on historical plant cost and power production expenses for their hydroelectric plants with a generator nameplate capacity of 10 or more megawatts; each steam-electric plant with a generator nameplate capacity of 25 or more megawatts; and each gas-turbine plant with a generator nameplate capacity of 10 or more megawatts. Less detailed data are required for other plants.

This data base supports queries from the Executive Branch, Congress, other public agencies, and the general public. Summary and detail data from the FERC Form 1 are also contained in the *State Energy Data Report;* the *Financial Statistics of Major U.S. Investor-Owned Electric Utilities;* the *State Energy Price and Expenditure Report;* the *Annual Energy Review;* 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 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 500 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 Ste. 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.

This data base supports queries from the Executive Branch, Congress, other public agencies, and the general public. Summary and detail data from the Form EIA-412 are also contained in the *Financial Statistics of Major U.S. Publicly Owned Electric Utilities;* the *State Energy Price and Expenditure Report;* the 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.

Data Processing. The processing of data reported on this survey is the responsibility of the Coal and Electric Data and Renewables 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.

This data base supports queries from the Executive Branch, Congress, other public agencies, and the general public. Summary and detail data from the Form EIA-767 are also contained in the *Electric Power Annual Volume I;* and the *Coal Industry Annual.* These reports present aggregate totals for electric utilities on a national level, by State, and by ownership type.

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"; and 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 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 1990 through 1994 presented in this report, are reasonable given the growth in manufacturing on site generation that occurred between 1985 and 1988 as reported in MECS. As a historical reference, these tables are Table 9 in the 1985 MECS Consumption publication and Tables 14 through 17 and Tables 20 through 24 in the 1988 publication.

Data for the Form EIA-867 are collected from all existing and planned nonutility generating facilities in the United States with a total generator nameplate capacity of 1 or more megawatts. These data are aggregated to provide geographic totals for selected States and at the Census division and national levels. Since the Form EIA-867 data are considered confidential, suppression of some data is necessary to protect the confidentiality of the individual respondent data. See "Confidentiality of the Data" in this section for further information on the nondisclosure of data.

Allocating Capacity. The installed capacity for nonutility generating units is allocated to one energy source using the following algorithms:

- For generating units using a single fossil energy source, the capacity is allocated totally to that energy source.
- For generating units that use hydraulic, geothermal, solar, biomass, or wind energy, the capacity is allocated to that energy source (even if a secondary fuel is burned).
- For generating units using a combination of fossil energy and renewable energy sources, capacity is classified as fossil or renewable based on the greatest percentage of Btu consumed when summed.
- To allocate capacity by fuel within the fossil energy and renewable energy sources, the single fuel within that energy source with the greatest percentage of Btu consumed is used.

Allocating Generation. The generation for nonutility facilities is allocated to one energy source using the following algorithms:

- For generating units that use energy sources that are not burned (hydraulic, geothermal, nuclear, solar, or wind energy), the generation is allocated to that energy source (even if a secondary fuel is burned).
- For facilities having generating units using energy sources that are burned, the generation is allocated based on the percentage of Btu consumed. This algorithm assumes that unit efficiency is the same for all energy sources.

A comparison of installed capacity for facilities of 1 megawatts or more of EIA's data with data published by Edison Electric Institute (EEI) in *Capacity and Generation of Non-Utility Sources of Energy* shows a difference of approximately 1 percent.

Gross-to-Net Generation Conversion Methodology. Gross electricity generation data from the Form EIA-867, reported by generator, are aggregated to provide totals by energy source and geographic area. Nonutility power producers report gross electricity generated on the Form EIA-867, unlike electric utilities that report net generation on various EIA and FERC forms. Nonutilities generally do not measure and record electrical consumption used solely for the production of electricity. Nonutility generators and associated auxiliary equipment are often an integral part of a manufacturing or other industrial process and individual watthour meters are not generally installed on auxiliary equipment.

Estimated values for net generation from nonutility power producers were developed by EIA using gross generation, prime mover, fuels, and type of air pollution control data reported on the Form EIA-867. The difference between gross and net generation is the electricity consumed by auxiliary equipment and environmental control devices such as pumps, fans, coal pulverizers, particulate collectors, and flue gas desulfurization (FGD) units. The difference between gross and net generation is sometimes called parasitic load. In smaller power plants rotating auxiliaries are almost always electric motors. In large power plants that produce steam, rotating auxiliaries can be powered by either steam turbines or electric motors and sometimes both because of cold startup requirements.

This methodology for estimating net generation from gross generation is based on determining typical energy consumption for auxiliary electrical equipment associated with electrical generators. For instance, wind turbines have none of the auxiliaries common to a coal-burning power plant such as a coal pulverizers, fans, and emission controls. On the other hand, windfarms do consume electricity since automatic, computer-based control systems are used to control blade pitch and speed thereby affecting generator electricity output.

Shown below are the conversion factors used to estimated net generation by nonutility generators. The factors are typical of a modern electric power plant but could vary significantly between individual plants. Net generation is calculated by multiplying the appropriate conversion factor by the reported gross electrical generation.

Prime Mover Type	Gross-to-Net Generation Conversion Factor
Gas (Combustion) Turbine	.98
Steam Turbine	.97[a]
Internal Combustion	.98
Wind Turbine	.99
Solar-Photovoltaic	.99
Hydraulic Turbine	.99
Fuel Cell	.99
Other	.97

[a]Factor reduced by .01 if the facility has flue gas particulate collectors and another .03 if the facility has flue gas desulfurization (FGD) equipment. Facilities under 25 megawatts that burn coal in traditional boilers (i.e., not fluidized bed boilers) are assumed to have particulate and FGD equipment.

These conversion factors were estimated by the staff of the Office of Coal, Nuclear, Electric and Alternate Fuels, Energy Information Administration. The primary reference used in developing the conversion factors was *Steam, Its Generation and Use* , 40th Edition, Babcock & Wilcox, Barberton, Ohio.

Emissions for the Production of Electricity Methodology. Emissions for nonutility power producers include emissions from cogeneration facilities that produce electric power as an integral part of a manufacturing or other thermal consuming process. Emissions are directly proportional to the quantities of fuels consumed. To calculate emissions for the production of electricity, a methodology was developed to estimate the consumption of fuel associated for the production of electricity by cogeneration facilities. The methodology is based on net generation heat rates by primary fuel and prime-mover. The primary fuel is the predominant energy source for the generator based on fuel consumption at the facility expressed in total Btu by fuel type. The heat rates were estimated by the staff of the Office of Coal, Nuclear, Electric and Alternate Fuels; Energy Information Administration. The primary reference used in developing the conversion factors was *TAG--Technical Assessment Guide,* Volume 1: Electricity Supply--1986, Electric Power Research Institute, Palo Alto, California, December 1986. The procedure to estimate the fuel consumed for the production of electricity is to calculate net generation by primary fuel and prime-mover (see gross-to-net generation methodology), multiply the net generation by the appropriate heat rate to obtain total Btu consumed for the production of electricity, and apportion by the total Btu weighted by energy source.

Net generation heat rates by primary fuel and prime mover are as follows:

Prime Mover	Heat Rate (net Btu per kilowatthour) by Primary Fuel			
	Coal	Petroleum	Natural Gas	Other
Gas (Combustion) Turbine				
Single Cycle	--	14,000	14,500	--
Combined Cycle	--	8,100	8,200	--
Steam Turbine				
Single Cycle	10,200	9,600	9,600	16,500
Combined Cycle	9,000	9,000	9,000	10,500
Internal Combustion	--	11,700	11,700	--
Other	10,200	11,700	11,700	10,500

Nameplate Capacity to Summer Capability Conversion Methodology. Form EIA-867, "Annual Nonutility Power Producer Report," collects nameplate capacity for electric generating units. Estimated values for net summer capability from nameplate capacity are aggregated to provide a U.S. total. The methodology used for estimating summer capability from nameplate capacity is the same methodology shown in this Appendix for the Form EIA-860.

Business Classification. The nonutility industry consists of all manufacturing, agricultural, forestry, transportation, finance, service and administrative industries, based on the Office of Management and Budget's Standard Industrial Classification (SIC) Manual.[30] 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

Construction
15 to 17

Manufacturing
20 Food and kindred products
21 Tobacco products
22 Textile and mill products
23 Apparel and other finished products made from fabrics and similar materials
24 Lumber and wood products, except furniture
25 Furniture and fixtures
26 Paper and allied products (other than 2621 or 2631)
2621 Paper mills, except building paper
2631 Paperboard mills
27 Printing and publishing
28 Chemicals and allied products (other than 2819, 2821, 2869, or 2873)
2819 Industrial Inorganic Chemicals
2821 Plastics materials and resins
2869 Industrial organic chemicals
2873 Nitrogenous fertilizers
29 Petroleum refining and related industries (other than 2911)
2911 Petroleum refining
30 Rubber and miscellaneous plastic products
31 Leather and leather products
32 Stone, clay, glass, and concrete products (other than 3241)
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

Wholesale Trade
50 to 51

Retail Trade
52 to 59

Finance, Insurance, and Real Estate
60 Depository Institutions
61 Nondepository credit institutions

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

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

Public Administration
91 to 97

Other (explain):

Historically, (Tables 56 and 59) show cogeneration facilities reporting the Standard Classification Code (SIC) that identified the user of the electric and/or thermal energy. Beginning in 1993, the SIC code was broadened to include the SIC code(s) of the producing facility based on the facilities consumption. This revision provides an alternative method of comparing power needs and utilization within the nonutility power industry. Tables A1 and A2 show the installed capacity and gross generation of electricity by the producing energy group, respectively.

Form PO-411

The Form PO-411 is filed annually as a voluntary report. The information reported includes: (1) actual energy and peak demand for the preceding year and 10 additional years; (2) existing and future generating capacity; (3) scheduled capacity transfers; (4) projections of capacity, demand, purchases, sales, and scheduled maintenance; (5) assessment of adequacy; (6) generating capacity unavailability; (7) bulk power system maps; (8) near term transmission adequacy; (9) future critical bulk power facilities that may not be in service when required; and, (10) system evaluation criteria. These data support queries from the executive branch, Congress, other public agencies, and the general public. These reports present various council aggregate totals for their member electric utilities, with some nonmember information included.

Instrument and Design History. The Form PO-411 program was initiated under the Federal Power Commission Docket R-362, reliability and adequacy of electric service, and Orders 383-2, 383-3, and 383-4. The Department of Energy, established in October 1977, assumed the responsibility for this activity. This form is considered voluntary under the authority of the Federal Power Act (Public Law 88-280), The Federal Energy Administration Act of 1974 (Public Law 93-275), and the Department of Energy Organization Act (Public Law 95-91). The responsibility for collecting these data has been delegated to the Office of Emergency Planning and Operations within the Department of Energy.

Data Processing. The Form PO-411 is filed annually on April 1 by the ten North American Electric Reliability Councils. The forms are compiled from data furnished by electric utilities within the council areas.

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 revised data collection forms and systems. Once implemented, the actual performance of working data collection systems is also validated. Computerized respondent data files are checked to identify those who fail to respond to the survey. By law, nonrespondents may be fined or otherwise penalized for not filing a mandatory EIA data form. Before invoking the law, the EIA tries to obtain the required information by encouraging cooperation of nonrespondents.

Completed forms received by the CNEAF office are sorted, screened for completeness of reported information, and keyed onto computer tapes for storage and transfer to random access data bases for computer processing. The information coded on the computer tapes is manually spot-checked against the forms to certify accuracy of the tapes. To ensure the quality standards established by the EIA, formulas that use the past history of data values in the data base have been designed and implemented to check data input for errors automatically. Data values that fall outside the ranges prescribed in the formulas are verified by telephoning respondents to resolve any discrepancies.

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 unless approved by the Office Director.
3. The magnitude of changes due to revisions experienced in the past will be included in the data reports, so that the reader can assess the accuracy of the data.
4. After data are published as final, corrections will be made only in the event of a greater than one percent difference at the national level. Corrections for differences that are less than the before-mentioned threshold are left to the discretion of the Office Director.

The *Electric Power Annual Volume II* 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:

- **U.S. Electric Utility Retail Sales and Revenue**
  Data on sales, revenue, and average revenue per kilowatthour from the Form EIA-861 for 1994 are preliminary. The data are revised and declared final in the *Electric Sales and Revenue 1994.* A comparison of preliminary versus final annual data at the national level for 1994 will be provided in the *Electric Power Annual Volume II* 1995.
- **U.S. Electric Utility Financial Statistics**
  Financial data from the Federal Energy Regulatory Commission Form 1 and the Form EIA-412 for 1994 are final.
- **U.S. Electric Utility Environmental Statistics**
  Data from the Form EIA-767 for 1993 are final. The methodology for calculating emissions of sulfur dioxides, nitrogen oxides, and carbon dioxide has been revised. As a result, final data for 1992 at the national level differ from the preliminary by -2.0 percent for sulfur dioxide, -28.1 percent for nitrogen oxides, and 0.2 percent for carbon dioxide. Data for 1994 are preliminary. A comparison of preliminary versus final data at the national level for 1994 will be provided in the *Electric Power Annual Volume II* 1995.
- **U.S. Electric Power Transactions**
  All data from the Forms PO-411 and FE-718R are final. Data from the Form EIA-861 for 1994 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 1993 are final. As a result, final data for 1993 at the national level differ from the preliminary data by 2.1 percent for energy savings, -0.5 percent lower for actual peak load reductions, -0.3 percent lower for potential peak load reduction, and -0.9 percent lower for DSM cost. Data for 1994 are preliminary. A comparison of preliminary versus final data at the national level for 1994 will be provided in the *Electric Power Annual Volume II* 1995.
- **U.S. Nonutility Power Producers** Data from the Form EIA-867 for 1990 through 1994 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-861

Data for the Form EIA-861 are collected at the utility level from all electric utilities in the United States, its territories, and Puerto Rico. Form EIA-861 data in this publication are for the United States only. These data are then aggregated to provide geographic totals at the State, NERC region, Census division, and national level. Sources and disposition of data are also provided by utility class of ownership and retail consumer class of service. Average revenue (nominal dollars) per kilowatthour of electricity sold is calculated by dividing total annual retail revenue (nominal dollars) by the total annual retail sales of electricity.

Average revenue per kilowatthour is defined as the cost per unit of electricity sold and is calculated by dividing retail electric revenue by the corresponding sales of electricity. The average revenue per kilowatthour is calculated for all consumers and for each sector (residential, commercial, industrial, and other sales).

Electric utilities typically employ a number of rate schedules within a single sector. These alternative rate schedules reflect the varying consumption levels and patterns of consumers and their associated impact on the costs to the electric utility for providing electrical service. The average revenue per kilowatthour reported in this publication by sector represents a weighted average of consumer revenue and sales within that sector and across sectors for all consumers.

The electric revenue used to derive the average revenue per kilowatthour is the operating revenue reported by the electric utility. Operating revenue includes energy charges, demand charges, consumer service charges, environmental surcharges, fuel adjustments, and other miscellaneous charges.

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

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

EIA collects Demand-Side Management (DSM) information 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 peak load reductions and energy savings for the reporting year (1994), annual peak load reductions and energy savings for the reporting year and first- and fifth-forecast years (1995 and 1999), and 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, and 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 peak load reductions and energy savings. They also report total utility cost, total nonutility cost, and total DSM cost for the reporting year and first and fifth forecast years. In years prior to 1992, utilities with sales less than 120,000 megawatthours did not report on DSM activities.

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 =

$$\frac{\sum_i (EOR_i)}{\sum_i (U_i)},$$

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 =

$$\frac{\sum_i (OR_i)}{\sum_i (A_i)},$$

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 =

$$\frac{\sum_i (CAA_i)}{\sum_i (CAL_i)},$$

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 =

$$\frac{\sum_i (LTD_i)}{\sum_i (C_i)} \times 100,$$

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 =

$$\frac{\sum_i (PS_i)}{\sum_i (C_i)} \times 100,$$

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 =

$$\frac{\sum_i (CSE_i)}{\sum_i (C_i)} \times 100,$$

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 =

$$\frac{\sum_i (LTD_i + STD_i)}{\sum_i (TA_i)} \times 100,$$

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 =

$$\frac{\sum_i (CSE_i)}{\sum_i (TA_i)} \times 100,$$

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 =

$$\frac{\sum_i \begin{pmatrix} IBI_i + EIT_i + GIT_i \\ + OUIT_i + TOID_i - AC_i \end{pmatrix}}{\sum_i (IE_i)},$$

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 =

$$\frac{\sum_i (NI_i)}{\sum_i (OR_i)} \times 100,$$

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 =

$$\frac{\sum_i(NI_i)}{\left(\sum_i(CSEB_i) + \sum_i(CSEE_i)\right)/2} \times 100,$$

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 =

$$\frac{\sum_i(NI_i)}{\sum_i(TA_i)} \times 100,$$

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.

Form EIA-412

Composite Financial Indicators for Major Publicly Owned Electric Utilities

Electric Utility Plant per Dollar of Revenue =

$$\frac{\sum_i(EUP_i)}{\sum_i(EOR_i)},$$

where EUP is the Electric Utility Plant for the the i^{th} public utility; and, EOR is the Electric Operating Revenue for the i^{th} public utility.

Current Assets to Current Liabilities =

$$\frac{\sum_i(CA_i)}{\sum_i(CL_i)},$$

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 =

$$\frac{\sum_i(EUP_i)}{\sum_i(TA_i)} \times 100,$$

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 =

$$\frac{\sum_i(NEUP_i)}{\sum_i(TA_i)} \times 100,$$

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 =

$$\frac{\sum_i(D_i)}{\sum_i(TL_i)} \times 100,$$

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 =

$$\frac{\sum_i(APD_i)}{\sum_i(EUP_i)} \times 100,$$

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 =

$$\frac{\sum_i(EOME_i)}{\sum_i(EOR_i)} \times 100,$$

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 =

$$\frac{\sum_i (EDA_i)}{\sum_i (EOR_i)} \times 100,$$

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 =

$$\frac{\sum_i (TTE_i)}{\sum_i (EOR_i)} \times 100,$$

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 =

$$\frac{\sum_i (IE_i)}{\sum_i (EOR_i)} \times 100,$$

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 =

$$\frac{\sum_i (NI_i)}{\sum_i (EOR_i)} \times 100,$$

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.

Purchase Power Cents Per Kilowatthour =

$$\frac{\sum_i (PPC_i)}{\sum_i (PPK_i)} \times 10, \qquad (A1)$$

where PPC_i is the Purchase Power Costs (in cents) for the i^{th} public utility; and, PPK_i is the Purchased Power Kilowatthours for the i^{th} public utility.

Generated Cents Per Kilowatthour =

$$\frac{\sum_i (TGC_i)}{\sum_i (TGK_i)} \times 10, \qquad (A2)$$

where TGC_i is the Total Generation Costs (in cents) for the i^{th} public utility; and, TGK_i is the Total Generated Kilowatthours for the i^{th} public utility.

Total Power Supply Per Kilowatthour Sold =

$$\frac{\sum_i (TPC_i)}{\sum_i (TPK_i)} \times 10, \qquad (A3)$$

where TPC_i is the Total Generation and Purchase Power Cost for the i^{th} public utility; and, TPK_i is the Total Generated and Purchased Power Kilowatthours Sold 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 A3).[31] Environmental Protection Agency emission factors are based on boiler type, firing configuration, and fuel burned. The methodology for determining emissions of CO_2 has been revised since the 1991 publication. Emissions of carbon dioxide for 1992 and prior years have been revised using the set of factors shown in Tables A3 and A4.

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 emission factors, by rank and State were derived on the basis of data contained in EIA's Coal Analysis File.[32]

In editions prior to 1992 of this publication, separate conversion factors by coal rank were published and used to estimate emissions of CO_2. The special study by EIA concluded that since geographic location of coal in addition to rank of coal is a significant factor in determining the carbon/heat content relationship, the use of emission factors that consider both of these elements may yield more accurate estimates of CO_2 emissions. The emission factors for coal were developed in the units of pounds of CO_2 per million Btu of coal.

The emission factors for CO_2 (Table A4) 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 by the quantity of coal consumed by plant, as reported on Form EIA-767, "Steam-Electric Plant Operation and Design Report," to determine the emissions of CO_2. The emission factors for CO_2 based on 100-percent combustion of the carbon in the fuel. Since a small percentage of the carbon in the coal is not converted to CO_2, 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 SO_2 and NO_x do not always accurately depict the quantity of emissions released into the atmosphere because they fail to reflect reductions from control equipment and/or operating technologies. Consequently, controlled emissions are calculated to provide a more accurate estimate of actual utility air emission.

Controlled Sulfur Dioxide Emissions. Because of environmental regulations controlling SO_2 emissions, many utilities are required to install FGD units at their coal-fired plants.[33] FGD units typically remove between 70 to 90 percent of SO_2 from the boiler flue gas although higher removal efficiencies can be achieved. Electric utilities report both sulfur removal efficiency (percent) and their most stringent SO_2 emission limits on the Form EIA-767. To determine controlled SO_2 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 SO_2 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 A5. 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 CO_2 emissions. Information pertinent to the estimation of controlled CO_2 emissions is not collected on the Form EIA-767; therefore, no estimates of controlled CO_2 emissions are made.

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

32 For a description of methodology and data use to develop the EIA CO_2 emission factors, see B. D. Hong and E. R. Slatick, "Carbon Dioxide Emission Factors for Coal," *Quarterly Coal Report, January-March 1994,* DOE/EIA-0121(94/1Q) (Washington, DC, August 1994), Energy Information Administration.

33 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 SO_2, NOx, and CO_2 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 SO_2, NO_x, and CO_2 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 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. As with electric utilities, the source of both the SO_2 and NO_x emission factors, when available, is the Environmental Protection Agency report AP-42, "Compilation of Air Pollutant Emission Factors."[34] However, the boiler type and firing configuration are not reported on the Form EIA-867 so all boilers are assumed to be large boilers[35] 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 CO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 emissions are calculated for respondents reporting FGD equipment or fluidized bed combustion. For facilities reporting first electrical generation before August 1973, no reductions are assumed. For facilities reporting first electrical generation between August 1973 and June 1986, the controlled emission is estimated as the lesser of either: the uncontrolled emission, or a weighted average of 1.2 and 0.8 pounds of SO_2 per million Btu of solid and liquid fossil fuel consumed, respectively. For facilities

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

[35] Boilers with a gross heat rate of 100 million Btu per hour or greater.

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 SO_2 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 SO_2 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 SO_2 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 SO_2 emission is estimated as the lesser of either: the uncontrolled SO_2 emission, or 1.2 pound of SO_2 per million Btu of fuel consumed. For facilities reporting their first electrical generation after August 1980, the controlled SO_2 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 A4.

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 CO_2 emissions. Information pertinent to the estimation of controlled CO_2 emissions is not collected on the Form EIA-867; therefore, no estimates of controlled CO_2 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

Upon EIA approval of the *Electric Power Annual Volume II* these data are available for public use.

Magnetic 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 deposit accounts. To place an order, contact:

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Table A1. Installed Capacity at U.S. Nonutility Generating Facilities by Producing Energy Group and Census Division, 1993 and 1994
(Megawatts)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
			1993 (1 Megawatt or More)				
New England	1,692	2,919	W	—	W	—	4,729
Middle Atlantic	2,945	5,409	295	—	W	W	8,730
East North Central	3,015	2,141	267	W	W	W	5,546
West North Central	702	184	165	W	W	W	1,261
South Atlantic	5,715	4,405	84	W	W	61	10,303
East South Central	1,676	18	W	W	W	—	1,734
West South Central	10,175	2,512	203	180	—	—	13,069
Mountain	431	989	77	245	—	278	2,020
Pacific	3,541	8,137	236	1,142	239	91	13,385
U.S. Total	**29,892**	**26,714**	**1,444**	**1,860**	**297**	**571**	**60,778**
			1994 (1 Megawatt or More)				
New England	1,455	3,322	118	—	—	—	4,895
Middle Atlantic	3,311	8,170	W	—	W	W	11,752
East North Central	3,059	2,492	272	W	W	W	5,947
West North Central	706	213	166	W	W	W	1,296
South Atlantic	6,114	6,027	102	W	W	67	12,384
East South Central	2,029	18	W	27	W	—	2,088
West South Central	10,604	2,778	202	180	—	—	13,764
Mountain	425	1,602	58	245	—	352	2,682
Pacific	3,206	8,706	293	1,142	239	68	13,654
U.S. Total	**30,909**	**33,328**	**1,445**	**1,867**	**330**	**581**	**68,461**

W = Withheld to avoid disclosure of individual company data.

Notes: •Data for 1993 and 1994 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 A2. Gross Generation by U.S. Nonutility Generating Facilities by Producing Energy Group and Census Division, 1993 and 1994

(Million Kilowatthours)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
			1993 (1 Megawatt or More)				
New England	9,833	17,930	466	—	(*)	—	28,229
Middle Atlantic	16,469	30,513	W	(*)	(*)	W	48,705
East North Central	14,763	9,981	956	W	W	W	26,211
West North Central	2,983	341	403	W	W	W	4,675
South Atlantic	32,412	10,769	159	W	W	W	43,620
East South Central	10,531	72	W	W	W	(*)	10,741
West South Central	61,708	16,627	611	1,127	—	—	80,073
Mountain	2,443	5,701	W	523	—	W	9,572
Pacific	20,704	41,692	1,407	7,720	1,530	346	73,400
U.S. Total	**171,845**	**133,627**	**5,541**	**10,689**	**1,767**	**1,757**	**325,226**
			1994 (1 Megawatt or More)				
New England	7,840	21,613	471	—	(*)	—	29,925
Middle Atlantic	17,948	37,167	W	(*)	W	W	56,457
East North Central	14,728	12,762	993	W	W	W	28,993
West North Central	3,150	434	421	W	W	W	5,077
South Atlantic	35,043	16,720	166	W	W	W	52,152
East South Central	12,478	81	W	148	W	(*)	12,786
West South Central	62,636	18,351	539	464	—	—	81,989
Mountain	2,473	7,199	336	563	—	701	11,273
Pacific	19,485	45,193	1,720	8,069	1,523	281	76,271
U.S. Total	**175,782**	**159,520**	**5,781**	**10,618**	**1,747**	**1,477**	**354,925**

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

Notes: •Data for 1993 and 1994 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 A3. Sulfur Dioxide, Nitrogen Oxide, and Carbon Dioxide Emission Factors

Fuel	Boiler Type/ Firing Configuration	Emission Factors		
		Sulfur Dioxide[1]	Nitrogen Oxides[2]	Carbon Dioxide[3]
Utility				
Coal and Other Solid Fuels		lbs per ton	lbs per ton	lbs per ton
Bituminous[4]	cyclone	38.00 x S	33.8	See Table A4
	fluidized bed[5]	39.60 x S	9.6	See Table A4
	spreader stoker	38.00 x S	13.7	See Table A4
	tangential	38.00 x S	14.4	See Table A4
	all others	38.00 x S	21.7(34)	See Table A4
Subbituminous[4]	cyclone	35.00 x S	33.8	See Table A4
	fluidized bed[5]	39.60 x S	9.6	See Table A4
	spreader stoker	35.00 x S	13.7	See Table A4
	tangential	35.00 x S	14.4	See Table A4
	all others	35.00 x S	21.7(34)	See Table A4
Lignite[4]	cyclone	30.00 x S	12.50	See Table A4
	fluidized bed[5]	30.00 x S	3.60	See Table A4
	front/opposed	30.00 x S	11.10	See Table A4
	spreader stoker	30.00 x S	5.80	See Table A4
	tangential	30.00 x S	7.30	See Table A4
	all others	30.00 x S	11.10	See Table A4
Petroleum Coke[6]	fluidized bed[5]	39.00 x S	1.80	5,680
	all others	39.00 x S	18.00	5,680
Refuse	all types	3.46	2.69	2,344
Wood	all types	0.08	1.50	2,100
Petroleum and Other Liquid Fuels		lbs per 10^3 gal	lbs per 10^3 gal	lbs per 10^3 gal
Residual Oil[7]	tangential	162.7 x S	42.00	25,445
	vertical	162.7 x S	67.00	25,445
	all others	162.7 x S	67.00	25,445
Distillate Oil[7]	all types	144.00 x S	20.00	22,572
Methanol	all types	0.05	12.40	7,603
Propane (liquid)	all types	0.05	19.00	12,500
Coal-Oil Mixture	all types	185.00 x S	50.00	22,368
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	120,000
	all others	0.60	550.00	120,000
Blast Furnance Gas	all types	0.60	550.00	120,000
Nonutility				
Coal and Other Solid Fuels		lbs per ton	lbs per ton	lbs per ton
Anthracite Culm	all types	39.00 x S	9.00	See Table A4
Bituminous[4]	all types	38.00 x S	21.70	See Table A4
Bituminous Gob	all types	38.00 x S	21.70	See Table A4
Subituminous	all types	35.00 x S	21.70	See Table A4
Lignite[4]	all types	30.00 x S	11.10	See Table A4
Lignite Waste	all types	30.00 x S	11.10	See Table A4
Peat	all types	30.00 x S	11.10	See Table A4
Agricultural Waste	all types	0.08	1.20	1,560
Black Liquor	all types	7.00	1.50	2,725
Chemicals	all types	7.00	1.50	2,725
Closed Loop Biomass	all types	0.08	1.50	2,100
Internal	all types	0.08	1.50	2,100

See footnotes at end of table.

Table A3. Sulfur Dioxide, Nitrogen Oxide, and Carbon Dioxide Emission Factors (Continued)

Fuel	Boiler Type/ Firing Configuration	Emission Factors: Sulfur Dioxide[1]	Nitrogen Oxides[2]	Carbon Dioxide[3]
Coal and Other Solid Fuels (Continued)		lbs per ton	lbs per ton	lbs per ton
Liquid Acetonitrile Waste	all types	7.00	1.50	2,725
Liquid Waste	all types	7.00	1.50	2,725
Municipal Solid Waste	all types	3.46	2.69	2,344
Petroleum Coke[7]	all types	39.00 x S	18.00	5,680
Pitch	all types	30.00 x S	11.10	See Table A4
Railroad Ties	all types	0.08	1.50	2,100
Red Liquor	all types	7.00	1.50	2,725
Sludge	all types	2.80	8.60	2,100
Sludge Waste	all types	2.80	8.60	2,100
Sludge Wood	all types	2.80	8.60	2,100
Spent Sulfite Liquor	all types	7.00	1.50	2,725
Straw	all types	0.08	1.50	2,100
Sulfur	all types	7.00	0.00	0
Tar Coal	all types	30.00 x S	11.10	See Table A4
Tires	all types	38.00 x S	21.70	5,715
Waste Byproducts	all types	3.46	2.69	2,344
Waste Coal	all types	38.00 x S	21.70	See Table A4
Wood/Wood Waste	all types	0.08	1.50	2,100
Petroleum and Other Liquid Fuels		lbs per 10^3 gal	lbs per 10^3 gal	lbs per 10^3 gal
Heavy Oil[7]	all types	162.7 x S	67.00	25,445
Light Oil[7]	all types	162.70 x S	20.00	22,572
Diesel	all types	162.70 x S	20.00	22,572
Kerosene	all types	162.70 x S	20.00	22,572
Butane (liquid)	all types	0.60	21.00	14,700
Fish Oil	all types	0.50	12.40	7,603
Methanol	all types	0.50	12.40	7,603
Oil Waste	all types	17.6 x S	2.30	20,000
Propane (liquid)	all types	0.50	19.00	12,500
Sludge Oil	all types	17.6 x S	2.30	20,000
Tar Oil	all types	162.70 x S	67.00	25,445
Waste Alcohol	all types	0.50	12.40	7,603
Natural Gas and Other Gaseous Fuels		lbs per 10^6 cf	lbs per 10^6 cf	lbs per 10^6 cf
Natural Gas	all types	0.60	550.00	120,000
Butane (gas)	all types	0.60	550.00	479,450
Hydrogen	all types	0.00	550.00	0
Landfill Gas	all types	0.60	550.00	120,000
Methane	all types	0.60	550.00	116,436
Other Gas	all types	0.60	550.00	120,000
Propane (gas)	all types	0.60	550.00	358,333

[1] Uncontrolled sulfur dioxide emission factors. "x S" indicates that the constant must be multiplied by the percentage (by weight) of sulfur in the fuel. Sulfur dioxide emission estimates from facilities with flue gas desulfurization equipment are calculated by multiplying uncontrolled emission estimates by one minus the reported sulfur removal efficiencies. Sulfur dioxide emission factors also account for small quantities of sulfur trioxide and gaseous sulfates.

[2] 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 A5 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*, Fourth Edition, Research Triangle Park, North Carolina, July 1993. •For carbon dioxide factors: Department of Energy, "Carbon Dioxide Emissions from Fossil Fuels: A Procedure for Estimation of Results, 1950-1981," June 1983.

Table A4. 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, Office of Coal, Nuclear, Electric, and Alternate Fuels.

Table A5. 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 Recuction 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 A6. 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, Office of Coal, Nuclear, Electric and Alternate fuels.

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 peak loads 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 Costs: The costs incurred by the utility to achieve the capacity and energy savings from the Demand-Side Management Program. Costs incurred by consumers or third parties are to be excluded. The costs are to be reported in nominal dollars in the year in which they are incurred, regardless of when the savings occur. Program costs 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 costs that are general, administrative, or not specific to a particular Demand-Side Management category are to be included in "other" costs.

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 peak load effects are reported here and seasonal (i.e., summer and winter) peak load 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 peak loads 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 oversite 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: Particule matter from coal ash in which the particle diameter is less than 1×10^{-4} meter. This is removed from the flue gas using flue gas particulate collectors such as fabric filters and electrostatic precipitators.

Forced Outage: The shutdown of a generating unit, transmission line or other facility, for emergency reasons or a condition in which the generating equipment is unavailable for load due to unanticipated breakdown.

Fossil Fuel: Any naturally occurring organic fuel, such as petroleum, coal, and natural gas.

Fossil-Fuel Plant: A plant using coal, petroleum, or gas as its source of energy.

Fuel: Any substance that can be burned to produce heat; also, materials that can be fissioned in a chain reaction to produce heat.

Fuel Expenses: These costs include the fuel used in the production of steam or driving another prime mover for the generation of electricity. Other associated expenses include unloading the shipped fuel and all handling of the fuel up to the point where it enters the first bunker, hopper, bucket, tank, or holder in the boiler-house structure.

Full-Forced Outage: The net capability of main generating units that is unavailable for load for emergency reasons.

Gas: A fuel burned under boilers and by internal combustion engines for electric generation. These include natural, manufactured and waste gas.

Gas Turbine Plant: A plant in which the prime mover is a gas turbine. A gas turbine consists typically of an axial-flow air compressor, one or more combustion chambers, where liquid or gaseous fuel is burned and the hot gases are passed to the turbine and where the hot gases expand to drive the generator and are then used to run the compressor.

Generating Unit: Any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

Generation (Electricity): The process of producing electric energy by transforming other forms of energy; also, the amount of electric energy produced, expressed in watthours (Wh).

Gross Generation: The total amount of electric energy produced by the generating units at a generating station or stations, measured at the generator terminals.

Net Generation: Gross generation less the electric energy consumed at the generating station for station use.

Generator: A machine that converts mechanical energy into electrical energy.

Generator Nameplate Capacity: The full-load continuous rating of a generator, prime mover, or other electric power production equipment under specific conditions as designated by the manufacturer. Installed generator nameplate rating is usually indicated on a nameplate physically attached to the generator.

Geothermal Plant: A plant in which the prime mover is a steam turbine. The turbine is driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the earth. The energy is extracted by drilling and/or pumping.

Gigawatt (GW): One billion watts.

Gigawatthour (GWh): One billion watthours.

Greenhouse Effect: The increasing mean global surface temperature of the earth caused by gases in the atmosphere (including carbon dioxide, methane, nitrous oxide, ozone, and chlorofluorocarbon). The greenhouse effect allows solar radiation to penetrate but absorbs the infrared radiation returning to space.

Grid: The layout of an electrical distribution system.

Gross Generation: The total amount of electric energy produced by a generating facility, as measured at the generator terminals.

Heating System: Energy Efficiency program promotion aimed at improving the efficiency of the heating delivery system, including replacement, in the residential, commercial, or industrial sectors.

Heavy Oil: The fuel oils remaining after the lighter oils have been distilled off during the refining process. Except for start-up and flame stabilization, virtually all petroleum used in steam plants is heavy oil.

Hydroelectric Plant: A plant in which the turbine generators are driven by falling water.

Incremental Effects: The annual effects in energy use (measured in megawatthours) and peak load (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 peak load, 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 peak load effects are reported on the Form EIA-861 and seasonal (i.e., summer and winter) peak load effects are reported on the OE-411).

Kilowatt (kW): One thousand watts.

Kilowatthour (kWh): One thousand watthours.

Leverage Ratio: A measure that indicates the financial ability to meet debt service requirements and increase the value of the investment to the stockholders. (i.e. the ratio of total debt to total assets).

Liability: An amount payable in dollars or by future services to be rendered.

Light Oil: Lighter fuel oils distilled off during the refining process. Virtually all petroleum used in internal combustion and gas-turbine engines is light oil.

Lignite: A brownish-black coal of low rank with high inherent moisture and volatile matter (used almost exclusively for electric power generation). It is also referred to as brown coal. Comprises two groups classified according to the following ASTM Specification D388-84 for calorific values on a moist material-matter-free basis:

	Limits Btu/lb.	
	GE	LT
Lignite A	6300	8300
Lignite B	-	6300

Load (Electric): The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers.

Load Building: Refers to programs that are aimed at increasing the usage of existing electric equipment or the addition of electric equipment. Examples include industrial technologies such as induction heating and melting, direct arc furnaces and infrared drying; cooking for commercial establishments; and heat pumps for residences. Load Building should include programs that promote electric fuel substitution. Load Building effects should be reported as a negative number, shown with a minus sign.

Marketing Cost: Expenses directly associated with the preparation and implementation of the strategies designed to encourage participation in a DSM program. The category excludes general market and load research costs.

Monitoring & Evaluation Cost: Expenditures associated with the planning, collection, and analysis of data used to assess program operation and effects. It includes the activities such as load metering, customer surveys, new technology testing, and program evaluations that are intended to establish or improve the ability to monitor and evaluate the impacts of DSM programs, collectively or individually.

Maximum Demand: The greatest of all demands of the load that has occurred within a specified period of time.

Mcf: One thousand cubic feet.

Megawatt (MW): One million watts.

Megawatthour (MWh): One million watthours.

MMcf: One million cubic feet.

Natural Gas: A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in porous geological formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane.

Net Capability: The maximum load-carrying ability of the equipment, exclusive of station use, under specified conditions for a given time interval, independent of the characteristics of the load. (Capability is determined by design characteristics, physical conditions, adequacy of prime mover, energy supply, and operating limitations such as cooling and circulating water supply and temperature, headwater and tailwater elevations, and electrical use.)

Net Generation: Gross generation minus plant use from all electric utility owned plants. The energy required for pumping at a pumped-storage plant is regarded as plant use and must be deducted from the gross generation.

Net Summer Capability: The steady hourly output, which generating equipment is expected to supply to system load exclusive of auxiliary power, as demonstrated by tests at the time of summer peak demand.

Net Winter Capability: The steady hourly output which generating equipment is expected to supply to system load exclusive of auxiliary power, as demonstrated by tests at the time of winter peak demand.

New Construction: Energy-efficiency program promotion to encourage the building of new homes, buildings, and plants to exceed standard government-mandated energy efficiency codes; it may include major renovations of existing facilities.

Noncoincidental Peak Load: The sum of two or more peak loads on individual systems that do not occur in the same time interval. Meaningful only when considering loads within a limited period of time, such as a day, week, month, a heating or cooling season, and usually for not more than 1 year.

Non-Firm Power: Power or power-producing capacity supplied or available under a commitment having limited or no assured availability.

Nonutility Power Producer: A corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not an electric utility. Nonutility power producers include qualifying cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers) without a designated franchised service area, and which do not file forms listed in the Code of Federal Regulations, Title 18, Part 141.

North American Electric Reliability Council (NERC): A council formed in 1968 by the electric utility industry to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America. NERC consists of ten regional reliability councils and encompasses essentially all the power regional of the contiguous United States, Canada, and Mexico. The NERC Regions are:

ASCC - Alaskan System Coordination Council

ECAR - East Central Area Reliability Coordination Agreement

ERCOT - Electric Reliability Council of Texas

MAIN - Mid-America Interconnected Network

MAAC - Mid-Atlantic Area Council

MAPP - Mid-Continent Area Power Pool

NPCC - Northeast Power Coordinating Council

SERC - Southeastern Electric Reliability Council

SPP - Southwest Power Pool

WSCC - Western Systems Coordinating Council

Nuclear Fuel: Fissionable materials that have been enriched to such a composition that, when placed in a nuclear reactor, will support a self-sustaining fission chain reaction, producing heat in a controlled manner for process use.

Nuclear Power Plant: A facility in which heat produced in a reactor by the fissioning of nuclear fuel is used to drive a steam turbine.

Off-Peak Gas: Gas that is to be delivered and taken on demand when demand is not at its peak.

Ohm: The unit of measurement of electrical resistance. The resistance of a circuit in which a potential difference of 1 volt produces a current of 1 ampere.

Operable Nuclear Unit: A nuclear unit is "operable" after it completes low-power testing and is granted authorization to operate at full power. This occurs when it receives its full power amendment to its operating license from the Nuclear Regulatory Commission.

Other Cost: A residual category to capture the Indirect Costs of DSM programs that cannot be meaningfully included in any of the other cost categories listed and defined herein. Included are costs such as those incurred in the research and development of DSM technologies.

Other DSM Programs: A residual category to capture the effects of DSM programs that cannot be meaningfully included in any of the program categories listed and defined herein. The energy effects attributable to this category should be the net effects of all the residual programs. Programs that promote consumer's substitution of electricity by other energy types should be included in Other DSM Programs. Also, self-generation should be included in Other DSM Programs to the extent that it is not accounted for as backup generation in Other Load Management or Interruptible Load categories.

Other Incentives: Energy Efficiency programs that offer cash or noncash awards to electric energy efficiency deliverers, such as appliance and equipment dealers, building contractors, and architectural and engineering firms, that encourage consumer participation in a DSM program and adoption of recommended measures.

Other Load Management: Refers to programs other than Direct Load Control and Interruptible Load that limit or shift peak load from on-peak to off-peak time periods. It includes technologies that primarily shift all or part of a load from one time-of-day to another and secondarily may have an impact on energy consumption. Examples include space heating and water heating storage systems, cool storage systems, and load limiting devices in energy management systems. This category also includes programs that aggressively promote time-of-use (TOU) rates and other innovative rates such as real time pricing. These rates are intended to reduce consumer bills and shift hours of operation of equipment from on-peak to off-peak periods through the application of time-differentiated rates.

Outage: The period during which a generating unit, transmission line, or other facility is out of service.

Peak Demand: The maximum load during a specified period of time.

Peak Load Plant: A plant usually housing old, low-efficiency steam units; gas turbines; diesels; or pumped-storage hydroelectric equipment normally used during the peak-load periods.

Peaking Capacity: Capacity of generating equipment normally reserved for operation during the hours of highest daily, weekly, or seasonal loads. Some generating equipment may be operated at certain times as peaking capacity and at other times to serve loads on an around-the-clock basis.

Percent Difference: The relative change in a quantity over a specified time period. It is calculated as follows: the current value has the previous value subtracted from it; this new number is divided by the absolute value of the previous value; then this new number is multiplied by 100.

Petroleum: A mixture of hydrocarbons existing in the liquid state found in natural underground reservoirs, often associated with gas. Petroleum includes fuel oil No. 2, No. 4, No. 5, No. 6; topped crude; Kerosene; and jet fuel.

Petroleum Coke: See Coke (Petroleum).

Petroleum (Crude Oil): A naturally occurring, oily, flammable liquid composed principally of hydrocarbons. Crude oil is occasionally found in springs or pools but usually is drilled from wells beneath the earth's surface.

Planned Generator: A proposal by a company to install electric generating equipment at an existing or planned facility or site. The proposal is based on the owner having obtained (1) all environmental and regulatory approvals, (2) a signed contract for the electric energy, or (3) financial closure for the facility.

Plant: A facility at which are located prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or nuclear energy into electric energy. A plant may contain more than one type of prime mover. Electric utility plants exclude facilities that satisfy the definition of a qualifying facility under the Public Utility Regulatory Policies Act of 1978.

Plant Use: The electric energy used in the operation of a plant. Included in this definition is the energy required for pumping at pumped-storage plants.

Plant-Use Electricity: The electric energy used in the operation of a plant. This energy total is subtracted from the gross energy production of the plant; for reporting purposes the plant energy production is then reported as a net figure. The energy required for pumping at pumped-storage plants is, by definition, subtracted, and the energy production for these plants is then reported as a net figure.

Potential Peak Reduction: The potential annual peak load reduction (measured in kilowatts) that can be deployed from Direct Load Control, Interruptible Load, Other Load Management, and Other DSM Program activities. It represents the load that can be reduced either by the direct control of the utility system operator or by the consumer in response to a utility request to curtail load. It reflects the installed load reduction capability, as opposed to the Actual Peak Reduction achieved by participants, during the time of annual system peak load.

Power: The rate at which energy is transferred. Electrical energy is usually measured in watts. Also used for a measurement of capacity.

Power Pool: An association of two or more interconnected electric systems having an agreement to coordinate operations and planning for improved reliability and efficiencies.

Power Marketers: Power marketers are business entities engaged in buying and selling electricity, but do not own generating or transmission facilities. Power marketers, as opposed to Brokers, take ownership of the electricity and are involved in interstate trade. These entities file with FERC for status as a power marketer.

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 peak load 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.

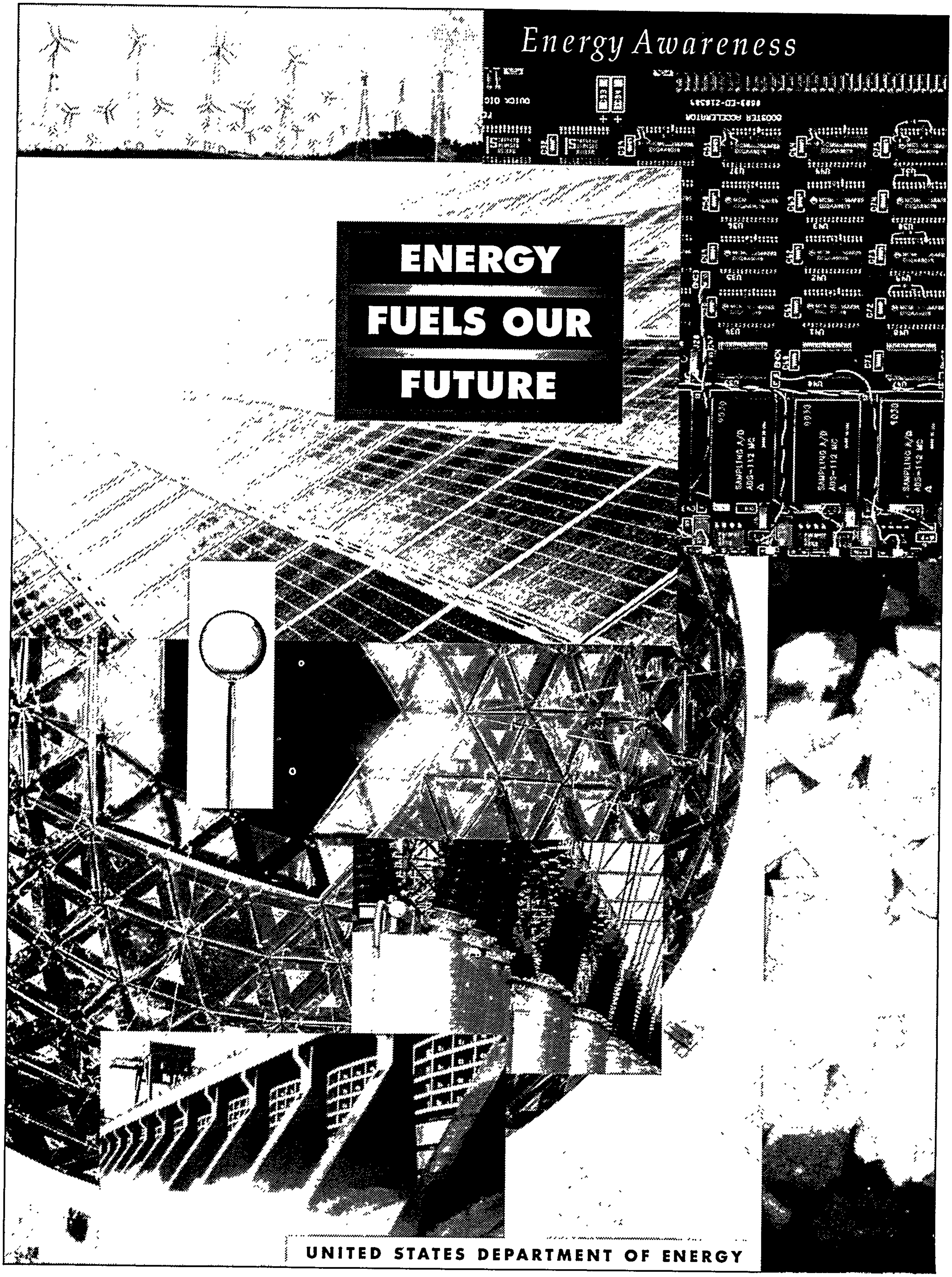
Water Heating: Energy Efficiency program promotion to increase efficiency in water heating, including low-flow shower heads and water heater insulation wraps. Could be applicable to residential, commercial, or industrial consumer sectors.

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, municipals, and Federal and State electric agencies for resale to ultimate consumers.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