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Preface

Electric Power Annual, Volumes I and II

The *Electric Power Annual* is published in two volumes. Volume I, released August 1997, contains 1996 data on U.S. electric utility net generation; fossil fuel consumption, stocks, receipts, and cost; preliminary data on generating unit capability and planned additions; and estimated retail sales of electricity, associated revenue, and average revenue per kilowatthour of electricity sold. Also included in Volume I is information on net generation and associated generating capability from renewable energy sources and estimates for national-level nonutility data.

Volume II contains annual summary statistics for the electric power industry, including information on both electric utilities and nonutility power producers. Included are data for electric utility retail sales of electricity, associated revenue, and average revenue per kilowatthour of electricity sold; financial statistics; environmental statistics; power transactions; and demand-side management. Also included are data for U.S. nonutility power producers on installed capacity; gross generation; emissions; and supply and disposition of energy.

The *Electric Power Annual 1996, 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 Electric Power 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, analysts, and individuals with policymaking and decisionmaking responsibilities in electric utility companies or other energy concerns. Other users include financial and investment institutions, economic development organizations, special interest groups, lobbyists, electric power associations, and the news media.

In the public sector, users include the U.S. Congress, Federal government agencies, State governments and public service commissions, and local governments. Data in this report can be used in analytic studies to evaluate new legislation and are used by analysts, researchers, statisticians, and other professionals with regulatory, policy, and program responsibilities for Federal, State, and local governments.

The *Electric Power Annual, Volume II* presents an overview of the electric power industry in the United States, and a summary of the key statistics for the reporting year. The chapters present information and data in each specific area: electric utility retail sales, revenue, and average revenue per kilowatthour; financial statistics for major electric utilities; wholesale trade among electric utilities; electric utility environmental statistics; electric utility demand-side management activities; and statistics for nonutility power producers. Monetary values in this publication are expressed in nominal terms.

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. These forms are described in detail in the “Technical Notes.”

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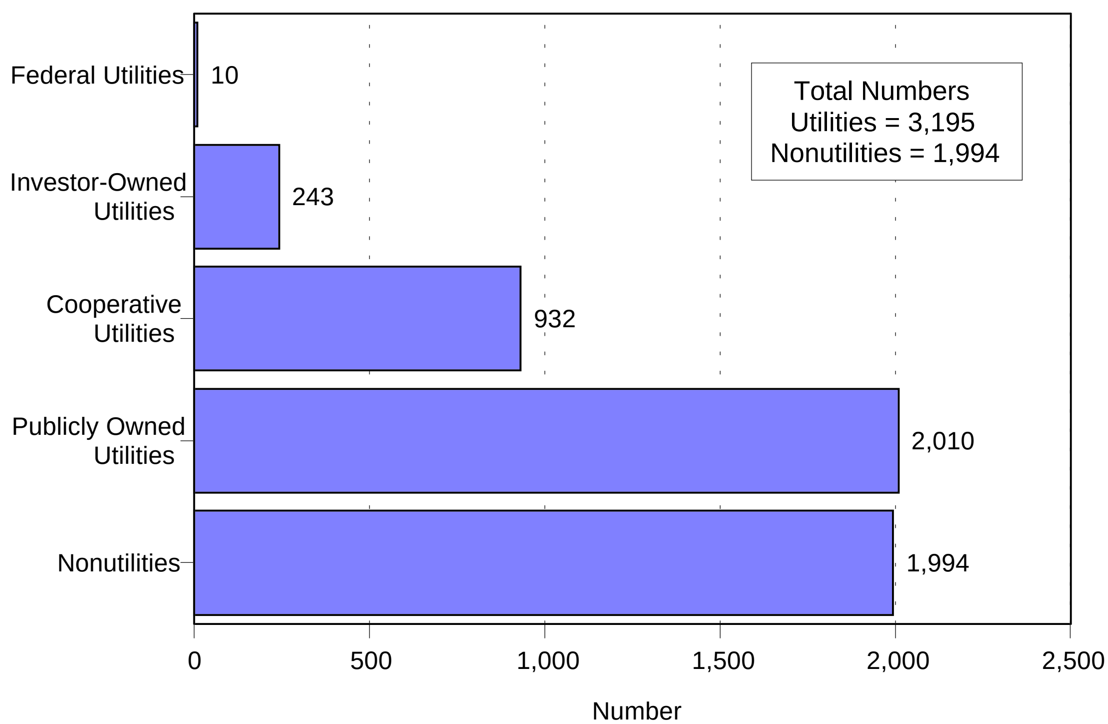
The U.S. Electric Power Industry at a Glance

Industry Profile

The electric power industry in the United States is composed of traditional electric utilities, including power marketers, and nonutility power producers. In this report, the traditional electric utilities are investor-owned, publicly owned, cooperative, and Federal utilities. They are defined as 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. They are generally vertically integrated companies that provide for generation, transmission, distribution, and/or energy services for all customers in a designated service territory. There are over 3,000 electric utilities in the United States. Additionally, power marketers, which buy and sell electricity but generally do not own or operate generation, transmission, or distribution facilities, are considered electric utilities. Currently, over 200 power marketers have filed rate tariffs with the Federal Energy Regulatory Commission to sell wholesale electric power, and approximately 80 are actively engaged in wholesale trade. Nonutility power producers are defined as any person, corporation, municipality, State, political subdivision or agency, Federal agency, or other legal entity that is either: (1) a Qualifying Facility (QF) under the Public Utilities Regulatory Policies Act of 1978 (PURPA), (2) a cogeneration facility (produces steam and electricity) engaged in business activities other than the sale of electric energy, such as agriculture, mining, manufacturing, transportation, or education, and produces steam for its own use or sale and generates electricity for its own use, selling excess power to the host utility, (3) an independent power producer which produces and sells electric power wholesale at nonregulated rates and does not have a franchised service territory, or (4) an exempt wholesale generator under the Energy Policy Act of 1992 (EPACT). There are approximately 2,000 nonutility power producers in the United States.

Figure 1. Composition of the Electric Power Industry in the United States, 1996



Notes: •Data are final. •Power marketers, Puerto Rico, and U.S. Territories are not included. •Nonutilities represent the number of generating facilities, as these facilities are generally incorporated, and each is required to file Form EIA-867.

Sources: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report," Form-EIA-867, "Annual Nonutility Power Producers Report."

Traditional Electric Utilities

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. Investor-owned utilities operate in all States except Nebraska. Like all private businesses, investor-owned electric utilities' objective is to produce a return for their investors. The profits are either distributed to stockholders as dividends or reinvested. Investor-owned electric utilities are granted service monopolies and are obligated to serve all customers in their service areas. 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. As the industry becomes competitive, utilities are organizing generation, transmission, distribution, and energy services into separate business units, and prices for these functions are being unbundled.

Publicly Owned Electric Utilities. Publicly owned electric utilities in the United States are nonprofit government agencies established to serve their communities and nearby consumers at cost, returning excess funds to the consumer in the form community contributions, economic and efficient facilities, and reduced rates. Publicly owned electric utilities 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 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. Cooperatives operate in all States except Connecticut, Hawaii, Massachusetts, and Rhode Island and the District of Columbia.

Federal Electric Utilities. Federal electric utilities are primarily producers and wholesalers of electric power and do not produce any 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. Wholesale Federal producers include the U.S. Army Corps of Engineers, the U.S. Bureau of Reclamation, and the International Boundary and Water Commission. Power produced by these Federal entities is marketed by Federal power marketing administrations in the U.S. Department of Energy: Bonneville, Southeastern, Southwestern, and Western Area Power Administrations. The Federal power marketing administrations operate in all areas except the Northeast, upper Midwest, and Hawaii. The largest producer of Federal electricity, the Tennessee Valley Authority, markets its own power. The Alaska Power Administration operates and distributes power from its own projects and markets both wholesale and retail electricity. On November 28, 1995, the President signed a bill authorizing the sale of the Alaska Power Administration's projects. Transfer of title to the State of Alaska and three utilities is anticipated by the end of 1998.

Power Marketers. Power marketers are a rapidly growing segment of the electric power industry. Like traditional electric utilities, power marketers buy and sell electric power in the wholesale market and fall under FERC's jurisdiction, since they take ownership of power and are engaged in interstate trade. Power marketers differ from traditional electric utilities in that they generally lack both ownership of generation, transmission, or distribution facilities and a designated service territory.

The number of registered power marketers has grown substantially in the past two years, although in 1996 fewer than half of those registered with the FERC actually conducted wholesale electricity transactions. Many registered power marketers undertook only a few transactions, seemingly to test and improve their techniques and procedures and to observe marketplace opportunities.

As the States open retail access for electricity, power marketers are entering these new markets. The State public utility commissions may require registration of retail electricity providers, including power marketers. In 1996, pilot programs for retail access were conducted in several States, including Illinois, New Hampshire, Massachusetts, New York, and Washington. Power marketers were active participants in the pilots.

Many power marketers are affiliated with companies owning reserves of other sources of energy, such as natural gas. An exchange of fuel for electricity known as "tolling" allows a power marketer with access to fuel resources to "rent" a generator from an electric utility, supply fuel to the unit to produce electricity, pay the "rental" fee with a portion of the generated power, and take delivery of the balance for sale to customers.

In 1996, 213 million megawatthours of electricity were reported as sales for resale by power marketers to the EIA, representing an increase of 500 percent over 1995. Marketers make numerous small transactions with many wholesale customers, including other power marketers. Although marketers generally are not all-requirements suppliers to distribution utilities, some marketers have successfully contracted with municipals to supply their power. The top three power marketers, Enron Power Marketing, Duke/Louis Dreyfus, and LG&E Power Marketing, reported sales for resale of over 102 million megawatthours in 1996.

Nonutility Power Producers

Qualifying Facilities. The Public Utility Regulatory Policies Act of 1978 (PURPA) facilitated the emergence of a group of nonutilty electricity-producing companies called qualifying facilities (QF). Under PURPA, small power producers and cogenerators receive status as a QF by meeting certain ownership, operating, and efficiency requirements established by the Federal Energy Regulatory Commission (FERC). Cogeneration is an energy efficient technology, and to meet QF requirements must produce electric energy and another form of useful thermal energy through the sequential use of energy. Small power producers must use renewable energy as a primary source. QF's receive certain benefits under PURPA.[1]

Cogenerators. Generating facilities that produce electricity and another form of useful thermal energy, usually heat or steam, for industrial processes or heating/cooling purposes are called cogenerators. These facilities produce electric energy, but are primarily engaged in business activities, such as agriculture, mining, manufacturing, transportation, or education, other than the sale of electric energy. Generally, they produce electricity for their own use, selling excess to the host utility. Many cogenerators have status as QF's.

Independent Power Producers. Also considered nonutility power producers in the United States are independent power producers (IPP). These facilities are wholesale electricity producers that operate within the franchised service territories of host utilities. Unlike traditional electric utilities, IPP's do not possess transmission facilities or have retail electric sales. By definition, a facility that has QF status is not an IPP.

Exempt Wholesale Generators. The Energy Policy Act of 1992 modified the Public Utility Holding Company Act (PUHCA) and created another class of nonutility power producers, exempt wholesale generators (EWG). EPACT exempted EWG's from the corporate and geographic restrictions that PUCHA imposed. With this modification, public utility holding companies are allowed to develop and operate independent power projects anywhere in the world.[2]

The Changing Industry

The electric power industry is being transformed from a structure of highly regulated monopolies to one which places growing reliance on competitive markets to establish prices. The implementation of the Energy Policy Act of 1992 (EPACT) by the Federal Energy Regulatory Commission (FERC) and adoption of retail access plans by a growing number of States are introducing greater competition in the generation and retail supply segments of the industry. Some State retail access plans also allow competition in the provision of metering, billing, and some customer services.

The EPACT amended the Federal Power Act (FPA), authorizing the FERC to order public utilities to provide transmission services for competitive wholesale power purchases and sales. 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 generators to make sales for resale to noncontiguous utilities. In 1996, relying on its authority to prevent undue discrimination in the provision of transmission services, the FERC issued Orders 888 and 889, requiring utilities to file open access transmission tariffs. Order 888 guaranteed suppliers and wholesale purchasers access to transmission services at the same prices, terms, and conditions available to the transmission-owning utilities. Order 888 also provided for utility recovery of costs that may be stranded as a result of open access. Potentially stranded costs are costs that utilities would have had the opportunity to recover under regulated rates, but following open access would be unable to recover at expected market prices.

Order 889 requires public utilities that own or operate transmission facilities to establish electronic information systems, known as Open Access Same-time Information Systems (OASIS), to provide all parties identical access to information on available transmission capacity. Order 889 also requires utilities to implement standards of conduct that functionally separate the operation of the transmission system from each utility's wholesale merchant function. There are currently 22 OASIS nodes in operation providing data and accepting transmission reservations on behalf of

[1] See the chapter, "Nonutility Power Producers," for a description of these benefits.

[2] EWG's are not considered electric utilities under PUCHA; they are restricted to selling wholesale power to electric utilities and municipalities. However, EWG's were considered to be electric utilities under the Federal Power Act.

approximately 150 utilities in the United States and Canada.

Power pools and groups of utilities in most regions of the United States have responded to the FERC rulemakings by proposing the formation of independent system operators (ISO) to ensure nondiscriminatory operation of their transmission systems and facilitate the development of regional transmission tariffs. In regions with tightly integrated transmission grids, power pools or groups of utilities also have proposed the formation of power exchanges or spot price pools to help create efficient spot markets.

The open access provisions of Order 888 have reduced barriers to FERC approval of market-based rates for wholesale power sales. Since the FERC began approving market-based pricing in 1988, the key impediment has been the potential for utilities to exercise market power through ownership or control of transmission facilities. Filing of an Order 888 open access transmission tariff meets FERC's standards with respect to mitigating market power in transmission. With this barrier removed, FERC has approved market-based rates for more than 300 utilities and power marketers.

Major mergers and acquisitions have been proposed as utilities position themselves for competition. From 1995 through 1997, seventeen significant electric utility mergers, involving companies with more than $80 billion in combined annual sales and more than 35 million customers, were proposed. Several are “convergence” mergers, combining electric and gas companies. In December 1996, the FERC revised its merger policy to facilitate decisions on a backlog of merger applications, provide greater certainty to merger applicants, and ensure that merger policies do not impede the development of competitive generation markets.

The EPACT lifted the corporate and geographic restrictions in the Public Utility Holding Company Act (PUCHA) for a new class of nonutility generators, exempt wholesale generators (EWG). This modification of PUCHA allowed public utility holding companies to develop and operate independent power projects anywhere in the world. A growing number of U.S. power companies are investing in utilities and power plants in Asia, Australia, Europe, and Latin America.

Legislatures and/or public utility commissions in most States are considering or have approved plans that will allow retail customers direct access to generation markets. Retail access would allow customers to choose among competitive suppliers of generation, financial risk management services limiting consumers' exposure to volatility in generation spot prices, and potentially other services. Some regions may establish generation tracking and disclosure systems, providing consumers the option of purchasing from suppliers of renewable or other preferred types of generation.

A number of States have adopted legislation or approved plans making retail access available to their customers. Pilot programs to initiate and evaluate retail access are being conducted in States where retail access plans are approved or likely to be approved soon. In some jurisdictions, retail access plans face legal challenges related to the recovery of potentially stranded costs and other issues.

Deregulation at both the Federal and State levels is rapidly transforming the generation and retail supply segments of the electric power industry into competitive markets that increasingly will replace State and Federal regulators in setting the price and terms of electric generation and supply services.

A Review of 1996

U.S. Electric Utility Statistics

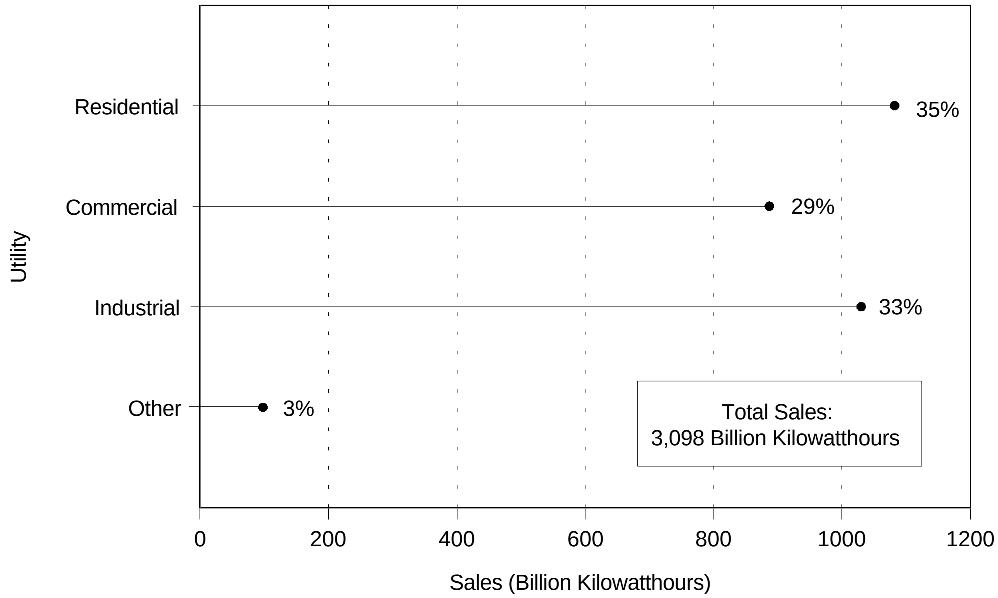
Retail Sales and Revenue. Sales of electricity to ultimate consumers increased 2.8 percent from 3,013 billion kilowatthours (kWh) in 1995 to 3,098 billion kWh in 1996. Revenue from retail sales increased 2.3 percent from $208 billion in 1995 to $212 billion in 1996 (Table 1). The national average revenue per kWh decreased slightly from 6.89 in 1995 to 6.86 in 1996. This is the third consecutive year that the national average revenue per kWh has decreased.

In the residential sector, sales to ultimate consumers increased 3.8 percent to 1,082 billion kilowatthours, and revenue increased 3.3 percent to $91 billion, for an average revenue per kWh of 8.36 cents. The commercial sector increased sales by 2.9 percent to 887 billion kWh, and revenue increased 2.2 percent to $68 billion resulting in an average revenue per kWh of 7.64 cents. The industrial sector increased sales by 1.7 percent to 1,030 billion kWh, and revenue increased slighty, 0.4 percent, remaining at $47 billion, which resulted in an average revenue per kWh of 4.60 cents.[3]

Investor-owned electric utilities account for more than 75 percent of all retail sales and revenue. In 1996, investor-owned utilities increased retail sales by 2.2 percent to 2,343 billion kWh, and revenue from retail sales increased 1.8 percent to $167 billion. This resulted in an average revenue per kWh of 7.12 cents for investor-owned electric utilities. Publicly owned electric utilities increased sales by 4.5 percent to 451 billion kWh, and revenue increased by 4.3 percent to $27 billion, resulting in an average revenue per kWh of 6.01 cents. Cooperative electric utilities' retail sales increased by 7.8 percent to 258 billion kWh, and revenue was $17 billion, increasing 5.0 percent. Average revenue per kWh for cooperative electric utilities was 6.74 cents per kWh. Federal electric utilities, although primarily sellers of wholesale electricity, had a small amount of retail sales, 46 billion kWh, a decrease of 7.8 percent, and a corresponding revenue decrease of 13.5 percent to $1.2 billion. The average revenue per kWh for Federal utilities' retail sales was 2.52 cents per kWh.

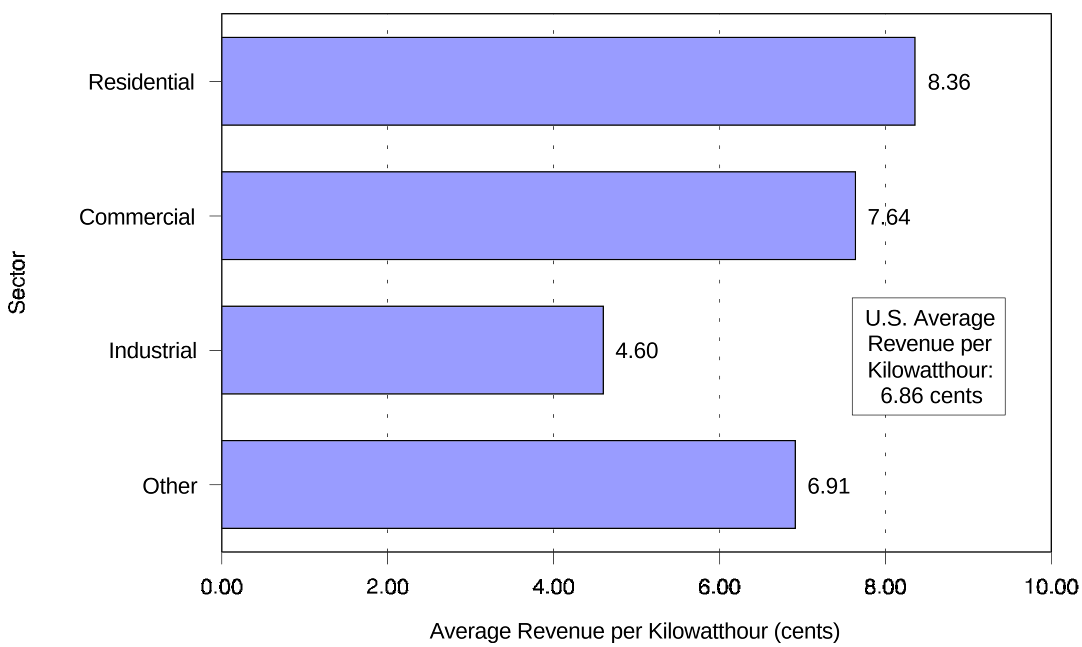
[3] Reclassification of consumers, usually between the commercial and industrial sectors, may occur from year to year due to changes in demand level, economic factors, or other factors, including the impacts or restructuring. This may skew the changes reported in the commercial and industrial sectors.

Figure 2. U.S. Electric Utility Sales to Ultimate Consumers, 1996



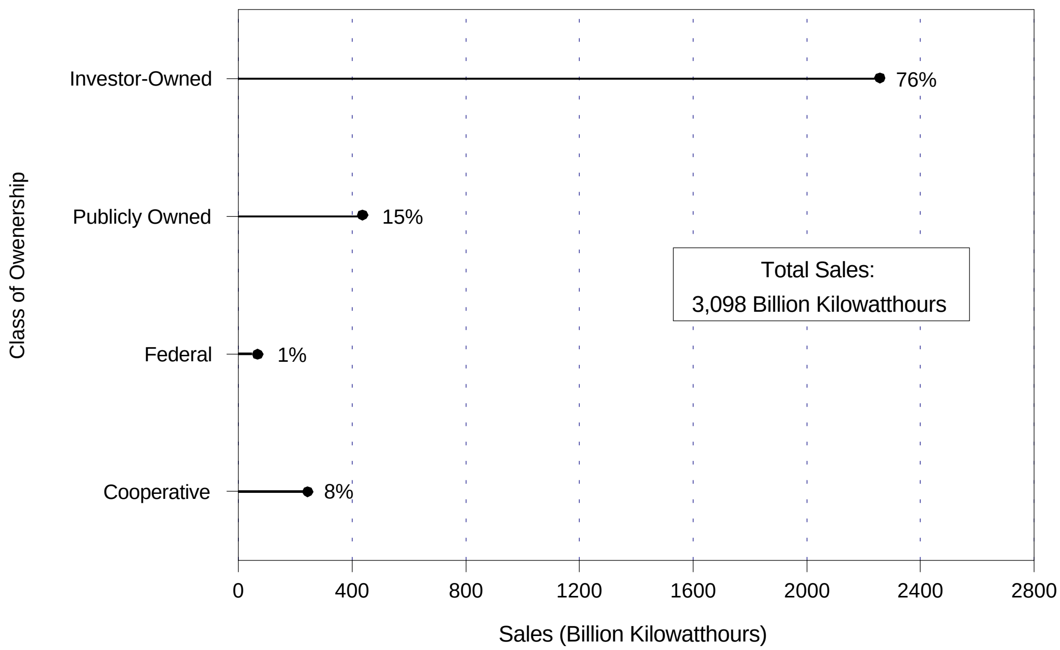
Notes: •Data are final. •Other includes sales for public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales. •Totals may not equal sum of components due to independent rounding.
Source: Energy Information Administration, Form EIA-861,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

Figure 3. U.S. Electric Utility Average Revenue per Kilowatthour by Sector, 1996



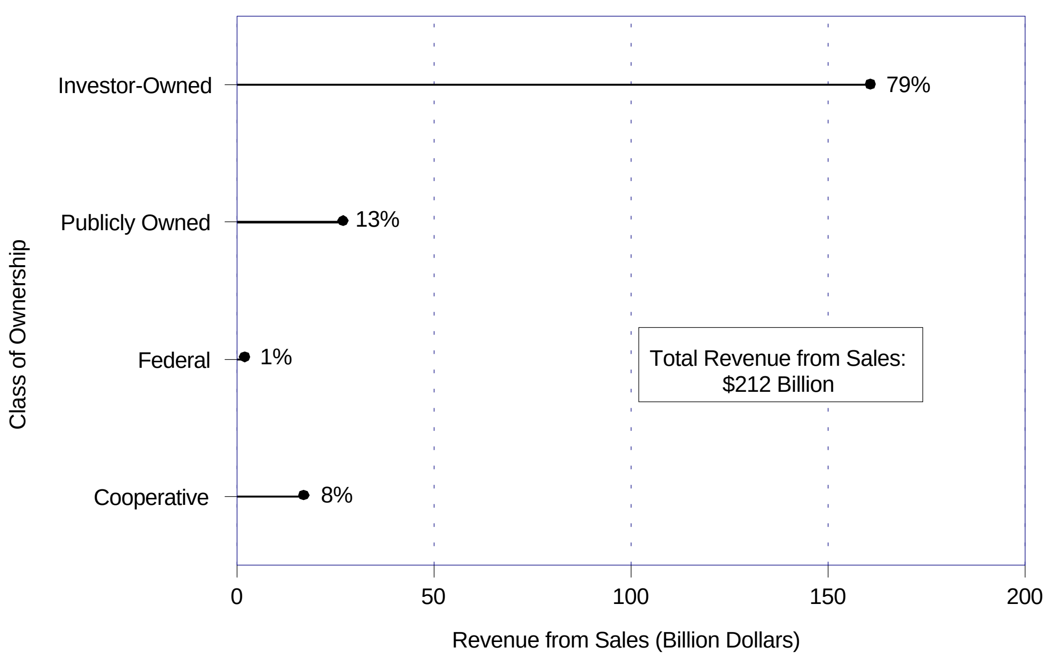
Notes: •Data are final. •Other includes sales for public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 4. U.S. Electric Utility Sales to Ultimate Consumers by Class of Ownership, 1996



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

Figure 5. Revenue from U.S. Electric Utility Sales to Ultimate Consumers by Class of Ownership, 1996



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

Financial Statistics. In 1996, the major investor-owned electric utilities had electric utility operating revenues of $188.9 billion, an increase of $5.2 billion. Electric operating expenses ($156.9 billion) increased by $6.3 billion resulting in a 3.3 percent decrease in electric operating income to $32.0 billion. Increases in cost of fuel, purchased power, and higher depreciation were primarily responsible for the operating expense increase. Net income ($21.2 billion) showed a decrease of 3.8 percent from 1995. Earnings available for common stocks decreased by almost $0.6 billion or 2.7 percent. Earnings available per average common share were $2.98, reversing the increases of previous years.

In 1996, investment in the major investor-owned segment of the industry was $582.0 billion, an increase of $3.1 billion from 1995. Electric utility construction work in progress (CWIP) was $11.4 billion, a decrease of 15.7 percent from 1995 and 44.8 percent from 1992. The total asset turnover ratio (operating revenues divided by total assets) remained about the same at 0.36. Total capitalization of $365.8 billion also remained at approximately the 1995 level. The percent of long-term debt to total capitalization stood at 47.2, down slightly from the ratio of 47.5 in the previous year.

In 1996, the major publicly owned generator electric utilities had electric utility operating revenue of $24.2 billion up by 3.1 percent. Generator electric utility operating expenses slightly increased by 0.1 percent, resulting in an increase in net income ($0.5 billion) of 42.3 percent. Total assets for publicly owned generator electric utilities essentially remained the same ending at $113.9 billion. The Electric Utility Plant per Dollar of Revenue ratio was 4.0 in 1996.

In 1996, the major publicly owned nongenerator electric utilities had electric utility operating revenue of $8.6 billion, a 1.6-percent growth over 1995. Nongenerator electric utility operating expenses increased by 1.7 percent to end the year at $8.1 billion. Net income for nongenerators increased to $0.5 billion. Total assets for nongenerator electric utilities decreased by 2.8 percent to end the year at $11.3 billion. The Electric Utility Plant per Dollar of Revenue ratio remained at 1.2 in 1996.

Environmental. In 1996, air emissions from electric utility operated fossil-fueled steam electric plants were estimated to have increased from the previous year (values are expressed in short tons). The most significant change was for sulfur dioxide (SO_2) up from 11.6 million tons to 12.2 million tons, an increase of about 5 percent. Nitrogen oxides (NO_x) and carbon dioxide (CO_2) showed increases of about 4 percent. Nitrogen oxides increased from 7.1 million short tons to 7.4 million tons, and carbon dioxide went from 1,968 million tons to 2,047 million tons.

Flue gas desulfurizations (FGD) sometimes referred to as scrubbers use chemicals such as lime to remove sulfur oxides from the combustion gases of boilers before the gases are discharged into the atmosphere. In 1996, there were 182 generators connected to scrubbers at U.S. power plants, compared with 177 in 1995 and 151 in 1986, a 3- and 21-percent increase, respectively. The average sulfur content of coal delivered to all U.S. electric utility plants increased from 1.08 percent by weight in 1995 to 1.10 percent by weight in 1996.[4]

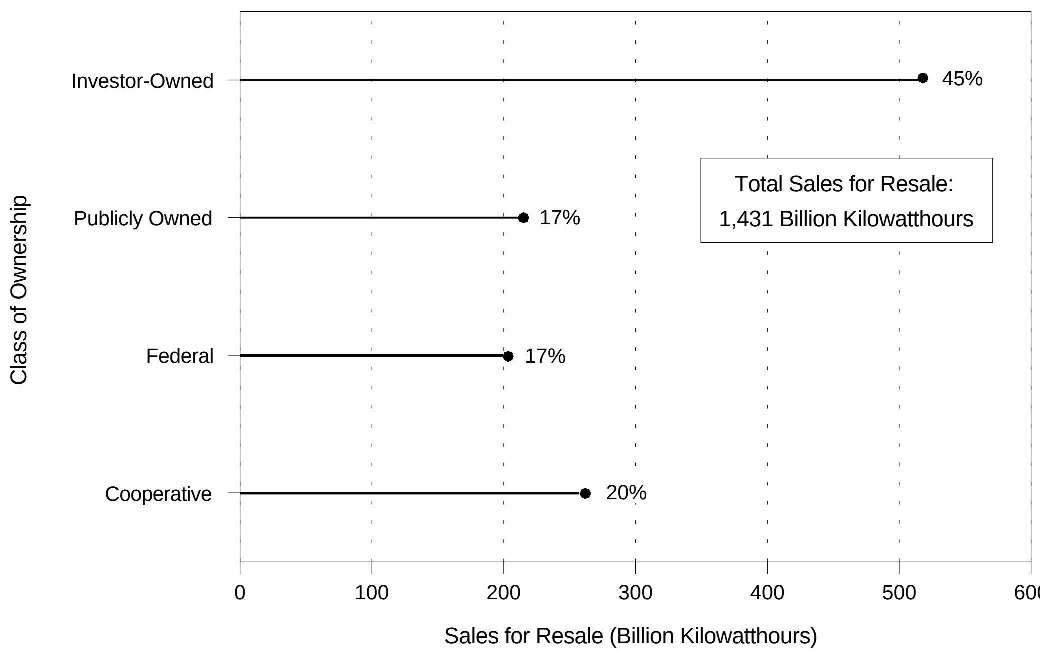
Power Transactions. On a national basis in 1996, wholesale power receipts (purchased power plus exchanges received and wheeling received) increased by 245 billion kilowatthours (kWh) to reach 2,267 billion kWh. Sales to ultimate consumers totaled 3,098 billion kWh, and 1,431 billion kWh of this (46 percent) is from wholesale trade with other electric utilities (Requirement and Nonrequirement Sales for Resale). To supply this electric energy in 1996, electric utilities had planned capacity resources on-hand for the summer of 727 million kilowatts and 739 million kilowatts for the winter, resulting in national capacity margins of 18.9 percent and 28.7 percent, respectively.

In 1996, the noncoincidental peak load at electric utilities in the contiguous United States showed a decrease of less than half of 1 percent, dropping from the 620 to 617 million kilowatts for the summer. The winter peak load was 554 million kilowatts, growing by 9 million kilowatts which represented a change of about 2 percent. Both the summer and winter peak loads for the contiguous United States are projected for 2000 to grow to 666 and 592 million kilowatts, respectively. By the year 2005, the growth in the noncoincidental peak load will be above the 1996 actual by over 100 million kilowatts for the summer and nearly 100 million kilowatts for the winter.

Imports of electricity in 1996 by electric utilities and nonutilities in the United States rose to 47 billion kilowatthours while exports were at 9 billion kilowatthours. Trade with Canada reached the level of 45 billion kilowatthours imported and nearly 8 billion kilowatthours exported. Imports and exports to Mexico were both above 1 billion kilowatthours. Nearly half the imports entered through the Midwest (Mid-Continent Area Power Pool - States of Minnesota and North Dakota) and the West (Western System Coordinating Council - Washington State). For exports, almost 70 percent exited from the West (Western System Coordinating Council - Washington State). For Mexico, almost all imports and exports came from the West (Western System Coordinating Council - State of California).

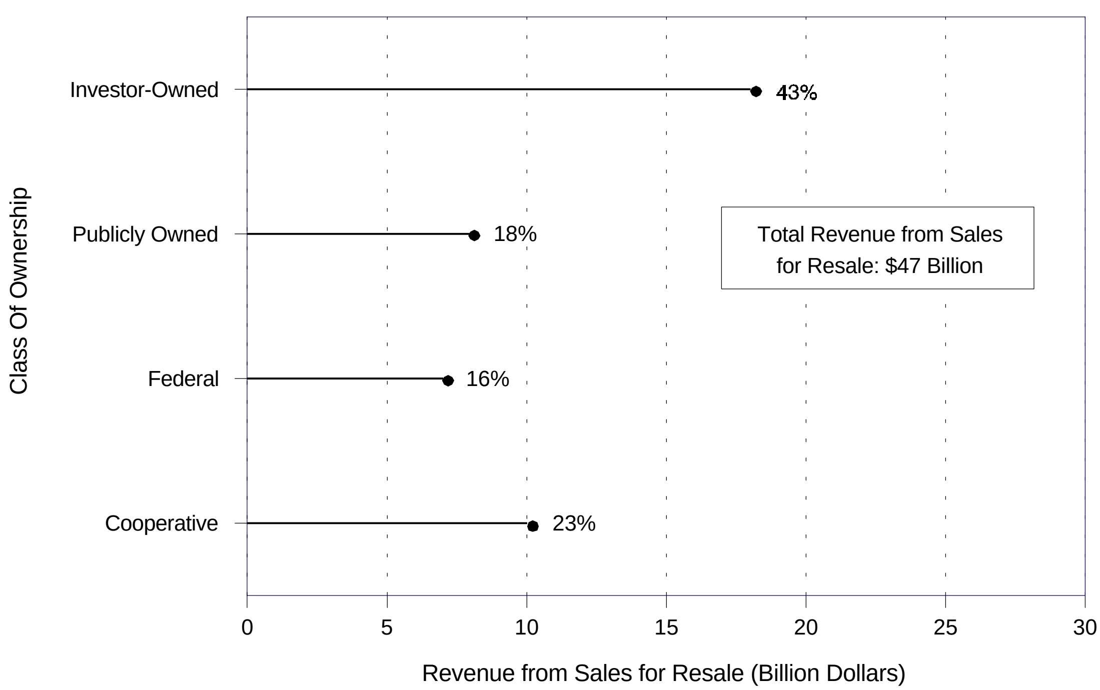
[4] Energy Information Administration, *Cost and Quality of Fuels 1996,* DOE/EIA-0191(96) (Washington DC, 1997).

Figure 6. U.S. Electric Utility Sales for Resale by Class of Ownership, 1996



Notes: ●Data are final. ●Totals may not equal sum of components because of independent rounding. ●Power marketers are not shown this year.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 7. Revenue from U.S. Electric Utility Sales for Resale by Class of Ownership, 1996



Notes: ●Data are final. ●Totals may not equal sum of components because of independent rounding. ●Power marketers are not shown this year.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Demand-Side Management. In 1996, 1,003 electric utilities in the United States reported having demand-side management programs. Of these 1,003, 573 are classified as large and 430 are classified as small utilities.[5] The 573 large utilities account for 71 percent of the total retail sales of electricity in the United States.

Energy savings for the 573 large electric utilities increased to 61,842 million kilowatthours (kWh), 4,421 million kWh over 1995. These energy savings represent 2.0 percent of annual electric sales of 3,098 billion kWh to ultimate consumers in 1996.

Actual peak load reductions for large utilities increased 1.1 percent from 29,561 megawatts in 1995 to 29,893 megawatts in 1996. Potential peak load reductions increased 2.8 percent from 47,029 megawatts in 1995 to 48,344 megawatts in 1996.

DSM costs decreased from $2.42 billion in 1995 to $1.90 billion.[6] This is the third consecutive year that DSM costs have decreased from a high of $2.74 billion in 1993.

Incremental effects are those caused by new programs and new participants in existing programs for the current reporting year. For 1996, incremental energy savings for large utilities were 6,844 million kilowatthours, incremental actual peak load reductions were 3,690 megawatts, and incremental potential peak load reductions were 6,408 megawatts.

U.S. Nonutility Power Producer Statistics

Generation. In 1996, U.S. nonutility power producers with facilities having an installed capacity of 1 megawatt or more generated 383 billion kilowatthours (kWh) of electricity. U.S. nonutility power producers received 104 billion kWh from and delivered 239 billion kWh to electric utilities and other end users. Nonutility power producers delivered approximately 62.5 percent of their gross generation to electric utilities and other end users and used 248 billion kWh for power plant operation and for industrial processes. The highest level of nonutility production of electricity occurred in California and Texas, with 64 and 57 billion kWh, respectively.

Gross generation for nonutility power producers with an installed capacity of 1 megawatt or more was 1.8 percent higher in 1996 than a year earlier. Slightly more than half of the generation by nonutility power producers was gas-fired, with generation from coal accounting for 16.0 percent of the total. Of the total nonutility generation, 321 billion kWh were from qualifying facilities, more than five 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 Middle 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 was 73,183 megawatts at the end of 1996. The installed capacity for facilities of 1 megawatt or more increased by 4.2 percent from 1995. Nonutility capacity in 1996 was equivalent to 9.4 percent of the total U.S. electric industry capacity.[7]

Of all energy sources, gas accounted for the largest amount (30,713 megawatts) of nonutility capacity. The West South Central Census Division accounted for 34.7 percent of that gas-fired capacity. The second largest share of nonutility capacity was provided by petroleum, followed by coal. The largest volume of petroleum capacity (4,195 megawatts) was located in the Middle Atlantic Census Division. Cogeneration accounts for 72.2 percent of nonutility capacity (63.0 percent qualifying facility capacity and 9.2 percent nonqualifying facility capacity). Small power producers and other nonutilities account for 13.6 and 7.6 percent, respectively, of nonutility capacity.

The greatest number (534) of nonutility generating facilities was in the Pacific Census Division, and most of the capacity (14,521 megawatts) was in the Pacific Census Division. In the Pacific Census Division, California dominated because the State actively promoted alternative energy sources 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.

[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 reductions and energy savings for the reporting year (1996), annual peak load reduction and energy savings for the first and fifth forecast years (1997 and 2001), and itemized direct and indirect utility costs for all three years (1996, 1997, and 2001). 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-kilowatthours 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 cost 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.

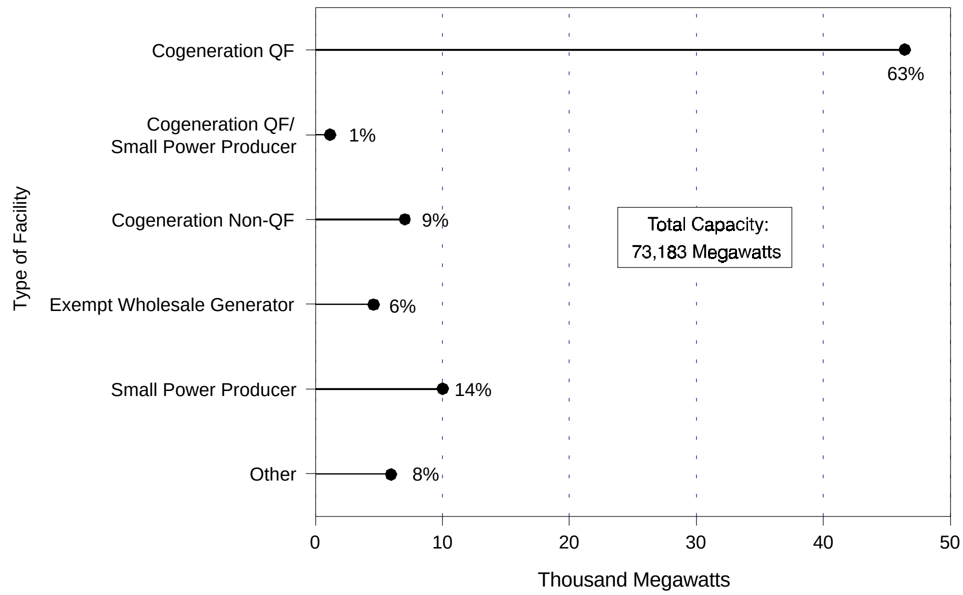
[7] Energy Information Administration, *Inventory of Power Plants in the United States as of January 1, 1997,* DOE/EIA-0095(97).

Nonutilities plan approximately 8 gigawatts of capacity additions; 4 gigawatts through 1999 with 10 gigawatts (generator nameplate capacity) planned for the same period by electric utilities. Electric utilities have planned 42 gigawatts (generator nameplate capacity) in capacity additions for the 10-year period, 1997 through 2006. Of the nonutility planned capacity, 38.0 percent is gas-fired. Renewable capacity represents 26.0 percent of the total planned nonutility additions.

Consumption. In 1996, consumption by nonutilities of 1 megawatt or more included 2,450 billion cubic feet of natural gas, 53 million short tons of coal, and 43 million barrels of petroleum. Compared to 1995, consumption increased 9.5 percent for petroleum, 5.7 percent for coal, and 6.3 percent for gas. Natural gas was the fuel most used by nonutilities.

Emissions. In 1996, estimated air emissions from nonutility facilities of 1 megawatt or more were 1,521 thousand short tons in SO_2, 1,539 thousand short tons of NO_x, and 593,526 thousand short tons of CO_2. This is a 25.0 percent increase of SO_2 emissions from the previous year.

Figure 8. Installed Capacity at U.S. Nonutility Generating Facilities by Type of Facility, 1996

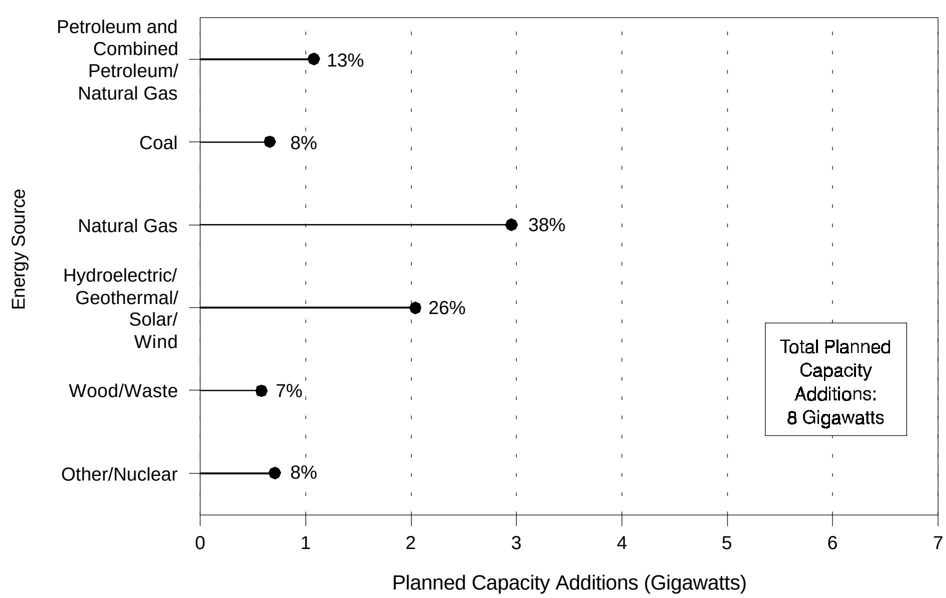


QF=Qualifying facility.

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 9. Planned Capacity Additions for U.S. Nonutility Generating Facilities by Energy Source, as of December 31, 1996



Notes: • Totals may not equal sum of components because of independent rounding. • Other includes hydrogen, sulfur, batteries, and chemicals. • 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, 1995 and 1996

Item	1995	1996	Percent Change
Electric Power Industry[1]			
Generating Capability (megawatts)[2]	769,517	776,199	0.9
Net Generation (million kilowatthours)	3,357,837	3,447,098	2.7
Emissions (thousand short tons)			
Sulfur Dioxide (SO2)	12,317	13,093	6.3
Nitrogen Oxides (NOX)	8,310	8,684	4.5
Carbon Dioxide (CO2)	2,379,238	2,483,728	4.4
Electric Utilities			
Generating Capability (megawatts)[2] [3]	706,111	710,279	.6
Coal	300,610	302,421	.6
Petroleum	64,464	70,421	9.2
Gas	142,536	140,002	−1.8
Nuclear	99,515	101,121	1.6
Renewable			
Hydroelectric (conventional)	75,274	73,129	−2.8
Geothermal	1,747	1,622	−7.2
Biomass[4]	567	442	−22.0
Wind	8	8	.0
Solar Thermal	–-	–-	–-
Photovoltaic	4	4	.0
Hydroelectric Pumped Storage	21,387	21,110	−1.3
Net Generation (million kilowatthours)	2,994,529	3,077,442	2.8
Coal	1,652,914	1,737,453	5.1
Petroleum[5]	60,844	67,346	10.7
Gas	307,306	262,730	−14.5
Nuclear	673,402	674,729	.2
Renewable			
Hydroelectric (conventional)	296,378	331,058	11.7
Geothermal	4,745	5,234	10.3
Biomass[4]	1,649	1,967	19.3
Wind	11	10	−9.1
Solar Thermal	–-	–-	–-
Photovoltaic	4	3	−25.0
Hydroelectric Pumped Storage[6]	−2,725	−3,088	13.3
Consumption			
Coal (million short tons)	829	875	5.5
Petroleum (million barrels)[7]	102	113	10.8
Gas (billion cubic feet)	3,197	2,732	−14.5
Stocks (Year End)			
Coal (million short tons)	126	115	−8.7
Petroleum (million barrels)[8]	50	48	−4.0
Receipts			
Coal (million short tons)	827	863	4.4
Petroleum (million barrels)[9]	84	107	27.4
Gas (billion cubic feet)[10]	3,026	2,607	−13.8
Cost (cents per million Btu)[11]			
Coal	131.8	128.9	−2.2
Petroleum[12]	267.9	315.7	17.8
Gas	198.4	264.1	33.1
Sales To Ultimate Consumers (million kilowatthours)	3,013,287	3,097,810	2.8
Residential	1,042,501	1,082,491	3.8
Commercial	862,685	887,425	2.9
Industrial	1,012,693	1,030,356	1.7
Other[13]	95,407	97,539	2.2
Revenue From Ultimate Consumers (million dollars)	207,717	212,455	2.3
Residential	87,610	90,501	3.3
Commercial	66,365	67,827	2.2
Industrial	47,175	47,385	.4
Other[13]	6,567	6,741	2.6
Average Revenue per Kilowatthour (cents)	6.89	6.86	−.4
Residential	8.40	8.36	−.5
Commercial	7.69	7.64	−.7
Industrial	4.66	4.60	−1.3
Other[13]	6.88	6.91	.4
Net Electric Plant Inc Fuel (million dollars)			
Major Investor Owned	371,402	369,298	−.6
Major Publicly Owned Generator/Nongenerator	63,305	62,973	−.5
Emissions (thousand short tons)[14]			
Sulfur Dioxide (SO2)	11,571	12,202	5.5
Nitrogen Oxides (NOX)	7,135	7,426	4.1
Carbon Dioxide (CO2)	1,967,669	2,047,368	4.1
Noncoincidental Summer Peak Load (megawatts)	620,871	616,790	−.7
DSM Actual Peak Load Reductions (megawatts)	29,561	29,893	1.1
DSM Energy Savings (million kilowatthours)	57,421	61,842	7.7

Table 1. Electric Power Industry Summary Statistics for the United States, 1995 and 1996 (Continued)

Item	1995	1996	Percent Change
Nonutility Power Producers			
Installed Capacity (megawatts)	70,254	73,183	4.2
Coal[15]	R 10,877	12,122	11.4
Petroleum Only[16]	R 2,116	3,185	50.5
Gas Only[17]	R 29,122	31,024	6.5
Petroleum/Natural Gas (combined)	10,479	10,875	3.8
Nuclear[18]	–-	–-	–-
Renewable			
Hydroelectric (conventional)	3,399	3,419	.6
Geothermal	1,295	1,346	3.9
Biomass[4]	R 10,316	8,494	–17.7
Wind	1,723	1,670	–3.1
Solar Thermal	354	354	.0
Photovoltaic	–-	–-	–-
Other[19]	574	694	20.9
Gross Generation (million kilowatthours)	R 375,901	382,530	1.8
Coal[15]	R 60,234	61,424	2.0
Petroleum[16]	R 15,049	14,951	–.7
Gas[17]	R 210,617	213,359	1.3
Nuclear[18]	–-	–-	–-
Renewable			
Hydroelectric (conventional)	14,774	16,555	12.1
Geothermal	9,912	10,198	2.9
Biomass[4]	R 57,514	57,997	.8
Wind	3,185	3,400	6.8
Solar Thermal	824	903	9.6
Photovoltaic	–-	–-	–-
Other[19]	3,792	3,744	–1.3
Consumption			
Coal (Thousand short tons)	R 50,328	53,202	5.7
Petroleum (Thousand barrels)[20]	R 39,219	42,926	9.5
Natural Gas (Million cubic feet)	R 2,303,944	2,449,996	6.3
Other Gas (Million cubic feet)[21]	R 1,611,993	1,738,362	7.8
Supply and Disposition (million kilowatthours)			
Gross Generation	R 375,901	382,530	1.8
Receipts[22]	89,919	104,101	15.8
Deliveries[23]	R 233,454	238,958	2.4
Facility Use	R 232,367	247,673	6.6
Emissions (thousand short tons)[24]			
Sulfur Dioxide (SO_2)	1,217	1,521	25.0
Nitrogen Oxides (NOX)	1,440	1,539	6.9
Carbon Dioxide (CO_2)	556,324	593,526	6.7

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 Data are based on the initial commercial operation year for the generator.
3 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.
4 Includes wood, wood waste, peat, wood liquors, railroad ties, pitch, wood sludge, municipal solid waste, agricultural byproduct, straw, tires, landfill gases, fish oils.
5 Includes petroleum coke.
6 Represents total pumped storage facility production minus energy used for pumping. Negative generation denotes that electric power consumed for plant use exceeds gross generation.
7 Does not include petroleum coke consumption of 761 thousand short tons in 1995 and 681 thousand short tons in 1996.
8 Does not include petroleum coke stocks of 65 thousand short tons at year end 1995 and 91 thousand short tons at year end 1996.
9 Does not include petroleum coke receipts of 1,263 thousand short tons in 1995 and 1,410 thousand short tons in 1996.
10 Includes small amounts of coke-oven, refinery, and blast furnance gas.
11 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.
12 Does not include petroleum coke cost of 65.2 cents per million Btu in 1995 and 78.2 cents per million Btu in 1996.
13 Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.
14 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.
15 Includes coal, anthracite culm, coke breeze, fine coal waste coal, bituminous gob and lignite waste.
16 Includes petroleum, petroleum coke, diesel, kerosene, liquid butane, liquid propane, oil waste and tar oil.
17 Includes natural gas, waste heat, waste gas, butane, methane, propane and other gas.
18 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.
19 Includes hydrogen, sulfur, batteries, chemicals, purchased steam and other.
20 Does not include petroleum coke consumption of 4,188 thousand short tons for 1995, and 4,484 thousand short tons for 1996.
21 Includes butane, methane, propane, digester gas, and other gas.
22 Includes purchases, interchanges, and exchanges of electric energy with utilities and other nonutilities.
23 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 contribute 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.

[24] 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.

Notes: •Data previously published has been reclassified by energy source and has been changed to reflect these changes.

Notes: •Data for nonutility power producers, and emissions are preliminary for 1996; 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. •DSM = Demand-Side Management.

Sources: •Energy Information Administration, Form EIA-412, ''Annual Report of Public Electric Utilities''; 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 1, ''Annual Report of Major Electric Utilities, Licensees, and Others''; Form 423, ''Monthly Report of Cost and Quality of Fuels for Electric Plants.'' Form EIA-411, ''Coordinated Bulk Power Supply Programs''; Department of Energy, Office of Emergency Policy, Form OE-411, ''Coordinated Bulk Power Supply Program.''

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) and total installed capacity. Renewable energy resources shown in Table 1, "Electric Power Industry Summary Statistics for the United States, 1995 and 1996," are reported in detail in the *Renewable Energy Annual, 1996.*

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 energy sources 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, and distribution lines is a power system. Electric utilities historically build, design, and operate power systems. Most large investor-owned electric utilities own and operate entire power systems: the generation, transmission, and distribution functions. Many small companies are distribution companies, purchasing their electricity from generation suppliers, which can include traditional electric utilities, nonutility power producers, and power marketers. In anticipation of competition in the electric power industry, electric utility companies are forming separate business units for generation and customer service apart from transmission and distribution.

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. As the electric power industry transitions to a competitive environment, access to tranmission and distribution lines will be opened; however, revenue associated with these facilities will remain regulated. The generation function is now competitive at the wholesale trade level, and some States are planning to initiate competition at the retail level.

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). Electric utilities may classify their commercial and industrial service based on demand or annual usage falling within a range specified by the utility, such as classifying a light manufacturer as commercial. The other sector includes public street and highway lighting, transportation, 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. In the future, competition at the retail level may change the way rates are set and by whom. In a deregulated environment, generation prices will be market-based rather than cost-based as under the current regulated system. Rates will be “unbundled,” and bills will include a list of services and the associated rates and charges such as energy, transmission, distribution, metering, and other charges. Access will be opened to transmission and distribution lines, though the revenue associated with these lines will likely remain regulated. Under open access rules allowing competition for wholesale generation, some costs that are currently collected in rate schedules for generation assets may become stranded. This means that the costs of the generation asset may not be recoverable at market-based rates in a competitive environment for generation. The recovery of stranded costs is an issue that will need resolution as the industry undergoes deregulation. These stranded costs may be recovered in nonbypassable charges in the form of a rate per kilowatthour paid by all consumers in the jurisdictional distribution utility.

Currently, under a regulated environment, the rate schedules to generate revenue requirements for electric utilities, which are unique to each utility, are developed using a cost-based methodology and are subject to approval by the appropriate authority 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 (FERC). Under new FERC rules, transmission of wholesale power will remain regulated to ensure open access to transmission systems in a competitive environment, while wholesale rates for generation will become deregulated. State public utility commissions will continue to regulate retail sales and distribution. However, some States are considering retail competition for generation that will allow market-based rates for energy, while regulating distribution rates. Public electric utilities, in most States, are controlled through locally elected or appointed officials, and are not under the jurisdiction of FERC. Their rate schedules will, however, possibly be affected by any changes in State regulations addressing retail competition. A detailed discussion on utility classes of ownership and the emerging competitive environment are included in the "Industry Profile" section of 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 3,250) that own and/or operate facilities within the United States, its territories, and Puerto Rico.[8] Data collected include the generation, transmission, distribution, sales, and associated revenue of electric energy and is 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*[9]

Table 2. U.S. Electric Utility Sales to Ultimate Consumers and Associated Revenue by Sector, 1992 Through 1996

Item	1992	1993	1994	1995	1996
Sales (million kilowatthours)					
Residential	935,939	994,781	1,008,482	1,042,501	1,082,491
Commercial	761,271	794,573	820,269	862,685	887,425
Industrial	972,714	977,164	1,007,981	1,012,693	1,030,356
Other[1]	93,442	94,944	97,830	95,407	97,539
U.S. Total	**2,763,365**	**2,861,462**	**2,934,563**	**3,013,287**	**3,097,810**
Revenue (million dollars)					
Residential	76,848	82,814	84,552	87,610	90,501
Commercial	58,343	61,521	63,396	66,365	67,827
Industrial	46,993	47,357	48,069	47,175	47,385
Other[1]	6,296	6,528	6,689	6,567	6,741
U.S. Total	**188,480**	**198,220**	**202,706**	**207,717**	**212,455**

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

8 Summary data in this publication are for the United States only and do not include Puerto Rico and the U.S. territories.

9 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 3. Average Revenue per Kilowatthour for U.S. Electric Utilities by Sector, 1992 Through 1996
(Cents)

Sector	1992	1993	1994	1995	1996
Residential	8.21	8.32	8.38	8.40	8.36
Commercial	7.66	7.74	7.73	7.69	7.64
Industrial	4.83	4.85	4.77	4.66	4.60
Other[1]	6.74	6.88	6.84	6.88	6.91
All Sectors	**6.82**	**6.93**	**6.91**	**6.89**	**6.86**

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

Notes: •Data are final. •The average revenue per kilowatthour of electricity sold is calculated by dividing revenue by sales. •Totals may not equal sum of components because of independent rounding.

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

Table 4. U.S. Electric Utility Sales to Ultimate Consumers by Sector, Census Division, and State, 1995 and 1996
(Million Kilowatthours)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other[1]	
	1995	1996	1995	1996	1995	1996	1995	1996	1995	1996
New England	**106,789**	**108,408**	**38,191**	**38,792**	**41,111**	**42,224**	**26,043**	**26,007**	**1,444**	**1,385**
Connecticut	27,970	28,417	10,760	10,943	10,926	11,172	5,913	5,928	370	374
Maine	11,561	11,726	3,629	3,679	2,835	3,212	4,959	4,772	138	64
Massachusetts	46,510	47,294	15,993	16,256	19,894	20,346	10,026	10,085	598	607
New Hampshire	9,007	9,127	3,364	3,427	3,226	3,239	2,286	2,334	131	127
Rhode Island	6,636	6,604	2,472	2,481	2,625	2,607	1,374	1,351	165	165
Vermont	5,104	5,239	1,973	2,006	1,605	1,649	1,484	1,537	42	48
Middle Atlantic	**323,475**	**326,040**	**105,159**	**106,561**	**117,086**	**118,464**	**86,834**	**86,758**	**14,396**	**14,257**
New Jersey	66,754	66,889	22,470	22,632	29,792	30,152	13,989	13,603	504	502
New York	130,471	131,527	39,887	40,285	52,751	52,915	25,317	25,947	12,515	12,380
Pennsylvania	126,251	127,623	42,802	43,645	34,544	35,396	47,528	47,208	1,377	1,375
East North Central	**524,531**	**528,123**	**156,215**	**156,555**	**137,089**	**139,229**	**216,112**	**217,018**	**15,115**	**15,321**
Illinois	126,231	125,589	38,386	37,535	37,217	37,432	42,251	42,050	8,377	8,572
Indiana	87,006	88,901	26,560	26,860	18,123	18,292	41,777	43,203	546	546
Michigan	94,701	96,302	28,623	28,901	31,306	32,038	33,921	34,499	852	863
Ohio	158,626	158,587	44,010	44,573	35,549	36,034	74,473	73,394	4,592	4,585
Wisconsin	57,967	58,744	18,635	18,685	14,893	15,433	23,690	23,871	749	755
West North Central	**217,064**	**223,623**	**78,627**	**80,583**	**59,498**	**61,809**	**73,319**	**75,682**	**5,620**	**5,548**
Iowa	34,301	34,999	11,640	11,537	7,607	7,338	13,771	14,789	1,284	1,335
Kansas	30,357	31,291	10,356	10,672	10,273	11,005	9,356	9,231	372	383
Minnesota	53,959	54,942	16,974	17,157	9,700	10,115	26,577	26,934	707	735
Missouri	62,259	64,843	25,409	26,448	21,606	22,522	14,321	14,915	923	958
Nebraska	20,892	21,497	7,597	7,741	5,986	6,272	5,802	6,193	1,508	1,291
North Dakota	7,883	8,314	3,384	3,602	2,237	2,378	1,771	1,835	490	500
South Dakota	7,414	7,736	3,268	3,426	2,088	2,179	1,722	1,785	335	346
South Atlantic	**620,624**	**639,019**	**252,129**	**261,981**	**194,932**	**199,778**	**154,099**	**157,304**	**19,464**	**19,956**
Delaware	9,580	9,641	3,168	3,271	2,842	2,911	3,511	3,399	58	59
District of Columbia	10,316	10,137	1,608	1,614	8,079	7,905	262	252	366	366
Florida	167,492	171,832	85,770	88,315	60,079	60,988	16,473	17,212	5,171	5,317
Georgia	96,192	101,307	35,812	37,763	27,741	29,140	31,493	33,175	1,145	1,229
Maryland	56,158	56,998	22,234	22,986	23,096	23,126	10,057	10,098	771	787
North Carolina	104,673	108,296	39,506	41,592	29,195	30,662	34,063	34,142	1,909	1,901
South Carolina	65,074	67,086	21,392	22,514	14,020	14,545	28,819	29,185	843	843
Virginia	85,162	87,596	33,472	34,651	24,028	24,565	18,554	19,021	9,109	9,359
West Virginia	25,977	26,127	9,166	9,277	5,852	5,936	10,867	10,820	92	94
East South Central	**264,454**	**277,405**	**89,999**	**97,285**	**35,524**	**37,447**	**133,643**	**137,276**	**5,288**	**5,396**
Alabama	70,007	73,104	24,314	25,634	12,284	13,328	32,847	33,523	561	620
Kentucky	74,548	77,019	20,537	21,353	10,524	10,659	40,490	41,930	2,997	3,077
Mississippi	37,868	39,622	14,181	14,965	7,539	7,913	15,477	16,043	671	702
Tennessee	82,030	87,659	30,967	35,333	5,176	5,548	44,828	45,781	1,060	996
West South Central	**412,170**	**433,147**	**145,684**	**154,204**	**102,417**	**105,780**	**146,982**	**155,152**	**17,087**	**18,010**
Arkansas	34,671	36,137	12,417	12,934	7,147	7,442	14,483	15,139	625	621
Louisiana	72,827	75,269	24,116	24,311	15,575	15,920	30,692	32,544	2,444	2,494
Oklahoma	41,392	43,291	16,319	17,303	11,115	11,553	11,714	12,160	2,244	2,276
Texas	263,279	278,450	92,831	99,656	68,580	70,866	90,093	95,308	11,775	12,619
Mountain	**183,678**	**195,177**	**56,934**	**61,394**	**55,932**	**59,456**	**63,829**	**66,962**	**6,983**	**7,366**
Arizona	48,589	52,085	18,036	19,746	16,290	17,252	11,992	12,783	2,272	2,303
Colorado	35,317	37,073	11,307	11,871	13,420	14,239	9,706	9,947	884	1,016
Idaho	19,620	21,119	6,193	6,508	5,291	5,883	7,843	8,380	293	348
Montana	13,419	13,820	3,640	3,911	3,133	3,299	6,368	6,306	278	305
Nevada	20,659	22,574	6,655	7,526	4,731	5,150	8,496	9,075	777	823
New Mexico	16,416	17,173	4,124	4,328	5,094	5,296	5,651	5,921	1,547	1,628
Utah	18,460	19,858	5,041	5,481	5,642	5,911	6,957	7,660	820	806
Wyoming	11,199	11,475	1,939	2,022	2,330	2,425	6,817	6,891	113	138
Pacific	**346,683**	**352,711**	**115,245**	**120,693**	**114,175**	**118,226**	**107,483**	**103,728**	**9,781**	**10,063**
California	212,605	218,112	68,783	71,396	80,874	83,392	57,367	57,683	5,580	5,642
Oregon	45,725	47,185	16,315	17,285	12,900	13,388	15,839	15,804	672	708
Washington	88,353	87,413	30,147	32,012	20,401	21,446	34,276	30,241	3,528	3,713
Pacific Noncontiguous	**13,819**	**14,159**	**4,319**	**4,442**	**4,921**	**5,011**	**4,349**	**4,468**	**230**	**237**
Alaska	4,632	4,780	1,713	1,766	2,200	2,250	546	584	172	179
Hawaii	9,188	9,379	2,606	2,676	2,721	2,761	3,803	3,884	57	58
U. S. Total	**3,013,287**	**3,097,810**	**1,042,501**	**1,082,491**	**862,685**	**887,425**	**1,012,693**	**1,030,356**	**95,407**	**97,539**

[1] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.
Notes: •Data 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, 1995 and 1996
(Thousands)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other[1]	
	1995	1996	1995	1996	1995	1996	1995	1996	1995	1996
New England	**6,245**	**6,286**	**5,521**	**5,559**	**650**	**655**	**30**	**29**	**44**	**42**
Connecticut	1,469	1,478	1,332	1,340	126	127	6	6	5	5
Maine	693	701	599	607	72	73	3	2	18	18
Massachusetts	2,730	2,746	2,410	2,424	295	296	14	14	12	12
New Hampshire	593	595	508	510	77	77	3	3	5	5
Rhode Island	448	451	401	404	44	44	3	3	1	1
Vermont	312	315	271	275	38	38	1	1	3	1
Middle Atlantic	**16,184**	**16,266**	**14,301**	**14,369**	**1,776**	**1,790**	**57**	**57**	**50**	**50**
New Jersey	3,415	3,437	3,005	3,024	386	390	14	13	10	10
New York	7,340	7,370	6,469	6,495	824	828	15	15	32	32
Pennsylvania	5,429	5,459	4,827	4,850	565	572	29	29	8	8
East North Central	**19,422**	**19,631**	**17,385**	**17,572**	**1,881**	**1,904**	**74**	**73**	**82**	**82**
Illinois	5,053	5,099	4,561	4,604	462	465	5	5	25	25
Indiana	2,636	2,680	2,349	2,389	261	265	17	18	9	7
Michigan	4,316	4,368	3,867	3,914	418	424	13	13	18	17
Ohio	4,972	5,027	4,437	4,482	485	493	31	31	18	20
Wisconsin	2,444	2,457	2,170	2,183	254	257	7	5	12	13
West North Central	**8,888**	**8,968**	**7,696**	**7,755**	**1,027**	**1,043**	**49**	**47**	**116**	**123**
Iowa	1,363	1,375	1,181	1,190	163	166	4	4	16	16
Kansas	1,267	1,279	1,075	1,085	167	171	16	13	9	10
Minnesota	2,144	2,141	1,894	1,888	215	211	9	10	25	31
Missouri	2,585	2,620	2,281	2,310	280	286	11	10	13	13
Nebraska	843	855	685	694	113	115	6	6	38	39
North Dakota	327	333	276	281	44	46	2	2	5	4
South Dakota	359	365	303	306	45	47	2	2	10	10
South Atlantic	**22,500**	**22,944**	**19,838**	**20,208**	**2,426**	**2,494**	**78**	**79**	**158**	**164**
Delaware	346	352	310	316	34	35	1	1	1	1
District of Columbia	219	219	192	192	27	27	*	*	*	*
Florida	7,335	7,473	6,476	6,595	785	802	23	22	51	54
Georgia	3,324	3,419	2,952	3,032	331	346	14	14	27	27
Maryland	2,099	2,101	1,886	1,888	204	205	7	7	1	1
North Carolina	3,607	3,694	3,134	3,206	436	452	13	14	24	22
South Carolina	1,813	1,867	1,567	1,608	229	239	4	5	12	15
Virginia	2,849	2,904	2,531	2,577	275	281	5	5	39	41
West Virginia	908	916	789	794	105	107	11	11	3	3
East South Central	**7,684**	**7,795**	**6,641**	**6,731**	**923**	**942**	**70**	**70**	**50**	**52**
Alabama	2,069	2,100	1,781	1,806	264	270	13	13	11	11
Kentucky	1,850	1,880	1,616	1,642	205	207	11	10	19	21
Mississippi	1,252	1,273	1,075	1,090	159	164	9	9	10	9
Tennessee	2,513	2,541	2,170	2,193	296	300	37	38	11	11
West South Central	**13,043**	**13,297**	**11,335**	**11,557**	**1,439**	**1,474**	**126**	**128**	**142**	**138**
Arkansas	1,249	1,274	1,086	1,106	125	129	25	25	14	14
Louisiana	1,950	1,962	1,714	1,726	199	201	14	15	23	21
Oklahoma	1,655	1,668	1,428	1,442	194	195	16	18	16	13
Texas	8,188	8,393	7,107	7,284	921	949	71	70	89	90
Mountain	**7,145**	**7,374**	**6,128**	**6,329**	**827**	**852**	**37**	**39**	**152**	**153**
Arizona	1,850	1,919	1,643	1,706	177	183	5	5	24	25
Colorado	1,840	1,886	1,534	1,573	212	217	2	2	92	93
Idaho	553	568	464	477	81	83	4	4	4	4
Montana	452	460	373	379	63	65	4	4	12	12
Nevada	706	748	616	652	88	93	1	1	2	1
New Mexico	760	779	650	668	95	96	6	6	9	10
Utah	727	753	641	664	69	71	12	13	5	5
Wyoming	257	261	207	211	42	43	3	3	4	4
Pacific Contiguous	**16,561**	**16,772**	**14,511**	**14,690**	**1,913**	**1,938**	**58**	**63**	**78**	**81**
California	12,550	12,672	10,987	11,096	1,480	1,492	38	38	45	45
Oregon	1,500	1,534	1,299	1,324	184	190	7	8	10	11
Washington	2,511	2,566	2,226	2,270	249	256	13	16	23	25
Pacific Noncontiguous	**659**	**668**	**561**	**570**	**87**	**88**	**1**	**1**	**10**	**8**
Alaska	251	256	211	216	35	36	*	1	6	4
Hawaii	408	412	351	354	52	52	1	1	4	4
U. S. Average	**118,330**	**120,002**	**103,917**	**105,341**	**12,949**	**13,181**	**581**	**586**	**882**	**894**

[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 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, 1995 and 1996

(Million Dollars)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other[1]	
	1995	1996	1995	1996	1995	1996	1995	1996	1995	1996
New England	**10,967**	**11,146**	**4,485**	**4,584**	**4,185**	**4,302**	**2,095**	**2,060**	**201**	**199**
Connecticut	2,938	2,987	1,286	1,319	1,129	1,149	469	466	53	54
Maine	1,097	1,109	454	463	292	333	330	299	22	15
Massachusetts	4,705	4,789	1,800	1,829	1,976	2,022	843	850	86	88
New Hampshire	1,056	1,058	454	461	367	367	219	214	16	17
Rhode Island	689	692	283	293	265	264	122	115	19	20
Vermont	483	511	208	221	157	167	112	117	6	6
Middle Atlantic	**31,413**	**31,815**	**12,396**	**12,616**	**12,216**	**12,454**	**5,419**	**5,368**	**1,382**	**1,377**
New Jersey	6,972	7,026	2,692	2,714	3,049	3,111	1,140	1,109	91	92
New York	14,435	14,633	5,544	5,654	6,290	6,390	1,466	1,459	1,135	1,130
Pennsylvania	10,006	10,155	4,161	4,248	2,877	2,952	2,813	2,800	155	155
East North Central	**33,960**	**34,210**	**13,242**	**13,265**	**10,059**	**10,266**	**9,610**	**9,610**	**1,049**	**1,069**
Illinois	9,712	9,655	3,982	3,882	2,933	2,984	2,227	2,204	570	586
Indiana	4,557	4,651	1,790	1,819	1,072	1,086	1,645	1,696	50	50
Michigan	6,679	6,836	2,387	2,448	2,462	2,543	1,739	1,751	91	94
Ohio	9,906	9,983	3,784	3,831	2,731	2,778	3,104	3,086	287	288
Wisconsin	3,106	3,084	1,298	1,285	861	876	896	873	51	51
West North Central	**13,002**	**13,218**	**5,765**	**5,826**	**3,720**	**3,825**	**3,164**	**3,211**	**353**	**356**
Iowa	2,069	2,078	959	942	490	479	542	578	79	80
Kansas	1,992	2,041	820	839	687	733	451	434	34	35
Minnesota	3,011	3,046	1,217	1,223	601	621	1,143	1,148	51	53
Missouri	3,892	3,962	1,843	1,873	1,334	1,360	649	662	65	67
Nebraska	1,128	1,143	484	487	333	345	223	228	88	84
North Dakota	450	469	211	223	139	144	80	81	21	21
South Dakota	460	478	231	240	137	143	76	79	15	16
South Atlantic	**40,774**	**41,804**	**19,847**	**20,530**	**12,824**	**13,177**	**6,890**	**6,841**	**1,213**	**1,255**
Delaware	662	664	288	293	201	204	166	159	7	7
District of Columbia	735	745	123	125	578	585	11	11	23	23
Florida	11,745	12,343	6,711	7,060	3,838	4,043	850	879	346	362
Georgia	6,363	6,514	2,811	2,892	2,031	2,089	1,423	1,423	98	110
Maryland	3,964	3,966	1,875	1,898	1,596	1,580	425	419	68	68
North Carolina	6,885	7,075	3,207	3,348	1,888	1,959	1,652	1,634	138	133
South Carolina	3,703	3,802	1,611	1,688	890	928	1,153	1,135	49	51
Virginia	5,331	5,334	2,626	2,633	1,458	1,451	772	759	474	492
West Virginia	1,386	1,362	596	592	343	339	438	423	9	9
East South Central	**13,404**	**13,993**	**5,609**	**6,018**	**2,252**	**2,347**	**5,224**	**5,303**	**319**	**326**
Alabama	3,831	3,913	1,631	1,700	827	865	1,332	1,306	41	42
Kentucky	3,034	3,104	1,155	1,185	552	553	1,186	1,222	140	143
Mississippi	2,265	2,383	991	1,054	529	561	688	707	57	61
Tennessee	4,274	4,594	1,832	2,078	344	369	2,018	2,067	80	79
West South Central	**24,734**	**26,348**	**11,011**	**11,741**	**6,741**	**7,062**	**5,902**	**6,382**	**1,081**	**1,163**
Arkansas	2,174	2,224	991	1,005	488	502	653	676	42	41
Louisiana	4,189	4,569	1,744	1,836	1,055	1,134	1,219	1,405	170	194
Oklahoma	2,306	2,405	1,113	1,160	642	670	440	459	111	116
Texas	16,066	17,151	7,162	7,740	4,556	4,756	3,590	3,842	758	813
Mountain	**11,124**	**11,708**	**4,340**	**4,654**	**3,707**	**3,884**	**2,684**	**2,751**	**394**	**418**
Arizona	3,700	3,930	1,640	1,767	1,313	1,375	631	664	117	124
Colorado	2,162	2,244	839	889	815	844	438	432	70	78
Idaho	802	835	330	344	237	251	220	224	15	17
Montana	624	653	222	243	166	182	219	208	17	20
Nevada	1,260	1,342	473	519	319	340	429	445	39	37
New Mexico	1,112	1,161	368	386	403	420	249	258	92	97
Utah	979	1,049	350	381	334	349	259	283	37	36
Wyoming	484	495	118	124	119	123	239	237	8	10
Pacific Contiguous	**26,831**	**26,586**	**10,375**	**10,684**	**10,120**	**9,935**	**5,791**	**5,420**	**545**	**547**
California	21,070	20,668	7,983	8,088	8,485	8,199	4,226	4,018	376	364
Oregon	2,135	2,253	895	984	653	689	550	539	37	41
Washington	3,626	3,665	1,497	1,612	982	1,047	1,014	863	132	142
Pacific Noncontiguous	**1,509**	**1,627**	**540**	**582**	**541**	**574**	**398**	**439**	**30**	**31**
Alaska	471	489	192	201	210	215	46	49	23	24
Hawaii	1,038	1,137	347	382	331	359	352	390	7	7
U. S. Total	**207,717**	**212,455**	**87,610**	**90,501**	**66,365**	**67,827**	**47,175**	**47,385**	**6,567**	**6,741**

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

Notes: •Data 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, 1995 and 1996

(Cents)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other[1]	
	1995	1996	1995	1996	1995	1996	1995	1996	1995	1996
New England	**10.27**	**10.28**	**11.74**	**11.82**	**10.18**	**10.19**	**8.04**	**7.92**	**13.94**	**14.39**
Connecticut	10.50	10.51	11.95	12.05	10.33	10.29	7.94	7.86	14.38	14.35
Maine	9.49	9.46	12.51	12.58	10.28	10.35	6.65	6.26	15.67	23.03
Massachusetts	10.12	10.13	11.26	11.25	9.93	9.94	8.41	8.43	14.31	14.53
New Hampshire	11.72	11.59	13.50	13.44	11.38	11.32	9.56	9.16	12.32	13.34
Rhode Island	10.38	10.48	11.47	11.81	10.08	10.14	8.87	8.51	11.44	11.82
Vermont	9.46	9.74	10.52	10.99	9.80	10.14	7.56	7.58	14.03	12.96
Middle Atlantic	**9.71**	**9.76**	**11.79**	**11.84**	**10.43**	**10.51**	**6.24**	**6.19**	**9.60**	**9.66**
New Jersey	10.44	10.50	11.98	11.99	10.23	10.32	8.15	8.15	18.07	18.29
New York	11.06	11.13	13.90	14.04	11.92	12.08	5.79	5.62	9.07	9.13
Pennsylvania	7.93	7.96	9.72	9.73	8.33	8.34	5.92	5.93	11.29	11.29
East North Central	**6.47**	**6.48**	**8.48**	**8.47**	**7.34**	**7.37**	**4.45**	**4.43**	**6.94**	**6.98**
Illinois	7.69	7.69	10.37	10.34	7.88	7.97	5.27	5.24	6.80	6.84
Indiana	5.24	5.23	6.74	6.77	5.92	5.94	3.94	3.93	9.12	9.19
Michigan	7.05	7.10	8.34	8.47	7.86	7.94	5.13	5.08	10.71	10.84
Ohio	6.24	6.30	8.60	8.60	7.68	7.71	4.17	4.21	6.26	6.28
Wisconsin	5.36	5.25	6.97	6.88	5.78	5.68	3.78	3.66	6.85	6.79
West North Central	**5.99**	**5.91**	**7.33**	**7.23**	**6.25**	**6.19**	**4.32**	**4.24**	**6.29**	**6.41**
Iowa	6.03	5.94	8.24	8.16	6.44	6.53	3.94	3.91	6.13	5.98
Kansas	6.56	6.52	7.92	7.86	6.68	6.67	4.82	4.70	9.21	9.10
Minnesota	5.58	5.54	7.17	7.13	6.19	6.14	4.30	4.26	7.21	7.26
Missouri	6.25	6.11	7.25	7.08	6.18	6.04	4.53	4.44	7.05	7.03
Nebraska	5.40	5.32	6.37	6.29	5.56	5.49	3.84	3.68	5.86	6.49
North Dakota	5.71	5.65	6.23	6.19	6.20	6.07	4.50	4.44	4.21	4.14
South Dakota	6.20	6.18	7.08	7.00	6.55	6.57	4.43	4.45	4.58	4.59
South Atlantic	**6.57**	**6.54**	**7.87**	**7.84**	**6.58**	**6.60**	**4.47**	**4.35**	**6.23**	**6.29**
Delaware	6.91	6.88	9.09	8.97	7.08	7.00	4.72	4.68	11.95	12.04
District of Columbia	7.12	7.35	7.62	7.77	7.15	7.40	4.36	4.36	6.33	6.41
Florida	7.01	7.18	7.82	7.99	6.39	6.63	5.16	5.11	6.69	6.80
Georgia	6.62	6.43	7.85	7.66	7.32	7.17	4.52	4.29	8.60	8.96
Maryland	7.06	6.96	8.43	8.26	6.91	6.83	4.23	4.15	8.79	8.64
North Carolina	6.58	6.53	8.12	8.05	6.47	6.39	4.85	4.79	7.21	7.02
South Carolina	5.69	5.67	7.53	7.50	6.35	6.38	4.00	3.89	5.87	6.03
Virginia	6.26	6.09	7.84	7.60	6.07	5.91	4.16	3.99	5.21	5.26
West Virginia	5.34	5.21	6.50	6.38	5.86	5.71	4.03	3.91	9.36	9.27
East South Central	**5.07**	**5.04**	**6.23**	**6.19**	**6.34**	**6.27**	**3.91**	**3.86**	**6.03**	**6.04**
Alabama	5.47	5.35	6.71	6.63	6.73	6.49	4.05	3.90	7.35	6.82
Kentucky	4.07	4.03	5.62	5.55	5.25	5.19	2.93	2.92	4.68	4.66
Mississippi	5.98	6.01	6.99	7.04	7.01	7.09	4.44	4.41	8.56	8.68
Tennessee	5.21	5.24	5.91	5.88	6.65	6.64	4.50	4.52	7.56	7.96
West South Central	**6.00**	**6.08**	**7.56**	**7.61**	**6.58**	**6.68**	**4.02**	**4.11**	**6.32**	**6.46**
Arkansas	6.27	6.15	7.98	7.77	6.83	6.74	4.51	4.47	6.65	6.58
Louisiana	5.75	6.07	7.23	7.55	6.77	7.12	3.97	4.32	6.97	7.78
Oklahoma	5.57	5.56	6.82	6.71	5.78	5.80	3.75	3.78	4.93	5.08
Texas	6.10	6.16	7.71	7.77	6.64	6.71	3.98	4.03	6.44	6.44
Mountain	**6.06**	**6.00**	**7.62**	**7.58**	**6.63**	**6.53**	**4.20**	**4.11**	**5.65**	**5.68**
Arizona	7.62	7.54	9.09	8.95	8.06	7.97	5.26	5.19	5.15	5.39
Colorado	6.12	6.05	7.42	7.49	6.07	5.93	4.52	4.35	7.87	7.69
Idaho	4.09	3.96	5.33	5.28	4.48	4.26	2.81	2.68	5.13	4.79
Montana	4.65	4.72	6.09	6.22	5.31	5.51	3.44	3.30	6.21	6.42
Nevada	6.10	5.95	7.11	6.90	6.75	6.61	5.05	4.90	5.00	4.56
New Mexico	6.77	6.76	8.93	8.93	7.91	7.93	4.40	4.35	5.95	5.93
Utah	5.30	5.28	6.94	6.96	5.92	5.90	3.72	3.70	4.46	4.45
Wyoming	4.32	4.31	6.09	6.13	5.11	5.08	3.50	3.45	7.16	7.22
Pacific Contiguous	**7.74**	**7.54**	**9.00**	**8.85**	**8.86**	**8.40**	**5.39**	**5.23**	**5.57**	**5.43**
California	9.91	9.48	11.61	11.33	10.49	9.83	7.37	6.97	6.73	6.45
Oregon	4.67	4.77	5.49	5.69	5.06	5.15	3.47	3.41	5.49	5.74
Washington	4.10	4.19	4.97	5.03	4.82	4.88	2.96	2.85	3.75	3.84
Pacific Noncontiguous	**10.92**	**11.49**	**12.50**	**13.11**	**10.99**	**11.45**	**9.16**	**9.82**	**12.97**	**13.23**
Alaska	10.17	10.24	11.24	11.36	9.54	9.58	8.38	8.47	13.26	13.34
Hawaii	11.29	12.12	13.32	14.26	12.16	12.99	9.27	10.03	12.11	12.91
U. S. Average	**6.89**	**6.86**	**8.40**	**8.36**	**7.69**	**7.64**	**4.66**	**4.60**	**6.88**	**6.91**

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 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.

Increasing competion and the pending shift to deregulation are causing utilities to position themselves to meet a changing industry structure through increased operating efficiencies, mergers, and restructuring. In an effort to restructure, utilities may have sold assets such as generating units, formed unregulated utility subsidiaries, or invested in nonutility power producers or foreign enterprises. Many States are proposing some level of retail access in 1998. California passed legislation to implement full retail access starting in 1998, while other States are proposing pilot programs where a small percentage of ultimate consumers are eligible for the program. The impact of restructuring on the financial statistics is unclear, although for 1996 it is relatively small. As the industry continues to restructure, the impact on the financial statistics will have to be evaluated.

Background

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

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

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

Electric utilities must submit data for a 12-month period (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 1996. 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 operating ratios that measure specific costs associated with the sale of each kilowatthour of electricity have been included. *Pur-*

chase 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 1995. 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 1991 through 1995 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 three consecutive years, sales or transmission service that exceeds one or more of the following:

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

Of the 243 investor-owned electric utilities, the 179 major utilities are required to submit the FERC Form 1. These major investor-owned electric utilities represent about three-fourths 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.*[10]

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

[10] For detailed data, including data for independent power producers and cooperatives jurisdictional to the Federal Energy Regulatory Commission, see *Financial Statistics of Major U.S. Investor-Owned Electric Utilities,* DOE/EIA-0437/1, published annually by the Energy Information Administration (EIA).

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*.[11]

[11] For detailed data see *Financial Statistics of Major U.S. Publicly Owned Electric Utilities*, DOE/EIA-0437/2, published annually by the Energy Information Administration (EIA).

Table 8. Composite Statement of Income for Major U.S. Investor-Owned Electric Utilities, 1992 Through 1996

(Thousand Dollars)

Description	1992	1993	1994	1995	1996
Operating Revenue	**185,493,458**	**193,637,843**	**196,281,500**	**199,966,979**	**207,459,078**
Electric	169,488,035	176,354,365	179,307,260	183,655,263	188,900,781
Gas	14,937,370	16,686,912	16,221,506	15,580,382	17,869,394
Other Utility	1,068,053	596,567	752,734	731,333	688,903
Operating Expenses	**153,682,429**	**161,908,147**	**164,207,153**	**165,321,023**	**173,920,492**
Electric	139,009,093	146,118,013	148,662,734	150,598,710	156,937,816
Fuel	30,254,398	31,214,057	30,107,888	29,121,982	30,706,261
Other Operating and Maintenance	69,212,541	72,561,087	75,021,900	74,525,998	78,550,226
Depreciation[1]	17,091,753	18,098,736	18,679,022	19,885,482	21,193,742
Taxes Other Than Income Taxes	12,760,152	13,040,400	13,275,354	13,519,143	13,569,490
Regulatory Debits (net)	—	429,481	706,108	1,142,138	683,105
Income Taxes	7,197,682	8,296,900	9,625,569	11,479,763	11,194,656
Deferred Income Tax	3,017,335	2,993,143	1,831,593	1,473,977	1,616,998
Investment Tax Credit (Net)	R –524,768	R –515,791	R –584,701	R –549,772	–576,741
Gas	13,691,253	15,234,557	14,877,836	14,073,160	16,257,611
Income Taxes	279,618	251,533	465,076	531,748	223,871
Other	13,411,635	14,983,024	14,412,760	13,541,412	16,033,740
Other Utility	982,083	555,577	666,584	649,154	725,066
Income Taxes	26,956	10,763	14,963	5,807	–21,775
Other	955,127	544,814	651,621	643,347	746,841
Operating Income	**31,811,029**	**31,729,696**	**32,074,346**	**34,645,955**	**33,538,586**
Electric	30,478,942	30,236,352	30,644,526	33,056,553	31,962,965
Gas	1,246,117	1,452,354	1,343,670	1,507,223	1,611,783
Other	85,970	40,990	86,150	82,180	–36,163
Other Income and Deductions	**1,689,045**	**1,346,398**	**1,809,553**	**1,811,414**	**1,614,287**
Allowance for Other Funds Used During Construction	611,514	591,445	402,569	315,651	230,791
Less Taxes	379,461	1,119,581	477,529	350,716	597,230
Deferred Earnings (Misc.) (acct 421)	1,341,354	677,360	802,120	372,642	774,012
Less Other Income and Expenses[2]	–115,638	–1,197,174	–1,082,393	–1,473,837	–1,206,714
Total Income Before Interest Charges	**33,500,074**	**33,076,094**	**33,883,899**	**36,457,369**	**35,152,873**
Net Interest Charges	15,223,174	14,700,488	14,161,602	14,421,406	13,990,388
Interest Expense	15,307,441	14,566,753	13,915,384	14,169,979	13,645,951
Less Allowance for Borrowed Funds Used During Construction	558,348	555,021	420,828	435,386	326,158
Other Charges--Net	474,080	688,756	667,046	686,814	670,597
Net Income Before Extraordinary Charges	**18,276,900**	**18,375,606**	**19,722,298**	**22,035,963**	**21,162,485**
Less Extraordinary Items After Taxes[2]	**–107,544**	**484,409**	**–165,288**	**–24,691**	**–65,696**
Net Income	**18,384,444**	**17,891,198**	**19,887,586**	**22,060,655**	**21,228,180**
Dividends Declared - Preferred Stock	**2,039,449**	**1,765,286**	**1,581,940**	**1,518,904**	**1,248,409**
Earnings Available for Common Stocks	**16,344,995**	**16,125,912**	**18,305,646**	**20,541,751**	**19,979,771**
Dividends Declared - Common Stock	**14,897,608**	**15,334,377**	**15,875,659**	**16,249,715**	**16,810,054**
Additions Total Earnings	**2,184,266**	**296,171**	**2,063,432**	**4,281,899**	**2,193,444**
Average Shares of Common Stock Outstanding	**6,261,284**	**6,129,888**	**6,223,816**	**6,752,352**	**6,704,954**
Earnings Available Per Average Common Share (Dollars)	**2.61**	**2.63**	**2.94**	**3.04**	**2.98**

1 Includes amortization and depletion.

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

R = Revised data.

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, 1992 Through 1996
(Thousand Dollars)

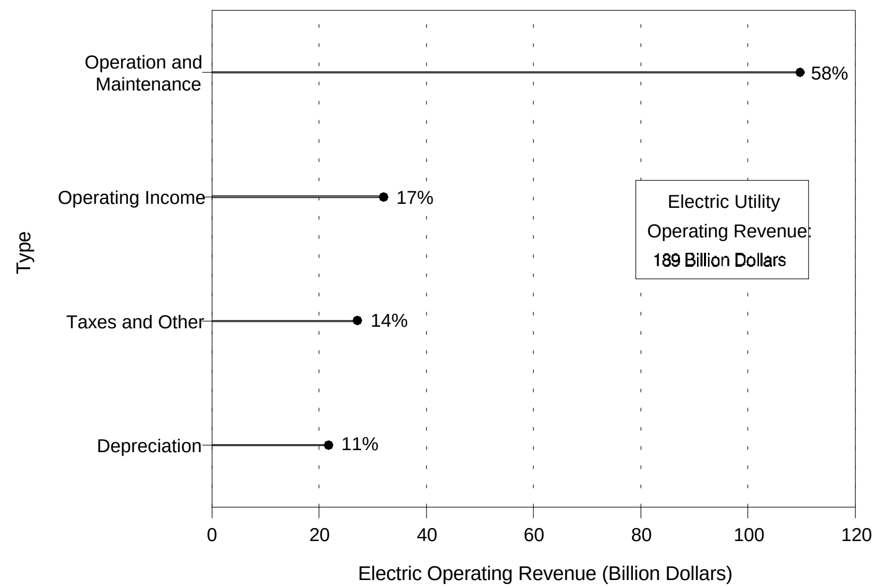
Description	1992	1993	1994	1995	1996
Assets					
Utility Plant - Net	**386,864,738**	**393,829,243**	**397,812,254**	**397,383,148**	**396,437,823**
Electric Utility Plant - Net	358,300,259	363,829,459	366,936,417	366,116,061	363,853,762
Electric Utility Plant	498,118,599	519,207,367	535,928,383	553,857,823	569,968,617
Construction Work in Progress	20,648,234	18,048,849	17,148,353	13,523,358	11,395,525
Less Accumulated Depreciation	160,466,573	173,426,756	186,140,318	201,265,120	217,510,379
Nuclear Fuel - Net	6,836,719	5,964,178	5,656,878	5,285,850	5,443,854
Other Utility Plant - Net	21,727,759	24,035,606	25,218,959	25,981,238	27,140,206
Other Property and Investments	**18,045,977**	**20,063,695**	**23,479,360**	**27,987,677**	**33,119,898**
Current and Accrued Assets	**43,447,871**	**42,409,989**	**41,262,977**	**44,139,661**	**43,515,064**
Deferred Debits	**57,993,875**	[1] **110,338,355**	**111,957,082**	**109,423,227**	**108,918,179**
Total Assets and other Debits	**506,352,461**	**566,641,282**	**574,511,673**	**578,933,714**	**581,990,963**
Capitalization and Liabilities					
Capitalization	**356,026,762**	**360,455,273**	**364,724,736**	**365,774,716**	**365,782,779**
Common Stock Equity (End of Year)	156,346,650	160,296,897	164,482,824	170,497,132	174,325,424
Common Stock	103,963,697	107,470,838	109,522,096	111,301,825	112,633,284
Retained Earnings (Adjusted)	52,382,953	52,826,059	54,960,728	59,195,307	61,692,140
Preferred Stock	25,539,216	25,304,294	24,859,833	21,569,105	18,830,248
Long-term Debt	174,140,896	174,854,082	175,382,079	173,708,479	172,627,107
Current Liabilities and Deferred Credits	**150,325,698**	**206,186,010**	**209,786,937**	**213,158,998**	**216,208,185**
Other Noncurrent Liabilities	8,627,882	11,478,303	13,452,636	14,352,102	15,309,391
Current and Accrued Liabilities	45,557,601	48,878,976	48,035,058	49,929,403	49,341,620
Deferred Credits	96,140,215	145,828,731	148,299,243	148,877,493	151,557,174
Accumulated Deferred Income Taxes	65,020,984	104,964,188	107,054,667	108,615,175	110,537,249
Accumulated Deferred Investment Tax Credit	14,046,840	13,428,995	12,784,415	12,138,942	11,491,332
Other Deferred Credits (Adjusted)	17,072,392	27,435,549	28,460,160	28,123,375	29,528,592
Total Liabilities and Other Credits	**506,352,461**	**566,641,282**	**574,511,673**	**578,933,714**	**581,990,963**

[1] 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.

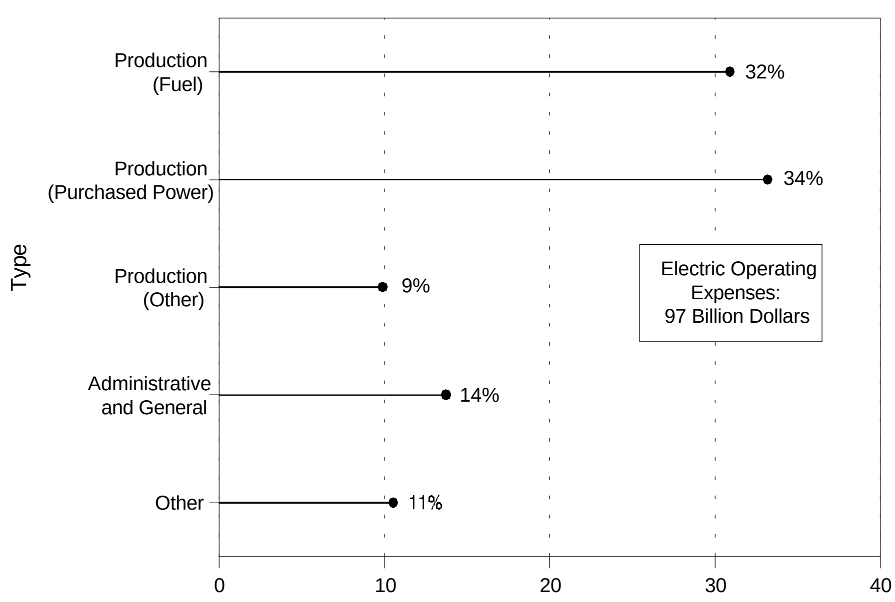
Figure 10. Allocation of the Revenue Dollar from Electric Operations for Major U.S. Investor-Owned Electric Utilities, 1996



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.

Figure 11. Electric Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 1996



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 10. Composite Financial Indicators for Major U.S. Investor-Owned Electric Utilities, 1992 Through 1996

Description[1]	1992	1993	1994	1995	1996
Activity					
1. Electric Fixed Asset (Net Plant) Turnover	0.47	0.48	0.49	0.50	0.52
2. Total Asset Turnover	.37	.34	.34	.35	.36
Leverage					
3. Current Assets to Current Liabilities	.95	.87	.86	.88	.88
4. Long-term Debt to Capitalization	48.91	48.51	48.09	47.49	47.19
5. Preferred Stock to Capitalization	7.17	7.02	6.82	5.90	5.15
6. Common Stock Equity to Capitalization	43.91	44.47	45.10	46.61	47.66
7. Total Debt to Total Assets[2]	36.13	32.48	32.35	31.89	31.57
8. Common Stock Equity to Total Assets	30.88	28.29	28.63	29.45	29.95
9. Interest Coverage Before Taxes without AFUDC	2.62	2.78	3.10	3.37	3.36
Profitability					
10. Profit Margin	9.91	9.24	10.13	11.03	10.23
11. Return on Average Common Stock Equity[3]	11.94	11.30	12.24	13.17	12.31
12. Return on Investment	3.63	3.16	3.46	3.81	3.65

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

[2] 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 $11,129,401 for 1996; $10,895,101 for 1995; $10,448,573 for 1994; $9,210,845 for 1993; and $8,791,477 for 1992.

[3] The Average Common Stock Equity is the average of the beginning and ending year balances. The value for the beginning of 1991 was $154,008,977.

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.

Table 11. Revenue and Expense Statistics for Major U.S. Investor-Owned Electric Utilities, 1992 Through 1996

(Thousand Dollars)

Description	1992	1993	1994	1995	1996
Utility Operating Revenues	**185,493,458**	**193,637,843**	**196,281,500**	**199,966,979**	**207,459,078**
Electric Utility	169,488,035	176,354,365	179,307,260	183,655,263	188,900,781
Other Utility	16,005,423	17,283,479	16,974,240	16,311,715	18,558,297
Utility Operating Expenses	**153,682,429**	**161,908,147**	**164,207,153**	**165,321,023**	**173,920,492**
Electric Utility	139,009,093	146,118,013	148,662,734	150,598,710	156,937,816
Operation	87,272,134	91,328,230	93,107,998	91,880,940	97,206,642
Production	66,979,805	68,780,803	69,268,652	68,983,410	73,436,927
Cost of Fuel	30,254,398	31,214,057	30,107,888	29,121,982	30,706,261
Purchased Power	26,212,238	27,715,512	29,213,084	29,981,379	32,987,034
Other	10,513,169	9,851,234	9,947,680	9,880,049	9,743,632
Transmission	1,308,101	1,354,058	1,361,080	1,425,058	1,503,196
Distribution	2,498,514	2,595,023	2,581,409	2,560,835	2,604,058
Customer Accounts	3,347,124	3,418,487	3,546,489	3,613,101	3,848,302
Customer Service	1,531,369	1,852,267	1,955,991	1,922,475	1,920,450
Sales	198,647	203,291	231,589	348,345	435,477
Administrative and General	11,408,575	13,124,300	14,162,788	13,027,716	13,458,234
Maintenance	12,194,805	12,446,914	12,021,790	11,767,040	12,049,844
Depreciation	17,091,753	18,098,736	18,679,022	19,885,482	21,193,742
Taxes and Other	22,450,401	24,244,133	24,853,924	27,065,248	26,487,588
Other Utility	14,673,336	15,790,134	15,544,420	14,722,314	16,982,677
Net Utility Operating Income	**31,811,029**	**31,729,696**	**32,074,346**	**34,645,955**	**33,538,586**

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, 1992 Through 1996

Description	1992	1993	1994	1995	1996
Utility Operating Revenues	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
Electric Utility	91.4	91.1	91.4	91.8	91.1
Other Utility	8.6	8.9	8.6	8.2	8.9
Utility Operating Expenses	**82.9**	**83.6**	**83.7**	**82.7**	**83.8**
Electric Utility	74.9	75.5	75.7	75.3	75.6
Operation	47.0	47.2	47.4	45.9	46.9
Production	36.1	35.5	35.3	34.5	35.4
Cost of Fuel	16.3	16.1	15.3	14.6	14.8
Purchased Power	14.1	14.3	14.9	15.0	15.9
Other	5.7	5.1	5.1	4.9	4.7
Transmission	.7	.7	.7	.7	.7
Distribution	1.3	1.3	1.3	1.3	1.3
Customer Accounts	1.8	1.8	1.8	1.8	1.9
Customer Service	.8	1.0	1.0	1.0	.9
Sales	.1	.1	.1	.2	.2
Administrative and General	6.2	6.8	7.2	6.5	6.5
Maintenance	6.6	6.4	6.1	5.9	5.8
Depreciation	9.2	9.3	9.5	9.9	10.2
Taxes and Other	12.1	12.5	12.7	13.5	12.8
Other Utility	7.9	8.2	7.9	7.4	8.2
Net Utility Operating Income	**17.1**	**16.4**	**16.3**	**17.3**	**16.2**

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, 1992 Through 1996

(Mills per Kilowatthour)

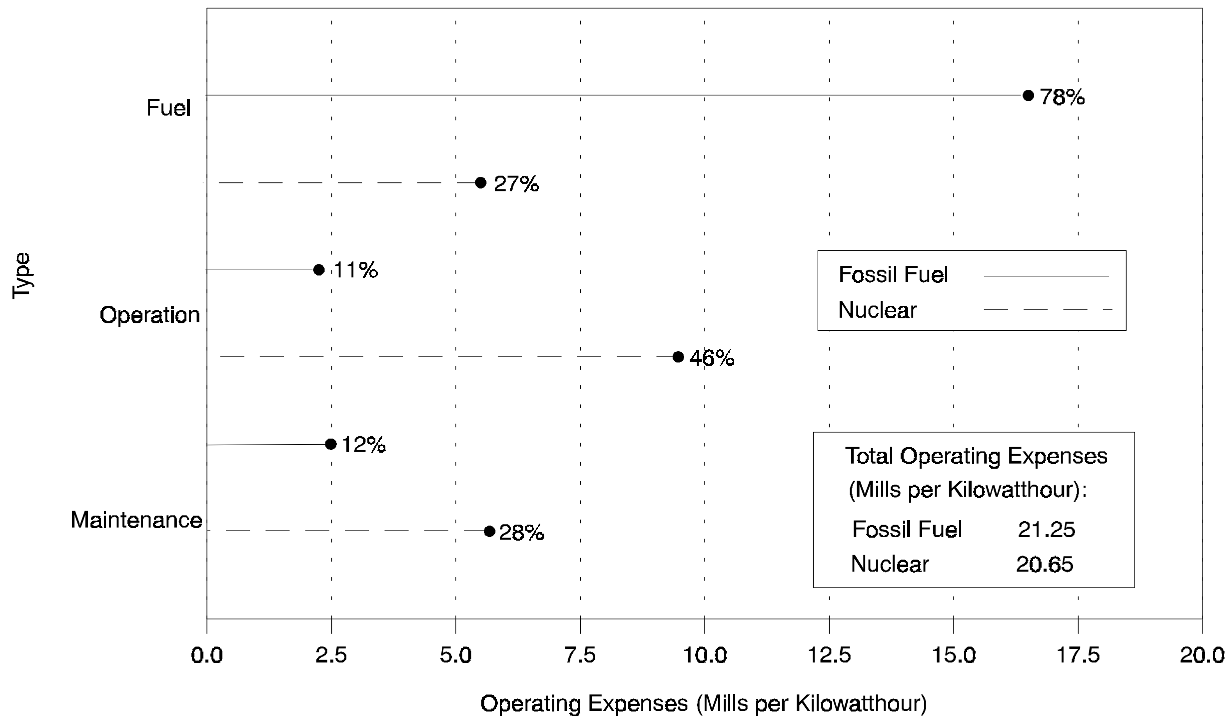
Plant Type	1992	1993	1994	1995	1996
			Operation		
Nuclear	10.43	10.20	9.79	9.43	9.47
Fossil Steam	2.38	2.37	2.32	2.38	2.25
Hydroelectric[1]	4.33	3.82	4.53	3.69	3.87
Gas Turbine and Small Scale[2]	10.18	6.47	4.58	3.57	5.08
			Maintenance		
Nuclear	5.93	5.73	5.20	5.21	5.68
Fossil Steam	2.95	2.96	2.82	2.65	2.49
Hydroelectric[1]	3.30	2.65	2.90	2.19	2.08
Gas Turbine and Small Scale[2]	12.15	7.52	5.39	4.28	4.98
			Fuel		
Nuclear	6.12	5.88	5.87	5.75	5.50
Fossil Steam	17.49	17.65	16.67	16.07	16.51
Hydroelectric[1]	—	—	—	—	—
Gas Turbine and Small Scale[2]	28.59	26.39	22.19	20.83	30.58
			Total[3]		
Nuclear	22.48	21.80	20.86	20.39	20.65
Fossil Steam	22.83	22.97	21.80	21.11	21.25
Hydroelectric[1]	7.63	6.47	7.43	5.89	5.95
Gas Turbine and Small Scale[2]	50.92	40.38	32.16	28.67	40.64

1 Includes Pumped Storage.
2 Includes gas turbine, internal combustion, photovoltaic, and wind plants.
3 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 12. Average Operating Expenses of Fossil-Fueled and Nuclear Steam-Electric Plants for Major U.S. Investor-Owned Electric Utilities, 1996



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 14. Composite Statement of Income for Major U.S. Publicly Owned Generator Electric Utilities, 1992 Through 1996
(Thousand Dollars)

Description	1992	1993	1994	1995	1996
Operating Revenue - Electric	**21,686,349**	**22,521,847**	**23,266,686**	**23,472,888**	**24,207,226**
Operating Expenses - Electric	**17,190,647**	**18,162,164**	**18,648,687**	**18,958,876**	**19,083,980**
Operation Excluding Fuel	9,591,495	9,803,647	10,191,897	11,167,114	11,270,829
Fuel	2,935,940	3,437,920	3,385,718	2,485,770	2,497,215
Maintenance	1,564,792	1,565,293	1,584,444	1,575,208	1,637,828
Depreciation and Amortization	2,417,279	2,596,099	2,720,560	2,933,594	3,015,664
Taxes and Tax Equivalents	681,140	759,205	756,068	797,189	622,443
Operating Income - Electric	**4,495,703**	**4,359,683**	**4,617,999**	**4,514,013**	**5,123,246**
Other Income and Deductions	**1,628,944**	**1,219,709**	**1,098,922**	**1,174,316**	**1,237,173**
Income from Electric Plant Leased to Others	15,129	23,576	30,242	16,365	25,914
Allowance for Funds Used During Construction	24,183	28,476	7,872	9,145	6,660
Other Income Net	1,839,484	1,455,984	1,237,067	1,371,621	1,440,435
Less Other Electric Deductions	249,852	288,325	176,259	222,815	235,836
Total Income Before Interest Charges	**6,124,646**	**5,579,392**	**5,716,920**	**5,688,329**	**6,360,419**
Net Interest Charges	**5,025,758**	**4,682,023**	**4,681,141**	**4,728,063**	**4,634,548**
Interest Expenses	4,757,583	4,433,067	4,332,296	4,206,294	4,155,829
Other Income Deductions	268,175	248,956	348,845	521,769	478,719
Net Income Before Extraordinary Charges	**1,098,889**	**897,369**	**1,035,779**	**960,266**	**1,725,871**
Less **Extraordinary Items**	**115,275**	**214,227**	**124,211**	**−250,918**	**−2,304**
Net Income	**983,613**	**683,142**	**911,568**	**1,211,184**	**1,723,567**

Notes: •Data for 1996 are preliminary; data for prior years are final. •Totals may not equal sum of components because of independent rounding. •The number of publicly owned generating electric utilities that reported were 231 for 1996, 226 for 1995, 227 for 1994, 226 for 1993, and 225 for 1992.

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, 1992 Through 1996
(Thousand Dollars)

Description	1992	1993	1994	1995	1996
Assets					
Electric Utility Plant-Net Inc Nuclear Fuel	**61,710,753**	**62,477,584**	**63,576,104**	**63,412,608**	**64,159,411**
Electric Utility Plant Inc Nuclear Fuel	85,359,878	88,353,146	92,044,086	93,771,319	97,433,005
Accumulated Provision for Depreciation and Amortization	23,649,125	25,875,562	28,467,982	30,358,711	33,273,595
Other Property and Investments	**18,228,937**	**20,487,402**	**20,973,996**	**20,996,914**	**19,674,912**
Current and Accrued Assets	**14,990,707**	**15,357,112**	**15,782,291**	**15,086,442**	**16,521,745**
Deferred Debits	**12,017,041**	**13,987,324**	**13,913,754**	**14,242,677**	**13,520,724**
Total Assets and Other Debits	**106,947,439**	**112,309,422**	**114,246,146**	**113,738,640**	**113,876,791**
Liabilities and Other Credits					
Investment of Municipality - Surplus	**22,823,226**	**23,527,598**	**24,518,851**	**25,447,162**	**27,472,346**
Long-Term Debt	**72,004,391**	**76,168,783**	**76,815,309**	**74,982,156**	**73,950,415**
Other Noncurrent Liabilities	**698,351**	**590,789**	**701,406**	**714,354**	**766,093**
Current and Accrued Liabilities	**8,080,777**	**8,594,053**	**8,913,155**	**9,084,862**	**8,167,668**
Deferred Credits	**3,340,694**	**3,428,200**	**3,297,425**	**3,510,106**	**3,520,270**
Total Liabilities and Other Credits	**106,947,439**	**112,309,422**	**114,246,146**	**113,738,640**	**113,876,791**

Notes: •Data for 1996 are preliminary; data for prior years are final. •Totals may not equal sum of components because of independent rounding. •The number of publicly owned generating electric utilities that reported were 231 for 1996, 226 for 1995, 227 for 1994, 226 for 1993, and 225 for 1992.

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, 1992 Through 1996

Description	1992	1993	1994	1995	1996
Electric Utility Plant per Dollar of Revenue	3.9	3.9	4.0	4.0	4.0
Current Assets to Current Liabilities	1.9	1.8	1.8	1.7	2.0
Electric Utility Plant as a Percent of Total Assets	79.8	78.7	80.6	82.4	85.6
Net Electric Utility Plant as a Percent of Total Assets	57.7	55.6	55.6	55.8	56.3
Debt as a Percent of Total Liabilities	74.9	75.5	75.0	73.9	72.1
Accumulated Provision for Depreciation as a Percent of Electric Utility Plant	27.7	29.3	30.9	32.4	34.2
Electric Operation and Maintenance Expenses as a Percent of Electric Operating Revenues	65.0	65.7	65.2	64.9	63.6
Electric Depreciation and Amortization as a Percent of Electric Operating Revenues	10.5	10.8	11.1	11.9	11.9
Taxes and Tax Equivalents as a Percent of Electric Operating Revenues	3.1	3.4	3.3	3.4	2.7
Interest Expenses as a Percent of Electric Operating Revenues	21.9	19.7	18.6	17.9	17.2
Net Income as a Percent of Electric Operating Revenues	4.5	3.0	3.9	5.2	7.1
Purchase Power Cents Per Kilowatthour	3.7	3.6	3.6	3.6	3.8
Generated Cents Per Kilowatthour	1.9	1.9	1.9	1.8	1.5
Total Power Supply Per Kilowatthour Sold	2.6	2.6	2.6	2.5	2.4

Notes: •Data for 1996 are preliminary; data for prior years are final. •Totals may not equal sum of components because of independent rounding. •The number of publicly owned generating electric utilities that reported were 231 for 1996, 226 for 1995, 227 for 1994, 226 for 1993, and 225 for 1992.

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, 1992 Through 1996
(Thousand Dollars)

Description	1992	1993	1994	1995	1996
Operating Revenue - Electric	**21,686,349**	**22,521,847**	**23,266,686**	**23,472,888**	**24,207,226**
Operating Expenses - Electric	**17,190,647**	**18,162,164**	**18,648,687**	**18,958,876**	**19,083,980**
Operation Including Fuel	12,527,435	13,241,567	13,577,615	13,652,884	13,768,044
Production	9,712,324	10,254,301	10,444,534	10,384,858	11,080,348
Transmission	534,512	579,635	609,612	628,098	344,371
Distribution	388,703	408,335	429,535	425,831	497,019
Customer Accounts	299,209	314,992	316,794	323,122	365,277
Customer Service	82,731	94,089	104,101	102,061	103,390
Sales	17,545	17,210	22,436	19,617	17,528
Administrative and General	1,492,411	1,573,005	1,650,603	1,769,298	1,360,111
Maintenance	1,564,792	1,565,293	1,584,444	1,575,208	1,637,828
Depreciation and Amortization Excluding Nuclear Fuel	2,417,279	2,596,099	2,591,423	2,933,594	3,015,664
Taxes and Tax Equivalents	681,140	759,205	766,068	797,189	662,443
Income from Electric Utility Operations	**4,495,703**	**4,359,683**	**4,617,999**	**4,514,013**	**5,123,246**

Notes: •Data for 1996 are preliminary; data for prior years are final. •Totals may not equal sum of components because of independent rounding. •The number of publicly owned generating electric utilities that reported were 231 for 1996, 226 for 1995, 227 for 1994, 226 for 1993, and 225 for 1992.

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, 1992 Through 1996

(Thousand Dollars)

Description	1992	1993	1994	1995	1996
Operating Revenue - Electric	**7,247,407**	**7,523,453**	**7,995,632**	**8,435,445**	**8,573,080**
Operating Expenses - Electric	**6,843,539**	**7,063,260**	**7,566,745**	**7,978,811**	**8,114,610**
Operation Excluding Fuel	6,244,812	6,424,783	6,857,958	7,172,611	7,351,011
Fuel	19	15	13	247	—
Maintenance	192,635	207,046	233,967	249,580	243,969
Depreciation and Amortization	251,079	256,736	273,770	312,724	313,479
Taxes and Tax Equivalents	154,994	174,681	201,038	243,648	206,151
Operating Income - Electric	**403,868**	**460,193**	**428,887**	**456,634**	**458,470**
Other Income and Deductions	**74,486**	**98,822**	**97,664**	**142,214**	**153,710**
Income from Electric Plant Leased to Others	1,773	2,405	2,185	4,345	12,569
Allowance for Funds Used During Construction	39	106	51	41	70
Other Income Net	172,938	172,569	178,515	215,559	207,720
Less Other Electric Deductions	100,264	76,258	83,086	77,731	66,649
Total Income Before Interest Charges	**478,354**	**559,015**	**526,551**	**598,847**	**612,180**
Net Interest Charges	**140,861**	**172,792**	**156,433**	**168,632**	**148,098**
Interest Expenses	109,378	114,527	108,647	127,013	99,730
Other Income Deductions	31,483	58,264	47,786	41,619	48,367
Net Income Before Extraordinary Charges	**337,493**	**386,223**	**370,118**	**430,215**	**464,082**
Less **Extraordinary Items**	**2,156**	**25,600**	**3,821**	**6,659**	**4,110**
Net Income	**335,338**	**360,624**	**366,297**	**423,556**	**459,972**

Notes: •Data for 1996 are preliminary; data for prior years are final. •Totals may not equal sum of components because of independent rounding. •The number of publicly owned nongenerating electric utilities that reported were 284 for 1996, 286 for 1995, 276 for 1994, 269 for 1993, and 258 for 1992.

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, 1992 Through 1996

(Thousand Dollars)

Description	1992	1993	1994	1995	1996
Assets					
Electric Utility Plant-Net Inc Nuclear Fuel	**4,881,003**	**5,268,229**	**5,496,059**	**6,272,158**	**6,256,424**
Electric Utility Plant Inc Nuclear Fuel	7,733,037	8,317,096	8,759,850	9,936,064	9,917,693
Accumulated Provision for Depreciation and Amortization	2,852,034	3,048,867	3,263,791	3,663,906	3,661,269
Other Property and Investments	**1,890,451**	**1,911,724**	**1,904,194**	**2,196,898**	**1,883,118**
Current and Accrued Assets	**2,227,084**	**2,495,760**	**2,497,816**	**2,884,088**	**2,699,760**
Deferred Debits	**386,263**	**423,907**	**400,447**	**492,691**	**407,885**
Total Assets and Other Debits	**9,384,801**	**10,099,620**	**10,298,517**	**11,841,016**	**11,247,157**
Liabilities and Other Credits					
Investment of Municipality - Surplus	**5,522,242**	**5,983,376**	**6,281,647**	**6,938,969**	**7,145,596**
Long-Term Debt	**2,713,721**	**2,898,817**	**2,723,507**	**3,441,757**	**2,591,327**
Other Noncurrent Liabilities	**10,284**	**10,749**	**11,414**	**16,179**	**17,991**
Current and Accrued Liabilities	**983,865**	**1,039,867**	**1,098,941**	**1,232,623**	**1,262,762**
Deferred Credits	**154,689**	**166,812**	**183,009**	**211,487**	**229,481**
Total Liabilities and Other Credits	**9,384,801**	**10,099,620**	**10,298,517**	**11,841,016**	**11,247,157**

Notes: •Data for 1996 are preliminary; data for prior years are final. •Totals may not equal sum of components because of independent rounding. •The number of publicly owned nongenerating electric utilities that reported were 284 for 1996, 286 for 1995, 276 for 1994, 269 for 1993, and 258 for 1992.

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, 1992 Through 1996

Description	1992	1993	1994	1995	1996
Electric Utility Plant per Dollar of Revenue	1.1	1.1	1.1	1.2	1.2
Current Assets to Current Liabilities	2.3	2.4	2.3	2.3	2.1
Electric Utility Plant as a Percent of Total Assets	82.4	82.4	85.1	83.9	88.2
Net Electric Utility Plant as a Percent of Total Assets	52.0	52.2	53.4	52.9	55.6
Debt as a Percent of Total Liabilities	39.4	39.0	37.1	39.5	34.3
Accumulated Provision for Depreciation as a Percent of Electric Utility Plant	36.9	36.7	37.3	36.9	36.9
Electric Operation and Maintenance Expenses as a Percent of Electric Operating Revenues	88.8	88.1	88.7	88.0	88.6
Electric Depreciation and Amortization as a Percent of Electric Operating Revenues	3.4	3.4	3.4	3.7	3.6
Taxes and Tax Equivalents as a Percent of Electric Operating Revenues	2.1	2.3	2.5	2.9	2.4
Interest Expenses as a Percent of Electric Operating Revenues	1.5	1.5	1.4	1.5	1.2
Net Income as a Percent of Electric Operating Revenues	4.6	4.8	4.6	5.0	5.4
Purchase Power Cents Per Kilowatthour	4.1	4.1	4.1	4.3	4.0

Notes: •Data for 1996 are preliminary; data for prior years are final. •Totals may not equal sum of components because of independent rounding. •The number of publicly owned nongenerating electric utilities that reported were 284 for 1996, 286 for 1995, 276 for 1994, 269 for 1993, and 258 for 1992.
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, 1992 Through 1996
(Thousand Dollars)

Description	1992	1993	1994	1995	1996
Operating Revenue - Electric	**7,247,407**	**7,523,453**	**7,995,632**	**8,435,445**	**8,573,080**
Operating Expenses - Electric	**6,843,539**	**7,063,260**	**7,566,745**	**7,978,811**	**8,114,610**
Operation Including Fuel	6,244,831	6,424,798	6,857,970	7,172,858	7,351,011
Production	5,617,261	5,760,626	6,185,035	6,421,965	6,571,536
Transmission	32,956	33,755	34,045	35,184	50,446
Distribution	176,188	189,023	190,181	204,130	233,861
Customer Accounts	109,196	117,353	119,019	125,143	141,178
Customer Service	15,629	17,166	16,941	17,934	18,238
Sales	11,646	8,704	9,845	9,535	11,615
Administrative and General	281,954	298,171	302,904	358,367	324,137
Maintenance	192,635	207,046	233,967	249,580	243,969
Depreciation and Amortization Excluding Nuclear Fuel	251,079	256,736	268,790	312,724	313,479
Taxes and Tax Equivalents	154,994	174,681	201,038	243,648	206,151
Income from Electric Utility Operations	**403,868**	**460,193**	**428,887**	**456,634**	**458,470**

Notes: •Data for 1996 are preliminary; data for prior years are final. •Totals may not equal sum of components because of independent rounding. •The number of publicly owned nongenerating electric utilities that reported were 284 for 1996, 286 for 1995, 276 for 1994, 269 for 1993, and 258 for 1992.
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 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 compounds. 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 A. Additional detailed information on emissions from electric utilities can be obtained in Chapter 6 of the *Annual Energy Outlook.*[12] 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 over 800 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 67 nuclear power plants in the Form EIA-767 respondent universe.

[12] Energy Information Administration, *Annual Energy Outlook* DOE/EIA-0383(98)(Washington, DC, 1997).

Table 22. Estimated Emissions from Fossil-Fueled Steam-Electric Generating Units at U.S. Electric Utilities, 1992 Through 1996

(Thousand Short Tons)

Emission	1992	1993	1994	1995	1996
Sulfur Dioxide (SO_2)	15,175	15,014	14,377	11,571	12,202
Nitrogen Oxides (NO_x)[1]	7,188	7,378	7,168	7,135	7,426
Carbon Dioxide (CO_2)[1]	1,902,884	1,970,193	1,972,001	1,967,669	2,047,368

[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 1996 are preliminary; data for prior years are final. •Emissions of CO2, NOx, and SO2 have been revised from the updated (January 1996) Air Pollutant Emissions Factors (AP-42 5th release) 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, 1992 Through 1996

Environmental Equipment	Scrubbers		Particulate Collectors	
	Number of Generators	Capacity[1] (megawatts)	Number of Generators	Capacity[1] (megawatts)
1992	155	71,531	1,168	353,365
1993	154	71,106	1,151	350,808
1994	168	80,617	1,135	351,180
1995	177	84,260	1,133	350,780
1996	182	86,359	1,132	352,070
	Cooling Towers		**Total[2]**	
	Number of Generators	Capacity[1] (megawatts)	Number of Generators	Capacity[1] (megawatts)
1992	484	165,030	1,345	379,034
1993	486	164,807	1,330	376,831
1994	480	165,452	1,309	376,899
1995	471	165,012	1,295	375,408
1996	477	166,749	1,297	377,060

[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 1996 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, 1995 and 1996
(Thousand Short Tons)

Census Division State	1995			1996		
	Sulfur Dioxide	Nitrogen Oxides[1]	Carbon Dioxide[1]	Sulfur Dioxide	Nitrogen Oxides[1]	Carbon Dioxide[1]
New England	**164**	**71**	**31,063**	**185**	**72**	**31,958**
Connecticut	26	11	6,538	35	12	7,459
Maine	4	1	782	5	1	605
Massachusetts	89	47	18,917	101	47	19,270
New Hampshire	45	11	4,614	45	11	4,391
Rhode Island	—	—	—	—	—	—
Vermont	*	*	212	*	*	233
Middle Atlantic	**1,312**	**409**	**151,838**	**1,270**	**404**	**151,414**
New Jersey	37	32	7,252	42	32	6,940
New York	207	111	43,221	215	96	39,472
Pennsylvania	1,067	267	101,365	1,012	276	105,001
East North Central	**3,248**	**1,785**	**418,708**	**3,554**	**1,897**	**440,027**
Illinois	624	353	71,395	725	403	79,651
Indiana	900	501	114,544	855	516	116,564
Michigan	368	266	69,004	386	264	69,829
Ohio	1,172	493	122,046	1,397	530	130,483
Wisconsin	183	172	41,718	190	184	43,499
West North Central	**841**	**921**	**212,475**	**860**	**981**	**222,162**
Iowa	169	147	33,386	140	142	33,270
Kansas	71	129	31,574	102	154	35,806
Minnesota	81	150	34,577	84	152	35,013
Missouri	303	297	59,139	326	322	63,268
Nebraska	61	89	18,188	61	89	18,307
North Dakota	129	94	32,283	133	99	33,699
South Dakota	28	15	3,328	14	24	2,800
South Atlantic	**2,805**	**1,210**	**376,073**	**3,011**	**1,285**	**402,505**
Delaware	42	18	6,134	39	16	6,036
District of Columbia	1	*	189	1	*	122
Florida	572	330	94,039	630	338	97,333
Georgia	452	187	69,335	460	183	69,033
Maryland	214	83	28,872	235	85	29,334
North Carolina	340	171	54,275	412	194	63,421
South Carolina	204	82	26,518	228	93	30,636
Virginia	188	77	25,614	182	84	28,713
West Virginia	791	263	71,097	825	293	77,876
East South Central	**1,837**	**845**	**227,655**	**1,894**	**866**	**235,407**
Alabama	488	228	69,625	538	244	74,959
Kentucky	777	332	85,677	793	337	88,207
Mississippi	78	77	14,425	85	92	16,795
Tennessee	494	208	57,928	478	193	55,446
West South Central	**831**	**1,053**	**303,848**	**887**	**1,078**	**319,427**
Arkansas	74	83	26,063	80	91	29,117
Louisiana	171	163	42,568	298	144	40,145
Oklahoma	109	149	40,844	114	153	42,411
Texas	477	658	194,373	395	691	207,754
Mountain	**461**	**736**	**209,909**	**448**	**735**	**209,889**
Arizona	123	110	34,880	107	109	34,317
Colorado	96	131	33,278	94	137	35,063
Idaho	—	—	—	—	—	—
Montana	20	52	16,840	19	44	14,152
Nevada	51	62	18,899	52	66	19,809
New Mexico	59	119	30,444	61	119	30,396
Utah	28	95	31,648	28	90	31,488
Wyoming	84	166	43,921	86	171	44,663
Pacific Contiguous	**52**	**92**	**30,926**	**72**	**95**	**29,441**
California	1	56	22,126	1	47	18,141
Oregon	5	7	1,734	5	8	1,916
Washington	46	29	7,066	66	40	9,384
Pacific Noncontiguous	**21**	**13**	**5,175**	**21**	**12**	**5,137**
Alaska	1	3	495	1	2	381
Hawaii	20	10	4,681	20	10	4,756
U.S. Total	**11,571**	**7,135**	**1,967,669**	**12,202**	**7,426**	**2,047,368**

[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 1996 are preliminary; data for prior years are final. •Emissions of CO2, NOx, and SO2 have been revised from the updated (January 1996) Air Pollutant Emissions Factors (AP-42 5th release) 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, 1996
(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	**110**	**44**	**17,194**	**76**	**17**	**11,357**	*	**11**	**3,148**	*	*	**259**
Connecticut	10	5	2,433	25	6	4,523	*	1	493	*	*	10
Maine	0	0	0	5	1	605	0	0	0	0	0	0
Massachusetts	63	28	11,192	38	9	5,418	*	11	2,653	*	*	5
New Hampshire	37	10	3,569	8	1	809	0	*	*	*	*	13
Rhode Island	--	--	--	--	--	--	--	--	--	--	--	--
Vermont	0	0	0	*	*	2	0	*	1	*	*	230
Middle Atlantic	**1,220**	**365**	**129,720**	**50**	**19**	**12,401**	*	**21**	**9,235**	*	*	**58**
New Jersey	41	30	6,272	1	1	277	*	2	389	*	*	2
New York	175	64	21,285	39	14	9,711	*	18	8,464	0	*	12
Pennsylvania	1,003	271	102,163	9	4	2,413	*	1	382	*	*	44
East North Central	**3,544**	**1,887**	**435,651**	**10**	**3**	**2,017**	*	**7**	**2,063**	*	*	**296**
Illinois	720	397	77,396	5	1	795	*	5	1,460	0	0	0
Indiana	855	515	116,178	*	*	184	*	1	203	0	0	0
Michigan	382	262	68,836	4	2	798	*	1	195	*	*	*
Ohio	1,397	530	130,212	*	*	208	0	*	63	0	0	0
Wisconsin	189	183	43,028	*	*	33	*	1	143	*	*	296
West North Central	**857**	**972**	**218,897**	**1**	**1**	**357**	*	**8**	**1,798**	**1**	**1**	**1,109**
Iowa	140	141	32,968	*	*	26	*	1	187	*	*	89
Kansas	102	149	34,561	1	*	129	*	5	1,116	0	0	0
Minnesota	83	150	33,737	*	*	23	*	1	282	1	1	971
Missouri	325	321	63,026	1	*	97	*	*	144	*	*	1
Nebraska	60	89	18,233	*	*	6	0	*	68	0	*	*
North Dakota	133	98	33,628	*	*	70	0	0	*	0	0	0
South Dakota	14	24	2,745	*	*	6	0	*	2	*	*	48
South Atlantic	**2,807**	**1,195**	**367,854**	**204**	**45**	**22,604**	*	**45**	**11,905**	*	*	**143**
Delaware	34	13	4,671	5	2	1,046	*	1	316	*	*	4
District of Columbia	0	0	0	1	*	113	0	0	0	*	*	8
Florida	445	255	66,983	185	40	19,307	*	42	10,997	*	*	45
Georgia	459	183	68,757	1	*	109	*	*	154	*	*	13
Maryland	227	82	27,764	8	2	1,207	*	1	312	*	*	50
North Carolina	412	193	63,303	*	*	119	0	0	0	0	0	0
South Carolina	228	93	30,547	*	*	41	0	*	26	*	*	23
Virginia	178	83	28,125	4	1	510	0	*	78	0	0	0
West Virginia	825	293	77,703	*	*	151	0	*	22	0	0	0
East South Central	**1,890**	**849**	**230,634**	**3**	**3**	**1,174**	*	**14**	**3,536**	*	*	**63**
Alabama	538	243	74,711	*	*	78	*	*	130	*	*	41
Kentucky	793	337	88,077	*	*	94	0	*	36	0	*	*
Mississippi	82	76	12,488	3	2	915	*	14	3,370	*	*	22
Tennessee	478	192	55,359	*	*	87	0	0	0	0	0	0
West South Central	**884**	**788**	**235,557**	**3**	**1**	**826**	*	**289**	**83,041**	*	*	**3**
Arkansas	79	85	27,052	1	*	69	*	6	1,996	0	0	0
Louisiana	298	92	25,340	1	*	158	*	51	14,647	0	0	0
Oklahoma	114	126	35,354	*	*	73	*	27	6,984	0	0	0
Texas	393	485	147,811	1	1	526	*	204	59,414	*	*	3
Mountain	**448**	**719**	**205,236**	**1**	*	**341**	*	**16**	**4,312**	**0**	*	*
Arizona	107	106	33,600	*	*	51	*	2	666	0	0	0
Colorado	94	135	34,684	*	*	98	*	1	281	0	*	*
Idaho	--	--	--	--	--	--	--	--	--	--	--	--
Montana	19	43	14,134	*	*	11	0	*	7	0	*	*
Nevada	52	59	18,150	*	*	87	*	7	1,572	0	0	0
New Mexico	61	115	28,715	*	*	19	*	5	1,662	0	0	0
Utah	28	90	31,345	*	*	24	*	*	118	0	0	0
Wyoming	86	171	44,607	*	*	51	0	*	5	0	0	0
Pacific Contiguous	**71**	**48**	**10,671**	**1**	*	**498**	*	**46**	**17,651**	*	*	**621**
California	0	0	0	1	*	491	*	46	17,650	0	0	0
Oregon	5	8	1,913	*	*	3	0	0	0	0	0	0
Washington	66	40	8,758	*	*	4	0	*	*	*	*	621
Pacific Noncontiguous	**1**	**2**	**374**	**20**	**10**	**4,763**	**0**	**0**	**0**	**0**	**0**	**0**
Alaska	1	2	374	*	*	8	0	0	0	0	0	0
Hawaii	0	0	0	20	10	4,756	0	0	0	0	0	0
U.S. Total	**11,830**	**6,868**	**1,851,787**	**369**	**99**	**56,340**	**1**	**457**	**136,689**	**2**	**2**	**2,552**

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 1996 are preliminary. •Emissions of CO2, NOx, and SO2 have been revised from the updated (January 1996) Air Pollutant Emissions Factors (AP-42 5th release) 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, 1996

Census Division State	Generating Units[1]		Scrubbers		Particulate Collectors		Cooling Towers	
	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)
New England	**15**	**2,773**	**0**	**0**	**15**	**2,773**	**0**	**0**
Connecticut	1	400	0	0	1	400	0	0
Maine	0	0	0	0	0	0	0	0
Massachusetts	9	1,764	0	0	9	1,764	0	0
New Hampshire	5	609	0	0	5	609	0	0
Rhode Island	—	—	—	—	—	—	—	—
Vermont	0	0	0	0	0	0	0	0
Middle Atlantic	**83**	**24,070**	**14**	**7,048**	**83**	**24,070**	**16**	**11,366**
New Jersey	6	1,685	1	163	6	1,685	0	0
New York	25	3,721	3	978	25	3,721	0	0
Pennsylvania	52	18,664	10	5,907	52	18,664	16	11,366
East North Central	**291**	**81,309**	**26**	**12,609**	**291**	**81,309**	**41**	**20,489**
Illinois	55	17,123	4	1,439	55	17,123	2	562
Indiana	68	21,207	14	5,964	68	21,207	23	9,395
Michigan	49	12,124	0	0	49	12,124	2	199
Ohio	80	23,801	6	5,046	80	23,801	11	8,854
Wisconsin	39	7,053	2	160	39	7,053	3	1,479
West North Central	**137**	**35,742**	**24**	**10,692**	**137**	**35,742**	**38**	**11,770**
Iowa	29	5,691	1	176	29	5,691	6	1,681
Kansas	17	5,547	7	3,920	17	5,547	8	3,258
Minnesota	26	5,499	8	3,333	26	5,499	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	**217**	**71,037**	**23**	**11,988**	**217**	**71,037**	**66**	**37,648**
Delaware	6	1,034	0	0	6	1,034	1	442
District of Columbia	0	0	0	0	0	0	0	0
Florida	28	11,342	8	4,566	28	11,342	12	6,757
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	26	6,333	6	2,509	26	6,333	15	4,795
Virginia	26	5,397	2	848	26	5,397	5	1,561
West Virginia	33	14,958	6	3,942	33	14,958	13	9,822
East South Central	**132**	**40,471**	**29**	**12,295**	**132**	**40,471**	**28**	**12,893**
Alabama	39	12,586	4	1,597	39	12,586	4	2,599
Kentucky	54	15,956	21	7,698	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**	**59**	**33,690**	**32**	**17,262**
Arkansas	5	3,958	0	0	5	3,958	4	3,400
Louisiana	8	3,799	1	721	8	3,799	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**	**30,608**	**50**	**21,181**	**88**	**30,608**	**76**	**26,113**
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	4,351	10	4,351	10	4,351	5	2,081
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	**1,027**	**321,785**	**182**	**86,359**	**1,025**	**321,721**	**301**	**139,065**

[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, 1996

Census Division State	Generating Units[1]		Particulate Collectors		Cooling Towers	
	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)
New England	**25**	**6,369**	**24**	**5,954**	**1**	**415**
Connecticut	12	2,167	11	1,752	1	415
Maine	4	846	4	846	0	0
Massachusetts	8	2,942	8	2,942	0	0
New Hampshire	1	414	1	414	0	0
Rhode Island	—	—	—	—	—	—
Vermont	0	0	0	0	0	0
Middle Atlantic	**35**	**10,952**	**33**	**9,251**	**3**	**1,877**
New Jersey	7	952	7	952	1	176
New York	18	6,635	18	6,635	0	0
Pennsylvania	10	3,365	8	1,664	2	1,701
East North Central	**10**	**2,158**	**5**	**625**	**5**	**1,533**
Illinois	1	210	0	0	1	210
Indiana	2	92	0	0	2	92
Michigan	6	1,743	4	512	2	1,231
Ohio	1	114	1	114	0	0
Wisconsin	0	0	0	0	0	0
West North Central	**14**	**1,334**	**1**	**19**	**13**	**1,315**
Iowa	1	19	1	19	0	0
Kansas	10	1,255	0	0	10	1,255
Minnesota	0	0	0	0	0	0
Missouri	3	61	0	0	3	61
Nebraska	0	0	0	0	0	0
North Dakota	0	0	0	0	0	0
South Dakota	0	0	0	0	0	0
South Atlantic	**47**	**15,186**	**34**	**11,937**	**17**	**4,425**
Delaware	4	597	4	597	2	132
District of Columbia	2	580	0	0	2	580
Florida	31	9,975	22	8,625	9	1,351
Georgia	0	0	0	0	0	0
Maryland	6	2,131	4	813	3	1,480
North Carolina	0	0	0	0	0	0
South Carolina	0	0	0	0	0	0
Virginia	4	1,902	4	1,902	1	882
West Virginia	0	0	0	0	0	0
East South Central	**3**	**206**	**0**	**0**	**3**	**206**
Alabama	0	0	0	0	0	0
Kentucky	0	0	0	0	0	0
Mississippi	3	206	0	0	3	206
Tennessee	0	0	0	0	0	0
West South Central	**84**	**13,579**	**4**	**2,258**	**82**	**12,420**
Arkansas	2	183	0	0	2	183
Louisiana	12	2,308	2	1,184	11	1,716
Oklahoma	19	4,350	1	567	18	3,783
Texas	51	6,738	1	507	51	6,738
Mountain	**29**	**2,597**	**2**	**101**	**29**	**2,597**
Arizona	13	1,382	0	0	13	1,382
Colorado	3	111	2	101	3	111
Idaho	—	—	—	—	—	—
Montana	0	0	0	0	0	0
Nevada	1	53	0	0	1	53
New Mexico	9	800	0	0	9	800
Utah	3	252	0	0	3	252
Wyoming	0	0	0	0	0	0
Pacific Contiguous	**23**	**2,895**	**4**	**205**	**23**	**2,895**
California	23	2,895	4	205	23	2,895
Oregon	0	0	0	0	0	0
Washington	0	0	0	0	0	0
Pacific Noncontiguous	**0**	**0**	**0**	**0**	**0**	**0**
Alaska	0	0	0	0	0	0
Hawaii	0	0	0	0	0	0
U.S. Total	**270**	**55,275**	**107**	**30,349**	**176**	**27,684**

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, 1995 and 1996

Census Division State	Coal						Petroleum				Gas	
	1995			1996			1995		1996		1995	1996
	Average Btu per Pound	Sulfur Percent by Weight	Ash Percent by Weight	Average Btu per Pound	Sulfur Percent by Weight	Ash Percent by Weight	Average Btu per Gallon	Sulfur Percent by Weight	Average Btu per Gallon	Sulfur Percent by Weight	Average Btu per Cubic Foot	
New England	**12,742**	**0.85**	**7.3**	**12,632**	**0.86**	**7.9**	**151,271**	**1.02**	**152,037**	**1.06**	**1,023**	**1,033**
Connecticut	13,080	.56	7.0	13,016	.54	7.1	151,656	.85	152,681	.88	1,016	1,020
Maine	—	—	—	—	—	—	150,860	.76	150,991	1.23	—	—
Massachusetts	12,599	.72	7.7	12,453	.75	8.4	150,942	1.07	151,476	1.11	1,025	1,036
New Hampshire	12,953	1.43	6.6	12,952	1.45	6.8	152,111	1.49	153,015	1.59	1,017	1,020
Rhode Island	—	—	—	—	—	—	—	—	—	—	—	—
Vermont	—	—	—	—	—	—	137,900	.18	136,888	.12	998	1,013
Middle Atlantic	**12,244**	**1.97**	**11.2**	**12,210**	**1.98**	**11.1**	**149,387**	**.59**	**149,457**	**.64**	**1,027**	**1,030**
New Jersey	13,201	1.30	8.0	12,888	1.36	8.9	148,338	.45	148,828	.60	1,031	1,034
New York	12,888	1.74	8.2	12,868	1.72	8.2	149,514	.59	149,442	.65	1,027	1,029
Pennsylvania	12,065	2.05	12.0	12,040	2.07	11.8	149,280	.62	149,584	.61	1,030	1,030
East North Central	**10,646**	**1.33**	**8.2**	**10,550**	**1.35**	**8.0**	**144,648**	**.53**	**145,087**	**.76**	**1,018**	**1,019**
Illinois	9,899	1.18	7.1	9,797	1.19	7.2	147,812	.46	148,544	.99	1,018	1,019
Indiana	10,325	1.60	7.8	10,321	1.48	7.0	137,673	.33	137,498	.33	1,018	1,013
Michigan	10,603	.64	6.9	10,388	.65	6.9	145,048	.73	146,068	.78	1,018	1,023
Ohio	12,085	1.93	11.0	12,000	2.13	11.2	137,672	.28	137,713	.30	1,025	1,031
Wisconsin	9,331	.47	6.1	9,171	.46	5.7	139,834	.32	138,900	.39	1,006	1,007
West North Central	**8,351**	**.56**	**6.5**	**8,406**	**.54**	**6.9**	**140,860**	**.57**	**144,160**	**.69**	**992**	**986**
Iowa	8,672	.51	5.8	8,608	.44	5.8	137,468	.36	138,334	.32	1,006	1,003
Kansas	8,702	.45	5.6	8,760	.48	5.6	138,252	.29	146,996	.67	980	975
Minnesota	8,803	.51	6.7	8,877	.50	9.6	139,018	.33	138,558	.34	1,007	1,005
Missouri	9,071	.59	5.5	9,052	.60	5.5	145,350	1.03	148,021	1.19	1,004	1,008
Nebraska	8,532	.35	5.3	8,579	.34	5.1	138,945	.25	138,578	.23	993	1,006
North Dakota	6,579	.73	9.3	6,594	.71	9.2	139,978	.44	139,557	.41	1,074	1,057
South Dakota	6,901	.83	8.1	8,925	.54	6.9	139,020	.33	137,458	.21	1,003	1,021
South Atlantic	**12,074**	**1.26**	**9.7**	**12,048**	**1.26**	**9.7**	**151,284**	**1.35**	**151,486**	**1.43**	**1,014**	**1,013**
Delaware	12,830	1.09	8.5	12,801	.99	8.7	151,116	.84	150,288	.78	1,035	1,036
District of Columbia	—	—	—	—	—	—	143,291	.87	143,557	.80	—	—
Florida	12,187	1.47	8.1	12,099	1.54	8.1	151,778	1.43	152,055	1.53	1,011	1,010
Georgia	11,544	.82	8.9	11,541	.84	8.9	144,591	1.61	142,996	1.22	1,024	1,024
Maryland	12,944	1.06	9.6	12,870	1.14	9.5	150,999	1.18	150,516	1.02	1,039	1,041
North Carolina	12,430	.84	10.2	12,389	.86	10.0	138,942	.20	139,334	.20	—	—
South Carolina	12,763	1.19	8.6	12,705	1.19	8.9	138,117	.25	139,976	.22	1,024	1,021
Virginia	12,728	1.02	10.1	12,578	.97	10.6	149,880	.92	147,486	1.10	1,039	1,165
West Virginia	11,463	1.98	12.0	11,475	1.90	11.9	139,004	.33	138,910	.34	1,000	1,000
East South Central	**11,863**	**1.74**	**9.9**	**11,770**	**1.74**	**9.9**	**138,669**	**.30**	**150,297**	**.47**	**1,032**	**1,026**
Alabama	11,773	1.18	10.8	11,754	1.21	10.7	138,253	.29	138,887	.30	1,022	1,036
Kentucky	11,817	2.13	10.2	11,745	2.22	10.4	138,949	.26	138,746	.33	1,022	1,022
Mississippi	11,151	1.05	7.9	10,969	.87	6.8	141,391	.86	154,130	.53	1,032	1,026
Tennessee	12,173	1.98	8.8	12,025	1.93	9.0	138,365	.28	138,209	.26	—	—
West South Central	**7,626**	**.66**	**9.7**	**7,746**	**.39**	**7.9**	**139,326**	**.47**	**143,374**	**.54**	**1,029**	**1,025**
Arkansas	8,545	.31	4.9	8,616	.30	4.5	138,111	.65	146,261	1.48	1,023	1,025
Louisiana	7,888	.64	7.8	7,954	.58	7.3	138,829	.41	145,264	.57	1,044	1,039
Oklahoma	8,544	.38	5.3	8,589	.37	5.2	141,980	.91	141,755	.95	1,038	1,030
Texas	7,258	.77	11.6	7,407	.39	9.0	138,927	.33	142,704	.35	1,023	1,021
Mountain	**9,794**	**.55**	**11.2**	**9,794**	**.55**	**11.3**	**139,312**	**.29**	**141,069**	**.39**	**1,026**	**1,016**
Arizona	10,325	.53	12.1	10,224	.54	12.4	140,279	.34	141,919	.36	1,023	1,015
Colorado	9,869	.40	7.1	9,955	.39	7.0	138,253	.33	137,586	.37	986	984
Idaho	—	—	—	—	—	—	—	—	—	—	—	—
Montana	8,487	.68	9.3	8,467	.68	9.0	141,000	.50	141,000	.50	1,073	1,078
Nevada	11,934	.48	9.7	11,896	.49	9.9	144,160	.49	148,669	.69	1,030	1,027
New Mexico	9,154	.77	21.6	9,119	.80	22.7	134,785	.10	134,769	.10	1,021	1,011
Utah	11,622	.48	10.6	11,586	.48	10.9	138,168	.21	138,281	.20	1,055	1,021
Wyoming	8,664	.51	8.2	8,639	.54	8.0	139,052	.18	139,262	.18	1,043	1,040
Pacific Contiguous	**8,218**	**.59**	**11.6**	**7,856**	**.62**	**13.8**	**146,891**	**.50**	**144,475**	**.41**	**1,025**	**1,025**
California	—	—	—	—	—	—	147,127	.51	144,557	.41	1,025	1,025
Oregon	8,831	.29	5.4	8,708	.27	4.7	138,800	.50	138,800	.50	—	—
Washington	8,074	.66	13.1	7,694	.68	15.5	139,900	.12	139,957	.11	1,036	1,035
Pacific Noncontiguous	**7,759**	**.18**	**10.0**	**7,795**	**.20**	**10.1**	**148,994**	**.69**	**148,891**	**.68**	**—**	**—**
Alaska	7,759	.18	10.0	7,795	.20	10.1	137,600	.29	138,128	.28	—	—
Hawaii	—	—	—	—	—	—	148,999	.69	148,911	.68	—	—
U.S. Average	**10,203**	**1.08**	**9.2**	**10,191**	**1.05**	**8.9**	**150,087**	**1.00**	**150,356**	**1.04**	**1,026**	**1,024**

Notes: •Data for 1996 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, 1992 Through 1996

Census Division State	Average O&M Costs (mills per kilowatthour)					Average Installed Costs (dollars per kilowatt)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
New England	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Connecticut	—	—	—	—	—	—	—	—	—	—
Maine	—	—	—	—	—	—	—	—	—	—
Massachusetts	—	—	—	—	—	—	—	—	—	—
New Hampshire	—	—	—	—	—	—	—	—	—	—
Rhode Island	—	—	—	—	—	—	—	—	—	—
Vermont	—	—	—	—	—	—	—	—	—	—
Middle Atlantic	**4.91**	**3.96**	**2.68**	**3.02**	**2.25**	**183**	**184**	**184**	**184**	**183**
New Jersey	NM	NM	NM	3.36	3.66	398	398	398	398	398
New York	1.03	1.09	1.03	1.18	1.33	319	331	331	331	331
Pennsylvania	6.04	4.65	2.96	3.40	2.38	157	157	157	158	156
East North Central	**1.83**	**1.90**	**2.05**	**1.79**	**1.84**	**147**	**130**	**127**	**128**	**129**
Illinois	2.47	2.52	2.71	2.51	2.28	197	147	147	147	147
Indiana	1.58	1.58	1.53	1.52	1.68	149	143	142	144	145
Michigan	—	—	—	—	—	—	—	—	—	—
Ohio	2.06	2.25	2.92	1.93	1.92	83	83	88	88	90
Wisconsin	—	—	2.86	2.08	2.13	—	—	16	16	16
West North Central	**.75**	**.66**	**.60**	**.58**	**.53**	**83**	**84**	**84**	**78**	**78**
Iowa	2.42	1.87	1.53	1.56	1.37	202	202	202	202	202
Kansas	.66	.49	.46	.49	.35	72	72	73	61	61
Minnesota	.40	.43	.39	.37	.39	73	73	73	73	73
Missouri	2.12	1.86	1.35	1.20	1.36	87	87	87	50	50
Nebraska	—	—	—	—	—	—	—	—	—	—
North Dakota	.74	.81	.79	.74	.72	101	102	102	102	102
South Dakota	—	—	—	—	—	—	—	—	—	—
South Atlantic	**1.28**	**.98**	**1.16**	**.95**	**.91**	**143**	**119**	**115**	**120**	**120**
Delaware[1]	NM	—	—	—	—	1,385	—	—	—	—
District of Columbia	—	—	—	—	—	—	—	—	—	—
Florida	1.15	.78	1.01	.87	.96	69	69	67	73	73
Georgia	—	—	—	5.13	4.82	—	—	—	NM	NM
Maryland	—	—	—	—	—	—	—	—	—	—
North Carolina	—	—	—	—	—	—	—	—	—	—
South Carolina	.64	.59	.60	.48	.59	43	43	43	43	43
Virginia	—	—	—	—	.20	—	—	—	—	NM
West Virginia	2.23	2.09	2.33	1.44	1.35	260	217	209	216	216
East South Central	**1.65**	**1.45**	**1.06**	**1.05**	**1.09**	**140**	**137**	**143**	**143**	**143**
Alabama	1.00	.69	.82	.57	.62	80	80	80	80	80
Kentucky	1.91	1.76	1.60	1.58	1.50	135	132	140	140	140
Mississippi	.30	.27	.27	.35	.50	70	70	70	70	70
Tennessee	NM	NM	.05	.36	.37	202	196	204	204	204
West South Central	**1.22**	**1.01**	**1.08**	**.91**	**.82**	**73**	**74**	**76**	**71**	**83**
Arkansas	—	—	—	—	—	—	—	—	—	—
Louisiana	NM	NM	NM	NM	NM	75	75	75	75	75
Oklahoma	.55	.54	.50	.59	1.14	92	92	92	92	92
Texas	1.26	1.03	1.11	.93	.81	72	72	75	70	83
Mountain	**.69**	**.68**	**.73**	**.79**	**.70**	**148**	**146**	**150**	**150**	**149**
Arizona	.68	.42	.77	.88	.72	175	160	175	175	175
Colorado	.57	.67	.52	.85	.60	69	69	69	69	69
Idaho	—	—	—	—	—	—	—	—	—	—
Montana	.90	1.10	1.11	1.14	.92	274	274	274	274	274
Nevada	.93	.99	.74	1.57	1.07	126	126	126	126	126
New Mexico	1.03	1.07	1.07	1.03	.92	165	165	165	165	162
Utah	.48	.37	.41	.47	.52	97	97	101	101	101
Wyoming	.55	.54	.62	.61	.62	137	137	137	137	137
Pacific Contiguous	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
California	—	—	—	—	—	—	—	—	—	—
Oregon	—	—	—	—	—	—	—	—	—	—
Washington	—	—	—	—	—	—	—	—	—	—
Pacific Noncontiguous	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Alaska	—	—	—	—	—	—	—	—	—	—
Hawaii	—	—	—	—	—	—	—	—	—	—
U.S. Average	**1.32**	**1.19**	**1.14**	**1.16**	**1.07**	**132**	**125**	**127**	**126**	**128**

[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 1996 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 1996

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	80.0
Cholla 2	–	289	7806	1.20	Venturi	Lime	90.0
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
Atlantic City Electric Co							
B L England 2	476	163	9501	3.20	Spray	Limestone	93.0
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 R Station 1	1,710	570	8007	.80	Spray	Limestone	90.0
Laramie R Station 2	–	570	8107	.80	Spray	Limestone	90.0
Laramie R Station 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
HMP&L Station 2 H1	365	180	9506	4.20	Tray	Lime	95.0
HMP&L Station 2 H2	–	185	9506	4.20	Tray	Lime	95.0
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
Black Hills Corp							
Neil Simpson II 2	–	–	9511	.90	Circulating Dry	Lime	92.0
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

See footnotes at end of table.

Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1996 (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)
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
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							
Frank E Ratts 1FGD	1,080	540	8309	3.00	Spray	Limestone	90.0
Frank E Ratts 2FGD	–	540	8202	3.00	Spray	Limestone	90.0
Houston Lighting & Power Co							
Limestone FGD1	1,627	813	8510	3.10	Spray	Limestone	90.0
Limestone FGD2	–	813	8610	3.10	Spray	Limestone	90.0
W A Parish FGD8	3,953	615	8212	.50	Spray	Limestone	85.0
Indianapolis Power & Light Co							
Petersburg 1	1,873	253	9605	4.50	Spray	Limestone	95.0
Petersburg 2	–	471	9605	4.50	Spray	Limestone	95.0
Petersburg 3	–	574	7711	–	Tray	Limestone	85.0
Petersburg 4	–	574	8604	–	Spray	Limestone	95.0
Jacksonville Electric Auth							
St. Johns River Powe 1	1,358	679	8703	2.20	Spray	Limestone	90.0
St. Johns River Powe 2	–	679	8805	2.20	Spray	Limestone	90.0
Kansas City Power & Light Co							
Lacygne 1	1,579	893	7306	5.40	Venturi	Limestone	80.0
Kentucky Utilities Co							
Ghent 1	2,226	557	9412	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	.60	Spray	Limestone	90.0
Intermountain 2CCC	–	820	8707	.60	Spray	Limestone	90.0
Louisville Gas & Electric Co							
Cane Run 4	792	163	7612	3.50	Spray	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							
Fayette Power Prjc 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

See footnotes at end of table.

Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1996 (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)
Minnesota Power & Light Co							
Clay Boswell AQCS2	1,073	558	8004	1.00	Spray	Alkaline Fly Ash	83.2
Clay Boswell SCR3	–	365	7302	1.00	Spray	Alkaline Fly Ash	25.4
Syl Laskin SCR1	116	58	7105	1.00	Spray	Alkaline Fly Ash	–
Syl Laskin SCR2	–	58	7105	1.00	Spray	Alkaline Fly Ash	–
Minnkota Power Coop Inc							
Milton R Young FGD2	734	477	7806	1.20	Spray	Lime/Alkaline Fly Ash	77.9
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 Plant 1 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
Milliken 1	322	155	9506	3.20	Spray	Limestone	95.0
Milliken 2	–	167	9501	3.20	Spray	Limestone	95.0
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 CO 1	2,129	660	7605	.90	Venturi	Limestone/Alk Fly Ash	50.0
Sherburne CO 2	–	660	7704	.90	Spray	Limestone/Alk Fly Ash	50.0
Sherburne CO 3	–	809	8711	.90	Spray Dry	Lime/Alkaline Fly Ash	72.3
Ohio Edison Co							
Niles 1	266	266	9510	3.00	Spray	Limestone	90.0
Ohio Power Co							
Gen J M Gavin 1	2,600	1,300	9412	3.50	Spray	Lime	95.0
Gen J M Gavin 2	–	1,300	9503	3.50	Spray	Lime	95.0
Orlando Utilities Comm							
Stanton Energy Cente 1	929	465	8707	3.50	Spray	Limestone	90.0
Stanton Energy Cente 2	–	465	9606	3.40	Spray	Limestone	95.0
Owensboro City of							
Elmer Smith FGD	416	416	9411	3.50	Spray	Limestone	96.0

See footnotes at end of table.

Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1996 (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)
PacifiCorp							
Dave Johnston SC44	817	360	7202	0.40	Venturi	Lime	–
Hunter 1	1,339	446	7806	.60	Spray	Lime	80.0
Hunter 2	–	446	8006	.60	Spray	Lime	80.0
Hunter 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	2.70	Spray	Limestone	95.0
Conemaugh 2	–	936	9511	2.70	Spray	Limestone	95.0
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							
Pegs 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	1,848	369	7804	1.30	Tray	Other	90.0
San Juan 2	–	369	7808	1.30	Tray	Other	90.0
San Juan 3	–	555	8203	1.30	Tray	Other	90.0
San Juan 4	–	555	8204	1.30	Tray	Other	90.0
PSI Energy Inc							
Tibson 4	3,340	668	9501	3.50	Spray	Limestone	92.0
Tibson 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	90.0
Seminole 2	–	715	8412	3.00	Spray	Limestone	90.0
Sierra Pacific Power Co							
Valmy 2	521	267	8507	.50	Spray Dry	Lime	70.0

See footnotes at end of table.

Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1996 (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)
Sikeston City of							
Sikeston 1	261	261	8111	2.80	Venturi	Limestone	75.5
South Carolina Electric&Gas Co							
Cope COP1	417	417	9511	1.90	Spray Dry	Lime	95.0
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
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 Power ST 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	.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

See footnotes at end of table.

Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1996 (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					
Tucson Electric Power Co							
Springerville 1	850	425	8506	0.70	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 Station 10	172	172	8206	.70	Spray Dry	Lime	70.0
Virginia Electric & Power Co							
Clover 1	848	424	9510	2.00	Spray	Limestone	90.0
Clover 2	–	424	9606	2.00	Spray	Limestone	90.0
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 EC 1	2,160	720	7807	.30	Spray	Limestone	60.0
Jeffrey EC 2	–	720	8005	.30	Spray	Limestone	60.0
Jeffrey EC 3	–	720	8305	.30	Spray	Limestone	60.0
Lawrence EC 4N	604	114	6906	.90	Venturi	Limestone	73.0
Lawrence EC 4S	–	114	6906	.90	Venturi	Limestone	73.0
Lawrence EC 5	–	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.[13] 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 having control and security responsibilities. Historically, the dispatch center inventoried and prioritized all generating capacity available to it, tracked transactions involving the buying or selling of either electric power or capacity, monitored current load, and anticipated future load on the system. In the future, this responsibility may be handled differently. How, is now being determined by participants in the new electric power industry.

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. In the near future, a competitive power market will address this allocation of resources through the open buying and selling of electricity and the independent pricing of system operating costs which were bundled into the total charges for electricity.

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 or power marketer to other electric utilities for distribution. (Direct interstate wholesale sales to retail customers by power marketers are not authorized.) 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 have extended over several years. The use of exchange transactions is disappearing. Spot and futures markets will eventually replace this type of transaction. Wheeling transactions are the movement of electricity from one utility to another utility over the transmission facilities of one or more intervening utilities.

[13] 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 Utility Transactions

Electric power transactions *(wholesale electricity trade)* allowed electric utilities to acquire power, to share resources, and to provide mutual assistance in times of potential and actual need. They allowed the utility systems to provide lower cost service to their consumers by taking advantage of the load diversity of each utility. These transactions also allowed 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. Competitive markets (spot and futures) are expected to be substituted as the electric utility industry continues to change from a monopoly based structure. 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 is expected to be inconsistent in the future as well.

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. Now, opportunities are developing for price based decisions.

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. The future of this type of agreement will hinge on the full implementation of the Federal Energy Regulatory Commission (FERC) Orders that directed changes be made to these agreements.

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. They 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. In the future, if the concept of an independent system operator takes hold, many power pools may reinvent themselves and operate under a new structure of rules.

NERC Profile

The North American Electric Reliability Council (NERC) consists of 9 regional reliability councils whose memberships comprise essentially all of the electric utility systems in the contiguous United States, Canada, and Baja California Norte, Mexico. Part of the State of Alaska operates together and is an affiliate member; sometimes referenced as the tenth council. 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 13).

Regulation of U.S. Electric Utility Transactions

The Federal Energy Regulatory Commission (FERC) is responsible for regulating interstate wholesale transactions. U.S. electric utilities and potential power marketers (registration and rate structure) file with the FERC for approval of proposed rate schedules for transmission services and charges, and for wholesale transactions. Historically, transmission filings covered 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. The issue of who will build new transmission lines in the future is uncertain. Changing responsibilities in the electric power industry may make it difficult to justify new construction in one State that address requirements for new transmission capability or reliability support coming from another State.

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 change the cost of the output of some existing plants, alter construction approaches to new facilities, cause changes to the fuel use of other power plants, and cause an reexamination by powerplant operators of what can be done to reduce emissions. 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 are going to be altered by changing practices in the new electric power industry. Cost issues will change to one of price. Availability of electrical energy will change to issues concerning more effective capacity utilization and that may mean more use of high emission source generators.

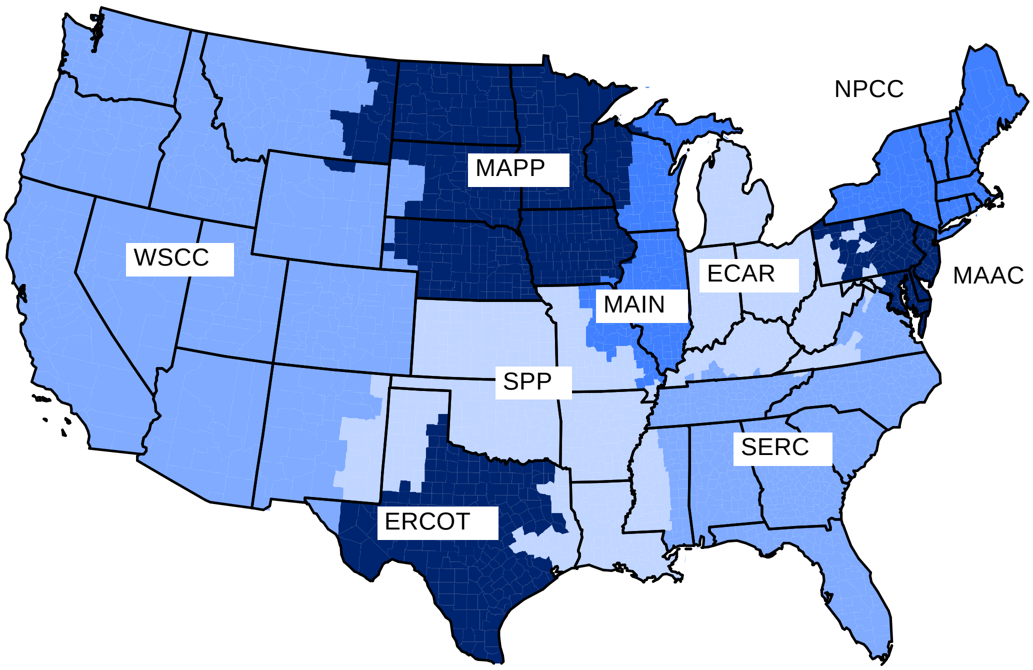
International Transactions

U.S. electric utilities and power marketers have taken advantage of being able to enter into international trade agreements to acquire energy from Canada and Mexico. These trade agreements between Canadian utilities and U.S. participants in the electric power industry 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 contracted requirements for supply; the holding of purchased electricity (as reservoir water) to be reacquired when needed; and sharing the benefits of coordinated operations planning for the electrical 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

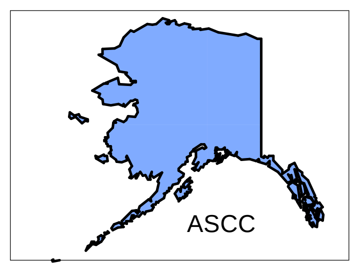
Statistics on electricity transactions among U.S. electric utilities and on international electricity trade (including the United States, Canada, and Mexico) are presented in the following tables. These data were obtained from the Form EIA-861, "The Annual Electric Utility Report"; the Form EIA-860,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

Figure 13. North American Electric Reliability Council Regions for the Contiguous United States and Alaska



NERC Regional Councils

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



Note: The Alaska Systems Coordinating Council (ASCC) is an affiliate NERC member.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

Source: North American Electric Reliability Council.

Table 31. Sources and Disposition of Electricity at U.S. Electric Utilities, 1992 Through 1996
(Million Kilowatthours)

Item	1992	1993	1994	1995	1996
Source					
Net Generation	2,805,092	2,897,815	2,924,961	3,002,304	3,099,945
Purchases from Utilities	1,146,323	1,218,882	1,226,814	1,284,995	1,465,174
Purchases from Nonutilities	166,283	188,537	208,778	222,092	229,018
Net Exchange	–3,504	–2,725	–3,659	66	–11,677
Net Wheeling	5,756	4,668	4,225	7,016	7,324
Disposition					
Sales to Ultimate Consumers	2,763,365	2,861,462	2,934,563	3,013,287	3,097,810
Requirements and Nonrequirements Sales for Resale	1,119,948	1,200,047	1,185,352	1,255,618	1,431,179
Energy Furnished Without Charge	4,409	5,003	4,762	5,362	6,205
Energy Used by Utility Electric Department	15,651	14,245	15,495	12,455	13,886
Energy Losses[1]	216,592	226,415	220,948	228,076	238,695

[1] 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 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, 1992 Through 1996
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1992	1993	1994	1995	1996
ECAR	483,530	494,602	492,074	509,468	528,214
ERCOT	190,442	198,187	204,256	210,596	218,497
MAAC	193,330	205,552	206,221	203,801	200,669
MAIN	200,288	217,284	221,770	229,424	231,315
MAPP(U.S.)	120,053	124,808	124,607	130,637	132,689
NPCC(U.S.)	202,978	195,140	189,546	183,021	185,521
SERC	637,803	667,464	678,423	703,899	740,784
SPP	242,514	256,901	260,025	274,475	276,205
WSCC(U.S.)	522,863	527,428	537,399	546,208	574,878
Contiguous U.S.	**2,793,801**	**2,887,366**	**2,914,320**	**2,991,529**	**3,088,772**
ASCC	4,735	4,660	4,913	4,925	5,178
Hawaii	6,555	5,790	5,728	5,851	5,994
U.S. Total	**2,805,092**	**2,897,815**	**2,924,961**	**3,002,304**	**3,099,945**

Notes: •Data 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, 1992 Through 1996

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	All Sectors	Residential	Commercial	Industrial	Other[1]
	1992				
ECAR	429,591	129,847	97,007	192,916	9,820
ERCOT	203,206	71,802	53,342	69,306	8,755
MAAC	210,799	72,221	65,971	69,797	2,810
MAIN	200,571	56,685	54,013	81,314	8,558
MAPP(U.S.)	117,283	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**
	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	249,891	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	459,747	139,521	111,731	198,793	9,701
ERCOT	218,781	78,708	57,209	73,248	9,615
MAAC	223,635	78,264	75,475	66,999	2,897
MAIN	214,304	62,094	60,086	83,056	9,068
MAPP(U.S.)	128,935	45,372	28,015	51,776	3,771
NPCC(U.S.)	238,679	79,177	89,591	55,255	14,656
SERC	656,478	261,240	164,290	212,424	18,524
SPP	257,183	62,962	65,485	94,302	8,488
WSCC(U.S.)	523,696	171,081	163,782	167,957	20,876
Contiguous U.S.	**2,921,437**	**1,004,366**	**815,664**	**1,003,811**	**97,596**
ASCC	4,533	1,688	2,155	511	179
Hawaii	8,593	2,428	2,451	3,659	56
U.S. Total	**2,934,563**	**1,008,482**	**820,269**	**1,007,981**	**97,830**

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, 1992 Through 1996 (Continued)

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	All Sectors	Residential	Commercial	Industrial	Other[1]
			1995		
ECAR	477,126	147,019	116,092	204,072	9,942
ERCOT	222,465	81,158	59,065	72,542	9,700
MAAC	227,532	79,483	86,687	58,440	2,922
MAIN	218,728	66,039	62,774	80,711	9,204
MAPP(U.S.)	134,495	47,489	29,530	53,636	3,840
NPCC(U.S.)	238,492	78,615	94,185	51,661	14,031
SERC	686,458	273,502	172,424	221,297	19,234
SPP	266,912	93,533	67,399	97,392	8,588
WSCC(U.S.)	527,641	171,479	169,704	168,739	17,719
Contiguous U.S.	**2,999,849**	**1,038,317**	**857,860**	**1,008,492**	**95,179**
ASCC	4,631	1,713	2,200	546	172
Hawaii	8,806	2,471	2,625	3,655	55
U.S. Total	**3,013,287**	**1,042,501**	**862,685**	**1,012,693**	**95,407**
			1996		
ECAR	483,750	149,381	117,924	206,397	10,048
ERCOT	235,780	87,324	60,959	77,113	10,383
MAAC	229,013	81,141	87,597	57,336	2,939
MAIN	219,978	66,015	63,919	80,655	9,390
MAPP(U.S.)	137,767	48,099	30,233	55,600	3,835
NPCC(U.S.)	241,258	79,650	95,532	52,236	13,840
SERC	714,441	288,556	178,815	227,381	19,689
SPP	277,115	96,689	70,230	101,332	8,864
WSCC(U.S.)	544,937	181,329	177,304	167,988	18,316
Contiguous U.S.	**3,084,040**	**1,078,184**	**882,513**	**1,026,039**	**97,304**
ASCC	4,779	1,766	2,250	584	179
Hawaii	8,991	2,540	2,662	3,733	55
U.S. Total	**3,097,810**	**1,082,491**	**887,425**	**1,030,356**	**97,539**

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

Notes: •Data 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, 1992 Through 1996

(Megawatts)

North American Electric Reliability Council Region and Hawaii	1992	1993	1994	1995	1996
ECAR	104,591	104,748	104,553	104,426	105,001
ERCOT	51,688	52,889	52,948	53,400	53,718
MAAC	51,553	51,589	51,494	52,083	51,908
MAIN	49,730	50,314	50,862	51,430	51,728
MAPP(U.S.)	30,964	30,906	31,357	31,311	31,419
NPCC(U.S.)	54,637	56,043	55,956	55,567	61,586
SERC	147,747	148,686	150,214	153,434	149,037
SPP	70,771	70,998	71,085	71,375	71,778
WSCC(U.S.)	129,501	129,110	128,794	129,751	130,760
Contiguous U.S.	**691,182**	**695,283**	**697,262**	**702,778**	**706,935**
ASCC	1,670	1,711	1,737	1,732	1,734
Hawaii	1,560	1,602	1,602	1,602	1,610
U.S. Total	**694,412**	**698,595**	**700,601**	**706,111**	**710,279**

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 Actual and Projected, by North American Electric Reliability Council Region and Hawaii, 1992 Through 2005

(Megawatts)

North American Electric Reliability Council Region and Hawaii	Actual				
	1992	1993	1994	1995	1996
	Summer				
ECAR	78,550	85,930	87,165	92,619	90,798
ERCOT	42,619	44,255	44,162	46,618	47,480
MAAC	43,658	46,494	46,019	48,577	44,302
MAIN	38,819	41,956	42,562	45,782	46,402
MAPP(U.S.)	22,638	24,396	27,000	29,192	28,253
NPCC(U.S.)	43,658	46,706	47,581	47,705	45,094
SERC	128,236	136,101	132,584	146,569	145,650
SPP	51,324	57,106	56,035	59,595	60,072
WSCC(U.S.)	99,205	97,809	102,212	103,592	108,739
Contiguous U.S.	**548,707**	**580,753**	**585,320**	**620,249**	**616,790**
ASCC	504	511	524	622	NA
Hawaii	(1)	(1)	(1)	(1)	(1)
U.S. Total	**549,211**	**581,264**	**585,844**	**620,871**	**616,790**
	Winter				
ECAR	72,885	81,846	75,638	83,465	84,534
ERCOT	35,055	35,407	36,180	36,965	38,868
MAAC	37,915	41,406	40,653	40,790	37,806
MAIN	31,289	34,966	33,999	35,734	37,162
MAPP(U.S.)	21,866	21,955	23,033	23,429	24,251
NPCC(U.S.)	41,125	42,063	42,547	42,755	41,200
SERC	121,250	133,635	132,661	142,032	146,030
SPP	39,912	41,644	42,505	44,626	49,095
WSCC(U.S.)	91,686	88,811	91,037	94,890	95,135
Contiguous U.S.	**492,983**	**521,733**	**518,253**	**544,684**	**554,081**
ASCC	635	632	641	676	NA
Hawaii	(1)	(1)	(1)	(1)	(1)
U.S. Total	**493,618**	**522,365**	**518,894**	**545,360**	**554,081**

See footnotes at end of table.

Table 35. Noncoincidental Peak Load, Actual and Projected, by North American Electric Reliability Council Region and Hawaii, 1992 Through 2005 (Continued)

(Megawatts)

North American Electric Reliability Council Region and Hawaii	Projected				
	1997	1998	1999	2000	2005
	Summer				
ECAR	91,573	93,219	96,073	99,191	104,440
ERCOT	48,277	48,649	49,308	50,373	55,391
MAAC	47,867	48,565	49,306	49,977	53,644
MAIN	45,292	47,868	48,597	49,404	53,056
MAPP(U.S.)	29,199	29,836	30,228	30,917	33,711
NPCC(U.S.)	48,950	49,690	50,247	50,795	53,197
SERC	150,640	154,921	158,291	162,447	179,108
SPP	61,826	62,808	63,183	64,365	70,093
WSCC(U.S.)	105,731	107,612	109,660	111,175	121,668
Contiguous U.S.	**631,355**	**643,168**	**653,595**	**665,526**	**724,308**
ASCC	(2)	(2)	(2)	(2)	(2)
Hawaii	(1)	(1)	(1)	(1)	(1)
U.S. Total	**631,355**	**643,168**	**653,595**	**665,526**	**724,308**
	Winter				
ECAR	83,520	84,721	85,764	87,170	94,326
ERCOT	39,635	40,011	41,097	42,278	47,522
MAAC	42,496	43,203	43,848	44,489	47,902
MAIN	36,950	37,467	38,209	38,788	41,725
MAPP(U.S.)	24,693	25,120	25,595	25,973	28,338
NPCC(U.S.)	43,900	44,551	45,099	45,694	47,969
SERC	145,957	150,088	153,790	157,505	174,442
SPP	45,618	46,759	47,281	47,516	52,141
WSCC(U.S.)	97,459	99,369	100,892	102,299	112,177
Contiguous U.S.	**560,228**	**571,289**	**581,575**	**591,712**	**646,542**
ASCC	(2)	(2)	(2)	(2)	(2)
Hawaii	(1)	(1)	(1)	(1)	(1)
U.S. Total	**560,228**	**571,289**	**581,575**	**591,712**	**646,542**

(1) Data for Hawaii are not submitted on this form.
(2) Data for ASCC (Alaska) was not filed for 1997.
Notes: •Data are final. •Totals may not equal sum of components because of independent rounding.
Sources: **Data for 1996 and beyond:** Form EIA-411, *''Coordinated Bulk Power Supply Programs''*; **Data for prior years:** Department of Emergency Policy, Form OE-411, *''Coordinated Regional Bulk Power Supply Program.''*

Table 36. U.S. Electric Utility Receipts by North American Electric Reliability Council Region and Hawaii, 1992 Through 1996

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Receipts[1]	Purchased Power	Exchange Received	Wheeling Received
		1992		
ECAR	190,220	155,564	2,853	31,803
ERCOT	130,049	59,661	46,311	24,077
MAAC	92,676	71,675	11,134	9,868
MAIN	55,810	52,108	213	3,489
MAPP(U.S.)	125,334	81,610	32,062	11,661
NPCC(U.S.)	227,570	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**
		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	199,000	166,157	1,982	30,861
ERCOT	141,092	61,901	55,122	24,069
MAAC	94,910	79,907	3,214	11,789
MAIN	66,538	61,159	502	4,877
MAPP(U.S.)	109,057	87,606	2,414	19,038
NPCC(U.S.)	267,351	194,510	3,957	68,883
SERC	397,661	340,918	31,609	25,134
SPP	172,119	142,619	5,955	23,545
WSCC(U.S.)	472,025	294,190	49,919	127,915
Contiguous U.S.	**1,919,751**	**1,428,966**	**154,675**	**336,111**
ASCC	3,952	3,184	73	695
Hawaii	3,444	3,442	3	0
U.S. Total	**1,927,147**	**1,435,591**	**154,750**	**336,805**

See footnotes at end of table.

Table 36. U.S. Electric Utility Receipts by North American Electric Reliability Council Region and Hawaii, 1992 Through 1996 (Continued)

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Receipts[1]	Purchased Power	Exchange Received	Wheeling Received
	1995			
ECAR	223,966	188,679	2,158	33,128
ERCOT	145,430	61,215	50,420	33,795
MAAC	114,216	98,773	528	14,915
MAIN	67,367	60,707	389	6,270
MAPP(U.S.)	112,956	92,315	2,826	17,816
NPCC(U.S.)	262,947	199,059	3,998	59,890
SERC	426,796	354,477	41,550	30,769
SPP	176,109	147,082	5,525	23,502
WSCC(U.S.)	484,202	297,960	51,633	134,610
Contiguous U.S.	**2,013,988**	**1,500,268**	**159,026**	**354,694**
ASCC	4,217	3,301	137	779
Hawaii	3,522	3,518	4	0
U.S. Total	**2,021,728**	**1,507,087**	**159,167**	**355,473**
	1996			
ECAR	264,825	203,637	1,361	59,827
ERCOT	148,971	73,590	55,354	20,027
MAAC	141,448	120,701	474	20,272
MAIN	75,234	67,287	252	7,695
MAPP(U.S.)	124,893	102,960	4,189	17,744
NPCC(U.S.)	276,773	209,271	3,799	63,703
SERC	454,193	384,930	31,998	37,264
SPP	198,090	166,768	5,340	25,982
WSCC(U.S.)	574,451	358,142	51,859	164,449
Contiguous U.S.	**2,258,877**	**1,687,286**	**154,627**	**416,964**
ASCC	4,257	3,338	99	820
Hawaii	3,572	3,568	4	0
U.S. Total	**2,266,707**	**1,694,192**	**154,731**	**417,784**

1 Equals purchased power plus exchange received plus wheeling received and imports.

Notes: •Data 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, 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, 1992 Through 1996

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Deliveries[1]	Requirements and Nonrequirements Sales for Resale	Exchange Delivered	Wheeling Delivered
	1992			
ECAR	212,729	178,224	2,887	31,618
ERCOT	102,966	32,299	46,577	24,090
MAAC	59,416	48,364	1,272	9,779
MAIN	40,706	37,240	62	3,404
MAPP(U.S.)	116,200	71,447	33,906	10,847
NPCC(U.S.)	178,603	116,451	1,657	60,495
SERC	357,147	300,686	31,053	25,408
SPP	137,540	109,595	6,306	21,639
WSCC(U.S.)	431,563	223,114	83,426	125,023
Contiguous U.S.	**1,636,870**	**1,117,421**	**207,145**	**312,304**
ASCC	3,020	2,528	14	478
Hawaii	3	0	3	0
U.S. Total	**1,639,893**	**1,119,948**	**207,162**	**312,782**
	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	199,188	166,045	2,513	30,630
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.)	198,490	128,171	1,731	68,587
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.	**1,672,389**	**1,182,180**	**158,324**	**331,885**
ASCC	3,945	3,172	78	695
Hawaii	6	0	6	0
U.S. Total	**1,676,341**	**1,185,352**	**158,409**	**332,580**

See footnotes at end of table.

Table 37. U.S. Electric Utility Deliveries by North American Electric Reliability Council Region and Hawaii, 1992 Through 1996 (Continued)

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Deliveries[1]	Requirements and Nonrequirements Sales for Resale	Exchange Delivered	Wheeling Delivered
		1995		
ECAR	221,627	186,464	2,270	32,893
ERCOT	118,456	34,017	50,644	33,796
MAAC	71,357	56,800	9	14,548
MAIN	61,427	55,044	209	6,175
MAPP(U.S.)	95,503	74,621	4,285	16,596
NPCC(U.S.)	186,345	124,463	2,256	59,626
SERC	393,683	327,687	37,116	28,880
SPP	161,207	132,687	5,113	23,406
WSCC(U.S.)	449,423	260,585	57,080	131,758
Contiguous U.S.	**1,759,028**	**1,252,369**	**158,981**	**347,678**
ASCC	4,138	3,250	109	779
Hawaii	11	0	11	0
U.S. Total	**1,763,177**	**1,255,618**	**159,101**	**348,457**
		1996		
ECAR	274,275	213,373	1,381	59,522
ERCOT	115,163	39,924	55,230	20,009
MAAC	93,421	73,221	22	20,177
MAIN	69,301	61,421	330	7,550
MAPP(U.S.)	104,835	82,899	5,479	16,457
NPCC(U.S.)	201,223	135,832	1,991	63,400
SERC	429,948	352,216	42,307	35,425
SPP	174,435	143,548	5,017	25,870
WSCC(U.S.)	541,181	325,405	54,546	161,230
Contiguous U.S.	**2,003,783**	**1,427,839**	**166,304**	**409,640**
ASCC	4,257	3,340	97	820
Hawaii	7	0	7	0
U.S. Total	**2,008,047**	**1,431,179**	**166,407**	**410,460**

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

Notes: •Data 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, 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, 1992 Through 1996

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Net Energy Flow[1]	Receipts[2]	Deliveries[3]
		1992	
ECAR	–22,509	190,220	212,729
ERCOT	27,082	130,049	102,966
MAAC	33,260	92,676	59,416
MAIN	15,105	55,810	40,706
MAPP(U.S.)	9,134	125,334	116,200
NPCC(U.S.)	48,967	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**
		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	–188	199,000	199,188
ERCOT	28,107	141,092	112,985
MAAC	34,705	94,910	60,205
MAIN	7,954	66,538	58,584
MAPP(U.S.)	16,223	109,057	92,834
NPCC(U.S.)	68,861	267,351	198,490
SERC	30,580	397,661	367,081
SPP	18,130	172,119	153,989
WSCC(U.S.)	42,990	472,025	429,034
Contiguous U.S.	**247,362**	**1,919,751**	**1,672,389**
ASCC	6	3,952	3,945
Hawaii	3,438	3,444	6
U.S. Total	**250,806**	**1,927,147**	**1,676,341**

See footnotes at end of table.

Table 38. U.S. Electric Utility Net Energy Flow by North American Electric Reliability Council Region and Hawaii, 1992 Through 1996 (Continued)

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Net Energy Flow[1]	Receipts[2]	Deliveries[3]
		1995	
ECAR	2,339	223,966	221,627
ERCOT	26,974	145,430	118,456
MAAC	42,859	114,216	71,357
MAIN	5,940	67,367	61,427
MAPP(U.S.)	17,453	112,956	95,503
NPCC(U.S.)	76,602	262,947	186,345
SERC	33,112	426,796	393,683
SPP	14,902	176,109	161,207
WSCC(U.S.)	34,779	484,202	449,423
Contiguous U.S.	**254,960**	**2,013,988**	**1,759,028**
ASCC	79	4,217	4,138
Hawaii	3,512	3,522	11
U.S. Total	**258,551**	**2,021,728**	**1,763,177**
		1996	
ECAR	–9,450	264,825	274,275
ERCOT	33,808	148,971	115,163
MAAC	48,027	141,448	93,421
MAIN	5,933	75,234	69,301
MAPP(U.S.)	20,058	124,893	104,835
NPCC(U.S.)	75,550	276,773	201,223
SERC	24,245	454,193	429,948
SPP	23,655	198,090	174,435
WSCC(U.S.)	33,270	574,451	541,181
Contiguous U.S.	**255,095**	**2,258,877**	**2,003,783**
ASCC	*	4,257	4,257
Hawaii	3,565	3,572	7
U.S. Total	**258,660**	**2,266,707**	**2,008,047**

1 Equals receipts minus deliveries.
2 Equals purchased power plus exchange received plus wheeling received and imports.
3 Equals sales for resale plus exchange delivered plus wheeling delivered and exports.
* =Value less than 0.5.

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •This is a summation of all 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, 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, 1992 Through 1996

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1992	1993	1994	1995	1996
ECAR	10,420	11,962	12,659	13,131	15,861
ERCOT	23,666	24,267	23,264	22,653	23,916
MAAC	16,433	18,083	20,911	23,870	23,892
MAIN	347	401	392	447	468
MAPP(U.S.)	576	582	585	585	706
NPCC(U.S.)	36,116	42,724	49,348	57,511	56,207
SERC	15,304	19,021	24,020	29,184	31,276
SPP	5,457	6,809	6,856	5,345	6,090
WSCC(U.S.)	55,637	61,580	67,297	65,842	67,028
Contiguous U.S.	**163,957**	**185,429**	**205,332**	**218,567**	**225,445**
ASCC	1	4	4	7	5
Hawaii	2,324	3,103	3,442	3,518	3,568
U.S. Total	**166,283**	**188,537**	**208,778**	**222,092**	**229,018**

Notes: •Data 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 Internal Demand, Planned Capacity Resources, and Capacity Margins by North American Electric Reliability Council Region and Hawaii, 1996 Through 2005
(Megawatts)

North American Electric Reliability Council Region and Hawaii	1996			1997		
	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)
	Summer					
ECAR	85,643	103,003	16.9	88,573	104,953	15.6
ERCOT	44,990	55,074	18.3	45,636	55,230	17.4
MAAC	45,224	56,881	20.5	45,628	56,774	16.7
MAIN	43,229	52,112	17.0	44,470	52,880	19.6
MAPP(U.S)	27,487	32,665	15.9	27,298	33,121	15.9
NPCC(U.S)	48,290	62,368	22.6	48,950	58,592	16.5
SERC	137,434	165,844	17.1	141,138	164,433	14.2
SPP	57,951	69,354	16.4	59,017	69,344	14.9
WSCC(U.S)	99,612	130,180	23.5	101,728	135,049	24.7
Contiguous U.S	**589,860**	**727,481**	**18.9**	**602,438**	**730,376**	**17.5**
ASCC	551	1,167	52.8	([1])	([1])	([1])
Hawaii	([2])	([2])	([2])	([2])	([2])	([2])
U.S. Total	**590,411**	**728,648**	**18.9**	**602,438**	**730,376**	**17.5**

North American Electric Reliability Council Region and Hawaii	2000			2005		
	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)
	Summer					
ECAR	92,774	108,410	14.4	101,068	115,654	12.6
ERCOT	47,466	55,040	13.8	52,261	60,225	13.2
MAAC	47,569	58,803	13.7	51,061	61,076	10.4
MAIN	46,148	55,199	16.4	49,040	58,275	16.4
MAPP(U.S)	28,563	33,361	14.4	31,126	32,945	5.5
NPCC(U.S)	50,795	61,982	18.0	53,197	59,675	10.9
SERC	151,847	173,671	12.6	168,355	189,018	10.9
SPP	61,408	71,346	13.9	66,953	75,515	11.3
WSCC(U.S)	107,412	135,608	20.8	117,931	136,411	13.5
Contiguous U.S	**633,982**	**753,420**	**15.9**	**690,992**	**788,794**	**12.4**
ASCC	([1])	([1])	([1])	([1])	([1])	([1])
Hawaii	([2])	([2])	([2])	([2])	([2])	([2])
U.S. Total	**633,982**	**753,420**	**15.9**	**690,992**	**788,794**	**12.4**

North American Electric Reliability Council Region and Hawaii	1996			1997		
	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)
	Winter					
ECAR	79,684	104,119	23.5	80,592	106,399	24.3
ERCOT	36,419	55,350	34.2	37,267	55,422	32.8
MAAC	40,978	59,862	31.5	41,338	59,671	30.7
MAIN	33,930	52,039	34.8	35,093	53,364	34.2
MAPP(U.S)	23,106	31,650	27.0	23,697	32,511	27.1
NPCC(U.S)	43,420	63,022	31.1	43,900	62,304	29.5
SERC	130,021	169,667	23.4	136,040	167,894	19.0
SPP	44,123	69,575	36.6	43,880	69,617	37.0
WSCC(U.S)	954,942	133,912	28.7	96,233	136,574	29.5
Contiguous U.S	**527,175**	**739,196**	**28.7**	**538,040**	**743,756**	**27.7**
ASCC	710	1,272	44.2	([1])	([1])	([1])
Hawaii	([2])	([2])	([2])	([2])	([2])	([2])
U.S. Total	**527,885**	**740,468**	**28.7**	**538,040**	**743,756**	**27.7**

See footnotes at end of table.

Table 40. Net Internal Demand, Planned Capacity Resources, and Capacity Margins by North American Electric Reliability Council Region and Hawaii

(Megawatts)¬Continued

North American Electric Reliability Council Region and Hawaii	2000 Net Internal Demand	2000 Planned Capacity Resources	2000 Capacity Margin (percent)	2005 Net Internal Demand	2005 Planned Capacity Resources	2005 Capacity Margin (percent)
			Winter			
ECAR	84,186	111,144	24.3	91,314	120,984	24.5
ERCOT	39,790	55,550	28.4	44,721	59,810	25.2
MAAC	43,361	61,889	29.9	46,736	64,034	27.0
MAIN	36,675	54,089	32.2	39,409	58,649	32.8
MAPP(U.S)	24,874	32,516	23.5	27,069	32,131	15.8
NPCC(U.S)	45,694	62,773	27.2	47,969	62,005	22.6
SERC	146,774	175,019	16.1	163,433	189,702	13.8
SPP	45,821	71,579	36.0	50,234	75,753	33.7
WSCC(U.S)	101,129	136,903	26.1	111,035	137,682	19.4
Contiguous U.S	**568,304**	**761,462**	**25.4**	**621,920**	**800,750**	**22.3**
ASCC	([1])	([1])	([1])	([1])	([1])	([1])
Hawaii	([2])	([2])	([2])	([2])	([2])	([2])
U.S. Total	**568,304**	**761,462**	**25.4**	**621,920**	**800,750**	**22.3**

1 Data for ASCC (Alaska) was not filed in 1997.
2 Data for Hawaii are not submitted on this form.
Notes: •Data are final. •Totals may not equal sum of components because of independent rounding.
Sources: **Data for 1996 and beyond:** Form EIA-411, *''Coordinated Bulk Power Supply Programs.''*

Table 41. Net Imports at U.S. Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1992 Through 1996

(Thousand Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1992	1993	1994	1995	1996
ECAR	–231,967	931,679	6,906,673	5,758,866	1,901,577
ERCOT	–169,142	–7,760	–25,191	–6,475	3,171
MAAC	–-	–-	–-	–-	–-
MAIN	–-	–-	–-	–-	–-
MAPP(U.S.)	6,921,800	7,808,685	9,380,144	9,858,469	11,203,425
NPCC(U.S.)	12,053,907	16,756,045	23,535,934	22,309,577	19,022,934
SERC	–-	–-	–-	–-	–-
SPP	–-	–-	–-	–-	–-
WSCC(U.S.)	9,773,701	2,938,533	4,840,154	–306,773	5,392,064
Contiguous U.S.	**28,348,299**	**28,427,182**	**44,637,717**	**37,613,664**	**37,523,171**
ASCC	*	*	*	*	*
Hawaii	–-	–-	–-	–-	–-
U.S. Total	**28,348,299**	**28,427,182**	**44,637,717**	**37,613,664**	**37,523,171**
Net Canada	31,927,468	27,283,021	43,695,066	36,510,673	37,575,644
Net Mexico	1,032,552	1,144,160	942,651	1,102,990	–52,474

* =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 42. Imports to U.S. Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1992 Through 1996

(Thousand Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1992	1993	1994	1995	1996
ECAR	82,151	959,746	6,909,598	5,798,944	2,110,820
ERCOT	–-	14	70	0	5,566
MAAC	–-	–-	–-	–-	–-
MAIN	–-	–-	–-	–-	–-
MAPP(U.S.)	8,573,652	10,767,276	10,130,216	10,332,719	11,852,438
NPCC(U.S.)	14,699,638	18,741,212	25,080,505	23,413,069	20,548,422
SERC	–-	–-	–-	–-	–-
SPP	–-	–-	–-	–-	–-
WSCC(U.S.)	13,848,735	8,613,566	10,109,276	7,215,641	12,026,170
Contiguous U.S.	**37,204,176**	**39,081,814**	**52,229,668**	**46,760,374**	**46,543,416**
ASCC	*	*	*	*	*
Hawaii	–-	–-	–-	–-	–-
U.S. Total	**37,204,176**	**39,081,814**	**52,229,668**	**46,760,374**	**46,543,416**
From Canada	35,181,757	37,088,486	50,218,349	44,502,962	45,280,264
From Mexico	2,022,419	1,993,327	2,011,319	2,257,411	1,263,152

* =Value less than 0.5.

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

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

Table 43. Exports from U.S. Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1992 Through 1996

(Thousand Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1992	1993	1994	1995	1996
ECAR	314,118	28,067	2,925	40,078	209,243
ERCOT	169,142	7,774	25,261	6,475	2,395
MAAC	–-	–-	–-	–-	–-
MAIN	–-	–-	–-	–-	–-
MAPP(U.S.)	1,651,852	2,958,591	750,072	474,250	649,013
NPCC(U.S.)	2,645,731	1,985,167	1,544,571	1,103,492	1,525,488
SERC	–-	–-	–-	–-	–-
SPP	–-	–-	–-	–-	–-
WSCC(U.S.)	4,075,034	5,675,033	5,269,122	7,522,414	6,634,106
Contiguous U.S.	**8,855,877**	**10,654,632**	**7,591,951**	**9,146,710**	**9,020,245**
ASCC	*	*	*	*	*
Hawaii	–-	–-	–-	–-	–-
U.S. Total	**8,855,877**	**10,654,632**	**7,591,951**	**9,146,710**	**9,020,245**
To Canada	7,866,010	9,805,465	6,523,283	7,992,289	7,704,620
To Mexico	989,867	849,167	1,068,668	1,154,421	1,315,625

* =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 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 optimize the use of generating resources. This chapter provides a brief description of the key elements of electric utility DSM programs in the United States.

Background

DSM consists of electric utilities planning, implementing, and monitoring activities that are designed to encourage consumers to modify their level and pattern of electricity usage. The primary objective of most DSM programs has been to provide cost-effective energy and capacity resources to help defer the need for new sources of power, 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 costs 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 sources. With the changes that are occurring within the electric utility industry, there is a great deal of uncertainty about the direction of utility sponsored DSM programs. Some utilities are moving toward energy service companies, while other utilities are making no changes to their DSM programs.

In many states DSM programs are still a key component of the integrated resource plans (IRP) of a 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 some State regulatory commissions use the IRP process to assess a variety of resource options that 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. 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 organization 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). Second, load management programs are aimed at reducing or shifting demand at certain critical times (such as summer or winter peak), and are focused on changing the timing of electricity demand. These program types usually have only a minor effect on the amount of annual electricity consumption. For example, residential and commercial air conditioners or water heaters may be allowed to operate unimpeded during off-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, 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 these 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 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 substitution of other energy types for electricity and self-generation of electricity for consumers' own use are included.[14]

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.[15]

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 resource 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 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.

The Participant Test measures the quantifiable benefits and costs to consumers who participate in the DSM program. It attempts to answer whether the participant is better off with the DSM technology and likely to participate in future programs.

[14] 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.

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

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 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). 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.[16] 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.[17]

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 cite-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-

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

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

sponsored efforts to develop DSM potential in the commercial sector have increased significantly, with program activities focusing on energy-management assistance, cool storage, lighting, heating and air conditioning, and water heating improvements.

DSM program development in the industrial sector has been slow compared to its development in the residential and commercial sectors. The wide variety of industrial processes used 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 customized 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 will decide whether 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.[18]

With utility DSM budgets approaching $2.0 billion in 1996, 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.[19]

Data Sources

The data in the following tables were collected on Schedule V, "Demand-Side Management Information," of the 1996 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 (1996) and the first and fifth forecast years (1997 and 2001).

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 given year. It includes all participants in existing and new programs (those implemented during the given

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

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

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 44. U.S. Electric Utility Demand Side Management Program Energy Savings, Actual and Potential Peak Load Reductions, and Cost, 1992 Through 1996

Item	1992	1993	1994	1995	1996
Energy Savings (million kilowatthours)[1]	35,563	45,294	52,483	57,421	61,842
Actual Peak Load Reductions (megawatts)[1] [2]	17,204	23,069	25,001	29,561	29,893
Potential Peak Load Reductions (megawatts)[1]	32,442	39,508	42,917	47,029	48,344
Cost (thousand dollars)[3]	2,348,094	2,743,533	2,715,657	2,421,261	1,902,197

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.

Notes: •Data 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.

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

Table 45. U.S. Electric Utility Actual Peak Load Reductions by North American Electric Reliability Council Region and Hawaii, by Demand-Side Management Program Category, 1992 Through 1996

(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.	**23,057**	**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**

See footnotes at end of table.

Table 45. U.S. Electric Utility Actual Peak Load Reductions by North American Electric Reliability Council Region and Hawaii, by Demand-Side Management Program Category, 1992 Through 1996 (Continued)

(Megawatts)

	Total Actual Peak Load Reduction	Direct Load Control	Interruptible Load	Energy Efficiency	Other Load Management	Other Demand-Side Management
			1995			
ECAR	2,458	364	1,088	839	107	60
ERCOT	1,873	22	94	1,447	306	4
MAAC	2,110	311	752	671	362	13
MAIN	1,254	23	505	658	59	9
MAPP(U.S.)	3,373	1,284	1,198	661	215	15
NPCC(U.S.)	2,594	87	301	2,178	28	*
SERC	10,103	2,928	3,314	3,134	495	232
SPP	746	152	203	200	172	19
WSCC(U.S.)	5,028	178	947	3,415	424	63
Contiguous U.S.	**29,539**	**5,350**	**8,401**	**13,203**	**2,168**	**416**
ASCC	9	3	0	2	0	5
Hawaii	13	0	0	7	0	6
U.S. Total	**29,561**	**5,352**	**8,401**	**13,212**	**2,168**	**426**
			1996			
ECAR	2,547	398	1,129	852	103	64
ERCOT	2,002	27	91	1,571	309	4
MAAC	1,773	230	167	936	426	15
MAIN	1,625	42	790	697	84	12
MAPP(U.S.)	3,106	1,205	853	797	235	15
NPCC(U.S.)	2,554	79	230	2,219	18	9
SERC	10,203	3,221	2,793	3,468	508	212
SPP	924	165	387	176	182	13
WSCC(U.S.)	5,134	206	945	3,517	405	62
Contiguous U.S.	**29,869**	**5,573**	**7,387**	**14,233**	**2,270**	**405**
ASCC	7	3	3	2	0	0
Hawaii	17	0	0	8	8	1
U.S. Total	**29,893**	**5,575**	**7,390**	**14,243**	**2,278**	**407**

Notes: •Data 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 load reduction), achieved by all program participants during the reporting year.

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 Program Category, 1996

Program	Actual Peak Load Reductions[1] (megawatts)	Potential Peak Load Reductions[2] (megawatts)	Energy Savings (million kilowatthours)
	Annual Effects[3]		
Large Utilities[4]			
Energy Efficiency[5]	14,243	14,243	59,853
Direct Load Control	5,575	9,443	134
Interruptible Load	7,390	21,558	362
Other Load Management[6]	2,278	2,596	–196
Other Demand-Side Management[7]	407	503	1,689
U.S. Total	29,893	48,344	61,842
	Incremental Effects[8]		
Large Utilities[4]			
Energy Efficiency[5]	1,381	1,381	6,361
Direct Load Control	399	587	12
Interruptible Load	1,692	4,126	267
Other Load Management[6]	191	273	–16
Other Demand-Side Management[7]	27	41	219
Small Utilities[9]			
Energy Efficiency[5]	2	2	7
Direct Load Control	24	49	3
Interruptible Load	11	21	1
Other Load Management[6]	9	13	2
Other Demand-Side Management[7]	6	7	*
U.S. Total	3,742	6,500	6,857

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, and also includes 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.

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 final. •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 Demand-Side Management Program Annual and Incremental Effects by Sector, 1996

Sector	Actual Peak Load Reductions[1] (megawatts)	Potential Peak Load Reductions[2] (megawatts)	Energy Savings (million kilowatthours)
	Annual Effects[3]		
Large Utilities[4]			
Residential	11,471	14,697	20,585
Commercial	8,678	12,452	29,186
Industrial	9,083	20,275	10,493
Other	661	921	1,578
U.S. Total	29,893	48,344	61,842
	Incremental Effects[5]		
Large Utilities[4]			
Residential	792	950	1,179
Commercial	935	1,512	3,537
Industrial	1,870	3,800	1,787
Other	93	146	341
Small Utilities[6]			
Residential	30	46	7
Commercial	9	17	3
Industrial	8	16	2
Other	5	13	1
U.S. Total	3,742	6,500	6,857

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, and also includes 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 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.

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

Notes: •Data 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 48. U.S. Electric Utility Potential Peak Load Reductions 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	
	1992	1993	1994	1995	1996	1997	2001
	Direct Load Control						
ECAR	222	227	247	413	442	444	639
ERCOT	121	164	202	215	145	148	53
MAAC	933	1,033	1,260	1,296	1,120	1,160	1,331
MAIN	147	190	211	169	203	266	499
MAPP(U.S.)	1,054	1,252	1,368	1,876	2,053	2,098	2,381
NPCC(U.S.)	188	219	104	111	105	79	80
SERC	3,814	3,950	4,339	4,007	4,456	4,677	5,449
SPP	533	615	434	321	324	332	359
WSCC(U.S.)	612	612	724	627	587	599	645
Contiguous U.S.	**7,624**	**8,263**	**8,888**	**9,034**	**9,435**	**9,805**	**11,435**
ASCC	2	2	2	3	8	8	9
Hawaii	0	0	0	0	0	0	0
U.S. Total	**7,626**	**8,266**	**8,890**	**9,036**	**9,443**	**9,813**	**11,444**
	Interruptible Load						
ECAR	1,214	1,456	1,643	2,270	2,315	2,192	2,398
ERCOT	1,736	1,968	1,803	1,918	1,585	1,448	1,403
MAAC	838	1,152	1,614	1,781	1,288	1,365	1,448
MAIN	867	803	1,116	1,220	1,130	1,308	1,315
MAPP(U.S.)	789	823	973	1,326	1,254	1,338	1,601
NPCC(U.S.)	371	358	245	349	343	311	270
SERC	4,204	6,624	6,816	7,621	7,568	8,146	8,316
SPP	1,181	2,041	2,004	1,964	1,960	2,115	1,994
WSCC(U.S.)	3,353	2,997	3,167	3,371	4,104	3,563	3,350
Contiguous U.S.	**14,553**	**18,222**	**19,380**	**21,820**	**21,547**	**21,786**	**22,097**
ASCC	0	0	0	0	6	4	4
Hawaii	13	12	4	0	5	4	4
U.S. Total	**14,566**	**18,235**	**19,384**	**21,820**	**21,558**	**21,794**	**22,105**

Notes: •Data 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 49. 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	
	1992	1993	1994	1995	1996	1997	2001
ECAR	1,129	1,779	2,237	3,030	3,695	3,340	4,588
ERCOT	1,013	2,288	3,739	3,757	3,866	3,904	3,790
MAAC	954	1,150	1,820	3,000	3,620	4,255	6,202
MAIN	1,212	2,125	2,453	2,732	3,007	3,253	3,170
MAPP(U.S.)	940	1,581	1,883	2,506	3,153	3,685	5,067
NPCC(U.S.)	5,049	6,769	8,422	9,694	10,022	10,004	11,785
SERC	10,492	11,264	11,768	10,143	10,404	10,867	12,534
SPP	273	365	492	335	358	393	413
WSCC(U.S.)	14,491	17,954	19,634	22,178	23,663	24,476	26,852
Contiguous U.S.	**35,554**	**45,275**	**52,449**	**57,374**	**61,789**	**64,178**	**74,402**
ASCC	*	2	3	4	5	5	4
Hawaii	9	17	31	43	49	69	146
U.S. Total	**35,563**	**45,294**	**52,483**	**57,421**	**61,842**	**64,252**	**74,552**

* =Value less than 0.5.

Notes: •Data 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 50. 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	
	1992	1993	1994	1995	1996	1997	2001
ECAR	130,903	187,137	137,118	138,910	77,031	77,395	73,496
ERCOT	55,675	62,533	69,538	70,421	54,120	65,131	35,985
MAAC	178,420	262,111	305,190	300,347	225,253	275,595	290,798
MAIN	133,610	128,607	96,253	78,004	70,350	69,977	72,522
MAPP(U.S.)	85,021	103,185	138,256	158,971	156,688	127,273	125,466
NPCC(U.S.)	542,222	565,145	462,668	346,716	263,160	282,918	215,754
SERC	510,489	643,081	684,647	681,161	551,038	559,155	580,116
SPP	30,927	33,376	28,626	26,523	28,385	21,037	17,897
WSCC(U.S.)	679,752	756,947	792,387	619,575	471,759	482,734	393,758
Contiguous U.S.	**2,347,019**	**2,741,832**	**2,714,726**	**2,420,628**	**1,897,782**	**1,961,215**	**1,805,792**
ASCC	315	419	386	633	291	340	369
Hawaii	760	1,282	588	0	4,124	12,684	6,038
Total Cost[1]	**2,348,094**	**2,743,533**	**2,715,657**	**2,421,261**	**1,902,197**	**1,974,239**	**1,812,199**

[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 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.

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

Table 51. U.S. Electric Utility Demand-Side Management Direct and Indirect Cost, Selected Years

(Thousand Dollars)

Program	Historical Cost	Projected Costs	
	1996	1997	2001
Total Direct Cost[1]	**1,623,588**	**1,706,414**	**1,565,865**
Energy Efficiency	1,051,922	1,071,122	936,526
Direct Load Control	322,733	332,577	353,264
Interruptible Load	186,250	189,572	181,734
Other Load Management	25,667	24,466	14,485
Other Demand-Side Management	37,016	88,677	79,856
Total Indirect Cost[2]	**278,609**	**269,976**	**248,982**
Administrative	150,887	113,977	104,937
Marketing	51,241	56,124	57,274
Monitoring and Evaluation	47,501	61,342	57,077
Other[3]	28,980	38,533	29,694
Total Cost[4]	**1,902,197**	**1,976,390**	**1,814,847**

[1] Reflects electric utility cost incurred during the year that are identified with one of the demand-side program categories.

[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 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 52. Number of U.S. Electric Utilities with Demand-Side Management Energy Efficiency Programs by End Uses and Program Types by Sector, 1996

Item	Residential	Commercial	Industrial
End Uses			
Heating System	278	195	107
Cooling System	274	217	130
Water Heating	292	159	101
Lighting	182	214	181
Building Shell	192	128	86
New Construction	207	132	93
Appliances	130	65	42
Motors	–-	143	164
Process Heating	–-	47	80
Electrolytics	–-	9	22
Other System	15	22	27
Program Types			
Energy Audits	303	263	198
Rebates	256	196	133
Loaning	138	91	62
Other Incentives[1]	83	69	63
Other	50	47	45

[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 final. •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 1992 through 1996. 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.

By the late 1970's changing economic conditions and legislation made nonutility generation attractive again for many industrial facilities and power project developers. During the 1970's, 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. The 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. These factors led to a re-examination of alternatives such as nonutility electric power.

Nonutility power producing facilities seeking to establish interconnected operations with electric utilities 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.

Congress acted to relieve a nationwide energy crisis by enacting the National Energy Act of 1978, which encompassed the Public Utility Regulatory Policies Act (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 energy 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. QF's include cogenerators and small power producers. 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,[20] 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 utilities' 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.

PURPA became a catalyst for competition in the electricity supply industry because it opened generation markets to facilities that met certain ownership, operating, and efficiency criteria, established by the FERC. Utilities initially did not welcome this competition, but some utilities soon discovered that buying generation from a QF has certain advantages over adding to their own capacity, especially because of the increasing uncertainty of recovering capital costs.

Nonutilities are not subject to 'rate base' as the basis of the price setting process and, therefore, the economic regulation regarding recovery of the investments of nonutilities is generally established on a different basis from that of a regulated public utility that is subject to 'avoided cost' based pricing, pricing that is a direct result of negotiations between the parties, 'market-based' pricing and others. As a result of this exception, a shorter lead time exists for the types of contracts signed by the nonutilities with their contractors (turnkey and other incentive based construction contracts). This type of contract had not been the historical practice of the utility industry, but under current conditions, clearly utilities and nonutilities alike will avail themselves of whatever provisions will allow the shortest lead time and lowest cost. The utility and nonutility are both looking at the need for and timing of new capacity in very similar ways. The NERC Reliability Assessment 1996-2005 states that in the later years of the ten-year assessment period, a number of Regions and subregions are no longer reporting generation capacity additions needed to satisfy regional criteria, although they do recognize such needs. However, it does signal an increased reliance on short lead-time resources that allow commitments to be delayed until required and reflects a shift toward a market-driven supply where customers choose the quantity and level of supply appropriate for their purposes.

The growth of nonutilities was further advanced by the Energy Policy Act of 1992 (EPACT). EPACT expanded the nonutility markets by creating a new category of power producers called exempt wholesale generators (EWG), which are exempt from the corporate and geographic restrictions imposed by the Public Utility Holding Company Act of 1935 (PUCHA).[21] EWG's are defined as businesses that own and/or operate a facility exclusively for the generation of electric energy for sale at wholesale. Exempting EWG's from PUHCA regulation removed obstacles to wholesale power competition by allowing utilities and nonutilities to form EWG's without triggering the restrictions of PUHCA. EWG's differ from QF's in several ways. They are not required to meet PURPA's cogeneration or renewable fuels limitations, utilities are not required to purchase their power, and they may charge market-based rates.

While the passage of PURPA opened generation markets to nonutility power producers of electricity, EPACT expanded the wholesale generation markets by opening access to the transmission system. In 1996, the FERC issued rules for implementing open access to the transmission network. Marketing of EWG wholesale power is being facilitated by transmission provisions that gave FERC the authority to order utilities to provide access to their transmission systems at nondiscriminatory rates.

With increasing competition in the electric power industry, PURPA in under review for repeal or modification. Several bills were introduced in Congress in 1996 and 1997 that would either repeal or amend PURPA. Proponents of repeal or reform contend that its QF power purchase mandate is anticompetitive and costly, and its environmental and fuel diversification goals will be maintained by the workings of a free market. Opponents of PURPA's repeal maintain the mandate is a necessary check against utility monopoly power.

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 electric power and another form of useful energy. The technology selected depends on the requirement for processed steam. Cogenerating tech-

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

[21] PUCHA was designed to discourage holding companies from structuring their operations in ways that would prevent effective State regulation.

nologies 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 14), 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 14 represent most topping-cycle facilities.

In a bottoming-cycle system (Figure 15), 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 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. 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 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 restrictions imposed by their site or transmission access.

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 facilities are 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 economic conditions. A nonutility power producer with many options for fuel choice has an economic advantage over a producer tied to only one fuel source.

Data Sources

Summary statistics on nonutility capacity, generation, sales, consumption, and emissions in the United States are provided in the following tables. All data are preliminary. 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 from 5 megawatts to 1 megawatt to include all facilities with a combined nameplate capacity of 1 or more megawatts. Previously, data were collected from facilities with a nameplate capacity between 1 and 5 megawatts every 3 years. 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, 1996, are presented by energy source in Figure 9. These data represent all nonutility planned generating facilities that meet one or more of the criteria defined earlier.

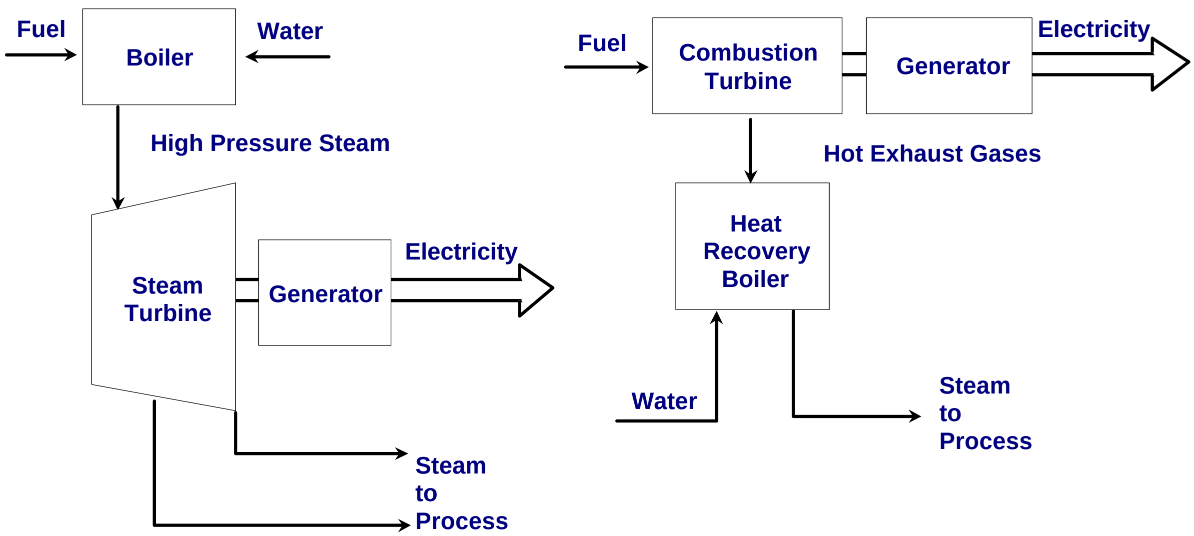
Some nonutility power producers of 1 or more megawatts use only fossil fuels; some use only renewable energy; and some use a combination of both fossil fuels and renewable energy sources. Although the majority of nonutility power producers generate electric power using fossil energy, those using renewable 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 53, 55, 56, 59 and 60 include hydrogen, sulfur, batteries, chemicals, and purchased steam.

The number of facilities shown for 1996 includes operational facilities in 1995 and new facilities or planned facilities that became operational during that year.

The total capacity for 1992 through 1996 (Table 53) 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, test, maintenance/repairs, out of service, and indefinite shutdown represented 11 percent of the total nonutility generating capacity in 1996.

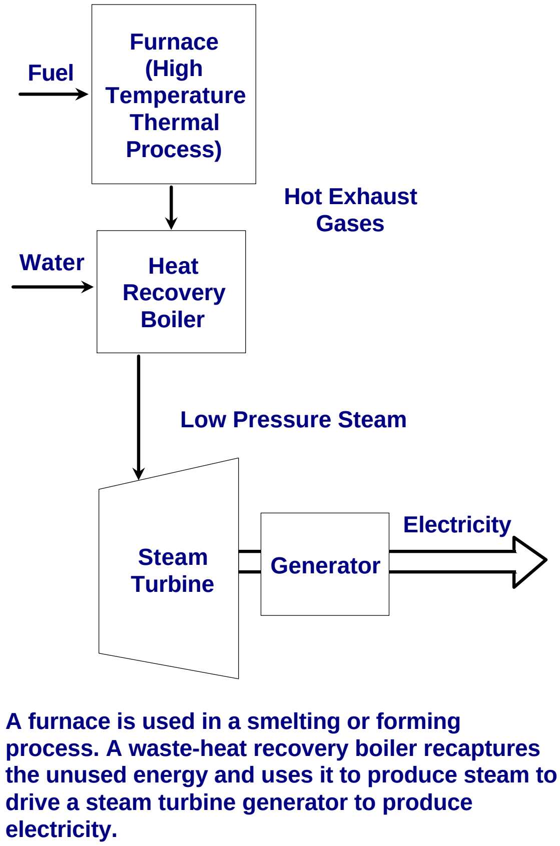
Figure 14. Two Topping-Cycle Plant Configurations



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 15. Bottoming-Cycle Plant Configuration



Source: Federal Energy Regulatory Commission, *Cogeneration,* 1985

Table 53. Summary Statistics for U.S. Nonutility Power Producers, 1992 Through 1996

Item	1992	1993	1994	1995	1996
Installed Capacity (megawatts)	**56,814**	**60,778**	**68,461**	**70,254**	**73,183**
Coal[1]	8,503	9,772	10,372	R 10,877	12,122
Petroleum[2]	1,730	2,043	2,262	R 2,116	3,185
Natural Gas[3]	21,542	23,463	26,925	R 27,906	30,840
Other Gas[4]	—	—	1,130	1,217	184
Petroleum/Natural Gas (Combined)	8,478	8,505	9,820	10,479	10,875
Hydroelectric	2,684	2,741	3,364	3,399	3,419
Geothermal	1,254	1,318	1,335	1,295	1,346
Solar	360	360	354	354	354
Wind	1,822	1,813	1,737	1,723	1,670
Wood[5]	6,805	7,046	7,416	R 6,885	5,938
Waste[6]	3,006	3,131	3,150	R 3,430	2,556
Nuclear[7]	20	20	—	—	—
Other[8]	611	566	597	574	694
Gross Generation (million kilowatthours)	**296,001**	**325,226**	**354,925**	R **375,901**	**382,530**
Coal[1]	47,363	53,367	59,035	R 60,234	61,424
Petroleum[2]	10,963	13,364	15,069	R 15,049	14,951
Natural Gas[4]	158,798	174,282	179,735	R 196,633	198,606
Other Gas[3]	—	—	12,480	R 13,984	14,753
Hydroelectric	9,446	11,511	13,227	14,774	16,555
Geothermal	8,578	9,749	10,122	9,912	10,198
Solar	746	897	824	824	903
Wind	2,916	3,052	3,482	3,185	3,400
Wood[5]	36,255	37,421	38,595	R 37,283	37,549
Waste[6]	17,352	18,325	18,797	R 20,231	20,449
Nuclear[7]	67	78	54	—	—
Other[8]	3,516	3,181	3,507	R 3,792	3,744
Consumption					
Coal (Thousand short tons)	R 44,607	48,343	52,261	R 50,328	53,202
Petroleum (Thousand barrels)[9]	R 34,626	R 40,142	R 46,630	R 39,219	42,926
Natural Gas (Million cubic feet)	R 1,844,857	2,013,788	2,149,246	R 2,303,944	2,449,996
Other Gas (Million cubic feet)[4]	R 1,587,632	R 1,681,916	R 1,591,051	R 1,611,993	1,738,362
Supply and Disposition (million kilowatthours)					
Gross Generation	296,001	325,226	354,925	R 375,901	382,530
Receipts[10]	83,421	85,323	94,166	89,919	104,101
Sales to Utilities[11]	164,374	187,466	204,688	R 217,906	224,675
Sales to Other End Users[12]	10,786	15,569	17,626	15,548	14,283
Facility Use	204,261	207,514	226,777	R 232,367	247,673

1 Includes coal, anthracite culm, bituminous gob, coke breeze, fine coal, tar coal, lignite waste, and waste coal.
2 Includes petroleum, petroleum coke, liquid butane, diesel, light oil, kerosene, methanol, oil waste, sludge oil, tar oil and liquid propane.
3 Includes natural gas, waste heat and waste gas.
4 Includes butane, methane, propane, other gas and digester gas.
5 Includes black liquor, pitch, peat, railroad ties, sludge wood, wood/wood waste, spent sulfite liquor and red liquor.
6 Includes agricultural byproducts, fish oil, liquid acetonitrile waste, landfill gas, municipal solid waste, sludge waste, straw, tires, waste alcohol, solid byproducts, and tall oil.
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 batteries, chemicals, hydrogen, sulfur, purchased steam and other.
9 Does not include petroleum coke consumption of 4,188 thousand short tons for 1995 and 4,484 thousand short tons in 1996.
10 Includes purchases, interchanges, and exchanges of electric energy with utilities and other nonutilities.
11 Includes sales, interchanges, and exchanges of electric energy with utilities.
12 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.

R = Revised data.

NA = Not available.

Notes: •All data are for 1 megawatt and greater. •Data for 1996 are preliminary;data for prior years are final; •Data previously published has been reclassified by energy source and has been changed to reflect these changes. •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 54. Installed Capacity at U.S. Nonutility Generating Facilities by Fossil Fuels, Renewable Energy Sources, and Census Division, 1992 Through 1996
(Megawatts)

Census Division	Fossil Fuels[1]	Renewables/ Other/ Nuclear[2]	Both Fossil Fuels and Renewables/ Other/ Nuclear
		1992	
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	
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	
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**
		1995	
New England	2,619	1,426	992
Middle Atlantic	10,617	1,269	591
East North Central	4,243	503	1,171
West North Central	918	185	130
South Atlantic	8,202	2,095	2,698
East South Central	437	234	1,418
West South Central	11,413	261	2,217
Mountain	1,890	614	253
Pacific	8,014	5,014	831
U.S. Total	**48,354**	**11,601**	**10,299**
		1996	
New England	3,240	1,253	709
Middle Atlantic	11,042	862	1,083
East North Central	4,896	393	785
West North Central	902	196	157
South Atlantic	9,164	1,699	2,799
East South Central	508	234	1,425
West South Central	11,935	287	2,212
Mountain	1,919	604	359
Pacific	8,763	4,825	933
U.S. Total	**52,369**	**10,352**	**10,463**

1 Includes petroleum, natural gas, digester gas, coke breeze, fine coal and/or coal as energy sources.
2 Includes hydroelectric, geothermal, solar, wind, wood, wood/wood waste, peat, wood liquors, railroad ties, pitch, municipal solid waste, other waste, agrricultural waste, straw, tires, landfill gases, fish oils, tall oil, sludge, other (sulfur, hydrogen, batteries, chemicals,) and/ or nuclear as energy sources.

Notes: •All data are for 1 megawatt and greater. •Data for 1996 are preliminary; data for prior years are final. •See Technical Notes for a description of allocating capacity. •Total may not equal sum of components because of independent rounding.

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

Table 55. Installed Capacity at U.S. Nonutility Generating Facilities by Energy Source and Census Division, 1992 Through 1996 (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
				1992			
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			
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			
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**
				1995			
New England	353	1,118	1,579	584	1,404	—	5,037
Middle Atlantic	R 2,590	4,713	W	485	R 913	W	12,477
East North Central	W	3,044	577	103	690	W	5,917
West North Central	782	53	127	95	176	—	1,232
South Atlantic	3,536	1,746	3,755	568	3,010	379	12,995
East South Central	312	225	W	W	1,254	W	2,088
West South Central	W	R 10,808	R 887	W	1,145	W	13,891
Mountain	W	1,294	447	560	153	W	2,757
Pacific	W	R 6,122	1,387	4,012	R 1,571	W	13,860
U.S. Total	R **10,877**	R **29,122**	R **12,595**	**6,771**	R **10,316**	**574**	**70,254**
				1996			
New England	441	955	2,247	589	W	W	5,202
Middle Atlantic	2,553	5,313	4,195	485	441	—	12,987
East North Central	1,861	2,879	676	W	532	W	6,074
West North Central	741	124	170	103	116	—	1,255
South Atlantic	3,875	2,273	3,792	568	2,774	381	13,662
East South Central	397	258	64	W	1,234	W	2,167
West South Central	1,202	10,778	1,024	W	1,120	W	14,433
Mountain	200	1,390	511	560	W	W	2,881
Pacific	853	7,055	1,380	3,978	1,132	123	14,521
U.S. Total	**12,122**	**31,024**	**14,060**	**6,788**	**8,494**	**694**	**73,183**

1 Includes coal, anthracite culm, bituminous gob, coke breeze, fine coal, tar coal, lignite waste, and waste coal.
2 Includes natural gas, waste heat, butane, methane, propane, other gas, waste gas, and digester gas.
3 Includes petroleum, petroleum coke, liquid butane, diesel, light oil, kerosene, methanol, oil waste, sludge oil, tar oil and liquid propane.
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 black liquor, pitch, peat, railroad ties, sludge wood, wood/wood waste, spent sulfite liquor, and red liquor.
6 Includes agricultural byproducts, fish oil, landfill gas, municipal solid waste, sludge waste, straw, tires, waste alcohol, solid byproducts, and tall oil.
7 Includes batteries, chemicals, hydrogen, sulfur, purchased steam and other.
R = Revised data.

Notes: •All data are for 1 megawatt and greater. •Data for 1996 are preliminary; data for prior years are final. •Data previously published has been reclassified by energy source and has been changed to reflect these changes. •Totals may not equal sum of components because of independent rounding. •W = Withheld to avoid disclosure of individual company data.

Table 56. Installed Capacity at U.S. Nonutility Generating Facilities by Energy Source and State, 1996
(Megawatts)

State	Coal[1]	Natural Gas[2]	Petroleum[3] only / and Natural Gas[4]	Hydroelectric/ Geothermal/ Solar / Wind	Wood[5] / Waste[6]	Other[7] / Nuclear	Total
	1996						
Alaska	W	W	54	—	W	—	306
Alabama	W	184	W	—	835	—	1,105
Arkansas	—	W	W	W	368	—	416
Arizona	W	W	52	—	—	—	W
California	503	5,770	566	3,680	662	86	11,267
Colorado	W	663	W	32	—	—	768
Connecticut	W	W	297	22	134	—	721
District of Columbia	—	—	—	—	—	—	—
Delaware	W	—	W	—	—	W	193
Florida	W	1,530	646	—	1,050	W	4,284
Georgia	253	34	663	W	561	W	1,533
Hawaii	W	W	W	83	178	—	833
Iowa	277	W	W	W	W	—	357
Idaho	W	W	—	264	W	W	462
Illinois	402	278	61	21	64	—	826
Indiana	259	W	331	—	W	—	945
Kansas	—	W	42	W	—	—	55
Kentucky	W	—	—	—	W	—	W
Louisiana	W	2,346	W	W	465	W	3,299
Massachusetts	W	693	1,071	W	222	—	2,084
Maryland	W	W	W	—	W	—	674
Maine	W	W	410	362	426	W	1,430
Michigan	619	2,201	157	29	318	—	3,324
Minnesota	331	108	45	96	99	—	679
Missouri	104	W	W	—	—	—	117
Mississippi	—	45	W	—	W	W	W
Montana	—	—	W	W	W	—	129
North Carolina	1,047	W	248	W	217	W	1,975
North Dakota	W	—	W	—	W	—	W
Nebraska	W	W	—	—	—	—	W
New Hampshire	—	—	42	91	135	—	269
New Jersey	W	1,716	1,308	W	78	—	3,630
New Mexico	W	168	W	—	—	—	259
Nevada	—	394	W	W	—	—	845
New York	424	3,142	2,285	383	200	—	6,434
Ohio	204	W	71	W	18	—	357
Oklahoma	W	301	—	—	W	—	840
Oregon	W	W	W	115	123	W	1,016
Pennsylvania	1,614	455	603	89	163	—	2,924
Rhode Island	—	W	423	W	W	—	621
South Carolina	W	W	W	19	296	—	400
South Dakota	—	—	—	—	—	—	—
Tennessee	334	W	W	W	W	W	649
Texas	729	8,086	756	W	213	W	9,878
Utah	W	W	W	W	—	—	142
Virginia	1,298	551	1,616	W	517	W	4,008
Vermont	—	—	W	51	W	—	77
Washington	W	382	437	101	132	W	1,100
Wisconsin	378	W	56	51	115	W	623
West Virginia	344	W	W	W	—	—	595
Wyoming	W	W	W	W	—	W	W
U.S. Total	**12,122**	**31,024**	**14,060**	**6,788**	**8,494**	**694**	**73,183**

1 Includes coal, anthracite culm, bituminous gob, coke breeze, fine coal, tar coal, lignite waste, and waste coal.
2 Includes natural gas, waste heat, butane, methane, propane, other gas, waste gas, and digester gas.
3 Includes petroleum, petroleum coke, liquid butane, diesel, light oil, kerosene, methanol, oil waste, sludge oil, tar oil and liquid propane.
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 black liquor, pitch, peat, railroad ties, sludge wood, wood/wood waste, spent sulfite liquor, and red liquor.
6 Includes agricultural byproducts, fish oil, landfill gas, municipal solid waste, sludge waste, straw, tires, waste alcohol, solid byproducts, and tall oil.
7 Includes batteries, chemicals, hydrogen, sulfur, purchased steam and other.
R = Revised data.

Notes: •All data are for 1 megawatt and greater. •Data for 1996 are preliminary. •Totals may not equal sum of components because of independent rounding. •W = Withheld to avoid disclosure of individual company data.

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

Table 57. Installed Capacity at U.S. Nonutility Generating Facilities by Qualifying Facility Status and Census Division, 1992 Through 1996
(Megawatts)

Census Division	QF Capacity		Non-QF Capacity		Total Capacity	
	No. of Facilities	Capacity (megawatts)	No. of Facilities	Capacity (megawatts)	No. of Facilities	Capacity (megawatts)
			1992			
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			
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			
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**
			1995			
New England	119	3,478	73	1,560	192	5,037
Middle Atlantic	258	12,087	48	390	306	12,477
East North Central	112	3,712	110	2,205	222	5,917
West North Central	28	575	52	658	80	1,232
South Atlantic	160	9,066	125	3,929	285	12,995
East South Central	28	1,143	31	945	59	2,088
West South Central	109	12,165	58	1,726	167	13,891
Mountain	85	1,980	38	777	123	2,757
Pacific	400	11,940	139	1,920	539	13,860
U.S. Total	**1,299**	**56,145**	**674**	**14,109**	**1,973**	**70,254**
			1996			
New England	119	3,625	76	1,577	195	5,202
Middle Atlantic	259	12,604	45	383	304	12,987
East North Central	113	3,758	116	2,316	229	6,074
West North Central	28	576	54	679	82	1,255
South Atlantic	165	9,728	123	3,934	288	13,662
East South Central	27	1,214	32	954	59	2,167
West South Central	111	12,696	62	1,737	173	14,433
Mountain	90	2,102	40	779	130	2,881
Pacific	401	12,041	133	2,480	534	14,521
U.S. Total	**1,313**	**58,345**	**681**	**14,839**	**1,994**	**73,183**

QF = Nonutility generating facilities that have obtained status as qualifying facilities under the Public Utility Regulatory Policies Act of 1978. (qualifying cogen, qualifying small power producers, qualifying cogen, small power producers exempt wholesale generator).

Non-QF = Cogenerator and other nonutility generator.

Notes: •All data are for 1 megawatt and greater. •Data for 1996 are preliminary; data for prior years are final. •The number of facilities shown includes operational, new, and planned facilities. •Totals may not equal sum of components because of independent rounding.

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

Table 58. Installed Capacity at U.S. Nonutilities Attributed to Major Industry Groups and Census Divisions, 1992 Through 1996

(Megawatts)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
				1992			
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			
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			
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**
				1995			
New England	2,281	2,602	W	—	—	W	5,037
Middle Atlantic	9,202	2,074	553	W	W	225	12,477
East North Central	5,086	356	353	W	W	W	5,917
West North Central	755	104	164	W	W	W	1,232
South Atlantic	8,842	3,704	169	W	W	204	12,995
East South Central	2,027	W	W	27	W	—	2,088
West South Central	13,297	W	202	177	—	W	13,891
Mountain	865	823	132	245	—	692	2,757
Pacific	5,250	5,258	436	2,498	242	176	13,860
U.S. Total	**47,606**	**15,144**	**2,165**	**3,428**	**544**	**1,368**	**70,254**
				1996			
New England	2,654	2,391	W	—	—	W	5,202
Middle Atlantic	9,374	2,400	562	W	W	225	12,987
East North Central	5,172	459	358	W	W	W	6,074
West North Central	762	118	168	W	—	W	1,255
South Atlantic	9,202	3,777	165	W	W	447	13,662
East South Central	2,104	22	W	26	W	—	2,167
West South Central	13,409	743	197	72	W	W	14,433
Mountain	922	913	137	242	—	667	2,881
Pacific	5,930	5,247	430	2,498	241	176	14,521
U.S. Total	**49,529**	**16,070**	**2,175**	**3,313**	**542**	**1,555**	**73,183**

Notes: •All data are for 1 megawatt and greater. •Data for 1996 are preliminary; data for prior years are final. •See Technical Notes for Standard Industrial Classifications for these industry groups. •Totals may not equal sum of components because of independent rounding. •W = Withheld to avoid disclosure of individual company data.

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

Table 59. Gross Generation for U.S. Nonutility Power Producers by Energy Source and Census Division, 1992 Through 1996

(Million Kilowatthours)

Census Division	Coal[1]	Petroleum[2]	Natural Gas[3]	Hydroelectric	Geothermal/ Solar/Wind	Wood[4] / Waste[5]	Other[6] / Nuclear	Total
				1992				
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				
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				
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**
				1995				
New England	2,404	R 1,860	R 13,425	2,561	—	R 9,099	—	29,350
Middle Atlantic	R 14,799	1,781	R 45,187	1,584	—	R 6,227	189	69,768
East North Central	R 6,795	R 646	R 16,187	W	—	R 4,247	W	28,436
West North Central	2,680	W	R 707	303	W	908	—	4,702
South Atlantic	R 18,948	R 2,736	R 15,535	2,799	—	R 15,622	1,985	57,624
East South Central	R 2,378	125	R 2,175	W	—	R 7,033	W	12,708
West South Central	R 6,314	W	R 67,102	W	—	R 5,880	R 1,122	R 84,635
Mountain	1,511	179	6,828	1,171	W	745	W	12,263
Pacific	4,404	W	R 43,471	4,070	12,205	R 7,754	W	76,415
U.S. Total	R **60,234**	R **15,049**	R **210,617**	**14,774**	**13,921**	R **57,514**	R **3,792**	R **375,901**
				1996				
New England	2,290	W	13,522	3,235	—	9,036	W	29,862
Middle Atlantic	15,569	1,425	43,062	2,337	—	W	W	68,860
East North Central	6,982	812	18,149	W	—	4,653	W	31,189
West North Central	2,504	W	564	382	W	812	—	4,362
South Atlantic	19,458	3,033	15,319	3,042	—	15,960	1,674	58,485
East South Central	2,418	194	2,571	W	—	7,031	W	13,249
West South Central	6,032	3,402	66,133	W	W	5,789	1,592	84,013
Mountain	1,461	W	7,749	1,280	1,663	W	187	13,480
Pacific	4,710	W	46,290	3,878	12,703	7,635	W	79,030
U.S. Total	**61,424**	**14,951**	**213,359**	**16,555**	**14,500**	**57,997**	**3,744**	**382,530**

1 Includes coal, anthracite culm, bituminous gob, coke breeze, fine coal, tar coal, lignite waste and waste coal.
2 Includes petroleum, petroleum coke, liquid butane, diesel, light oil, kerosene, methanol, oil waste, sludge oil, tar oil and liquid propane.
3 Includes natural gas, waste heat, butane, methane, propane, other gas, waste gas, and digester gas.
4 Includes black liquor, pitch, peat, railroad ties, sludge wood, wood/wood waste, spent sulfite liquor, and red liquor.
5 Includes agricultural byproducts, fish oil, landfill gas, municipal solid waste, sludge waste, straw, tires, waste alcohol, solid byproducts, and tall oil.
6 Includes batteries, chemicals, hydrogen, sulfur, purchased steam and other.
R = Revised data.

Notes: •All data are for 1 megawatt and greater. •Data for 1996 are preliminary; data for prior years are final. •Data previously published has been reclassified by energy source and has been changed to reflect these changes. •Totals may not equal sum of components because of independent rounding. •Percent change is calculated before rounding. •W = Withheld to avoid disclosure of individual company data.

Table 60. Gross Generation for U.S. Nonutility Power Producers by Energy Source and State, 1996
(Million Kilowatthours)

State	Coal[1]	Petroleum[2]	Natural Gas[3]	Hydroelectric	Geothermal/ Solar/Wind	Wood[4] / Waste[5]	Other[6] / Nuclear	Total
				1996				
Alaska	W	132	W	–	–	W	–	1,200
Alabama	583	169	1,553	–	–	4,580	–	6,885
Arkansas	W	W	810	W	–	W	–	2,519
Arizona	W	5	W	–	–	W	–	W
California	2,692	W	38,338	2,940	12,431	5,331	W	63,965
Colorado	W	W	2,880	119	–	W	–	3,276
Connecticut	W	142	1,023	W	–	1,736	–	4,688
District of Columbia	–	–	–	–	–	–	–	–
Delaware	W	W	W	–	–	–	–	778
Florida	5,391	597	9,525	–	–	6,082	1,416	23,011
Georgia	965	772	862	53	–	3,273	–	5,924
Hawaii	W	W	W	88	W	632	–	4,410
Iowa	998	16	57	W	–	W	–	1,131
Idaho	W	W	162	1,055	–	529	W	1,898
Illinois	2,013	37	1,567	84	–	329	–	4,031
Indiana	1,077	W	3,069	–	–	W	–	4,561
Kansas	–	W	57	W	–	–	–	73
Kentucky	–	W	–	–	–	W	–	W
Louisiana	W	W	13,971	W	–	3,124	W	20,209
Massachusetts	W	251	7,854	271	–	2,215	W	10,673
Maryland	W	W	907	–	–	771	–	1,969
Maine	517	1,240	W	2,173	–	3,665	W	7,604
Michigan	1,976	W	12,803	144	–	2,962	W	18,087
Minnesota	1,145	W	338	353	W	761	–	2,660
Missouri	251	W	W	–	–	W	–	306
Mississippi	W	W	806	–	–	W	–	W
Montana	W	W	W	W	–	W	–	836
North Carolina	5,509	336	285	W	–	1,697	W	9,986
North Dakota	W	W	W	–	–	W	–	W
Nebraska	W	–	W	–	–	–	–	W
New Hampshire	–	82	2	503	–	1,110	–	1,697
New Jersey	W	516	14,656	W	–	1,198	–	18,541
New Mexico	–	W	836	–	–	W	–	841
Nevada	–	W	2,681	W	1,663	–	W	4,387
New York	2,555	373	25,055	1,862	–	2,640	–	32,486
Ohio	704	20	441	W	–	W	–	1,609
Oklahoma	W	W	1,505	–	–	W	–	4,674
Oregon	W	W	W	406	–	587	–	3,239
Pennsylvania	10,861	536	3,351	W	–	2,576	W	17,833
Rhode Island	–	64	4,635	W	–	W	–	4,809
South Carolina	408	165	130	55	–	1,655	–	2,414
South Dakota	–	–	–	–	–	–	–	–
Tennessee	1,785	W	212	W	–	611	W	3,645
Texas	W	1,559	49,847	W	W	772	W	56,611
Utah	W	W	W	W	–	–	–	764
Virginia	4,711	657	3,059	92	–	2,482	–	11,001
Vermont	–	W	–	179	–	W	–	391
Washington	W	162	4,620	444	–	962	W	6,216
Wisconsin	1,213	W	269	292	–	818	W	2,902
West Virginia	2,062	W	W	W	–	W	W	3,403
Wyoming	W	W	W	–	–	–	W	W
U.S. Total	**61,424**	**14,951**	**213,359**	**16,555**	**14,500**	**57,997**	**3,744**	**382,530**

1 Includes coal, anthracite culm, bituminous gob, coke breeze, fine coal, tar coal, lignite waste and waste coal.
2 Includes petroleum, petroleum coke, liquid butane, diesel, light oil, kerosene, methanol, oil waste, sludge oil, tar oil and liquid propane.
3 Includes natural gas, waste heat, butane, methane, propane, other gas, waste gas, and digester gas.
4 Includes black liquor, pitch, peat, railroad ties, sludge wood, wood/wood waste, spent sulfite liquor, and red liquor.
5 Includes agricultural byproducts, fish oil, landfill gas, municipal solid waste, sludge waste, straw, tires, waste alcohol, solid byproducts, and tall oil.
6 Includes batteries, chemicals, hydrogen, sulfur, purchased steam and other.
– Data not available.

Notes: •All data are for 1 megawatt and greater. •Data for 1996 are preliminary. •Totals may not equal sum of components because of independent rounding. •Percent change is calculated before rounding. •W = Withheld to avoid disclosure of individual company data.

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

Table 61. Gross Generation at U.S. Nonutility Generating Facilities by Qualifying Facility Status and Census Division, 1992 Through 1996

(Million Kilowatthours)

Census Division	QF Generation		Non-QF Generation		Total Generation	
	No. of Facilities	Generation (million kilowatthours)	No. of Facilities	Generation (million kilowatthours)	No. of Facilities	Generation (million kilowatthours)
			1992			
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			
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			
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	408	70,659	146	5,612	554	76,271
U.S. Total	**1,267**	**292,082**	**701**	**62,843**	**1,968**	**354,925**
			1995			
New England	119	21,681	73	7,669	192	29,350
Middle Atlantic	258	67,661	48	2,107	306	69,768
East North Central	112	19,255	110	9,182	222	28,436
West North Central	28	2,377	52	2,325	80	4,702
South Atlantic	160	44,277	125	13,348	285	57,624
East South Central	28	7,567	31	5,142	59	12,708
West South Central	109	R 74,579	58	10,056	167	R 84,635
Mountain	85	10,024	38	2,239	123	12,263
Pacific	400	69,168	139	7,247	539	76,415
U.S. Total	**1,299**	R **316,587**	**674**	**59,314**	**1,973**	R **375,901**
			1996			
New England	119	21,489	76	8,372	195	29,862
Middle Atlantic	259	66,782	45	2,078	304	68,860
East North Central	113	21,806	116	9,383	229	31,189
West North Central	28	2,196	54	2,166	82	4,362
South Atlantic	165	46,234	123	12,252	288	58,485
East South Central	27	7,727	32	5,522	59	13,249
West South Central	111	74,126	62	9,887	173	84,013
Mountain	90	11,007	40	2,473	130	13,480
Pacific	401	69,831	133	9,199	534	79,030
U.S. Total	**1,313**	**321,198**	**681**	**61,332**	**1,994**	**382,530**

R = Revised data.

QF = Nonutility generating facilities that have obtained status as qualifying facilities under the Public Utility Regulatory Policies Act of 1978. (qualifying cogen, qualifying small power producer, exempt wholesale generator).

Non-QF = Cogenerator and other nonutility generator.

Notes: •All data are for 1 megawatt and greater. •Data for 1996 are preliminary; data for prior years are final. •The number of facilities shown includes operational, new, and planned facilities. •Totals may not equal sum of components because of independent rounding.

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

Table 62. Gross Generation of U.S. Nonutilities Attributed to Major Industry Groups and Census Divisions, 1992 Through 1996
(Million Kilowatthours)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
				1992			
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			
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			
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**
				1995			
New England	13,334	15,422	W	—	—	W	29,350
Middle Atlantic	51,375	10,749	3,668	W	968	W	69,768
East North Central	24,716	1,994	1,345	W	W	W	28,436
West North Central	3,025	W	403	W	W	W	4,702
South Atlantic	45,772	10,998	657	W	W	168	57,624
East South Central	12,448	70	W	125	W	—	12,708
West South Central	R 82,434	W	614	492	—	W	R 84,635
Mountain	4,976	3,603	890	482	—	2,311	12,263
Pacific	30,630	23,352	2,606	17,730	1,528	569	76,415
U.S. Total	R **268,711**	**67,695**	**10,775**	**21,277**	**2,617**	**4,826**	R **375,901**
				1996			
New England	15,208	13,987	W	—	—	W	29,862
Middle Atlantic	48,575	12,347	3,819	W	W	1,621	68,860
East North Central	27,183	2,506	1,381	W	W	W	31,189
West North Central	2,830	561	403	W	—	W	4,362
South Atlantic	45,995	10,679	722	W	W	1,066	58,485
East South Central	12,983	69	W	118	W	—	13,249
West South Central	80,794	2,190	566	385	W	W	84,013
Mountain	5,347	3,921	863	550	—	2,800	13,480
Pacific	32,691	23,616	2,638	18,060	1,535	489	79,030
U.S. Total	**271,606**	**69,874**	**11,058**	**21,214**	**2,659**	**6,120**	**382,530**

R = Revised data.

Notes: •All data are for 1 megawatt and greater. •Data for 1996 are preliminary; data for prior years are final. •See Technical Notes for Standard Industrial Classifications for these industry groups. •Totals may not equal sum of components because of independent rounding. •W = Withheld to avoid disclosure of individual company data.

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

Table 63. U.S. Nonutility Electricity Supply and Disposition for Facilities by Census Division and State, 1995 and 1996

(Million Kilowatthours)

Census Division and State	Gross Generation		Receipts[1]		Sales[2]		Facility Use	
	1995	1996	1995	1996	1995	1996	1995	1996
New England	**29,350**	**29,862**	**3,858**	**3,984**	**23,967**	**24,134**	**9,241**	**9,712**
Connecticut	4,812	4,688	288	291	4,064	3,958	1,036	1,021
Maine	7,625	7,604	2,509	2,662	4,556	4,393	5,578	5,873
Massachusetts	11,022	10,673	669	735	10,073	9,641	1,618	1,766
New Hampshire	1,580	1,697	287	191	1,206	1,283	661	605
Rhode Island	3,965	4,809	W	W	3,777	4,522	W	W
Vermont	347	391	W	W	291	337	W	W
Middle Atlantic	**69,768**	**68,860**	**5,408**	**5,522**	**59,316**	**58,520**	**15,860**	**15,862**
New Jersey	18,815	18,541	848	901	16,804	16,492	2,859	2,950
New York	33,502	32,486	1,410	1,475	30,069	29,106	4,843	4,854
Pennsylvania	17,450	17,833	3,151	3,146	12,443	12,922	8,158	8,057
East North Central	**28,436**	**31,189**	**18,931**	**19,077**	**12,147**	**14,865**	**35,220**	**35,401**
Illinois	3,952	4,031	5,903	6,069	370	415	9,484	9,685
Indiana	4,281	4,561	5,376	5,149	83	109	9,573	9,600
Michigan	15,587	18,087	1,813	1,845	11,294	14,027	6,106	5,905
Ohio	1,551	1,609	2,896	3,023	56	75	4,390	4,556
Wisconsin	3,066	2,902	2,944	2,990	343	239	5,667	5,653
West North Central	**4,702**	**4,362**	**5,682**	**6,013**	**769**	**938**	**9,615**	**9,437**
Iowa	1,177	1,131	1,425	1,493	209	217	2,394	2,407
Kansas	195	73	W	W	W	W	1,188	1,209
Minnesota	2,803	2,660	2,845	2,967	517	683	5,131	4,944
Missouri	333	306	W	288	W	W	584	568
Nebraska	W	W	W	W	—	—	W	W
North Dakota	W	W	W	W	W	W	W	W
South Dakota	—	—	—	—	—	—	—	—
South Atlantic	**57,624**	**58,485**	**15,660**	**24,210**	**32,927**	**34,133**	**40,358**	**48,562**
Delaware	750	778	W	373	W	W	W	W
District of Columbia	—	—	—	—	—	—	—	—
Florida	21,197	23,011	1,737	1,845	13,500	14,928	9,435	9,928
Georgia	6,285	5,924	3,206	11,432	368	143	9,123	17,213
Maryland	1,773	1,969	W	2,015	W	W	W	W
North Carolina	10,788	9,986	2,998	3,274	7,604	7,366	6,182	5,894
South Carolina	2,632	2,414	664	510	390	381	2,906	2,542
Virginia	10,844	11,001	2,823	3,001	8,548	8,538	5,119	5,464
West Virginia	3,356	3,403	1,779	1,760	1,241	1,333	3,894	3,830
East South Central	**12,708**	**13,249**	**7,817**	**8,250**	**2,127**	**2,101**	**18,398**	**19,398**
Alabama	6,269	6,885	W	3,280	W	W	8,558	9,228
Kentucky	W	W	—	—	W	W	W	W
Mississippi	W	W	W	1,860	114	W	W	W
Tennessee	3,615	3,645	W	3,111	1,107	W	W	5,738
West South Central	R **84,635**	**84,013**	**19,288**	**25,531**	R **30,365**	**29,856**	R **73,557**	**79,688**
Arkansas	2,618	2,519	W	839	W	W	3,147	3,314
Louisiana	20,196	20,209	7,134	7,923	3,592	3,385	23,737	24,747
Oklahoma	5,031	4,674	W	1,048	W	W	2,635	2,432
Texas	R 56,789	56,611	10,374	15,720	R 23,125	23,136	R 44,038	49,195
Mountain	**12,263**	**13,480**	**4,052**	**3,946**	**9,395**	**10,768**	**6,920**	**6,658**
Arizona	878	W	W	222	W	W	671	641
Colorado	3,057	3,276	178	152	2,681	3,109	553	319
Idaho	1,823	1,898	W	W	1,667	1,781	W	1,204
Montana	617	836	W	W	468	668	W	W
Nevada	4,127	4,387	W	W	3,799	4,027	W	362
New Mexico	413	841	1,313	1,359	W	W	W	1,801
Utah	744	764	W	W	W	W	W	W
Wyoming	604	W	W	140	W	W	951	797
Pacific	**76,415**	**79,030**	**9,223**	**7,570**	**62,441**	**63,643**	**23,197**	**22,957**
Alaska	1,232	1,200	106	109	31	21	1,307	1,288
California	62,832	63,965	4,047	3,279	52,412	52,615	14,467	14,629
Hawaii	4,327	4,410	65	65	3,594	3,680	799	795
Oregon	1,321	3,239	931	842	830	2,514	1,421	1,567
Washington	6,703	6,216	4,074	3,275	5,574	4,813	5,203	4,678
U.S. Total	R **375,901**	**382,530**	**89,919**	**104,101**	R **233,454**	**238,958**	R **232,367**	**247,673**

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.

R = Revised data.

Notes: •All data are for 1 megawatt and greater. •Data for 1996 are preliminary; data for prior year are final. •Totals may not equal sum of components because of independent rounding. •W = Withheld to avoid disclosure of individual company data.

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

Table 64. Estimated Emissions from U.S. Nonutility Power Producers Facilities by Census Division, 1992 Through 1996 (Thousand Short Tons)

Census Division	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide[1]
		1992	
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	
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	
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**
		1995	
New England	45	65	40,427
Middle Atlantic	118	206	61,567
East North Central	227	295	89,212
West North Central	77	45	16,020
South Atlantic	380	299	135,217
East South Central	94	68	43,405
West South Central	194	242	93,766
Mountain	26	61	17,514
Pacific Contiguous	44	140	51,453
Pacific Noncontiguous	12	19	7,743
U.S. Total	**1,217**	**1,440**	**556,324**
		1996	
New England	53	61	35,195
Middle Atlantic	135	215	63,102
East North Central	298	341	103,327
West North Central	77	44	14,052
South Atlantic	422	291	140,507
East South Central	127	86	49,267
West South Central	289	269	107,160
Mountain	23	62	17,815
Pacific Contiguous	82	151	55,725
Pacific Noncontiguous	15	19	7,376
U.S. Total	**1,521**	**1,539**	**593,526**

[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: •All data are for 1 megawatt and greater. •Estimates for 1996 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 Electric Power 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 EIA-411, “Coordinated Bulk Power Supply Program Report”; 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 three consecutive years, sales or transmission service that exceeds one or more of the following: (1) 1 million megawatthours of total annual sales, (2) 100 megawatthours of annual sales for resale, (3) 500 megawatthours of annual power exchanges delivered, or (4) 500 megawatthours of annual wheeling for or (4) 500 megawatthours of annual 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 179 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 eight independent power producers (IPP's): Black Creek Hydro, Inc., Catalyst Old River Hydroelectric Limited Partnership, Entergy Power Inc., Hardee Power Partners Limited, Hermiston Generating Company, L.P., Nevada Sun-Peak Limited Partnership, Ocean State Power, and Ocean State Power II are under FERC jurisdiction. These IPP's must therefore submit the FERC Form 1. The FERC has also determined that Anoka Electric Cooperative; Golden Spread Electric Cooperative; New Hampshire Electric Cooperative; Midwest Energy, Incorporated; Old Dominion Electric Cooperative; People's Electric Cooperative; Pacific Northwest Generating Cooperative; Rayburn Country Electric Cooperative; Soyland Power Cooperative, Inc.; and Valley Electric Association, Inc. should file a FERC Form 1 under Section 201 of the Federal Power Act. Data from these 10 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 detailed 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, both hard copy and diskettes, are returned to the FERC on or before April 30, containing data for the preceding calendar year. A copy of each survey and diskette 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 and the Environmental Protection Agency.

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 for which addresses were confirmed was 100 percent. The data are manually edited before being keyed for automated 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 1992 through 1996 presented in this report, are reasonable given the growth in manufacturing on site generation.

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

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

[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 and burning coal in traditional boilers (e.g., not fluidized bed boilers) are assumed to have particulate and FGD equipment.

These conversion factors were estimated by the staff of the Office of Coal, 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 with 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 I: 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 But consumed for the production of electricity, and proportion by the total But weighted by energy source.

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

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

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

Business Classification. The nonutility industry consists of all manufacturing, agricultural, forestry, transportation, finance, service and administrative industries, based on the Office of Management and Budget's Standard Industrial Classification (SIC) Manual.[22] 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
    4922 Natural gas transmission
    4941 Water supply
    4952 Sewerage systems
    4953 Refuse systems
    4971 Irrigation systems

Wholesale Trade
50 to 51

Retail Trade
52 to 59

Finance, Insurance, and Real Estate
60 Depository Institutions
61 Nondepository credit institutions
62 Security and commodity brokers, dealers, exchanges, and services
63 Insurance carriers
64 Insurance agents, brokers, and services
65 Real estate
67 Holding and other investment offices

Services
70 Hotels
72 Personal services
73 Business services
75 Automotive repair, services, and parking
76 Miscellaneous repair services
78 Motion pictures
79 Amusement and recreation services
80 Health services
81 Legal services
82 Education services
83 Social services
84 Museums, art galleries, and botanical and zoological gardens
86 Membership organizations

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

87 Engineering, accounting, research, management, and related services
88 Private households
89 Miscellaneous services

Public Administration
91 to 97

Other (explain):

Historically, (Tables 58 and 62) 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 EIA-411

The Form EIA-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; and (5) bulk power system maps. 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 EIA-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 had been delegated to the Office of Emergency Planning and Operations within the Department of Energy and was returned to EIA for the reporting year 1996.

Data Processing. The Form EIA-411 is filed annually on June 1 by the ten North American Electric Reliability Councils. The forms are compiled from data furnished by electric utilities and nonutilities (members, associates, and for nonmembers) 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 1996 are final.
- **U.S. Electric Utility Financial Statistics** Financial data from the Federal Energy Regulatory Commission Form 1 and the Form EIA-412 for 1996 are preliminary.
- **U.S. Electric Utility Environmental Statistics** Data from the Form EIA-767 for 1995 are final. Data for 1996 are preliminary. A comparison of preliminary versus final data at the national level for 1996 will be provided in the *Electric Power Annual Volume II* 1997.
- **U.S. Electric Power Transactions** All data from the Forms EIA-411 and FE-718R are final. Data from the Form EIA-861 for 1996 and prior years are final. Data from the Form EIA-860 are final.
- **U.S. Electric Utility Demand-Side Management** All data on demand-side management from the Form EIA-861 are final.
- **U.S. Nonutility Power Producers** Data from the Form EIA-867 for 1992 through 1995 are final. Data for 1996 are preliminary.

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, annual peak load reductions and energy savings for the reporting year and first- and fifth-forecast years, 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.

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 =

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

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).[23] 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.[24]

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.[25] 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 emis-

[23] "*Compilation of Air Pollutant Emission Factors,* Vol. 1: Stationary Point and Area Sources (AP-44);" 5th Edition (including Supplement A) Research Triangle Park, North Carolina, January 1996.

[24] 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.

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

sion 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.

Sulfur Dioxide Emission Comparison. Title IV of the Clean Air Act Amendments of 1990 requires annual sulfur dioxide (SO_2) emissions from electric power plants to be reduced 10 million tons below their 1990 level by the year 2010. The Clean Air Act required electric utility units covered under the Acid Rain Program (units 25 megawatts and greater) to be equipped with continuous emission monitoring systems (CEMS). CEMS is the industry standard for measuring and recording hourly SO_2, nirogen oxide (NO_x), and carbon dioxide (CO_2) emissions. In 1994, the first 263 utility units covered under the Acid Rain Program were required to install CEMS and submit a year's worth of emissions data to the Environmental Protection Agency (EPA). In 1995, the operators of more than 2,000 additional units were required to measure and report emissions data. EPA published 1994 CEMS emissions data by state and plant in its publication *Acid Rain Program, Emissions Scorecard 1994 (EPA430/R-95-012)* .

Preliminary 1995 CEMS data for about 1,000 power plants was received from EPA just prior to the publication deadline. A comparison was made between SO_2 emissions data from 719 electric utility plants for which both EPA and EIA collected data for 1995. On a national basis, the data collected by EPA is 5 percent higher than SO_2 emissions calculated by EIA. When 1995 CEMS data are finalized by EPA, EIA plans to conduct a plant-by-plant comparison of CEMS and EIA-calculated SO_2, NO_x, and CO_2 emissions.

Controlled Nitrogen Oxide Emissions. The controlled NO_x emission is calculated by applying the appropriate reduction factor in Table A5. Prior to 1995 for utility boilers with regulated nitrogen oxide emission limits, the annual controlled estimate used was 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.

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 the 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."[26] However, the boiler type and firing configuration are not reported on the Form EIA-867 so all boilers are assumed to be large boilers[27] 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 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 A5.

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 emis-

[26] "*Compilation of Air Pollutant Emission Factors* , Vol. I: Stationary Point and Area Sources(AP-42)," 5th Edition (including Supplement A) Research Triangle Park, North Carolina, January 1996.

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

sion 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:

National Technical Information Service (NTIS)
Office of Data Base Services
U.S. Department of Commerce
5285 Port Royal Road
Springfield, Virginia 22161
(703) 487-4650 or Fax (703) 321-8547

Personal computer diskette (3 1/2" or 5 1/4") may be purchased by using Visa or MasterCard, as well as money orders or checks payable to the U.S. Department of Energy. To place an order, contact:

Office of Scientific and Technical Information
U.S. Department of Energy
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P.O. Box 62
Oak Ridge, Tennessee 37831
(615) 576-8401 or Fax (615) 576-2865

Table A1. Installed Capacity at U.S. Nonutility Generating Facilities by Producing Energy Group and Census Division, 1993 through 1996

(Megawatts)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
				1993			
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			
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**
				1995			
New England	1,247	3,718	72	—	—	—	5,037
Middle Atlantic	2,225	10,127	W	W	—	W	12,477
East North Central	3,020	2,489	323	W	W	W	5,917
West North Central	755	137	131	W	W	W	1,232
South Atlantic	4,653	8,104	100	W	W	64	12,995
East South Central	1,920	127	W	27	W	—	2,088
West South Central	9,294	4,218	202	177	—	—	13,891
Mountain	393	1,716	51	245	—	352	2,757
Pacific	2,396	10,346	200	644	188	85	13,860
U.S. Total	**25,902**	**40,982**	**1,186**	**1,369**	**273**	**541**	**70,254**
				1996			
New England	1,190	3,938	75	—	—	—	5,202
Middle Atlantic	1,757	11,107	W	—	—	W	12,987
East North Central	3,076	2,584	331	W	W	W	6,074
West North Central	762	151	135	W	—	W	1,255
South Atlantic	4,690	8,739	96	W	W	67	13,662
East South Central	1,997	129	W	26	W	—	2,167
West South Central	9,527	4,636	W	72	W	—	14,433
Mountain	391	2,074	W	242	—	W	2,881
Pacific	2,460	11,120	163	595	99	85	14,521
U.S. Total	**25,850**	**44,477**	**1,162**	**1,204**	**179**	**311**	**73,183**

W = Withheld to avoid disclosure of individual company data.

Notes: •All data are for 1 megawatt and greater. •Data for the 1996 are preliminary; data for prior years are final; •See Technical Notes for Standard Industrial Classifications for these industry groups. •Totals may not equal sum of components because of independent rounding.

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

Table A2. Gross Generation by U.S. Nonutility Generating Facilities by Producing Energy Group and Census Division, 1993 through 1996

(Million Kilowatthours)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
				1993			
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			
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**
				1995			
New England	6,581	22,593	175	—	—	—	29,350
Middle Atlantic	12,831	56,428	419	W	—	W	69,768
East North Central	14,859	12,134	1,159	W	W	W	28,436
West North Central	3,025	W	W	W	W	W	4,702
South Atlantic	25,931	31,284	237	W	W	W	57,624
East South Central	11,593	W	W	125	W	—	12,708
West South Central	57,667	R 25,861	614	492	—	—	R 84,635
Mountain	2,190	8,455	255	482	—	880	12,263
Pacific	12,714	56,952	1,022	4,338	1,104	285	76,415
U.S. Total	**147,392**	R **215,247**	**4,196**	**6,440**	**1,217**	**1,408**	R **375,901**
				1996			
New England	5,940	23,653	268	—	—	—	29,862
Middle Atlantic	9,433	58,894	W	—	—	W	68,860
East North Central	14,854	14,988	1,232	W	W	W	31,189
West North Central	2,830	659	305	W	—	W	4,362
South Atlantic	25,712	32,365	247	W	19	W	58,485
East South Central	12,132	W	W	118	W	—	13,249
West South Central	56,461	26,598	W	385	W	—	84,013
Mountain	2,051	W	220	550	—	W	13,480
Pacific	13,970	59,501	837	4,096	389	237	79,030
U.S. Total	**143,382**	**227,780**	**4,163**	**5,783**	**480**	**943**	**382,530**

R = Revised data.

Notes: •All data are for 1 megawatt and greater. •Data for 1996 are preliminary; data for prior years are final; •See Technical Notes for Standard Industrial Classifications for these industry groups. •Totals may not equal sum of components because of independent rounding.

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

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

Fuel	Boiler Type/ Firing Configuration	Emission Factors: Sulfur Dioxide[1]	Emission Factors: Nitrogen Oxides[2]	Emission Factors: 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	10.00 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	162.70 x S	42.00	25,445
	vertical	162.70 x S	67.00	25,445
	all others	162.70 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	5.00	2,100
Sludge Waste	all types	2.80	5.00	2,100
Sludge Wood	all types	2.80	5.00	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	162.70 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	147.00 x S	19.00	20,000
Propane (liquid)	all types	0.50	19.00	12,500
Sludge Oil	all types	147.00 x S	19.00	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. If bottom type is unknown, dry bottom is assumed. 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*, Fifth Edition (including supplement A), Research Triangle Park, North Carolina, January, 1996. •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	--	30[1]
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	30[1]
Other (or Unspecified)	OT	OT	20
Overfire Air	OV	OA	20[1]
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

[1] Starting with 1995 data, reduction factors for advanced overfire air, low nitrogen oxide burners, and overfire air were reduced by 10.
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 nonparticipants, 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.

Inoperable Capacity: Utility-owned or operated capacity that is totally or partially out of service for reasons such as: environmental restrictions, legal or regulatory restrictions, extensive modifications or repair, or capacity specified as being in a mothballed state.

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.

Internal Demand: Peak hour integrated megawatt demand is defined as the sum of the demands of all customers that a system serves, including the demands of the organization providing the electric service, plus the losses incidental to that service. Total Internal Demand is the sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demand of station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) is not included.

Internal Demand includes adjustments for utility indirect demand-side management programs such as conservation programs, improvements in efficiency of electric energy use, rate incentives, and rebates. Internal Demand should not be reduced by Direct Control Load Management or Interruptible Demand.

Interruptible Demand: The magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the NERC Council or Reporting Party seasonal peak by direct control of the System Operator or by action of the customer at the direct request of the System Operator. In some instances, the demand reduction may be effected by direct action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions. For example, demands that can be interrupted to fulfill planning or operating reserve requirements normally should be reported as Interruptible Demand. Interruptible Demand as reported here does not include Direct Control Load Management.

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 Internal Demand: Internal Demand less Direct Control Load Management and Interruptible Demand.

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 Capacity Resources: Utility- and IPP-owned generating capacity that is existing or in various stages of planning or construction, less inoperable capacity, plus planned capacity purchases from other resources, less planned capacity sales.

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 Demand: The Demand specified by contractual arrangement with a customer to provide power and energy to that customer as a secondary source or backup for an outage of the customer's primary source. Standby Demand is intended to be used infrequently by any one customer.

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.