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Preface

Electric Power Annual, Volumes I and II

The *Electric Power Annual* is published in two volumes. Volume I, released May 1999, contains 1998 data on U.S. electric utility net generation; fossil fuel consumption, stocks, receipts, and cost; preliminary data on generating 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 1998, 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 seven 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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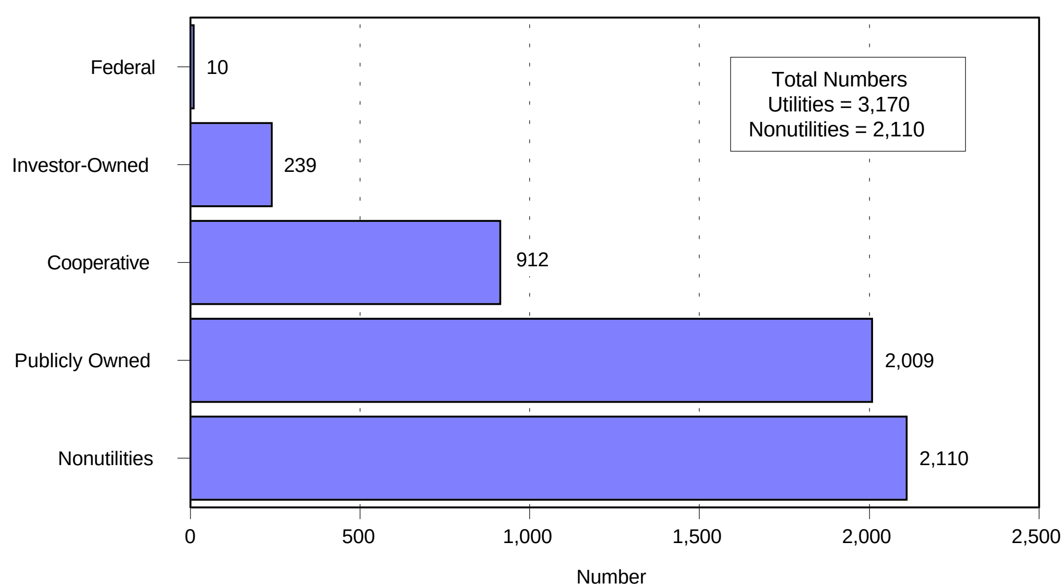
The U.S. Electric Power Industry at a Glance

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. Historically, they have generally been vertically integrated companies that provide for generation, transmission, distribution, and/or energy services for all customers in a designated service territory. However, the industry is currently changing from this vertically integrated and regulated monopoly to a functionally unbundled industry with a competitive market for power generation.[1]

There are over 3,300 electric utilities (including power marketers) 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 400 power marketers have filed rate tariffs with the Federal Energy Regulatory Commission to sell wholesale electric power. However, fewer than one-third of those 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 cogeneration qualifying facility under the Public Utilities Regulatory Policies Act of 1978 (PURPA), (2) small power producers qualified under PURPA that provide at least 75 percent of the total energy input in the form of renewable resources, (3) exempt wholesale generators (EWG) under the Energy Policy Act of 1992 (EPACT), (4) cogenerator non-qualifying facilities, and (5) independent power producers (IPP). There are approximately 2,000 nonutility power producers in the United States.

Figure 1. Composition of the Electric Power Industry in the United States, 1998



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 Producer Report."

[1] A detailed discussion covering the background of electric industry deregulation is contained in Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE/EIA-0562(96)(Washington, DC, December 1996).

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 operated and distributed power from its own projects and marketed 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 occurred August 1998.

Power Marketers. Power marketers continue to be 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 three years, although in 1998, as in previous years, fewer than one-third 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 require registration of retail electricity providers, including power marketers and energy service providers.

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 1998, 2,183 million megawatthours of electricity were reported as sales for resale by power marketers to the EIA. 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.

Nonutility Power Producers

Cogenerator Qualifying Facilities. These are generating facilities that produce electricity and another form of useful thermal energy, usually heat or steam, for industrial processes, or heating/cooling purposes. Cogenerators are qualified under the Public Utility Regulatory Policies Act of 1978 (PURPA) by meeting certain ownership, operating and efficiency criteria as set forth by the Federal Energy Regulatory Commission (FERC). They are guaranteed that utilities will purchase their output at a price based on the utility's "avoided cost" and will be provided backup service at nondiscriminatory rates.[2]

Small Power Producers. These are also qualified under PURPA by meeting certain ownership, operating, and efficiency criteria as set forth by the FERC. They are distinguishable by their use of renewable resources such as biomass, geothermal, solar, wind, or water as a primary energy source. Renewable resources must provide at least 75 percent of the total energy input. Like cogenerators, they are also guaranteed that utilities will purchase their output based on the utility's "avoided cost" and provide backup service at nondiscriminatory rates.

Exempt Wholesale Generators. The Energy Policy Act of 1992 (EPACT) modified the Public Utility Holding Company Act (PUHCA) and created another class of nonutility power producers, exempt wholesale generators (EWG). EPACT exempted EWGs from the corporate and geographic restrictions that PUHCA imposed. With this modification, public utility holding companies are allowed to develop and operate independent power projects anywhere in the world.[3] Lacking transmission facilities and selling wholesale only, EWGs are regulated but usually may charge market-based rates. Utilities are not required to purchase their electricity.

Cogenerator Non-Qualifying Facilities. These facilities utilize cogeneration technology and may themselves consume part of the electricity they cogenerate. They are not qualified under PURPA.

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 and are usually authorized to sell at market-based rates. Unlike traditional electric utilities, IPPs do not possess transmission facilities or have retail electric sales.

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.[4] 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. The EPACT amended the Federal Power Act 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-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 at expected market prices.

Stakeholder disagreements soon arose as to how the FERC should deal with the transition costs associated with the shift to competition. As a result, the Commission's Order on Rehearing (Order No. 888-A) was issued in early 1997. Basically, Order 888-A strives to achieve a balance between the different approaches on how to achieve the recovery of stranded costs. Most critically addressed is how to maintain the financial health of the industry, maintain the regulatory deals concerning large past investments, and to avoid shifting the costs to customers that had no responsibility for these stranded costs.

Order 889 requires public utilities that own or operate transmission facilities to establish electronic information systems, known as Open Access Same-time Infor-

[2] See the chapter, "Nonutility Power Producers," for a description of the benefits under PURPA.

[3] EWGs are not considered electric utilities under PUHCA; they are restricted to selling wholesale power to electric utilities and municipalities. However, EWGs were considered to be electric utilities under the Federal Power Act.

[4] For a further treatise and more detailed information on the transformation of the electric power industry, the reader is referred to the publication Energy Information Administration, *The Changing Structure of the Electric Power Industry: Selected Issues, 1998,* DOE/EIA-0562(98)(Washington, DC, July 1998).

mation 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.

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. Known as comparable service, Order 888 requires utilities owning bulk power transmission facilities to treat any of their own new wholesale sales and purchases of energy over their own transmission facilities to the same transmission tariffs that they apply to others. Advantages are expected to arise from the operational efficiencies that result from overseeing a large regional transmission system and from the elimination of multiple tariffs. However, this program is not without its detractors who claim that advantages may still go to vertically integrated utilities who maintain transmission ownership rights as opposed to nonowners. A possible effect, they assert, is that the ISO will curtail needed future transmission facility expansion. Currently, four ISOs are operating and seven more are in various stages of planning.

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, the FERC has approved market-based rates for more than 300 utilities and power marketers.

Mergers and acquisitions have been proposed as utilities position themselves for competition. During 1998 there were at least 11 completed and 19 pending significant electric utility merger and acquisition activities. 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. Proponents of mergers cite increased economies of scale through the elimination of duplicate functions, penetration into new and additional customer territory, and the economic and financial advantages that come with increased financial strength and operational size.

The EPACT lifted the corporate and geographic restrictions in the Public Utility Holding Company Act (PUHCA) for a new class of nonutility generators, exempt wholesale generators (EWG). This modification of PUHCA allowed public utility holding companies to develop and operate independent power projects anywhere in the world. Also provided is consumer protection against financial abuses and cross-subsidization between regulated and unregulated utilities. The EPACT also amended the Public Utility Regulatory Policies Act (PURPA) by creating inducements for investments in cost-effective improvements in efficiency of power generation and supply. Also added were new rulemaking standards concerning wholesale purchased power. The Federal Power Act of 1935 was amended by broadening when the FERC can order transmission-owning utilities to wheel power and ensuring recovery of the associated costs. Also, the issuance of any order that is inconsistent with State laws governing the retail marketing areas of electric utilities is precluded.

During 1998, the sale of generating units by utilities to nonutility companies increased. The amount of capability which was sold to nonutilities during 1998 was 23,397 MW. Although the effect of the shift from utility to nonutility ownership of generating units was relatively small at the national level, it can be observed more strongly at the State level when restructuring legislation required or encourage divestiture of the utility's generating assets. This shift in ownership reflects the sale of plants, as well as unit additions and retirements during the year. By the end of 1998, four States had over 45 percent of their capability owned by nonutility companies--California, Maine, Massachusetts, and Rhode Island.

Electric utilities added 892 MW of new capability and retired 3,164 MW during 1998. Seventy-three percent of this new utility capacity is gas-fired. In addition, nonutility companies added 4,053 MW of new capability.

Restructuring 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. 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 by allowing customers to choose among competitive suppliers of generation. 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. As of December 1998, 13 States had enacted restructuring legislation. A comprehensive regulatory order had been issued in five States. Legislation was either pending in, or a commission established, or had an ongoing investigation in 30 States. Only Florida and South Dakota had no significant activity.

A Review of 1998

U.S. Electric Utility Statistics

In 1998, the electric power industry experienced a variety of changes to its sales, finances, power transactions and other industry indicators. The following is a summary of those changes.

Retail Sales and Revenue

Sales of electricity to ultimate consumers increased 3.2 percent from 3,140 billion kilowatthours (kWh) in 1997 to 3,240 billion kWh in 1998. Revenue from retail sales increased 1.5 percent to $218 billion in 1998 (Table 1). The national average revenue per kWh decreased from 6.85 in 1997 to 6.74 in 1998. This is the fifth consecutive year that the national average revenue per kWh has decreased.

On a sectorial basis, sales to commercial consumers rose by 4.3 percent in 1998, and sales to residential customers increased by 4.8 percent. The average revenue per kWh declined by 1.1 percent for industrial users (to 4.48 cents) and 2.4 percent for commercial customers (to 7.41 cents), while the average revenue from residential customers was 2 percent lower (to 8.26 cents) after increasing in 1997.[5]

The retail sales of investor-owned utilities increased at a slower rate than sales of the publicly owned and cooperative electric utilities reflecting the selective impact of expanding "customer choice" programs structured by States to primarily affect State-regulated, investor-owned customers. Investor-owned utilities increased sales by 2.3 percent in 1998. Publicly owned utilities increased sales by 5.6 percent, including the transfer in New York of the customers of investor-owned Long Island Lighting Company to publicly owned Long Island Power Authority. Cooperative utilities increased sales by 6.3 percent and Federal utilities increased retail sales, primarily to non-residential customers, by 7.8 percent after declining sales in 1997.

Financial Statistics. Electric operating revenues for the major investor-owned electric utilities were up $5.7 billion to $201.6 billion in 1998. Electric utility operating expenses were up $5.8 billion primarily due to increases in purchased power and income taxes. A 57.4-percent decline in net extraordinary charges enabled a $0.7-billion increase in net income to $17.5 billion. Dividends declared on preferred stock continued their decline, dropping almost 25 percent to $0.8 billion. Although the $17.4 billion of common dividends declared was slightly below that of 1997, it was still $1.5 billion more than in 1994. The profit margin rebounded by going from 7.84 percent to 8.04 percent as well as the return on investment, increasing from 2.88 percent to 2.93 percent.

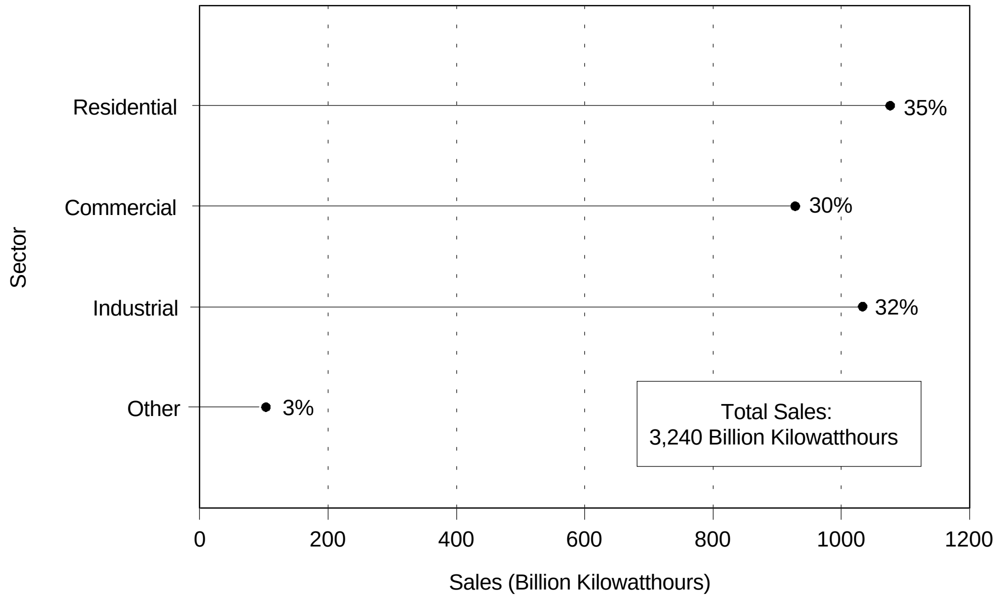
In 1998, the major investor-owned segment continued to position itself in response to restructuring of the industry. Net electric utility plant declined for the second consecutive year, falling 6.6 percent to $328.2 billion. Accumulated depreciation accelerated almost 8.0 percent to $257.9 billion. Other property and investments continued to rise ($48.4 billion), more than double the amount in 1994. Current and accrued assets rose 14.4 percent to $54.5 billion. Total capitalization declined $2.3 billion to $366.8 billion, primarily due to declines in preferred stock and retained earnings. A material increase of 28.0 percent occurred in other deferred credits.

In 1998, the major publicly owned generator electric utilities had electric utility operating revenue of $26.2 billion up by 3.0 percent. Generator electric utility operating expenses increased 2.3 percent, resulting in an increase in net income ($0.3 billion or 302 million) of 18.5 percent. Total assets for publicly owned generator electric utilities fell ($1.39 billion) ending at $113.5 billion. The electric utility plant per dollar of revenue ratio was 3.9 in 1998.

In 1998, the major publicly owned nongenerator electric utilities had electric utility operating revenue of $8.8 billion, a 2.0-percent growth over 1997. Nongenerator electric utility operating expenses increased by 2.3 percent to end the year at $8.2 billion. Net income for nongenerators remained at $0.5 billion. Total assets for nongenerator electric utilities decreased by 12.6 percent to end the year at $12.1 billion. The electric utility plant per dollar of revenue ratio decreased to 1.2 in 1998.

[5] 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 of restructuring. This may skew the changes reported in the commercial and industrial sectors.

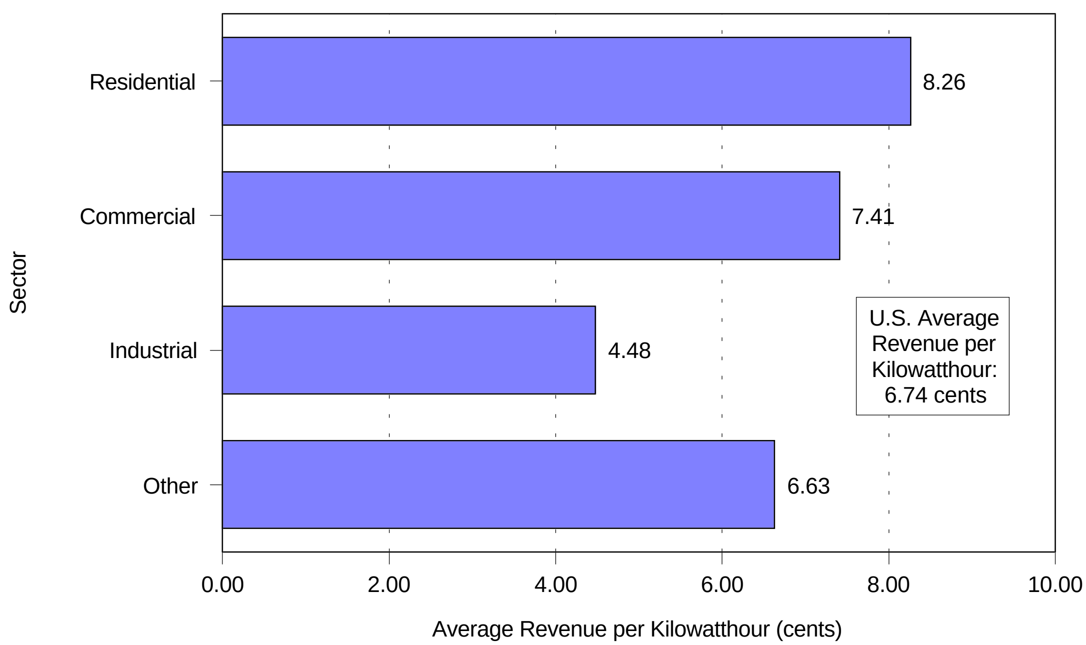
Figure 2. U.S. Electric Utility Sales to Ultimate Consumers by Sector, 1998



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."

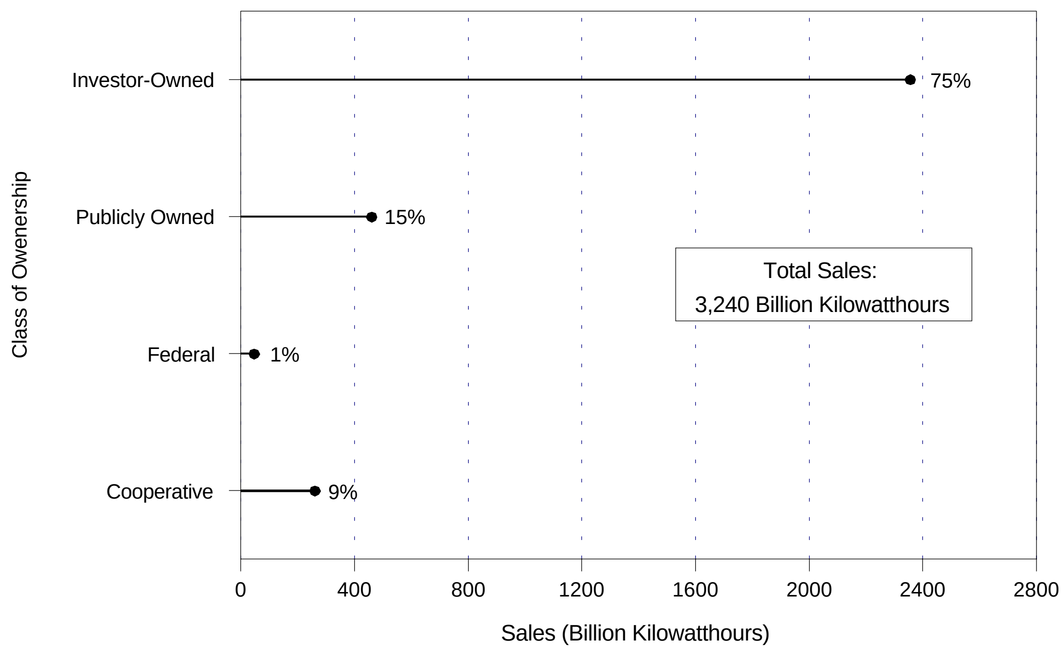
Figure 3. U.S. Electric Utility Average Revenue per Kilowatthour by Sector, 1998



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.

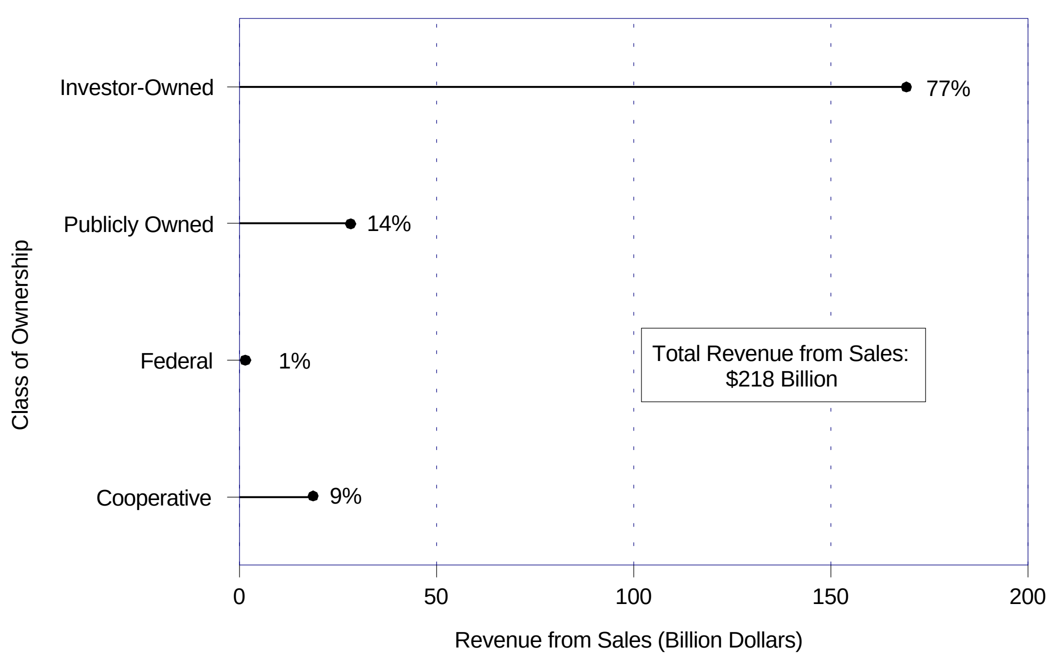
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 4. U.S. Electric Utility Sales to Ultimate Consumers by Class of Ownership, 1998



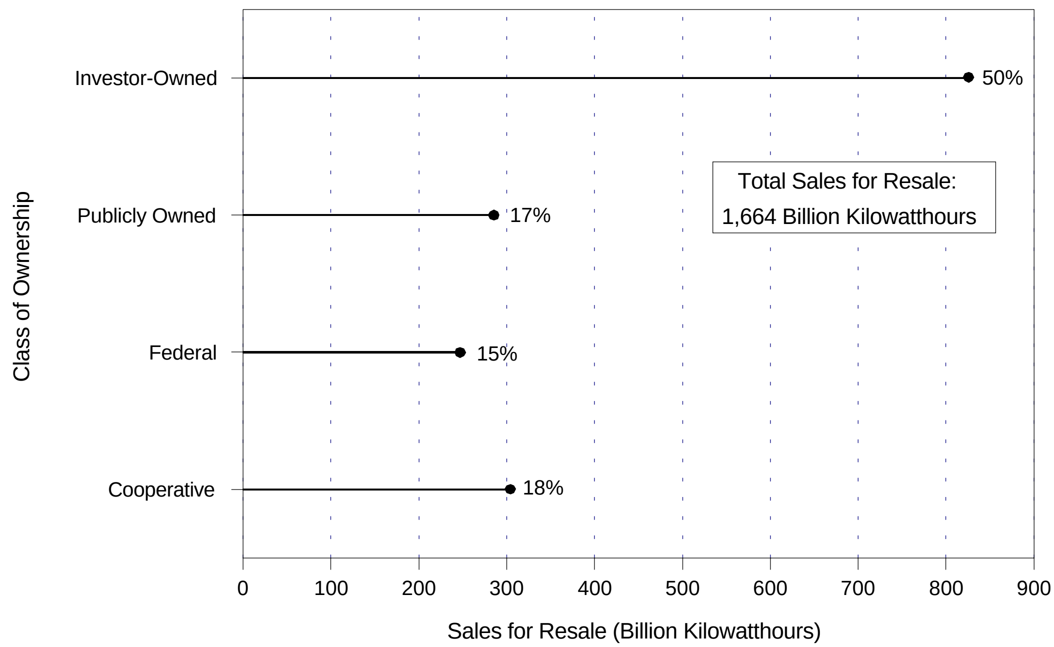
Notes: •Data are final. •Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 5. Revenue from U.S. Electric Utility Sales to Ultimate Consumers by Class of Ownership, 1998



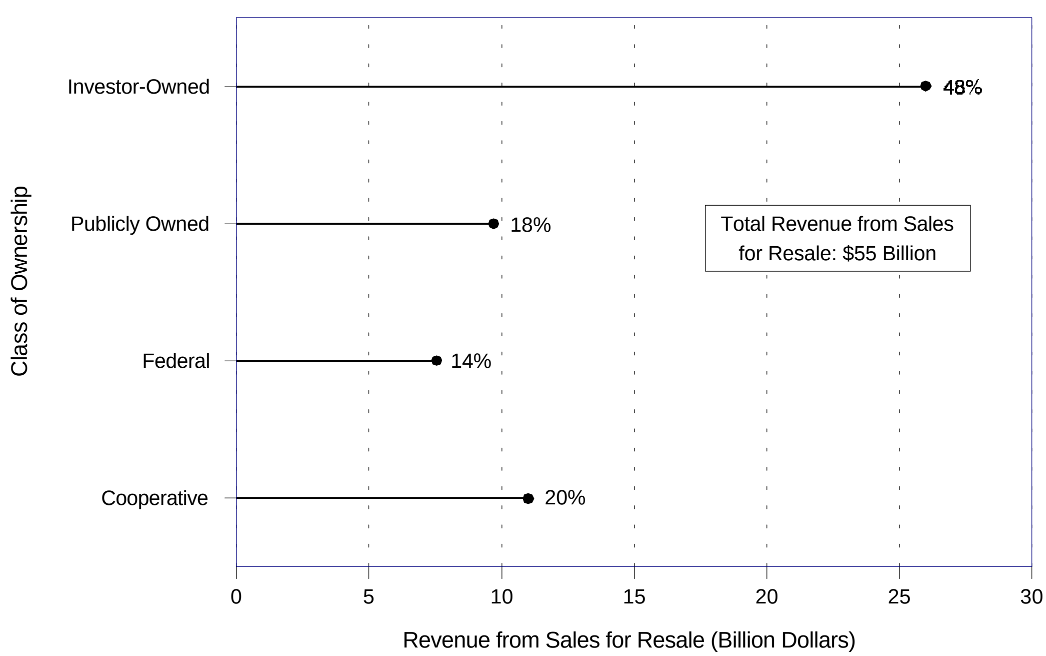
Notes: •Data are final. •Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 6. U.S. Electric Utility Sales for Resale by Class of Ownership, 1998



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, 1998



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.”

Environmental. In 1998, 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). Sulfur dioxide (SO_2) emissions were up from 12.3 million tons to 12.4 million tons, an increase of about 0.9 percent. Nitrogen oxides (NO_x) emissions showed a slight decrease of 6 thousand short tons, or about 0.1 percent. Carbon dioxide (CO_2) emissions increased from 2,142 million tons to 2,209 million tons, or about 3.0 percent.

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 1998, there were 186 generators connected to scrubbers at U.S. power plants, compared with 183 in 1997 and 151 in 1986. The average sulfur content of coal delivered to all U.S. electric utility plants decreased slightly from 1.11 percent by weight in 1997 to 1.06 percent by weight in 1998.[6]

Power Transactions. On a national basis in 1998, wholesale power receipts (purchased power plus exchanges received and wheeling received) increased by 40 billion kilowatthours (kWh) to reach 2,514 billion kWh. Sales to ultimate consumers totaled 3,240 billion kWh, and 1,664 billion kWh of this (51 percent) is from wholesale trade with other electric utilities (Requirement and Nonrequirement Sales for Resale). To supply this electric energy in 1998, electric utilities had planned capacity resources on-hand for the summer of 745 million kilowatts and 752 million kilowatts for the winter, resulting in national capacity margins of 14.3 percent and 25.7 percent, respectively.

In 1998, the noncoincidental peak load at electric utilities in the contiguous United States showed an increase of 1.3 percent, from 660 to 669 million kilowatts for the summer. The winter peak load was 583 million kilowatts, increasing by 15 million kilowatts, which represented a change of about 2.7 percent. Both the summer and winter peak loads for the contiguous United States are projected for 2000 to grow to 694 and 606 million kilowatts respectively. By the year 2003, the growth in the noncoincidental peak load will be above the 1998 actual by almost 64 million kilowatts for the summer and 57 million kilowatts for the winter.

Imports of electricity in 1998 by electric utilities in the United States declined 3.5 billion kilowatthours to 40 billion kilowatthours, while exports rose 42 percent to almost 13 billion kilowatthours. Trade with Canada reached 39.5 billion kilowatthours of imported electricity and nearly 12 billion kilowatthours of exported electricity. Exports to Mexico were down one third to just over 1 billion kilowatthours. Mexican imports were half the amount of 1997 and remained insignificant. Almost half (44 percent) of the imports entered the Northeast Power Coordinating Council (NPCC) Region. For exports, about two-thirds exited the East Central Area Reliability Coordination Agreement (ECAR) and the Western Systems Coordinating Council (WSCC) Regions

On January 1, 1997, the Florida Reliability Council (FRCC) officially became the tenth reliability region of the North American Electric Reliability Council (NERC). Current membership includes power marketers, municipals, and investor-owned utilities. All 37 entities joining the FRCC are full voting members. In 1997, the FRCC Operating Reliability Subcommittee instituted new operating procedures in the areas of regional import and export limits, real-time system security, and scheduled transmission outages. Reflecting the new NERC transmission load relief procedures for the Eastern Interconnection, the FRCC implemented a transmission loading distribution factor cutoff of 5 percent to manage system constraints.

Demand-Side Management. In 1998, 972 electric utilities reported having demand-side management (DSM) programs. Of these, 508 are classified as large and 464 are classified as small utilities. The 508 large utilities account for 88.9 percent of the total retail sales of electricity in the United States.[7]

Energy savings for the 508 large electric utilities decreased to 49,167 million kilowatthours (kWh), 7,239 million kWh less than 1997. These energy savings represent 1.5 percent of annual electric sales of 3,240 billion kWh to ultimate consumers in 1998.

Actual peak load reductions for large utilities increased in 1998 to 27,231 megawatts. Potential peak load reductions of 41,430 megawatts were almost unchanged from 1997.

DSM costs continued to decrease from $1.6 billion in 1997 to $1.4 billion in 1998.[8] This is the fifth consecutive year that DSM costs have decreased from a high of $2.74 billion in 1993.

For 1998, incremental energy savings for large utilities were 3,361 million kilowatthours, incremental actual peak load reductions were 2,617 megawatts,

[6] Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1998 Tables,* DOE/EIA-0191(98) (Washington DC, 1999).

[7] Large utilities are those reporting sales to ultimate consumers or sales for resale greater than or equal to 150,000 megawatthours. Small utilities with sales to ultimate consumers and sales for resale of less than 150,000 megawatthours are only required to report incremental energy savings and peak load reduction, and total utility and total DSM costs for the reporting year and for the first forecast year.

[8] 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.

and incremental potential peak load reductions were 3,628 megawatts.

U.S. Nonutility Generating Facility Statistics

Generation. In 1998, U.S. nonutility generating facilities generated 421 billion kilowatthours (kWh) of electricity. U.S. nonutility generating facilities received 91 billion kWh from and delivered 275 billion kWh to electric utilities and other end users. Nonutility power producers delivered approximately 65.3 percent of their gross generation to electric utilities and other end users and used 237 billion kWh for their own power plant operations and industrial processes. Almost one-third of national nonutility production of electricity occurred in California and Texas, with 76 and 64 billion kWh, respectively.

Gross generation for nonutility generating facilities was 9.6 percent higher in 1998 than a year earlier. Slightly more than half of the generation by nonutility generating facilities was gas-fired, with generation from coal accounting for 16.7 percent of the total. Of the total nonutility generation, 328 billion kWh were from qualifying facilities, more than three 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 (Arkansas, Louisiana, Oklahoma, and Texas), followed by the Pacific Census Division (Alaska, California, Hawaii, Oregon, and Washington). The manufacturing sector dominates electricity generation and is concentrated in the West South Central Census Division, Middle Atlantic Census Division (New Jersey, New York, and Pennsylvania), and South Atlantic Census Division (Delaware, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, and West Virginia) 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 generating facilities was 98,085 megawatts at the end of 1998, 32.5 percent more than in 1997. Nonutility capacity in 1998 was equivalent to 12.6 percent of the total U.S. electric industry capacity.

Of all energy sources, gas accounted for the largest amount (37,530 megawatts) of nonutility capacity. The Pacific Census Division accounted for 36.5 percent of that gas-fired capacity. The second largest share of nonutility capacity was provided by petroleum only and natural gas, followed by wood and waste. Cogeneration accounts for 55.1 percent of nonutility capacity (47.3 percent qualifying facility capacity and 7.7 percent nonqualifying facility capacity). Small power producers and other nonutilities account for 9.7 and 5.1 percent, respectively, of nonutility capacity.

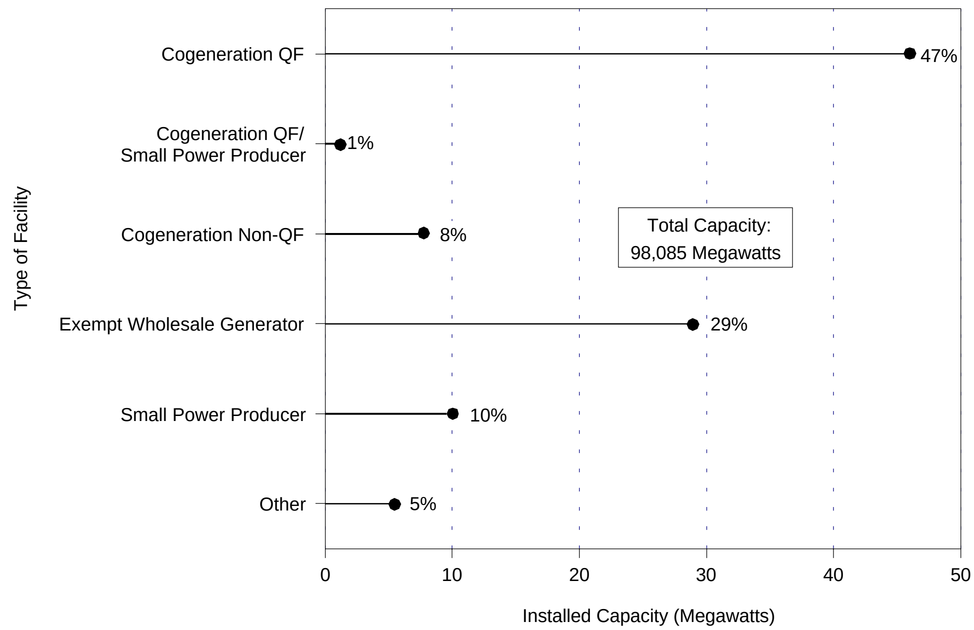
The greatest number (529) of nonutility generating facilities was in the Pacific Census Division, and most of the capacity (26,785 megawatts) was in the Pacific Census Division. In the Pacific Census Division, California dominated because the State actively promoted alternative energy sources in the 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.

Nonutilities plan approximately 5 gigawatts of capacity additions for 1999; 62 gigawatts are planned for 1999 through 2003, with 28 gigawatts (generator nameplate capacity) planned for 1999 through 2003 by electric utilities. Of the nonutility planned capacity, 36.0 percent is gas-fired and 10.0 percent is from renewable capacity.

Consumption. In 1998, consumption by nonutilities included 2,666 billion cubic feet of natural gas, 57 million short tons of coal, and 59 million barrels of petroleum. Compared to 1997, consumption increased 47.0 percent for petroleum, 7.4 percent for coal, and 19.5 percent for gas.

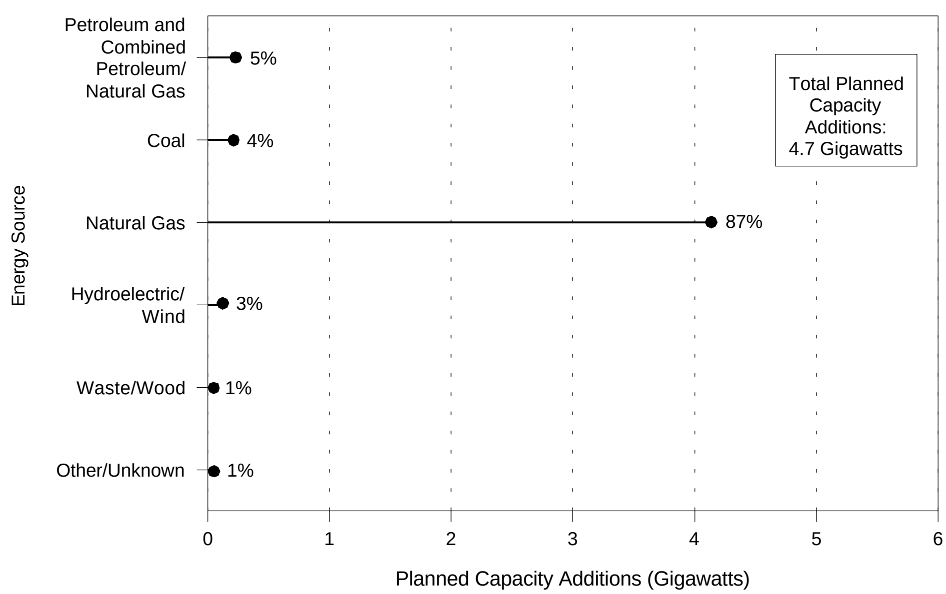
Emissions. In 1998, estimated air emissions from nonutility facilities were 651 thousand short tons in SO_2, 681 thousand short tons of NO_x, and 245,981 thousand short tons of CO_2. This is a 16.8 percent increase of NO_x emissions from the previous year.

Figure 8. Installed Capacity at U.S. Nonutility Generating Facilities by Type of Facility, 1998



QF=Qualifying facility.
Notes: • Data are preliminary. •Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-860B, "Annual Electric Generator Report - Nonutility."

Figure 9. Planned Capacity Additions for U.S. Nonutility Generating Facilities by Energy Source, as of December 31, 1998



Notes: • Data are preliminary. •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."
Source: Energy Information Administration, Form EIA-860B, "Annual Electric Generator Report - Nonutility."

Table 1. Electric Power Industry Summary Statistics for the United States, 1997 and 1998

Item	1997	1998	Percent Change
Electric Power Industry[1]			
Generating Capability (megawatts)[2]	778,502	775,885	–0.3
Net Generation (million kilowatthours)	3,494,223	3,617,873	3.5
Emissions (thousand short tons)[3]			
Sulfur Dioxide (SO_2)	12,988	13,083	.7
Nitrogen Oxides (NOX)	7,810	7,902	1.2
Carbon Dioxide (CO_2)[4]	2,360,792	2,455,267	4.0
Electric Utilities			
Generating Capability (megawatts)[2] [5]	[9] 711,889	[9] 686,692	–3.5
Coal	302,866	299,739	–1.0
Petroleum	69,539	62,959	–9.5
Gas	136,957	125,386	–8.4
Hydroelectric Pumped Storage	19,310	18,898	–2.1
Nuclear	99,716	97,070	–2.7
Waste Heat	4,979	4,818	–3.2
Hydroelectric (conventional)	76,177	75,525	–.9
Other Renewable			
Geothermal	1,622	1,550	–4.4
Biomass[6]	482	504	4.6
Wind	14	9	–35.7
Photovoltaic	5	5	.0
Net Generation (million kilowatthours)	3,122,523	3,212,171	2.9
Coal	1,787,806	1,807,480	1.1
Petroleum[7]	77,753	110,158	41.7
Gas	283,625	309,222	9.0
Nuclear	628,644	673,702	7.2
Hydroelectric Pumped Storage[8]	–4,040	–4,441	9.9
Hydroelectric (conventional)	341,273	308,844	–9.5
Other Renewable			
Geothermal	5,469	5,176	–5.4
Biomass[6]	1,983	2,024	2.1
Wind	6	3	–50.0
Photovoltaic	3	3	.0
Consumption			
Coal (million short tons)	900	911	1.2
Petroleum (million barrels)[10]	125	179	43.2
Gas (billion cubic feet)	2,968	3,258	9.8
Stocks (Year End)			
Coal (million short tons)	99	121	22.2
Petroleum (million barrels)[11]	49	54	10.2
Receipts			
Coal (million short tons)	881	929	5.4
Petroleum (million barrels)[12]	118	165	39.8
Gas (billion cubic feet)[13]	2,766	2,924	5.7
Cost (cents per million Btu)[14]			
Coal	127.3	125.2	–1.6
Petroleum[15]	288.0	213.6	–25.8
Gas	276.0	238.1	–13.7
Sales To Ultimate Consumers (million kilowatthours)	3,139,761	3,239,818	3.2
Residential	1,075,767	1,127,735	4.8
Commercial	928,440	968,528	4.3
Industrial	1,032,653	1,040,038	.7
Other[16]	102,901	103,518	.6
Revenue From Ultimate Consumers (million dollars)	215,059	218,346	1.5
Residential	90,694	93,164	2.7
Commercial	70,482	71,769	1.8
Industrial	46,772	46,550	–.5
Other[16]	7,110	6,863	–3.5
Average Revenue per Kilowatthour (cents)	6.85	6.74	–1.6
Residential	8.43	8.26	–2.0
Commercial	7.59	7.41	–2.4
Industrial	4.53	4.48	–1.1
Other[16]	6.91	6.63	–4.1
Net Electric Plant Inc Fuel (million dollars)			
Major Investor Owned	R 356,645	333,006	–6.6
Major Publicly Owned Generator/Nongenerator	72,387	69,725	–3.7
Emissions (thousand short tons)[17]			
Sulfur Dioxide (SO_2)	12,317	12,432	.9
Nitrogen Oxides (NOX)	7,227	7,221	–.1
Carbon Dioxide (CO_2)	2,142,118	2,209,286	3.1
Noncoincidental Summer Peak Load (megawatts)	R 660,293	669,069	1.3
DSM Actual Peak Load Reductions (megawatts)	25,284	27,231	7.7
DSM Energy Savings (million kilowatthours)	56,406	49,167	–12.8

Table 1. Electric Power Industry Summary Statistics for the United States, 1997 and 1998 (Continued)

Item	1997	1998	Percent Change
Nonutility Power Producers			
Installed Capacity (megawatts)	74,004	98,085	32.5
Coal[18]	11,027	13,712	24.3
Petroleum Only[19]	2,924	2,629	–10.1
Gas Only[20]	31,127	37,530	20.6
Petroleum/Natural Gas (combined)	10,029	23,105	130.4
Nuclear	–-	–-	–-
Hydroelectric (conventional)	3,770	4,136	9.7
Other Renewable			
Geothermal	1,303	1,449	11.2
Biomass[6]	10,676	10,374	–2.8
Wind	1,566	1,689	7.9
Solar Thermal	354	385	5.1
Photovoltaic	–-	–-	–-
Other[21]	1,229	3,075	150.2
Gross Generation (million kilowatthours)	384,496	421,364	9.6
Coal[18]	59,211	70,369	18.8
Petroleum[19]	15,930	17,533	10.1
Gas[20]	219,215	247,613	13.0
Nuclear	–-	–-	–-
Hydroelectric (conventional)	17,902	14,633	–18.3
Other Renewable			
Geothermal	9,382	9,882	5.3
Biomass[6]	55,144	53,682	–2.7
Wind	3,248	3,015	–7.2
Solar Thermal	893	887	–1.9
Photovoltaic	–-	–-	–-
Other[21]	3,572	3,750	5.0
Consumption[22]			
Coal (Thousand short tons)	52,913	56,850	7.4
Petroleum (Thousand barrels)[23]	39,958	58,745	47.0
Natural Gas (Million cubic feet)	2,231,363	2,666,430	19.5
Other Gas (Million cubic feet)[24]	954,976	881,017	–7.7
Supply and Disposition (million kilowatthours)			
Gross Generation	384,496	421,364	9.6
Receipts[25]	88,506	90,675	2.5
Deliveries[26]	241,679	275,260	13.9
Facility Use	231,138	236,770	2.4
Emissions (thousand short tons)[27]			
Sulfur Dioxide (SO2)	671	651	–3.0
Nitrogen Oxides (NOX)	583	681	16.8
Carbon Dioxide (CO2)	218,674	245,981	12.5

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 In 1997, the useful utility thermal output produced additional emissions of 192 thousand short tons of sulfur dioxide, 66 thousand short tons of nitrogen oxides, and 18,159 thousand short tons of carbon dioxide. In 1998, the useful utility thermal output produced additional emissions of 231 thousand short tons of sulfur dioxide, 91 thousand short tons of nitrogen oxides, and 29,267 thousand short tons of carbon dioxide. In 1997, the useful nonutility thermal output produced additional emissions of 775 thousand short tons of sulfur dioxide, 473 thousand short tons of nitrogen oxides, and 143,824 thousand short tons of carbon dioxide. In 1998, the useful nonutility thermal output produced additional emissions of 756 thousand short tons of sulfur dioxide, 493 thousand short tons of nitrogen oxides, and 185,084 thousand short tons of carbon dioxide.

4 The report, ‘‘Carbon Dioxide Emissions from the Generation of Electric Power in the United States,’’ presented carbon dioxide emissions of 2,359,853 thousand short tons in 1997 and 2,447,457 thousand short tons in 1998. The nonutility data were revised since the October 15, 1999, release of that report.

5 Net summer capability based on primary energy source; 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.

6 Includes wood, wood waste, peat, wood liquors, railroad ties, pitch, wood sludge, municipal solid waste, agricultural byproduct, straw, tires, landfill gases, fish oils.

7 Includes petroleum coke.

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

9 For 1998, includes 216 megawatts multi-fueled capacity and 13 megawatts fueled by hot nitrogen; for 1997, includes 209 megawatts multi-fueled capacity and 13 megawatts fueled by hot nitrogen.

10 Does not include petroleum coke consumption of 1400 thousand short tons in 1997 and 1769 thousand short tons in 1998.

11 Does not include petroleum coke stocks of 469 thousand short tons at year end 1997 and 559 thousand short tons at year end 1998.

12 Does not include petroleum coke receipts of 2,192 thousand short tons in 1997 and 3,217 thousand short tons in 1998.

13 Includes small amounts of coke-oven, refinery, blast furnance gas, and landfill gas.

14 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.

15 Does not include petroleum coke cost of 91.2 cents per million Btu in 1997 and 71.2 cents per million Btu in 1998.

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

17 Includes only those power plants with a fossil-fueled steam-electric nameplate capacity (existing or planned) of 10 or more megawatts. As of 1998, emission factors for the calculation of carbon dioxide emissions have been changed--historical data were revised to reflect that change--see the Technical Notes for more information.

18 Includes coal, anthracite culm, coke breeze, fine coal waste coal, bituminous gob and lignite waste.

19 Includes petroleum, petroleum coke, diesel, kerosene, liquid butane, liquid propane, oil waste and tar oil.

[20] Includes natural gas, waste heat, waste gas, butane, methane, propane and other gas.
[21] Includes hydrogen, sulfur, batteries, chemicals, purchased steam.
[22] Includes all combustible fuels burned at generating facilities (not just for the production of electricity).
[23] Does not include petroleum coke consumption of 4,364 thousand short tons for 1997 and 4,470 thousand short tons for 1998.
[24] Includes butane, methane, propane, digester gas, and other gas.
[25] Includes purchases, interchanges, and exchanges of electric energy with utilities and other nonutilities.
[26] 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-860B and the Form EIA-867 are 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-860B and the Form EIA-867 are derived from utility surveys, the Form EIA-860B and the Form EIA-867 universes lag 1 year.
[27] In 1998, emission factors for the calculation of carbon dioxide and the reductions from nitrogen oxide and sulfur dioxide have been changed--historical data were revised to reflect that change--see technical notes for more information.

R = Revised data.

Notes: •Data previously published has been reclassified by energy source and has been changed to reflect these changes. •Data for nonutiliity power producers and emissions are preliminary for 1998; 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'' for 1997; Form EIA-860A, ''Annual Electric Generator Report - Utility'' for 1998; Form EIA-861, ''Annual Electric Utility Report''; Form EIA-767, ''Steam-Electric Plant Operation and Design Report''; Form EIA-860B, ''Annual Electric Generator Report - Nonutility'' for 1998 and Form EIA-867, ''Annual Nonutility Power Producer Report'' for 1997; Federal Energy Regulatory Commission (FERC) Form 1, ''Annual Report of Major Electric Utilities, Licensees, and Others'' as edited by Navigant Consulting, Inc.; Federal Energy Regulatory Commission (FERC) 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. The renewable energy resources shown in Table 1, "Electric Power Industry Summary Statistics for the United States, 1997 and 1998," are reported in detail in the *Renewable Energy Annual, 1999.*

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, North American Industry Classification (NAICS) 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 (NAICS codes 111 through 3399). 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 3,300) that own and/or operate facilities within the United States, its territories, and Puerto Rico.[9] 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*[10]

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

[10] 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 2. U.S. Electric Utility Sales to Ultimate Consumers and Associated Revenue by Sector, 1994 Through 1998

Item	1994	1995	1996	1997	1998
Sales (million kilowatthours)					
Residential	1,008,482	1,042,501	1,082,491	1,075,767	1,127,735
Commercial	820,269	862,685	887,425	928,440	968,528
Industrial	1,007,981	1,012,693	1,030,356	1,032,653	1,040,038
Other[1]	97,830	95,407	97,539	102,901	103,518
U.S. Total	**2,934,563**	**3,013,287**	**3,097,810**	**3,139,761**	**3,239,818**
Revenue (million dollars)					
Residential	84,552	87,610	90,501	90,694	93,164
Commercial	63,396	66,365	67,827	70,482	71,769
Industrial	48,069	47,175	47,385	46,772	46,550
Other[1]	6,689	6,567	6,741	7,110	6,863
U.S. Total	**202,706**	**207,717**	**212,455**	**215,059**	**218,346**

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

Notes: •Data are final. •Data do not include sales to ultimate consumers by power marketers in several State ''retail wheeling'' pilot programs. •Totals may not equal sum of components because of independent rounding.

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

Table 3. Average Revenue per Kilowatthour for U.S. Electric Utilities by Sector, 1994 Through 1998 (Cents)

Sector	1994	1995	1996	1997	1998
Residential	8.38	8.40	8.36	8.43	8.26
Commercial	7.73	7.69	7.64	7.59	7.41
Industrial	4.77	4.66	4.60	4.53	4.48
Other[1]	6.84	6.88	6.91	6.91	6.63
All Sectors	**6.91**	**6.89**	**6.86**	**6.85**	**6.74**

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

Notes: •Data are final. •Data do not include sales to ultimate consumers by power marketers in several State ''retail wheeling'' pilot programs. •The average revenue per kilowatthour of electricity sold is calculated by dividing revenue by sales.

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, 1997 and 1998 (Million Kilowatthours)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other[1]	
	1997	1998	1997	1998	1997	1998	1997	1998	1997	1998
New England	**109,137**	**110,647**	**38,639**	**38,769**	**42,967**	**44,276**	**26,085**	**26,059**	**1,446**	**1,544**
Connecticut	28,432	28,956	10,859	10,935	11,278	11,683	5,919	5,838	376	500
Maine	11,959	11,599	3,659	3,589	3,279	3,324	4,957	4,622	63	63
Massachusetts	47,659	48,607	16,274	16,388	20,834	21,422	9,930	10,212	622	585
New Hampshire	9,081	9,254	3,368	3,384	3,248	3,328	2,339	2,415	127	127
Rhode Island	6,693	6,868	2,486	2,522	2,652	2,731	1,380	1,439	174	177
Vermont	5,312	5,363	1,992	1,951	1,675	1,786	1,561	1,534	84	92
Middle Atlantic	**325,727**	**325,581**	**105,060**	**104,788**	**119,879**	**120,478**	**86,608**	**85,918**	**14,179**	**14,397**
New Jersey	65,915	68,162	22,286	23,191	29,753	31,127	13,369	13,339	507	504
New York	131,936	131,161	40,059	40,240	54,226	53,164	25,282	25,089	12,369	12,669
Pennsylvania	127,875	126,258	42,715	41,358	35,899	36,188	47,957	47,490	1,304	1,223
East North Central	**531,588**	**545,637**	**154,668**	**160,431**	**141,163**	**147,552**	**220,347**	**222,901**	**15,410**	**14,752**
Illinois	126,449	131,217	37,246	39,685	38,136	39,681	42,375	43,031	8,692	8,820
Indiana	89,147	92,059	26,550	27,334	18,514	19,368	43,550	44,848	533	509
Michigan	97,391	100,506	28,726	29,808	32,411	33,840	35,430	35,983	824	875
Ohio	158,508	159,793	43,635	44,516	36,373	38,472	73,888	72,998	4,612	3,807
Wisconsin	60,094	62,061	18,510	19,087	15,730	16,193	25,103	26,040	751	741
West North Central	**228,402**	**236,377**	**81,006**	**84,066**	**62,987**	**65,601**	**78,373**	**80,826**	**6,036**	**5,885**
Iowa	36,148	37,318	11,673	11,855	7,594	8,034	15,531	16,079	1,350	1,350
Kansas	32,270	34,140	10,862	11,832	11,424	12,073	9,365	9,762	618	473
Minnesota	55,674	56,744	17,073	17,378	10,137	10,436	27,713	28,214	750	716
Missouri	65,673	68,986	26,595	28,265	22,825	23,896	15,267	15,801	985	1,024
Nebraska	22,582	23,145	7,989	8,160	6,500	6,594	6,580	6,916	1,514	1,475
North Dakota	8,282	8,220	3,437	3,272	2,300	2,305	2,076	2,187	469	456
South Dakota	7,773	7,824	3,376	3,303	2,207	2,263	1,841	1,868	349	390
South Atlantic	**645,037**	**679,757**	**256,596**	**274,833**	**204,992**	**218,067**	**163,157**	**165,686**	**20,292**	**21,171**
Delaware	10,122	10,398	3,257	3,339	3,068	3,227	3,741	3,779	56	53
District of Columbia	10,107	10,281	1,554	1,596	7,925	8,051	262	262	366	372
Florida	175,041	187,355	87,845	95,768	63,337	67,346	18,266	18,448	5,593	5,792
Georgia	102,250	110,720	36,831	41,519	30,200	32,766	33,957	35,077	1,262	1,358
Maryland	56,264	57,834	21,937	22,407	23,419	24,284	10,128	10,344	781	799
North Carolina	109,050	113,596	40,611	42,890	31,388	33,637	35,095	34,986	1,955	2,083
South Carolina	68,534	72,454	21,611	23,558	14,806	16,370	31,278	31,606	840	920
Virginia	87,420	90,609	33,923	34,703	24,905	26,176	19,249	20,024	9,342	9,705
West Virginia	26,247	26,511	9,027	9,053	5,944	6,208	11,180	11,161	96	89
East South Central	**278,395**	**289,283**	**94,076**	**100,817**	**63,266**	**66,012**	**115,549**	**116,859**	**5,504**	**5,596**
Alabama	74,554	79,173	24,893	27,327	16,397	17,662	32,617	33,539	646	644
Kentucky	76,836	75,850	20,998	21,669	12,169	12,729	40,600	38,260	3,069	3,192
Mississippi	40,089	42,510	14,817	16,392	9,955	10,781	14,622	14,599	694	738
Tennessee	86,917	91,750	33,367	35,428	24,745	24,840	27,710	30,461	1,095	1,021
West South Central	**443,900**	**469,633**	**155,961**	**170,993**	**107,616**	**115,169**	**161,355**	**162,942**	**18,967**	**20,528**
Arkansas	36,858	39,315	12,990	14,339	7,597	8,205	15,632	16,066	638	705
Louisiana	75,886	77,716	24,502	26,709	16,222	17,274	32,493	30,999	2,669	2,734
Oklahoma	44,453	47,897	17,376	19,511	11,754	12,459	12,802	13,175	2,521	2,752
Texas	286,704	304,705	101,094	110,434	72,042	77,231	100,429	102,702	13,138	14,337
Mountain	**199,587**	**206,019**	**63,347**	**64,980**	**61,408**	**64,275**	**67,271**	**68,508**	**7,560**	**8,256**
Arizona	54,456	55,843	20,683	21,611	17,788	18,440	13,253	12,549	2,732	3,244
Colorado	38,069	39,574	12,261	12,652	14,600	15,959	10,297	9,998	911	965
Idaho	21,235	21,276	6,628	6,610	5,969	6,005	8,322	8,393	316	268
Montana	11,917	13,774	3,804	3,722	3,293	3,313	4,537	6,403	284	335
Nevada	24,219	25,037	7,801	7,975	5,454	5,655	10,034	10,518	930	889
New Mexico	17,528	18,173	4,502	4,642	5,440	5,703	6,187	6,186	1,399	1,642
Utah	20,376	20,700	5,661	5,756	6,469	6,709	7,430	7,511	815	724
Wyoming	11,786	11,641	2,007	2,013	2,394	2,490	7,211	6,950	174	188
Pacific	**363,786**	**362,528**	**122,020**	**123,650**	**119,200**	**122,015**	**109,296**	**105,733**	**13,270**	**11,130**
California	227,876	226,396	73,086	74,792	83,570	85,678	62,017	58,856	9,203	7,071
Oregon	47,603	45,083	17,185	17,496	14,047	14,103	15,931	13,070	440	414
Washington	88,306	91,050	31,749	31,362	21,583	22,235	31,348	33,807	3,627	3,645
Pacific Noncontiguous	**14,204**	**14,356**	**4,394**	**4,409**	**4,962**	**5,083**	**4,612**	**4,606**	**235**	**259**
Alaska	4,841	5,095	1,726	1,768	2,181	2,307	756	818	178	202
Hawaii	9,363	9,261	2,668	2,641	2,782	2,776	3,856	3,787	57	57
U. S. Total	**3,139,761**	**3,239,818**	**1,075,767**	**1,127,735**	**928,440**	**968,528**	**1,032,653**	**1,040,038**	**102,901**	**103,518**

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

Notes: •Data are final. •Data do not include sales to ultimate consumers by power marketers in several State ''retail wheeling'' pilot programs. •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, 1997 and 1998
(Thousands)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other[1]	
	1997	1998	1997	1998	1997	1998	1997	1998	1997	1998
New England	**6,345**	**6,412**	**5,608**	**5,663**	**666**	**676**	**29**	**29**	**42**	**43**
Connecticut	1,481	1,492	1,342	1,351	128	130	6	6	5	5
Maine	707	714	613	618	74	75	2	3	18	18
Massachusetts	2,779	2,805	2,451	2,473	302	306	14	14	11	13
New Hampshire	598	616	511	525	79	82	3	3	5	6
Rhode Island	462	465	414	417	44	45	3	3	1	1
Vermont	317	320	277	279	38	39	1	1	1	1
Middle Atlantic	**16,371**	**16,474**	**14,450**	**14,529**	**1,819**	**1,842**	**51**	**51**	**51**	**52**
New Jersey	3,471	3,506	3,050	3,076	397	407	13	13	11	11
New York	7,397	7,432	6,516	6,545	841	846	8	9	32	32
Pennsylvania	5,503	5,536	4,885	4,908	581	589	29	29	8	10
East North Central	**19,906**	**20,221**	**17,815**	**18,072**	**1,944**	**1,998**	**73**	**73**	**74**	**77**
Illinois	5,163	5,290	4,653	4,751	480	506	5	5	25	28
Indiana	2,720	2,767	2,424	2,462	271	278	18	18	8	10
Michigan	4,428	4,487	3,975	4,024	432	441	13	13	8	8
Ohio	5,095	5,140	4,543	4,582	500	509	31	31	21	19
Wisconsin	2,499	2,537	2,220	2,253	261	266	6	6	12	12
West North Central	**9,132**	**9,248**	**7,898**	**7,995**	**1,065**	**1,086**	**47**	**47**	**122**	**120**
Iowa	1,389	1,402	1,202	1,214	167	169	4	4	16	16
Kansas	1,298	1,315	1,099	1,111	175	180	11	11	12	14
Minnesota	2,215	2,244	1,963	1,988	219	222	10	11	23	23
Missouri	2,659	2,699	2,341	2,373	294	302	10	10	14	14
Nebraska	865	874	701	711	116	117	7	8	42	38
North Dakota	335	339	282	285	47	47	2	2	5	5
South Dakota	371	375	311	314	48	49	2	2	10	10
South Atlantic	**23,426**	**23,932**	**20,615**	**21,040**	**2,563**	**2,640**	**77**	**77**	**170**	**175**
Delaware	357	363	320	325	36	37	1	1	1	1
District of Columbia	220	220	193	194	27	26	*	*	*	*
Florida	7,627	7,771	6,727	6,851	823	840	22	24	55	57
Georgia	3,518	3,623	3,115	3,205	360	377	12	12	31	29
Maryland	2,125	2,147	1,908	1,928	208	210	7	8	1	1
North Carolina	3,790	3,900	3,289	3,384	465	481	13	12	23	23
South Carolina	1,910	1,970	1,641	1,684	249	263	6	5	14	18
Virginia	2,955	3,003	2,621	2,663	287	293	5	5	42	42
West Virginia	924	935	800	807	110	114	11	11	3	3
East South Central	**8,006**	**8,148**	**6,889**	**7,020**	**1,025**	**1,054**	**22**	**20**	**70**	**54**
Alabama	2,149	2,187	1,844	1,873	285	296	7	6	12	11
Kentucky	1,918	1,956	1,674	1,705	216	221	7	7	21	22
Mississippi	1,296	1,320	1,109	1,129	174	178	5	5	9	9
Tennessee	2,643	2,686	2,263	2,312	349	360	3	2	28	12
West South Central	**13,550**	**13,852**	**11,756**	**12,015**	**1,525**	**1,551**	**126**	**127**	**143**	**159**
Arkansas	1,291	1,316	1,121	1,140	132	136	26	26	12	14
Louisiana	1,985	2,018	1,745	1,772	204	209	15	15	21	22
Oklahoma	1,690	1,709	1,459	1,476	199	201	16	16	16	16
Texas	8,584	8,808	7,431	7,627	990	1,005	70	70	93	107
Mountain	**7,621**	**7,877**	**6,544**	**6,767**	**879**	**909**	**41**	**41**	**156**	**160**
Arizona	1,989	2,059	1,769	1,830	187	194	5	5	28	29
Colorado	1,944	1,987	1,623	1,662	224	227	5	4	92	94
Idaho	587	602	491	503	86	89	6	7	4	3
Montana	468	511	385	419	67	74	4	5	11	13
Nevada	790	830	689	725	98	103	1	1	2	2
New Mexico	797	813	683	697	98	99	6	6	10	10
Utah	781	808	691	716	75	77	10	9	5	5
Wyoming	264	267	212	216	44	45	4	4	4	3
Pacific Contiguous	**17,063**	**17,194**	**14,885**	**15,053**	**1,966**	**1,987**	**96**	**72**	**116**	**83**
California	12,885	12,941	11,231	11,331	1,510	1,523	65	40	79	47
Oregon	1,570	1,596	1,351	1,376	195	198	12	12	11	11
Washington	2,608	2,657	2,303	2,346	261	267	19	20	25	24
Pacific Noncontiguous	**670**	**683**	**572**	**583**	**87**	**89**	**1**	**1**	**9**	**10**
Alaska	255	265	215	223	35	37	*	*	5	5
Hawaii	415	417	357	360	52	52	1	1	4	4
U. S. Average	**122,089**	**124,041**	**107,033**	**108,737**	**13,540**	**13,833**	**563**	**538**	**952**	**933**

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. •Data do not include sales to ultimate consumers by power marketers in several State ''retail wheeling'' pilot programs. •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, 1997 and 1998
(Million Dollars)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other[1]	
	1997	1998	1997	1998	1997	1998	1997	1998	1997	1998
New England	**11,420**	**11,062**	**4,660**	**4,483**	**4,462**	**4,337**	**2,092**	**2,039**	**207**	**203**
Connecticut	2,991	2,983	1,318	1,306	1,159	1,169	459	449	55	58
Maine	1,137	1,131	466	467	341	343	315	306	15	15
Massachusetts	4,993	4,659	1,886	1,737	2,145	2,003	872	835	90	84
New Hampshire	1,059	1,104	460	471	369	388	212	228	18	17
Rhode Island	716	658	301	275	276	253	118	109	22	20
Vermont	525	527	228	227	173	181	116	112	8	8
Middle Atlantic	**31,852**	**30,899**	**12,576**	**12,244**	**12,675**	**12,314**	**5,221**	**4,976**	**1,380**	**1,364**
New Jersey	6,950	6,932	2,693	2,642	3,079	3,141	1,084	1,059	93	90
New York	14,682	14,043	5,656	5,496	6,577	6,184	1,314	1,241	1,134	1,121
Pennsylvania	10,221	9,923	4,227	4,106	3,019	2,989	2,822	2,676	153	152
East North Central	**34,360**	**35,408**	**13,229**	**13,652**	**10,350**	**10,804**	**9,713**	**9,925**	**1,068**	**1,027**
Illinois	9,747	9,792	3,886	3,908	3,023	3,085	2,243	2,199	595	600
Indiana	4,713	4,914	1,844	1,916	1,118	1,177	1,701	1,770	50	50
Michigan	6,852	7,129	2,462	2,584	2,540	2,642	1,761	1,809	90	94
Ohio	9,911	10,198	3,765	3,875	2,789	2,950	3,076	3,142	282	231
Wisconsin	3,137	3,376	1,273	1,369	881	951	933	1,004	51	52
West North Central	**13,463**	**14,019**	**5,880**	**6,152**	**3,885**	**4,040**	**3,329**	**3,459**	**370**	**368**
Iowa	2,157	2,255	958	993	502	536	614	641	82	84
Kansas	2,036	2,145	837	905	739	766	423	435	37	38
Minnesota	3,121	3,239	1,235	1,273	632	656	1,201	1,257	53	54
Missouri	4,002	4,195	1,885	2,001	1,370	1,430	681	699	67	64
Nebraska	1,196	1,227	510	527	355	359	238	249	94	92
North Dakota	468	469	216	212	141	143	91	94	20	19
South Dakota	483	489	239	240	146	150	81	83	16	17
South Atlantic	**42,009**	**43,745**	**20,277**	**21,443**	**13,525**	**14,048**	**6,940**	**6,957**	**1,266**	**1,297**
Delaware	708	716	300	305	221	228	180	176	7	7
District of Columbia	747	762	122	128	589	598	12	11	24	24
Florida	12,588	13,127	7,097	7,557	4,191	4,298	920	887	380	385
Georgia	6,515	7,087	2,852	3,185	2,147	2,297	1,402	1,483	114	122
Maryland	3,928	4,045	1,827	1,890	1,607	1,656	426	429	69	70
North Carolina	7,068	7,332	3,263	3,434	2,018	2,137	1,655	1,620	133	142
South Carolina	3,771	4,008	1,623	1,767	937	1,021	1,160	1,165	51	55
Virginia	5,366	5,324	2,628	2,608	1,487	1,469	770	764	481	484
West Virginia	1,317	1,345	565	570	329	345	415	422	8	8
East South Central	**14,051**	**15,257**	**5,902**	**6,502**	**3,813**	**4,103**	**4,006**	**4,305**	**330**	**347**
Alabama	3,970	4,404	1,679	1,897	1,040	1,155	1,209	1,306	42	47
Kentucky	3,097	3,155	1,172	1,216	644	675	1,138	1,115	143	149
Mississippi	2,369	2,543	1,040	1,152	666	713	603	616	60	62
Tennessee	4,615	5,155	2,011	2,238	1,462	1,560	1,056	1,269	86	89
West South Central	**26,896**	**27,849**	**11,881**	**12,695**	**7,174**	**7,395**	**6,657**	**6,484**	**1,183**	**1,275**
Arkansas	2,266	2,272	1,013	1,076	515	484	695	669	42	42
Louisiana	4,544	4,490	1,811	1,889	1,134	1,132	1,426	1,288	173	181
Oklahoma	2,410	2,602	1,152	1,282	673	705	465	481	120	134
Texas	17,676	18,486	7,905	8,448	4,852	5,074	4,071	4,047	848	917
Mountain	**11,839**	**12,210**	**4,763**	**4,897**	**3,946**	**4,116**	**2,724**	**2,766**	**406**	**431**
Arizona	4,019	4,092	1,824	1,875	1,394	1,430	669	643	132	144
Colorado	2,265	2,357	910	942	842	904	441	433	73	76
Idaho	821	855	341	349	249	261	216	233	15	12
Montana	619	661	244	242	191	195	166	204	19	20
Nevada	1,357	1,442	528	558	344	368	450	480	36	36
New Mexico	1,192	1,233	402	411	431	445	273	277	86	100
Utah	1,054	1,069	390	394	370	383	259	259	35	33
Wyoming	511	502	125	126	126	131	250	235	10	10
Pacific Contiguous	**27,512**	**26,318**	**10,934**	**10,526**	**10,075**	**10,051**	**5,637**	**5,224**	**866**	**517**
California	21,750	20,439	8,405	7,930	8,343	8,275	4,312	3,876	690	358
Oregon	2,197	2,209	956	1,019	698	705	514	457	28	28
Washington	3,565	3,670	1,572	1,577	1,035	1,070	811	891	147	132
Pacific Noncontiguous	**1,657**	**1,578**	**592**	**568**	**576**	**560**	**455**	**415**	**34**	**35**
Alaska	488	508	197	203	207	219	57	59	26	28
Hawaii	1,169	1,070	395	365	369	342	398	357	8	7
U. S. Total	**215,059**	**218,346**	**90,694**	**93,164**	**70,482**	**71,769**	**46,772**	**46,550**	**7,110**	**6,863**

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

Notes: •Data are final. •Data do not include sales to ultimate consumers by power marketers in several State ''retail wheeling'' pilot programs. •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, 1997 and 1998

(Cents)

Census Division State	All Sectors		Residential		Commercial		Industrial		Other[1]	
	1997	1998	1997	1998	1997	1998	1997	1998	1997	1998
New England	**10.46**	**10.00**	**12.06**	**11.56**	**10.38**	**9.80**	**8.02**	**7.82**	**14.30**	**13.16**
Connecticut	10.52	10.30	12.13	11.95	10.28	10.01	7.76	7.70	14.52	11.65
Maine	9.51	9.75	12.75	13.02	10.39	10.33	6.36	6.61	23.23	23.64
Massachusetts	10.48	9.59	11.59	10.60	10.29	9.35	8.78	8.18	14.49	14.35
New Hampshire	11.66	11.93	13.67	13.92	11.35	11.64	9.06	9.42	14.06	13.76
Rhode Island	10.70	9.58	12.12	10.91	10.40	9.26	8.52	7.61	12.35	11.51
Vermont	9.89	9.83	11.45	11.61	10.33	10.12	7.44	7.27	9.56	8.91
Middle Atlantic	**9.78**	**9.49**	**11.97**	**11.68**	**10.57**	**10.22**	**6.03**	**5.79**	**9.73**	**9.47**
New Jersey	10.54	10.17	12.08	11.39	10.35	10.09	8.11	7.94	18.35	17.92
New York	11.13	10.71	14.12	13.66	12.13	11.63	5.20	4.95	9.17	8.85
Pennsylvania	7.99	7.86	9.90	9.93	8.41	8.26	5.89	5.63	11.71	12.45
East North Central	**6.46**	**6.49**	**8.55**	**8.51**	**7.33**	**7.32**	**4.41**	**4.45**	**6.93**	**6.96**
Illinois	7.71	7.46	10.43	9.85	7.93	7.77	5.29	5.11	6.84	6.80
Indiana	5.29	5.34	6.94	7.01	6.04	6.08	3.91	3.95	9.44	9.83
Michigan	7.04	7.09	8.57	8.67	7.84	7.81	4.97	5.03	10.88	10.74
Ohio	6.25	6.38	8.63	8.70	7.67	7.67	4.16	4.30	6.12	6.07
Wisconsin	5.22	5.44	6.88	7.17	5.60	5.87	3.72	3.86	6.77	7.01
West North Central	**5.89**	**5.93**	**7.26**	**7.32**	**6.17**	**6.16**	**4.25**	**4.28**	**6.12**	**6.25**
Iowa	5.97	6.04	8.21	8.38	6.61	6.67	3.95	3.99	6.09	6.21
Kansas	6.31	6.28	7.71	7.65	6.47	6.34	4.51	4.46	5.97	7.96
Minnesota	5.61	5.71	7.23	7.33	6.23	6.28	4.33	4.45	7.12	7.48
Missouri	6.09	6.08	7.09	7.08	6.00	5.99	4.46	4.43	6.77	6.25
Nebraska	5.30	5.30	6.38	6.46	5.46	5.45	3.61	3.60	6.19	6.27
North Dakota	5.65	5.70	6.27	6.49	6.15	6.20	4.38	4.30	4.27	4.27
South Dakota	6.22	6.26	7.08	7.27	6.63	6.62	4.42	4.44	4.72	4.28
South Atlantic	**6.51**	**6.44**	**7.90**	**7.80**	**6.60**	**6.44**	**4.25**	**4.20**	**6.24**	**6.13**
Delaware	7.00	6.88	9.22	9.13	7.19	7.07	4.82	4.65	12.45	13.17
District of Columbia	7.39	7.41	7.87	8.00	7.43	7.43	4.42	4.38	6.54	6.56
Florida	7.19	7.01	8.08	7.89	6.62	6.38	5.04	4.81	6.80	6.64
Georgia	6.37	6.40	7.74	7.67	7.11	7.01	4.13	4.23	9.05	8.99
Maryland	6.98	6.99	8.33	8.44	6.86	6.82	4.21	4.14	8.80	8.82
North Carolina	6.48	6.45	8.03	8.01	6.43	6.35	4.71	4.63	6.78	6.79
South Carolina	5.50	5.53	7.51	7.50	6.33	6.24	3.71	3.69	6.04	5.99
Virginia	6.14	5.88	7.75	7.51	5.97	5.61	4.00	3.82	5.14	4.98
West Virginia	5.02	5.07	6.26	6.29	5.54	5.56	3.71	3.78	8.71	9.39
East South Central	**5.05**	**5.27**	**6.27**	**6.45**	**6.03**	**6.22**	**3.47**	**3.68**	**6.00**	**6.20**
Alabama	5.33	5.56	6.74	6.94	6.34	6.54	3.71	3.89	6.47	7.26
Kentucky	4.03	4.16	5.58	5.61	5.29	5.30	2.80	2.91	4.64	4.67
Mississippi	5.91	5.98	7.02	7.03	6.69	6.62	4.12	4.22	8.61	8.45
Tennessee	5.31	5.62	6.03	6.32	5.91	6.28	3.81	4.17	7.88	8.71
West South Central	**6.06**	**5.93**	**7.62**	**7.42**	**6.67**	**6.42**	**4.13**	**3.98**	**6.24**	**6.21**
Arkansas	6.15	5.78	7.80	7.51	6.78	5.90	4.45	4.16	6.61	5.98
Louisiana	5.99	5.78	7.39	7.07	6.99	6.56	4.39	4.15	6.48	6.62
Oklahoma	5.42	5.43	6.63	6.57	5.73	5.66	3.63	3.65	4.76	4.88
Texas	6.17	6.07	7.82	7.65	6.74	6.57	4.05	3.94	6.45	6.40
Mountain	**5.93**	**5.93**	**7.52**	**7.54**	**6.43**	**6.40**	**4.05**	**4.04**	**5.38**	**5.22**
Arizona	7.38	7.33	8.82	8.68	7.83	7.76	5.05	5.12	4.84	4.43
Colorado	5.95	5.95	7.42	7.45	5.77	5.67	4.28	4.34	8.00	7.92
Idaho	3.87	4.02	5.15	5.28	4.17	4.34	2.60	2.77	4.68	4.59
Montana	5.20	4.80	6.40	6.50	5.80	5.87	3.66	3.19	6.68	6.07
Nevada	5.60	5.76	6.77	7.00	6.31	6.50	4.48	4.57	3.83	4.02
New Mexico	6.80	6.78	8.92	8.85	7.92	7.80	4.42	4.47	6.17	6.11
Utah	5.17	5.16	6.89	6.84	5.72	5.71	3.49	3.45	4.34	4.50
Wyoming	4.33	4.31	6.22	6.28	5.27	5.25	3.46	3.38	5.84	5.15
Pacific Contiguous	**7.56**	**7.26**	**8.96**	**8.51**	**8.45**	**8.24**	**5.16**	**4.94**	**6.53**	**4.65**
California	9.54	9.03	11.50	10.60	9.98	9.66	6.95	6.59	7.50	5.06
Oregon	4.61	4.90	5.56	5.82	4.97	5.00	3.23	3.50	6.44	6.67
Washington	4.04	4.03	4.95	5.03	4.79	4.81	2.59	2.64	4.06	3.61
Pacific Noncontiguous	**11.66**	**10.99**	**13.48**	**12.89**	**11.61**	**11.03**	**9.86**	**9.01**	**14.37**	**13.37**
Alaska	10.07	9.97	11.44	11.50	9.51	9.48	7.48	7.17	14.75	13.68
Hawaii	12.49	11.56	14.80	13.82	13.26	12.31	10.32	9.41	13.20	12.28
U. S. Average	**6.85**	**6.74**	**8.43**	**8.26**	**7.59**	**7.41**	**4.53**	**4.48**	**6.91**	**6.63**

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

Notes: •Data are final. •Data do not include sales to ultimate consumers by power marketers in several State ''retail wheeling'' pilot programs. •The average revenue per kilowatthour of electricity sold is calculated by dividing revenue by sales.

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 competition 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.

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 1998. 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. *Purchase Power Cents Per Kilowatthour* is the ratio of the cost of purchased power to the number of kilowatthours purchased. This ratio measures the purchased power component of power supply cost. *Generated Cents Per Kilowatthour* is the ratio of the cost of labor, materials used and expenses incurred in the production of electric generation. This ratio measures the generation component of production expenses. *Total Power Supply Per Kilowatthour Sold* is the ratio of the total cost of power supply to total sales to both ultimate and resale consumers. This ratio measures all power supply costs, including generation and purchase power, associated with the sale of each kilowatthour of electricity.

Revenue and Expense Statistics

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

Electric Operating Expenses

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

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

Investor-owned electric utilities are the major sources of total electricity generation, accounting for about 80 percent of total utility generation in the United States in 1998. 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 1994 through 1998 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).

Effective for 1997 and 1998, FERC Form 1 data in this publication have been edited by Navigant Consulting, Inc. Detailed data for 1994 through 1996 are published in the *Financial Statistics of Major U.S. Investor-Owned Electric Utilities.*[11] This publication has now been discontinued. However, complete 1997 and 1998 FERC Form 1 data may be obtained on a utility-by-utility basis from the FERC World Wide Website (http://www.ferc.fed.us).

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:

- 150,000 megawatthours of sales to ultimate consumers
- 150,000 megawatthours of sales for resale.

The 1994-1998 data represents those public electric utilities meeting a threshold of 120,000 ultimate consumers' sales and or resales. Approximately 500 publicly owned electric utilities are required to submit the Form EIA-412 for 1998. These major publicly owned electric utilities represent about one-fourth of all publicly owned electric utilities and more than 80 percent of total sales by publicly owned electric utilities to ultimate consumers. These electric utilities are requested, but not required, to follow the FERC Uniform System of Accounts. Detailed financial statistics on public electric utilities, Federal electric utilities, and rural electric cooperatives are published in the *Financial Statistics of Major U.S. Publicly Owned Electric Utilities.*[12]

[11] 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).

[12] 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, 1994 Through 1998
(Thousand Dollars)

Description	1994	1995	1996	1997[1]	1998
Operating Revenue	**196,281,500**	**199,966,979**	**207,459,078**	**215,082,593**	**217,817,986**
Electric	179,307,260	183,655,263	188,900,781	195,897,868	201,612,978
Gas	16,221,506	15,580,382	17,869,394	18,662,611	15,734,812
Other Utility	752,734	731,333	688,903	522,114	470,197
Operating Expenses	**164,207,153**	**165,321,023**	**173,920,492**	**182,796,184**	**186,103,079**
Electric	148,662,734	150,598,710	156,937,816	165,443,479	171,294,039
Operation	93,107,998	91,880,940	97,206,642	104,337,106	110,807,022
Maintenance	12,021,790	11,767,040	12,049,844	12,367,646	12,451,410
Depreciation[2]	18,679,022	19,885,482	21,193,742	23,072,100	23,890,201
Taxes Other Than Income Taxes	13,275,354	13,519,143	13,569,490	13,611,714	12,836,324
Regulatory Debits (net)	706,108	1,142,138	683,185	615,575	−585,381
Income Taxes	9,625,569	11,479,763	11,194,656	11,862,201	13,077,616
Deferred Income Tax	1,831,593	1,473,977	1,616,998	25,433	−534,606
Investment Tax Credit (Net)	−584,701	−549,772	−576,741	−448,296	−648,547
Gas	14,877,836	14,073,160	16,257,611	16,925,438	14,395,995
Income Taxes	465,076	531,748	223,871	584,937	667,681
Other	14,412,760	13,541,412	16,033,740	16,340,501	13,718,314
Other Utility	666,584	649,154	725,066	427,267	413,044
Income Taxes	14,963	5,807	−21,775	1,945	−3,977
Other	651,621	643,347	746,841	425,321	417,021
Operating Income	**32,074,346**	**34,645,955**	**33,538,586**	**32,286,409**	**31,714,908**
Electric	30,644,526	33,056,553	31,962,965	30,454,389	30,318,938
Gas	1,343,670	1,507,223	1,611,783	1,737,173	1,338,817
Other	86,150	82,180	−36,163	94,847	57,152
Other Income and Deductions	**1,809,553**	**1,811,414**	**1,614,287**	**1,813,459**	**1,112,330**
Allowance for Other Funds Used During Construction	402,569	315,651	230,791	201,208	183,836
Less Taxes	477,529	350,716	597,230	1,006,783	1,737,905
Deferred Earnings (Misc.) (acct 421)	802,120	372,642	774,012	665,506	2,769,990
Less Other Income and Expenses[3]	−1,082,393	−1,473,837	−1,206,714	−1,953,528	103,591
Total Income Before Interest Charges	**33,883,899**	**36,457,369**	**35,152,873**	**34,099,868**	**32,827,237**
Net Interest Charges	**14,161,602**	**14,421,406**	**13,990,388**	**14,085,736**	**13,963,184**
Interest Expense	13,915,384	14,169,979	13,645,951	13,767,563	13,653,551
Less Allowance for Borrowed Funds Used During Construction	420,828	435,386	326,158	331,057	322,692
Other Charges--Net	667,046	686,814	670,597	649,300	632,325
Net Income Before Extraordinary Charges	**19,722,298**	**22,035,963**	**21,162,485**	**20,014,132**	**18,864,053**
Less Extraordinary Items After Taxes[3]	**−165,288**	**−24,691**	**−65,696**	**3,151,490**	**1,343,507**
Net Income	**19,887,586**	**22,060,655**	**21,228,180**	**16,862,642**	**17,520,546**
Dividends Declared - Preferred Stock	**1,581,940**	**1,518,904**	**1,248,409**	**1,005,367**	**756,185**
Earnings Available for Common Stocks	**18,305,646**	**20,541,751**	**19,979,771**	**15,857,275**	**16,764,361**
Dividends Declared - Common Stock	**15,875,659**	**16,249,715**	**16,810,054**	**17,756,067**	**17,360,682**
Additions Total Earnings	**2,063,432**	**4,281,899**	**2,193,444**	**−1,959,552**	**−17,244**

1 Data for 1997 have been revised by Navigant Consulting, Inc.
2 Includes amortization and depletion.
3 Other Income and Expenses and Extraordinary Items After Taxes were affected negatively by aftertax write offs, accounting adjustments, and regulatory rate decisions.

Notes: •Data for 1994 through 1997 are final; whereas data for 1998 are preliminary. •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.'' The 1997 and 1998 data are edited by Navigant Consulting, Inc. 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, 1994 Through 1998
(Thousand Dollars)

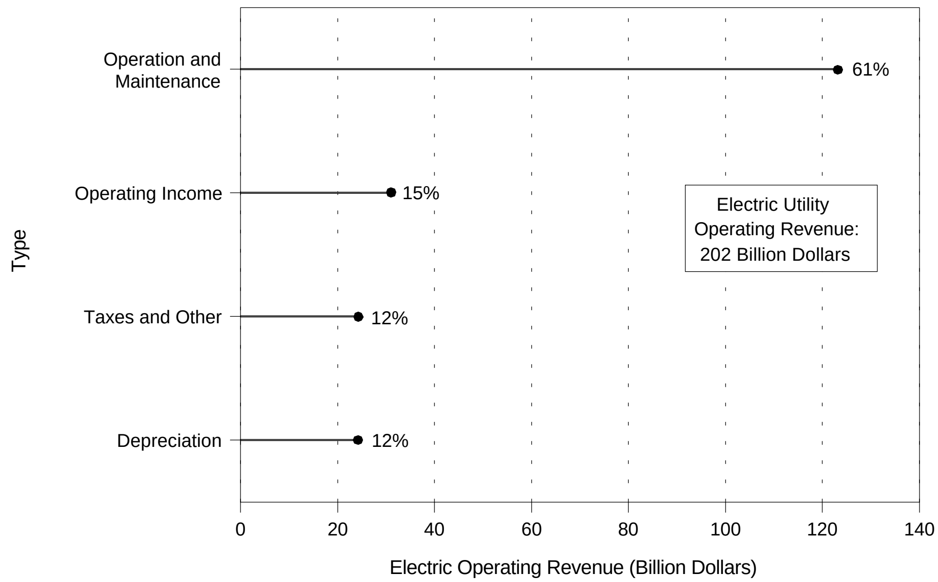
Description	1994	1995	1996	1997[1]	1998
Assets					
Utility Plant - Net	**397,812,254**	**397,383,148**	**396,437,823**	**385,258,389**	**363,014,722**
Electric Utility Plant - Net	366,936,417	366,116,061	363,853,762	351,426,794	328,214,549
Electric Utility Plant	535,928,383	553,857,823	569,968,617	579,042,425	574,715,852
Construction Work in Progress	17,148,353	13,523,358	11,395,525	11,163,637	11,353,173
Less Accumulated Depreciation	186,140,318	201,265,120	217,510,379	238,779,268	257,854,477
Nuclear Fuel - Net	5,656,878	5,285,850	5,443,854	5,218,574	4,791,340
Other Utility Plant - Net	25,218,959	25,981,238	27,140,206	28,613,021	30,008,833
Other Property and Investments	**23,479,360**	**27,987,677**	**33,119,898**	**43,247,896**	**48,397,799**
Current and Accrued Assets	**41,262,977**	**44,139,661**	**43,515,064**	**47,639,268**	**54,490,876**
Deferred Debits	**111,957,082**	**109,423,227**	**108,918,179**	**110,095,573**	**133,047,879**
Total Assets and other Debits	**574,511,673**	**578,933,714**	**581,990,963**	**586,241,128**	**598,951,276**
Capitalization and Liabilities					
Capitalization	**364,724,736**	**365,774,716**	**365,782,779**	**369,079,448**	**366,814,048**
Common Stock Equity (End of Year)	164,482,824	170,497,132	174,325,424	174,467,159	172,350,999
Common Stock	109,522,096	111,301,825	112,633,284	113,889,942	113,169,122
Retained Earnings (Adjusted)	54,960,728	59,195,307	61,692,140	60,577,217	59,181,877
Preferred Stock	24,859,833	21,569,105	18,830,248	16,080,195	14,337,088
Long-term Debt	175,382,079	173,708,479	172,627,107	178,532,093	180,125,961
Current Liabilities and Deferred Credits	**209,786,937**	**213,158,998**	**216,208,185**	**217,161,680**	**232,137,228**
Other Noncurrent Liabilities	13,452,636	14,352,102	15,309,391	17,085,609	18,004,430
Current and Accrued Liabilities	48,035,058	49,929,403	49,341,620	51,594,407	57,743,451
Deferred Credits	148,299,243	148,877,493	151,557,174	148,481,665	156,389,347
Accumulated Deferred Income Taxes	107,054,667	108,615,175	110,537,249	106,393,740	106,549,622
Accumulated Deferred Investment Tax Credit	12,784,415	12,138,942	11,491,332	10,782,506	9,792,775
Other Deferred Credits (Adjusted)	28,460,160	28,123,375	29,528,592	31,305,418	40,046,949
Total Liabilities and Other Credits	**574,511,673**	**578,933,714**	**581,990,963**	**586,241,128**	**598,951,276**

[1] Data for 1997 have been revised by Navigant Consulting, Inc.

Notes: •Data for 1994 through 1997 are final; whereas data for 1998 are preliminary. •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.'' The 1997 and 1998 data are edited by Navigant Consulting, Inc. See Appendix A for a detailed description of this restricted-universe census.

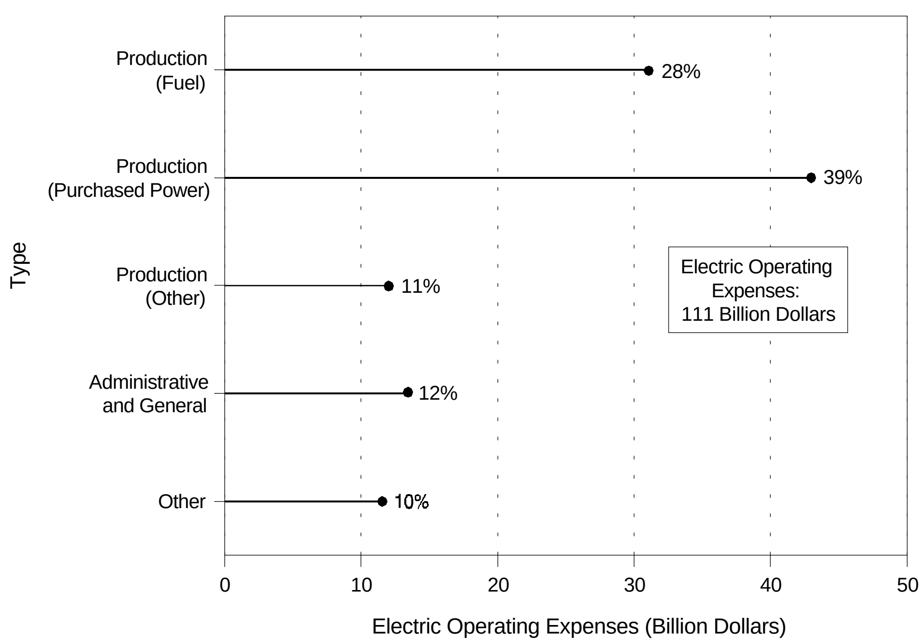
Figure 10. Allocation of the Revenue Dollar from Electric Operations for Major U.S. Investor-Owned Electric Utilities, 1998



Notes: •Data are preliminary. •Depreciation includes amortization and depletion. •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." The 1998 data are edited by Navigant Consulting, Inc. 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, 1998



Notes: •Data are preliminary. •Other includes transmission, distribution, customer account, customer service, and sales. •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." The 1998 data are edited by Navigant Consulting, Inc. 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, 1994 Through 1998

Description[1]	1994	1995	1996	1997[2]	1998
Activity					
1. Electric Fixed Asset (Net Plant) Turnover	0.49	0.50	0.52	0.56	0.61
2. Total Asset Turnover	.34	.35	.36	.37	.36
Leverage					
3. Current Assets to Current Liabilities	.86	.88	.88	.92	.94
4. Long-term Debt to Capitalization	48.09	47.49	47.19	48.37	49.11
5. Preferred Stock to Capitalization	6.82	5.90	5.15	4.36	3.91
6. Common Stock Equity to Capitalization	45.10	46.61	47.66	47.27	46.99
7. Total Debt to Total Assets[3]	32.35	31.89	31.57	32.23	32.00
8. Common Stock Equity to Total Assets	28.63	29.45	29.95	29.76	28.78
9. Interest Coverage Before Taxes without AFUDC	3.10	3.37	3.36	3.33	3.37
Profitability					
10. Profit Margin	10.13	11.03	10.23	7.84	8.04
11. Return on Average Common Stock Equity[4]	12.24	13.17	12.31	9.67	10.10
12. Return on Investment	3.46	3.81	3.65	2.88	2.93

[1] Indicators 1, 2, 3, and 9 are ratios. Indicators 4 through 8 and 10 through 12 are percentages.
[2] Data for 1997 have been revised by Navigant Consulting, Inc.
[3] Total debt is the sum of Long-term Debt and Short-term Debt. The values for Short-term Debt included in Current and Accrued liabilities (Notes Payable) $11,531,000,000 for 1998; $10,417,018,000 for 1997; $11,129,401,000 for 1996; $10,895,101,000 for 1995; and $10,448,573,000 for 1994.
[4] The Average Common Stock Equity is the average of the beginning and ending year balances. The value for the beginning of 1994 was $160,296,897,000.

AFUDC=Allowance for Funds Used During Construction.

Notes: •Data for 1994 through 1997 are final; whereas data for 1998 are preliminary. •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.'' The 1997 and 1998 data are edited by Navigant Consulting, Inc. 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, 1994 Through 1998

(Thousand Dollars)

Description	1994	1995	1996	1997[1]	1998
Utility Operating Revenues	**196,281,500**	**199,966,979**	**207,459,078**	**215,082,593**	**217,817,986**
Electric Utility	179,307,260	183,655,263	188,900,781	195,897,868	201,612,978
Other Utility	16,974,240	16,311,715	18,558,297	19,184,725	16,205,009
Utility Operating Expenses	**164,207,153**	**165,321,023**	**173,920,492**	**182,796,184**	**186,103,079**
Electric Utility	148,662,734	150,598,710	156,937,816	165,443,479	171,294,039
Operation	93,107,998	91,880,940	97,206,642	104,337,106	110,807,022
Production	69,268,652	68,983,410	73,436,927	80,152,500	85,966,809
Cost of Fuel	30,107,888	29,121,982	30,706,261	31,860,594	31,119,843
Purchased Power	29,213,084	29,981,379	32,987,034	37,990,963	42,839,703
Other	9,947,680	9,880,049	9,743,632	10,300,942	12,007,263
Transmission	1,361,080	1,425,058	1,503,196	1,915,174	2,180,270
Distribution	2,581,409	2,560,835	2,604,058	2,699,803	2,760,503
Customer Accounts	3,546,489	3,613,101	3,848,302	3,767,257	4,003,728
Customer Service	1,955,991	1,922,475	1,920,450	1,197,459	1,948,378
Sales	231,589	348,345	435,477	500,934	514,737
Administrative and General	14,162,788	13,027,716	13,458,234	13,383,979	13,432,597
Maintenance	12,021,790	11,767,040	12,049,844	12,367,646	12,451,410
Depreciation	18,679,022	19,885,482	21,193,742	23,072,100	23,890,201
Taxes and Other	24,853,924	27,065,248	26,487,588	25,666,627	24,145,406
Other Utility	15,544,420	14,722,314	16,982,677	17,352,705	14,809,039
Net Utility Operating Income	**32,074,346**	**34,645,955**	**33,538,586**	**32,286,409**	**31,714,908**

1 Data for 1997 have been revised by Navigant Consulting, Inc.

Notes: •Data for 1994 through 1997 are final; whereas data for 1998 are preliminary. •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.'' The 1997 and 1998 data are edited by Navigant Consulting, Inc. 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, 1994 Through 1998

Description	1994	1995	1996	1997[1]	1998
Utility Operating Revenues	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
Electric Utility	91.4	91.8	91.1	91.1	92.6
Other Utility	8.6	8.2	8.9	8.9	7.4
Utility Operating Expenses	**83.7**	**82.7**	**83.8**	**85.0**	**85.4**
Electric Utility	75.7	75.3	75.6	76.9	78.6
Operation	47.4	45.9	46.9	48.5	50.9
Production	35.3	34.5	35.4	37.3	39.5
Cost of Fuel	15.3	14.6	14.8	14.8	14.3
Purchased Power	14.9	15.0	15.9	17.7	19.7
Other	5.1	4.9	4.7	4.8	5.5
Transmission	.7	.7	.7	.9	1.0
Distribution	1.3	1.3	1.3	1.3	1.3
Customer Accounts	1.8	1.8	1.9	1.8	1.8
Customer Service	1.0	1.0	.9	.9	.9
Sales	.1	.2	.2	.2	.2
Administrative and General	7.2	6.5	6.5	6.2	6.2
Maintenance	6.1	5.9	5.8	5.8	5.7
Depreciation	9.5	9.9	10.2	10.7	11.0
Taxes and Other	12.7	13.5	12.8	11.9	11.1
Other Utility	7.9	7.4	8.2	8.1	6.8
Net Utility Operating Income	**16.3**	**17.3**	**16.2**	**15.0**	**14.6**

1 Data for 1997 have been revised by Navigant Consulting, Inc.

Notes: •Data for 1994 through 1997 are final; whereas data for 1998 are preliminary. •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.'' The 1997 and 1998 data are edited by Navigant Consulting, Inc. 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, 1994 Through 1998

(Mills per Kilowatthour)

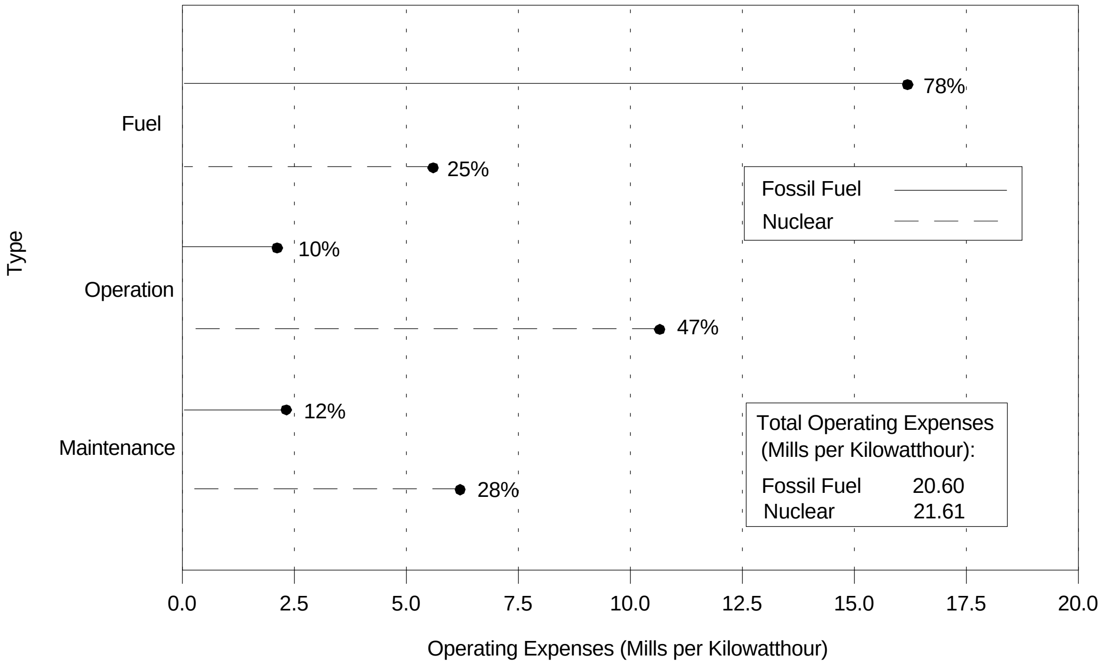
Plant Type	1994	1995	1996	1997[1]	1998
			Operation		
Nuclear	9.79	9.43	9.47	11.02	10.13
Fossil Steam	2.32	2.38	2.25	2.22	2.18
Hydroelectric[2]	4.53	3.69	3.87	3.29	3.80
Gas Turbine and Small Scale[3]	4.58	3.57	5.08	4.43	3.92
			Maintenance		
Nuclear	5.20	5.21	5.68	6.90	6.06
Fossil Steam	2.82	2.65	2.49	2.43	2.41
Hydroelectric[2]	2.90	2.19	2.08	2.49	2.00
Gas Turbine and Small Scale[3]	5.39	4.28	4.98	3.43	3.41
			Fuel		
Nuclear	5.87	5.75	5.50	5.42	5.42
Fossil Steam	16.67	16.07	16.51	16.80	16.01
Hydroelectric[2]	—	—	—	—	—
Gas Turbine and Small Scale[3]	22.19	20.83	30.58	24.94	23.11
			Total[4]		
Nuclear	20.86	20.39	20.65	23.33	21.61
Fossil Steam	21.80	21.11	21.25	21.45	20.60
Hydroelectric[2]	7.43	5.89	5.95	5.78	5.80
Gas Turbine and Small Scale[3]	32.16	28.67	40.64	32.80	30.45

1 Data for 1997 have been revised by Navigant Consulting, Inc.
2 Includes Pumped Storage.
3 Includes gas turbine, internal combustion, photovoltaic, and wind plants.
4 Totals may not equal sum of components because of independent rounding.

Notes: •Data for 1994 through 1997 are final; whereas data for 1998 are preliminary. •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.'' The 1997 and 1998 data are edited by Navigant Consulting, Inc. 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, 1998



Notes: •Data are preliminary. •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." The 1998 data are edited by Navigant Consulting, Inc. 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, 1994 Through 1998
(Thousand Dollars)

Description	1994	1995	1996	1997	1998
Operating Revenue - Electric	**23,266,686**	**23,472,888**	**24,207,226**	**25,397,219**	**26,154,732**
Operating Expenses - Electric	**18,648,687**	**18,958,876**	**19,083,980**	**20,425,111**	**20,880,194**
Operation Excluding Fuel	10,191,897	11,167,114	11,270,829	11,819,689	11,949,846
Fuel	3,385,718	2,485,770	2,497,215	3,097,486	3,169,838
Maintenance	1,584,444	1,575,208	1,637,828	1,608,781	1,631,484
Depreciation and Amortization	2,720,560	2,933,594	3,015,664	3,239,454	3,458,805
Taxes and Tax Equivalents	766,068	797,189	662,443	659,702	670,221
Operating Income - Electric	**4,617,999**	**4,514,013**	**5,123,246**	**4,972,108**	**5,274,538**
Other Income and Deductions	**1,098,922**	**1,174,316**	**1,237,173**	**1,351,939**	**1,352,927**
Income from Electric Plant Leased to Others	30,242	16,365	25,914	17,953	17,528
Allowance for Funds Used During Construction	7,872	9,145	6,660	4,320	5,208
Other Income Net	1,237,067	1,371,621	1,440,435	1,478,106	1,506,383
Less Other Electric Deductions	176,259	222,815	235,836	148,440	176,192
Total Income Before Interest Charges	**5,716,920**	**5,688,329**	**6,360,419**	**6,324,047**	**6,627,465**
Net Interest Charges	**4,681,141**	**4,728,063**	**4,634,548**	**4,681,830**	**4,574,910**
Interest Expenses	4,332,296	4,206,294	4,155,829	4,119,946	3,984,982
Other Income Deductions	348,845	521,769	478,719	561,883	589,928
Net Income Before Extraordinary Charges	**1,035,779**	**960,266**	**1,725,871**	**1,642,217**	**2,052,555**
Less **Extraordinary Items**	**124,211**	**–250,918**	**–2,304**	**13,258**	**120,722**
Net Income	**911,568**	**1,211,184**	**1,723,567**	**1,628,959**	**1,931,833**

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1994-1997 data represent those utilities meeting a threshold of 120,000 megawatthours of consumer sales or resales. •The number of publicly owned generating electric utilities that reported were 228 for 1998, 245 for 1997, 231 for 1996, 226 for 1995, and 227 for 1994.

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, 1994 Through 1998
(Thousand Dollars)

Description	1994	1995	1996	1997	1998
Assets					
Electric Utility Plant-Net Inc Nuclear Fuel	**63,576,104**	**63,412,608**	**64,159,411**	**63,939,798**	**62,854,031**
Electric Utility Plant Inc Nuclear Fuel	92,044,086	93,771,319	97,433,005	100,346,538	101,775,589
Accumulated Provision for Depreciation and Amortization	28,467,982	30,358,711	33,273,595	36,406,740	38,921,558
Other Property and Investments	**20,973,996**	**20,996,914**	**19,674,912**	**20,156,959**	**19,969,531**
Current and Accrued Assets	**15,782,291**	**15,086,442**	**16,521,745**	**17,148,023**	**17,245,072**
Deferred Debits	**13,913,754**	**14,242,677**	**13,520,724**	**13,619,929**	**13,381,374**
Total Assets and Other Debits	**114,246,146**	**113,738,640**	**113,876,791**	**114,864,710**	**113,450,008**
Liabilities and Other Credits					
Investment of Municipality - Surplus	**24,518,851**	**25,447,162**	**27,472,346**	**29,111,977**	**30,001,524**
Long-Term Debt	**76,815,309**	**74,982,156**	**73,950,415**	**73,035,157**	**70,145,214**
Other Noncurrent Liabilities	**701,406**	**714,354**	**766,093**	**593,007**	**608,049**
Current and Accrued Liabilities	**8,913,155**	**9,084,862**	**8,167,668**	**8,554,223**	**8,714,034**
Deferred Credits	**3,297,425**	**3,510,106**	**3,520,270**	**3,570,346**	**3,981,187**
Total Liabilities and Other Credits	**114,246,146**	**113,738,640**	**113,876,791**	**114,864,710**	**113,450,008**

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1994-1997 data represent those utilities meeting a threshold of 120,000 megawatthours of consumer sales or resales. •The number of publicly owned generating electric utilities that reported were 228 for 1998, 245 for 1997, 231 for 1996, 226 for 1995, and 227 for 1994.

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, 1994 Through 1998

Description	1994	1995	1996	1997	1998
Electric Utility Plant per Dollar of Revenue	4.0	4.0	4.0	4.0	3.9
Current Assets to Current Liabilities	1.8	1.7	2.0	2.0	2.0
Electric Utility Plant as a Percent of Total Assets	80.6	82.4	85.6	87.4	89.7
Net Electric Utility Plant as a Percent of Total Assets	55.6	55.8	56.3	55.7	55.4
Debt as a Percent of Total Liabilities	75.0	73.9	72.1	71.0	69.5
Accumulated Provision for Depreciation as a Percent of Electric Utility Plant	30.9	32.4	34.2	36.3	38.2
Electric Operation and Maintenance Expenses as a Percent of Electric Operating Revenues	65.2	64.9	63.6	65.1	64.0
Electric Depreciation and Amortization as a Percent of Electric Operating Revenues	11.1	11.9	11.9	12.1	12.4
Taxes and Tax Equivalents as a Percent of Electric Operating Revenues	3.3	3.4	2.7	2.6	2.6
Interest Expenses as a Percent of Electric Operating Revenues	18.6	17.9	17.2	16.2	15.2
Net Income as a Percent of Electric Operating Revenues	3.9	5.2	7.1	6.4	7.4
Purchase Power Cents Per Kilowatthour	3.6	3.6	3.8	3.2	3.2
Generated Cents Per Kilowatthour	1.9	1.8	1.5	1.7	1.7
Total Power Supply Per Kilowatthour Sold	2.6	2.5	2.4	2.4	2.4

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1994-1997 data represent those utilities meeting a threshold of 120,000 megawatthours of consumer sales or resales. •The number of publicly owned generating electric utilities that reported were 228 for 1998, 245 for 1997, 231 for 1996, 226 for 1995, and 227 for 1994.

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, 1994 Through 1998
(Thousand Dollars)

Description	1994	1995	1996	1997	1998
Operating Revenue - Electric	**23,266,686**	**23,472,888**	**24,207,226**	**25,397,219**	**26,154,732**
Operating Expenses - Electric	**18,648,687**	**18,958,876**	**19,083,980**	**20,425,111**	**20,880,194**
Operation Including Fuel	13,577,615	13,652,884	13,768,044	14,917,174	15,119,684
Production	10,444,534	10,384,858	11,080,348	11,481,328	11,608,407
Transmission	609,612	628,098	344,371	725,471	772,598
Distribution	429,535	425,831	497,019	538,320	603,199
Customer Accounts	316,794	323,122	365,277	390,231	390,430
Customer Service	104,101	102,061	103,390	133,257	126,813
Sales	22,436	19,617	17,528	46,181	50,804
Administrative and General	1,650,603	1,769,298	1,360,111	1,602,386	1,567,434
Maintenance	1,584,444	1,575,208	1,637,828	1,608,781	1,631,484
Depreciation and Amortization	2,720,560	2,933,594	3,015,664	3,080,165	3,240,505
Taxes and Tax Equivalents	766,068	797,189	662,443	659,702	670,221
Income from Electric Utility Operations	**4,617,999**	**4,514,013**	**5,123,246**	**4,972,108**	**5,274,538**

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1994-1997 data represent those utilities meeting a threshold of 120,000 megawatthours of consumer sales or resales. •The number of publicly owned generating electric utilities that reported were 228 for 1998, 245 for 1997, 231 for 1996, 226 for 1995, and 227 for 1994.

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, 1994 Through 1998

(Thousand Dollars)

Description	1994	1995	1996	1997	1998
Operating Revenue - Electric	**7,995,632**	**8,435,445**	**8,581,642**	**8,585,879**	**8,790,223**
Operating Expenses - Electric	**7,566,745**	**7,978,811**	**8,122,815**	**8,033,488**	**8,245,380**
Operation Excluding Fuel	6,857,958	7,172,612	7,358,599	7,117,155	7,437,112
Fuel	13	247	—	—	–540
Maintenance	233,967	249,580	244,115	337,769	263,356
Depreciation and Amortization	273,770	312,724	313,720	353,948	330,433
Taxes and Tax Equivalents	201,038	243,648	206,389	224,617	215,019
Operating Income - Electric	**428,887**	**456,634**	**458,827**	**552,391**	**544,843**
Other Income and Deductions	**97,664**	**142,214**	**153,864**	**102,307**	**130,282**
Income from Electric Plant Leased to Others	2,185	4,345	12,569	12,989	4,248
Allowance for Funds Used During Construction	51	41	70	311	192
Other Income Net	178,515	215,559	207,859	165,655	185,272
Less Other Electric Deductions	83,086	77,731	66,634	76,649	59,430
Total Income Before Interest Charges	**526,551**	**598,847**	**612,691**	**654,698**	**675,126**
Net Interest Charges	**156,433**	**168,632**	**148,146**	**148,297**	**152,428**
Interest Expenses	108,647	127,013	99,768	107,351	102,729
Other Income Deductions	47,786	41,619	48,378	40,947	49,699
Net Income Before Extraordinary Charges	**370,118**	**430,215**	**464,545**	**506,400**	**522,698**
Less **Extraordinary Items**	**3,821**	**6,659**	**4,065**	**–3,050**	**–9,842**
Net Income	**366,297**	**423,556**	**460,479**	**509,451**	**532,539**

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1994-1997 data represent those utilities meeting a threshold of 120,000 megawatthours of consumer sales or resales. •The number of publicly owned nongenerating electric utilities that reported were 259 for 1998, 299 for 1997, 284 for 1996, 286 for 1995, and 276 for 1994.

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, 1994 Through 1998

(Thousand Dollars)

Description	1994	1995	1996	1997	1998
Assets					
Electric Utility Plant-Net Inc Nuclear Fuel	**5,496,059**	**6,272,158**	**6,259,916**	**8,447,445**	**6,871,025**
Electric Utility Plant Inc Nuclear Fuel	8,759,850	9,936,064	9,925,097	12,831,306	10,963,297
Accumulated Provision for Depreciation and Amortization	3,263,791	3,663,906	3,665,181	4,383,861	4,092,272
Other Property and Investments	**1,904,194**	**2,196,898**	**1,885,263**	**2,067,375**	**2,123,546**
Current and Accrued Assets	**2,497,816**	**2,884,088**	**2,701,644**	**2,925,365**	**2,857,991**
Deferred Debits	**400,447**	**492,691**	**407,965**	**465,338**	**358,010**
Total Assets and Other Debits	**10,298,517**	**11,841,016**	**11,254,787**	**13,905,523**	**12,210,573**
Liabilities and Other Credits					
Investment of Municipality - Surplus	**6,281,647**	**6,938,969**	**7,150,022**	**8,543,320**	**7,871,482**
Long-Term Debt	**2,723,507**	**3,441,757**	**2,593,375**	**3,808,733**	**2,676,839**
Other Noncurrent Liabilities	**11,414**	**16,179**	**17,991**	**14,808**	**137,989**
Current and Accrued Liabilities	**1,098,941**	**1,232,623**	**1,263,814**	**1,259,125**	**1,317,256**
Deferred Credits	**183,009**	**211,487**	**229,585**	**279,537**	**207,007**
Total Liabilities and Other Credits	**10,298,517**	**11,841,016**	**11,254,787**	**13,905,523**	**12,210,573**

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1994-1997 data represent those utilities meeting a threshold of 120,000 megawatthours of consumer sales or resales. •The number of publicly owned nongenerating electric utilities that reported were 259 for 1998, 299 for 1997, 284 for 1996, 286 for 1995, and 276 for 1994.

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, 1994 Through 1998

Description	1994	1995	1996	1997	1998
Electric Utility Plant per Dollar of Revenue	1.1	1.2	1.2	1.5	1.2
Current Assets to Current Liabilities	2.3	2.3	2.1	2.3	2.2
Electric Utility Plant as a Percent of Total Assets	85.1	83.9	88.2	92.3	89.8
Net Electric Utility Plant as a Percent of Total Assets	53.4	52.9	55.6	60.7	56.3
Debt as a Percent of Total Liabilities	37.1	39.5	34.3	36.4	32.7
Accumulated Provision for Depreciation as a Percent of Electric Utility Plant	37.3	36.9	36.9	34.2	37.3
Electric Operation and Maintenance Expenses as a Percent of Electric Operating Revenues	88.7	88.0	88.6	86.8	87.6
Electric Depreciation and Amortization as a Percent of Electric Operating Revenues	3.4	3.7	3.6	4.1	3.7
Taxes and Tax Equivalents as a Percent of Electric Operating Revenues	2.5	2.9	2.4	2.6	2.4
Interest Expenses as a Percent of Electric Operating Revenues	1.4	1.5	1.2	1.3	1.2
Net Income as a Percent of Electric Operating Revenues	4.6	5.0	5.4	5.9	6.1
Purchase Power Cents Per Kilowatthour	4.1	4.3	4.0	4.0	4.1

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1994-1997 data represent those utilities meeting a threshold of 120,000 megawatthours of consumer sales or resales. •The number of publicly owned nongenerating electric utilities that reported were 259 for 1998, 299 for 1997, 284 for 1996, 286 for 1995, and 276 for 1994.

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, 1994 Through 1998

(Thousand Dollars)

Description	1994	1995	1996	1997	1998
Operating Revenue - Electric	**7,995,632**	**8,435,445**	**8,581,642**	**8,585,879**	**8,790,223**
Operating Expenses - Electric	**7,566,745**	**7,978,811**	**8,122,816**	**8,033,488**	**8,245,380**
Operation Including Fuel	6,857,970	7,172,858	7,358,592	7,117,155	7,436,572
Production	6,185,035	6,421,965	6,578,344	6,239,721	6,660,705
Transmission	34,045	35,184	50,812	56,969	44,443
Distribution	190,181	204,130	233,630	303,983	229,609
Customer Accounts	119,019	125,143	141,458	139,156	129,856
Customer Service	16,941	17,934	18,229	16,379	20,862
Sales	9,845	9,535	11,616	12,897	8,868
Administrative and General	302,904	358,367	324,503	348,051	342,228
Maintenance	233,967	249,580	244,115	337,769	263,356
Depreciation and Amortization	273,770	312,724	313,720	350,862	326,863
Taxes and Tax Equivalents	201,038	243,648	206,389	224,617	215,019
Income from Electric Utility Operations	**428,887**	**456,634**	**458,826**	**552,391**	**544,843**

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •The 1994-1997 data represent those utilities meeting a threshold of 120,000 megawatthours of consumer sales or resales. •The number of publicly owned nongenerating electric utilities that reported were 259 for 1998, 299 for 1997, 284 for 1996, 286 for 1995, and 276 for 1994.

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. Emissions of SO_2 and NO_x have been revised from the updated Air Pollutant Emissions Factors (AP-42 5th edition, through supplement E) of the Environment Protection Agency on July 1999. Emissions of CO_2 have been revised from the *Emissions of Greenhouse Gases in the United States 1997*, October 1998. Additional detailed information on emissions from electric utilities can be obtained in Chapter 6 of the *Annual Energy Outlook*.[13] 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.

[13] 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, 1994 Through 1998

(Thousand Short Tons)

Emission[1]	1994[R]	1995[R]	1996[R]	1997	1998
Sulfur Dioxide (SO2)	14,211	11,437	12,053	12,317	12,432
Nitrogen Oxides (NOx)	6,790	6,737	6,996	7,227	7,221
Carbon Dioxide (CO2)	1,986,079	1,995,471	2,065,339	2,142,118	2,209,286

1 In 1994, the useful utility thermal output produced additional emissions of 160 thousand short tons of sulfur dioxide, 44 thousand short tons of nitrogen oxides, and 11,007 thousand short tons of carbon dioxide. In 1995, the useful utility thermal output produced additional emissions of 141 thousand short tons of sulfur dioxide, 44 thousand short tons of nitrogen oxides, and 11,378 thousand short tons of carbon dioxide. In 1996, the useful utility thermal output produced additional emissions of 172 thousand short tons of sulfur dioxide, 58 thousand short tons of nitrogen oxides, and 15,837 thousand short tons of carbon dioxide. In 1997, the useful utility thermal output produced additional emissions of 192 thousand short tons of sulfur dioxide, 66 thousand short tons of nitrogen oxides, and 18,159 thousand short tons of carbon dioxide. In 1998, the useful utility thermal output produced additional emissions of 231 thousand short tons of sulfur dioxide, 91 thousand short tons of nitrogen oxides, and 29,267 thousand short tons of carbon dioxide.

R = Revised data.

Notes: •Estimates for 1998 are preliminary; data for prior years are final. •Emissions of NOx, and SO2 have been revised from the updated (July 1999) Air Pollutant Emissions Factors (AP-42, 5th edition, Supplement E) of the Environmental Protection Agency; emissions of CO2 have been revised from ''Emissions of Greenhouse Gases in the United States 1997,'' October 1998 (see Technical Notes). •Estimates are for steam-electric plants 10 megawatts and larger, based on fuel consumption data. Historical data have been revised to reflect additional data reported by respondents and additional emissions data from plants 10 megawatts or less.

Sources: Energy Information Administration, Form EIA-767, ''Steam-Electric Plant Operation and Design Report,'' Form EIA-759, ''Monthly Power Plant Report.''

Table 23. Number and Capacity of Fossil-Fueled Steam-Electric Generators for U.S. Electric Utility Plants with Environmental Equipment, 1994 Through 1998

Environmental Equipment	Scrubbers		Particulate Collectors	
	Number of Generators	Capacity[1] (megawatts)	Number of Generators	Capacity[1] (megawatts)
1994	168	80,617	1,135	351,180
1995	178	84,677	1,134	351,198
1996	182	86,359	1,136	352,254
1997	183	86,605	1,136	352,254
1998	186	87,783	1,130	351,790
	Cooling Towers		Total[2]	
	Number of Generators	Capacity[1] (megawatts)	Number of Generators	Capacity[1] (megawatts)
1994	480	165,452	1,309	376,899
1995	471	165,295	1,295	375,691
1996	477	166,749	1,301	377,244
1997	480	166,886	1,304	377,381
1998	474	166,896	1,294	377,117

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 1998 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, 1997 and 1998
(Thousand Short Tons)

Census Division State	1997			1998		
	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide
New England	**255**	**84**	**45,275**	**209**	**60**	**35,692**
Connecticut	52	15	11,499	48	12	10,143
Maine	11	1	1,345	12	2	1,550
Massachusetts	134	50	25,359	98	33	18,307
New Hampshire	58	14	5,450	51	12	4,935
Rhode Island	0	4	1,607	*	2	697
Vermont	0	0	15	0	0	60
Middle Atlantic	**1,346**	**414**	**163,567**	**1,408**	**424**	**172,089**
New Jersey	48	32	9,619	44	28	8,525
New York	222	93	42,860	268	103	49,776
Pennsylvania	1,076	289	111,088	1,096	293	113,788
East North Central	**3,558**	**1,834**	**447,455**	**3,433**	**1,795**	**451,923**
Illinois	776	375	85,139	695	329	80,024
Indiana	799	483	118,197	803	473	119,709
Michigan	403	268	70,564	411	286	76,098
Ohio	1,372	525	127,225	1,315	522	130,543
Wisconsin	207	183	46,330	209	186	45,549
West North Central	**798**	**865**	**220,703**	**813**	**906**	**234,968**
Iowa	138	140	33,479	147	151	36,402
Kansas	95	125	33,044	98	129	34,014
Minnesota	86	121	31,665	83	133	34,856
Missouri	266	268	66,905	265	268	70,749
Nebraska	59	89	19,680	56	95	21,176
North Dakota	133	104	32,159	144	112	34,149
South Dakota	21	18	3,771	20	17	3,621
South Atlantic	**3,071**	**1,327**	**435,293**	**3,250**	**1,332**	**459,510**
Delaware	38	16	5,993	35	15	5,920
District of Columbia	0	0	98	1	0	267
Florida	597	319	107,099	710	334	119,454
Georgia	484	202	73,399	483	205	75,283
Maryland	237	86	29,689	265	93	33,066
North Carolina	458	211	68,677	448	199	68,411
South Carolina	227	94	31,521	250	90	33,079
Virginia	192	93	31,359	204	100	35,088
West Virginia	838	307	87,459	853	296	88,941
East South Central	**1,850**	**879**	**243,101**	**1,796**	**813**	**240,386**
Alabama	499	248	73,688	511	243	75,079
Kentucky	790	353	91,252	739	314	87,135
Mississippi	97	64	19,815	128	69	22,472
Tennessee	464	213	58,346	419	186	55,700
West South Central	**905**	**957**	**324,579**	**927**	**966**	**337,137**
Arkansas	73	86	26,688	74	89	28,162
Louisiana	200	122	40,475	179	126	41,946
Oklahoma	112	153	44,981	89	149	45,535
Texas	519	597	212,435	585	602	221,494
Mountain	**458**	**774**	**221,131**	**503**	**818**	**235,313**
Arizona	117	124	38,205	96	133	41,070
Colorado	93	133	35,593	94	132	36,495
Idaho	0	0	0	0	0	*
Montana	16	53	16,661	18	60	18,835
Nevada	50	66	20,882	54	74	23,146
New Mexico	65	123	31,774	120	127	32,246
Utah	30	100	33,450	30	102	34,447
Wyoming	87	174	44,566	91	190	49,074
Pacific Contiguous	**58**	**77**	**32,384**	**75**	**94**	**33,943**
California	0	32	22,323	0	27	17,703
Oregon	5	8	2,300	11	19	5,354
Washington	52	36	7,761	64	48	10,885
Pacific Noncontiguous	**20**	**16**	**8,630**	**18**	**15**	**8,325**
Alaska	1	8	2,982	0	6	2,654
Hawaii	19	8	5,648	18	8	5,671
U.S. Total	**12,317**	**7,227**	**2,142,118**	**12,432**	**7,221**	**2,209,286**

Notes: •Estimates for 1998 are preliminary; data for prior years are final. •Emissions of NOx, and SO2 have been revised from the updated (July 1999) Air Pollutant Emissions Factors (AP-42, 5th edition, Supplement E) of the Environmental Protection Agency; emissions of CO2 have been revised from ''Emissions of Greenhouse Gases in the United States 1997,'' October 1998 (see Technical Notes). •Estimates are for steam-electric plants 10 megawatts and larger, based on fuel consumption data.

Sources: Energy Information Administration, Form EIA-767, ''Steam-Electric Plant Operation and Design Report,'' Form EIA-759, ''Monthly Power Plant Report.''

Table 25. Estimated Emissions from Fossil-Fueled Steam-Electric Generating Units at U.S. Electric Utilities by Fossil Fuel, Census Division, and State, 1998
(Thousand Short Tons)

Census Division State	Coal			Petroleum			Gas			Other[1]		
	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide
New England	**88**	**35**	**13,267**	**121**	**20**	**19,649**	*****	**6**	**2,776**	*****	**0**	*****
Connecticut	6	4	1,568	42	8	7,945	*	1	630	*	0	*
Maine	0	0	0	12	2	1,550	0	0	0	0	0	0
Massachusetts	44	21	8,069	55	9	8,798	*	3	1,441	*	0	*
New Hampshire	38	10	3,630	13	1	1,298	0	*	7	*	0	*
Rhode Island	0	0	0	*	*	9	0	2	688	0	0	0
Vermont	0	0	0	*	*	49	0	*	11	*	0	0
Middle Atlantic	**1,300**	**379**	**139,168**	**107**	**22**	**18,229**	*****	**23**	**14,691**	*****	**0**	**0**
New Jersey	42	23	6,128	1	1	542	*	4	1,855	*	0	0
New York	207	72	24,315	61	14	13,177	*	17	12,285	0	0	0
Pennsylvania	1,051	284	108,726	45	7	4,511	*	1	551	*	0	0
East North Central	**3,421**	**1,771**	**441,787**	**12**	**3**	**2,502**	*****	**16**	**7,634**	*****	**5**	**0**
Illinois	693	321	75,849	2	1	672	*	6	3,503	0	0	0
Indiana	802	472	118,957	*	*	205	*	1	547	0	0	0
Michigan	406	279	72,828	5	2	1,085	*	5	2,185	*	0	0
Ohio	1,315	521	129,815	*	*	281	*	1	446	0	0	0
Wisconsin	205	178	44,337	4	1	259	*	2	953	*	5	0
West North Central	**801**	**891**	**228,506**	**10**	**2**	**1,097**	*****	**10**	**4,468**	**1**	**2**	**897**
Iowa	140	149	35,626	7	1	308	*	1	373	*	*	95
Kansas	98	124	31,725	*	*	140	*	5	2,149	0	0	0
Minnesota	82	130	33,493	*	*	79	*	1	485	1	2	799
Missouri	262	265	69,359	3	1	436	*	2	951	*	*	3
Nebraska	56	95	20,784	*	*	51	*	1	341	0	0	0
North Dakota	144	112	34,103	*	*	46	0	0	0	0	0	0
South Dakota	20	16	3,416	*	*	36	0	*	169	0	0	0
South Atlantic	**2,879**	**1,218**	**392,904**	**371**	**66**	**44,984**	*****	**48**	**21,621**	**0**	**0**	**0**
Delaware	30	12	4,238	5	1	1,095	*	1	587	0	0	0
District of Columbia	0	0	0	1	*	267	0	0	0	0	0	0
Florida	383	242	66,380	328	56	36,437	*	37	16,637	0	0	0
Georgia	480	202	73,102	3	1	824	*	3	1,357	0	0	0
Maryland	247	87	29,031	18	4	3,300	*	2	735	0	0	0
North Carolina	448	197	67,374	*	*	306	0	2	731	0	0	0
South Carolina	250	89	32,449	*	*	282	0	1	347	0	0	0
Virginia	189	94	31,562	15	3	2,323	0	3	1,202	0	0	0
West Virginia	853	296	88,767	*	*	149	0	*	25	0	0	0
East South Central	**1,733**	**787**	**227,195**	**63**	**9**	**5,355**	*****	**18**	**7,836**	**0**	**0**	**0**
Alabama	511	239	73,352	*	*	220	*	3	1,507	0	0	0
Kentucky	738	314	86,665	*	*	130	*	1	341	0	0	0
Mississippi	65	49	12,459	63	8	4,390	*	12	5,623	0	0	0
Tennessee	419	185	54,718	*	1	616	0	1	366	0	0	0
West South Central	**870**	**760**	**229,226**	**56**	**5**	**2,293**	**1**	**201**	**105,618**	**0**	**0**	**0**
Arkansas	73	85	25,596	1	*	134	*	4	2,431	0	0	0
Louisiana	124	88	22,394	55	5	2,034	*	33	17,519	0	0	0
Oklahoma	89	125	34,332	*	*	8	*	24	11,195	0	0	0
Texas	584	462	146,904	*	*	118	*	140	74,473	0	0	0
Mountain	**502**	**797**	**225,629**	*****	*****	**213**	*****	**20**	**9,471**	**0**	**0**	**0**
Arizona	96	128	38,760	*	*	52	*	5	2,258	0	0	0
Colorado	94	131	35,835	*	*	32	*	1	628	0	0	0
Idaho	0	0	0	0	0	*	0	0	0	0	0	0
Montana	18	60	18,790	*	*	12	0	*	32	0	0	0
Nevada	54	65	19,485	*	*	33	*	8	3,628	0	0	0
New Mexico	120	122	29,676	*	*	21	*	5	2,549	0	0	0
Utah	30	102	34,048	*	*	27	*	1	372	0	0	0
Wyoming	91	190	49,034	*	*	36	0	*	5	0	0	0
Pacific Contiguous	**75**	**61**	**13,693**	*****	*****	**192**	*****	**32**	**20,058**	**0**	**0**	**0**
California	0	0	0	*	*	130	*	26	17,574	0	0	0
Oregon	11	15	3,630	*	*	24	0	4	1,700	0	0	0
Washington	64	46	10,062	*	*	38	0	2	785	0	0	0
Pacific Noncontiguous	*****	**1**	**251**	**18**	**9**	**6,380**	**0**	**4**	**1,694**	**0**	**0**	**0**
Alaska	*	1	251	*	1	709	0	4	1,694	0	0	0
Hawaii	0	0	0	18	8	5,671	0	0	0	0	0	0
U.S. Total	**11,671**	**6,701**	**1,911,627**	**759**	**137**	**100,895**	**1**	**377**	**195,868**	**1**	**7**	**897**

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

Notes: •Estimates for 1998 are preliminary; •Emissions of NOx, and SO2 have been revised from the updated (July 1999) Air Pollutant Emissions Factors (AP-42, 5th edition, Supplement E) of the Environmental Protection Agency; emissions of CO2 have been revised from ‘‘Emissions of Greenhouse Gases in the United States 1997,’’ October 1998 (see Technical Notes). •Estimates are for steam-electric plants 10 megawatts and larger, based on fuel consumption data. •*=Value less than 0.5.

Sources: Energy Information Administration, Form EIA-767, ‘‘Steam-Electric Plant Operation and Design Report,’’ Form EIA-759, ‘‘Monthly Power Plant 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, 1998

Census Division State	Generating Units[1]		Scrubbers		Particulate Collectors		Cooling Towers	
	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)
New England	**15**	**2,773**	**0**	**0**	**15**	**2,773**	**0**	**0**
Connecticut	1	400	0	0	1	400	0	0
Maine	0	0	0	0	0	0	0	0
Massachusetts	9	1,764	0	0	9	1,764	0	0
New Hampshire	5	609	0	0	5	609	0	0
Rhode Island	0	0	0	0	0	0	0	0
Vermont	0	0	0	0	0	0	0	0
Middle Atlantic	**81**	**23,992**	**14**	**7,048**	**81**	**23,992**	**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	50	18,586	10	5,907	50	18,586	16	11,366
East North Central	**294**	**81,325**	**25**	**11,992**	**294**	**81,325**	**41**	**20,489**
Illinois	55	17,123	3	821	55	17,123	2	562
Indiana	68	21,125	14	5,964	68	21,125	23	9,395
Michigan	49	12,124	0	0	49	12,124	2	199
Ohio	83	23,899	6	5,046	83	23,899	11	8,854
Wisconsin	39	7,053	2	160	39	7,053	3	1,479
West North Central	**130**	**35,358**	**24**	**10,732**	**130**	**35,358**	**38**	**11,770**
Iowa	29	5,691	1	176	29	5,691	6	1,681
Kansas	14	5,385	7	3,920	14	5,385	8	3,258
Minnesota	22	5,236	8	3,333	22	5,236	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	4,049	6	2,849	12	4,049	4	1,826
South Dakota	1	456	0	0	1	456	0	0
South Atlantic	**216**	**70,991**	**23**	**11,948**	**216**	**70,991**	**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	4,526	28	11,342	12	6,757
Georgia	37	14,491	1	123	37	14,491	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**	**40,501**	**29**	**12,307**	**131**	**40,338**	**28**	**12,893**
Alabama	39	12,586	4	1,597	39	12,586	4	2,599
Kentucky	54	15,985	21	7,710	53	15,822	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**	**33,703**	**16**	**10,562**	**59**	**33,703**	**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	20,737	14	9,321	36	20,737	14	7,109
Mountain	**87**	**30,581**	**55**	**23,194**	**87**	**30,581**	**75**	**26,087**
Arizona	14	5,749	11	4,484	14	5,749	12	5,347
Colorado	25	4,932	8	2,364	25	4,932	23	4,480
Idaho	0	0	0	0	0	0	0	0
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	5,856	10	5,018	15	5,856	14	5,494
Pacific Contiguous	**6**	**2,128**	**0**	**0**	**3**	**2,020**	**5**	**1,568**
California	3	108	0	0	0	0	3	108
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	**1,020**	**321,353**	**186**	**87,783**	**1,016**	**321,082**	**301**	**139,082**

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, 1998

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	**28**	**6,475**	**27**	**6,060**	**1**	**415**
Connecticut	12	2,167	11	1,752	1	415
Maine	7	953	7	953	0	0
Massachusetts	8	2,942	8	2,942	0	0
New Hampshire	1	414	1	414	0	0
Rhode Island	0	0	0	0	0	0
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	**16**	**1,497**	**3**	**181**	**13**	**1,315**
Iowa	1	19	1	19	0	0
Kansas	10	1,255	0	0	10	1,255
Minnesota	2	163	2	163	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	**48**	**15,232**	**35**	**11,983**	**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	1	46	1	46	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	**87**	**13,882**	**4**	**2,258**	**85**	**12,723**
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	54	7,041	1	507	54	7,041
Mountain	**33**	**3,157**	**3**	**145**	**32**	**3,113**
Arizona	13	1,382	0	0	13	1,382
Colorado	4	481	3	145	3	437
Idaho	0	0	0	0	0	0
Montana	0	0	0	0	0	0
Nevada	4	243	0	0	4	243
New Mexico	9	800	0	0	9	800
Utah	3	252	0	0	3	252
Wyoming	0	0	0	0	0	0
Pacific Contiguous	**14**	**2,205**	**4**	**205**	**14**	**2,205**
California	14	2,205	4	205	14	2,205
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	**274**	**55,764**	**114**	**30,708**	**173**	**27,814**

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, 1997 and 1998

Census Division State	Coal 1997 Average Btu per Pound	Coal 1997 Sulfur Percent by Weight	Coal 1997 Ash Percent by Weight	Coal 1998 Average Btu per Pound	Coal 1998 Sulfur Percent by Weight	Coal 1998 Ash Percent by Weight	Petroleum 1997 Average Btu per Gallon	Petroleum 1997 Sulfur Percent by Weight	Petroleum 1998 Average Btu per Gallon	Petroleum 1998 Sulfur Percent by Weight	Gas 1997 Average Btu per Cubic Foot	Gas 1998 Average Btu per Cubic Foot
New England	**12,650**	**0.91**	**7.9**	**12,627**	**0.86**	**8.1**	**151,474**	**1.04**	**150,910**	**1.06**	**1,031**	**1,030**
Connecticut	13,064	.53	7.2	13,123	.53	6.8	151,890	.86	151,221	.88	1,022	1,034
Maine	—	—	—	—	—	—	151,039	1.34	151,063	1.28	—	—
Massachusetts	12,442	.75	8.3	12,453	.71	8.6	151,126	1.11	150,695	1.09	1,034	1,029
New Hampshire	12,997	1.61	7.3	12,939	1.41	6.9	152,353	1.27	150,919	1.64	1,019	1,019
Rhode Island	—	—	—	—	—	—	—	—	—	—	—	—
Vermont	—	—	—	—	—	—	—	—	136,130	.07	1,012	1,013
Middle Atlantic	**12,509**	**1.98**	**11.1**	**12,517**	**2.02**	**11.1**	**149,621**	**.63**	**150,035**	**.75**	**1,028**	**1,034**
New Jersey	12,910	1.15	8.8	12,862	1.22	9.2	148,383	.73	149,192	.66	1,035	1,042
New York	12,940	1.75	8.2	12,960	1.70	8.0	149,608	.69	149,866	.76	1,028	1,034
Pennsylvania	12,396	2.08	11.9	12,403	2.13	11.9	149,827	.30	150,828	.69	1,014	1,031
East North Central	**10,495**	**1.37**	**8.3**	**10,604**	**1.35**	**8.2**	**143,808**	**.61**	**144,408**	**.61**	**1,014**	**1,017**
Illinois	9,658	1.14	7.0	9,706	1.12	7.1	145,803	.67	145,307	.48	1,014	1,018
Indiana	10,385	1.60	7.9	10,468	1.65	8.1	137,121	.31	137,143	.31	1,010	1,020
Michigan	10,407	.68	6.9	10,416	.66	6.6	146,863	.78	147,020	.83	1,016	1,016
Ohio	11,867	2.10	11.8	11,851	2.04	11.5	137,819	.29	137,798	.29	1,032	1,030
Wisconsin	9,263	.49	5.7	9,967	.56	5.6	139,684	.27	140,116	.28	1,006	1,011
West North Central	**8,372**	**.52**	**6.3**	**8,344**	**.49**	**6.2**	**143,452**	**.64**	**144,045**	**1.21**	**990**	**1,003**
Iowa	8,579	.43	5.6	8,579	.42	5.6	138,451	.35	138,382	.42	1,010	1,012
Kansas	8,715	.50	5.7	8,682	.48	5.6	144,847	.74	138,273	.32	981	1,000
Minnesota	8,920	.52	6.4	8,908	.49	6.3	138,143	.38	137,482	.17	1,006	1,010
Missouri	8,920	.47	5.3	8,906	.40	5.2	145,726	.94	141,381	.49	1,006	1,010
Nebraska	8,568	.31	4.8	8,547	.28	4.7	139,126	.40	149,640	2.35	1,000	999
North Dakota	6,530	.75	9.4	6,487	.77	9.2	144,063	.41	142,908	.51	1,055	—
South Dakota	8,650	.61	8.6	8,681	.60	8.8	139,492	.36	139,923	.39	1,022	1,003
South Atlantic	**12,224**	**1.27**	**10.0**	**12,257**	**1.29**	**10.0**	**152,068**	**1.45**	**151,141**	**1.40**	**1,017**	**1,016**
Delaware	12,823	1.07	9.0	12,778	.97	8.3	149,928	.88	149,024	.78	1,036	1,044
District of Columbia	—	—	—	—	—	—	144,441	.84	143,280	.77	—	—
Florida	11,976	1.61	8.2	11,977	1.63	8.1	152,639	1.54	151,587	1.49	1,014	1,014
Georgia	11,603	.84	9.3	11,731	.84	9.3	143,556	1.44	146,199	1.93	1,025	1,024
Maryland	12,894	1.16	9.6	12,931	1.18	9.0	150,823	1.03	150,633	.96	1,041	1,047
North Carolina	12,334	.89	10.3	12,370	.88	10.4	139,459	.20	139,459	.20	—	—
South Carolina	12,758	1.19	8.8	12,783	1.28	8.8	138,094	.21	139,522	.13	1,024	1,037
Virginia	12,582	1.00	10.8	12,559	.98	10.7	149,706	1.09	149,854	1.11	1,259	1,059
West Virginia	12,352	1.84	12.1	12,316	1.89	12.4	139,032	.34	139,128	.34	1,000	1,000
East South Central	**11,631**	**1.68**	**9.9**	**11,578**	**1.61**	**10.0**	**148,571**	**2.08**	**148,335**	**2.20**	**1,025**	**1,032**
Alabama	11,542	1.10	10.4	11,472	1.11	10.3	138,871	.29	139,116	.29	1,047	1,068
Kentucky	11,727	2.18	10.6	11,707	2.12	11.0	137,562	.39	137,855	.32	1,023	1,023
Mississippi	10,430	.66	6.2	10,580	.76	6.3	149,998	2.32	149,052	2.33	1,023	1,030
Tennessee	11,891	1.88	9.0	11,755	1.66	8.7	138,182	.28	138,105	.24	—	—
West South Central	**7,699**	**.62**	**9.4**	**7,760**	**.61**	**9.2**	**147,751**	**.92**	**150,392**	**1.19**	**1,024**	**1,025**
Arkansas	8,572	.30	5.5	8,570	.30	4.7	141,918	.91	145,967	1.29	1,025	1,016
Louisiana	7,940	.64	7.4	7,932	.56	7.5	151,655	1.18	152,101	1.26	1,036	1,035
Oklahoma	8,565	.34	5.1	8,637	.31	4.9	140,587	.58	138,763	.32	1,035	1,030
Texas	7,355	.72	11.1	7,435	.73	11.1	139,354	.26	139,951	.25	1,020	1,022
Mountain	**9,796**	**.56**	**11.3**	**9,763**	**.56**	**11.3**	**138,616**	**.20**	**140,519**	**.21**	**1,019**	**1,022**
Arizona	10,177	.54	12.6	10,214	.55	12.7	138,509	.16	139,153	.08	1,013	1,012
Colorado	9,860	.38	6.8	9,841	.39	6.8	135,684	.10	138,645	.10	1,010	1,009
Idaho	—	—	—	—	—	—	—	—	—	—	—	—
Montana	8,472	.75	9.3	8,433	.72	9.5	141,000	.50	141,000	.50	1,044	1,052
Nevada	11,973	.47	9.8	11,903	.48	9.7	142,195	.42	148,935	.47	1,029	1,042
New Mexico	9,193	.82	22.7	9,064	.80	22.7	134,751	.10	134,722	.10	1,012	1,012
Utah	11,532	.49	11.1	11,485	.49	11.7	138,594	.12	139,123	.13	1,032	1,042
Wyoming	8,711	.55	7.6	8,757	.55	7.5	138,722	.20	139,301	.15	1,041	1,044
Pacific Contiguous	**7,855**	**.58**	**12.9**	**8,118**	**.53**	**10.8**	**143,445**	**.39**	**141,842**	**.41**	**1,021**	**1,023**
California	—	—	—	—	—	—	146,189	.41	146,226	.55	1,021	1,023
Oregon	8,752	.34	5.4	8,707	.33	5.2	138,804	.50	138,800	.50	—	—
Washington	7,685	.62	14.3	7,927	.60	12.6	140,000	.05	140,000	.05	1,023	1,037
Pacific Noncontiguous	**7,753**	**.17**	**10.0**	**7,596**	**.16**	**10.8**	**149,464**	**.67**	**149,143**	**.63**	**—**	**—**
Alaska	7,753	.17	10.0	7,596	.16	10.8	132,349	.27	133,973	.29	—	—
Hawaii	—	—	—	—	—	—	149,497	.67	149,207	.63	—	—
U.S. Average	**10,218**	**1.08**	**9.2**	**10,235**	**1.07**	**9.1**	**150,812**	**1.13**	**150,418**	**1.17**	**1,023**	**1,025**

Notes: •Data for 1998 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, 1994 Through 1998

Census Division State	Average O&M Costs (mills per kilowatthour)					Average Installed Costs (dollars per kilowatt)				
	1994	1995	1996	1997	1998	1994	1995	1996	1997	1998
New England	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Connecticut	—	—	—	—	—	—	—	—	—	—
Maine	—	—	—	—	—	—	—	—	—	—
Massachusetts	—	—	—	—	—	—	—	—	—	—
New Hampshire	—	—	—	—	—	—	—	—	—	—
Rhode Island	—	—	—	—	—	—	—	—	—	—
Vermont	—	—	—	—	—	—	—	—	—	—
Middle Atlantic	**2.68**	**3.02**	**2.25**	**2.21**	**2.19**	**184**	**184**	**183**	**183**	**183**
New Jersey	NM	3.36	3.66	3.24	4.85	398	398	398	398	398
New York	1.03	1.18	1.33	1.35	1.19	331	331	331	331	331
Pennsylvania	2.96	3.40	2.38	2.36	2.35	157	158	156	156	157
East North Central	**2.05**	**1.79**	**1.84**	**3.39**	**2.68**	**127**	**128**	**129**	**129**	**125**
Illinois	2.71	2.51	2.28	3.54	3.08	147	147	147	147	112
Indiana	1.53	1.52	1.68	1.59	1.51	142	144	145	146	145
Michigan	—	—	—	—	—	—	—	—	—	—
Ohio	2.92	1.93	1.92	5.47	3.79	88	88	90	90	90
Wisconsin	2.86	2.08	2.13	.10	.08	16	16	16	16	16
West North Central	**.60**	**.58**	**.53**	**.56**	**.63**	**84**	**78**	**78**	**78**	**78**
Iowa	1.53	1.56	1.37	1.39	1.41	202	202	202	202	202
Kansas	.46	.49	.35	.38	.55	73	61	61	61	61
Minnesota	.39	.37	.39	.37	.46	73	73	73	73	73
Missouri	1.35	1.20	1.36	1.05	NM	87	50	50	50	50
Nebraska	—	—	—	—	—	—	—	—	—	—
North Dakota	.79	.74	.72	.82	.83	102	102	102	102	101
South Dakota	—	—	—	—	—	—	—	—	—	—
South Atlantic	**1.16**	**.95**	**.91**	**.83**	**1.00**	**115**	**120**	**120**	**116**	**117**
Delaware	—	—	—	—	—	—	—	—	—	—
District of Columbia	—	—	—	—	—	—	—	—	—	—
Florida	1.01	.87	.96	.90	.84	67	73	73	67	72
Georgia	—	5.13	4.82	4.85	4.04	—	NM	NM	NM	NM
Maryland	—	—	—	—	—	—	—	—	—	—
North Carolina	—	—	—	—	—	—	—	—	—	—
South Carolina	.60	.48	.59	.49	.64	43	43	43	43	43
Virginia	—	—	.20	.02	.02	—	—	NM	NM	NM
West Virginia	2.33	1.44	1.35	1.28	1.62	209	216	216	217	224
East South Central	**1.06**	**1.05**	**1.09**	**1.00**	**1.16**	**143**	**143**	**143**	**143**	**143**
Alabama	.82	.57	.62	.75	1.02	80	80	80	80	80
Kentucky	1.60	1.58	1.50	1.59	1.67	140	140	140	140	139
Mississippi	.27	.35	.50	.68	.45	70	70	70	70	70
Tennessee	.05	.36	.37	.11	.18	204	204	204	204	204
West South Central	**1.08**	**.91**	**.82**	**.81**	**.86**	**76**	**71**	**83**	**86**	**89**
Arkansas	—	—	—	—	—	—	—	—	—	—
Louisiana	NM	NM	NM	NM	NM	75	75	75	75	75
Oklahoma	.50	.59	1.14	1.26	.91	92	92	92	92	92
Texas	1.11	.93	.81	.79	.86	75	70	83	87	90
Mountain	**.73**	**.79**	**.70**	**.60**	**.57**	**150**	**150**	**149**	**152**	**139**
Arizona	.77	.88	.72	.33	.40	175	175	175	180	180
Colorado	.52	.85	.60	.49	.40	69	69	69	64	64
Idaho	—	—	—	—	—	—	—	—	—	—
Montana	1.11	1.14	.92	.97	.76	274	274	274	274	274
Nevada	.74	1.57	1.07	.47	.66	126	126	126	126	126
New Mexico	1.07	1.03	.92	.90	.83	165	165	162	162	93
Utah	.41	.47	.52	.48	.47	101	101	101	101	101
Wyoming	.62	.61	.62	.63	.60	137	137	137	137	137
Pacific Contiguous	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
California	—	—	—	—	—	—	—	—	—	—
Oregon	—	—	—	—	—	—	—	—	—	—
Washington	—	—	—	—	—	—	—	—	—	—
Pacific Noncontiguous	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Alaska	—	—	—	—	—	—	—	—	—	—
Hawaii	—	—	—	—	—	—	—	—	—	—
U.S. Average	**1.14**	**1.16**	**1.07**	**1.09**	**1.12**	**127**	**126**	**128**	**129**	**126**

O&M = Operation and Maintenance

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

Notes: •Data for 1998 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 1998

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
Black Hills Corp							
Neil Simpson II 2	—	—	9511	.90		Lime	92.0
Central Illinois Light Co							
Duck Creek 1	441	441	7607	3.40	Venturi	Limestone	86.0
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	Circulating Dry	Lime	89.7
Conesville 6	—	444	7708	7.90	Spray	Lime	89.7
Coop Power Assn							
Coal Creek 1	1,052	506	7908	1.00	Spray	Lime	90.0
Coal Creek 2	—	546	8107	1.00	Spray	Lime	90.0
Deseret Generation & Tran Coop							
Bonanza 1-1	400	400	8605	.50	Spray	Limestone	95.0
Duquesne Light Co							
Elrama SCRB	510	510	7609	2.50	Venturi	Lime	83.0
F R Phillips SCRB	411	411	7406	2.50	Venturi	Lime	83.0
East Kentucky Power Coop Inc							
H L Spurlock 2	814	508	8306	3.60	Spray Dry	Lime	90.0
Georgia Power Co							
Yates Y1FG	1,488	123	9210	2.50	Bubbling Reactor	Limestone	90.0
Golden Valley Elec Assn Inc							
Healy 2	—	—		.20	Spray Dry	Limestone	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 1998 (Continued)

Utility Plant and FGD No.	Nameplate Capacity (megawatts) by Plant	Nameplate Capacity (megawatts) by Unit with FGD System	Initial Start up Date of FGD System	Design Coal Sulfur (Percent by WT)	FGD Type	Sorbent	Designed SO2 Removal (Percent Efficiency)
Grand Haven City of							
J B Sims 3	78	58	8308	2.80	Tray	Lime	90.0
Grand River Dam Authority							
GRDA 2	1,010	520	8604	1.50	Spray Dry	Lime/Alkaline Fly Ash	85.0
Hoosier Energy R E C Inc							
Merom 1FGD	1,080	540	8309	3.00	Spray	Limestone	90.0
Merom 2FGD	—	540	8202	3.00	Bubbling Reactor	Limestone	90.0
Houston Lighting & Power Co							
Limestone FGD1	1,627	813	8510	3.10	Tray	Limestone	90.0
Limestone FGD2	—	813	8610	3.10	Spray Dry	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 Power 1	1,358	679	8703	2.20	Spray	Limestone	90.0
St Johns River Power 2	—	679	8805	2.20	Spray	Limestone	90.0
Kansas City Power & Light Co							
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	645	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 Prj 3	1,703	475	8804	1.70	Spray	Limestone	90.0
Marquette City of							
Shiras 3	40	40	8307	.50	Spray Dry	Limestone	80.0
Michigan South Central Pwr Agy							
Endicott Generating 1	55	50	8305	4.30	Spray	Limestone	90.0
Minnesota Power & Light Co							
Clay Boswell AQCS2	1,073	558	8004	1.00	Spray	Alkaline Fly Ash	83.2
Clay Boswell SCR3	—	365	7302	1.00	Spray	Alkaline Fly Ash	25.4
Syl Laskin SCR1	116	58	7105	1.00	Spray	Alkaline Fly Ash	—
Syl Laskin SCR2	—	58	7105	1.00	Spray	Alkaline Fly Ash	—

See footnotes at end of table.

Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1998 (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)
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
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
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 Ctr 1	929	465	8707	3.50	Spray	Limestone	90.0
Stanton Energy Ctr 2	—	465	9606	3.40	Spray	Limestone	95.0
Otter Tail Power Co							
Coyote FGD1	450	450	8105	.80	Spray Dry	Lime/Alkaline Fly Ash	70.0
Owensboro City of							
Elmer Smith FGD	445	445	9411	3.50	Spray	Limestone	96.0
PacifiCorp							
Dave Johnston SC44	817	360	7202	.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	2,260	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	—	578	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

See footnotes at end of table.

Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1998 (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)
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							
Escalante 1	233	233	8412	.80	Spray	Limestone	95.0
Platte River Power Authority							
Rawhide 101	285	285	8404	.30	Spray Dry	Lime/Alkaline Fly Ash	80.0
Public Service Co of Colorado							
Arapahoe 4	232	100	9306	.40	Spray Dry	Other	20.0
Cherokee 1	710	100	9802	.40	Spray Dry	Other	50.0
Cherokee 4	—	350	8905	.40	Spray Dry	Other	26.0
Hayden H1	465	190	9812	.40	Spray Dry	Lime	85.0
Public Service Co of NM							
San Juan 1	1,848	369	9810	.90	Spray	Limestone	75.0
San Juan 2	—	369	9810	.90	Spray	Limestone	75.0
San Juan 3	—	555	9810	.90	Spray	Limestone	75.0
San Juan 4	—	555	9810	.90	Spray	Limestone	75.0
PSI Energy Inc							
Gibson 4	3,340	668	9501	3.50	Spray	Limestone	92.0
Gibson 5	—	668	8210	4.40	Spray	Limestone	86.0
Richmond City of							
Whitewater Valley LFC	—	—	9410	2.10	Spray Dry	Limestone	72.5
Salt River Proj Ag I & P Dist							
Coronado FGD1	822	411	7912	1.00	Spray	Limestone	82.5
Coronado FGD2	—	411	8011	1.00	Spray	Limestone	82.5
Navajo 2	2,409	803	9811	.60	Spray	Limestone	92.0
Navajo 3	—	803	9711	.60	Spray	Limestone	92.0
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
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

See footnotes at end of table.

Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1998 (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)
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	95.0
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	.60	Spray	Limestone	85.0
Craig C2	—	446	8005	.60	Spray	Limestone	85.0
Craig C3	—	446	8410	.70	Spray Dry	Lime	85.0
Tucson Electric Power Co							
Springerville 1	850	425	8506	.70	Spray Dry	Lime/Alkaline Fly Ash	61.3
Springerville 2	—	425	9006	.70	Spray Dry	Lime/Alkaline Fly Ash	61.3

See footnotes at end of table.

Table 30. Flue Gas Desulfurization (FGD) Capacity in Operation at U.S. Electric Utility Plants as of December 1998 (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)
United Power Assn							
Elk River 1	46	46	8903	—	Spray Dry	Lime	90.0
Stanton 10	172	172	8206	0.70	Spray Dry	Lime	70.0
Virginia Electric & Power Co							
Clover 1	848	424	9510	2.00	Spray	Limestone	90.0
Clover 2	—	424	9603	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.[14] 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.

[14] 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.

NERC Profile

The North American Electric Reliability Council (NERC) consists of 11 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. 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. 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.

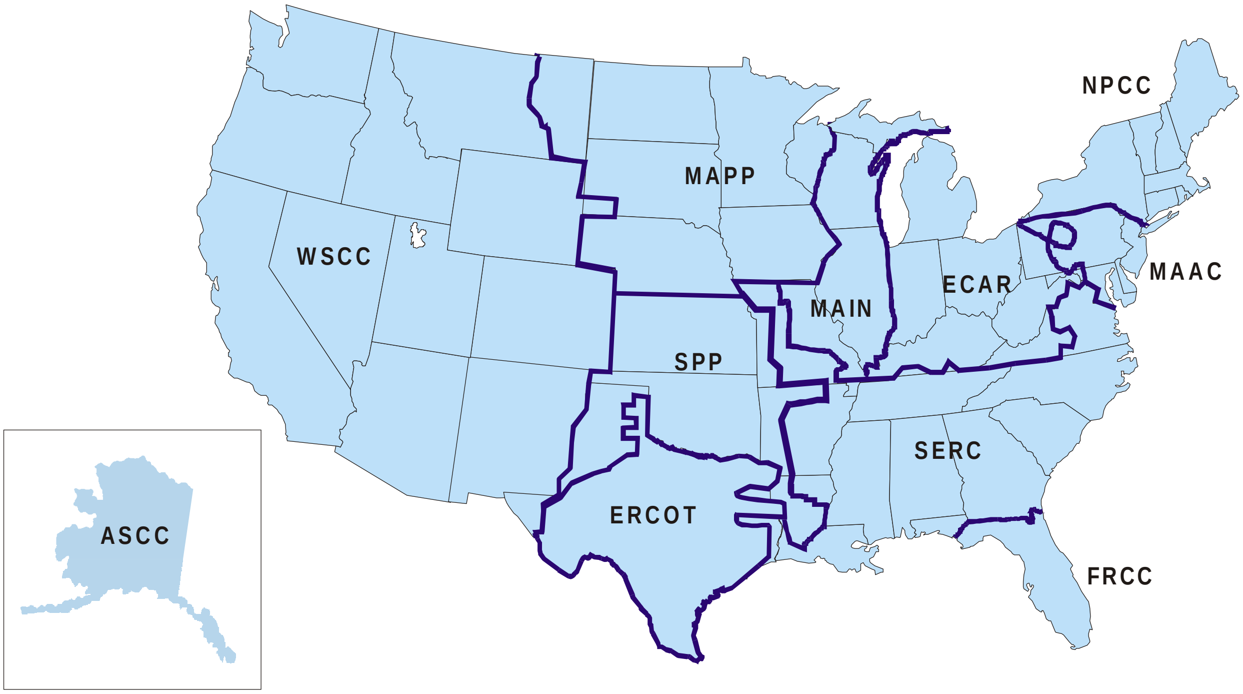
International Transactions

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



ECAR - East Central Area Reliability Coordination Agreement
ERCOT - Electric Reliability Council of Texas
FRCC - Florida Reliability Coordinating Council
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: North American Electric Reliability Council.

Table 31. Sources and Disposition of Electricity at U.S. Electric Utilities, 1994 Through 1998
(Million Kilowatthours)

Item	1994	1995	1996	1997	1998
Source					
Net Generation	2,924,961	3,002,304	3,099,945	3,144,756	3,219,994
Purchases from Utilities	1,226,814	R 1,284,995	1,465,174	1,634,886	1,668,665
Purchases from Nonutilities	208,778	R 222,092	229,018	243,213	258,534
Net Exchange	–3,659	R 66	–11,677	–17,088	–858
Net Wheeling	4,225	7,016	7,324	7,135	8,076
Disposition					
Sales to Ultimate Consumers	2,934,563	3,013,287	3,097,810	3,139,761	3,239,818
Requirements and Nonrequirements Sales for Resale	1,185,352	R 1,255,618	1,431,179	1,616,318	1,664,081
Energy Furnished Without Charge	4,762	5,362	6,205	6,318	5,109
Energy Used by Utility Electric Department	15,495	12,455	13,886	13,424	10,808
Energy Losses[1]	220,948	R 228,076	238,695	234,926	232,112

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.

R = Revised data.

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, 1994 Through 1998
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1994	1995	1996	1997	1998
ECAR	492,074	509,468	528,214	530,896	528,252
ERCOT	204,256	210,596	218,497	221,407	237,176
FRCC	—	—	—	146,217	167,910
MAAC	206,221	203,801	200,669	204,269	222,509
MAIN	221,770	229,424	231,315	216,732	221,883
MAPP(U.S.)	124,607	130,637	132,689	133,885	139,209
NPCC(U.S.)	189,546	183,021	185,521	188,063	178,096
SERC	678,423	703,899	740,784	617,191	747,031
SPP	260,025	274,475	276,205	278,701	184,483
WSCC(U.S.)	537,399	546,208	574,878	596,496	582,768
Contiguous U.S.	**2,914,320**	**2,991,529**	**3,088,772**	**3,133,858**	**3,209,317**
ASCC	4,913	4,925	5,178	5,013	4,719
Hawaii	5,728	5,851	5,994	5,886	5,958
U.S. Total	**2,924,961**	**3,002,304**	**3,099,945**	**3,144,756**	**3,219,994**

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. •In 1998 several utilities realigned from SPP to SERC. •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, 1994 Through 1998

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	All Sectors	Residential	Commercial	Industrial	Other[1]
			1994		
ECAR	459,747	139,521	111,731	198,793	9,701
ERCOT	218,781	78,708	57,209	73,248	9,615
FRCC	—	—	—	—	—
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	88,909	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**
			1995		
ECAR	477,126	147,019	116,092	204,072	9,942
ERCOT	222,465	81,158	59,065	72,542	9,700
FRCC	—	—	—	—	—
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
FRCC	—	—	—	—	—
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**

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, 1994 Through 1998 (Continued)
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	All Sectors	Residential	Commercial	Industrial	Other[1]
			1997		
ECAR	485,244	146,537	119,440	209,236	10,030
ERCOT	243,029	88,459	61,965	81,583	11,022
FRCC	149,249	73,598	56,159	14,364	5,128
MAAC	228,115	79,143	88,156	57,952	2,864
MAIN	222,714	65,456	64,920	82,790	9,548
MAPP(U.S.)	141,200	48,375	30,738	58,069	4,019
NPCC(U.S.)	242,428	79,286	97,605	51,641	13,896
SERC	571,424	208,635	152,495	195,263	15,030
SPP	282,082	97,417	71,826	103,442	9,398
WSCC(U.S.)	560,473	184,603	180,278	173,858	21,734
Contiguous U.S.	**3,125,958**	**1,071,510**	**923,583**	**1,028,197**	**102,668**
ASCC	4,840	1,726	2,180	756	178
Hawaii	8,963	2,531	2,677	3,701	55
U.S. Total	**3,139,761**	**1,075,767**	**928,440**	**1,032,653**	**102,901**
			1998		
ECAR	494,942	149,895	124,956	210,679	9,411
ERCOT	258,684	96,749	66,654	83,395	11,886
FRCC	175,214	89,614	63,480	16,384	5,736
MAAC	230,855	79,331	90,719	58,007	2,798
MAIN	224,576	67,011	66,753	81,167	9,646
MAPP(U.S.)	143,942	48,651	31,625	59,725	3,941
NPCC(U.S.)	243,180	79,623	97,862	51,396	14,298
SERC	723,580	266,502	187,200	251,340	18,538
SPP	165,351	58,274	48,405	51,991	6,680
WSCC(U.S.)	565,531	187,814	185,893	171,497	20,327
Contiguous U.S.	**3,225,854**	**1,123,463**	**963,546**	**1,035,583**	**103,261**
ASCC	5,095	1,768	2,307	818	202
Hawaii	8,870	2,504	2,675	3,636	55
U.S. Total	**3,239,818**	**1,127,735**	**968,528**	**1,040,038**	**103,518**

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

Notes: •Data are final. •In 1998 several utilities realigned from SPP to SERC. •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, 1994 Through 1998

(Megawatts)

North American Electric Reliability Council Region and Hawaii	1994	1995	1996	1997	1998
ECAR	104,812	104,426	103,360	102,518	101,115
ERCOT	53,110	53,400	53,903	53,711	54,018
FRCC	—	—	32,751	32,616	34,904
MAAC	51,629	52,083	53,163	53,588	53,168
MAIN	50,863	51,430	52,155	52,093	49,020
MAPP(U.S.)	31,357	31,311	30,610	34,820	34,815
NPCC(U.S.)	55,956	55,567	52,177	51,406	43,263
SERC	151,127	153,434	125,079	155,786	154,320
SPP	71,099	71,375	71,593	42,871	42,669
WSCC(U.S.)	128,937	129,751	131,292	129,232	116,159
Contiguous U.S.	**698,890**	**702,777**	**706,083**	**708,641**	**683,451**
ASCC	1,737	1,732	1,734	1,750	1,721
Hawaii	1,602	1,602	1,610	1,499	1,519
U.S. Total	**702,229**	**706,111**	**709,942**	**711,889**	**686,692**

Notes: •Data are final. •The collection of data are as of Janaury 1 of the following year. The 1996 data include the Florida Reliability Coordinating Council created January 1, 1997. The 1997 data include the Entergy Corporation which became part of the SERC from the SPP effective January 1, 1998. •In 1998 several utilities realigned from SPP to SERC. •Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Data for 1998: Form EIA-860A, ''Annual Electric Generator Report - Utility''; Data for 1997 and prior: Form EIA-860, ''Annual Electric Generator Report''.

Table 35. Noncoincidental Peak Load, Actual and Projected, by North American Electric Reliability Council Region and Hawaii, 1994 Through 2003

(Megawatts)

North American Electric Reliability Council Region and Hawaii	Actual				
	1994	1995	1996	1997[1]	1998
			Summer		
ECAR	87,165	92,619	90,798	93,784	95,675
ERCOT	44,162	46,618	47,480	54,666	53,330
FRCC	NA	NA	NA	38,730	37,327
MAAC	46,019	48,577	44,302	48,445	49,807
MAIN	42,562	45,782	46,402	47,509	47,875
MAPP(U.S.)	27,000	29,192	28,253	30,722	31,991
NPCC(U.S.)	47,581	47,705	45,094	49,566	51,760
SERC	132,584	146,569	145,650	143,226	147,223
SPP	56,035	59,595	60,072	37,724	38,180
WSCC(U.S.)	102,212	103,592	108,739	115,921	115,901
Contiguous U.S.	**585,320**	**620,249**	**616,790**	**660,293**	**669,069**
ASCC	524	622	(2)	(2)	(2)
Hawaii	(3)	(3)	(3)	(3)	(3)
U.S. Total	**585,844**	**620,871**	**616,790**	**660,293**	**669,069**
			Winter		
ECAR	75,638	83,465	84,534	84,401	86,020
ERCOT	36,180	36,965	38,868	41,876	42,574
FRCC	NA	NA	NA	39,975	40,165
MAAC	40,653	40,790	40,468	36,532	43,009
MAIN	33,999	35,734	37,162	37,410	38,170
MAPP(U.S.)	23,033	23,429	24,251	26,080	26,781
NPCC(U.S.)	42,547	42,755	41,208	44,199	44,160
SERC	132,661	142,032	143,060	127,416	130,738
SPP	42,505	44,626	49,095	27,847	27,986
WSCC(U.S.)	91,037	94,890	95,435	101,822	103,087
Contiguous U.S.	**518,253**	**544,684**	**554,081**	**567,558**	**582,690**
ASCC	641	676	(2)	(2)	(2)
Hawaii	(3)	(3)	(3)	(3)	(3)
U.S. Total	**518,894**	**545,360**	**554,081**	**567,558**	**582,690**

See footnotes at end of table.

Table 35. Noncoincidental Peak Load, Actual and Projected, by North American Electric Reliability Council Region and Hawaii, 1994 Through 2003 (Continued)

(Megawatts)

North American Electric Reliability Council Region and Hawaii	Projected				
	1999	2000	2001	2002	2003
			Summer		
ECAR	97,475	99,322	101,194	102,894	104,169
ERCOT	54,199	55,173	56,623	57,845	59,182
FRCC	37,864	38,528	39,235	40,059	40,876
MAAC	50,576	51,426	52,238	53,048	53,892
MAIN	48,542	49,135	49,763	50,505	51,362
MAPP(U.S.)	32,406	32,969	33,681	34,322	34,869
NPCC(U.S.)	52,415	53,235	54,035	54,831	55,557
SERC	149,380	154,632	158,159	161,668	165,149
SPP	38,795	39,305	40,092	41,045	41,834
WSCC(U.S.)	117,874	119,963	121,920	124,069	125,874
Contiguous U.S.	**679,526**	**693,688**	**706,940**	**720,286**	**732,764**
ASCC	(2)	(2)	(2)	(2)	(2)
Hawaii	(3)	(3)	(3)	(3)	(3)
U.S. Total	**679,526**	**693,688**	**706,940**	**720,286**	**732,764**
			Winter		
ECAR	87,748	89,281	90,717	91,749	93,849
ERCOT	44,061	45,230	46,221	47,371	48,643
FRCC	41,176	42,103	43,048	43,966	44,889
MAAC	43,628	44,264	44,917	45,575	46,247
MAIN	38,945	39,500	39,958	40,636	40,775
MAPP(U.S.)	26,980	27,514	27,969	28,428	28,832
NPCC(U.S.)	44,550	45,341	46,206	46,844	47,513
SERC	133,116	137,644	140,505	143,156	146,285
SPP	28,311	28,898	29,591	30,281	30,951
WSCC(U.S.)	104,936	106,533	108,292	109,813	111,334
Contiguous U.S.	**593,451**	**606,308**	**617,424**	**627,819**	**639,318**
ASCC	(2)	(2)	(2)	(2)	(2)
Hawaii	(3)	(3)	(3)	(3)	(3)
U.S. Total	**593,451**	**606,308**	**617,424**	**627,819**	**639,318**

1 Revised.
(2) Data for ASCC (Alaska) was not filed beginning in 1996.
(3) Data for Hawaii are not submitted on this form.
Notes: •Data are final. •In 1998 several utilities realigned from SPP to SERC. •Totals may not equal sum of components because of independent rounding.
Sources: Data for 1996 and beyond: Form EIA-411, ''Coordinated Bulk Power Supply Program''; Data for prior years: Department of Energy, Office 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, 1994 Through 1998

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Receipts	Purchased Power	Exchange Received	Wheeling Received
		1994		
ECAR	199,000	166,157	1,982	30,861
ERCOT	141,092	61,901	55,122	24,069
FRCC	—	—	—	—
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**
		1995		
ECAR	223,966	188,679	2,158	33,128
ERCOT	145,430	62,215	50,420	33,795
FRCC	—	—	—	—
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
FRCC	—	—	—	—
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**

See footnotes at end of table.

Table 36. U.S. Electric Utility Receipts by North American Electric Reliability Council Region and Hawaii, 1994 Through 1998 (Continued)

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Receipts	Purchased Power	Exchange Received	Wheeling Received
	1997			
ECAR	319,495	259,081	1,764	58,650
ERCOT	134,715	78,170	56,545	[1] 0
FRCC	50,820	40,140	33	10,647
MAAC	151,729	135,582	518	15,629
MAIN	105,159	88,743	294	16,121
MAPP(U.S.)	132,758	108,253	3,814	20,691
NPCC(U.S.)	290,015	201,349	4,879	83,786
SERC	425,460	343,939	29,589	51,932
SPP	210,562	169,136	9,780	31,645
WSCC(U.S.)	645,818	446,733	47,919	151,166
Contiguous U.S.	**2,466,530**	**1,871,127**	**155,135**	**440,268**
ASCC	4,267	3,348	79	840
Hawaii	3,627	3,625	2	0
U.S. Total	**2,474,424**	**1,878,099**	**155,217**	**441,108**
	1998			
ECAR	350,223	276,928	6,974	66,322
ERCOT	137,785	82,765	54,389	[1] 631
FRCC	67,693	55,730	42	11,921
MAAC	158,175	145,124	733	12,318
MAIN	117,000	88,766	570	27,664
MAPP(U.S.)	136,784	109,152	4,222	23,409
NPCC(U.S.)	272,560	209,550	4,798	58,212
SERC	532,068	434,074	19,662	78,332
SPP	110,978	84,182	5,229	21,568
WSCC(U.S.)	622,881	433,920	36,989	151,972
Contiguous U.S.	**2,506,147**	**1,920,191**	**133,607**	**452,350**
ASCC	4,064	3,570	115	379
Hawaii	3,440	3,437	3	0
U.S. Total	**2,513,651**	**1,927,198**	**133,725**	**452,728**

[1] ''Wheeling Received'' and ''Wheeling Delivered'' for ERCOT in 1997 and 1998 reflect enactment by the Public Utility Commission of Texas (the Commission) of Substantive Rule 23.67 (''Open-access Comparable Transmission Service''), effective on September 12, 1996. SR 23.67 governs virtually all phases of transmission access in Texas and requires that wheeling services, provided by transmission facility operators under the jurisdiction of the Commission, shall be reimbursed using the vector-absolute, megawatt/mile method. This method derives reimbursement rates utilizing information on the total line-mileage under load, the maximum load in megawatts, and the fee per megawatt-mile. Use of this method does not require transmission service providers to measure energy flows.''

Notes: •Data are final. •In 1998 several utilities realigned from SPP to SERC. •Totals may not equal sum of components because of independent rounding.

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, 1994 Through 1998
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Deliveries	Requirements and Nonrequirements Sales for Resale	Exchange Delivered	Wheeling Delivered
		1994		
ECAR	199,188	166,045	2,513	30,630
ERCOT	112,985	33,536	55,360	24,088
FRCC	—	—	—	—
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**
		1995		
ECAR	221,627	186,464	2,270	32,893
ERCOT	118,456	34,017	50,644	33,796
FRCC	—	—	—	—
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
FRCC	—	—	—	—
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**

See footnotes at end of table.

Table 37. U.S. Electric Utility Deliveries by North American Electric Reliability Council Region and Hawaii, 1994 Through 1998 (Continued)

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Total Deliveries	Requirements and Nonrequirements Sales for Resale	Exchange Delivered	Wheeling Delivered
			1997	
ECAR	329,876	269,688	1,782	58,406
ERCOT	96,812	40,346	56,467	[1] 0
FRCC	37,627	27,182	19	10,426
MAAC	108,060	92,418	16	15,626
MAIN	83,187	66,939	331	15,918
MAPP(U.S.)	112,294	89,619	3,306	19,370
NPCC(U.S.)	215,175	128,369	3,315	83,491
SERC	431,021	336,819	44,850	49,352
SPP	183,461	141,120	10,656	31,685
WSCC(U.S.)	621,041	420,704	51,476	148,860
Contiguous U.S.	**2,218,554**	**1,613,202**	**172,219**	**433,133**
ASCC	4,037	3,115	82	840
Hawaii	4	0	4	0
U.S. Total	**2,222,596**	**1,616,318**	**172,305**	**433,973**
			1998	
ECAR	347,326	275,006	7,043	65,277
ERCOT	98,143	42,958	54,570	[1] 615
FRCC	47,955	36,226	56	11,673
MAAC	131,873	119,627	13	12,233
MAIN	99,397	71,254	618	27,525
MAPP(U.S.)	117,460	92,457	3,623	21,380
NPCC(U.S.)	188,205	126,177	4,127	57,902
SERC	503,114	399,718	26,469	76,927
SPP	115,035	88,547	5,051	21,438
WSCC(U.S.)	591,499	409,307	32,888	149,304
Contiguous U.S.	**2,240,008**	**1,661,277**	**134,458**	**444,274**
ASCC	3,301	2,803	119	379
Hawaii	6	0	6	0
U.S. Total	**2,243,316**	**1,664,081**	**134,583**	**444,652**

1 ''Wheeling Received'' and ''Wheeling Delivered'' for ERCOT in 1997 and 1998 reflect enactment by the Public Utility Commission of Texas (the Commission) of Substantive Rule 23.67 (''Open-access Comparable Transmission Service''), effective on September 12, 1996. SR 23.67 governs virtually all phases of transmission access in Texas and requires that wheeling services, provided by transmission facility operators under the jurisdiction of the Commission, shall be reimbursed using the vector-absolute, megawatt/mile method. This method derives reimbursement rates utilizing information on the total line-mileage under load, the maximum load in megawatts, and the fee per megawatt-mile. Use of this method does not require transmission service providers to measure energy flows.''

Notes: •Data are final. •In 1998 several utilities realigned from SPP to SERC. •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, 1994 Through 1998

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Net Energy Flow[1]	Receipts[2]	Deliveries[3]
		1994	
ECAR	–188	199,000	199,188
ERCOT	28,107	141,092	112,985
FRCC	—	—	—
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**
		1995	
ECAR	2,339	223,966	221,627
ERCOT	26,974	145,430	118,456
FRCC	—	—	—
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
FRCC	—	—	—
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	0	4,257	4,257
Hawaii	3,565	3,572	7
U.S. Total	**258,660**	**2,266,707**	**2,008,047**

See footnotes at end of table.

Table 38. U.S. Electric Utility Net Energy Flow by North American Electric Reliability Council Region and Hawaii, 1994 Through 1998 (Continued)

(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Net Energy Flow[1]	Receipts[2]	Deliveries[3]
		1997	
ECAR	–10,381	319,495	329,876
ERCOT	37,903	134,715	96,812
FRCC	13,192	50,820	37,627
MAAC	43,669	151,729	108,060
MAIN	21,971	105,159	83,187
MAPP(U.S.)	20,463	132,758	112,294
NPCC(U.S.)	74,840	290,015	215,175
SERC	–5,561	425,460	431,021
SPP	27,101	210,562	183,461
WSCC(U.S.)	24,778	645,818	621,041
Contiguous U.S.	**247,976**	**2,466,530**	**2,218,554**
ASCC	230	4,267	4,037
Hawaii	3,623	3,627	4
U.S. Total	**251,828**	**2,474,424**	**2,222,596**
		1998	
ECAR	2,897	350,223	347,326
ERCOT	39,642	137,785	98,143
FRCC	19,738	67,693	47,955
MAAC	26,302	158,175	131,873
MAIN	17,603	117,000	99,397
MAPP(U.S.)	19,324	136,784	117,460
NPCC(U.S.)	84,355	272,560	188,205
SERC	28,954	532,068	503,114
SPP	–4,057	110,978	115,035
WSCC(U.S.)	31,382	622,881	591,499
Contiguous U.S.	**266,139**	**2,506,147**	**2,240,008**
ASCC	763	4,064	3,301
Hawaii	3,434	3,440	6
U.S. Total	**270,336**	**2,513,651**	**2,243,316**

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.

Notes: •Data are final. •In 1998 several utilities realigned from SPP to SERC. •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, 1994 Through 1998
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1994	1995	1996	1997	1998
ECAR	12,659	13,131	15,861	15,989	14,692
ERCOT	23,264	22,653	23,916	25,908	26,562
FRCC	—	—	—	11,824	13,254
MAAC	20,911	23,870	23,892	24,019	24,360
MAIN	392	447	468	971	3,348
MAPP(U.S.)	585	585	706	1,053	1,863
NPCC(U.S.)	49,348	57,511	56,207	58,858	63,557
SERC	24,020	29,184	31,276	15,324	17,289
SPP	6,856	5,345	6,090	5,130	484
WSCC(U.S.)	67,297	65,842	67,028	80,502	89,372
Contiguous U.S.	**205,332**	**218,567**	**225,445**	**239,577**	**254,779**
ASCC	4	7	5	10	317
Hawaii	3,442	3,518	3,568	3,625	3,437
U.S. Total	**208,778**	**222,092**	**229,018**	**243,213**	**258,534**

Notes: •Data are final. •In 1998 several utilities realigned from SPP to SERC. •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, 1998 Through 2003
(Megawatts)

North American Electric Reliability Council Region and Hawaii	1998			1999		
	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)
	Summer					
ECAR	92,359	105,545	12.5	94,157	107,132	12.1
ERCOT	50,254	59,788	15.9	51,322	62,686	18.1
FRCC	34,562	39,708	13.0	35,026	40,481	13.5
MAAC	47,626	55,511	14.2	48,360	55,470	12.8
MAIN	45,570	52,722	13.6	46,165	53,607	13.9
MAPP(U.S)	29,766	34,773	14.4	30,041	34,847	13.8
NPCC(U.S)	51,760	60,439	14.4	52,415	61,841	15.2
SERC	138,146	158,360	12.8	140,710	162,952	13.6
SPP	36,402	42,554	14.5	36,811	42,552	13.5
WSCC(U.S)	111,641	135,270	17.5	113,488	135,733	16.4
Contiguous U.S	**638,086**	**744,670**	**14.3**	**648,495**	**757,301**	**14.4**
ASCC	(1)	(1)	(1)	(1)	(1)	(1)
Hawaii	(2)	(2)	(2)	(2)	(2)	(2)
U.S. Total	**638,086**	**744,670**	**14.3**	**648,495**	**757,301**	**14.4**

	2000			2003		
	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)
	Summer					
ECAR	95,950	107,576	10.8	100,789	111,536	9.6
ERCOT	52,265	63,502	17.7	56,200	65,320	14.0
FRCC	35,685	41,684	14.4	38,087	45,286	15.9
MAAC	49,204	55,707	11.7	51,660	57,142	9.6
MAIN	46,702	54,976	15.1	48,898	57,831	15.4
MAPP(U.S)	30,433	35,401	14.0	32,022	35,343	9.4
NPCC(U.S)	53,235	60,628	12.2	55,557	61,820	10.1
SERC	145,904	168,709	13.5	156,280	179,758	13.1
SPP	37,366	44,228	15.5	39,706	46,243	14.1
WSCC(U.S)	115,528	139,058	16.9	121,436	140,705	13.7
Contiguous U.S	**662,272**	**771,469**	**14.2**	**700,635**	**800,984**	**12.5**
ASCC	(1)	(1)	(1)	(1)	(1)	(1)
Hawaii	(2)	(2)	(2)	(2)	(2)	(2)
U.S. Total	**662,272**	**771,469**	**14.2**	**700,635**	**800,984**	**12.5**

	1998			1999		
	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)
	Winter					
ECAR	82,974	107,567	22.9	84,663	107,850	21.5
ERCOT	39,630	60,071	34.0	41,300	63,346	34.8
FRCC	36,153	41,768	13.4	37,067	42,403	12.6
MAAC	41,859	57,956	27.8	42,477	57,921	26.7
MAIN	36,205	52,308	30.8	36,681	53,333	31.2
MAPP(U.S)	25,609	33,961	24.6	25,778	34,243	24.7
NPCC(U.S)	44,160	60,967	27.6	44,550	61,939	28.1
SERC	123,533	158,892	22.3	125,911	163,963	23.2
SPP	27,180	42,239	35.7	27,444	42,506	35.4
WSCC(U.S)	101,748	136,635	25.5	103,546	138,009	25.0
Contiguous U.S	**559,051**	**752,365**	**25.7**	**569,417**	**765,513**	**25.6**
ASCC	(1)	(1)	(1)	(1)	(1)	(1)
Hawaii	(2)	(2)	(2)	(2)	(2)	(2)
U.S. Total	**559,051**	**752,365**	**25.7**	**569,417**	**765,513**	**25.6**

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, 1998 Through 2003 (Continued)
(Megawatts)

North American Electric Reliability Council Region and Hawaii	2000			2003		
	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)	Net Internal Demand	Planned Capacity Resources	Capacity Margin (percent)
	Winter					
ECAR	86,196	107,970	20.2	90,776	112,287	19.2
ERCOT	42,438	63,653	33.3	45,783	65,469	30.1
FRCC	38,031	44,238	14.0	40,804	48,276	15.5
MAAC	43,112	58,158	25.9	45,092	59,599	24.3
MAIN	37,181	53,529	30.5	39,000	56,772	31.3
MAPP(U.S)	26,248	34,696	24.3	27,418	34,790	21.2
NPCC(U.S)	45,341	61,915	26.8	47,513	63,398	25.1
SERC	130,394	171,192	23.8	138,868	182,740	24.0
SPP	28,023	44,546	37.1	30,018	46,016	34.8
WSCC(U.S)	105,151	140,180	25.0	109,936	142,112	22.6
Contiguous U.S	**582,115**	**780,077**	**25.4**	**615,208**	**811,459**	**24.2**
ASCC	(1)	(1)	(1)	(1)	(1)	(1)
Hawaii	(2)	(2)	(2)	(2)	(2)	(2)
U.S. Total	**582,115**	**780,077**	**25.4**	**615,208**	**811,459**	**24.2**

(1) Data for ASCC (Alaska) were not filed.
(2) Data for Hawaii are not submitted on this form.
Notes: •Data are final. •In 1998 several utilities realigned from SPP to SERC. •Totals may not equal sum of components because of independent rounding.
Source: Form EIA-411, ''Coordinated Bulk Power Supply Program''.

Table 41. Net Imports at U.S. Electric Utilities by North American Electric Reliability Council Region and Hawaii, 1994 Through 1998
(Thousand Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1994[1]	1995[1]	1996[1]	1997[1]	1998
ECAR	6,909,055	5,759,606	1,906,706	1,379,798	–1,533,577
ERCOT	–964,700	–925,370	–1,024,062	–577,345	–288,303
FRCC	–-	–-	–-	–-	–-
MAAC	141,341	15,725	199,333	113,318	–163,858
MAIN	–-	450	163,471	879,588	806,805
MAPP(U.S.)	8,714,165	9,171,991	9,705,026	10,251,395	7,724,305
NPCC(U.S.)	24,031,159	23,067,556	20,428,597	15,917,517	15,665,514
SERC	–-	–-	–-	–-	–-
SPP	–-	–-	–-	350	3,700
WSCC(U.S.)	5,990,966	2,139,805	8,814,286	6,090,941	4,567,857
Contiguous U.S.	**44,821,986**	**39,229,763**	**40,193,357**	**34,055,562**	**26,782,443**
ASCC	1,309	1,102	1,185	1,629	992
Hawaii[2]	–-	–-	–-	–-	–-
U.S. Total	**44,823,295**	**39,230,865**	**40,194,542**	**34,057,191**	**26,783,435**
Net Canada	43,880,644	38,127,875	40,247,015	35,538,169	27,818,833
Net Mexico	942,651	1,102,990	–52,473	–1,480,978	–1,035,398

1 Data for 1994 through 1997 are revised. The methodology for calculating import and export data for Canada has been modified by basing on metered energy and include both firm and interruptible energy. Originally collected from ''Presidential Permits'', the data are now obtained from the National Energy Board of Canada. The methodology for Mexico remains the same.
2 Data for Hawaii are not submitted on this form.
Notes: •Data for 1998 are preliminary. Data for all other years are final. •In 1998 several utilities realigned from SPP to SERC. •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.
•Sources: Canada: National Energy Board of Canada; Mexico: 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, 1994 Through 1998

(Thousand Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1994[1]	1995[1]	1996[1]	1997[1]	1998
ECAR	6,910,227	5,800,588	2,125,829	3,384,292	2,027,472
ERCOT	70	–-	5,566	526,185	738,369
FRCC	–-	–-	–-	–-	–-
MAAC	141,341	22,625	207,183	113,818	10,965
MAIN	–-	450	163,471	879,588	840,607
MAPP(U.S.)	8,950,985	9,374,324	10,019,894	10,523,784	9,337,540
NPCC(U.S.)	24,708,662	23,636,732	21,209,207	17,540,075	17,446,689
SERC	–-	–-	–-	–-	–-
SPP	–-	–-	–-	350	3,700
WSCC(U.S.)	6,120,583	4,017,709	9,764,193	10,061,509	9,107,024
Contiguous U.S.	**46,831,868**	**42,852,428**	**43,495,343**	**43,029,601**	**39,512,366**
ASCC	1,309	1,102	1,185	1,629	992
Hawaii[2]	–-	–-	–-	–-	–-
U.S. Total	**46,833,177**	**42,853,530**	**43,496,528**	**43,031,230**	**39,513,358**
From Canada	44,821,858	40,596,119	42,233,376	43,008,501	39,502,108
From Mexico	2,011,319	2,257,411	1,263,152	22,729	11,249

1 Data for 1994 through 1997 are revised. The methodology for calculating import and export data for Canada has been modified by basing on metered energy and include both firm and interruptible energy. Originally collected from ''Presidential Permits'', the data are now obtained from the National Energy Board of Canada. The methodology for Mexico remains the same.

2 Data for Hawaii are not submitted on this form.

Notes: •Data for 1998 are preliminary. Data for all other years are final. •In 1998 several utilities realigned from SPP to SERC. •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.

•Sources: Canada: National Energy Board of Canada; Mexico: 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, 1994 Through 1998

(Thousand Kilowatthours)

North American Electric Reliability Council Region and Hawaii	1994[1]	1995[1]	1996[1]	1997[1]	1998
ECAR	1,172	40,982	219,123	2,004,494	3,561,049
ERCOT	964,770	925,370	1,029,628	1,103,530	1,026,672
FRCC	–-	–-	–-	–-	–-
MAAC	–-	6,900	7,850	500	174,823
MAIN	–-	–-	–-	–-	33,802
MAPP(U.S.)	236,820	202,333	314,868	272,389	1,613,235
NPCC(U.S.)	677,503	569,176	780,610	1,622,558	1,781,175
SERC	–-	–-	–-	–-	–-
SPP	–-	–-	–-	–-	–-
WSCC(U.S.)	129,617	1,877,904	949,907	3,970,568	4,539,167
Contiguous U.S.	**2,009,882**	**3,622,665**	**3,301,986**	**8,974,039**	**12,729,923**
ASCC	–-	–-	–-	–-	–-
Hawaii[2]	–-	–-	–-	–-	–-
U.S. Total	**2,009,882**	**3,622,665**	**3,301,986**	**8,974,039**	**12,729,923**
To Canada	941,214	2,468,244	1,986,361	7,470,332	11,683,276
To Mexico	1,068,668	1,154,421	1,315,625	1,503,707	1,046,647

1 Data for 1994 through 1997 are revised. The methodology for calculating import and export data for Canada has been modified by basing on metered energy and include both firm and interruptible energy. Originally collected from ''Presidential Permits'', the data are now obtained from the National Energy Board of Canada. The methodology for Mexico remains the same.

2 Data for Hawaii are not submitted on this form.

Notes: •Data for 1998 are preliminary. Data for all other years are final. •In 1998 several utilities realigned from SPP to SERC. •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.

•Sources: Canada: National Energy Board of Canada; Mexico: 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. In the past, the primary objective of most DSM programs was 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. However, due to changes that are occurring within the industry, electric utilities are also using DSM as a way to enhance customer service.

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, and reduced capital requirements. Consumers can benefit from reduced costs and improved value of service. Society can benefit from reduced emissions and the conservation of finite 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 have abandoned their DSM programs altogether, other utilities have formed 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 varies depending on their overall organization and market environment, strategic objectives, and system operating characteristics. DSM programs generally promote one of three basic objectives that differ in their intended effects on electricity use (measured in kilowatthours) and demand (measured in kilowatts); energy efficiency, load management, and load shifting.

Energy efficiency or conservation programs are aimed at reducing the energy used by promoting high-efficiency equipment and building design. 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).

Load management programs are aimed at reducing demand at certain critical times (such as summer or winter peak) and usually have only a minor effect on annual energy 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 the utility during a few peak-demand hours.

Flexible load shape programs give consumers the incentive to alter 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.

Planning and Selection of Programs

The main elements of the DSM program planning and selection process are to evaluate consumer characteristics that influence the acceptance of DSM programs and utility considerations affecting resource requirements and the cost of alternative resource options. Among the consumers' characteristics that influence a program's success are demographics, income, knowledge and awareness, attitude and motivation, and discount rate. External influences such as economic conditions, energy prices, technologies, regulation, and tax credits also influence consumer's decisions regarding fuel and appliance choice, efficiency, and 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.

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.[15] 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 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.[16]

Data Sources

The data in the following tables were collected on Schedule V, “Demand-Side Management Information” of the 1998 Form EIA-861,“Annual Electric Utility Report.” Schedule V collects utility information on actual and potential peak load reductions and energy savings for two program categories: Energy Efficiency and Load Management programs, by four major consumer sectors (residential, commercial, industrial, and other). Utilities provide information for the reporting year 1998.

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 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 two categories. If the cost can be tracked to a specific program category (energy efficiency, or load management), 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.

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

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

Why the Numbers are Changing

It is no longer possible to directly compare results between 1997 and 1998 as the threshold for small and large utilities was changed. Small utilities in 1998 are classified as having sales for resale and sales to ultimate consumers of less than 150,000 megawatthours. For 1997 and prior years, small utilities were classified as having sales for resale and sales to ultimate consumers of less than 120,000 megawatthours.

Utility sponsored demand-side management (DSM) programs and cost continue to be affected by changes within the electric utility industry. As in 1997, utilities have found it is no longer advantageous to offer energy efficiency programs as in the years prior to restructuring. Instead, many utilities have created energy service companies (ESCO's). In these instances, the utility is able to pass along the costs for energy efficiency programs to their customers. As subsidiaries, ESCO's are not required to report to the EIA.

The lack of major changes in potential peak load reduction is an expected result. A number of utilities continue to offer interruptible and time-of-use rates to their commercial and industrial customers. However, there have been major reductions in the installation of residential peak load shaving programs. Factors other than restructuring, such as weather variations, can influence fluctuations in actual peak load reduction.

Table 44. U.S. Electric Utility Demand-Side Management Program Energy Savings, Actual and Potential Peak Load Reductions, and Cost, 1994 Through 1998

Item	1994	1995	1996	1997	1998
Energy Savings (million kilowatthours)[1]	52,483	57,421	61,842	56,406	49,167
Actual Peak Load Reductions (megawatts)[1] [2]	25,001	29,561	29,893	25,284	27,231
Potential Peak Load Reductions (megawatts)[1]	42,917	47,029	48,344	41,237	41,430
Cost (thousand dollars)[3]	2,715,657	2,421,261	1,902,197	1,636,020	1,420,920

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, at the time of annual peak load, as opposed to the installed peak load reduction capability (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 for 1998 are provided for electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 150,000 megawatthours, and for prior years greater than or equal to 120,000 megawatts.

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, 1994 Through 1998
(Megawatts)

North American Electric Reliability Council Region and Hawaii	Total Actual Peak Load Reduction	Direct Load Control	Interruptible Load	Energy Efficiency	Other Load Management	Other Demand-Side Management
			1994			
ECAR	1,583	200	634	631	103	15
ERCOT	1,838	20	77	1,420	301	19
FRCC	—	—	—	—	—	—
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**
			1995			
ECAR	2,458	364	1,088	839	107	60
ERCOT	1,873	22	94	1,447	306	4
FRCC	—	—	—	—	—	—
MAAC	2,110	311	752	671	362	13
MAIN	1,254	26	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	744	150	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
FRCC	—	—	—	—	—	—
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**

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, 1994 Through 1998 (Continued)
(Megawatts)

North American Electric Reliability Council Region and Hawaii	Total Actual Peak Load Reduction	Energy Efficiency	Load Management
		1997	
ECAR	1,239	418	821
ERCOT	1,699	1,593	106
FRCC	3,439	1,909	1,531
MAAC	1,548	1,028	520
MAIN	1,390	377	1,013
MAPP(U.S.)	2,502	902	1,600
NPCC(U.S.)	2,586	2,287	299
SERC	6,043	1,671	4,372
SPP	709	215	493
WSCC(U.S.)	4,108	2,917	1,190
Contiguous U.S.	**25,263**	**13,318**	**11,945**
ASCC	7	1	6
Hawaii	14	7	7
U.S. Total	**25,284**	**13,326**	**11,958**
	Total Actual Peak Load Reduction	**Energy Efficiency**	**Load Management**
		1998	
ECAR	1,624	487	1,137
ERCOT	2,144	2,052	92
FRCC	3,983	2,109	1,874
MAAC	1,569	1,106	463
MAIN	2,890	1,373	1,517
MAPP(U.S.)	3,081	956	2,125
NPCC(U.S.)	2,270	1,977	293
SERC	4,329	1,123	3,205
SPP	816	158	658
WSCC(U.S.)	4,477	2,234	2,244
Contiguous U.S.	**27,184**	**13,576**	**13,608**
ASCC	5	1	4
Hawaii	41	13	28
U.S. Total	**27,231**	**13,591**	**13,640**

Notes: •Data are final. •In 1998 several utilities realigned from SPP to SERC. •Data for 1998 are provided for electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 150,000 megawatthours, and for prior years greater than or equal to 120,000 megawatts. •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, 1998

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]	13,591	13,591	48,775
Load Management[3]	13,640	27,840	392
U.S. Total	**27,231**	**41,430**	**49,167**
	Incremental Effects[6]		
Large Utilities[4]			
Energy Efficiency[5]	796	796	3,324
Load Management[3]	1,821	2,832	37
Total	**2,617**	**3,628**	**3,361**
Small Utilities[7]			
Energy Efficiency[5]	12	12	11
Load Management[3]	124	160	7
Total	**136**	**172**	**18**
U.S. Total	**2,753**	**3,800**	**3,379**

1 Represents the reduction in annual peak load achieved by consumers, at the time of annual peak load .

2 Represents the potential peak load reduction as a result of load 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 150,000 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 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.

7 Refers to electric utilities with sales to ultimate consumers and sales for resale less than 150,000 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 47. U.S. Electric Utility Demand-Side Management Program Annual and Incremental Effects by Sector, 1998

Sector	Actual Peak Load Reductions[1] (megawatts)	Potential Peak Load Reductions[2] (megawatts)	Energy Savings (million kilowatthours)
	Annual Effects[3]		
Large Utilities[4]			
Residential	9,327	13,022	16,564
Commercial	9,482	12,210	25,125
Industrial	7,927	15,512	6,647
Other	495	686	831
U.S. Total	**27,231**	**41,430**	**49,167**
	Incremental Effects[5]		
Large Utilities[4]			
Residential	599	751	909
Commercial	1,176	1,863	1,703
Industrial	799	1,438	645
Other	43	76	104
Total	**2,617**	**3,628**	**3,361**
Small Utilities[6]			
Residential	35	49	8
Commercial	34	41	6
Industrial	56	70	3
Other	11	12	1
Total	**136**	**172**	**18**
U.S. Total	**2,753**	**3,800**	**3,379**

1 Represents the reduction in annual peak load achieved by consumers, at the time of annual peak load .
2 Represents the potential peak load reduction as a result of load 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 150,000 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 150,000 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 Demand-Side Management Energy Savings by North American Electric Reliability Council Region and Hawaii, 1994 Through 1998
(Million Kilowatthours)

North American Electric Reliability Council Region and Hawaii	Historical Savings				
	1994	1995	1996	1997	1998
ECAR	2,237	3,030	3,695	1,984	2,311
ERCOT	3,739	3,757	3,866	3,530	3,690
FRCC	—	—	—	5,418	5,839
MAAC	1,820	3,000	3,620	4,003	4,531
MAIN	2,453	2,732	3,007	1,429	3,233
MAPP(U.S.)	1,883	2,506	3,153	3,442	3,546
NPCC(U.S.)	8,422	9,694	10,022	9,125	6,928
SERC	11,768	10,143	10,404	4,588	4,148
SPP	492	335	358	253	240
WSCC(U.S.)	19,634	22,178	23,663	22,570	14,575
Contiguous U.S.	**52,449**	**57,374**	**61,789**	**56,342**	**49,041**
ASCC	3	4	5	9	7
Hawaii	31	43	49	55	119
U.S. Total	**52,483**	**57,421**	**61,842**	**56,406**	**49,167**

Notes: •Data are final. •In 1998 several utilities realigned from SPP to SERC. •Totals may not equal sum of components because of independent rounding. •Data for 1998 are provided for electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 150,000 megawatthours, and for prior years greater than or equal to 120,000 megawatts.

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

Table 49. U.S. Electric Utility Demand-Side Management Cost by North American Electric Reliability Council Region and Hawaii, 1994 Through 1998

(Thousand Dollars)

North American Electric Reliability Council Region and Hawaii	Existing				
	1994	1995	1996	1997	1998
ECAR	137,118	138,910	77,031	37,270	28,406
ERCOT	69,538	70,421	54,120	41,839	30,158
FRCC	—	—	—	267,738	268,565
MAAC	305,190	300,347	225,253	184,125	207,803
MAIN	96,253	78,004	70,350	50,513	77,361
MAPP(U.S.)	138,256	158,971	156,688	125,804	129,462
NPCC(U.S.)	462,668	346,716	263,160	272,144	185,970
SERC	684,647	681,161	551,038	245,385	175,585
SPP	28,626	26,523	28,385	18,751	33,289
WSCC(U.S.)	792,387	619,575	471,759	384,197	273,095
Contiguous U.S.	**2,714,726**	**2,420,628**	**1,897,782**	**1,627,766**	**1,409,694**
ASCC	386	633	291	322	319
Hawaii	588	0	4,124	7,932	10,907
Total Cost[1]	**2,715,657**	**2,421,261**	**1,902,197**	**1,636,020**	**1,420,920**

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. •In 1998 several utilities realigned from SPP to SERC. •Totals may not equal sum of components because of independent rounding. •Data for 1998 are provided for electric utilities with sales to ultimate consumers or sales for resale greater than or equal to 150,000 megawatthours, and for prior years greater than or equal to 120,000 megawatts. •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 50. U.S. Electric Utility Demand-Side Management Direct and Indirect Cost, 1997 and 1998

(Thousand Dollars)

Program	1997	1998
Total Direct Cost[1]	**1,347,245**	**1,233,018**
Energy Efficiency	892,468	766,384
Load Management	454,777	466,634
Indirect Utility Cost[2]	**288,775**	**187,902**
Cost (thousand dollars)	**1,636,020**	**1,420,920**

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

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

Notes: •Data 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 150,000 megawatthours.

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 1994 through 1998. These data are aggregated at the U.S. Census division level. Since nonutility data for 1994 through 1997 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” (renamed, Form EIA-860B, “Annual Electric Generator Report - Nonutility” starting with the 1998 collection). 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-860B” 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,[17] 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).[18] 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-

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

[18] 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. In 1997, the SIC Manual name was changed to North American Industry Classification System (NAICS). 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. Data for 1998 are preliminary; data for prior years are final. These data were obtained from the Form EIA-860B, “Annual Electric Generator Report - Nonutility” (prior Form EIA-867, “Annual Nonutility Power Producer Report.”) The Form EIA-860B 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, 1998, 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.

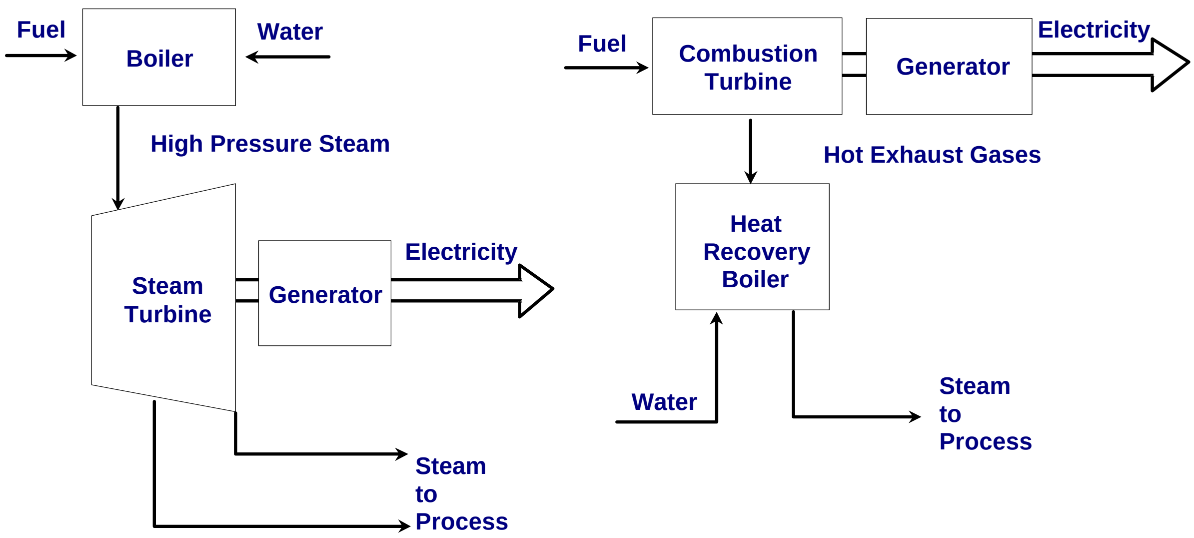
Some nonutility power producers of 1 or more megawatts use only fossil fuels; some use only renewable energy; and some use a combination of both fossil fuels and renewable energy sources. Although the majority of nonutility power producers generate electric power using fossil energy, those using renewable 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 51, 53, 54, 57, and 58 include hydrogen, sulfur, batteries, chemicals, and purchased steam.

The number of facilities shown for 1998 includes operational facilities in 1997 and new facilities or planned facilities that became operational during that year.

The total capacity for 1994 through 1998 (Table 51) 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 18 percent of the total nonutility generating capacity in 1998.

Figure 14. Two Topping-Cycle Plant Configurations

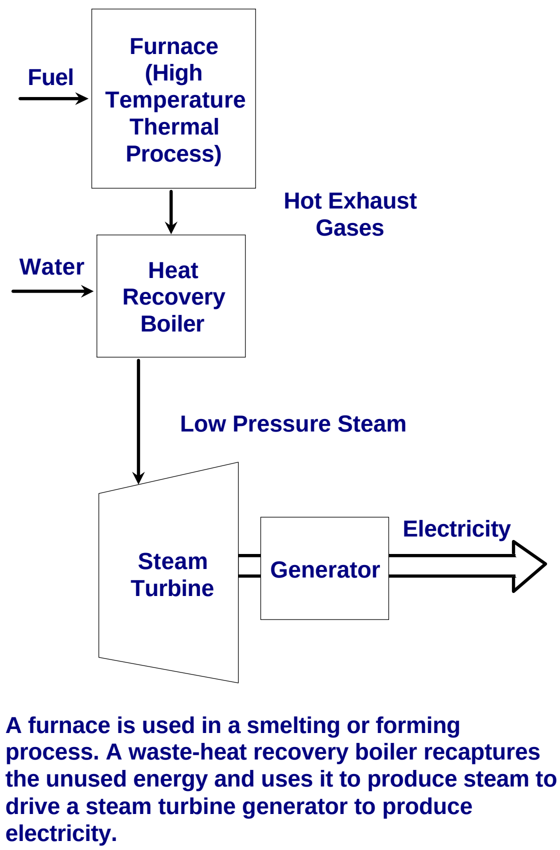


1. A boiler produces steam to power a turbine-generator to produce electricity. The turbine steam leaving the turbine is used in thermal applications such as space heating or food preparation.

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 51. Summary Statistics for U.S. Nonutility Generating Facilities, 1994 Through 1998

Item	1994	1995	1996	1997	1998
Installed Capacity (megawatts)	**68,461**	**70,254**	**73,189**	**74,004**	**98,085**
Coal[1]	10,372	10,877	11,370	11,027	13,712
Petroleum[2]	2,262	2,116	2,251	2,924	2,629
Natural Gas[3]	26,925	27,906	30,166	31,092	37,325
Other Gas[4]	1,130	1,217	327	35	205
Petroleum/Natural Gas (Combined)	9,820	10,479	10,912	10,029	23,105
Hydroelectric	3,364	3,399	3,419	3,770	4,136
Geothermal	1,335	1,295	1,346	1,303	1,449
Solar	354	354	354	354	385
Wind	1,737	1,723	1,670	1,566	1,689
Wood[5]	7,416	6,885	7,263	7,282	6,887
Waste[6]	3,150	3,430	3,463	3,394	3,488
Nuclear	—	—	—	—	—
Other[7]	597	574	648	1,229	3,075
Gross Generation (million kilowatthours)	**354,925**	**375,901**	**382,423**	**384,496**	**421,364**
Coal[1]	59,035	60,234	61,375	59,211	70,369
Petroleum[2]	15,069	15,049	14,959	15,930	17,533
Natural Gas[3]	179,735	196,633	198,555	207,527	238,747
Other Gas[4]	12,480	13,984	14,750	11,687	8,866
Hydroelectric	13,227	14,774	16,555	17,902	14,633
Geothermal	10,122	9,912	10,198	9,382	9,882
Solar	824	824	903	893	887
Wind	3,482	3,185	3,400	3,248	3,015
Wood[5]	38,595	37,283	37,525	34,898	32,596
Waste[6]	18,797	20,231	20,412	20,246	21,086
Nuclear	54	—	—	—	—
Other[7]	3,507	3,792	3,793	3,572	3,750
Consumption[8]					
Coal (Thousand short tons)	52,261	50,328	53,199	52,913	56,850
Petroleum (Thousand barrels)[9]	46,630	39,219	42,928	39,958	58,745
Natural Gas (Million cubic feet)	2,149,246	2,303,944	2,447,720	2,231,363	2,666,430
Other Gas (Million cubic feet)[4]	1,591,051	1,611,993	1,737,271	954,976	881,017
Supply and Disposition (million kilowatthours)					
Gross Generation	354,925	375,901	382,423	384,496	421,364
Receipts[10]	94,166	89,919	103,219	88,506	90,675
Sales to Utilities[11]	204,688	217,906	224,646	223,532	249,483
Sales to Other End Users[12]	17,626	15,548	14,284	18,147	25,777
Facility Use	226,777	232,367	246,713	231,138	236,770

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 Includes batteries, chemicals, hydrogen, sulfur, purchased steam.
8 Includes all combustible fuels burned at generating facilities (not just for the production of electricity).
9 Does not include petroleum coke consumption of 4,740 thousand short tons for 1994, 4,188 thousand short tons for 1995, 4,484 thousand short tons for 1996, 4,364 thousand short tons for 1997, and 4,470 thousand short tons for 1998.
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 Forms EIA-860B and EIA-867 are 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 Forms EIA-860B and EIA-867 are derived from utility surveys the Forms EIA-860B and EIA-867 universe lags 1 year.

Notes: •All data are for 1 megawatt and greater. •Data for 1998 are preliminary;data for prior years are final; •Totals may not equal sum of components because of independent rounding. •Percent change is calculated before rounding. •See the Technical Notes for the methodology for allocating capacity and generation by energy sources, respectively.

Sources: Energy Information Administration, Data for 1998: Form EIA-860B ''Annual Electric Generator Report - Nonutility''; Data for 1997 and prior: Form EIA-867 ''Annual Nonutility Power Producer Report''.

Table 52. Installed Capacity at U.S. Nonutility Generating Facilities by Fossil Fuels, Renewable Energy Source, and Census Division, 1994 Through 1998
(Megawatts)

Census Division	Fossil Fuels[1]	Renewables/ Other/ Nuclear[2]	Both Fossil Fuels and Renewables/ Other/ Nuclear
		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	2,773	1,233	1,196
Middle Atlantic	11,096	859	1,032
East North Central	4,396	391	1,287
West North Central	912	194	149
South Atlantic	8,831	1,785	3,046
East South Central	438	234	1,495
West South Central	11,919	285	2,230
Mountain	1,962	604	316
Pacific	8,578	4,821	1,128
U.S. Total	**50,905**	**10,406**	**11,879**
		1997	
New England	3,019	1,436	840
Middle Atlantic	11,084	1,389	547
East North Central	4,322	788	1,073
West North Central	1,176	214	220
South Atlantic	8,597	2,471	2,742
East South Central	463	598	1,150
West South Central	10,591	556	3,742
Mountain	1,919	644	305
Pacific	8,647	4,465	1,005
U.S. Total	**49,820**	**12,561**	**11,624**
		1998	
New England	8,428	2,042	1,348
Middle Atlantic	10,726	854	1,226
East North Central	6,417	359	1,431
West North Central	1,199	250	237
South Atlantic	8,375	1,468	3,807
East South Central	2,705	238	1,430
West South Central	12,827	652	2,394
Mountain	2,032	563	291
Pacific	19,755	5,576	1,454
U.S. Total	**72,465**	**12,002**	**13,619**

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 1998 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.

Sources: Energy Information Administration, Data for 1998: Form EIA-860B ''Annual Electric Generator Report - Nonutility''; Data for 1997 and prior: Form EIA-867 ''Annual Nonutility Power Producer Report''.

Table 53. Installed Capacity at U.S. Nonutility Generating Facilities by Energy Source and Census Division, 1994 Through 1998 (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
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	2,590	4,713	W	485	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	10,808	887	W	1,145	W	13,891
Mountain	W	1,294	447	560	153	W	2,757
Pacific	W	6,122	1,387	4,012	1,571	W	13,860
U.S. Total	**10,877**	**29,122**	**12,595**	**6,771**	**10,316**	**574**	**70,254**
1996							
New England	441	925	W	589	1,436	W	5,202
Middle Atlantic	2,554	4,947	4,083	485	919	—	12,987
East North Central	1,792	W	583	105	730	W	6,074
West North Central	741	63	172	103	175	—	1,255
South Atlantic	3,694	2,255	3,549	568	3,257	340	13,662
East South Central	324	197	W	W	1,328	W	2,167
West South Central	839	W	1,011	W	1,117	81	14,433
Mountain	239	W	513	560	150	W	2,881
Pacific	748	6,715	1,379	3,978	1,614	93	14,527
U.S. Total	**11,370**	**30,493**	**13,163**	**6,788**	**10,726**	**648**	**73,189**
1997							
New England	353	966	1,961	599	1,301	114	5,295
Middle Atlantic	2,583	4,930	3,888	526	1,018	74	13,020
East North Central	1,596	W	481	W	918	171	6,183
West North Central	W	W	373	111	213	W	1,611
South Atlantic	3,621	2,345	3,277	1,036	3,160	371	13,810
East South Central	309	192	156	W	1,292	W	2,212
West South Central	829	11,187	1,225	372	1,119	158	14,890
Mountain	W	W	487	534	150	83	2,868
Pacific	741	7,076	1,104	3,506	1,505	185	14,117
U.S. Total	**11,027**	**31,127**	**12,953**	**6,993**	**10,676**	**1,229**	**74,004**
1998							
New England	1,321	1,095	6,339	1,645	1,408	9	11,818
Middle Atlantic	2,136	5,229	3,863	449	882	248	12,806
East North Central	3,044	2,986	1,117	98	870	93	8,207
West North Central	682	167	421	202	203	11	1,686
South Atlantic	3,424	1,360	4,410	530	3,076	850	13,650
East South Central	1,839	279	829	172	1,209	46	4,373
West South Central	466	11,423	2,194	227	1,063	500	15,873
Mountain	197	1,305	656	520	150	58	2,887
Pacific	605	13,685	5,905	3,816	1,513	1,261	26,785
U.S. Total	**13,712**	**37,530**	**25,734**	**7,659**	**10,374**	**3,075**	**98,085**

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.

Notes: •All data are for 1 megawatt and greater. •Data for 1998 are preliminary; data for prior years are final. •Totals may not equal sum of components because of independent rounding. •W = Withheld to avoid disclosure of individual company data.

Sources: Energy Information Administration, Data for 1998: Form EIA-860B ''Annual Electric Generator Report - Nonutility''; Data for 1997 and prior: Form EIA-867 ''Annual Nonutility Power Producer Report''.

Table 54. Installed Capacity at U.S. Nonutility Generating Facilities by Energy Source and State, 1998

(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
Alabama	—	117	194	—	839	—	1,150
Alaska	156	49	89	—	—	114	408
Arizona	—	64	120	—	—	—	184
Arkansas	—	98	52	—	267	4	421
California	206	13,264	5,245	3,522	967	308	23,513
Colorado	35	707	4	32	—	—	778
Connecticut	214	347	215	20	262	—	1,058
Delaware	20	1	155	—	—	—	176
Florida	740	812	884	32	1,060	529	4,057
Georgia	360	119	785	10	562	27	1,863
Hawaii	228	—	339	81	164	—	812
Idaho	12	21	8	245	140	27	452
Illinois	1,662	292	169	24	143	—	2,290
Indiana	671	424	429	—	11	11	1,547
Iowa	244	5	92	5	6	—	351
Kansas	—	39	14	2	—	—	55
Kentucky	1,527	—	620	—	4	—	2,151
Louisiana	—	2,510	240	192	520	309	3,771
Maine	275	3	167	363	629	2	1,439
Maryland	65	91	370	—	138	10	674
Massachusetts	833	540	5,035	710	325	3	7,446
Michigan	283	2,119	76	25	472	68	3,042
Minnesota	358	113	247	194	188	11	1,111
Mississippi	—	127	—	—	279	2	408
Missouri	54	5	55	—	—	—	114
Montana	42	—	65	12	11	—	129
Nebraska	8	5	5	—	—	—	18
Nevada	—	329	284	230	—	—	843
New Hampshire	—	—	34	380	155	3	572
New Jersey	515	1,954	1,001	13	200	3	3,686
New Mexico	—	122	137	—	—	—	259
New York	247	2,759	2,294	363	342	110	6,116
North Carolina	776	—	424	410	287	40	1,936
North Dakota	19	—	8	—	10	—	37
Ohio	112	1	94	—	125	12	345
Oklahoma	464	310	51	—	80	—	905
Oregon	14	8	57	126	181	621	1,006
Pennsylvania	1,374	516	568	73	339	135	3,004
Rhode Island	—	205	888	2	15	1	1,111
South Carolina	30	118	6	19	356	2	531
South Dakota	–-	–-	–-	–-	–-	–-	–-
Tennessee	312	35	15	172	87	45	664
Texas	2	8,504	1,851	35	197	187	10,776
Utah	108	3	4	2	—	19	136
Vermont	—	—	—	171	22	—	192
Virginia	1,129	219	1,775	22	673	—	3,819
Washington	2	364	175	86	201	218	1,046
West Virginia	304	—	12	37	—	242	595
Wisconsin	316	149	349	49	119	2	983
Wyoming	—	59	34	1	—	12	105
U.S. Total	**13,712**	**37,530**	**25,734**	**7,659**	**10,374**	**3,075**	**98,085**

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.

Notes: •All data are for 1 megawatt and greater. •Data for 1998 are preliminary. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-860B ''Annual Electric Generator Report - Nonutility'';

Table 55. Installed Capacity at U.S. Nonutility Generating Facilities by Qualifying Facility Status and Census Division, 1994 Through 1998

(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)
			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	12,042	134	2,485	535	14,527
U.S. Total	**1,313**	**58,345**	**682**	**14,844**	**1,995**	**73,189**
			1997			
New England	121	3,707	79	1,588	200	5,295
Middle Atlantic	257	12,628	45	392	302	13,020
East North Central	120	3,909	110	2,273	230	6,183
West North Central	29	931	56	680	85	1,611
South Atlantic	171	9,897	120	3,913	291	13,810
East South Central	29	1,237	32	975	61	2,212
West South Central	111	13,050	66	1,839	177	14,890
Mountain	88	2,086	39	782	127	2,868
Pacific	376	11,671	125	2,446	501	14,117
U.S. Total	**1,302**	**59,116**	**672**	**14,888**	**1,974**	**74,004**
			1998			
New England	122	3,624	100	8,193	222	11,818
Middle Atlantic	252	12,263	44	543	296	12,806
East North Central	125	4,280	114	3,927	239	8,207
West North Central	29	896	57	790	86	1,686
South Atlantic	163	9,771	112	3,879	275	13,650
East South Central	28	1,249	36	3,124	64	4,373
West South Central	114	14,127	64	1,746	178	15,873
Mountain	86	2,101	37	785	123	2,887
Pacific	394	12,072	135	14,713	529	26,785
U.S. Total	**1,313**	**60,384**	**699**	**37,701**	**2,012**	**98,085**

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 1998 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.

Sources: Energy Information Administration, Data for 1998: Form EIA-860B ''Annual Electric Generator Report - Nonutility''; Data for 1997 and prior: Form EIA-867 ''Annual Nonutility Power Producer Report''.

Table 56. Installed Capacity at U.S. Nonutility Generating Facilities Attributed to Major Industry Group and Census Division, 1994 Through 1998
(Megawatts)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
				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	207	166	W	W	W	1,296
South Atlantic	8,180	3,875	176	W	W	79	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**	**15,668**	**2,070**	**3,252**	**542**	**1,252**	**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	98	164	W	W	W	1,232
South Atlantic	8,842	3,691	169	W	W	218	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**	**15,124**	**2,165**	**3,428**	**544**	**1,388**	**70,254**
				1996			
New England	W	2,391	154	—	—	W	5,202
Middle Atlantic	W	2,400	562	W	221	225	12,987
East North Central	5,172	459	358	W	W	W	6,074
West North Central	762	112	168	W	—	W	1,255
South Atlantic	W	3,763	165	W	64	461	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	W	913	W	242	—	667	2,881
Pacific	5,930	5,247	436	2,498	241	176	14,527
U.S. Total	**49,529**	**16,050**	**2,181**	**3,313**	**542**	**1,575**	**73,189**
				1997			
New England	W	2,440	148	—	—	W	5,295
Middle Atlantic	W	2,596	565	W	221	225	13,020
East North Central	5,149	548	398	W	W	W	6,183
West North Central	1,103	127	168	W	—	W	1,611
South Atlantic	W	4,259	168	W	139	404	13,810
East South Central	2,089	76	W	26	W	—	2,212
West South Central	13,886	726	197	68	W	W	14,890
Mountain	W	910	W	239	—	667	2,868
Pacific	5,910	4,876	433	2,498	238	161	14,117
U.S. Total	**49,791**	**16,559**	**2,223**	**3,306**	**616**	**1,510**	**74,004**
				1998			
New England	2,635	5,072	139	—	—	3,972	11,818
Middle Atlantic	9,390	2,203	570	205	221	218	12,806
East North Central	5,040	2,466	678	—	5	18	8,207
West North Central	1,077	219	172	203	—	15	1,686
South Atlantic	9,329	3,604	169	6	63	480	13,650
East South Central	2,149	2,176	14	24	11	—	4,373
West South Central	14,636	959	197	66	1	14	15,873
Mountain	943	952	133	240	—	620	2,887
Pacific	6,057	6,875	435	2,531	234	10,653	26,785
U.S. Total	**51,255**	**24,527**	**2,506**	**3,275**	**534**	**15,989**	**98,085**

Notes: •All data are for 1 megawatt and greater. •Data for 1998 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.

Sources: Energy Information Administration, Data for 1998: Form EIA-860B ''Annual Electric Generator Report - Nonutility''; Data for 1997 and prior: Form EIA-867 ''Annual Nonutility Power Producer Report''.

Table 57. Gross Generation for U.S. Nonutility Generating Facilities by Energy Source and Census Division, 1994 Through 1998

(Million Kilowatthours)

Census Division	Coal[1]	Petroleum[2]	Natural Gas[3]	Hydro-ectric	Geothermal/ Solar/Wind	Wood[4] Waste[5]	Other/[6] Nuclear	Total
				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	1,860	13,425	2,561	—	9,099	—	29,350
Middle Atlantic	14,799	1,781	45,187	1,584	—	6,227	189	69,768
East North Central	6,795	646	16,187	W	—	4,247	W	28,436
West North Central	2,680	W	707	303	W	908	—	4,702
South Atlantic	18,948	2,736	15,535	2,799	—	15,622	1,985	57,624
East South Central	2,378	125	2,175	W	—	7,033	W	12,708
West South Central	6,314	W	67,102	W	—	5,880	1,122	84,635
Mountain	1,511	179	6,828	1,171	W	745	W	12,263
Pacific	4,404	W	43,471	4,070	12,205	7,754	W	76,415
U.S. Total	**60,234**	**15,049**	**210,617**	**14,774**	**13,921**	**57,514**	**3,792**	**375,901**
				1996				
New England	2,289	1,779	W	3,235	—	9,036	W	29,862
Middle Atlantic	15,569	1,425	W	2,337	—	6,414	W	68,860
East North Central	6,972	812	18,113	525	—	4,630	79	31,130
West North Central	2,503	W	564	382	W	812	W	4,362
South Atlantic	19,429	3,034	15,319	3,042	—	15,959	1,703	58,485
East South Central	2,418	194	2,571	W	—	7,031	W	13,249
West South Central	6,026	3,409	66,115	W	W	5,783	1,598	83,994
Mountain	1,461	W	W	1,280	1,663	668	187	13,480
Pacific	4,708	3,784	46,290	3,878	12,703	7,605	33	79,001
U.S. Total	**61,375**	**14,959**	**213,304**	**16,555**	**14,500**	**57,937**	**3,793**	**382,423**
				1997				
New England	2,463	1,845	W	2,981	—	8,884	W	30,273
Middle Atlantic	14,429	1,530	W	2,163	—	6,105	W	68,518
East North Central	7,308	748	17,906	528	—	4,777	98	31,366
West North Central	2,983	W	455	W	W	833	W	4,807
South Atlantic	17,724	3,757	12,369	3,566	916	15,550	1,673	55,555
East South Central	2,300	170	3,059	W	—	5,605	W	12,860
West South Central	6,150	3,572	W	2,109	W	5,626	679	91,270
Mountain	1,507	W	W	1,267	1,576	637	255	13,744
Pacific	4,348	3,696	45,986	3,712	10,895	7,128	338	76,103
U.S. Total	**59,211**	**15,930**	**219,215**	**17,902**	**13,523**	**55,144**	**3,572**	**384,496**
				1998				
New England	5,854	4,024	20,133	3,295	—	8,046	—	41,352
Middle Atlantic	14,784	1,213	42,196	1,963	—	6,389	34	66,579
East North Central	9,783	1,125	17,557	438	—	5,391	31	34,325
West North Central	2,812	623	760	292	148	769	1	5,405
South Atlantic	17,727	3,292	13,935	2,618	—	15,440	1,709	54,720
East South Central	6,906	852	3,833	807	—	5,870	104	18,372
West South Central	6,416	2,253	79,793	1,083	81	4,181	1,547	95,354
Mountain	1,807	456	7,988	1,124	1,571	570	173	13,689
Pacific	4,281	3,695	61,418	3,013	11,984	7,025	150	91,567
U.S. Total	**70,369**	**17,533**	**247,613**	**14,633**	**13,784**	**53,682**	**3,750**	**421,364**

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.

Notes: •All data are for 1 megawatt and greater. •Data for 1998 are preliminary; data for prior years are final. •Totals may not equal sum of components because of independent rounding. •Percent change is calculated before rounding. •W = Withheld to avoid disclosure of individual company data.

Sources: Energy Information Administration, Data for 1998: Form EIA-860B ''Annual Electric Generator Report - Nonutility''; Data for 1997 and prior: Form EIA-867 ''Annual Nonutility Power Producer Report''.

Table 58. Gross Generation for U.S. Nonutility Generating Facilities by Energy Source and State, 1998

(Million Kilowatthours)

State	Coal[1]	Petroleum[2]	Natural Gas[3]	Hydro-ectric	Geothermal/ Solar/Wind	Wood[4] Waste[5]	Other/[6] Nuclear	Total
Alabama	501	150	2,111	—	—	4,215	—	6,976
Alaska	371	70	865	—	—	1	1	1,308
Arizona	363	2	456	—	—	—	—	821
Arkansas	43	10	1,440	3	—	1,103	1	2,601
California	2,319	2,248	52,660	2,094	11,701	4,985	15	76,021
Colorado	300	13	3,062	117	—	—	—	3,491
Connecticut	1,646	47	1,325	64	—	1,737	—	4,820
Delaware	104	301	214	—	—	—	—	620
Florida	5,142	616	8,269	—	—	5,597	1,442	21,067
Georgia	1,446	1,316	1,075	36	—	3,083	—	6,956
Hawaii	1,540	1,334	332	109	264	536	—	4,115
Idaho	61	—	336	911	—	525	89	1,922
Illinois	5,504	84	1,460	90	—	668	—	7,806
Indiana	932	206	3,659	—	—	127	—	4,924
Iowa	1,024	14	68	20	—	57	1	1,183
Kansas	—	4	91	12	—	—	—	107
Kentucky	4,412	689	2	—	—	16	—	5,119
Louisiana	79	1,835	18,185	1,074	—	1,986	1,059	24,218
Maine	1,051	929	1,310	1,915	—	2,671	—	7,876
Maryland	227	12	1,181	—	—	810	—	2,230
Massachusetts	3,156	2,506	12,252	346	—	2,192	—	20,453
Michigan	1,525	157	11,187	131	—	2,971	21	15,992
Minnesota	1,405	575	473	261	148	707	—	3,568
Mississippi	33	3	1,395	—	—	1,101	—	2,532
Missouri	253	12	42	—	—	3	—	311
Montana	297	429	48	65	—	45	—	885
Nebraska	46	1	32	—	—	—	—	79
Nevada	—	1	2,579	15	1,569	—	5	4,169
New Hampshire	—	78	71	628	—	1,142	—	1,919
New Jersey	2,210	245	14,706	21	—	1,368	—	18,551
New Mexico	—	3	932	—	—	—	—	935
New York	1,774	456	23,571	1,586	—	2,445	—	29,832
North Carolina	4,224	603	375	1,710	—	1,509	265	8,685
North Dakota	83	18	55	—	—	2	—	158
Ohio	452	20	364	—	—	747	—	1,584
Oklahoma	3,329	7	1,360	—	—	233	—	4,930
Oregon	27	—	3,878	402	20	459	135	4,921
Pennsylvania	10,800	511	3,919	357	—	2,576	34	18,197
Rhode Island	—	462	5,175	9	—	113	—	5,759
South Carolina	620	114	477	67	—	1,701	2	2,981
South Dakota	—	—	—	—	—	—	—	—
Tennessee	1,960	10	325	807	—	539	104	3,745
Texas	2,965	401	58,806	6	81	859	487	63,605
Utah	553	4	219	16	—	—	—	792
Vermont	—	1	—	333	—	191	—	525
Virginia	3,625	329	2,039	73	—	2,740	—	8,806
Washington	23	42	3,684	409	—	1,045	—	5,203
West Virginia	2,337	1	304	732	—	—	—	3,375
Wisconsin	1,370	657	887	217	—	877	10	4,019
Wyoming	233	3	357	—	2	—	80	674
U.S. Total	**70,369**	**17,533**	**247,613**	**14,633**	**13,784**	**53,682**	**3,750**	**421,364**

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.

Notes: •All data are for 1 megawatt and greater. •Data for 1998 are preliminary; data for prior years are final. •Totals may not equal sum of components because of independent rounding. •Percent change is calculated before rounding.

Source: Energy Information Administration, Form EIA-860B ''Annual Electric Generator Report - Nonutility''.

Table 59. Gross Generation at U.S. Nonutility Generating Facilities by Qualifying Facility Status and Census Division, 1994 Through 1998
(Million Kilowatthours)

Census Division	QF Generation		Non-QF Generation		Total Generation	
	No. of Facilities[1]	Generation (million kilowatthours)	No. of Facilities[1]	Generation (million kilowatthours)	No. of Facilities[1]	Generation (million kilowatthours)
			1994			
New England	115	21,832	73	8,093	188	29,925
Middle Atlantic	244	54,274	47	2,183	291	56,457
East North Central	96	17,961	111	11,033	207	28,993
West North Central	25	2,480	50	2,597	75	5,077
South Atlantic	149	39,312	121	12,840	270	52,152
East South Central	23	5,702	34	7,085	57	12,786
West South Central	106	70,773	57	11,217	163	81,989
Mountain	85	9,089	37	2,183	122	11,273
Pacific	400	70,659	146	5,612	546	76,271
U.S. Total	**1,243**	**292,082**	**676**	**62,843**	**1,919**	**354,925**
			1995			
New England	115	21,681	72	7,669	187	29,350
Middle Atlantic	252	67,661	47	2,107	299	69,768
East North Central	107	19,255	105	9,182	212	28,436
West North Central	28	2,377	52	2,325	80	4,702
South Atlantic	158	44,277	120	13,348	278	57,624
East South Central	28	7,567	31	5,142	59	12,708
West South Central	107	74,579	57	10,056	164	84,635
Mountain	84	10,024	37	2,239	121	12,263
Pacific	391	69,168	136	7,247	527	76,415
U.S. Total	**1,270**	**316,587**	**657**	**59,314**	**1,927**	**375,901**
			1996			
New England	112	21,489	75	8,372	187	29,862
Middle Atlantic	255	66,782	44	2,078	299	68,860
East North Central	108	21,747	110	9,383	218	31,130
West North Central	25	2,196	54	2,166	79	4,362
South Atlantic	159	46,234	119	12,252	278	58,485
East South Central	26	7,727	32	5,522	58	13,249
West South Central	110	74,126	60	9,868	170	83,994
Mountain	87	11,007	39	2,473	126	13,480
Pacific	383	69,801	132	9,200	515	79,001
U.S. Total	**1,265**	**321,109**	**665**	**61,314**	**1,930**	**382,423**
			1997			
New England	116	21,971	78	8,302	194	30,273
Middle Atlantic	247	66,594	45	1,924	292	68,518
East North Central	108	22,077	102	9,289	210	31,366
West North Central	26	2,256	56	2,551	82	4,807
South Atlantic	164	44,163	111	11,392	275	55,555
East South Central	28	7,891	32	4,969	60	12,860
West South Central	109	81,635	64	9,635	173	91,270
Mountain	83	11,124	37	2,620	120	13,744
Pacific	365	66,681	122	9,423	487	76,103
U.S. Total	**1,246**	**324,392**	**647**	**60,105**	**1,893**	**384,496**
			1998			
New England	116	21,843	98	19,508	214	41,352
Middle Atlantic	245	64,138	41	2,441	286	66,579
East North Central	113	22,277	110	12,049	223	34,325
West North Central	27	2,578	57	2,827	84	5,405
South Atlantic	156	43,482	105	11,238	261	54,720
East South Central	27	7,575	36	10,797	63	18,372
West South Central	111	86,181	62	9,173	173	95,354
Mountain	82	11,240	35	2,449	117	13,689
Pacific	379	68,663	132	22,905	511	91,567
U.S. Total	**1,256**	**327,977**	**676**	**93,387**	**1,932**	**421,364**

[1] The number of facilities with no generation that were not retired were 49 in 1994, 46 in 1995, 65 in 1996, 81 in 1997, and 80 in 1998.

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 1998 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.

Sources: Energy Information Administration, Data for 1998: Form EIA-860B ''Annual Electric Generator Report - Nonutility''; Data for 1997 and prior: Form EIA-867 ''Annual Nonutility Power Producer Report''.

Table 60. Gross Generation of U.S. Nonutility Generating Facilities Attributed to Major Industry Group and Census Division, 1994 Through 1998

(Million Kilowatthours)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
				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	422	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**	**68,969**	**9,900**	**21,024**	**3,172**	**4,024**	**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	169	57,624
East South Central	12,448	70	W	125	W	—	12,708
West South Central	82,434	W	614	492	—	W	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	**268,711**	**67,682**	**10,775**	**21,277**	**2,617**	**4,839**	**375,901**
				1996			
New England	W	13,987	640	—	—	W	29,862
Middle Atlantic	W	12,347	3,819	W	1,033	1,621	68,860
East North Central	27,124	2,506	1,381	W	W	W	31,130
West North Central	2,829	548	W	W	—	W	4,362
South Atlantic	W	10,678	722	W	19	1,066	58,485
East South Central	12,983	69	W	118	W	—	13,249
West South Central	80,776	2,190	566	385	W	W	83,994
Mountain	5,347	3,921	863	550	—	2,800	13,480
Pacific	32,691	23,586	2,639	18,060	1,535	489	79,001
U.S. Total	**271,528**	**69,831**	**11,059**	**21,214**	**2,659**	**6,133**	**382,423**
				1997			
New England	W	13,892	460	—	—	W	30,273
Middle Atlantic	W	13,799	3,873	W	951	1,510	68,518
East North Central	27,406	2,476	1,399	—	W	W	31,366
West North Central	2,863	588	W	W	—	W	4,807
South Atlantic	42,180	10,889	746	W	W	1,358	55,555
East South Central	12,330	306	W	114	W	—	12,860
West South Central	86,424	3,801	539	427	W	W	91,270
Mountain	5,483	3,901	865	503	—	2,991	13,744
Pacific	31,872	21,874	2,577	17,718	1,582	480	76,103
U.S. Total	**271,330**	**71,526**	**10,946**	**21,192**	**2,983**	**6,519**	**384,496**
				1998			
New England	15,408	19,967	456	—	—	5,521	41,352
Middle Atlantic	46,083	13,024	3,596	1,517	883	1,476	66,579
East North Central	25,430	6,468	2,367	—	17	44	34,325
West North Central	3,143	669	427	1,146	—	21	5,405
South Atlantic	42,059	10,481	772	6	31	1,373	54,720
East South Central	12,955	5,155	92	114	56	—	18,372
West South Central	88,639	5,718	552	368	—	77	95,354
Mountain	5,607	4,287	856	488	—	2,451	13,689
Pacific	33,678	22,928	2,657	17,977	1,562	12,765	91,567
U.S. Total	**273,002**	**88,697**	**11,774**	**21,615**	**2,548**	**23,728**	**421,364**

Notes: •All data are for 1 megawatt and greater. •Data for 1998 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.

Sources: Energy Information Administration, Data for 1998: Form EIA-860B ''Annual Electric Generator Report - Nonutility''; Data for 1997 and prior: Form EIA-867 ''Annual Nonutility Power Producer Report''.

Table 61. U.S. Nonutility Electricity Supply and Disposition for Generating Facilities by Census Division and State, 1997 and 1998

(Million Kilowatthours)

Census Division and State	Gross Generation 1997	Gross Generation 1998	Receipts[1] 1997	Receipts[1] 1998	Sales[2] 1997	Sales[2] 1998	Facility Use 1997	Facility Use 1998
New England	**30,273**	**41,352**	**3,480**	**2,551**	**24,064**	**34,071**	**9,690**	**9,209**
Connecticut	4,717	4,820	273	272	3,845	4,057	1,146	1,035
Maine	7,582	7,876	2,138	1,046	4,124	3,321	5,596	4,944
Massachusetts	11,466	20,453	780	929	10,226	19,148	2,020	2,233
New Hampshire	1,685	1,919	197	197	1,271	1,479	611	634
Rhode Island	W	5,759	W	104	4,273	5,560	W	303
Vermont	W	525	W	4	325	505	W	62
Middle Atlantic	**68,518**	**66,579**	**4,936**	**5,196**	**58,345**	**56,605**	**15,083**	**15,170**
New Jersey	17,414	18,551	808	852	15,530	16,580	2,693	2,823
New York	33,657	29,832	1,342	1,601	30,213	26,696	4,789	4,737
Pennsylvania	17,447	18,197	2,786	2,743	12,602	13,329	7,601	7,610
East North Central	**31,366**	**34,325**	**17,915**	**17,001**	**14,897**	**19,031**	**34,286**	**32,212**
Illinois	4,349	7,806	5,792	6,152	603	3,602	9,538	10,341
Indiana	4,475	4,924	4,394	3,309	101	758	8,768	7,408
Michigan	17,818	15,992	1,794	1,646	13,918	13,419	5,694	4,219
Ohio	1,731	1,584	3,124	2,920	66	65	4,788	4,439
Wisconsin	2,993	4,019	2,811	2,974	209	1,188	5,498	5,805
West North Central	**4,807**	**5,405**	**5,166**	**5,031**	**1,741**	**1,868**	**8,241**	**8,568**
Iowa	1,171	1,183	1,223	1,285	218	240	2,176	2,229
Kansas	87	107	W	1,105	W	11	1,105	1,201
Minnesota	3,033	3,568	2,484	2,190	1,480	1,590	4,037	4,168
Missouri	W	311	268	282	W	26	553	567
Nebraska	63	79	58	58	—	—	121	136
North Dakota	W	158	W	111	W	1	249	268
South Dakota	–-	–-	–-	–-	–-	–-	–-	–-
South Atlantic	**55,555**	**54,720**	**17,285**	**17,230**	**33,089**	**31,085**	**39,835**	**40,929**
Delaware	W	620	W	427	W	57	W	990
Florida	22,039	21,067	1,876	1,668	14,998	13,173	9,001	9,562
Georgia	6,023	6,956	3,681	3,513	1,017	1,229	8,687	9,293
Maryland	2,231	2,230	147	2,041	1,601	1,669	777	2,602
North Carolina	8,572	8,685	5,344	3,419	6,005	6,106	7,911	6,009
South Carolina	W	2,981	W	1,089	W	1,003	W	3,067
Virginia	9,953	8,806	3,183	3,156	7,688	6,525	5,448	5,438
West Virginia	3,403	3,375	1,970	1,918	1,354	1,324	4,019	3,968
East South Central	**12,860**	**18,372**	**8,834**	**8,552**	**2,180**	**6,809**	**19,528**	**20,115**
Alabama	6,405	6,976	3,681	3,503	1,090	856	9,011	9,623
Kentucky	W	5,119	—	—	W	5,060	W	60
Mississippi	W	2,532	W	1,765	W	27	W	4,269
Tennessee	W	3,745	W	3,284	1,032	867	5,919	6,162
West South Central	**91,270**	**95,354**	**19,009**	**23,605**	**35,350**	**38,475**	**74,836**	**81,027**
Arkansas	2,540	2,601	730	754	46	53	3,224	3,302
Louisiana	22,606	24,218	8,413	8,903	3,853	4,080	27,166	29,041
Oklahoma	4,783	4,930	1,050	1,180	3,400	3,643	2,434	2,977
Texas	61,341	63,605	8,816	12,767	28,051	30,699	42,013	45,707
Mountain	**13,744**	**13,689**	**4,352**	**4,284**	**10,883**	**11,040**	**7,213**	**6,933**
Arizona	W	821	263	236	W	411	W	645
Colorado	3,395	3,491	185	176	3,098	3,334	481	334
Idaho	W	1,922	W	1,188	1,907	1,816	1,253	1,294
Montana	816	885	W	393	658	756	W	522
Nevada	W	4,169	W	1	3,961	3,843	309	328
New Mexico	W	935	1,519	1,520	W	500	1,944	1,954
Utah	W	792	W	538	W	372	1,061	958
Wyoming	W	674	241	232	W	8	915	898
Pacific	**76,103**	**91,567**	**7,528**	**7,227**	**61,130**	**76,275**	**22,427**	**22,609**
Alaska	W	1,308	W	127	14	222	1,196	1,211
California	62,422	76,021	2,988	2,811	50,929	64,342	14,407	14,483
Hawaii	4,288	4,115	31	35	3,708	3,519	611	723
Oregon	W	4,921	W	680	2,982	4,471	1,159	1,136
Washington	4,859	5,203	3,692	3,574	3,497	3,722	5,054	5,056
U.S. Total	**384,496**	**421,364**	**88,506**	**90,675**	**241,679**	**275,260**	**231,138**	**236,770**

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-860B and the Form EIA-867 are 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.

Notes: •All data are for 1 megawatt and greater. •Data for 1998 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.

Sources: Energy Information Administration, Data for 1998: Form EIA-860B ''Annual Electric Generator Report - Nonutility''; Data for 1997: Form EIA-867 ''Annual Nonutility Power Producer Report''.

Table 62. Estimated Emissions from U.S. Nonutility Generating Facilities by Census Division, 1994 Through 1998
(Thousand Short Tons)

Census Division	Sulfur Dioxide[1]	Nitrogen Oxides[1]	Carbon Dioxide[1]
		1994	
New England	28	31	15,257
Middle Atlantic	65	86	34,151
East North Central	166	96	19,685
West North Central	22	11	4,490
South Atlantic	187	145	39,037
East South Central	37	24	4,699
West South Central	195	114	46,852
Mountain	7	22	5,274
Pacific Contiguous	23	61	30,629
Pacific Noncontiguous	6	10	3,608
U.S. Total	**736**	**600**	**203,682**
		1995	
New England	22	33	15,123
Middle Atlantic	72	105	40,415
East North Central	103	102	19,462
West North Central	19	12	3,679
South Atlantic	197	158	39,502
East South Central	39	24	4,104
West South Central	185	123	46,048
Mountain	7	24	5,471
Pacific Contiguous	23	71	30,194
Pacific Noncontiguous	6	9	3,757
U.S. Total	**673**	**661**	**207,755**
		1996	
New England	25	34	15,886
Middle Atlantic	71	111	40,717
East North Central	106	138	22,076
West North Central	19	11	3,398
South Atlantic	156	137	38,310
East South Central	42	26	5,090
West South Central	197	120	46,537
Mountain	6	25	6,517
Pacific Contiguous	23	72	30,602
Pacific Noncontiguous	5	11	3,840
U.S. Total	**650**	**685**	**212,973**
		1997	
New England	23	34	16,749
Middle Atlantic	95	97	41,022
East North Central	99	92	16,386
West North Central	19	13	3,999
South Atlantic	164	110	36,092
East South Central	41	19	5,368
West South Central	176	121	54,142
Mountain	8	14	6,279
Pacific Contiguous	38	71	34,026
Pacific Noncontiguous	8	12	4,611
U.S. Total	**671**	**583**	**218,674**
		1998	
New England	61	46	23,470
Middle Atlantic	49	92	40,694
East North Central	116	94	19,873
West North Central	18	13	4,561
South Atlantic	143	114	35,772
East South Central	55	32	9,574
West South Central	178	182	64,162
Mountain	5	17	6,253
Pacific Contiguous	21	80	37,968
Pacific Noncontiguous	5	11	3,654
U.S. Total	**651**	**681**	**245,981**

[1] In 1998, emission factors for the calculation of carbon dioxide and the reductions from nitrogen oxide and sulfur dioxide have been changed--historical data were revised to reflect that change--see technical notes for more information. In 1994, the useful thermal output produced additional emissions of 790 thousand short tons of sulfur dioxide, 537 thousand short tons of nitrogen oxides, and 121,004 thousand short tons of carbon dioxide. In 1995, the useful thermal output produced additional emissions of 725 thousand short tons of sulfur dioxide, 538 thousand shorts tons of nitrogen oxides, and 119,752 thousand short tons of carbon dioxide. In 1996, the useful thermal output produced additional emissions of 810 thousand short tons of sulfur dioxide, 573 thou-

sand shorts tons of nitrogen oxides, and 133,989 thousand short tons of carbon dioxide. In 1997, the useful thermal output produced additional emissions of 775 thousand short tons of sulfur dioxide, 473 thousand shorts tons of nitrogen oxides, and 143,824 thousand short tons of carbon dioxide. In 1998, the useful thermal output produced additional emissions of 756 thousand short tons of sulfur dioxide, 493 thousand shorts tons of nitrogen oxides, and 185,084 thousand short tons of carbon dioxide.

Notes: •All data are for 1 megawatt and greater. •Estimates for 1998 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.

Sources: Energy Information Administration, Data for 1998: Form EIA-860B ''Annual Electric Generator Report - Nonutility''; Data for 1997 and prior: 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 seven 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-860A, "Annual Electric Generator Report - Utility"; the Form EIA-860B, "Annual Electric Generator Report - Nonutility"; 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. Publicly Owned Electric Utilities;* the *Annual Energy Outlook; Electric Trade in the United States*, and, for 1994 through 1996, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*, and *U.S. Electric Utility Demand-Side Management.* 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 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 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* (through 1996 only); 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. Effective for 1997 and 1998, FERC Form 1 data has been edited by Navigant Consulting, Inc.

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. 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-860A

The Form EIA-860A is a mandatory census of electric utilities in the United States that operate power plants or plan to operate a power plant within 5 years of the reporting year. The survey is used to collect data on existing power plants from the electric utilities and their 5-year plans for constructing new plants, and modifying and retiring existing plants. Data on the survey are collected at the generating unit level. These data are then aggregated by energy source, geographic area, and prime mover. Final data from the Form EIA-860A are also summarized in the *Inventory of Electric Utility Power Plants in the United States*.

Instrument and Design History. The Form EIA-860A was implemented in January 1999 to collect data as of January 1, 1999. Form EIA-860A replaced Form EIA-860. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data.

Data Processing. The Form EIA-860A is mailed to approximately 900 respondents in December of each year and the completed forms are to be returned to the EIA by February 15 containing data as of January 1 of the following year. Respondents have the option of filing Form EIA-860A directly with the EIA or through an agent such as the respondent's regional electric reliability council. Data reported through the regional electric reliability councils are submitted to the EIA electronically from the North American Electric Reliability Council (NERC). Data for each respondent are preprinted from the applicable data base. Respondents are instructed to verify all preprinted data and to supply missing data. The data are manually edited before being keyed for automatic data processing. Computer programs containing additional edit checks are run. Respondents are telephoned to obtain correction or clarification of reported data and to obtain missing data, as a result of the manual and automatic editing process. After EIA approval, the data are made available for public use.

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 5 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 10 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.

The methodology has been modified for calculating import and export data for Canada by basing on metered energy and include both firm and interruptible energy. Originally collected from presidential permits, the data are now obtained from the National Energy Board of Canada. This became effective in 1998. However, the methodology was adapted to 1994 through 1997 data and as a result, Tables 41 through 43 have been revised. The methodology for Mexico remains the same.

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.

Form EIA-860B

In 1998, the Form EIA-867, "Annual Nonutility Power Producer Report," was renamed Form EIA-860B, "Annual Electric Generator Report - Nonutility." The Form EIA-860B 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, “North American Industry Classification System”; 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-860B 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. In 1998, the Form EIA-867 "Annual Nonutility Power Producer Report," form number and name has been changed to Form EIA-860B, "Annual Electric Generator Report - Nonutility." The Federal Energy Administration Act of 1984 (Public Law 93-275) defines the legislative authority to collect these data.

Data Processing. The Form EIA-860B 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 1994 through 1998 presented in this report, are reasonable given the growth in manufacturing on site generation.

Data for the Form EIA-860B 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. The Form EIA-867 data are considered confidential (1994 through 1997). Therefore, 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. In 1998, the Form EIA-860B data that are confidential are planned units that have sales to other end-users.

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.

Gross-to-Net Generation Conversion Methodology. Gross electricity generation data from the Form EIA-860B, 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-860B, 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-860B. The difference between gross and net generation--sometimes called parasitic load--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. In smaller power plants rotating auxiliaries are almost always electric motors. In large power plants that produce steam, rotating auxiliaries can be powered by either steam turbines or electric motors and sometimes both because of cold startup requirements.

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

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

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

[a]Factor reduced by .01 if the facility has flue gas particulate collectors and another .03 if the facility has flue gas desulfurization (FGD) equipment. Facilities under 25 megawatts 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 for the production of electricity by cogeneration facilities. The methodology is based on net generation heat rates by primary fuel and prime-mover. The primary fuel is the predominant energy source for the generator based on fuel consumption at the facility expressed in total Btu by fuel type. The heat rates were estimated by the staff of the Office of Coal, Nuclear, Electric and Alternate Fuels; Energy Information Administration. The primary reference used in developing the conversion factors was *TAG—Technical Assessment Guide*, Volume 1: Electricity Supply—1986, Electric Power Research Institute, Palo Alto, California, December 1986. The procedure to estimate the fuel consumed for the production of electricity is to calculate net generation by primary fuel and prime-mover (see gross-to-net generation methodology), multiply the net generation by the appropriate heat rate to obtain total Btu consumed for the production of electricity, and apportion by the total Btu weighted by energy source.

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

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

Nameplate Capacity to Summer Capability Conversion Methodology. Form EIA-860B, “Annual Electric Generator Report – Nonutility,” 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 based on data submitted for the Form EIA-860A.

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.[20] In 1997, the SIC Manual name was changed to North American Industry Classification System (NAICS). The following is a list from the Form EIA-860B of the main classifications and the category of primary business activity within each classification.

[20] Office of Management and Budget, *Standard Industrial Classification Manual, 1972* (Washington, DC, 1987).

Agriculture, Forestry, and Fishing
111 Agriculture production-crops
112 Agriculture production, livestock and animal specialties
115 Agricultural services
113 Forestry
114 Fishing, hunting, and trapping

Mining
2122 Metal mining
2121 Coal mining
211 Oil and gas extraction
2123 Mining and quarrying of nonmetallic minerals
except fuels

Construction
23

Manufacturing
311 Food and kindred products
3122 Tobacco products
314 Textile and mill products
315 Apparel and other finished products made from fabrics and similar materials
321 Lumber and wood products, except furniture
337 Furniture and fixtures
322 Paper and allied products (other than 322122 or 32213)
- 322122 Paper mills, except building paper
- 32213 Paperboard mills

323 Printing and publishing
325 Chemicals and allied products (other than 325188, 325211, 32512, or 325311)
- 325188 Industrial Inorganic Chemicals
- 325211 Plastics materials and resins
- 32512 Industrial organic chemicals
- 325311 Nitrogenous fertilizers

324 Petroleum refining and related industries (other than 32411)
- 32411 Petroleum refining

326 Rubber and miscellaneous plastic products
316 Leather and leather products
327 Stone, clay, glass, and concrete products (other than 32731)
- 32731 Cement, hydraulic

331 Primary metal industries (other than 331111 or 331312)
- 331111 Blast furnaces and steel mills
- 331312 Primary aluminum

332 Fabricated metal products, except machinery and transportation equipment
333 Industrial and commercial equipment and components except computer equipment
335 Electronic and other electrical equipment and components except computer equipment
336 Transportation equipment
3345 Measuring, analyzing, and controlling instruments, photographic, medical, and optical goods, watches and clocks
339 Miscellaneous manufacturing industries

Transportation and Public Utilities
482 Railroad transportation
485 Local and suburban transit and interurban highway passenger transport
484 Motor freight transportation and warehousing
491 United States Postal Service
483 Water transportation
481 Transportation by air
486 Pipelines, except natural gas
487 Transportation services
513 Communications
22 Electric, gas, and sanitary services
- 2212 Natural gas transmission
- 2213 Water supply
- 22132 Sewerage systems
- 562212 Refuse systems
- 22131 Irrigation systems

Wholesale Trade
421 to 422

Retail Trade
441 to 454

Finance, Insurance, and Real Estate
521 to 533

Services
721 Hotels
812 Personal services
514 Business services
8111 Automotive repair, services, and parking
811 Miscellaneous repair services
512 Motion pictures
713 Amusement and recreation services
622 Health services
541 Legal services
611 Education services
624 Social services
712 Museums, art galleries, and botanical and zoological gardens
813 Membership organizations
561 Engineering, accounting, research, management, and related services
814 Private households
514199 Miscellaneous services

92 Public Administration
92

Other (explain):

Historically, (Tables 56 and 60) 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. In 1998 all the tables are based on North American Industry Classification System. Tables A1 and A2 show the installed capacity and gross generation of electricity by the producing energy group, respectively.

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 1998 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, (1994-1997)" 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

Certain data reported on the Form EIA-860B, "Annual Electric Generator Report - Nonutility," 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 1998 are final.
- **U.S. Electric Utility Financial Statistics** Financial data from the Federal Energy Regulatory Commission Form 1 and the Form EIA-412 for 1998 are preliminary.
- **U.S. Electric Utility Environmental Statistics** Data from the Form EIA-767 for 1997 are final. Data for 1998 are preliminary. A comparison of preliminary versus final data at the national level for 1998 will be provided in the *Electric Power Annual Volume II 1999.*
- **U.S. Electric Power Transactions** All data from the Forms EIA-411, EIA-860A, and EIA-861 are final. Data from the Form FE-781R are preliminary for 1998.
- **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 1994 through 1997 are final. Data from Form EIA-860B for 1998 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 150,000 megawatthours report their incremental peak load reductions, energy savings, direct and indirect utility costs attributable to DSM programs, annual peak load reductions, and energy savings for the reporting year. Annual and incremental effects for the reporting year are reported by consumer sector (residential, commercial, industrial, other) for each program category (energy efficiency and load management). Utilities with sales to ultimate consumers and sales for resale less than 150,000 megawatthours report incremental peak load reductions and energy savings. They also report total utility cost for the reporting year.

FERC Form 1

Composite Financial Indicators for Major Investor-Owned Electric Utilities

All financial monetary data in this report are expressed in nominal terms. The following formulas are used to calculate composite financial indicators.

Electric Fixed Asset (Net Plant) Turnover =

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

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 =

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

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" (Tables A3 and A5).[20] Emissions of SO_2 and NO_x have been revised from the updated Air Pollutant Emissions Factor (AP-42 5th edition, through Supplement E) of the Environmental Protection Agency on July 1999. 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 1997 publication.

The coefficients for determining emissions of CO_2 from electric utility power plants come from the publication, *Emissions of Greenhouse Gases in the United States,* (DOE/EIA-0573). The nonutility coefficients were developed to be consistent with the utility coefficients.

[20] "*Compilation of Air Pollutant Emission Factors*, Vol. 1: Stationary Point and Area Sources (AP-42);" 5th Edition (through Supplement E) Research Triangle Park, North Carolina, July 1999.

Methodology

The methodology for developing the CO_2 emission estimates for steam utility plants and nonsteam utility plants (calculations done on a plant basis by fuel), as well as for nonutility plants (calculations done on a facility basis by fuel), is as follows:

Steam Utility Plants

Step 1. Sum of Monthly Consumption (EIA-767) times Monthly Average Btu Content (EIA-767) divided by Total Annual Consumption (EIA-767) = Weighted Annual Btu Content Factor.

Step 2. Annual Consumption (EIA-767) times Weighted Annual Btu Content Factor (Step 1) = Annual Btu Consumption.

Step 3. Annual Btu Consumption (Step 2) times CO_2 factors = Annual CO_2 Emissions.

Step 4. Reduce Annual CO_2 Emissions (Step 3) by 1 percent to assume 99 percent burn factor.

Step 5. Divide Annual CO_2 Emissions (Step 4) by 2000 to obtain result in short tons.

Nonsteam Utility Plants

Step 1(a). If monthly EIA-759 and monthly FERC-423 is available: Sum of Monthly Consumption (EIA-759) times Monthly Average Btu Content (FERC-423) divided by Total Annual Consumption = Weighted Annual Btu Content Factor.

Step 1(b). If monthly EIA-759 is available, but not monthly FERC-423: Sum of Monthly Consumption (EIA-759) times Average Monthly Btu Content (calculated from FERC-423) divided by Total Annual Consumption = Weighted Annual Btu Content Factor.

Step 1(c). If only annual EIA-759 is available: Annual Consumption (EIA-759) times Average Annual Btu Content (calculated from FERC-423) divided by Total Annual Consumption = Weighted Annual Btu Content Factor.

Step 2. Annual Consumption (EIA-759) times Weighted Annual Btu Content Factor (Step 1) = Annual Btu Consumption.

Step 3. Annual Btu Consumption (Step 2) x CO_2 Factors = Annual CO_2 Emissions.

Step 4. Reduce Annual CO_2 Emissions (Step 3) by 1 percent to assume 99 percent burn factor.

Step 5. Divide Annual CO_2 Emissions (Step 4) by 2000 to obtain result in short tons.

Coal Rank and Emissions. 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.[21]

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 are 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.

[21] 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.

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.[22] FGD units typically remove between 70 to 90 percent of SO_2 from the boiler flue gas although higher removal efficiencies can be achieved. Electric utilities report both sulfur removal efficiency (percent) and their most stringent SO_2 emission limits on the Form EIA-767. To determine controlled SO_2 emissions, the uncontrolled emissions are reduced by the annual average removal efficiencies reported on the Form EIA-767. This emission is the controlled emission. As a check, the controlled emission is compared with the most stringent legal limit reported on the Form EIA-767. The controlled emission should be less than the legal limit because research indicates that utilities routinely remove more SO_2 than required to assure an operating margin of safety. If the controlled emission is not less than the most stringent legal limit, it implies that the utility is out of legal compliance and could be subject to fines and other penalties.

Utilities are permitted to take credit for sulfur that remains in bottom ash -- ash remaining in the bottom of the furnace after the coal is burned. For example, if a utility is required to remove 90 percent of the sulfur in the coal and 3 percent remains in the ash, it has to remove only 87 percent using scrubbers. This credit is included in emissions data in this report. It is likely, however, that in many cases the credit is not taken. In order to take the ash credit, utilities need to monitor the coal consumed on a daily basis; this is both time-consuming and costly. To the extent that utilities do not take the ash credit, emissions might be slightly overstated.

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 1996 CEMS emissions data by state and plant in its publication *Acid Rain Program, Emissions Scorecard 1996 (EPA430/R-97-025)* .

Preliminary 1996 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 electric utility plants for which both EPA and EIA collected data. On a national basis, the data collected by EPA is 2.5 percent higher than SO_2 emissions calculated by EIA.

Controlled Nitrogen Oxide Emissions. The controlled NO_x emission is calculated by applying the appropriate reduction factor in Table A6. 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.

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.

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.

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-860B, "Annual Nonutility Power Producer Report." Form EIA-860B collects information annually from all nonutility power producers with a total generator nameplate rating of 1 megawatt (MW)

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

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-860B.

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."[23] However, the boiler type and firing configuration are not reported on the Form EIA-860B so all boilers are assumed to be large boilers[24] 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-860B. The methodology developed for CO_2 emission estimates for nonutility plants is as follows:

Step 1. Annual Consumption (EIA-860B) times Average Annual Btu Content (calculated from FERC-423) divided by Total Annual Consumption = Weighted Annual Btu Content Factor.

Step 2. Annual Consumption (EIA-860B) times Weighted Annual Btu Content Factor (Step 1) = Annual Btu Consumption.

Step 3. Annual Btu Consumption (Step 2) x CO_2 Factors = Annual CO_2 Emissions.

Step 4. Reduce Annual CO_2 Emissions (Step 3) by 1 percent to assume 99 percent burn factor.

Step 5. Divide Annual CO_2 Emissions (Step 4) by 2000 to obtain result in short tons.

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-860B. 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-860B. 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

[23] "*Compilation of Air Pollutant Emission Factors* , Vol. I: Stationary Point and Area Sources(AP-42)," 5th Edition (through Supplement E) Research Triangle Park, North Carolina, July 1999.

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

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-860B 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 A6.

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-860B. For facilities reporting electrical generation before August 1973, no control equipment is assumed and the controlled NO_x emission is estimated to be equal to the uncontrolled emission as calculated above. For facilities reporting the first date of electrical generation after August 1973, the controlled NO_x emission is estimated as the lesser of either: the uncontrolled NO_x emission, or 0.8 pounds of NO_x per million Btu of fuel consumed.

Controlled Carbon Dioxide Emissions. There are no Federal regulations that limit CO_2 emissions. Information pertinent to the estimation of controlled CO_2 emissions is not collected on the Form EIA-860B; therefore, no estimates of controlled CO_2 emissions are provided.

Table A1. Installed Capacity at U.S. Nonutility Generating Facilities by Producing Energy Group and Census Division, 1994 Through 1998

(Megawatts)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
				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	207	166	W	W	W	1,296
South Atlantic	6,114	6,015	102	W	W	79	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**	**33,311**	**1,445**	**1,867**	**330**	**599**	**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	3,021	2,489	323	W	W	W	5,917
West North Central	755	131	131	W	W	W	1,232
South Atlantic	4,653	8,090	100	W	W	78	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**	**40,962**	**1,186**	**1,369**	**273**	**561**	**70,254**
				1996			
New England	1,190	3,938	75	—	—	—	5,202
Middle Atlantic	1,757	W	105	—	—	W	12,987
East North Central	3,076	2,584	331	W	W	W	6,074
West North Central	762	145	135	W	—	W	1,255
South Atlantic	4,690	W	96	W	64	81	13,662
East South Central	1,997	129	W	26	W	—	2,167
West South Central	W	4,636	197	72	W	—	14,433
Mountain	W	W	W	242	—	W	2,881
Pacific	2,460	11,120	169	595	99	85	14,527
U.S. Total	**25,850**	**44,457**	**1,168**	**1,204**	**179**	**331**	**73,189**
				1997			
New England	1,166	4,062	67	—	—	—	5,295
Middle Atlantic	1,718	W	99	—	—	W	13,020
East North Central	3,034	2,682	382	W	W	W	6,183
West North Central	788	475	135	W	—	W	1,611
South Atlantic	4,724	W	86	W	139	99	13,810
East South Central	1,961	204	W	26	W	—	2,212
West South Central	W	4,264	197	68	W	—	14,890
Mountain	W	W	W	239	—	W	2,868
Pacific	2,360	10,837	169	595	96	61	14,117
U.S. Total	**26,492**	**44,538**	**1,200**	**1,197**	**252**	**325**	**74,004**
				1998			
New England	1,171	4,313	65	—	—	6,270	11,818
Middle Atlantic	1,706	10,976	106	—	—	18	12,806
East North Central	2,808	3,180	345	—	5	1,869	8,207
West North Central	722	616	135	203	—	11	1,686
South Atlantic	4,830	8,565	86	6	63	100	13,650
East South Central	2,042	135	14	24	11	2,147	4,373
West South Central	10,042	5,568	197	66	1	—	15,873
Mountain	407	2,070	52	240	—	118	2,887
Pacific	2,295	11,254	174	655	91	12,316	26,785
U.S. Total	**26,022**	**46,678**	**1,172**	**1,193**	**170**	**22,849**	**98,085**

W = Withheld to avoid disclosure of individual company data.

Notes: •All data are for 1 megawatt and greater. •Data for the 1998 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.

Sources: Energy Information Administration, Data for 1998: Form EIA-860B ''Annual Electric Generator Report - Nonutility''; Data for 1997 and prior: Form EIA-867 ''Annual Nonutility Power Producer Report''.

Table A2. Gross Generation of U.S. Nonutility Generating Facilities by Producing Energy Group and Census Division, 1994 Through 1998

(Million Kilowatthours)

Census Division	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
				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	422	421	W	W	W	5,077
South Atlantic	35,043	16,719	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**	**159,508**	**5,781**	**10,618**	**1,747**	**1,490**	**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	31,283	237	W	W	W	57,624
East South Central	11,593	W	W	125	W	—	12,708
West South Central	57,667	25,861	614	492	—	—	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**	**215,233**	**4,196**	**6,440**	**1,217**	**1,422**	**375,901**
				1996			
New England	5,940	23,653	268	—	—	—	29,862
Middle Atlantic	9,433	W	463	—	—	W	68,860
East North Central	14,795	14,988	1,232	W	W	W	31,130
West North Central	2,829	W	305	W	—	W	4,362
South Atlantic	25,712	W	247	W	19	138	58,485
East South Central	12,132	W	W	118	W	—	13,249
West South Central	W	26,598	566	385	W	—	83,994
Mountain	W	W	W	550	—	W	13,480
Pacific	13,970	59,471	838	4,096	389	237	79,001
U.S. Total	**143,304**	**227,736**	**4,164**	**5,783**	**480**	**956**	**382,423**
				1997			
New England	6,051	23,976	246	—	—	—	30,273
Middle Atlantic	9,526	W	463	—	—	W	68,518
East North Central	14,891	15,118	1,288	—	W	W	31,366
West North Central	2,863	685	327	W	—	W	4,807
South Atlantic	25,499	29,337	W	W	W	146	55,555
East South Central	11,381	1,255	W	114	W	—	12,860
West South Central	W	27,145	539	427	W	—	91,270
Mountain	W	W	232	503	—	W	13,744
Pacific	13,663	57,015	775	4,059	410	182	76,103
U.S. Total	**149,106**	**223,383**	**4,125**	**6,028**	**860**	**995**	**384,496**
				1998			
New England	6,078	35,027	246	—	—	—	41,352
Middle Atlantic	9,284	56,768	456	—	—	71	66,579
East North Central	13,709	19,246	1,310	—	17	44	34,325
West North Central	3,138	779	322	1,146	—	21	5,405
South Atlantic	25,300	29,001	237	6	31	145	54,720
East South Central	12,088	6,022	92	114	56	—	18,372
West South Central	60,498	33,937	552	368	—	—	95,354
Mountain	2,157	10,424	225	488	—	395	13,689
Pacific	11,925	74,170	850	4,047	410	165	91,567
U.S. Total	**144,177**	**265,375**	**4,291**	**6,169**	**513**	**840**	**421,364**

Notes: •All data are for 1 megawatt and greater. •Data for 1998 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.

Sources: Energy Information Administration, Data for 1998: Form EIA-860B ''Annual Electric Generator Report - Nonutility''; Data for 1997 and prior: 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 10^6 Btu**
Bituminous[4]	cyclone	38.00 x S	33.0	See Table A4
	fluidized bed[5]	31.00 x S	5.0	See Table A4
	spreader stoker	38.00 x S	11.0	See Table A4
	tangential	38.00 x S	15.0(14)	See Table A4
	all others	38.00 x S	22.0(31)	See Table A4
Subbituminous[4]	cyclone	35.00 x S	17.0	See Table A4
	fluidized bed[5]	31.00 x S	5.0	See Table A4
	spreader stoker	38.00 x S	8.8	See Table A4
	tangential	35.00 x S	8.4	See Table A4
	all others	35.00 x S	12.0(24)	See Table A4
Lignite[4]	cyclone	30.00 x S	15.00	See Table A4
	fluidized bed	10.00 x S	3.60	See Table A4
	front/opposed	30.00 x S	13.00	See Table A4
	spreader stoker	30.00 x S	5.80	See Table A4
	tangential	30.00 x S	7.10	See Table A4
	all others	30.00 x S	7.10(13)	See Table A4
Petroleum Coke[6]	fluidized bed[5]	39.00 x S	21.00	225.13
	all others	39.00 x S	21.00	225.13
Refuse	all types	3.90	5.00	199.82
Wood	all types	0.08	1.50	0.00
Petroleum and Other Liquid Fuels		**lbs per 10^3 gal**	**lbs per 10^3 gal**	**lbs per 10^6 Btu**
Residual Oil[7]	tangential	157.00 x S	32.00	173.72
	vertical	157.00 x S	47.00	173.72
	all others	157.00 x S	47.00	173.72
Distillate Oil[7]	all types	150.00 x S	24.00	161.27
Methanol	all types	See Table A5	See Table A5	138.15
Propane (liquid)	all types	86.5	19.00	139.04
Coal-Oil Mixture	all types	See Table A5	See Table A5	173.72
Natural Gas and Other Gaseous Fuels		**lbs per 10^6 cf**	**lbs per 10^6 cf**	**lbs per 10^6 Btu**
Natural Gas	tangential	0.60	170.00	116.38
	all others	0.60	280.00	116.38
Blast Furnance Gas	all types	950.00	280.00	116.38
Nonutility				
Coal and Other Solid Fuels		**lbs per ton**	**lbs per ton**	**lbs per 10^6 Btu**
Anthracite Culm	all types	39.00 x S	1.80	See Table A4
Bituminous[4]	all types	38.00 x S	22.00	See Table A4
Bituminous Gob	all types	38.00 x S	22.00	See Table A4
Subituminous	all types	35.00 x S	12.00	See Table A4
Lignite[4]	all types	30.00 x S	12.00	See Table A4
Lignite Waste	all types	30.00 x S	12.00	See Table A4
Peat	all types	30.00 x S	12.00	See Table A4
Agricultural Waste	all types	See Table A5	See Table A5	0
Black Liquor	all types	See Table A5	See Table A5	0
Chemicals	all types	See Table A5	See Table A5	0
Closed Loop Biomass	all types	See Table A5	See Table A5	0
Internal	all types	See Table A5	See Table A5	0

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 10^6 Btu**
Liquid Acetonitrile Waste	all types	See Table A5	See Table A5	150.76
Liquid Waste	all types	2.80	2.30	163.29
Municipal Solid Waste	all types	1.70	5.90	189.48
Petroleum Coke[7]	all types	39.00 x S	14.00	225.13
Pitch	all types	See Table A5	See Table A5	See Table A4
Railroad Ties	all types	See Table A5	See Table A5	0
Red Liquor	all types	See Table A5	See Table A5	0
Sludge	all types	2.80	5.00	0
Sludge Waste	all types	2.80	5.00	0
Sludge Wood	all types	2.80	5.00	0
Spent Sulfite Liquor	all types	See Table A5	See Table A5	0
Straw	all types	See Table A5	See Table A5	0
Sulfur	all types	7.00	0.00	0
Tar Coal	all types	See Table A5	See Table A5	See Table A4
Tires	all types	See Table A5	See Table A5	189.54
Waste Byproducts	all types	1.70	2.30	163.29
Waste Coal	all types	See Table A5	See Table A5	See Table A4
Wood/Wood Waste	all types	0.08	1.50	0
Petroleum and Other Liquid Fuels		**lbs per 10^3 gal**	**lbs per 10^3 gal**	**lbs per 10^6 Btu**
Heavy Oil[7]	all types	157.00 x S	47.00	173.72
Light Oil[7]	all types	142.00 x S	20.00	159.41
Diesel	all types	142.00 x S	20.00	161.27
Kerosene	all types	142.00 x S	20.00	159.41
Butane (liquid)	all types	0.09	21.00	143.20
Fish Oil	all types	See Table A5	See Table A5	0
Methanol	all types	See Table A5	See Table A5	138.15
Oil Waste	all types	147.00 x S	19.00	163.61
Propane (liquid)	all types	0.50	19.00	139.04
Sludge Oil	all types	147.00 x S	19.00	0
Tar Oil	all types	See Table A5	See Table A5	0
Waste Alcohol	all types	See Table A5	See Table A5	138.15
Natural Gas and Other Gaseous Fuels		**lbs per 10^6 cf**	**lbs per 10^6 cf**	**lbs per 10^6 Btu**
Natural Gas	all types	0.60	280.00	116.97
Butane (gas)	all types	0.60	21.00	143.20
Hydrogen	all types	See Table A5	550.00	0
Landfill Gas	all types	See Table A5	550.00	115.12
Methane	all types	See Table A5	550.00	115.11
Other Gas	all types	See Table A5	550.00	141.54
Propane (gas)	all types	0.60	19.00	139.04

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 A6 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 (through Supplement E), Research Triangle Park, North Carolina, July, 1999. •For carbon dioxide factors: Department of Energy, ''Emissions of Greenhouse Gases in the United States 1997,'' October 1998.

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, Quarterly Coal Report, Jan.-Mar. 1994, DOE-EIA-0121(94/Q1) (Washington, D.C, August 1994), pp. 1-8.)

Table A5. Sulfur Dioxide and Nitrogen Oxide Factors for Specific Fuels

Fuel	Boiler Type/ Firing Configuration	Emission Factors	
		Sulfur Dioxide[1]	Nitrogen Oxides[2]
Utility		**lbs per 10^3 gal**	**lbs per 10^3 gal**
Methanol	all types	0.05	12.40
Coal-Oil Mixture	all types	185.00 x S	50.00
Nonutility		**lbs per ton**	**lbs per ton**
Agricultural Waste	all types	0.08	1.20
Black Liquor	all types	7.00	1.50
Chemicals	all types	7.00	1.50
Closed Loop Biomass	all types	0.08	1.50
Internal	all types	0.08	1.50
Liquid Acetonitrile Waste	all types	7.00	1.50
Pitch	all types	30.00 x S	11.10
Railroad Ties	all types	0.08	1.50
Red Liquor	all types	7.00	1.50
Spent Sulfite Liquor	all types	7.00	1.50
Straw	all types	0.08	1.50
Tar Coal	all types	30.00 x S	11.10
Tires	all types	38.00 x S	21.70
Waste Coal	all types	38.00 x S	21.70
		lbs per 10^3 gal	**lbs per 10^3 gal**
Fish Oil	all types	0.50	12.40
Methanol	all types	0.50	12.40
Tar Oil	all types	162.70 x S	67.00
Waste Alcohol	all types	0.50	12.40
		lbs per 10^6 cf	**lbs per 10^6 cf**
Hydrogen	all types	0.00	550.00
Landfill Gas	all types	0.60	550.00
Methane	all types	0.60	550.00
Other Gas	all types	0.60	550.00

[1] Uncontrolled sulfur dioxide emission factor. ''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] 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 A6 for nitrogen oxide reduction factors used to calculate controlled nitrogen emission estimates.

Sources: Nitrogen Oxide emission factors from Hydrogen, Landfill Gas, Methane, and Other Gas calculated from Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources*, Fifth Edition (through Supplement E), Research Triangle Park, North Carolina, July, 1999. All other fuels calculated by the Office of Coal, Nuclear, Electric and Alternate Fuels.

Table A6. Nitrogen Oxide Reduction Factors

Nitrogen Oxide Control Technology	EIA-767 Code(s)	EIA-860B 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 A7. 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 annual revenue by the corresponding total annual 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 10 regional reliability councils and one affiliate member and encompasses essentially all the power regional of the contiguous United States and Alaska, Canada, and Mexico. The NERC Regions are:

ASCC - The Alaska Systems Coordinating Council (affiliate NERC member)

ECAR - East Central Area Reliability Coordination Agreement

ERCOT - Electric Reliability Council of Texas

FRCC - Florida Reliability Coordinating Council

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

North American Industry Classification System (NAICS): A set of codes developed by the Office of Management and Budget, which categorizes business into groups with similar economic activities. Formerly called the Standard Industrial Classification (SIC) prior to 1997.

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.

Other Sales 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.

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 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 (see North American Industry Classification System).

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.