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Electric Power Annual 2007

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Contacts

Questions of a general nature regarding this report should be directed to:

Robert Schnapp (202/586-5114)
Director, Electric Power Division
e-mail: robert.schnapp@eia.doe.gov

Publication Coordinator:
John W. Makens (202/586-4059)
e-mail: john.makens@eia.doe.gov;

Team Leader Coordinators:
Thomas J. Leckey (202/586-3548)
Survey Support and Analysis Team
e-mail: thomas.leckey@eia.doe.gov;

James Diefenderfer (202/586-2432)
Generation and Capacity Team
e-mail: james.diefenderfer@eia.doe.gov;

Dean Fennell (202/586-2462)
Monthly Sales and Finance Team
e-mail: dean.fennell@eia.doe.gov;

Questions of a specific nature should be directed to one of the following contributors:

Year-in-Review
Howard Stone (202/586-3189)
e-mail: howard.stone@eia.doe.gov;

Generation
Channele Wirman (202/586-5356)
e-mail: channele.wirman@eia.doe.gov;
Chris Cassar (202/586-5448)
e-mail: christopher.cassar@eia.doe.gov;
Ron S. Hankey (202/586-2630)
e-mail: ronald.hankey@eia.doe.gov;

Capacity
Elsie Bess (202/586-2402)
e-mail: elsie.bess@eia.doe.gov;

Demand, Capacity Resources, and Capacity Margins
John W. Makens (202/586-4059)
e-mail: john.makens@eia.doe.gov;

Fuel
Rebecca A. McNerney (202/586-4509)
e-mail: rebecca.mcnerney@eia.doe.gov;
Channele Wirman (202/586-5356)
e-mail: channele.wirman@eia.doe.gov;
Chris Cassar (202/586-5448)
e-mail: christopher.cassar@eia.doe.gov;
Ron S. Hankey (202/586-2630)
e-mail: ronald.hankey@eia.doe.gov;

Emissions
Kevin G. Lillis (202/586-3704)
e-mail: kevin.lillis@eia.doe.gov;

Trade
John W. Makens (202/586-4059)
e-mail: john.makens@eia.doe.gov;

Retail Customers, Sales, and Revenue
Karen McDaniel (202/586-4280)
e-mail: karen.mcdaniel@eia.doe.gov;

Revenue and Expense Statistics
Karen McDaniel (202/586-4280)
e-mail: karen.mcdaniel@eia.doe.gov;

Demand-Side Management
Karen McDaniel (202/586-4280)
e-mail: karen.mcdaniel@eia.doe.gov.

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The Energy Information Administration is committed to quality products and quality service. To ensure that this report meets the highest standards for quality, please forward your comments or suggestions about this publication to Robert Schnapp at 202/586-5114, or e-mail: robert.schnapp@eia.doe.gov.

For general inquiries about energy data, please contact the National Energy Information Center at 202/586-8800. Internet users may contact the center at: infoctr@eia.doe.gov.

Preface

The Electric Power Annual 2007 summarizes electric power industry statistics at the national level. The publication provides industry decision-makers, government policymakers, analysts, and the general public with historical data that may be used in understanding U.S. electricity markets. The *Electric Power Annual* is prepared by the Electric Power Division; Office of Coal, Nuclear, Electric and Alternate Fuels; Energy Information Administration (EIA); U.S. Department of Energy.

Data in this report can be used in analytic studies for public policy and business decisions. The chapters present information and data in the following areas: electricity generation; electric generating capacity; demand, capacity resources, and capacity margins; fuel, consumption and receipts; emissions; electricity trade; retail electric customers, sales, revenue and average retail price; electric utility revenue and expense statistics; and demand-side management.

Monetary values in this publication are expressed in nominal terms.

Data published in the *Electric Power Annual* are compiled from four surveys completed annually or monthly by electric utilities and other electric power producers and submitted to the EIA and five surveys performed by other government organizations[1]. The EIA forms are described in detail in the "Technical Notes."

[1] The Department of Energy, Office of Electricity Delivery and Energy Reliability; the Federal Energy Regulatory Commission; the Department of Agriculture, Rural Utility Services; and the National Energy Board of Canada.

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Overview

In 2007, average retail electricity prices increased 2.6 percent from 8.9 to 9.1 cents per kilowatthour (kWh) This followed a 3-year period during which average fossil fuel prices for electricity generation increased a cumulative 30.2 percent. As fuel prices increased 30.2 percent, the National average retail price of electricity increased 17.0 percent from 7.6 cents per kWh in 2004 to 8.9 per kWh in 2006. Fossil fuel prices increased an additional 7.0 percent in 2007, contributing to the 2.6 percent average retail electricity rate.

Both the number of residential and commercial customers increased 1.2 percent over 2006 levels. Residential and commercial customer growth, along with a modest increase in average consumption per residential and commercial customer, resulted in a 3.0 percent increase in residential electricity sales and a 2.8 percent increase in commercial electricity sales in 2007. Residential and commercial sales accounted for 69.5 percent of total retail sales. When all sales to ultimate consumers are considered (e.g., residential, commercial, industrial, transportation, other and direct use), electricity sales increased by 2.8 percent in 2007. In 2006, total sales increased only 0.2 percent from the prior year.

In response to the 2.8 percent increase in sales to ultimate customers, electric power generation increased 2.3 percent, from 4,065 million megawatthours (MWh) in 2006 to 4,157 MWh in 2007. The remaining energy requirements were met by imports from Canada and Mexico. Although electric power generation increased by 2.3 percent in 2007, net summer capacity increased by 8,673 megawatts (MW) or 0.9 percent. Since more than half of the new capacity was non-dispatchable wind capacity, the 2.3 percent increase in net generation was achieved primarily through the increased performance of existing coal-fired, natural gas-fired and nuclear capacity. All three of these types of capacity set net production levels, and increased average capacity factors, in 2007.

In 2007, for the first time, renewable energy sources, other than conventional hydroelectric capacity, accounted for the largest portion of capacity additions. Total net summer capacity increased 8,673 MW in 2007. Wind capacity accounted for 5,186 MW of this new capacity. Natural gas-fired generation accounted for 4,582 MW. Two new coal-fired plants with summer capacity totaling 1,354 MW were placed in service in 2007. However, retirements and downward adjustments to existing capacity resulted in a 217 MW net reduction in coal-fired capacity.

Summer peak demand (noncoincident) fell from 789,475 MW in 2006 to 782,227 MW in 2007. Winter peak demand (noncoincident), which is always smaller than summer peak demand, decreased in 2007, falling a modest 0.5 percent from 640,981 MW in 2006 to 637,905 in 2007.

While the National average retail price for electricity for all customer classes increased by 2.6 percent to an average of 9.1 cents per kilowatthour, regional variations were significant. For example, the average retail price in the West South Central Census Division declined in 2007, whereas the average price increased in all other Census Divisions. The East North Central Census Division experienced the largest average price increase at 6.9 percent. This increase was primarily the result of the lifting of rate caps in Illinois that were put in place with retail restructuring in 1997. Average prices increased by 4.0 percent in the New England Census Division, 3.4 percent in the East South Central Census Division and 3.3 percent in the Middle Atlantic Census Division.

Unlike 2006, when carbon dioxide, sulfur dioxide and nitrogen oxides emission declined, carbon dioxide emissions from conventional electric generation and combined heat and power plants increased 2.3 percent in 2007. Sulfur dioxide and nitrogen oxides decreased 5.1 percent and 3.9 percent, respectively. Since 1997, sulfur dioxide and nitrogen oxides emission have been reduced by 32.9 percent and 43.8 percent, respectively.

Generation

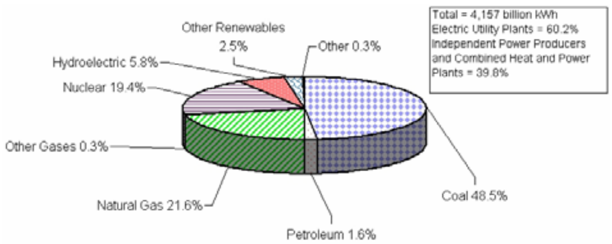
Net generation of electric power increased 2.3 percent in 2007, to 4,157 million megawatthours (MWh) from 4,065 million MWh in 2006 (Figure ES1). According to the Bureau of Economic Analysis, the U.S. real gross domestic product increased 2.0 percent in 2007.[1] The Federal Reserve Board reported a 1.7 percent increase in total industrial production.[2] Thus, the increase in electricity demand corresponded with economic growth in 2007. Weather also appears to have been a contributing factor to electricity demand. According to the National Oceanic and Atmospheric Administration (NOAA), heating degree days in 2007 were 6.5 percent higher and cooling degree days were 2.2 percent higher than they were in 2006. Thus, the combination of moderate economic growth and weather-related electricity demand appears to have

[1] See http://bea.doc.gov/national/index.htm#gdp.

[2] See http://www.federalreserve.gov/releases/g17/Current/table11.txt, accessed November 24, 2008.

contributed to the 2.3 percent increase in net generation, as compared to the relatively flat 0.2 percent growth observed in 2006.

Figure ES 1. US Electric Power Industry Net Generation, 2007



Source: Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report."

The three primary energy sources for generating electric power in the United States are coal, natural gas, and nuclear energy. These three sources consistently provided between 84.6 and 89.5 percent of total net generation during the period 1997 through 2007. Petroleum's relative share of total net generation was unchanged in 2007 from 2006 at 1.6 percent. Conventional hydroelectric power continues to decline as a share of total net generation. In 2007, conventional hydroelectric generating capacity accounted for 6.0 percent of total net generation, as compared to 10.2 percent in 1997. Renewable energy sources, excluding conventional hydroelectric generation, contributed 2.5 percent of total net electric generation in 2007. This marks the fourth consecutive year in which renewables' share of total net generation has increased.

In 2007, electricity generation from coal-fired capacity increased 1.3 percent, reversing the decline from 2005 to 2006. Coal-fired generation increased from 1,991 million MWh in 2006 to 2,016 million MWh in 2007. This is a new record, exceeding the previous all-time high of 2,013 million MWh set in 2005. The record level of coal-fired generation reflects a one percentage point increase in the average capacity factor of coal-fired generation to 73.6 percent. Additionally, two coal-fired power plants located in the Pacific Northwest returned to service during 2007. The Boardman Plant, located in Oregon returned to service in May 2006 following a series of outages that began in October 2005. Net generation from the Transalta Centralia Generating Plant, located in Washington State, increased in 2007 following a reduced level of production in 2006, when the plant conducted a test burn of Powder River Basin coal. Coal-fired electricity production was further enhanced by the commencement of commercial operations at the Walter Scott, Jr. Energy Center Unit No. 4, located in Council Bluffs, Iowa (923 MW nameplate rating) and the Cross Generating Station No. 3 located in South Carolina (591 MW nameplate rating).

In spite of setting a record level for generation in 2007, coal's share of total net generation continued its downward trend in 2007. It accounted for 48.5 percent of total net generation in 2007 as compared to 49.0 percent in 2006 and 52.8 percent in 1997. Nevertheless, it remains the primary source of baseload generation. The decline in coal's share of total net generation in 2007 was attributable to continued increase in the share of total net generation produced by natural gas-fired and nuclear capacity, as well as renewable sources, other than conventional hydroelectric capacity.

Net generation from natural gas-fired capacity increased 9.8 percent, from 816 million MWh to 897 million MWh in 2007. This was the second largest 1-year increase in natural-gas fired generation since the 10.8 percent increase that occurred in 1998. Natural gas-fired generation accounted for 21.6 percent of total net generation in 2007 as compared to 20.1 percent in 2006. For the second consecutive year, natural-gas fired generation was the second leading contributor to total net generation, surpassing nuclear generation, which historically was the second leading source of total net generation after coal.

Net generation at nuclear plants increased 2.4 percent in 2007 to 806 million MWh. Between 1996 and 2007, nuclear generation ranged from an 18.0-20.6 percent share of total net generation with an annual average growth in net generation of 1.6 percent from 1996 through 2007, despite the fact that no new nuclear units have been constructed. The continued growth in nuclear generation is due to improved capacity utilization, and in 2007, the resumption of commercial operations at the Tennessee Valley Authority's Browns Ferry Unit 1 after a 22-year shutdown. Since 1996, average capacity factors for nuclear plants increased from 76.2 percent to 91.8 percent (Table A6). In 2007, nuclear power plants operated at their highest average capacity factor, once again setting a record for net generation. In past years, growth in nuclear generation was the result of both improved capacity factors and uprates of existing plants. In 2007, the increase in nuclear generation appears to be primarily a function of improved plant performance. In 2007, nuclear plant operators reported a 47 MW increase in net winter capability and a 68 MW decrease in net summer capability. This is the first year since 1999 in which the net summer capability of nuclear plants declined, a significant departure from the annual increases in net summer capacity of existing nuclear plants that occurred between 1999 and 2006. During this period net summer capability of existing nuclear plants increased by 2,293 MW, which equates to an average annual increase of 418 MW of net summer capability.

Net generation from conventional hydroelectric plants declined 14.4 percent from 289 million MWh in 2006 to 248 million MWh in 2007. The decline in conventional hydroelectric generation is consistent with the drought conditions, which according to the National Climatic Data Center (NCDC) prevailed over the West and Southeast for much of the year. According to NCDC, evaporation caused by above normal summer temperatures exacerbated drought conditions in these regions. Moreover, precipitation was below average in the Southeast and the mountain snowpack in the Rocky Mountain and Western States was significantly below normal levels.[3]

Petroleum-fired generation increased 2.5 percent, to 66 million MWh. Its share of total net generation remained unchanged from 2006 at 1.6 percent.

Net generation produced by renewable energy sources, excluding hydroelectric generation, grew by 9.0 percent as compared to 10.5 percent growth in 2006. Renewable energy accounted for 2.5 percent or 105 million MWh of total net generation in 2007. Wood and wood derived fuels accounted for 39 million MWh or 0.9 percent of total net generation. Wind generation was the second largest renewable energy source, contributing 34 million MWh or 0.8 percent of total net generation in 2007. Geothermal power plants supplied 15 million MWh of net generation and other biomass 17 million MWh. Each of these renewable sources accounted for approximately 0.4 percent of total net generation in 2007. In 2007, wood and wood derived fuels continued to be the largest sources of renewable generation, accounting for 37.1 percent of total net renewable generation, excluding conventional hydroelectric generation. Wind generation is rapidly gaining a larger share of total renewable generation. In 2007, wind accounted for 32.7 percent of total net generation from non-hydroelectric renewable sources, as compared to 4.3 percent in 1997. The annual growth in solar thermal and photovoltaic generation has been sufficient for this renewable source to account, on average, for 0.5 percent of all non-hydroelectric renewable energy. Wood and wood derived fuels and geothermal have maintained fairly stable output levels averaging 38 million MWh and 15 MWh per year, respectively. Other biomass generation has declined from a 23 million MWh peak in 2000 to 17 million MWh in 2007.

Generation from other gases (refinery gases, blast furnace gas, etc.) and other miscellaneous sources accounted for the remaining net generation. Net generation from these sources declined from 27 million MWh in 2006 to 26 million MWh.

Finally, net energy requirements for pumped-storage hydroelectric generation increased 0.3 million MWh in 2007.

Fossil Fuel Stocks at Electric Power Plants

End-of-year coal stocks for 2007 increased 7.3 percent from 141 million tons to 151 million tons. The build in coal stocks in 2007 was considerably less than the 39.4 percent increase that occurred in 2006. This appears to be the result of the increase in coal-fired generation relative to 2006, and a reduction in coal purchases in response to rising coal prices. While coal consumption at electric power plants increased 16 billion tons receipts declined by 25 billion tons in 2007. The increase in end-of-year stocks is consistent with the finding in the North American Electric Reliability Corporation's (NERC) *2007/2008 Winter Reliability Assessment* that power plant inventories were ahead of historical normal levels, with inventory levels approaching 45 days as compared to 40 days.[4] While NERC concluded that coal stocks are satisfactory, it has identified longer-term market risks that could impact the security of supply in the long-run. These include capacity constraints on rail lines, particularly from the Powder River Basin and rolling stock shortages. NERC also indicated that rising coal prices may cause power plant owners to reduce on-site fuel supply in order to minimize carrying costs.[5]

Inventories of petroleum decreased from 51.6 million barrels at the end of 2006 to 47.2 million barrels by year end 2007. The decline in petroleum inventories is a function of increased consumption caused by the 2.5 percent increase in petroleum-fired generation, and a 12.6 million barrel reduction in petroleum receipts at

[3] National Climatic Data Center, Climate of 2007 Annual Review, U.S. Drought, January 15, 2008, http://www.ncdc.noaa.gov/oa/climate/research/2007/ann/us-summary.html

[4] North American Electric Reliability Corporation, *2007/2008 Winter Reliability Assessment*. November 2007., p.10

[5] North American Electric Reliability Corporation, *2007 Long-term Reliability Assessment 2007-2016,* October 2007, p. 89.

power plants, which is likely attributable to the 13.1 percent increase in petroleum prices.

Capacity

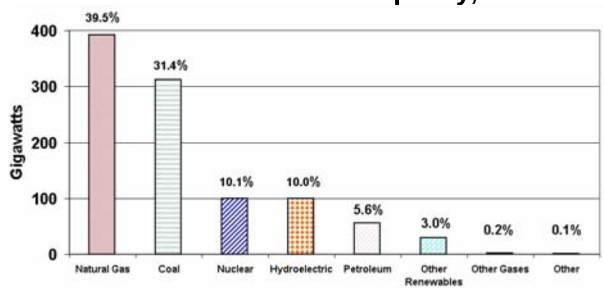
Total U.S. net summer generating capacity as of December 31, 2007 was 994,888 MW, an increase of 1.0 percent from January 1, 2007 (Figure ES2). During the year, net summer generating capacity increased 8,673 MW, after accounting for retirements, deratings (i.e., a reduction in power plant generating capability) and other adjustments. For the first time, non-hydroelectric, renewable energy capacity additions exceeded total fossil fuel capacity additions. Natural gas-fired generating units accounted for 4,582 MW or 52.8 percent of net summer capacity additions.

On December 31, 2007, natural gas-fired generating capacity represented 392,876 MW or 39.5 percent of total net summer generating capacity (Figure ES2). Although new natural gas-fired combined-cycle plants produce electricity more efficiently than older fossil-fueled plants, high natural gas prices can work against full utilization of these plants if such prices adversely affect economic dispatch. Since 1996, net summer natural gas-fired capacity has increased 218,741 MW net of retirements and adjustments. Natural gas capacity additions during this period were virtually equal to the 218,998 MW total increases in net summer capability. During this period coal, petroleum and nuclear capacity decreased by a net 17,612 MW, along with 783 MW of non-hydroelectric renewable capacity. That is, after additions and uprates, net summer capability associated with these types of resources collectively declined over the past 10 years. Since 1997, natural gas-fired additions in effect offset net retirements across all fuel types, with the cumulative net increase in capacity equal to 14,760 MW of non-hydroelectric, renewable capacity and 3,111 MW of other gases, hydroelectric and other capacity.

Petroleum-fired capacity totaled 56,068 MW, down 2,029 MW from 2006. Petroleum-fired capacity accounted for 5.6 percent of all generating capacity.

Coal-fired generating capacity remained essentially unchanged at 312,738 MW, or 31.4 percent of total generating capacity. This share of total capacity represents a slight decline from 2006. Retirements of and other adjustments to existing coal-fired capacity reported by operators in 2007 exceeded the 1,354 MW of net summer capacity of the 2 new plants placed in service by 1,514 MW. Since 1996, net summer coal-fired capacity has declined 644 MW after accounting for new additions, upgrades and other adjustments reported by operators. Nevertheless, net generation from the Nation's coal-fired plants continues to increase due to gains in operating efficiency.

Figure ES 2. U.S. Electric Power Industry Net Summer Capacity, 2007



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

Wind generating capacity totaled 16,515 MW in 2007, which amounts to a 45.8 percent increase over the 11,329 MW in operation during 2006. Of the 8,673 MW total increase in net summer capability in 2007, wind generating capacity accounted for 5,186 MW. Texas continues to lead the Nation in wind power development with 1,752 MW of new wind capacity placed in service in 2007, increasing its share of Nation's wind capacity currently in operation to 27.2 percent. California has the second highest share of total installed wind generating capacity at 2,312 MW. The remainder of the top five wind producing States includes Iowa at 7.1 percent, Washington at 7.0 percent and Minnesota at 6.9 percent of the Nation's total installed wind generating capacity. Collectively, 10,273 MW or 62.2 percent of total wind generating capacity is located in these 5 States. Wind power development has accelerated in Colorado, Illinois, Oklahoma and Oregon with the addition of 1,794 MW of capacity. Over the last three years 10,059 MW of wind generating capacity has been placed in service. The electric generating capacity from non-hydroelectric renewable energy sources increased 24.7 in 2007. Wind capacity accounted for 87.1 percent of the 5,596 MW of non-hydro renewable energy sources placed in service in 2007.

Nuclear net summer generating capacity totaled 100,266 MW or 10.1 percent of total capacity. Uprates totaling 179 MW of nameplate capacity were made at the Duane Arnold Energy Center and R. E. Ginna plant. However, nuclear plant operators reported that net summer capacity declined by 68 MW and net winter capacity increased by 47 MW. Thus, continued improvement in plant performance was the primary factor supporting the increase in nuclear generation in 2007, with a large share of that increase stemming from the resumption of output from the Browns Ferry 1 unit in Alabama, which returned to service in June 2007 after a two-decade hiatus.

Conventional hydroelectric generating capacity accounted for 7.8 percent of total capacity with a summer net generating capacity of 77,885 MW. Pumped storage hydroelectric generating capacity totaled 21,886 MW. Combined, conventional and pumped storage generating capacity accounted for 10.0 percent of total capacity. Like coal and nuclear, hydroelectric generating capacity has remained relatively unchanged over the last 10 years.

The year 2007 was the fourth year in which EIA has collected data on distributed and dispersed generating facilities. In 2004, 9,579 MW of dispersed and distributed generators were reported. By year-end 2007, the amount of dispersed and distributed generators has increased to 20,999 MW.[6] Of this total, 59.1 percent is internal combustion capacity. While internal combustion capacity is the predominant form of dispersed and distributed generating capacity, wind capacity has grown significantly. In 2004, there were 0.1 MW of dispersed and distributed wind capacity. As of 2007, there is 1,462 MW.

As of December 31, 2007, reported planned additions scheduled to start commercial operation between 2008 and 2012 have total nameplate capacity of 92,996 MW. This compares with 87,109 MW of planned capacity reported on December 31, 2006, for the 5-year period through 2011. The data also show that over the next two years there will be a significant increase in planned additions relative to the past 2 years, if additions are completed as planned. In 2006 and 2007, the industry added 28,381 MW of nameplate capacity. Planned capacity additions projected to be placed in service during calendar years 2008 and 2009 total 44,701 MW. Given the recent turmoil in financial markets, which has affected both the cost and access to capital, and slowdown in economic activity, it is likely that some of this capacity will be deferred. The data also reveal a shift in the fuel mix. New coal-fired and renewable energy sources are projected to play a more significant role over the next 5 years. The industry reports that it is planning to add 23,347 MW of coal-fired capacity over the next 5 years. In terms of net summer capacity, planned coal-fired additions account for 25.7 percent of planned additions over the next 5 years, which is an amount equivalent to 6.9 percent of existing coal-fired capacity. Renewable energy sources, excluding hydroelectric, are 19.5 percent of planned new net summer capacity. Natural gas-fired capacity is projected to be the dominant primary fuel for electricity generation with planned additions totaling 48,100 MW, or 51.7 percent of all planned additions for the 5-year period.

As expected, nuclear and coal-fired generation have the highest average capacity factors at 91.8 percent and 73.6 percent, respectively (Figure ES3). This is consistent with the economies of scale that these forms of capital intensive and energy efficient generation provide to serve energy requirements. Accordingly, coal and nuclear capacity serve baseload energy requirements, which are reflected by higher average capacity factors relative to other forms of generation. The average capacity factor for coal-fired generation reflects a one percentage point increase over the 72.6 percent average capacity factor achieved in 2006. The average capacity factor for nuclear generation increased from 89.6 percent to 91.8 percent. This compares to the 89.7 percent average over the past five years and the low of 72.0 percent that occurred in 1997. Because the industry continues to rely on new combined cycle natural gas generation to meet rising demand, average capacity factors for natural gas generation have been calculated for both combined cycle generation and simple cycle natural gas generation.[7] In 2007, the capacity factor for combined cycle generating capacity factor was 42.0 percent. In 2003, the average capacity factor for combined cycle generation was 33.5 percent. The 8.5 percentage point improvement in the average capacity factor reflects both the increased reliance on combined cycle generation to meet energy requirements and further efficiency gains in combined cycle generation technology. In 2007 the average capacity factor for simple cycle natural gas-fired generation was 11.4 percent.

The more recent emphasis placed on wind capacity, which is not a dispatchable resource, is reflected in the reduced performance of renewable resources in aggregate as measured by a composite capacity factor. Renewable generation other than hydroelectric had a 40.0 percent capacity factor in 2007. In 1999, the average capacity factor for other renewable generation was 56.9 percent. The continuous decline in the average capacity factor for all non-hydroelectric

[6] Dispersed and distribute generators are commercial and industrial generators. Dispersed generators are not connected to the grid. Distributed generators are connected to the grid. Both types of generators may be installed at or near a customer's site, or at other locations, and both types of generators may be owned by either the customers of the distribution utility or by the utility. This data is collected at the distribution utility level on the Form EIA-861.

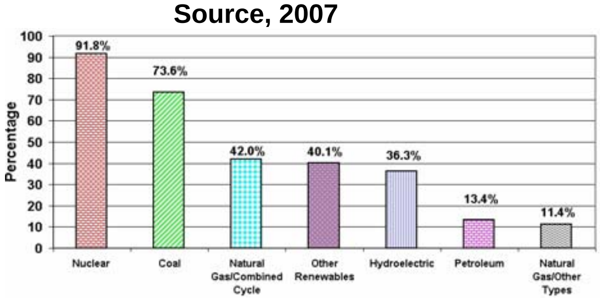
[7] The data required to average capacity factors for combined cycle and simple cycle natural gas-fired generation was obtained from plant-specific capacity and energy data from the Form EIA-860, Form EIA-906 and Form EIA-920.

renewable resources is consistent with the significant growth of wind capacity relative to other forms of renewable electricity generation. Wind is a non-dispatchable resource that is available for generation subject to prevailing wind conditions. It is expected to have a lower capacity factor relative to solid and liquid biomass generating capacity (e.g., landfill gas, municipal solid waste, black liquor and wood waste solids), which have greater continuity in the receipt of primary fuel supply for electricity generation. The primary factor limiting the capacity factor of biomass generating capacity is its position in the economic dispatch order relative to load.

Wind generating capacity exceeds all forms of non-hydroelectric renewable energy sources. In 2007, wind capacity accounted for 16,515 MW of net summer capacity. Wood and wood derived fuels contributed the second largest share of renewable capacity at 6,704 MW. The growth of this source of renewable energy has fluctuated between net increases and decreases in capacity over time. Since 1996, the amount of wood and wood derived fuels capacity has fallen by 104 MW. Wind generating capacity is the fastest growing renewable energy source. In 2007, 5,186 MW of new capacity was placed in service increasing total wind capacity to 16,515 MW. New wind capacity accounted for 87.1 percent of the 5,956 MW of total renewable capacity (other than conventional hydroelectric capacity) placed in service in 2007. As a result the average capacity factor for renewable energy declined as expected.

Conventional hydroelectric generation had an average capacity factor of 36.3 percent in 2007 as compared to 42.4 percent in 2006. The decline in conventional hydroelectric generation is a result of drought conditions in the Southeast, Rocky Mountains and West.

Figure ES 3. Average Capacity Factor by Energy Source, 2007



Sources: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report;" Form EIA-923, "Power Plant Operations Report."

Fuel Switching Capacity

The total amount of net summer capacity reporting natural gas as the primary fuel in 2007 was 392,876 MW, of which 123,862 MW (31.5 percent) reported a current operational capability to switch to fuel oil as an alternative fuel. This means that the capacity had in working order all necessary equipment, including fuel storage, to switch from gas to petroleum-fired operation. However, most of this capacity is subject to environmental regulatory limits on the use of oil, such as restrictions on how many hours per year a unit is allowed to burn oil. Of the 123.862 MW of gas-fired capacity that reported the ability to switch to oil, only 39,817 MW (32.1 percent) reported no environmental regulatory constraints or other factors that would limit oil-fired operations.

"Switchable" capacity is spread across the major generating technologies. Combustion turbine peaking units account for 43.7 percent (54,135 MW) of this capacity. Steam-electric generators (33,553 MW) and combined cycle units (35,270 MW) account for 27.1 percent and 28.4 percent, respectively. Internal combustion engines make up the remaining 0.7 percent. When running on fuel oil the net summer capability of the 33,553 MW of steam-electric generating capacity is 18,245 MW. The 54,135 MW of gas turbine capacity has an achievable net summer capacity of 15,358 MW when running on oil.

Over time, the achievable net summer capacity for natural-gas fired capacity when run on fuel oil has declined. Through 1974, the net achievable summer capacity for gas-fired capacity running on oil was 51.6 percent of all switchable natural gas-fired capacity. This ratio has gradually declined to 32.1 percent by the end of 2007.

Interconnection Costs

During 2007, 269 generators representing a total nameplate capacity of 14,061 MW were connected for the first time to the electric grid. The interconnection costs are presented by producer type (Table 2.12) and by distribution, subtransmission and transmission voltage class (Table 2.13). Total cost for individual generator interconnection varies based on its components. The components of the total cost may vary based on whether or not an interconnection infrastructure was already in place, and the type of equipment for which costs were incurred, along with other factors associated with the generator technology. Though the amount of capacity connected to the grid was about the same for both independent power producers (IPP) and electric utilities, the total cost for the IPP sector was significantly greater due in part to the interconnection of several large wind plants. Typically sited in relatively remote locations, wind plants usually require the construction of longer transmission line extensions to the plant sites than might be required for conventional power plants.

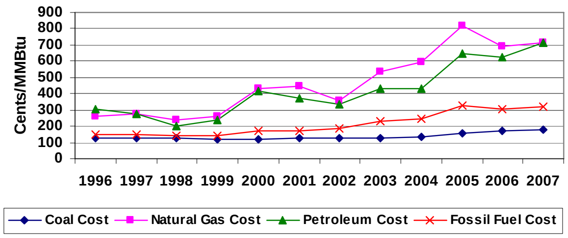
Fuel Costs

The 2007 average delivered cost for all fossil fuels used at electric power plants (coal, petroleum, and natural gas combined) for electricity generation was \$3.23 per million British thermal units (MMBtu) (Figure ES4) as compared to \$3.02 per MMBtu in 2006, an increase of 6.9 percent. Between 2003 and 2007, the average cost of all fossil fuels has increased 41.7 percent. The price of all fossil fuels increased in 2007. The cost of natural gas at electric power plants in 2007 increased 2.4 percent to \$7.11 per MMBtu. Since 2002, natural gas prices have increased 99.7 percent, with more than half of the total increase occurring between 2002 and 2003.

The cost of petroleum increased 15.1 percent, from \$6.23 per MMBtu in 2006 to \$7.17 MMBtu in 2007. This increase was caused by increased global demand for petroleum and tight supply. Petroleum-fired generation increased in spite of the significant increase in petroleum prices. This appears to be the result of petroleum capacity being used partially to offset the decline in conventional hydroelectric generation.

The 2007 delivered cost of coal increased 4.7 percent, from \$1.69 per MMBtu in 2006 to \$1.77 MMBtu in 2007. This marked the seventh straight year that coal prices have increased. Since 2000 the delivered cost of coal has increased 47.5 percent (Figure ES4).

Figure ES 4. Fuel Costs for Electricity Generation, 1996- 2007



Sources: Energy Information Administration, Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report," Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," "Annual Electric Generator Report;" Form EIA-923, "Power Plant Operations Report."

Emissions

The estimated carbon dioxide, sulfur dioxide and nitrogen oxide emissions for electricity are based on the fossil fuels consumed by electric power plants for electric power generation, and fossil fuels consumed by combined heat and power plants for the generation of electric power and useful thermal output. The emissions factors used in the estimation methodology are described in the discussion of Air Emissions in the Technical Notes, and are summarized in Tables A1, A2, and A3.

Estimated carbon dioxide emissions by U.S. electric generators and combined heat and power facilities increased by 2.3 percent from 2006 to 2007 (from 2,460 million metric tons to 2,517 million metric tons). This reverses the decline in carbon dioxide emissions reported for 2006. Total net generation of electricity from fossil fuels increased to meet the increase in demand in 2007. Coal-fired generation increased 1.3 percent and coal consumed for electric generation and by combined heat and power facilities increased by 1.5 percent. Petroleum-fired generation increased 2.5 percent and the petroleum consumed for electric generation and useful thermal output increased 1.1 percent from 131 million barrels in 2006 to 132 million barrels in 2007. Consumption of natural gas for electricity generation and useful thermal output, which contributes the least amount of carbon dioxide per Btu consumed, rose by 7.5 percent in 2007 as natural gas generation increased by 10.1 percent.

Estimated emissions of nitrogen oxides and sulfur dioxide continued to decline in 2007. Nitrogen oxides emissions dropped by 3.9 percent (from 3.799 to 3.650 million metric tons). Sulfur dioxide emissions decreased by 5.1 percent (from 9.524 to 9.042 million metric tons). Emissions of both of these gases are capped by the Clean Air Act and other legislation.

Trade

Total wholesale purchases of electric power in the United States declined in 2007 for the fourth straight year to 5,411 million MWh, a 1.7 percent reduction. Almost half the volume of wholesale sales is provided by energy-only providers, or power marketing companies, a class of electric entities, authorized by FERC to transact at market based rates, that came into being during the late 1990s with the deregulation of the wholesale power markets. In 2007, wholesale sales by wholesale power marketers and retail energy service providers increased from 2,446 million MWh in 2006 to 2,477 MWh, which represented 45.2 percent of the wholesale market. This is the first increase in market share for these entities since 2002 when they accounted for 67.2 percent of all wholesale sales. Independent power producers and combined heat and power (CHP) plants accounted for 25.5 percent of wholesale sales in 2007 compared to 24.6 percent in 2006.

The Nation's only international trade in electric power is with Canada and Mexico, and nearly all the trade is conducted with Canada. Most Mexican electric power trade is done with the State of California, while transactions with Canada are conducted through several large transmission corridors located in the Pacific Northwest, the Northern Plains, and New England. Much of the electricity provided from Canada is hydroelectric generation available for sale because of heavy seasonal river flows.

Total international net imports of electric power in 2007 increased 69.7 percent, from 18.4 million MWh in 2006 to 31.3 million MWh. Overall, total U.S. imports increased 8.7 million MWh in 2007 from 42.7 million MWh in 2006 to 51.4 million MWh, while exports declined by 4.1 million MWh. Imports from Canada increased from 41.5 million MWh in 2006 to 50.1 million MWh in 2007, and U.S. exports decreased from 23.4 million MWh to 19.6 million MWh. Electricity trade with Mexico followed a similar pattern of net imports, increasing relative to 2006 as a result of a decline in exports and an increase in imports. Net imports more than doubled, from 0.3 million MWh in 2006 to 0.7 million MWh in 2007.

Revenue and Expense Statistics

In 2007, major investor-owned electric utility operating revenues (from sales to ultimate customers, sales for resale, and other electric income) were $283 billion, a 2.1 percent increase from 2006. Operating expenses in 2007 stayed in line with revenue growth, also increasing 2.0 percent, to $252 billion. Net utility operating income in 2007 was $30.7 billion, a slight increase over the $30.0 billion realized in 2006.

In 2007, major investor-owned electric utility purchased power costs, which accounted for roughly 30 percent of total utility operating expenses, fell 1.7 percent as compared to the 1.5 percent increase realized in 2006. Fuel costs increased 10.5 percent in 2007. Transmission expenses were $6.1 billion in 2007 as compared to $6.2 billion in 2006. This modest decrease stands in contrast to the average 21.2 percent annual increase between 2001 and 2006. Distribution expenses increased 5.8 percent, more than twice the average annual increase incurred between 2001 and 2006.

Electricity Prices and Sales

In 2007, the average retail price for all customers rose 0.2 cents to 9.1 cents per kWh. This amounted to a 2.6 percent increase over the 8.9 cents per kWh average retail price paid in 2006. Year-over-year, the average retail price for all customers served increased in 40 of the 50 States. The average price of electricity increased by 10 percent or more in 5 States. In another 11 States, the average price for all customers declined within a 0.2 percent to 6.1 percent range. The average price of electricity to all customers increased in all regions of the country, with the exception of the West South Central Census Division. Within the four States of the West South Central Census Division, average electric prices declined by 1.6 percent. In Arkansas the average retail rate for all customers declined by 0.4 percent. In Oklahoma the average price declined by 0.2 percent and in Texas it declined by 2.3 percent. In Louisiana, the average electricity price for all customers increased by 1.0 percent. The East North Central Census Division experienced the largest increase in average retail prices for all customers at 6.9 percent. The New England and East South Central Census Divisions had the next largest average retail price increases over 2006, at 4.0 percent and 3.4 percent, respectively. The lowest regional price increase was in the Pacific Contiguous Census

Division, where the average price to all customers increased 0.8 percent over 2006.

Residential prices increased to 10.7 cents per kWh, or 2.4 percent, between 2006 and 2007. The average residential price increased by 10 percent or more in 6 States and the District of Columbia. These jurisdictions implemented retail competition and all of the investor-owned utilities operating within them participate in organized, competitive wholesale markets operated by independent system operators. The average residential price in Maryland increased 22.4 percent, from 9.7 cents per kWh in 2006 to 11.9 cents per kWh in 2007. This was the largest average increase in the Nation. It was caused by the transition to market based rates for the wholesale electricity portion of retail electric service. In order to mitigate the impact of higher retail prices, the Maryland Public Service Commission approved a plan for the largest investor-owned utility in the state that gave customers two payment options. The first option provided for retail prices based on the full market price of wholesale electricity prices, effective June 1, 2007. This option resulted in approximately a 50 percent increase in the average electric bill. The second option provided that the cost of wholesale electricity would be phased in over the 6 month period ending January 1, 2008. Deferred costs would be recovered by December 31, 2009.[8]

After Maryland, Illinois had the next largest increase in residential prices at 20.1 percent, followed by Maine (19.7 percent), Connecticut (13.4 percent), the District of Columbia (12.9 percent), Delaware (11.1 percent) and New Jersey (10.1 percent). On a regional basis, the highest average residential price increase was observed in the East North Central Division. This was primarily driven by Illinois, where the average residential price increase was nearly 4 times the average of the region overall. Like Maryland, the price increase in Illinois was the result of the termination of rate caps that had been put in place in 1997 as part of the transition to retail competition. Average residential prices in the New England and Mid-Atlantic Census Divisions increased 4.5 percent. Average residential prices fell by 2.9 percent in the West South Central Census Division, the only region to see a year-over-year decline in average residential prices. Texas out-paced the region with a 4.0 percent decline from 12.9 cents per kWh in 2006 to 12.3 cents per kWh in 2007.

A number of these States have taken legislative action in response to significant rate increases caused by a combination of rising fuel prices and the termination of rate caps imposed during the transition to retail competition. In Illinois average residential prices increased by 20.1 percent. The large average price increases for all customer groups in Illinois reflects the January 2, 2007 termination of the 10-year rate freeze that was imposed on the State's investor-owned utilities as part of its 1997 electric industry restructuring legislation. The termination of the rate freeze caused large rate increases primarily for residential and certain non-residential customers that did not select alternative energy suppliers and remained customers of the State's largest investor-owned utilities under standard offer service rate schedules. On August 28, 2007, Illinois Senate Bill 1592 was signed into law, which provided approximately $1 billion in refunds, eliminated the auction process under which the Illinois investor-owned utilities purchased wholesale power to supply standard offer service, and created the Illinois Power Agency as the entity responsible for energy procurement.[9]

Average commercial prices increased from 9.5 to 9.7 cents per kWh, a 2.0 percent increase over 2006. The largest regional price increase was in the East North Central Census Division at 4.2 percent. Average commercial prices in Illinois increased 7.8 percent, from 7.9 cents per kWh to 8.6 cents per kWh. Wisconsin had the second highest rate increase in the region at 4.0 percent. The average commercial rate in the West South Central Census Division was unchanged at 9.3 cents per kWh. The average commercial price declined by slightly less than 1 percent in Arkansas and Oklahoma, while increasing by 0.2 percent in Texas and 1.2 percent in Louisiana. In the Pacific Contiguous Census Division the average commercial price declined from 11.2 cents per kWh in 2006 to 11.0 cents per kWh in 2007. It was the only region in which average commercial rates declined. Oregon was the only the State within the region where rates increased, rising from 6.8 cents per kWh to 7.2 cents per kWh.

Average industrial prices increased 4 percent from 6.2 cents per kWh in 2006 to 6.4 cents per kWh in 2007.

Total retail sales of electricity in 2007 were 3,764 million MWh. Annual growth in electricity sales in 2007 was 2.6 percent, exceeding the 1.8 percent year average annual growth rate since 1996. Sales to the residential sector increased by 3.0 percent from 2006 to 2007. Sales to the commercial sector increased by 2.8 percent, and industrial sales increased 1.6 percent. Since 1997, annual industrial sales declined in three years. Otherwise, with the exception of 2003 when

[8] *In the Matter of Baltimore Gas and Electric Company's Proposal to Implement a Rate Stabilization Plan Pursuant to Section 7-548 of the Public Utility companies Article and the Commission's Inquiry into Factors Impacting Wholesale Electricity Prices,* Maryland Public Service Commission, Order No. 81423. Case No. 9099, May 23, 2007.

[9] Illinois General Assembly, Public Act 095-0481, effective August 28, 2007.

industrial sales increased 2.2 percent, they have increased annually by less than one percent. Thus, while the increase in industrial sales in 2007 showed significant improvement over prior years, the faster growth of residential and commercial sales in 2007 provides for the continuation of the gradual shift of total load away from the industrial sector. The industrial sector accounted for 33.0 percent of total retail sales in 1997. By 2007 it has declined to 27.3 percent. Between 1997 and 2007, the commercial sector share of retail sales increased from 29.5 percent to 35.5 percent. Over the same period, the residential sector has grown from 34.2 percent of total retail sales to 37.0 percent.

In the last few years, some States have encouraged utilities to adopt customer service programs which respond to growing concerns about the environment, electricity reliability, and the rising cost of providing electricity. Green pricing programs allow consumers to purchase electricity generated from wind and other renewable sources and pay for renewable energy development. In 2007, 835,651 retail consumers were reported to be purchasing electricity under green pricing programs. Residential consumers accounted for 773,391 or 92.5 percent of the total number of green pricing consumers. All of the States, with the exception of Louisiana, reported providing electric service under green pricing programs in 2007. Retail consumers in Texas accounted for 17.0 percent of all green pricing consumers nationwide. Oregon was ranked second with 12.0 percent of all green pricing consumers Nationwide. The top 5 States were rounded out by California (7.0 percent) and Colorado (6.9 percent) and Maryland (6.7 percent). Together, retail consumers in these 5 States accounted for 49.6 of consumers purchasing green power and 56.0 percent of green power sales volumes Nationwide.

Net metering programs allow consumers with onsite generators to send excess generation to the grid and to receive credit for that energy on their bill. The number of customers in these programs has been steadily increasing. In 2002 there were 4,472 customers in net metering programs; in 2007 there were nearly 48,820 customers participating in net metering programs. These customers were dispersed across 47 States and the District of Columbia. California leads the Nation in net metering, with 34,910 customers reported as participating. These customers accounted for 71.5 percent of all customers participating in such programs.

Demand-Side Management

In 2007, electricity providers reported total peak-load reductions of 30,276 MW resulting from demand-side management (DSM) programs, an 11.1 percent increase from the amount reported in 2006. Reported DSM costs increased to $2.5 billion, up 23.2 percent from the $2.1 billion reported in 2006. DSM costs can vary significantly from year to year because of business cycle fluctuations and regulatory changes. Since costs are reported as they occur, while program effects may appear in future years, DSM costs and effects may not always show a direct relationship. Since 2003, nominal DSM expenditures have increased at 18.1 percent average annual growth rate. During the same period, actual peak load reductions have grown at a 7.2 percent average annual rate from, 22,904 MW to 30,276 MW. The divergence between the growth rates of load reduction and expenditures is driven in large measure by 2007 expenditures, which are in response to higher overall energy prices. The full effect of these expenditures may appear in additional load reductions in the coming years. The combined DSM energy savings programs (i.e., load management and energy efficiency) increased to 69.1 million MWh in 2007 from 63.8 MWh.

Table ES1. Summary Statistics for the United States, 1996 through 2007

Description	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
Net Generation (thousand megawatthours)												
Coal[1]	2,016,456	1,990,511[R]	2,012,873[R]	1,978,301[R]	1,973,737	1,933,130	1,903,956	1,966,265	1,881,087	1,873,516	1,845,016	1,795,196
Petroleum[2]	65,739	64,166[R]	122,225[R]	121,145[R]	119,406	94,567	124,880	111,221	118,061	128,800	92,555	81,411
Natural Gas	896,590	816,441[R]	760,960[R]	710,100[R]	649,908	691,006	639,129	601,038	556,396	531,257	479,399	455,056
Other Gases[3]	13,453	14,177[R]	13,464[R]	15,252[R]	15,600	11,463	9,039	13,955	14,126	13,492	13,351	14,356
Nuclear	806,425	787,219	781,986	788,528	763,733	780,064	768,826	753,893	728,254	673,702	628,644	674,729
Hydroelectric Conventional[4]	247,510	289,246	270,321	268,417	275,806	264,329	216,961	275,573	319,536	323,336	356,453	347,162
Other Renewables[5]	105,238	96,525[R]	87,329[R]	83,067[R]	79,487	79,109	70,769	80,906	79,423	77,088	77,183	75,796
Wind	34,450	26,589	17,811	14,144	11,187	10,354	6,737	5,593	4,488	3,026	3,288	3,234
Solar Thermal and Photovoltaic	612	508	550	575	534	555	543	493	495	502	511	521
Wood and Wood Derived Fuels[6]	39,014	38,762[R]	38,856[R]	38,117[R]	37,529	38,665	35,200	37,595	37,041	36,338	36,948	36,800
Geothermal	14,637	14,568	14,692	14,811	14,424	14,491	13,741	14,093	14,827	14,774	14,726	14,329
Other Biomass[7]	16,525	16,099	15,420	15,421	15,812	15,044	14,548	23,131	22,572	22,448	21,709	20,911
Pumped Storage[8]	-6,896	-6,558	-6,558	-8,488	-8,535	-8,743	-8,823	-5,539	-6,097	-4,467	-4,040	-3,088
Other[9]	12,231	12,974[R]	12,821[R]	14,232[R]	14,045	13,527	11,906	4,794	4,024	3,571	3,612	3,571
All Energy Sources	**4,156,745**	**4,064,702**	**4,055,423**	**3,970,555**	**3,883,185**	**3,858,452**	**3,736,644**	**3,802,105**	**3,694,810**	**3,620,295**	**3,492,172**	**3,444,188**
Net Summer Generating Capacity (megawatts)												
Coal[1]	312,738	312,956	313,380	313,020	313,019	315,350	314,230	315,114	315,496	315,786	313,624	313,382
Petroleum[2]	56,068	58,097	58,548	59,119	60,730	59,651	66,162	61,837	60,069	66,282	72,463	72,518
Natural Gas[10]	392,876	388,294	383,061	371,011	355,442	312,512	252,832	219,590	195,119	180,288	176,471	174,135
Other Gases[3]	2,313	2,256	2,063	2,296	1,994	2,008	1,670	2,342	1,909	1,520	1,525	1,664
Nuclear	100,266	100,334	99,988	99,628	99,209	98,657	98,159	97,860	97,411	97,070	99,716	100,784
Hydroelectric Conventional[4]	77,885	77,821	77,541	77,641	78,694	79,356	78,916	79,359	79,393	79,151	79,415	76,437
Other Renewables[5]	30,069	24,113	21,205	18,717	18,153	16,710	16,101	15,572	15,942	15,444	15,351	15,309
Wind	16,515	11,329	8,706	6,456	5,995	4,417	3,864	2,377	2,252	1,720	1,610	1,678
Solar Thermal and Photovoltaic	502	411	411	398	397	397	392	386	389	335	334	333
Wood and Wood Derived Fuels[11]	6,704	6,372	6,193	6,182	5,871	5,844	5,882	6,147	6,795	6,802	6,924	6,808
Geothermal	2,214	2,274	2,285	2,152	2,133	2,252	2,216	2,793	2,846	2,893	2,893	2,893
Other Biomass[7]	4,134	3,727	3,609	3,529	3,758	3,800	3,748	3,869	3,660	3,694	3,590	3,598
Pumped Storage[12]	21,886	21,461	21,347	20,764	20,522	20,371	19,664	19,522	19,565	19,518	19,310	21,110
Other[13]	788	882	887	746	684	686	519	523	1,023	810	774	550
All Energy Sources	**994,888**	**986,215**	**978,020**	**962,942**	**948,446**	**905,301**	**848,254**	**811,719**	**785,927**	**775,868**	**778,649**	**775,890**
Demand, Capacity Resources, and Capacity Margins – Summer												
Net Internal Demand (megawatts)	764,476	760,108	746,470	692,908	696,752	696,376	674,833	680,941	653,857	638,086	618,389	602,438
Capacity Resources (megawatts)	915,292	906,155	882,125	875,870	856,131	833,380	788,990	808,054	765,744	744,670	737,855	730,376
Capacity Margins (percent)	16.5	16.1	15.4	20.9	18.6	16.4	14.5	15.7	14.6	14.3	16.2	17.5
Fuel												
Consumption of Fossil Fuels for Electricity Generation												
Coal (thousand tons)[1]	1,046,795	1,030,556[R]	1,041,448[R]	1,020,523[R]	1,014,058	987,583	972,691	994,933	949,802	946,295	931,949	907,209
Petroleum (thousand barrels)[2]	112,615	110,634[R]	206,785[R]	203,494[R]	206,653	168,597	216,672	195,228	207,871	222,640	159,715	144,626
Natural Gas (millions of cubic feet)	7,089,342	6,461,615[R]	6,036,370[R]	5,674,580[R]	5,616,135	6,126,062	5,832,305	5,691,481	5,321,984	5,081,384	4,564,770	4,312,458
Other Gases (millions of Btu)[3]	114,904	114,665[R]	109,916[R]	135,144[R]	156,306	131,230	97,308	125,971	126,387	124,988	119,412	158,560
Consumption of Fossil Fuels for Thermal Output in Combined Heat and Power Facilities												
Coal (thousand tons)[1]	22,810	23,227[R]	23,833[R]	24,275[R]	17,720	17,561	18,944	20,466	20,373	20,320	21,005	20,806
Petroleum (thousand barrels)[2]	19,775	20,371[R]	24,408[R]	25,870[R]	17,939	14,811	18,268	22,266	26,822	28,845	28,802	27,873
Natural Gas (millions of cubic feet)	872,579	942,817[R]	984,340[R]	1,052,100[R]	721,267	860,019	898,286	985,263	982,958	949,106	868,569	865,774
Other Gases (millions of Btu)[3]	214,321	226,464[R]	238,396[R]	218,295[R]	137,837	146,882	166,161	230,082	223,713	208,828	187,680	187,290
Consumption of Fossil Fuels for Electricity Generation and Useful Thermal Output												
Coal (thousand tons)[1]	1,069,606	1,053,783	1,065,281	1,044,798	1,031,778	1,005,144	991,635	1,015,398	970,175	966,615	952,955	928,015
Petroleum (thousand barrels)[2]	132,389	131,005	231,193	229,364	224,593	183,408	234,940	217,494	234,694	251,486	188,517	172,499
Natural Gas (millions of cubic feet)	7,961,922	7,404,432[R]	7,020,709[R]	6,726,679	6,337,402	6,986,081	6,730,591	6,676,744	6,304,942	6,030,490	5,433,338	5,178,232
Other Gases (millions of Btu)[3]	329,225	341,129	348,312	353,438[R]	294,143	278,111	263,469	356,053	350,100	333,816	307,092	345,850
Stocks at Electric Power Sector Facilities (year end)												
Coal (thousand tons)[14]	151,221	140,964	101,137	106,669	121,567	141,714	138,496	102,296	141,604	120,501	98,826	114,623
Petroleum (thousand barrels)[15]	47,203	51,583	50,062	51,434	53,170	52,490	57,031	40,932	54,109	56,591	51,138	48,146
Receipts of Fuel at Electricity Generators[16]												
Coal (thousand tons)[1]	1,054,664	1,079,943	1,021,437	1,002,032	986,026	884,287	762,815	790,274	908,232	929,448	880,588	862,701
Petroleum (thousand barrels)[2]	88,347	100,965	194,733	186,655	185,567	120,851	124,618	108,272	145,939	181,276	128,749	113,678
Natural Gas (millions of cubic feet)[17]	7,200,316	6,675,246	6,181,717	5,734,054	5,500,704	5,607,737	2,148,924	2,629,986	2,809,455	2,922,957	2,764,734	2,604,663
Cost of Fuel at Electricity Generators (cents per million Btu)[16]												
Coal[1]	177	169	154	136	128	125	123	120	122	125	127	129
Petroleum[2]	717	623	644	429	433	334	369	418	236	202	273	303
Natural Gas[17]	711	694	821	596	539	356	449	430	257	238	276	264
Emissions (thousand metric tons)												
Carbon Dioxide (CO_2)	2,516,580	2,459,800	2,513,609	2,456,934	2,415,680	2,395,048	2,389,745	2,441,722	2,338,660	2,324,139	2,232,709	2,161,258
Sulfur Dioxide (SO_2)	9,042	9,524	10,340	10,309	10,646	10,881	11,174	11,963[R]	12,843[R]	13,464[R]	13,480[R]	12,991[R]
Nitrogen Oxides (NO_X)	3,650	3,799	3,961	4,143	4,532	5,194	5,290	5,638[R]	5,955[R]	6,459[R]	6,500[R]	6,474[R]

See end of table for Notes and Sources.

Table ES1. Summary Statistics for the United States, 1996 through 2007 (Continued)

Description	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
Trade (million megawatthours)												
Purchases	5,411	5,503	6,092	6,999[R]	6,980	8,755	7,555	2,346	2,040	2,021	1,966	1,798
Sales for Resale	5,479	5,493	6,072	6,759[R]	6,921	8,569	7,345	2,355	1,998	1,922	1,839	1,656
Electricity Imports and Exports (thousand megawatthours)												
Imports	51,396	42,691	44,527[R]	34,210	30,395[R]	36,779	38,500	48,592	43,215	39,513	43,031	43,497
Exports	20,144	24,271	19,791[R]	22,898	23,975[R]	15,796	16,473	14,829	14,222	13,656	8,974	3,302
Retail Sales and Revenue Data – Bundled and Unbundled												
Number of Ultimate Customers (thousands)												
Residential	123,950	122,471	120,761	118,764	117,280	116,622	114,890	111,718	110,383	109,048	107,066	105,343
Commercial	17,377	17,172	16,872	16,607	16,550	15,334	14,867	14,349	14,074	13,887	13,542	13,181
Industrial	794	760	734	748	713	602	571	527	553	540	563	586
Transportation	1	1	1	1	1	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	1,067	1,030	974	935	933	952	894
All Sectors	142,122	140,404	138,367	136,119	134,544	133,624	131,359	127,568	125,945	124,408	122,123	120,004
Sales to Ultimate Customers (thousand megawatthours)												
Residential	1,392,241	1,351,520	1,359,227	1,291,982	1,275,824	1,265,180	1,201,607	1,192,446	1,144,923	1,130,109	1,075,880	1,082,512
Commercial	1,336,315	1,299,744	1,275,079	1,230,425	1,198,728	1,104,497	1,083,069	1,055,232	1,001,996	979,401	928,633	887,445
Industrial	1,027,832	1,011,298	1,019,156	1,017,850	1,012,373	990,238	996,609	1,064,239	1,058,217	1,051,203	1,038,197	1,033,631
Transportation	8,173	7,358	7,506	7,224	6,810	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	105,552	113,174	109,496	106,952	103,518	102,901	97,539
All Sectors	3,764,561	3,669,919	3,660,969	3,547,479	3,493,734	3,465,466	3,394,458	3,421,414	3,312,087	3,264,231	3,145,610	3,101,127
Direct Use[18]	159,254	146,927	150,016	168,470	168,295	166,184	162,649	170,943	171,629	160,866	156,239	152,638
Total Disposition	3,923,814	3,816,845	3,810,984	3,715,949	3,662,029	3,631,650	3,557,107	3,592,357	3,483,716	3,425,097	3,301,849	3,253,765
Revenue From Ultimate Customers (million dollars)												
Residential	148,295	140,582	128,393	115,577	111,249	106,834	103,158	98,209	93,483	93,360	90,704	90,503
Commercial	128,903	122,914	110,522	100,546	96,263	87,117	85,741	78,405	72,771	72,575	70,497	67,829
Industrial	65,712	62,308	58,445	53,477	51,741	48,336	50,293	49,369	46,846	47,050	47,023	47,536
Transportation	792	702	643	519	514	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	7,124	8,151	7,179	6,796	6,863	7,110	6,741
All Sectors	343,703	326,506	298,003	270,119	259,767	249,411	247,343	233,163	219,896	219,848	215,334	212,609
Average Retail Price (cents per kilowatthour)												
Residential	10.65	10.40	9.45	8.95	8.72	8.44	8.58	8.24	8.16	8.26	8.43	8.36
Commercial	9.65	9.46	8.67	8.17	8.03	7.89	7.92	7.43	7.26	7.41	7.59	7.64
Industrial	6.39	6.16	5.73	5.25	5.11	4.88	5.05	4.64	4.43	4.48	4.53	4.60
Transportation	9.70	9.54	8.57	7.18	7.54	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	6.75	7.20	6.56	6.35	6.63	6.91	6.91
All Sectors	9.13	8.90	8.14	7.61	7.44	7.20	7.29	6.81	6.64	6.74	6.85	6.86
Revenue and Expense Statistics (million dollars)												
Major Investor Owned												
Utility Operating Revenues	282,875	277,142	267,534	240,318	226,227	219,389	267,525	235,336	214,160	218,175	215,083	207,459
Utility Operating Expenses	252,216	247,170	238,590	207,161	197,459	188,745	235,198	210,324	182,258	186,498	182,796	173,920
Net Utility Operating Income	30,659	29,972	28,944	33,158	28,768	30,644	32,327	25,012	31,902	31,677	32,286	33,539
Major Publicly Owned (with Generation Facilities)												
Operating Revenues	NA	NA	NA	NA	33,906	32,776	38,028	31,843	26,767	26,155	25,397	24,207
Operating Expenses	NA	NA	NA	NA	29,637	28,638	32,789	26,244	21,274	20,880	20,425	19,084
Net Electric Operating Income	NA	NA	NA	NA	4,268	4,138	5,238	5,598	5,493	5,275	4,972	5,123
Major Publicly Owned (without Generation Facilities)												
Operating Revenues	NA	NA	NA	NA	12,454	11,546	10,417	9,904	9,354	8,790	8,586	8,582
Operating Expenses	NA	NA	NA	NA	11,481	10,703	9,820	9,355	8,737	8,245	8,033	8,123
Net Electric Operating Income	NA	NA	NA	NA	974	843	597	549	617	545	552	459
Major Federally Owned												
Operating Revenues	NA	NA	NA	NA	11,798	11,470	12,458	10,685	10,186	9,780	8,833	9,082
Operating Expenses	NA	NA	NA	NA	8,763	8,665	10,013	8,139	7,775	7,099	5,999	6,390
Net Electric Operating Income	NA	NA	NA	NA	3,035	2,805	2,445	2,546	2,411	2,681	2,834	2,692
Major Cooperative Borrower Owned												
Operating Revenues	38,208	36,723[R]	34,088	30,650	29,228	27,458	26,458	25,629	23,824	23,988	23,321	24,424
Operating Expenses	34,843	33,550[R]	31,209	27,828	26,361	24,561	23,763	22,982	21,283	21,223	20,715	23,149
Net Electric Operating Income	3,365	3,173[R]	2,879	2,822	2,867	2,897	2,696	2,647	2,541	2,764	2,606	1,274[R]
Demand-Side Management (DSM) Data												
Actual Peak Load Reductions (megawatts)												
Total Actual Peak Load Reduction	30,276	27,240	25,710	23,532	22,904	22,936	24,955	22,901	26,455	27,231	25,284	29,893
DSM Energy Savings (thousand megawatthours)												
Energy Efficiency	67,134	62,951	58,891	52,662	48,245	52,285	52,946	52,827	49,691	48,775	55,453	59,853
Load Management	1,937	865	1,006	2,047	2,020	1,790	990	875	872	392	953	1,989
DSM Cost (million dollars)												
Total Cost	2,527	2,051	1,921	1,557	1,297	1,626	1,630	1,565	1,424	1,421	1,636	1,902

[1] Includes anthracite, bituminous, subbituminous and lignite coal. Waste and synthetic coal are included starting in 2002.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology) and waste oil.
[3] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[4] Conventional hydroelectric power excluding pumped storage facilities.
[5] Other renewables represents the summation of the sub-categories of Wind, Solar Thermal and Photovoltaic, Wood and Wood Derived Fuels, Geothermal, and Other Biomass.
[6] Wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

[7] Biogenic municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).
[8] The generation from a hydroelectric pumped storage facility is the net value of production minus the energy used for pumping.
[9] Non-biogenic municipal solid waste, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.
[10] Includes a small number of generators for which waste heat is the primary energy source.
[11] Includes paper pellets, railroad ties, utility poles, wood chips, bark, black liquor and other wood waste solids and liquids.
[12] Pumped storage is the capacity to generate electricity from water previously pumped to an elevated reservoir and then released through a conduit to turbine generators located at a lower level.
[13] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.
[14] Anthracite, bituminous, subbituminous, lignite, and synthetic coal; excludes waste coal.
[15] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology). Data prior to 2004 includes small quantities of waste oil.
[16] Beginning in 2002, includes data from the Form EIA-423 for independent power producers and combined heat and power producers.
[17] Natural gas, including a small amount of supplemental gaseous fuels that cannot be identified separately.
[18] Direct Use represents commercial and industrial facility use of onsite net electricity generation; and electricity sales or transfers to adjacent or co-located facilities for which revenue information is not available.

NA = Not available.

R = Revised.

Note: ·See Glossary reference for definitions.·See Technical Notes Table A5 for conversion to different units of measure.·Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator.·Dual-fired capacity returned to respective fuel categories for current and all historical years. New fuel switchable capacity tables have replaced dual-fired breakouts.·Totals may not equal sum of components because of independent

Sources: Energy Information Administration Form EIA-411, "Coordinated Bulk Power Supply Program Report;" Form EIA-412, "Annual Electric Industry Financial Report" The Form EIA-412 was terminated in 2003; Form EIA-767, "Steam-Electric Plant Operation and Design Report was suspended;" Form EIA-860, "Annual Electric Generator Report;" Form EIA-861, "Annual Electric Power Industry Report;" Form EIA-923, "Power Plant Operations Report" replaces several form(s) including: Form EIA-906, "Power Plant Report;" Form EIA-920 "Combined Heat and Power Plant Report;" Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report; and FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," and their predecessor forms. Federal Regulatory Commission, FERC Form 1, "Annual Report of Major Utilities, Licensees and Others;" FERC Form 1-F, "Annual Report for Nonmajor Public Utilities and Licensees;" Rural Utility Services (RUS) Form 7, "Operating Report;" RUS Form 12, "Operating Report;" Imports and Exports: DOE, Office of Electricity Delivery and Energy Reliability, Form OE-781R, " Annual Report of International Electric Export/Import Data," predecessor forms, and National Energy Board of Canada. For 2001 forward, data from the California Independent System Operator are used in combination with the Form OE-781R values to estimate electricity trade with Mexico.

Table ES2. Supply and Disposition of Electricity, 1996 through 2007
(Million Megawatthours)

Category	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
Supply												
Generation												
Electric Utilities	2,504	2,484	2,475	2,505	2,462	2,549	2,630	3,015	3,174	3,212	3,123	3,077
Independent Power Producers	1,324	1,259	1,247	1,119	1,063	955	781	458	201	91	59	60
Combined Heat and Power, Electric	177	165	180	184	196	194	170	165	155	154	148	147
Electric Power Sector Generation Subtotal	4,005	3,908	3,902	3,808	3,721	3,698	3,580	3,638	3,530	3,457	3,329	3,284
Combined Heat and Power, Commercial	8	8	8	8	7	7	7	8	9	9	9	9
Combined Heat and Power, Industrial	143	148	145	154	155	153	149	157	156	154	154	151
Industrial and Commercial Generation Subtotal	151	157	153	162	162	160	157	165	165	163	163	160
Total Net Generation	4,157	4,065	4,055	3,971	3,883	3,858	3,737	3,802	3,695	3,620	3,492	3,444
Total Imports	51	43	45	34	30	37	39	49	43	40	43	43
Total Supply	**4,208**	**4,107**	**4,100**	**4,005**	**3,914**	**3,895**	**3,775**	**3,851**	**3,738**	**3,660**	**3,535**	**3,488**
Disposition												
Retail Sales												
Full-Service Providers	3,468	3,438	3,413	3,318	3,285	3,324	3,297	3,310	3,236	3,240	3,140	3,098
Energy-Only Providers	283	219	237	222	189	141	98	112	76	24	6	3
Facility Direct Retail Sales	14	12	11	8	20	NA	NA	NA	NA	NA	NA	NA
Total Electric Industry Retail Sales	3,765	3,670	3,661	3,547	3,494	3,465	3,394	3,421	3,312	3,264	3,146	3,101
Direct Use	159	147	150	168	168	166	163	171	172	161	156	153
Total Exports	20	24	20	23	24	16	16	15	14	14	9	3
Losses and Unaccounted For	264	266	269	266	228	248	202	244	240	221	224	231
Total Disposition	**4,208**	**4,107**	**4,100**	**4,005**	**3,914**	**3,895**	**3,775**	**3,851**	**3,738**	**3,660**	**3,535**	**3,488**

NA = Not available.

Notes: • Direct Use represents commercial and industrial facility use of onsite net electricity generation; electricity sales or transfers to adjacent or co-located facilities; and barter transactions. Losses and Unaccounted For includes: (1) reporting by utilities and power marketers that represent losses incurred in transmission and distribution, as well as volumes unaccounted for in their own energy balance; and (2) discrepancies among the differing categories upon balancing the table. • Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report;" Form EIA-861, "Annual Electric Power Industry Report;" and predecessor forms. Imports and Exports: Mexico data - DOE, Fossil Fuels, Office of Fuels Programs, Form FE-781R, "Annual Report of International Electrical Export/Import Data:" Canada data - National Energy Board of Canada (metered energy firm and interruptible).

Chapter 1. Generation and Useful Thermal Output

Table 1.1. Net Generation by Energy Source by Type of Producer, 1996 through 2007
(Thousand Megawatthours)

Period	Coal[1]	Petroleum [2]	Natural Gas	Other Gases[3]	Nuclear	Hydroelectric Conventional[4]	Other Renewables[5]	Hydroelectric Pumped Storage[6]	Other[7]	Total
Total (All Sectors)										
1996	1,795,196	81,411	455,056	14,356	674,729	347,162	75,796	-3,088	3,571	3,444,188
1997	1,845,016	92,555	479,399	13,351	628,644	356,453	77,183	-4,040	3,612	3,492,172
1998	1,873,516	128,800	531,257	13,492	673,702	323,336	77,088	-4,467	3,571	3,620,295
1999	1,881,087	118,061	556,396	14,126	728,254	319,536	79,423	-6,097	4,024	3,694,810
2000	1,966,265	111,221	601,038	13,955	753,893	275,573	80,906	-5,539	4,794	3,802,105
2001	1,903,956	124,880	639,129	9,039	768,826	216,961	70,769	-8,823	11,906	3,736,644
2002	1,933,130	94,567	691,006	11,463	780,064	264,329	79,109	-8,743	13,527	3,858,452
2003	1,973,737	119,406	649,908	15,600	763,733	275,806	79,487	-8,535	14,045	3,883,185
2004	1,978,301[R]	121,145[R]	710,100[R]	15,252[R]	788,528	268,417	83,067[R]	-8,488	14,232[R]	3,970,555
2005	2,012,873[R]	122,225[R]	760,960[R]	13,464[R]	781,986	270,321	87,329[R]	-6,558	12,821[R]	4,055,423
2006	1,990,511[R]	64,166[R]	816,441[R]	14,177[R]	787,219	289,246	96,525[R]	-6,558	12,974[R]	4,064,702
2007	2,016,456	65,739	896,590	13,453	806,425	247,510	105,238	-6,896	12,231	4,156,745
Electricity Generators, Electric Utilities										
1996	1,737,453	67,346	262,730	--	674,729	331,058	7,214	-3,088	--	3,077,442
1997	1,787,806	77,753	283,625	--	628,644	341,273	7,462	-4,040	--	3,122,523
1998	1,807,480	110,158	309,222	--	673,702	308,844	7,206	-4,441	--	3,212,171
1999	1,767,679	86,929	296,381	--	725,036	299,914	3,716	-5,982	--	3,173,674
2000	1,696,619	72,180	290,715	--	705,433	253,155	2,241	-4,960	--	3,015,383
2001	1,560,146	78,908	264,434	--	534,207	197,804	1,666	-7,704	486	2,629,946
2002	1,514,670	59,125	229,639	206	507,380	242,302	3,089	-7,434	480	2,549,457
2003	1,500,281	69,930	186,967	243	458,829	249,622	3,421	-7,532	519	2,462,281
2004	1,513,641	73,694	199,662	374	475,682	245,546	3,692	-7,526	467	2,505,231
2005	1,484,855	69,722	238,204	10	436,296	245,553	4,945	-5,383	643	2,474,846
2006	1,471,421	40,903	282,088	30	425,341	261,864	6,588	-5,281	700	2,483,656
2007	1,490,985	40,719	313,785	141	427,555	226,734	8,953	-5,328	586	2,504,131
Electricity Generators, Independent Power Producers										
1996	5,312	1,170	10,104	4	--	10,101	33,440	--	--	60,132
1997	5,344	2,557	7,506	31	--	9,375	33,929	--	--	58,741
1998	15,539	5,503	26,657	55	--	9,023	34,703	-26	--	91,455
1999	64,387	17,906	60,264	36	3,218	14,749	40,460	-115	--	200,905
2000	213,956	25,795	108,712	181	48,460	18,183	42,831	-579	--	457,540
2001	291,678	34,257	162,540	10	234,619	15,945	37,200	-1,119	5,460	780,592
2002	366,535	24,150	227,155	29	272,684	18,189	40,729	-1,309	7,168	955,331
2003	415,498	38,571	234,240	13	304,904	21,890	42,058	-1,003	7,035	1,063,205
2004	407,418	35,665	291,527	7	312,846	19,518	45,743	-962	7,108	1,118,870
2005	470,658	41,485	314,970	3	345,690	21,477	48,294	-1,174	5,569	1,246,971
2006	462,302	14,340	335,898	3	361,877	24,383	55,890	-1,277	5,646	1,259,062
2007	470,978	16,189	372,523	3	378,869	19,103	62,301	-1,569	5,458	1,323,856
Combined Heat and Power, Electric Power[8]										
1996	29,207	6,267	105,923	1,337	--	--	3,632	--	201	146,567
1997	27,611	6,170	108,465	1,503	--	--	4,299	--	63	148,111
1998	27,174	6,550	113,413	2,260	--	--	4,234	--	159	153,790
1999	26,551	6,704	116,351	1,571	--	--	4,088	--	139	155,404
2000	32,536	7,217	118,551	1,847	--	--	4,330	--	125	164,606
2001	31,003	5,984	127,966	576	--	--	3,393	--	595	169,515
2002	29,408	6,458	150,889	1,734	--	--	3,737	--	1,444	193,670
2003	36,935	5,195	146,097	2,392	--	--	4,002	--	1,053	195,674
2004	36,128[R]	5,320[R]	135,983[R]	3,187[R]	--	--	2,893[R]	--	747[R]	184,259
2005	36,541[R]	5,275[R]	130,655[R]	3,765[R]	--	10	3,415[R]	--	716[R]	180,375
2006	36,014[R]	4,465[R]	116,430[R]	4,220[R]	--	8	3,456[R]	--	766[R]	165,359
2007	36,428	4,398	128,444	3,898	--	6	3,450	--	733	177,356
Combined Heat and Power, Commercial[9]										
1996	1,051	369	5,249	*	--	126	2,235	--	*	9,030
1997	1,040	427	4,725	3	--	120	2,385	--	*	8,701
1998	985	383	4,879	7	--	120	2,373	--	--	8,748
1999	995	434	4,607	*	--	115	2,412	--	*	8,563
2000	1,097	432	4,262	*	--	100	2,012	--	*	7,903
2001	995	438	4,434	*	--	66	1,025	--	457	7,416
2002	992	431	4,310	*	--	13	1,065	--	603	7,415
2003	1,206	423	3,899	--	--	72	1,302	--	594	7,496
2004	1,340[R]	499[R]	3,969[R]	--	--	105	1,575[R]	--	781	8,270
2005	1,353[R]	375	4,249[R]	--	--	86	1,673[R]	--	756	8,492
2006	1,310[R]	235[R]	4,355[R]	*[R]	--	93	1,619[R]	--	758[R]	8,371
2007	1,371	189	4,257	--	--	77	1,614	--	764	8,273
Combined Heat and Power, Industrial[10]										
1996	22,172	6,260	71,049	13,015	--	5,878	29,274	--	3,370	151,017
1997	23,214	5,649	75,078	11,814	--	5,685	29,107	--	3,549	154,097
1998	22,337	6,206	77,085	11,170	--	5,349	28,572	--	3,412	154,132
1999	21,474	6,088	78,793	12,519	--	4,758	28,747	--	3,885	156,264
2000	22,056	5,597	78,798	11,927	--	4,135	29,491	--	4,669	156,673
2001	20,135	5,293	79,755	8,454	--	3,145	27,485	--	4,908	149,175
2002	21,525	4,403	79,013	9,493	--	3,825	30,489	--	3,832	152,580
2003	19,817	5,285	78,705	12,953	--	4,222	28,704	--	4,843	154,530
2004	19,773[R]	5,967[R]	78,959[R]	11,684[R]	--	3,248	29,164[R]	--	5,129[R]	153,925
2005	19,466[R]	5,368[R]	72,882[R]	9,687[R]	--	3,195	29,003[R]	--	5,137[R]	144,739
2006	19,464[R]	4,223[R]	77,669[R]	9,923[R]	--	2,899	28,972[R]	--	5,103[R]	148,254
2007	16,694	4,243	77,580	9,411	--	1,590	28,919	--	4,690	143,128

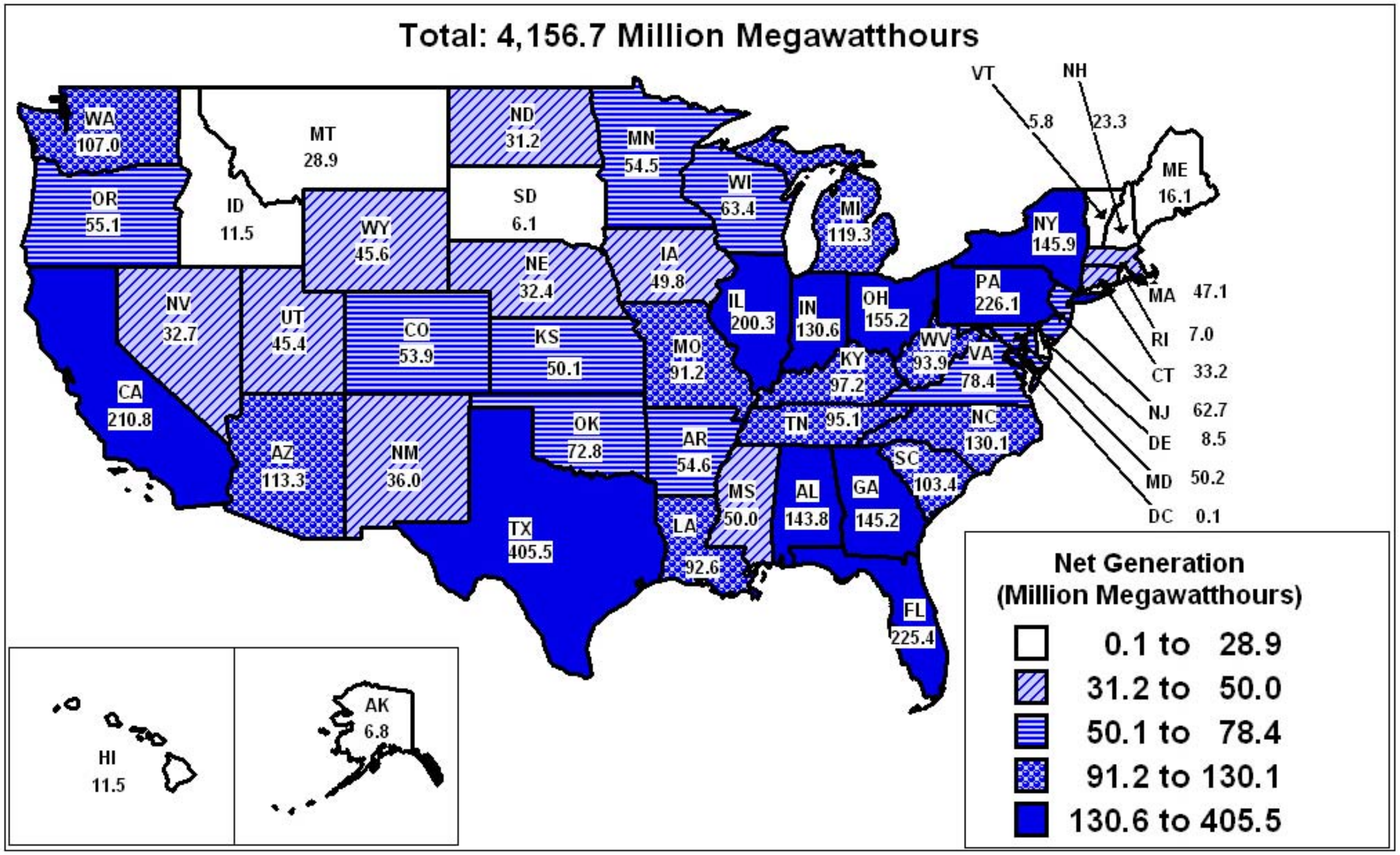
[1] Anthracite, bituminous coal, subbituminous coal, lignite, waste coal, and synthetic coal.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[3] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[4] Conventional hydroelectric power excluding pumped storage facilities.
[5] Other renewables represents the summation of the sub-categories of Wind, Solar Thermal and Photovoltaic, Wood and Wood Derived Fuels, Geothermal, and Other Biomass.
[6] The quantity of output from a hydroelectric pumped storage facility represents production minus energy used for pumping.
[7] Non-biogenic municipal solid waste, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.
[8] Electric utility CHP plants are included in Electricity Generators, Electric Utilities.
[9] Small number of commercial electricity-only plants included.
[10] Small number of industrial electricity-only plants included.
* = Value is less than half of the smallest unit of measure.

R = Revised.

Note: Totals may not equal sum of components because of independent rounding

Sources: Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920 "Combined Heat and Power Plant Report" and predecessor forms.

Figure 1.1. U.S. Electric Industry Net Generation by State, 2007



Note: Data are displayed as 5 groups of 10 States and the District of Columbia.
Sources: Energy Information Administration, Form EIA-923. "Power Plant Operations Report" and predecessor form(s) including Energy Information Administration, Form EIA-906. "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report"

Table 1.1.A. Net Generation by Selected Renewables by Type of Producer, 1996 through 2007
(Thousand Megawatthours)

Period	Wind	Solar Thermal and Photovoltaic	Wood and Wood-Derived Fuels[1]	Geothermal	Other Biomass[2]	Total (Other Renewables)
Total (All Sectors)						
1996	3,234	521	36,800	14,329	20,911	75,796
1997	3,288	511	36,948	14,726	21,709	77,183
1998	3,026	502	36,338	14,774	22,448	77,088
1999	4,488	495	37,041	14,827	22,572	79,423
2000	5,593	493	37,595	14,093	23,131	80,906
2001	6,737	543	35,200	13,741	14,548	70,769
2002	10,354	555	38,665	14,491	15,044	79,109
2003	11,187	534	37,529	14,424	15,812	79,487
2004	14,144	575	38,117	14,811	15,421	83,067
2005	17,811	550	38,856	14,692	15,420	87,329
2006	26,589	508	38,762	14,568	16,099	96,525
2007	34,450	612	39,014	14,637	16,525	105,238
Electricity Generators, Electric Utilities						
1996	10	3	788	5,234	1,179	7,214
1997	6	3	739	5,469	1,244	7,462
1998	3	3	719	5,176	1,305	7,206
1999	23	3	684	1,698	1,307	3,716
2000	29	3	700	151	1,358	2,241
2001	135	3	560	152	815	1,666
2002	213	3	709	1,402	761	3,089
2003	354	2	882	1,249	934	3,421
2004	405	6	1,209	1,248	824	3,692
2005	1,046	16	1,829	1,126	929	4,945
2006	2,351	15	1,937	1,162	1,123	6,588
2007	4,361	11	2,226	1,139	1,217	8,953
Electricity Generators, Independent Power Producers						
1996	3,224	518	5,705	9,095	14,899	33,440
1997	3,282	508	5,729	9,257	15,153	33,929
1998	3,023	500	5,925	9,598	15,658	34,703
1999	4,465	492	6,569	13,129	15,805	40,460
2000	5,565	491	6,601	13,942	16,234	42,831
2001	6,602	539	6,011	13,588	10,460	37,200
2002	10,141	552	6,556	13,089	10,391	40,729
2003	10,834	532	6,520	13,175	10,998	42,058
2004	13,739	569	6,940	13,563	10,932	45,743
2005	16,764	535	6,668	13,566	10,761	48,294
2006	24,238	493	6,374	13,406	11,379	55,890
2007	30,089	601	6,451	13,498	11,662	62,301
Combined Heat and Power, Electric Power[3]						
1996	--	--	1,893	--	1,738	3,632
1997	--	--	2,212	--	2,087	4,299
1998	--	--	1,964	--	2,270	4,234
1999	--	--	1,707	--	2,381	4,088
2000	--	--	1,615	--	2,715	4,330
2001	--	--	1,723	--	1,669	3,393
2002	--	--	1,744	--	1,993	3,737
2003	--	--	2,126	--	1,876	4,002
2004	--	--	1,588	--	1,306	2,893
2005	--	--	2,073	--	1,341	3,415
2006	--	--	2,030	--	1,426	3,456
2007	--	--	2,034	--	1,416	3,450
Combined Heat and Power, Commercial[4]						
1996	--	--	59	--	2,176	2,235
1997	--	--	43	--	2,342	2,385
1998	--	--	38	--	2,335	2,373
1999	--	--	20	--	2,393	2,412
2000	--	--	27	--	1,985	2,012
2001	--	--	18	--	1,007	1,025
2002	--	--	13	--	1,053	1,065
2003	--	--	13	--	1,289	1,302
2004	--	--	13	--	1,562	1,575
2005	--	--	16	--	1,657	1,673
2006	--	--	21	--	1,599	1,619
2007	--	--	15	--	1,599	1,614
Combined Heat and Power, Industrial[5]						
1996	--	--	28,354	--	919	29,274
1997	--	--	28,225	--	882	29,107
1998	--	--	27,693	--	880	28,572
1999	--	--	28,060	--	686	28,747
2000	--	--	28,652	--	839	29,491
2001	--	--	26,888	--	596	27,485
2002	--	--	29,643	--	846	30,489
2003	--	--	27,988	--	715	28,704
2004	--	--	28,367	--	797	29,164
2005	--	--	28,271	--	733	29,003
2006	--	--	28,400	--	572	28,972
2007	--	--	28,287	--	631	28,919

[1] Wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.
[2] Biogenic municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).
[3] Electric utility CHP plants are included in Electricity Generators, Electric Utilities.
[4] Small number of commercial electricity-only plants included.
[5] Small number of industrial electricity-only plants included.
Note: Totals may not equal sum of components because of independent rounding
Sources: Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920 "Combined Heat and Power Plant Report" and predecessor forms.

Table 1.2. Useful Thermal Output by Energy Source by Combined Heat and Power Producers, 1996 through 2007
(Billion Btus)

Period	Coal[1]	Petroleum[2]	Natural Gas	Other Gases[3]	Other Renewables[4]	Other[5]	Total
Total Combined Heat and Power							
1996	391,540	132,815	710,733	149,831	755,847	42,980	2,183,746
1997	388,944	136,742	712,683	150,144	785,306	53,361	2,227,180
1998	381,546	135,519	781,637	167,064	757,131	46,437	2,269,334
1999	385,926	125,486	810,918	178,971	744,470	47,871	2,293,642
2000	383,687	108,045	812,036	184,062	763,674	50,459	2,301,963
2001	354,204	90,308	740,979	132,937	584,560	55,162	1,958,151
2002	336,848	72,826	708,738	117,513	571,507	48,264	1,855,697
2003	333,361	85,263	610,122	110,263	632,368	54,960	1,826,335
2004[R]	351,871	97,484	654,242	126,157	667,341	45,456	1,942,550
2005[R]	341,806	92,383	624,008	138,469	664,691	41,400	1,902,757
2006[R]	332,548	78,232	603,288	126,049	689,549	49,308	1,878,973
2007	326,803	76,255	554,394	116,313	651,230	46,822	1,771,816
Combined Heat and Power, Electric Power							
1996	42,982	11,603	121,431	3,928	32,761	314	213,019
1997	39,437	11,823	132,125	7,746	30,147	29	221,307
1998	43,256	6,261	141,834	5,064	25,969	68	222,452
1999	52,061	6,718	145,525	3,548	30,172	28	238,052
2000	53,329	6,610	157,886	5,312	25,661	39	248,837
2001	51,515	6,087	164,206	4,681	12,676	3,343	242,508
2002	40,020	3,869	214,137	5,961	12,550	4,732	281,269
2003	38,249	7,379	200,077	9,282	19,786	3,296	278,068
2004[R]	39,014	8,217	239,416	18,200	17,347	3,822	326,017
2005[R]	39,652	7,809	239,324	36,694	18,240	3,884	345,605
2006[R]	38,133	7,065	207,095	22,567	17,284	4,435	296,579
2007	38,260	7,156	212,705	20,473	19,166	4,459	302,219
Combined Heat and Power, Commercial							
1996	19,742	2,905	32,770	--	18,057	--	73,474
1997	21,958	3,832	39,893	20	20,232	--	85,935
1998	20,185	4,853	38,510	34	18,426	--	82,008
1999	20,479	3,298	36,857	--	17,145	--	77,779
2000	21,001	3,827	39,293	--	17,613	--	81,734
2001	18,495	4,118	34,923	--	8,253	5,770	71,560
2002	18,477	2,743	36,265	--	6,901	4,801	69,188
2003	22,780	2,716	16,955	--	8,297	6,142	56,889
2004	22,450[R]	4,283[R]	21,851[R]	--	8,936[R]	6,350[R]	63,871[R]
2005	22,601[R]	3,684[R]	20,227[R]	--	8,647[R]	5,921[R]	61,081[R]
2006[R]	22,186	2,264	19,370	0	9,359	6,242	59,422
2007	22,595	1,861	20,040	--	6,651	3,983	55,131
Combined Heat and Power, Industrial							
1996	328,816	118,307	556,532	145,903	705,029	42,666	1,897,253
1997	327,549	121,087	540,665	142,378	734,927	53,332	1,919,938
1998	318,105	124,405	601,293	161,966	712,736	46,369	1,964,874
1999	313,386	115,470	628,536	175,423	697,153	47,843	1,977,811
2000	309,357	97,608	614,857	178,750	720,400	50,420	1,971,392
2001	284,194	80,103	541,850	128,256	563,631	46,049	1,644,083
2002	278,351	66,214	458,336	111,552	552,056	38,731	1,505,240
2003	272,332	75,168	393,090	100,981	604,285	45,522	1,491,378
2004[R]	290,407	84,984	392,974	107,956	641,058	35,284	1,552,663
2005[R]	279,552	80,889	364,457	101,775	637,803	31,594	1,496,071
2006[R]	272,229	68,903	376,822	103,481	662,906	38,630	1,522,971
2007	265,948	67,238	321,648	95,840	625,413	38,380	1,414,466

[1] Anthracite, bituminous coal, subbituminous coal, lignite, waste coal, and synthetic coal.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology) and waste oil.
[3] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[4] Other renewables represents the summation of the sub-categories of Wind, Solar Thermal and Photovoltaic, Wood and Wood Derived Fuels, Geothermal, and Other Biomass.
[5] Non-biogenic municipal solid waste, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.

R = Revised.

Notes: • The methodology to allocate fuel use by combined heat and power plants to electric power generation and useful thermal output was modified beginning in 2007, and retroactively applied to data from 2004 to 2006. For more information, please see the Technical Notes in the Appendices. • Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920 "Combined Heat and Power Plant Report" and predecessor forms.

Chapter 2. Capacity

Table 2.1. Existing Net Summer Capacity by Energy Source and Producer Type, 1996 through 2007
(Megawatts)

Period	Coal[1]	Petroleum [2]	Natural Gas[3]	Other Gases[4]	Nuclear	Hydroelectric Conventional[5]	Other Renewables[6]	Hydroelectric Pumped Storage[7]	Other[8]	Total
Total (All Sectors)										
1996	313,382	72,518	174,135	1,664	100,784	76,437	15,309	21,110	550	775,890
1997	313,624	72,463	176,471	1,525	99,716	79,415	15,351	19,310	774	778,649
1998	315,786	66,282	180,288	1,520	97,070	79,151	15,444	19,518	810	775,868
1999	315,496	60,069	195,119	1,909	97,411	79,393	15,942	19,565	1,023	785,927
2000	315,114	61,837	219,590	2,342	97,860	79,359	15,572	19,522	523	811,719
2001	314,230	66,162	252,832	1,670	98,159	78,916	16,101	19,664	519	848,254
2002	315,350	59,651	312,512	2,008	98,657	79,356	16,710	20,371	686	905,301
2003	313,019	60,730	355,442	1,994	99,209	78,694	18,153	20,522	684	948,446
2004	313,020	59,119	371,011	2,296	99,628	77,641	18,717	20,764	746	962,942
2005	313,380	58,548	383,061	2,063	99,988	77,541	21,205	21,347	887	978,020
2006	312,956	58,097	388,294	2,256	100,334	77,821	24,113	21,461	882	986,215
2007	312,738	56,068	392,876	2,313	100,266	77,885	30,069	21,886	788	994,888
Electricity Generators, Electric Utilities										
1996	302,420	70,421	139,936	63	100,784	73,129	2,079	21,110	--	709,942
1997	302,866	69,557	141,713	206	99,716	76,177	2,123	19,310	222	711,889
1998	299,739	62,704	130,404	55	97,070	75,525	2,067	18,898	229	686,692
1999	277,780	49,020	123,192	220	95,030	74,122	790	18,945	224	639,324
2000	260,990	41,032	123,665	57	85,968	73,738	837	18,020	13	604,319
2001	244,451	38,456	112,841	57	63,060	72,968	979	17,097	13	549,920
2002	244,056	33,876	127,692	61	63,202	73,391	959	17,807	--	561,074
2003	236,473	32,570	125,612	61	60,964	72,827	925	17,803	13	547,249
2004	235,976	31,415	131,734	58	60,651	71,696	960	18,048	13	550,550
2005	229,705	30,867	147,752	--	56,564	71,568	1,545	18,195	39	556,235
2006	230,644	30,419	157,742	104	56,143	71,840	2,291	18,301	39	567,523
2007	231,289	29,115	162,756	104	54,211	72,186	2,806	18,693	39	571,200
Electricity Generators, Independent Power Producers										
1996	719	228	3,122	--	--	2,171	6,850	--	--	13,091
1997	719	639	2,996	--	--	2,103	6,695	--	--	13,153
1998	6,132	1,463	17,051	--	--	2,454	6,955	620	--	34,675
1999	27,725	8,508	38,553	--	2,381	4,142	8,794	620	--	90,724
2000	44,164	18,771	60,327	--	11,892	4,509	8,994	1,502	--	150,159
2001	60,701	25,311	102,693	--	35,099	4,885	9,894[R]	2,567	79	241,230[R]
2002	61,770	23,664	140,404	9	35,455	4,911	10,420	2,564	80	279,246
2003	66,538	26,028	178,624	6	38,244	5,058	11,786	2,719	46	329,049
2004	67,242	25,918	190,855	8	38,978	5,274	12,070	2,717	46	343,106
2005	73,734	26,041	188,043	12	43,424	5,284	13,864	3,152	46	353,601
2006	72,730	25,384	184,196	20	44,190	5,263	15,865	3,160	46	350,854
2007	71,943	24,818	184,888	8	46,055	5,346	21,002	3,193	26	357,278
Combined Heat and Power, Electric Power										
1996	4,950	699	18,350	--	--	--	626	--	--	24,625
1997	4,895	810	18,660	5	--	--	707	--	--	25,076
1998	5,021	800	19,632	--	--	--	749	--	--	26,202
1999	5,230	1,097	19,390	--	--	--	741	--	--	26,459
2000	5,044	907	20,704	262	--	--	736	--	--	27,653
2001	4,628	972	21,226	287	--	1	498[R]	--	28	27,639[R]
2002	5,222	1,084	28,455	182	--	--	555	--	--	35,499
2003	5,534	1,051	34,895	185	--	1	665	--	--	42,332
2004	5,609	677	32,600	289	--	1	555	--	--	39,731
2005	5,560	530	31,740	289	--	1	614	--	--	38,735
2006	5,837	970	30,031	325	--	1	628	--	--	37,793
2007	5,885	907	29,468	339	--	--	656	--	--	37,254
Combined Heat and Power, Commercial										
1996	321	267	1,243	--	--	31	446	--	--	2,309
1997	314	380	1,157	--	--	32	450	--	--	2,333
1998	317	282	1,188	--	--	32	463	--	--	2,281
1999	317	381	1,106	--	--	32	465	--	--	2,302
2000	314	308	1,186	--	--	33	399	--	--	2,240
2001	295	299	1,950	--	--	22	348	--	--	2,912
2002	292	301	1,216	--	--	22	357	--	--	2,188
2003	347	343	994	--	--	22	371	--	--	2,077
2004	368	321	1,069	5	--	22	404	--	--	2,188
2005	397	333	1,024	5	--	25	435	--	--	2,219
2006	428	341	1,040	5	--	25	433	--	--	2,272
2007	428	348	1,064	5	--	22	443	--	3	2,312
Combined Heat and Power, Industrial										
1996	4,972	903	11,482	1,602	--	1,106	5,308	--	550	25,923
1997	4,830	1,078	11,945	1,315	--	1,102	5,376	--	552	26,198
1998	4,577	1,034	12,012	1,465	--	1,139	5,210	--	581	26,019
1999	4,443	1,062	12,877	1,689	--	1,097	5,151	--	799	27,119
2000	4,601	818	13,708	2,023	--	1,079	4,607	--	510	27,348
2001	4,156	1,124	14,123	1,327	--	1,041	4,382	--	399	26,553
2002	4,010	726	14,745	1,756	--	1,033	4,419	--	607	27,295
2003	4,127	738	15,316	1,742	--	786	4,406	--	625	27,740
2004	3,825	789	14,753	1,937	--	648	4,728	--	687	27,367
2005	3,984	777	14,501	1,757	--	662	4,747	--	802	27,230
2006	3,317	983	15,285	1,802	--	693	4,896	--	797	27,773
2007	3,194	880	14,699	1,858	--	331	5,163	--	720	26,844

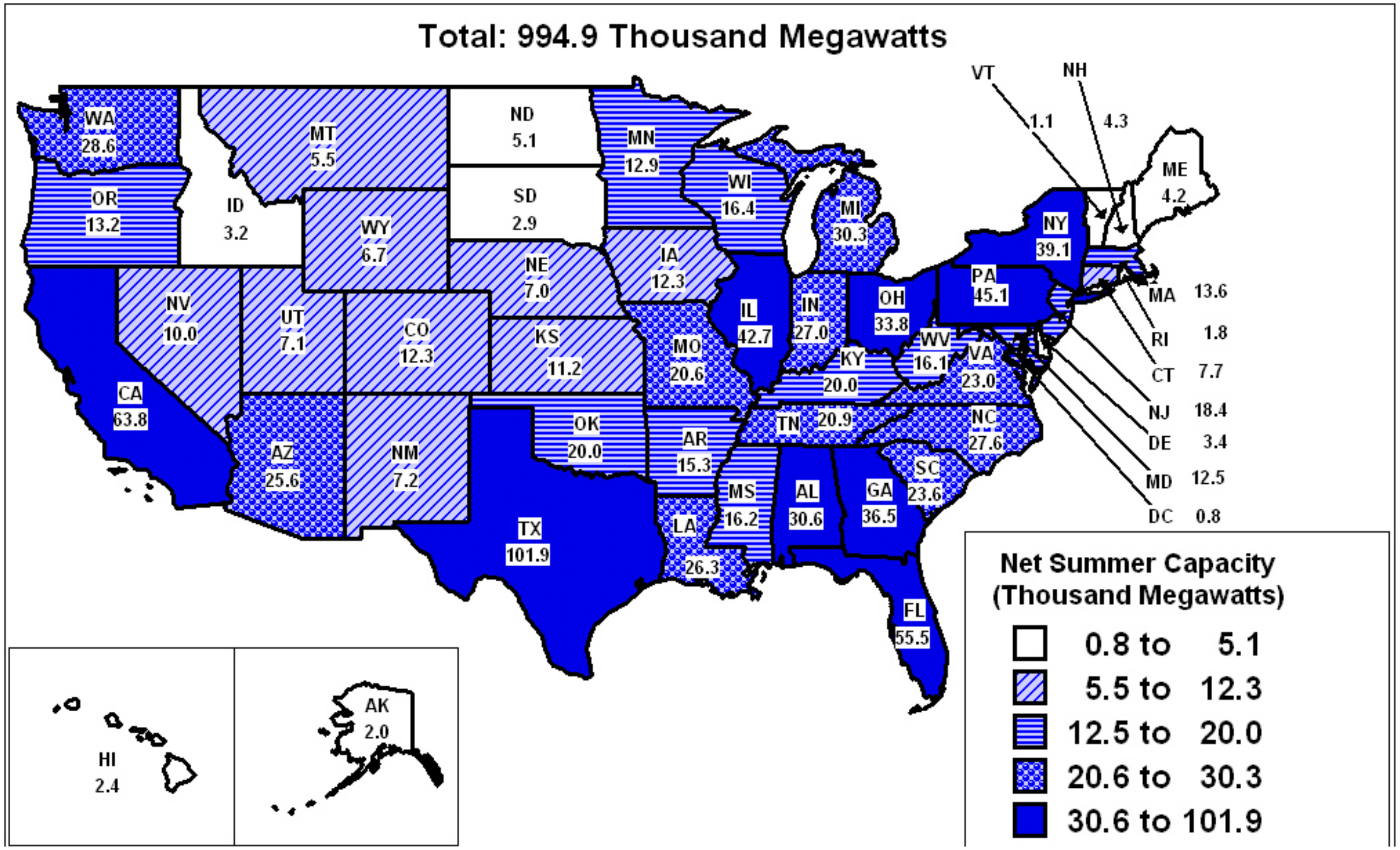
[1] Anthracite, bituminous coal, subbituminous coal, lignite, waste coal, and synthetic coal.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[3] Includes a small number of generators for which waste heat is the primary energy source.
[4] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[5] Conventional hydroelectric power excluding pumped storage facilities.
[6] Wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
[7] Pumped storage capacity generates electricity from water pumped to an elevated reservoir and then released through a conduit to turbine generators located at a lower level.
[8] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.

R = Revised.

Notes: • See Glossary reference for definitions. • Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator. • Totals may not equal sum of components because of independent rounding.

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

Figure 2.1. U.S. Electric Industry Generating Capacity by State, 2007



Note: Data are displayed as 5 groups of 10 States and the District of Columbia.
Source: Energy Information Administration, Form EIA-860. "Annual Electric Generator Report."

Table 2.1.A. Existing Net Summer Capacity of Other Renewables by Producer Type, 1996 through 2007
(Thousand Megawatts)

Period	Wind	Solar Thermal and Photovoltaic	Wood and Wood-Derived Fuels[1]	Geothermal	Other Biomass[2]	Total (Other Renewables)
Total (All Sectors)						
1996	1,678	333	6,808	2,893	3,598	15,309
1997	1,610	334	6,924	2,893	3,590	15,351
1998	1,720	335	6,802	2,893	3,694	15,444
1999	2,252	389	6,795	2,846	3,660	15,942
2000	2,377	386	6,147	2,793	3,869	15,572
2001	3,864	392	5,882	2,216	3,748	16,101
2002	4,417	397	5,844	2,252	3,800	16,710
2003	5,995	397	5,871	2,133	3,758	18,153
2004	6,456	398	6,182	2,152	3,529	18,717
2005	8,706	411	6,193	2,285	3,609	21,205
2006	11,329	411	6,372	2,274	3,727	24,113
2007	16,515	502	6,704	2,214	4,134	30,069
Electricity Generators, Electric Utilities						
1996	8	4	216	1,622	230	2,079
1997	14	5	247	1,622	235	2,123
1998	9	5	268	1,550	236	2,067
1999	29	5	240	273	243	790
2000	54	5	259	273	247	837
2001	60	4	309	271	335	979
2002	111	9	248	271	350	959
2003	140	9	268	162	346	925
2004	326	10	313	152	160	960
2005	765	11	391	242	136	1,545
2006	1,441	11	428	240	172	2,291
2007	1,928	12	418	158	290	2,806
Electricity Generators, Independent Power Producers						
1996	1,670	329	1,210	1,271	2,370	6,850
1997	1,596	329	1,205	1,271	2,293	6,695
1998	1,711	330	1,170	1,344	2,400	6,955
1999	2,222	385	1,244	2,573	2,370	8,794
2000	2,323	382	1,227	2,520	2,543	8,994
2001	3,804	388	1,178	1,945	2,580	9,894
2002	4,305	388	1,162	1,981	2,553	10,420
2003	5,855	388	1,121	1,972	2,450	11,786
2004	6,130	388	1,138	2,000	2,414	12,070
2005	7,941	400	1,033	2,044	2,447	13,864
2006	9,888	400	1,037	2,034	2,505	15,865
2007	14,587	489	1,066	2,056	2,803	21,002
Combined Heat and Power, Electric Power						
1996	--	--	305	--	321	626
1997	--	--	325	--	382	707
1998	--	--	356	--	393	749
1999	--	--	354	--	387	741
2000	--	--	242	--	494	736
2001	--	--	144	--	354	498
2002	--	--	144	--	411	555
2003	--	--	204	--	461	665
2004	--	--	179	--	375	555
2005	--	--	218	--	395	614
2006	--	--	212	--	416	628
2007	--	--	210	--	446	656
Combined Heat and Power, Commercial						
1996	--	--	7	--	439	446
1997	--	--	7	--	444	450
1998	--	--	7	--	456	463
1999	--	--	7	--	459	465
2000	--	--	7	--	392	399
2001	--	--	6	--	342	348
2002	--	--	6	--	351	357
2003	--	--	7	--	364	371
2004	--	--	7	--	397	404
2005	--	--	7	--	428	435
2006	--	--	7	--	426	433
2007	--	--	8	--	435	443
Combined Heat and Power, Industrial						
1996	--	--	5,070	--	238	5,308
1997	--	--	5,141	--	236	5,376
1998	--	--	5,001	--	209	5,210
1999	--	--	4,950	--	201	5,151
2000	--	--	4,413	--	194	4,607
2001	--	--	4,245	--	138	4,382
2002	--	--	4,285	--	134	4,419
2003	--	--	4,271	--	136	4,406
2004	--	--	4,545	--	183	4,728
2005	--	--	4,545	--	202	4,747
2006	--	--	4,688	--	208	4,896
2007	--	1	5,002	--	160	5,163

[1] Wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.
[2] Biogenic municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

Notes: • See Glossary reference for definitions. • Totals may not equal sum of components because of independent rounding. • Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator.

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

Table 2.2. Existing Capacity by Energy Source, 2007
(Megawatts)

Energy Source	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Coal[1]	1,470	336,040	312,738	314,944
Petroleum[2]	3,743	62,394	56,068	60,528
Natural Gas[3]	5,439	449,389	392,876	422,184
Other Gases[4]	105	2,663	2,313	2,292
Nuclear	104	105,764	100,266	101,765
Hydroelectric Conventional[5]	3,992	77,644	77,885	77,369
Wind	389	16,596	16,515	16,541
Solar Thermal and Photovoltaic	38	503	502	422
Wood and Wood Derived Fuels[6]	346	7,510	6,704	6,745
Geothermal	224	3,233	2,214	2,362
Other Biomass[7]	1,299	4,834	4,134	4,214
Pumped Storage	151	20,355	21,886	21,799
Other[8]	42	866	788	814
Total	**17,342**	**1,087,791**	**994,888**	**1,031,978**

[1] Anthracite, bituminous coal, subbituminous coal, lignite, waste coal, and synthetic coal.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[3] Includes a small number of generators for which waste heat is the primary energy source.
[4] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[5] The net summer capacity and/or the net winter capacity may exceed nameplate capacity due to upgrades to and overload capability of hydroelectric generators.
[6] Wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.
[7] Biogenic municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).
[8] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.

Notes: • Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator. • Totals may not equal sum of components because of independent rounding. • In some reporting of capacity data, such as for wind, solar and wave energy sites, the capacity for multiple generators is reported in a single generator record and is presented as a single generator in the count of number of generators.

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

Table 2.3. Existing Capacity by Producer Type, 2007
(Megawatts)

Producer Type	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Electric Power Sector				
Electric Utilities	9,237	616,525	571,200	588,881
Independent Power Producers	5,138	395,161	357,278	372,241
Total	**14,375**	**1,011,687**	**928,478**	**961,122**
Combined Heat and Power Sector				
Electric Power[1]	646	42,824	37,254	40,087
Commercial	635	2,586	2,312	2,404
Industrial	1,686	30,694	26,844	28,365
Total	**2,967**	**76,104**	**66,410**	**70,856**
Total All Sectors	**17,342**	**1,087,791**	**994,888**	**1,031,978**

[1] Includes only independent power producers` combined heat and power facilities.

Notes: • See Glossary reference for definitions. • Totals may not equal sum of components because of independent rounding. • In some reporting of capacity data, such as for wind, solar and wave energy sites, the capacity for multiple generators is reported in a single generator record and is presented as a single generator in the count of number of generators.

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

Table 2.4. Planned Nameplate Capacity Additions from New Generators, by Energy Source, 2008 through 2012
(Megawatts)

Energy Source	2008	2009	2010	2011	2012
Coal[1]	1,131	6,082	4,996	4,514	6,624
Petroleum[2]	90	1,045	55	720	--
Natural Gas	9,780	12,334	8,911	6,919	10,156
Other Gases[3]	--	--	--	--	--
Nuclear	--	--	--	--	1,270
Hydroelectric Conventional	18	6	6	204	2
Wind	9,821	3,661	1,045	90	--
Solar Thermal and Photovoltaic	23	127	315	1,050	880
Wood and Wood Derived Fuels[4]	32	60	68	14	114
Geothermal	138	30	87	128	--
Other Biomass[5]	173	129	1	122	2
Pumped Storage	--	--	--	--	--
Other[6]	22	--	--	--	--
Total	**21,226**	**23,475**	**15,484**	**13,762**	**19,049**

[1] Anthracite, bituminous coal, subbituminous coal, lignite, waste coal, and synthetic coal.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[3] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.

[4] Wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.
[5] Biogenic municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).
[6] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.

Notes: • Projected data are updated annually, so revision superscript is not used. • Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator. These data reflect plans as of December 31, 2007. • Totals may not equal sum of components because of independent rounding.

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

Table 2.5. Planned Capacity Additions from New Generators, by Energy Source, 2008-2012
(Count, Megawatts)

Energy Source	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
2008				
U.S. Total	**435**	**21,226**	**19,693**	**20,650**
Coal[1]	6	1,131	1,037	1,042
Petroleum[2]	23	90	82	89
Natural Gas	103	9,780	8,360	9,299
Other Gases[3]	--	--	--	--
Nuclear	--	--	--	--
Hydroelectric Conventional[4]	8	18	17	16
Wind	112	9,821	9,840	9,840
Solar Thermal and Photovoltaic	41	23	22	22
Wood and Wood Derived Fuels[5]	1	32	30	30
Geothermal	8	138	118	121
Other Biomass[6]	132	173	166	170
Pumped Storage	--	--	--	--
Other[7]	1	22	21	21
2009				
U.S. Total	**199**	**23,475**	**21,278**	**22,521**
Coal[1]	11	6,082	5,681	5,717
Petroleum[2]	10	1,045	971	983
Natural Gas	96	12,334	10,592	11,765
Other Gases[3]	--	--	--	--
Nuclear	--	--	--	--
Hydroelectric Conventional[4]	5	6	6	6
Wind	48	3,661	3,716	3,716
Solar Thermal and Photovoltaic	14	127	117	123
Wood and Wood Derived Fuels[5]	3	60	56	57
Geothermal	4	30	28	28
Other Biomass[6]	8	129	112	128
Pumped Storage	--	--	--	--
Other[7]	--	--	--	--
2010[4]				
U.S. Total	**116**	**15,484**	**14,043**	**14,826**
Coal[1]	11	4,996	4,676	4,696
Petroleum[2]	5	55	54	55
Natural Gas	79	8,911	7,803	8,563
Other Gases[3]	--	--	--	--
Nuclear	--	--	--	--
Hydroelectric Conventional[4]	4	6	6	6
Wind	8	1,045	1,045	1,045
Solar Thermal and Photovoltaic	3	315	315	315
Wood and Wood Derived Fuels[5]	2	68	63	64
Geothermal	3	87	80	81
Other Biomass[6]	1	1	1	1
Pumped Storage	--	--	--	--
Other[7]	--	--	--	--
2011				
U.S. Total	**57**	**13,762**	**12,258**	**12,923**
Coal[1]	9	4,514	4,146	4,199
Petroleum[2]	2	720	619	677
Natural Gas	31	6,919	5,904	6,462
Other Gases[3]	--	--	--	--
Nuclear	--	--	--	--
Hydroelectric Conventional[4]	4	204	194	188
Wind	1	90	100	100
Solar Thermal and Photovoltaic	2	1,050	1,050	1,050
Wood and Wood Derived Fuels[5]	1	14	13	13
Geothermal	3	128	119	120
Other Biomass[6]	4	122	113	115
Pumped Storage	--	--	--	--
Other[7]	--	--	--	--
2012				
U.S. Total	**72**	**19,049**	**16,935**	**17,935**
Coal[1]	13	6,624	6,067	6,193
Petroleum[2]	--	--	--	--
Natural Gas	51	10,156	8,717	9,573
Other Gases[3]	--	--	--	--
Nuclear	1	1,270	1,181	1,194
Hydroelectric Conventional[4]	1	2	2	2
Wind	--	--	--	--
Solar Thermal and Photovoltaic	3	880	860	863
Wood and Wood Derived Fuels[5]	1	114	106	107
Geothermal	--	--	--	--
Other Biomass[6]	2	2	2	2
Pumped Storage	--	--	--	--
Other[7]	--	--	--	--

[1] Anthracite, bituminous coal, subbituminous coal, lignite, waste coal, and synthetic coal.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[3] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[4] Conventional hydroelectric power excluding pumped storage facilities; includes ocean power technology (wave energy).
[5] Wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.
[6] Biogenic municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).
[7] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.

Notes: • Projected data are updated annually, so revision superscript is not used. • Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator. These data reflect plans as of December 31, 2007. • Totals may not equal sum of components because of independent rounding. • In some reporting of capacity data, such as for wind, solar and wave energy sites, the capacity for multiple generators is reported in a single generator record and is presented as a single generator in the count of number of generators.

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

Table 2.6. Capacity Additions, Retirements and Changes by Energy Source, 2007
(Count, Megawatts)

Energy Source	Generator Additions				Generator Retirements				Updates and Revisions[1]		
	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity (MW)
Coal[2]	2	1,514	1,354	1,374	21	1,272	1,196	1,210	-32	-375	-382
Petroleum[3]	47	268	242	253	76	401	402	417	-1,792	-1,870	-1,873
Natural Gas[4]	63	7,587	6,673	7,255	78	2,889	2,741	2,785	1,745	650	970
Other Gases[5]	--	--	--	--	1	11	10	10	111	66	105
Nuclear	--	--	--	--	--	--	--	--	179	-68	47
Hydroelectric Conventional	2	12	12	12	8	5	5	5	218	57	-30
Wind	48	5,209	5,193	5,195	2	1	1	1	54	-5	20
Solar Thermal and Photovoltaic	17	90	89	65	--	--	--	--	1	1	1
Wood and Wood Derived Fuels[6]	3	63	47	45	6	16	15	15	292	300	255
Geothermal	4	39	29	30	1	1	1	1	25	-88	-8
Other Biomass[7]	128	245	205	205	17	50	47	40	258	249	246
Pumped Storage	--	--	--	--	--	--	--	--	785	425	425
Other[8]	--	--	--	--	1	24	20	20	-87	-75	-74
Total	**314**	**15,026**	**13,845**	**14,434**	**211**	**4,670**	**4,439**	**4,504**	**1,758**	**-734**	**-299**

[1] Generator re-ratings, re-powering, and revisions/corrections to previously reported data.
[2] Anthracite, bituminous coal, subbituminous coal, lignite, waste coal, and synthetic coal.
[3] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[4] Includes a small number of generators for which waste heat is the primary energy source.
[5] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[6] Wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.
[7] Biogenic municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).
[8] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.

Notes: • Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator. • Totals may not equal sum of components because of independent rounding. • In some reporting of capacity data, such as for wind, solar and wave energy sites, the capacity for multiple generators is reported in a single generator record and is presented as a single generator in the count of number of generators.

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

Table 2.7.A. Capacity of Dispersed Generators by Technology Type, 2004 through 2007
(Count, Megawatts)

Period	Internal Combustion (MW)	Combustion Turbine (MW)	Steam Turbine (MW)	Hydroelectric (MW)	Wind and Other (MW)	Total	
						Number of Generators	(MW)
2004	3,369	210	552	26	2	11,123	4,156
2005	4,292	334	126	2	13	11,373	4,766
2006	6,469	339	156	2	8	9,536	7,037
2007	7,793	269	101	31	35	11,057	8,297

Note: Dispersed generators are commercial and industrial generators which are not connected to the grid. They may be installed at or near a customer`s site, or at other locations. They may be owned by either the customers of the distribution utility or by the utility. Other Technology includes generators for which technology is not specified.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 2.7.B. Capacity of Distributed Generators by Technology Type, 2004 through 2007
(Count, Megawatts)

Period	Internal Combustion (MW)	Combustion Turbine (MW)	Steam Turbine (MW)	Hydroelectric (MW)	Wind and Other (MW)	Total	
						Number of Generators	(MW)
2004	2,169	1,028	1,086	1,003	137	5,863	5,423
2005[1]	4,024	1,917	1,831	998	994	17,371	9,766
2006	3,625	1,299	2,580	806	1,078	5,044	9,641
2007	4,614	1,964	3,595	1,053	1,427	7,103	12,702

[1] Distributed generator data in 2005 include a significant number of generators reported by one respondent which may be for residential applications.
Note: Distributed generators are commercial and industrial generators which are connected to the grid. They may be installed at or near a customer`s site, or at other locations. They may be owned by either the customers of the distribution utility or by the utility. Other Technology includes generators for which technology is not specified.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 2.7.C. Total Capacity of Dispersed and Distributed Generators by Technology Type, 2004 through 2007
(Count, Megawatts)

Period	Internal Combustion (MW)	Combustion Turbine (MW)	Steam Turbine (MW)	Hydroelectric (MW)	Wind and Other (MW)	Total	
						Number of Generators	(MW)
2004	5,538	1,238	1,638	1,029	139	16,986	9,579
2005[1]	8,316	2,251	1,957	1,000	1,007	28,744	14,532
2006	10,094	1,638	2,736	808	1,086	14,580	16,678
2007	12,407	2,233	3,696	1,084	1,462	18,160	20,999

[1] Distributed generator data in 2005 include a significant number of generators reported by one respondent which may be for residential applications.
Note: Dispersed and distributed generators are commercial and industrial generators. Dispersed generators are not connected to the grid. Distributed generators are connected to the grid. Both types of generators may be installed at or near a customer`s site, or at other locations, and both types of generators may be owned by either the customers of the distribution utility or by the utility. Other Technology includes generators for which technology is not specified.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 2.8. Fuel Switching Capacity of Generators Reporting Natural Gas as the Primary Fuel, by Producer Type, 2007
(Megawatts, Percent)

Producer Type	Total Net Summer Capacity of All Generators Reporting Natural Gas as the Primary Fuel	Fuel-Switchable Part of Total			
		Net Summer Capacity of Natural Gas-Fired Generators Reporting the Ability to Switch to Petroleum Liquids[1]	Fuel Switchable Capacity as Percent of Total	Maximum Achievable Net Summer Capacity Using Petroleum Liquids[1]	Fuel Switchable Net Summer Capacity Reported to Have No Factors that Limit the Ability to Switch to Petroleum Liquids[1]
Electric Utility	162,756	74,274	45.6	72,424	27,001
Independent Power Producers	184,888	42,136	22.8	41,397	11,815
Combined Heat and Power, Electric Power[2]	29,468	6,052	20.5	6,265	628
Electric Power Sector Subtotal	**377,112**	**122,463**	**32.5**	**120,086**	**39,444**
Combined Heat and Power, Commercial	1,064	456	42.8	451	85
Combined Heat and Power, Industrial	14,699	944	6.4	884	289
All Sectors	**392,876**	**123,862**	**31.5**	**121,421**	**39,817**

[1] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, and waste oil.
[2] Electric Utility CHP plants are included in Electric Utilities.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 2.9. Fuel Switching Capacity of Generators Reporting Petroleum Liquids as the Primary Fuel, by Producer Type, 2007
(Megawatts, Percent)

Producer Type	Total Net Summer Capacity of All Generators Reporting Petroleum as the Primary Fuel[1]	Fuel-Switchable Part of Total		
		Net Summer Capacity of Petroleum-Fired Generators Reporting the Ability to Switch to Natural Gas	Fuel Switchable Capacity as Percent of Total	Maximum Achievable Net Summer Capacity Using Natural Gas
Electric Utility	29,115	9,170	31.5	8,817
Independent Power Producers	24,818	12,215	49.2	10,070
Combined Heat and Power Electric Power[2]	907	450	49.6	195
Electric Power Sector Subtotal	**54,840**	**21,835**	**39.8**	**19,082**
Combined Heat and Power Commercial	348	32	9.1	31
Combined Heat and Power Industrial	880	102	11.5	76
All Sectors	**56,068**	**21,969**	**39.2**	**19,189**

[1] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, and waste oil.
[2] Electric Utility CHP plants are included in Electric Utilities.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 2.10. Fuel-Switching Capacity: From Natural Gas to Petroleum Liquids, by Type of Prime Mover, 2007
(Count, Megawatts)

Prime Mover Type	Number of Generators	Net Summer Capacity	Fuel Switchable Net Summer Capacity Reported to Have No Factors that Limit the Ability to Switch to Petroleum Liquids[1]
Steam Generator	221	33,553	18,245
Combined Cycle	371	35,270	5,907
Internal Combustion	326	904	308
Gas Turbine	944	54,135	15,358
All Fuel Switchable Prime Movers	1,862	123,862	39,817

[1] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, and waste oil.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 2.11. Fuel-Switching Capacity: From Natural Gas to Petroleum Liquids, by Year of Initial Commercial Operation, 2007
(Count, Megawatts)

Year of Commercial Operation	Number of Generators	Net Summer Capacity	Fuel Switchable Net Summer Capacity Reported to Have No Factors that Limit the Ability to Switch to Petroleum Liquids[1]
pre-1970	404	17,543	9,765
1970-1974	384	18,784	8,965
1975-1979	108	11,108	6,249
1980-1984	47	2,690	1,901
1985-1989	112	3,037	491
1990-1994	211	12,738	2,176
1995-1999	139	10,131	2,369
2000-2004	386	39,674	6,406
2005-2007	71	8,157	1,496
Total	1,862	123,862	39,817

[1] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, and waste oil.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 2.12. Interconnection Cost and Capacity for New Generators, by Producer Type, 2006 and 2007

Sector	Units[1]	Nameplate Capacity (megawatts)[1]	Cost (thousand dollars)[1]
2006			
Total	222[R]	11,227[R]	251,953
Electric Utilities[2]	99[R]	5,901[R]	94,574
Independent Power Producers[3]	102[R]	5,186[R]	149,086
Commercial[4]	14[R]	27[R]	1,836
Industrial[5]	7	114	6,457
2007			
Total	269	14,061	397,921
Electric Utilities[2]	97	8,527	184,813
Independent Power Producers[3]	163	5,415	208,736
Commercial[4]	3	5	18
Industrial[5]	6	114	4,354

[1] Cost is the total cost incurred for the direct, physical interconnection of generators that started commercial operation in the respective years. These generator-specific costs may include costs for transmission or distribution lines, transformers, protective devices, substations, switching stations and other equipment necessary for interconnection. Units and Nameplate Capacity represent the number of units and associated capacity for which interconnection costs were incurred and reported.
[2] Electric utility CHP plants are included in Electric Generators, Electric Utilities.
[3] Includes only independent power producers` combined heat and power facilities.
[4] Small number of commercial electricity-only plants included.
[5] Small number of industrial electricity-only plants included.
R = Revised.
Notes: • See Glossary reference for definitions. • Totals may not equal sum of components because of independent rounding. • In some reporting of capacity data, such as for wind, solar and wave energy sites, the capacity for multiple generators is reported in a single generator record and is presented as a single generator in the count of number of generators.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 2.13. Interconnection Cost and Capacity for New Generators, by Grid Voltage Class, 2006 and 2007

Voltage Class	Units[1]	Nameplate Capacity (megawatts)[1]	Cost (thousand dollars)[1]
2006			
Total	222[R]	11,227[R]	251,953
Distribution (< 35 kV)	111[R]	386[R]	18,752
SubTransmission (35 kV - 138 kV)	47[R]	3,345[R]	76,905
Transmission (> 138 kV)	64[R]	7,496[R]	156,296
2007			
Total	269	14,061	397,921
Distribution (< 35 kV)	163	1,246	55,271
SubTransmission (35 kV - 138 kV)	44	3,083	97,031
Transmission (> 138 kV)	62	9,731	245,619

[1] Cost is the total cost incurred for the direct, physical interconnection of generators that started commercial operation in the respective years. These generator-specific costs may include costs for transmission or distribution lines, transformers, protective devices, substations, switching stations and other equipment necessary for interconnection. Units and Nameplate Capacity represent the number of units and associated capacity for which interconnection costs were incurred and reported.

R = Revised.

Notes: • See Glossary reference for definitions. • Totals may not equal sum of components because of independent rounding. • In some reporting of capacity data, such as for wind, solar and wave energy sites, the capacity for multiple generators is reported in a single generator record and is presented as a single generator in the count of number of generators.

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

Chapter 3. Demand, Capacity Resources, and Capacity Margins

Table 3.1. Noncoincident Peak Load, Actual and Projected by North American Electric Reliability Council Region, 2003 through 2012
(Megawatts)

North American Electric Reliability Council Region	Actual 2003	2004	2005	2006	2007
Summer					
ECAR[1]	98,487	95,300	NA	NA	NA
ERCOT	59,996	58,531	60,210	62,339	62,188
FRCC	40,475	42,383	46,396	45,751	46,676
MAAC[1]	53,566	52,049	NA	NA	NA
MAIN[1]	56,988	53,439	NA	NA	NA
MRO (U.S.) [2]	28,831	29,351	39,918	42,194	41,684
NPCC (U.S.)	55,018	52,549	58,960	63,241	58,314
Reliability*First*[3]	NA	NA	190,200	191,920	181,700
SERC	153,110	157,615	190,705	199,052	209,109
SPP	40,367	40,106	41,727	42,882	43,167
WECC (U.S.)	122,537	123,136	130,760	142,096	139,389
Contiguous U.S.	**709,375**	**704,459**	**758,876**	**789,475**	**782,227**
Winter					
ECAR[1]	86,332	91,800	NA	NA	NA
ERCOT	42,702	44,010	48,141	50,402	50,408
FRCC	36,841	44,839	42,657	42,526	41,701
MAAC[1]	45,625	45,905	NA	NA	NA
MAIN[1]	41,719	42,929	NA	NA	NA
MRO (U.S.) [2]	24,134	24,526	33,748	34,677	33,191
NPCC (U.S.)	48,079	48,176	46,828	46,697	46,795
Reliability*First*[3]	NA	NA	151,600	149,631	141,900
SERC	137,972	144,337	164,638	175,163	179,888
SPP	28,450	29,490	31,260	30,792	31,322
WECC (U.S.)	102,020	102,689	107,493	111,093	112,700
Contiguous U.S.	**593,874**	**618,701**	**626,365**	**640,981**	**637,905**

North American Electric Reliability Council Region	Projected 2008	2009	2010	2011	2012
Summer					
TRE (formerly ERCOT)	64,927	66,247	67,641	68,964	70,052
FRCC	47,364	48,181	49,093	50,284	51,499
MRO (U.S.) [2]	41,222	43,208	44,737	45,779	46,593
NPCC (U.S.)	61,779	62,647	63,399	64,173	64,932
Reliability*First*[3]	184,000	187,100	190,700	193,400	195,700
SERC	204,791	209,288	213,720	217,774	221,590
SPP	43,800	44,784	45,657	46,355	47,011
WECC (U.S.)	142,032	145,217	147,942	150,756	153,767
Contiguous U.S.	**789,915**	**806,672**	**822,889**	**837,485**	**851,144**
Winter					
TRE (formerly ERCOT)	47,270	48,285	49,250	50,053	50,590
FRCC	49,601	50,463	51,606	52,753	53,896
MRO (U.S.) [2]	34,100	35,085	36,298	36,967	37,556
NPCC (U.S.)	48,323	48,911	49,471	49,998	50,537
Reliability*First*[3]	147,100	149,100	151,500	153,400	154,800
SERC	182,055	185,850	188,473	192,292	194,541
SPP	31,954	32,585	33,293	33,932	34,515
WECC (U.S.)	116,586	118,832	120,782	122,778	125,016
Contiguous U.S.	**656,989**	**669,111**	**680,673**	**692,173**	**701,450**

[1] ECAR, MAAC, and MAIN dissolved at the end of 2005. Utility membership joined other reliability regional councils. Also, see Footnote 3.
[2] Regional name has changed from Mid-Continent Area Power Pool to Midwest Reliability Organization.
[3] ReliabilityFirst Corporation (RFC) came into existence on January 1, 2006, and submitted a consolidated filing covering the historical NERC regions of ECAR, MAAC, and MAIN. Many of the former utility members joined RFC.

NA = Not available.

Notes: • Projected data are updated annually, so revision superscript is not used. • NERC Regional Council names may be found in the Glossary reference. • Represents an hour of a day during the associated peak period. • The summer peak period begins on June 1 and extends through September 30. • The winter peak period begins on December 1 and extends through the end of February of the following year • The MRO, SERC, and SPP regional boundaries were altered as a variety of utilities changed reliability organizations. The historical data series have not been adjusted. • Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program."

Table 3.2. Net Internal Demand, Capacity Resources, and Capacity Margins by North American Electric Reliability Council Region, Summer, 1996 through 2007

(Megawatts)

Region and Item	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
ECAR[1]												
Net Internal Demand[2]	NA	NA	NA	95,300	98,487	101,251	100,235	98,651	94,072	92,359	91,103	88,573
Capacity Resources[3]...................	NA	NA	NA	127,919	123,755	119,736	113,136	115,379	107,451	105,545	105,106	104,953
Capacity Margin (percent)[4].........	NA	NA	NA	25.5	20.4	15.4	11.4	14.5	12.5	12.5	13.3	15.6
TRE (formerly ERCOT)												
Net Internal Demand[2]	63,725	62,669	59,060	58,531	59,282	55,833	55,106	53,649	51,697	50,254	47,746	45,636
Capacity Resources[3]...................	72,503	71,156	66,724	73,850	74,764	76,849	70,797	69,622	65,423	59,788	55,771	55,230
Capacity Margin (percent)[4].........	12.1	11.9	11.5	20.7	20.7	27.3	22.2	22.9	21.0	15.9	14.4	17.4
FRCC												
Net Internal Demand[2]	44,417	43,824	45,950	42,243	40,387	37,951	38,932	35,666	34,832	34,562	32,874	31,868
Capacity Resources[3]...................	53,553	53,171	50,200	48,579	46,806	43,342	42,290	43,083	40,645	39,708	39,613	38,237
Capacity Margin (percent)..........	17.1	17.6	8.5	13.0	13.7	12.4	7.9	17.2	14.3	13.0	17.0	16.7
MAAC[1]												
Net Internal Demand[2]	NA	NA	NA	52,049	53,566	54,296	54,015	51,358	49,325	47,626	46,548	45,628
Capacity Resources[3]...................	NA	NA	NA	66,167	65,897	63,619	59,533	60,679	57,831	55,511	56,155	56,774
Capacity Margin (percent)[4].........	NA	NA	NA	21.3	18.7	14.7	9.3	15.4	14.7	14.2	17.1	19.6
MAIN[1]												
Net Internal Demand[2]	NA	NA	NA	50,499	53,617	53,267	53,032	51,845	47,165	45,570	45,194	44,470
Capacity Resources[3]...................	NA	NA	NA	65,677	67,410	67,025	65,950	64,170	55,984	52,722	52,160	52,880
Capacity Margin (percent)[4].........	NA	NA	NA	23.1	20.5	20.5	19.6	19.2	15.8	13.6	13.4	15.9
MRO (U.S.)[5]												
Net Internal Demand[2]	41,260	41,754	38,266	29,094	28,775	28,825	27,125	28,006	30,606	29,766	28,221	27,298
Capacity Resources[3]...................	47,875	49,792	46,792	35,830	33,287	34,259	32,271	34,236	35,373	34,773	34,027	33,121
Capacity Margin (percent)[4].........	13.8	16.1	18.2	18.8	13.6	15.9	15.9	18.2	13.5	14.4	17.1	17.6
NPCC (U.S.)												
Net Internal Demand[2]	58,371	59,727	57,402	51,580	53,936	55,164	55,888	54,270	53,450	51,760	50,240	48,950
Capacity Resources[3]...................	72,105	70,607	72,258	71,532	70,902	66,208	63,760	63,376	63,077	60,439	60,729	58,592
Capacity Margin (percent)[4].........	19.0	15.4	20.6	27.9	23.9	16.7	12.3	14.4	15.3	14.4	17.3	16.5
Reliability*First*[6]												
Net Internal Demand[2]	177,200	179,600	190,200	NA	NA	NA	NA	NA	NA	NA	NA	NA
Capacity Resources[3]...................	213,787	213,792	220,000	NA	NA	NA	NA	NA	NA	NA	NA	NA
Capacity Margin (percent)[4].........	17.1	16.0	13.5	NA	NA	NA	NA	NA	NA	NA	NA	NA
SERC												
Net Internal Demand[2]	198,522	196,111	186,049	153,024	148,380	154,459	144,399	151,527	142,726	138,146	134,968	109,270
Capacity Resources[3]...................	235,485	231,123	219,749	182,861	177,231	172,485	171,530	169,760	160,575	158,360	155,016	126,196
Capacity Margin (percent)[4].........	15.7	15.1	15.3	16.3	16.3	10.5	15.8	10.7	11.1	12.8	12.9	13.4
SPP												
Net Internal Demand[2]	43,056	42,266	41,079	39,383	39,428	38,298	38,807	39,056	37,807	36,402	37,009	59,017
Capacity Resources[3]...................	50,109	46,564	46,376	48,000	45,802	47,233	45,530	46,109	43,111	42,554	43,591	69,344
Capacity Margin (percent)[4].........	14.1	9.2	11.4	18.0	13.9	18.9	14.8	15.3	12.3	14.5	15.1	14.9
WECC (U.S.)												
Net Internal Demand[2]	137,925	134,157	128,464	121,205	120,894	117,032	107,294	116,913	112,177	111,641	104,486	101,728
Capacity Resources[3]...................	169,876	169,950	160,026	155,455	150,277	142,624	124,193	141,640	136,274	135,270	135,687	135,049
Capacity Margin (percent)[4].........	18.8	21.1	19.7	22.0	19.6	17.9	13.6	17.5	17.7	17.5	23.0	24.7
Contiguous U.S.												
Net Internal Demand[2]...............	**764,476**	**760,108**	**746,470**	**692,908**	**696,752**	**696,376**	**674,833**	**680,941**	**653,857**	**638,086**	**618,389**	**602,438**
Capacity Resources[3].................	**915,292**	**906,155**	**882,125**	**875,870**	**856,131**	**833,380**	**788,990**	**808,054**	**765,744**	**744,670**	**737,855**	**730,376**
Capacity Margin (percent)[4]	**16.5**	**16.1**	**15.4**	**20.9**	**18.6**	**16.4**	**14.5**	**15.7**	**14.6**	**14.3**	**16.2**	**17.5**

[1] ECAR, MAAC, and MAIN dissolved at the end of 2005. Utility membership joined other reliability regional councils. Also, see Footnote 6.
[2] Net Internal Demand represent the system demand that is planned for by the electric power industry`s reliability authority and is equal to Internal Demand less Direct Control Load Management and Interruptible Demand.
[3] 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.
[4] Capacity Margin is the amount of unused available capability of an electric power system at peak load as a percentage of capacity resources.
[5] Regional name has changed from Mid-Continent Area Power Pool to Midwest Reliability Organization.
[6] ReliabilityFirst Corporation (RFC) came into existence on January 1, 2006, and submitted a consolidated filing covering the historical NERC regions of ECAR, MAAC, and MAIN. Many of the former utility members joined RFC.

NA = Not available.

Notes: • NERC Regional Council names may be found in the Glossary reference. • Represents an hour of a day during the associated peak period. • The summer peak period begins on June 1 and extends through September 30. • The MRO, SERC, and SPP regional boundaries were altered as a variety of utilities changed reliability organizations. The historical data series have not been adjusted. • Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program."

Table 3.3. Net Internal Demand, Actual or Planned Capacity Resources, and Capacity Margins by North American Electric Reliability Council Region, Summer, 2007 through 2012
(Megawatts)

North American Electric Reliability Council Region	Net Internal Demand[1]	Capacity Resources[2]	Capacity Margin (percent)[3]	Net Internal Demand[1]	Capacity Resources[2]	Capacity Margin (percent)[3]
	2007			2008		
TRE (formerly ERCOT)	63,725	72,503	12.1	65,028	75,749	14.2
FRCC	44,417	53,553	17.1	45,141	55,622	18.8
MRO (U.S.)[4]	41,260	47,875	13.8	42,558	49,182	13.5
NPCC (U.S.)	58,371	72,105	19.0	59,239	72,897	18.7
Reliability*First*[5]	177,200	213,787	17.1	180,300	214,783	16.1
SERC	198,522	235,485	15.7	202,854	237,037	14.4
SPP	43,056	50,109	14.1	44,018	51,901	15.2
WECC (U.S.)	137,925	169,876	18.8	140,940	172,167	18.1
Contiguous U.S.	**764,476**	**915,292**	**16.5**	**780,078**	**929,338**	**16.1**
	2009			2010		
TRE (formerly ERCOT)	66,422	77,894	14.7	67,745	77,918	13.1
FRCC	45,980	57,202	19.6	47,085	59,312	20.6
MRO (U.S.)[4]	43,508	49,055	11.3	44,252	49,313	10.3
NPCC (U.S.)	59,532	72,084	17.4	60,306	72,923	17.3
Reliability*First*[5]	183,900	217,625	15.5	186,600	219,492	15.0
SERC	207,110	237,304	12.7	211,114	238,933	11.6
SPP	44,902	53,420	15.9	45,594	53,881	15.4
WECC (U.S.)	143,502	173,494	17.3	146,205	175,269	16.6
Contiguous U.S.	**794,856**	**938,078**	**15.3**	**808,902**	**947,041**	**14.6**
	2011			2012		
TRE (formerly ERCOT)	68,833	78,843	12.7	70,235	78,843	10.9
FRCC	48,212	59,979	19.6	49,277	61,693	20.1
MRO (U.S.)[4]	44,993	49,529	9.2	45,732	49,884	8.3
NPCC (U.S.)	61,065	72,923	16.3	61,798	72,800	15.1
Reliability*First*[5]	188,900	219,492	13.9	191,600	219,492	12.7
SERC	214,834	240,273	10.6	218,943	240,423	8.9
SPP	46,248	54,328	14.9	46,947	54,630	14.1
WECC (U.S.)	149,137	175,431	15.0	151,837	176,064	13.8
Contiguous U.S.	**822,221**	**950,799**	**13.5**	**836,370**	**953,830**	**12.3**

[1] Net Internal Demand represent the system demand that is planned for by the electric power industry`s reliability authority and is equal to Internal Demand less Direct Control Load Management and Interruptible Demand.
[2] 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.
[3] Capacity Margin is the amount of unused available capability of an electric power system at peak load as a percentage of capacity resources.
[4] Regional name has changed from Mid-Continent Area Power Pool to Midwest Reliability Organization.
[5] ReliabilityFirst Corporation (RFC) came into existence on January 1, 2006, and submitted a consolidated filing covering the historical NERC regions of ECAR, MAAC, and MAIN. Many of the former utility members joined RFC.

Notes: • Actual data are final. • Projected data are updated annually, so revision superscript is not used. • Represents an hour of a day during the associated peak period. • The summer peak period begins on June 1 and extends through September 30. • The MRO, SERC, and SPP regional boundaries were altered as utilities changed reliability organizations. The historical data series have not been adjusted. • Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program."

Table 3.4. Net Internal Demand, Actual or Planned Capacity Resources, and Capacity Margins by North American Electric Reliability Council Region, Winter, 2007 through 2012
(Megawatts)

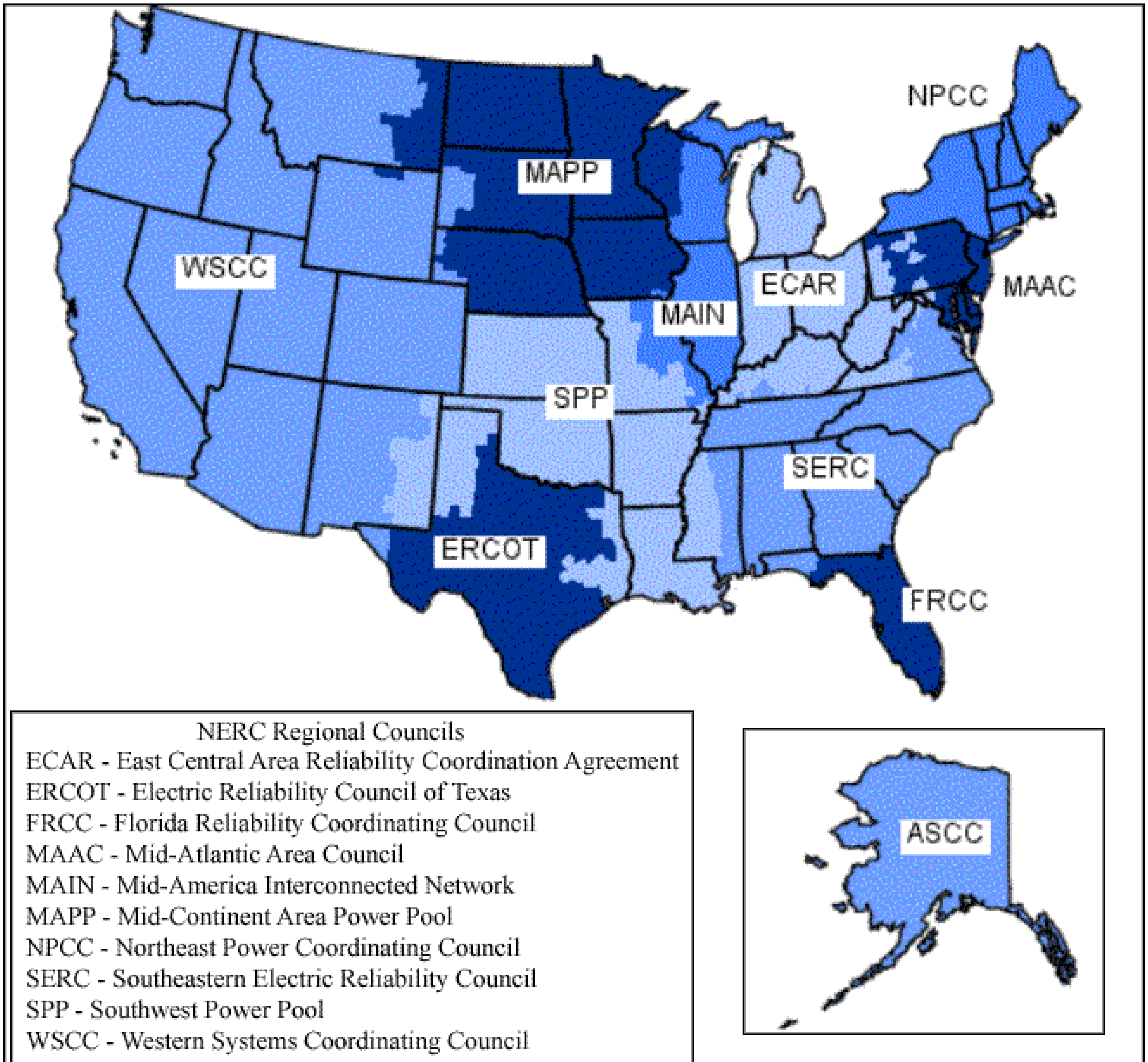
North American Electric Reliability Council Region	Net Internal Demand[1]	Capacity Resources[2]	Capacity Margin (percent)[3]	Net Internal Demand[1]	Capacity Resources[2]	Capacity Margin (percent)[2]
	2007/ 2008			2008/ 2009		
TRE (formerly ERCOT)	46,068	75,504	39.0	47,066	78,279	39.9
FRCC	46,093	57,510	19.9	46,901	59,878	21.7
MRO (U.S.)[4]	34,358	44,987	23.6	35,551	46,724	23.9
NPCC (U.S.)	46,185	75,772	39.0	46,773	76,515	38.9
Reliability*First*[5]	141,200	212,257	33.5	143,300	214,510	33.2
SERC	176,766	229,627	23.0	180,417	231,313	22.0
SPP	31,455	50,223	37.4	32,101	51,479	37.6
WECC (U.S.)	113,504	167,770	32.3	115,628	169,083	31.6
Contiguous U.S.	**635,629**	**913,650**	**30.4**	**647,737**	**927,781**	**30.2**
	2009/ 2010			2010/ 2011		
TRE (formerly ERCOT)	48,031	80,424	40.3	48,834	80,447	39.3
FRCC	47,963	61,580	22.1	49,041	64,007	23.4
MRO (U.S.)[4]	36,272	46,877	22.6	36,861	47,299	22.1
NPCC (U.S.)	47,192	72,950	35.3	47,719	73,591	35.2
Reliability*First*[5]	145,800	217,555	33.0	147,700	217,827	32.2
SERC	183,007	231,881	21.1	186,795	233,712	20.1
SPP	32,803	53,173	38.3	33,439	53,288	37.2
WECC (U.S.)	117,517	170,745	31.2	119,442	171,721	30.4
Contiguous U.S.	**658,585**	**935,184**	**29.6**	**669,831**	**941,892**	**28.9**
	2011/ 2012			2012/ 2013		
TRE (formerly ERCOT)	49,371	81,372	39.3	50,553	81,372	37.9
FRCC	50,104	65,107	23.0	51,055	66,615	23.4
MRO (U.S.)[4]	37,436	47,292	20.8	37,720	48,040	21.5
NPCC (U.S.)	48,258	73,759	34.6	48,813	73,599	33.7
Reliability*First*[5]	149,100	217,827	31.6	150,600	217,967	30.9
SERC	188,972	235,730	19.8	192,386	235,589	18.3
SPP	34,021	53,730	36.7	34,705	54,084	35.8
WECC (U.S.)	121,657	171,862	29.2	123,604	172,202	28.2
Contiguous U.S.	**678,918**	**946,679**	**28.3**	**689,435**	**949,467**	**27.4**

[1] Net Internal Demand represent the system demand that is planned for by the electric power industry`s reliability authority and is equal to Internal Demand less Direct Control Load Management and Interruptible Demand.
[2] 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.
[3] Capacity Margin is the amount of unused available capability of an electric power system at peak load as a percentage of capacity resources.
[4] Regional name has changed from Mid-Continent Area Power Pool to Midwest Reliability Organization.
[5] ReliabilityFirst Corporation (RFC) came into existence on January 1, 2006, and submitted a consolidated filing covering the historical NERC regions of ECAR, MAAC, and MAIN. Many of the former utility members joined RFC.

Notes: • Actual data are final. • Projected data are updated annually, so revision superscript is not used. • Represents an hour of a day during the associated peak period. • The winter peak period begins on December 1 and extends through the end of February of the following year. For example, winter 2004/2005 begins December 1, 2004, and extends to February 28, 2005 • The MRO, SERC, and SPP regional boundaries were altered as a variety of utilities changed reliability organizations. The historical data series have not been adjusted. • Totals may not equal sum of components because of independent rounding.

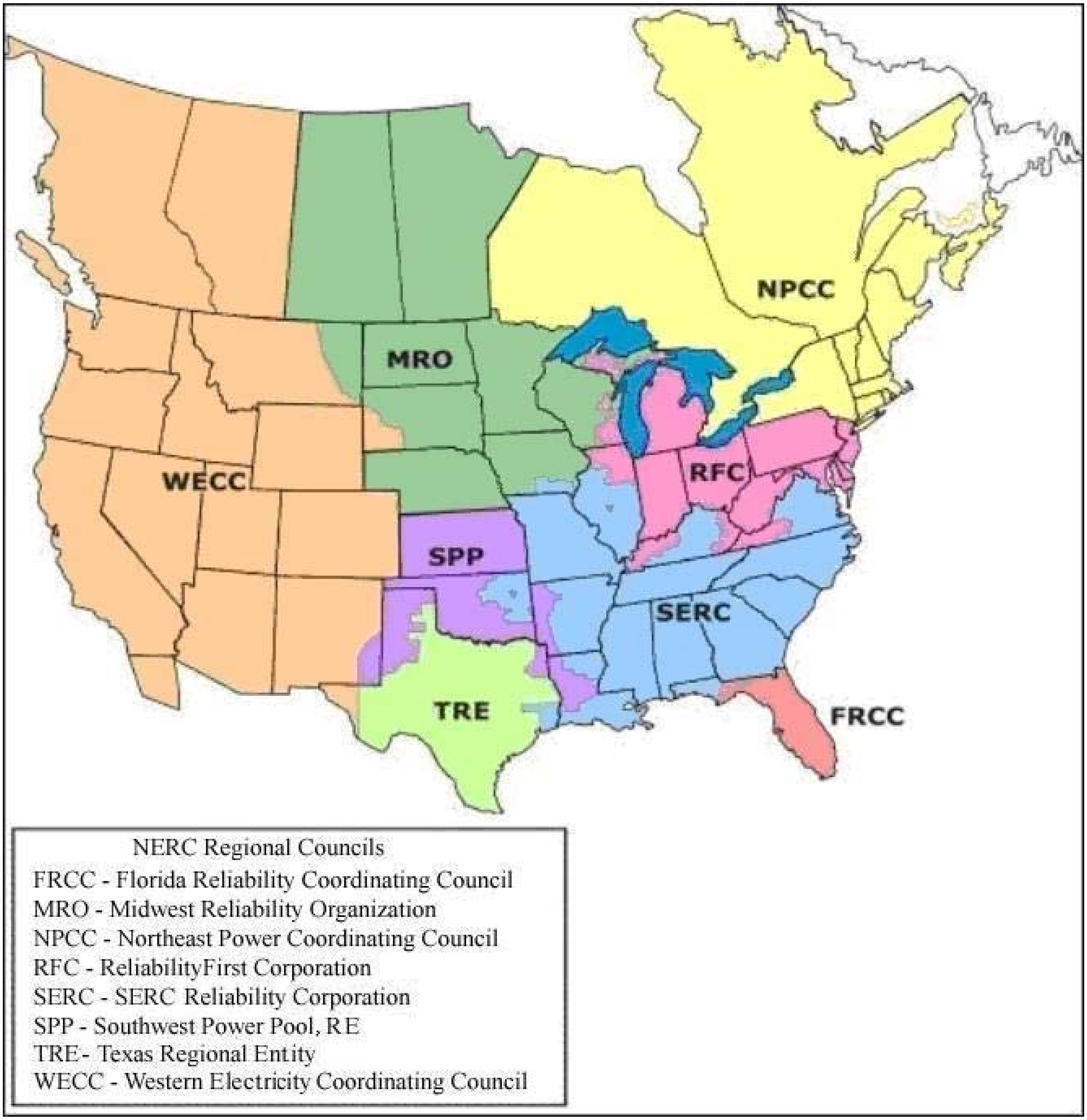
Source: Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program."

Figure 3.1 Historical North American Reliability Council Regions for the Contiguous U.S., 1996



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

Figure 3.2 Consolidated North American Electric Reliability Corporation Regional Entities, 2007



Source: North American Electric Reliability Corporation.

Chapter 4. Fuel

Table 4.1. Consumption of Fossil Fuels for Electricity Generation by Type of Power Producer, 1996 through 2007

Type of Power Producer and Period	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Natural Gas (Thousand Mcf)	Other Gases (Million Btu)[3]
Total (All Sectors)				
1996	907,209	144,626	4,312,458	158,560
1997	931,949	159,715	4,564,770	119,412
1998	946,295	222,640	5,081,384	124,988
1999	949,802	207,871	5,321,984	126,387
2000	994,933	195,228	5,691,481	125,971
2001	972,691	216,672	5,832,305	97,308
2002	987,583	168,597	6,126,062	131,230
2003	1,014,058	206,653	5,616,135	156,306
2004[R]	1,020,523	203,494	5,674,580	135,144
2005[R]	1,041,448	206,785	6,036,370	109,916
2006[R]	1,030,556	110,634	6,461,615	114,665
2007	1,046,795	112,615	7,089,342	114,904
Electricity Generators, Electric Utilities				
1996	874,681	116,680	2,732,107	--
1997	900,361	132,147	2,968,453	--
1998	910,867	187,461	3,258,054	--
1999	894,120	151,868	3,113,419	--
2000	859,335	125,788	3,043,094	--
2001	806,269	133,456	2,686,287	--
2002	767,803	99,219	2,259,684	5,182
2003	757,384	118,087	1,763,764	6,078
2004	772,224	124,541	1,809,443	5,163
2005	761,349	118,874	2,134,859	91
2006	753,390	71,624	2,478,396	358
2007	764,765	70,950	2,736,418	1,523
Electricity Generators, Independent Power Producers				
1996	4,143	2,169	91,617	71
1997	3,884	4,010	70,774	642
1998	9,486	9,676	285,878	1,345
1999	30,572	30,037	615,756	696
2000	107,745	45,011	1,049,636	1,951
2001	139,799	60,489	1,477,643	92
2002	192,274	44,993	1,998,782	354
2003	226,154	68,817	2,016,550	171
2004	222,550	63,060	2,332,092	86
2005	254,291	72,953	2,457,412	43
2006	251,379	26,873	2,612,653	49
2007	258,075	29,868	2,875,183	62
Combined Heat and Power, Electric Power[4]				
1996	15,575	11,320	836,086	15,494
1997	14,764	11,046	863,968	13,773
1998	13,773	12,310	871,881	21,406
1999	13,197	12,440	914,600	13,627
2000	15,634	13,147	921,341	16,871
2001	15,455	11,175	978,563	9,352
2002	15,174	11,942	1,149,812	19,958
2003	19,498	8,431	1,128,935	23,317
2004[R]	17,685	8,209	933,804	21,899
2005[R]	17,927	7,933	892,509	24,289
2006[R]	18,033	6,738	800,173	27,173
2007	18,506	6,498	890,012	25,428
Combined Heat and Power, Commercial[5]				
1996	656	645	42,380	*
1997	630	790	38,975	23
1998	440	802	40,693	54
1999	481	931	39,045	*
2000	514	823	37,029	*
2001	532	1,023	36,248	*
2002	477	834	32,545	*
2003	582	894	38,480	--
2004	377[R]	766[R]	32,839[R]	--
2005	377[R]	585[R]	33,785[R]	--
2006	347[R]	333[R]	34,623[R]	--
2007	361	258	34,087	--
Combined Heat and Power, Industrial[6]				
1996	12,153	13,813	610,268	142,995
1997	12,311	11,723	622,599	104,974
1998	11,728	12,392	624,878	102,183
1999	11,432	12,595	639,165	112,064
2000	11,706	10,459	640,381	107,149
2001	10,636	10,530	653,565	87,864
2002	11,855	11,608	685,239	105,737
2003	10,440	10,424	668,407	126,739
2004[R]	7,687	6,919	566,401	107,995
2005[R]	7,504	6,440	517,805	85,492
2006[R]	7,408	5,066	535,770	87,084
2007	5,089	5,041	553,643	87,892

[1] Includes anthracite, bituminous, subbituminous and lignite coal. Waste and synthetic coal were included starting in 2002.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[3] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[4] Electric utility CHP plants are included in Electricity Generators, Electric Utilities.
[5] Small number of commercial electricity-only plants included.
[6] Small number of industrial electricity-only plants included.
* = Value is less than half of the smallest unit of measure.

R = Revised.

Notes: • See Glossary reference for definitions • A new method of allocating fuel consumption between electric power generation and useful thermal output (UTO) was implemented. The new methodology evenly distributes a combined heat and power (CHP) plant`s losses between the two output products (electric power and UTO). In the historical data, UTO was consistently assumed to be 80 percent efficient and all other losses at the plant were allocated to electric power. This change results in the fuel for electric power to be lower while the fuel for UTO is higher than the prior set of data as both are given the same efficiency. This results in the appearance of an increase in efficiency of production of electric power between 2003 and 2004.

Sources: Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920 "Combined Heat and Power Plant Report" and predecessor forms.

Table 4.2. Consumption of Fossil Fuels for Useful Thermal Output by Type of Combined Heat and Power Producers, 1996 through 2007

Type of Power Producer and Year	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Natural Gas (Thousand Mcf)	Other Gases (Million Btu)[3]
Total Combined Heat and Power				
1996	20,806	27,873	865,774	187,290
1997	21,005	28,802	868,569	187,680
1998	20,320	28,845	949,106	208,828
1999	20,373	26,822	982,958	223,713
2000	20,466	22,266	985,263	230,082
2001	18,944	18,268	898,286	166,161
2002	17,561	14,811	860,019	146,882
2003	17,720	17,939	721,267	137,837
2004[R]	24,275	25,870	1,052,100	218,295
2005[R]	23,833	24,408	984,340	238,396
2006[R]	23,227	20,371	942,817	226,464
2007	22,810	19,775	872,579	214,321
Electric Power[4]				
1996	2,520	2,424	147,091	4,912
1997	2,355	2,466	161,608	9,684
1998	2,493	1,322	172,471	6,329
1999	3,033	1,423	175,757	4,435
2000	3,107	1,412	192,253	6,641
2001	2,910	1,171	199,808	5,849
2002	2,255	841	263,619	7,448
2003	2,080	1,596	225,967	11,601
2004[R]	3,809	2,688	388,424	31,132
2005[R]	3,918	2,424	384,365	59,569
2006[R]	3,834	2,129	330,878	36,963
2007	3,795	2,114	339,796	34,384
Commercial				
1996	1,005	601	40,075	--
1997	1,108	794	47,941	25
1998	1,002	1,006	46,527	41
1999	1,009	682	44,991	--
2000	1,034	792	47,844	--
2001	916	809	42,407	--
2002	929	416	41,430	--
2003	1,234	555	19,973	--
2004	1,540[R]	1,243[R]	39,233[R]	--
2005	1,544[R]	1,045[R]	34,172[R]	--
2006	1,539[R]	601[R]	33,112[R]	1
2007	1,566	494	35,987	--
Industrial				
1996	17,281	24,848	678,608	182,378
1997	17,542	25,541	659,021	177,971
1998	16,824	26,518	730,108	202,458
1999	16,330	24,718	762,210	219,278
2000	16,325	20,062	745,165	223,441
2001	15,119	16,287	656,071	160,312
2002	14,377	13,555	554,970	139,434
2003	14,406	15,788	475,327	126,236
2004[R]	18,926	21,939	624,443	187,162
2005[R]	18,371	20,940	565,803	178,827
2006[R]	17,854	17,640	578,828	189,501
2007	17,449	17,166	496,796	179,937

[1] Includes anthracite, bituminous, subbituminous and lignite coal. Waste and synthetic coal were included starting in 2002.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[3] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[4] Electric utility CHP plants are included in Table 4.1 with Electric Generators, Electric Utilities.
R = Revised.

Notes: • Totals may not equal sum of components because of independent rounding. • A new method of allocating fuel consumption between electric power generation and useful thermal output (UTO) was implemented. The new methodology evenly distributes a combined heat and power (CHP) plant`s losses between the two output products (electric power and UTO). In the historical data, UTO was consistently assumed to be 80 percent efficient and all other losses at the plant were allocated to electric power. This change results in the fuel for electric power to be lower while the fuel for UTO is higher than the prior set of data as both are given the same efficiency. This results in the appearance of an increase in efficiency of production of electric power between 2003 and 2004.

Sources: Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920 "Combined Heat and Power Plant Report" and predecessor forms.

Table 4.3. Consumption of Fossil Fuels for Electricity Generation and for Useful Thermal Output, 1996 through 2007

Period	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Natural Gas (Thousand Mcf)	Other Gases (Million Btu)[3]
Total (All Sectors)				
1996	928,015	172,499	5,178,232	345,850
1997	952,955	188,517	5,433,338	307,092
1998	966,615	251,486	6,030,490	333,816
1999	970,175	234,694	6,304,942	350,100
2000	1,015,398	217,494	6,676,744	356,053
2001	991,635	234,940	6,730,591	263,469
2002	1,005,144	183,408	6,986,081	278,111
2003	1,031,778	224,593	6,337,402	294,143
2004	1,044,798	229,364	6,726,679	353,438[R]
2005	1,065,281	231,193	7,020,709[R]	348,312
2006	1,053,783	131,005	7,404,432[R]	341,129
2007	1,069,606	132,389	7,961,922	329,225
Electricity Generators, Electric Utilities				
1996	874,681	116,680	2,732,107	--
1997	900,361	132,147	2,968,453	--
1998	910,867	187,461	3,258,054	--
1999	894,120	151,868	3,113,419	--
2000	859,335	125,788	3,043,094	--
2001	806,269	133,456	2,686,287	--
2002	767,803	99,219	2,259,684	5,182
2003	757,384	118,087	1,763,764	6,078
2004	772,224	124,541	1,809,443	5,163
2005	761,349	118,874	2,134,859	91
2006	753,390	71,624	2,478,396	358
2007	764,765	70,950	2,736,418	1,523
Electricity Generators, Independent Power Producers				
1996	4,143	2,169	91,617	71
1997	3,884	4,010	70,774	642
1998	9,486	9,676	285,878	1,345
1999	30,572	30,037	615,756	696
2000	107,745	45,011	1,049,636	1,951
2001	139,799	60,489	1,477,643	92
2002	192,274	44,993	1,998,782	354
2003	226,154	68,817	2,016,550	171
2004	222,550	63,060	2,332,092	86
2005	254,291	72,953	2,457,412	43
2006	251,379	26,873	2,612,653	49
2007	258,075	29,868	2,875,183	62
Combined Heat and Power, Electric Power[4]				
1996	18,096	13,744	983,177	20,406
1997	17,118	13,512	1,025,575	23,457
1998	16,266	13,632	1,044,352	27,735
1999	16,230	13,864	1,090,356	18,062
2000	18,741	14,559	1,113,595	23,512
2001	18,365	12,346	1,178,371	15,201
2002	17,430	12,783	1,413,431	27,406
2003	21,578	10,028	1,354,901	34,918
2004	21,494	10,897	1,322,228	53,031[R]
2005	21,845	10,357	1,276,874	83,858
2006	21,867	8,867	1,131,051	64,136
2007	22,301	8,613	1,229,808	59,812
Combined Heat and Power, Commercial[5]				
1996	1,660	1,246	82,455	*
1997	1,738	1,584	86,915	48
1998	1,443	1,807	87,220	95
1999	1,490	1,613	84,037	*
2000	1,547	1,615	84,874	*
2001	1,448	1,832	78,655	*
2002	1,405	1,250	73,975	*
2003	1,816	1,449	58,453	--
2004	1,917	2,009	72,072	--
2005	1,922	1,630	67,957[R]	--
2006	1,886	935	67,735[R]	1
2007	1,927	752	70,074	--
Combined Heat and Power, Industrial[6]				
1996	29,434	38,661	1,288,876	325,373
1997	29,853	37,265	1,281,620	282,945
1998	28,553	38,910	1,354,986	304,641
1999	27,763	37,312	1,401,374	331,342
2000	28,031	30,520	1,385,546	330,590
2001	25,755	26,817	1,309,636	248,176
2002	26,232	25,163	1,240,209	245,171
2003	24,846	26,212	1,143,734	252,975
2004	26,613	28,857	1,190,844	295,158[R]
2005	25,875	27,380	1,083,607	264,319
2006	25,262	22,706	1,114,597	276,585
2007	22,537	22,207	1,050,439	267,829

[1] Includes anthracite, bituminous, subbituminous and lignite coal. Waste and synthetic coal were included starting in 2002.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[3] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[4] Electric utility CHP plants are included in Electricity Generators, Electric Utilities.
[5] Small number of commercial electricity-only plants included.
[6] Small number of industrial electricity-only plants included.
* = Value is less than half of the smallest unit of measure.
R = Revised.

Note: Totals may not equal sum of components because of independent rounding
Sources: Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920 "Combined Heat and Power Plant Report" and predecessor forms.

Table 4.4. End-of-Year Stocks of Coal and Petroleum by Type of Producer, 1996 through 2007

Period	Electric Power Sector		Electric Utilities		Independent Power Producers	
	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]
1996	114,623	48,146	114,623	48,146	NA	NA
1997	98,826	51,138	98,826	51,138	NA	NA
1998	120,501	56,591	120,501	56,591	NA	NA
1999	141,604	54,109	129,041	46,169	12,563	7,940
2000	102,296	40,932	90,115	30,502	12,180	10,430
2001	138,496	57,031	117,147	37,308	21,349	19,723
2002	141,714	52,490	116,952	31,243	24,761	21,247
2003	121,567	53,170	97,831	29,953	23,736	23,218
2004	106,669	51,434	84,917	32,281	21,751	19,153
2005	101,137	50,062	77,457	31,400	23,680	18,661
2006	140,964	51,583	110,277	32,082	30,688	19,502
2007	151,221	47,203	120,504	29,297	30,717	17,906

[1] Anthracite, bituminous, subbituminous, lignite, and synthetic coal, excludes waste coal.

[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology). Data prior to 2005 includes small quantities of waste oil.

NA = Not available.

Note: Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920 "Combined Heat and Power Plant Report" and predecessor forms.

Table 4.5. Receipts, Average Cost, and Quality of Fossil Fuels for the Electric Power Industry, 1996 through 2007

Period	Coal[1]				Petroleum[2]				Natural Gas[3]		All Fossil Fuels
	Receipts	Average Cost		Avg. Sulfur Percent by Weight	Receipts	Average Cost		Avg. Sulfur Percent by Weight	Receipts	Average Cost	Average Cost
	(thousand tons)	(cents per MMBtu)	(dollars/ ton)		(thousand barrels)	(cents per MMBtu)	(dollars/ barrel)		(thousand Mcf)	(cents per MMBtu)	(cents per MMBtu)
1996	862,701	129	26.45	1.10	113,678	303	18.98	1.26	2,604,663	264	152
1997	880,588	127	26.16	1.11	128,749	273	17.18	1.37	2,764,734	276	152
1998	929,448	125	25.64	1.06	181,276	202	12.71	1.48	2,922,957	238	144
1999	908,232	122	24.72	1.01	145,939	236	14.81	1.51	2,809,455	257	144
2000	790,274	120	24.28	.93	108,272	418	26.30	1.33	2,629,986	430	174
2001	762,815	123	24.68	.89	124,618	369	23.20	1.42	2,148,924	449	173
2002[4]	884,287	125	25.52	.94	120,851	334	20.77	1.64	5,607,737	356	186[R]
2003	986,026	128	26.00	.97	185,567	433	26.78	1.53	5,500,704	539	228
2004	1,002,032	136	27.42	.97	186,655	429	26.56	1.66	5,734,054	596	248
2005	1,021,437	154	31.20	.98	194,733	644	39.65	1.61	6,181,717	821	325
2006	1,079,943	169	34.09	.97	100,965	623	37.66	2.31[5]	6,675,246	694	302
2007	1,054,664	177	35.48	.96	88,347	717	43.50	2.10	7,200,316	711	323

[1] Anthracite, bituminous, subbituminous, lignite, waste coal, and synthetic coal.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[3] Natural gas, including a small amount of supplemental gaseous fuels that cannot be identified separately. Natural gas values for 2001 forward do not include blast furnace gas or other gas.
[4] Beginning in 2002, data from the historic Form EIA-423 for independent power producers and combined heat and power producers are included in this table. Prior to 2002, these data were not collected; the data for 2001 and previous years include only data collected from electric utilities via the historic FERC Form 423.
[5] The sulfur content for petroleum liquids in 2006 was 0.74 percent and for petroleum coke it was 5.15 percent. Because the total receipts of petroleum liquids in 2006 went down by approximately 60 percent while the receipts of petroleum coke remained about the same, the weight of petroleum liquids was much less in 2006. As a result, the average sulfur content was more influenced by the petroleum coke receipts and, therefore, increased significantly.
R = Revised.
Note: MCF equals 1,000 cubic feet. Totals may not equal sum of components because of independent rounding.
Sources: Energy Information Administration, Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report;" Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 4.6. Receipts and Quality of Coal Delivered for the Electric Power Industry, 1996 through 2007

Period	Anthracite[1]			Bituminous[1]			Subbituminous			Lignite		
	Receipts (thousand tons)	Avg. Sulfur Percent by Weight	Avg. Ash Percent by Weight	Receipts (thousand tons)	Avg. Sulfur Percent by Weight	Avg. Ash Percent by Weight	Receipts (thousand tons)	Avg. Sulfur Percent by Weight	Avg. Ash Percent by Weight	Receipts (thousand tons)	Avg. Sulfur Percent by Weight	Avg. Ash Percent by Weight
1996	735	.52	37.7	454,814	1.64	10.3	328,874	.39	6.6	78,278	.92	13.6
1997	751	.53	36.7	466,104	1.65	10.5	336,805	.40	6.7	76,928	.98	13.8
1998	511	.55	37.6	478,252	1.61	10.5	373,496	.38	6.6	77,189	.95	13.8
1999	137	.64	37.8	444,399	1.57	10.2	386,271	.38	6.6	77,425	.90	14.2
2000	11	.64	37.2	375,673	1.45	10.1	341,242	.35	6.3	73,349	.91	14.2
2001	--	--	--	348,703	1.42	10.4	349,340	.35	6.1	64,772	.98	13.9
2002[2]	--	--	--	412,589	1.47	10.1	391,785	.36	6.2	65,555	.93	13.3
2003	--	--	--	436,809	1.49	9.9	432,513	.38	6.4	79,869	1.03	14.4
2004	--	--	--	441,186	1.50	10.3	445,603	.36	6.0	78,268	1.05	14.2
2005	--	--	--	451,680	1.55	10.5	456,856	.36	6.2	77,677	1.02	14.0
2006	--	--	--	462,992	1.57	10.5	504,947	.35	6.1	75,742	.95	14.4
2007	--	--	--	439,154	1.61	10.3	505,155	.34	6.0	71,930	.90	14.0

[1] Beginning in 2001, anthracite coal receipts were no longer reported separately. From 2001 forward, all anthracite coal receipts have been combined with bituminous coal receipts.
[2] Beginning in 2002, data from the historic Form EIA-423 for independent power producers and combined heat and power producers are included in this table. Prior to 2002, these data were not collected; the data for 2001 and previous years include only data collected from electric utilities via the historic FERC Form 423.
Note: Totals may not equal sum of components because of independent rounding.
Sources: Energy Information Administration, Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report;" Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 4.7. Average Quality of Fossil Fuel Receipts for the Electric Power Industry, 1996 through 2007

Year	Coal[1]			Petroleum[2]		Natural Gas[3]
	Average Btu per Pound	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Average Btu per Gallon	Average Sulfur Percent by Weight	Average Btu per Cubic Foot
1996	10,263	1.10	9.22	149,367	1.26	1,017
1997	10,275	1.11	9.36	149,838	1.37	1,019
1998	10,241	1.06	9.18	149,736	1.48	1,022
1999	10,163	1.01	9.01	149,407	1.51	1,019
2000	10,115	.93	8.84	149,857	1.33	1,020
2001	10,200	.89	8.80	147,857	1.42	1,020
2002[4]	10,168	.94	8.74	147,902	1.64	1,025
2003	10,137	.97	8.98	147,086	1.53	1,030
2004	10,074	.97	8.97	147,286	1.66	1,027
2005	10,107	.98	9.02	146,481	1.61	1,028
2006	10,063	.97	9.03	143,883	2.31[5]	1,027
2007	10,028	.96	8.84	144,545	2.10	1,027

[1] Anthracite, bituminous, subbituminous, lignite, waste coal, and synthetic coal.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[3] Natural gas, including a small amount of supplemental gaseous fuels that cannot be identified separately. Natural gas values for 2001 forward do not include blast furnace gas or other gas.
[4] Beginning in 2002, data from the historic Form EIA-423 for independent power producers and combined heat and power producers are included in this table. Prior to 2002, these data were not collected; the data for 2001 and previous years include only data collected from electric utilities via the historic FERC Form 423.
[5] The sulfur content for petroleum liquids in 2006 was 0.74 percent and for petroleum coke it was 5.15 percent. Because the total receipts of petroleum liquids in 2006 went down by approximately 60 percent while the receipts of petroleum coke remained about the same, the weight of petroleum liquids was much less in 2006. As a result, the average sulfur content was more influenced by the petroleum coke receipts and, therefore, increased significantly.

Note: Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report;" Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 4.8. Average Quality and Weighted Average Cost of Fossil Fuels for the Electric Power Industry, 1996 through 2007

Period	Coal								Petroleum		Natural Gas		Total Fossil Fuels	
	Bituminous		Subbituminous		Lignite		All Rank							
	Receipts (trillion Btu)	Average Cost (cents per MMBtu)	Receipts (trillion Btu)	Average Cost (cents per MMBtu)	Receipts (trillion Btu)	Average Cost (cents per MMBtu)	Receipts (trillion Btu)	Average Cost (cents per MMBtu)	Receipts (trillion Btu)	Average Cost (cents per MMBtu)	Receipts (trillion Btu)	Average Cost (cents per MMBtu)	Receipts (trillion Btu)	Average Cost (cents per MMBtu)
1996	10,940	137	5,738	120	1,018	94	17,707	129	713	303	2,649	264	21,069	152
1997	11,203	135	5,885	119	997	93	18,096	127	810	273	2,818	276	21,724	152
1998	11,510	135	6,520	113	999	94	19,036	125	1,140	202	2,986	238	23,162	144
1999	10,722	131	6,740	110	996	93	18,461	122	916	236	2,862	257	22,238	144
2000	9,050	130	5,991	108	947	94	15,988	120	681	418	2,682	430	19,351	174
2001	8,312	139	6,134	104	839	109	15,286	123	783	369	2,209	449	18,278	173
2002	9,932	142	6,878	105	851	104	17,982	125	751	334	5,750	356	24,483	186
2003	10,543	144	7,598	110	1,026	103	19,990	128	1,146	433	5,663	539	26,799	228
2004	10,538	156	7,817	112	1,012	106	20,189	136	1,155	429	5,891	596	27,234	248
2005	10,833	184	8,004	119	1,008	107	20,647	154	1,198	644	6,357	821	28,202	325
2006	11,129	204	8,842	131	982	115	21,735	169	610	623	6,856	694	29,201	302
2007	10,580	208	8,826	145	925	128	21,152	177	536	717	7,396	711	29,085	323

Note: Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report;" Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Chapter 5. Emissions

Table 5.1. Emissions from Energy Consumption at Conventional Power Plants and Combined-Heat-and-Power Plants, 1996 through 2007
(Thousand Metric Tons)

Emission	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
Carbon Dioxide (CO_2)	2,516,580	2,459,800	2,513,609	2,456,934	2,415,680	2,395,048	2,389,745	2,441,722	2,338,660	2,324,139	2,232,709	2,161,258
Sulfur Dioxide (SO_2)	9,042	9,524	10,340	10,309	10,646	10,881	11,174	11,963[R]	12,843[R]	13,464[R]	13,480[R]	12,991[R]
Nitrogen Oxides (NO_x)	3,650	3,799	3,961	4,143	4,532	5,194	5,290	5,638[R]	5,955[R]	6,459[R]	6,500[R]	6,474[R]

R = Revised.

Notes: • See Appendix A, Technical Notes, for a description of the sources and methodology used to develop the emissions estimates. • CO2 emissions for 1995 - 2000 have been revised to reflect the emission factors shown in Table A3.

Source: Calculations made by the Electric Power Division, Einergy Information Administration.

Table 5.2. Number and Capacity of Fossil-Fueled Steam-Electric Generators with Environmental Equipment, 1996 through 2007

Year	Flue Gas Desulfurization (Scrubbers)		Particulate Collectors		Cooling Towers		Total[1]	
	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)
1996	182	85,842	1,134	352,154	477	166,749	1,299	377,144
1997	183	86,605	1,133	352,068	480	166,886	1,301	377,195
1998	186	87,783	1,130	351,790	474	166,896	1,294	377,117
1999	192	89,666	1,148	353,480	505	175,520	1,343	387,192
2000	192	89,675	1,141	352,727	505	175,520	1,336	386,438
2001	236	97,988	1,273	360,762	616	189,396	1,485	390,821
2002	243	98,673	1,256	359,338	670	200,670	1,522	401,341
2003	246	99,567	1,244	358,009	695	210,928	1,546	409,954
2004	248	101,492	1,217	355,782	732	214,989	1,536	409,769
2005	248	101,648	1,216	355,599	730	217,646	1,535	411,840
2006	NA	NA	NA	NA	NA	NA	NA	NA
2007	NA	NA	NA	NA	NA	NA	NA	NA

[1] Components are not additive since some generators are included in more than one category.

[2] Nameplate capacity

NA = Not available. Form EIA-767 data collection was suspended in the data year 2006.

Notes: • These data are for plants with a fossil-fueled steam-electric capacity of 100 megawatts or more . • Data for Independent Power Producer and Combined Heat and Power plants are included beginning with 2001 data. • Beginning in 2001, data for plants with combustible renewable steam-electric capacity of 10 megawatts or more were also included. • 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 5.3. Average Flue Gas Desulfurization Costs, 1996 through 2007

Year	Average Overhead & Maintenance Costs (mills per kilowatthour)[1]	Average Installed Capital Costs (dollars per kilowatt)
1996	1.07	128.00
1997	1.09	129.00
1998	1.12	126.00
1999	1.13	125.00
2000	.96	124.00
2001	1.27	130.80
2002	1.11	124.18
2003	1.23	123.75
2004	1.38	144.64
2005	1.23	141.34
2006	NA	NA
2007	NA	NA

[1] A mill is one tenth of one cent.

NA = Not available. Form EIA-767 data collection was suspended in the data year 2006.

Notes: • These data are for plants with a fossil-fueled steam-electric capacity of 100 megawatts or more. • Beginning in 2001, data for plants with combustible renewable steam-electric capacity of 10 megawatts or more were also included. • Data for Independent Power Producer and Combined Heat and Power plants are included beginning with 2001 data. • 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."

Chapter 6. Trade

Table 6.1. Electric Power Industry - Electricity Purchases, 1996 through 2007
(Thousand Megawatthours)

	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
U.S. Total	**5,411,405**	**5,502,584**	**6,092,285**	**6,998,549[R]**	**6,979,669**	**8,754,807**	**7,555,276**	**2,345,540**	**2,039,969**	**2,020,622**	**1,966,447**	**1,797,720**
Electric Utilities	2,504,002	2,605,315	2,760,043	2,725,694	2,610,525	2,620,712	3,045,854	2,250,382	1,949,574	1,927,198	1,878,099	1,694,192
Energy-Only Providers	2,805,815	2,793,288	3,250,298	4,170,331[R]	4,264,102	6,050,159	4,412,064	NA	NA	NA	NA	NA
IPP	24,942	26,628	12,201	24,258	37,921	15,801	97,357[1]	10,622	4,358	4,089	1,647	7,713
CHP	76,646	77,353	69,744	78,267	67,122	68,135	NA	84,536	86,037	89,334	86,701	95,814

[1] For 2001, CHP purchases are combined with IPP data above.
NA = Not available.
R = Revised.
Notes: • Energy-only providers are wholesale and retail power marketers. • IPP are independent power producers and CHP are combined heat and power producers. • Totals may not equal sum of components because of independent rounding. • The data collection instrument was changed in 2001 to collect data at the corporate level, rather than the plant level. As a result, comparisons with data prior to 2001 and after 2001 should be done with caution.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report." For unregulated entities prior to 2001, Form EIA-860B, "Annual Electric Generator Report - Nonutility," and predecessor forms; and Form EIA-923, "Power Plant Operations Report" for 2007 and predecessor form(s) for earlier years.

Table 6.2. Electric Power Industry - Electricity Sales for Resale, 1996 through 2007
(Thousand Megawatthours)

	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
U.S. Total	**5,479,394**	**5,493,473**	**6,071,659**	**6,758,975[R]**	**6,920,954**	**8,568,678**	**7,345,319**	**2,355,154**	**1,998,090**	**1,921,858**	**1,838,539**	**1,656,090**
Electric Utilities	1,603,179	1,698,389	1,925,710	1,923,440	1,824,030	1,838,901	2,146,689	1,715,582	1,635,614	1,664,081	1,616,318	1,431,179
Energy-Only Providers	2,476,740	2,446,104	2,867,048	3,756,175[R]	3,906,220	5,757,283	4,386,632	NA	NA	NA	NA	NA
IPP	1,368,310	1,321,342	1,252,796	1,053,364	1,156,796	943,531	811,998[1R]	611,150	335,122	228,617	192,299	194,361
CHP	31,165	27,638	26,105	25,996	33,909	28,963	NA	28,421	27,354	29,160	29,922	30,550

[1] For 2001, CHP sales are combined with IPP data above.
NA = Not available.
R = Revised.
Notes: • Energy-only providers are wholesale and retail power marketers. • IPP are independent power producers and CHP are combined heat and power producers. • The data collection instrument was changed in 2001 to collect data at the corporate level, rather than the plant level. As a result, comparisons with data prior to 2001, and after 2001 should be done with caution. • Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report." For unregulated entities prior to 2001, Form EIA-860B, "Annual Electric Generator Report - Nonutility," and predecessor forms; and Form EIA-923, "Power Plant Operations Report" for 2007 and predecessor form(s) for earlier years.

Table 6.3. Electric Power Industry - U.S. Electricity Imports from and Electricity Exports to Canada and Mexico, 1996 through 2007
(Megawatthours)

Description	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
Electricity Imports and Exports												
Canada												
Imports	50,118,056	41,544,052	42,930,224[R]	33,007,487	29,324,625[R]	36,536,479	38,401,598	48,515,476	42,911,308	39,502,108	43,008,501	42,233,376
Exports	19,559,417	23,405,387	19,320,280[R]	22,482,109	23,584,513[R]	15,231,079	16,105,612	12,684,706	12,953,488	11,683,276	7,470,332	1,986,361
Mexico												
Imports[1]	1,277,644	1,147,258	1,597,275	1,202,576	1,069,926	242,596	98,649	76,800	303,439	11,249	22,729	1,263,152
Exports	584,176	865,948	470,731	415,754	390,190	564,603	367,680	2,144,676	1,268,284	1,973,203	1,503,707	1,315,625
Total Imports	**51,395,702**	**42,691,310**	**44,527,499[R]**	**34,210,063**	**30,394,551[R]**	**36,779,077**	**38,500,247**	**48,592,276**	**43,214,747**	**39,513,357**	**43,031,230**	**43,496,528**
Total Exports	**20,143,592**	**24,271,335**	**19,791,011[R]**	**22,897,863**	**23,974,703[R]**	**15,795,681**	**16,473,292**	**14,829,382**	**14,221,772**	**13,656,479**	**8,974,039**	**3,301,986**

[1] Includes contract terminations in 1997 and 2000.
R = Revised.
Note: Totals may not equal sum of components because of independent rounding.
Source: DOE, Office of Electricity Delivery and Energy Reliability, Form OE-781R, " Annual Report of International Electric Export/Import Data," predecessor forms, and National Energy Board of Canada. For 2001 forward, data from the California Independent System Operator are used in combination with the Form OE-781R values to estimate electricity trade with Mexico.

Chapter 7. Retail Customers, Sales, and Revenue

Table 7.1. Number of Ultimate Customers Served by Sector, by Provider, 1996 through 2007
(Number)

Period	Residential	Commercial	Industrial	Transportation	Other	All Sectors
Total Electric Industry						
1996	105,343,005	13,181,065	586,198	NA	893,884	120,004,152
1997	107,065,589	13,542,374	563,223	NA	951,863	122,123,049
1998	109,048,343	13,887,066	539,903	NA	932,838	124,408,150
1999	110,383,238	14,073,764	552,690	NA	935,311	125,945,003
2000	111,717,711	14,349,067	526,554	NA	974,185	127,567,517
2001	114,890,240	14,867,490	571,463	NA	1,030,046	131,359,239
2002	116,622,037	15,333,700	601,744	NA	1,066,554	133,624,035
2003	117,280,481	16,549,519	713,221	1,127	NA	134,544,348
2004	118,763,768	16,606,783	747,600	1,025	NA	136,119,176
2005	120,760,839	16,871,940	733,862	518	NA	138,367,159
2006	122,471,071	17,172,499	759,604	791	NA	140,403,965
2007	123,949,916	17,377,219	793,767	750	NA	142,121,652
Full-Service Providers[1]						
1996	105,341,408	13,180,632	586,169	NA	893,884	120,002,093
1997	107,033,338	13,540,374	562,972	NA	951,863	122,088,547
1998	108,736,845	13,832,662	538,167	NA	932,838	124,040,512
1999	109,817,057	13,963,937	527,329	NA	934,260	125,242,583
2000	110,505,820	14,058,271	512,551	NA	953,756	126,030,398
2001	112,472,629	14,364,578	553,280	NA	1,004,027	128,394,514
2002	113,790,812	14,899,747	586,217	NA	1,035,604	130,312,380
2003	115,029,545	16,136,616	695,616	1,042	NA	131,862,819
2004	116,325,747	16,161,269	733,809	941	NA	133,221,766
2005	118,469,928	16,389,549	719,219	496	NA	135,579,192
2006	120,677,627	16,673,766	745,645	764	NA	138,097,802
2007	121,782,003	16,767,635	771,637	710	NA	139,321,985
Energy-Only Providers						
1996	1,597	433	29	NA	0	2,059
1997	32,251	2,000	251	NA	0	34,502
1998	311,498	54,404	1,736	NA	0	367,638
1999	566,181	109,827	25,361	NA	1,051	702,420
2000	1,211,891	290,796	14,003	NA	20,429	1,537,119
2001	2,417,611	502,912	18,183	NA	26,019	2,964,725
2002	2,831,225	433,953	15,527	NA	30,950	3,311,655
2003	2,250,936	412,903	17,605	85	NA	2,681,529
2004	2,438,021	445,514	13,791	84	NA	2,897,410
2005	2,290,911	482,391	14,643	22	NA	2,787,967
2006	1,793,444	498,733	13,959	27	NA	2,306,163
2007	2,167,913	609,584	22,130	40	NA	2,799,667

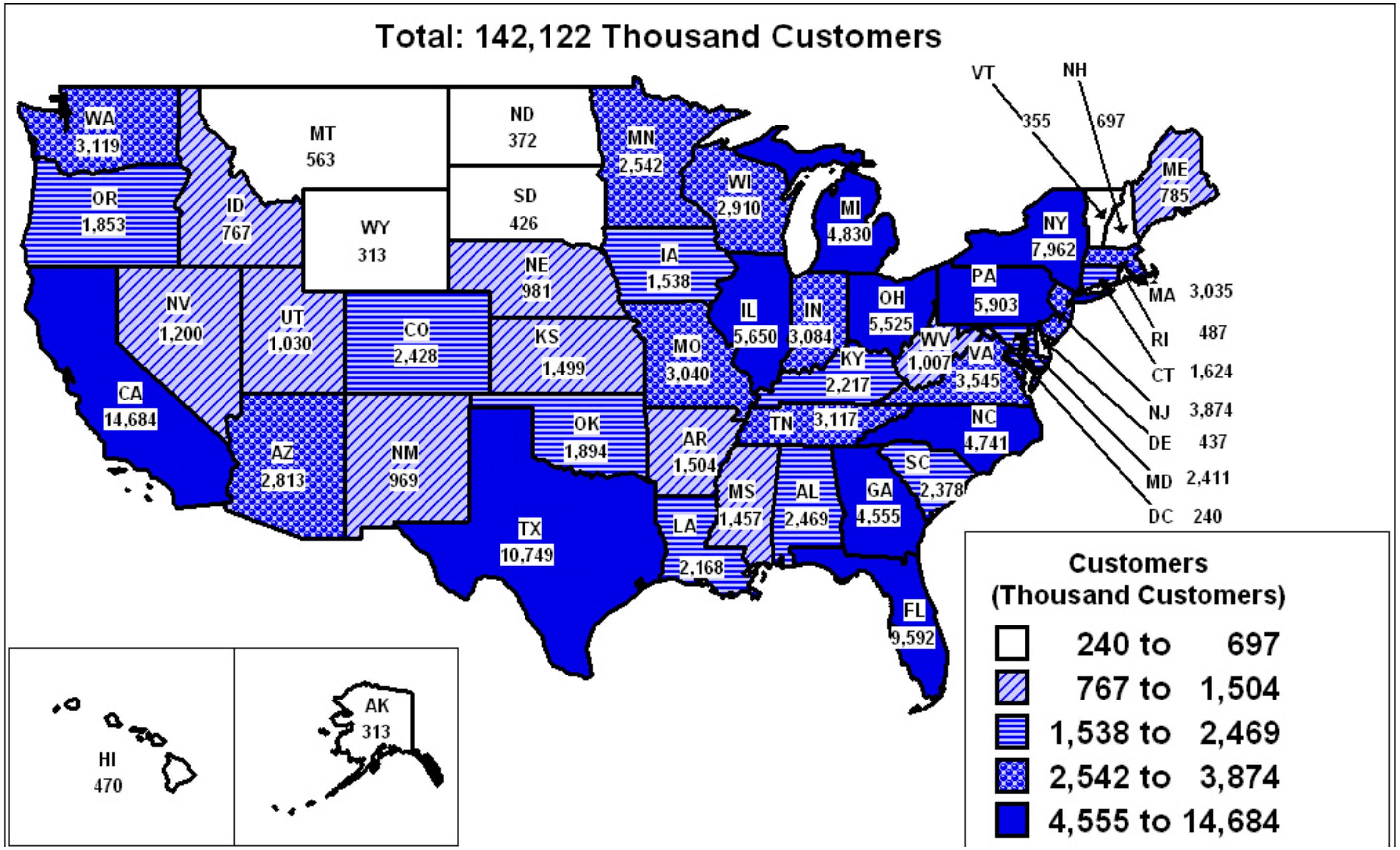
[1] Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas, all customers served by Retail Energy Providers must be provided fully-bundled energy and delivery services, so they are included under "Full-Service Providers."

NA = Not available.

Notes: • See Technical Notes reference for definitions. • Full Service Providers sell bundled electricity services (e.g., both energy and delivery) to end users. Full Service Providers may purchase electricity from others (such as Independent Power Producers or other full service providers) prior to delivery. Direct sales from independent facility generators to end use consumers are reported under Full Service Providers. Energy-Only Providers sell energy to end use customers; incumbent utility distribution firms provide Delivery-Only Services for these customers.

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

Figure 7.1. U.S. Electric Industry Total Ultimate Customers by State, 2007



Note: Data are displayed as 5 groups of 10 States and the District of Columbia.
Source: Energy Information Administration, Form EIA-861. “Annual Electric Power Industry Report.”

Table 7.2. Retail Sales and Direct Use of Electricity to Ultimate Customers by Sector, by Provider, 1996 through 2007

(Megawatthours)

Period	Sales						Direct Use[1]	Total End Use
	Residential	Commercial	Industrial	Transportation	Other	Total		
Total Electric Industry								
1996	1,082,511,751	887,445,174	1,033,631,379	NA	97,538,719	3,101,127,023	152,638,016	3,253,765,039
1997	1,075,880,098	928,632,774	1,038,196,892	NA	102,900,664	3,145,610,428	156,238,898	3,301,849,326
1998	1,130,109,120	979,400,928	1,051,203,115	NA	103,517,589	3,264,230,752	160,865,884	3,425,096,636
1999	1,144,923,069	1,001,995,720	1,058,216,608	NA	106,951,684	3,312,087,081	171,629,285	3,483,716,366
2000	1,192,446,491	1,055,232,090	1,064,239,393	NA	109,496,292	3,421,414,266	170,942,509	3,592,356,775
2001	1,201,606,593	1,083,068,516	996,609,310	NA	113,173,685	3,394,458,104	162,648,615	3,557,106,719
2002	1,265,179,869	1,104,496,607	990,237,631	NA	105,551,904	3,465,466,011	166,184,296	3,631,650,307
2003	1,275,823,910	1,198,727,601	1,012,373,247	6,809,728	NA	3,493,734,486	168,294,526	3,662,029,012
2004	1,291,981,578	1,230,424,731	1,017,849,532	7,223,642	NA	3,547,479,483	168,470,002	3,715,949,485
2005	1,359,227,107	1,275,079,020	1,019,156,065	7,506,321	NA	3,660,968,513	150,015,531	3,810,984,044
2006	1,351,520,036	1,299,743,695	1,011,297,566	7,357,543	NA	3,669,918,840	146,926,612	3,816,845,452
2007	1,392,240,996	1,336,315,196	1,027,831,925	8,172,595	NA	3,764,560,712	159,253,522	3,923,814,234
Full-Service Providers[2]								
1996	1,082,490,541	887,424,657	1,030,356,028	NA	97,538,719	3,097,809,945	NA	3,097,809,945
1997	1,075,766,590	928,440,265	1,032,653,445	NA	102,900,664	3,139,760,964	NA	3,139,760,964
1998	1,127,734,988	968,528,009	1,040,037,873	NA	103,517,589	3,239,818,459	NA	3,239,818,459
1999	1,140,761,016	970,600,943	1,017,783,037	NA	106,754,043	3,235,899,039	NA	3,235,899,039
2000	1,183,137,429	1,000,865,367	1,017,722,945	NA	107,824,323	3,309,550,064	NA	3,309,550,064
2001	1,188,219,590	1,037,998,484	961,812,417	NA	108,632,086	3,296,662,577	NA	3,296,662,577
2002	1,248,349,458	1,036,366,268	937,138,192	NA	102,238,786	3,324,092,704	NA	3,324,092,704
2003	1,257,766,998	1,112,206,121	931,661,404	3,315,043	NA	3,304,949,566	NA	3,304,949,566
2004	1,272,237,425	1,116,497,417	933,529,502	3,188,466	NA	3,325,452,810	NA	3,325,452,810
2005	1,339,568,275	1,151,327,861	929,675,932	3,341,814	NA	3,423,913,882	NA	3,423,913,882
2006	1,337,837,993	1,170,661,399	939,194,648	3,040,062	NA	3,450,734,102	NA	3,450,734,102
2007	1,375,450,126	1,180,789,042	923,148,031	2,635,498	NA	3,482,022,697	NA	3,482,022,697
Energy-Only Providers								
1996	21,210	20,517	3,275,351	NA	0	3,317,078	NA	3,317,078
1997	113,508	192,509	5,543,447	NA	0	5,849,464	NA	5,849,464
1998	2,374,132	10,872,919	11,165,242	NA	0	24,412,293	NA	24,412,293
1999	4,162,053	31,394,777	40,433,571	NA	197,641	76,188,042	NA	76,188,042
2000	9,309,062	54,366,723	46,516,448	NA	1,671,969	111,864,202	NA	111,864,202
2001	13,387,003	45,070,032	34,796,893	NA	4,541,599	97,795,527	NA	97,795,527
2002	16,830,411	68,130,339	53,099,439	NA	3,313,118	141,373,307	NA	141,373,307
2003	18,056,912	86,521,480	80,711,843	3,494,685	NA	188,784,920	NA	188,784,920
2004	19,744,153	113,927,314	84,320,030	4,035,176	NA	222,026,673	NA	222,026,673
2005	19,658,832	123,751,159	89,480,133	4,164,507	NA	237,054,631	NA	237,054,631
2006	13,682,043	129,082,296	72,102,918	4,317,481	NA	219,184,738	NA	219,184,738
2007	16,790,870	155,526,154	104,683,894	5,537,097	NA	282,538,015	NA	282,538,015

[1] Direct Use represents commercial and industrial facility use of onsite net electricity generation; and electricity sales or transfers to adjacent or co-located facilities for which revenue information is not available.

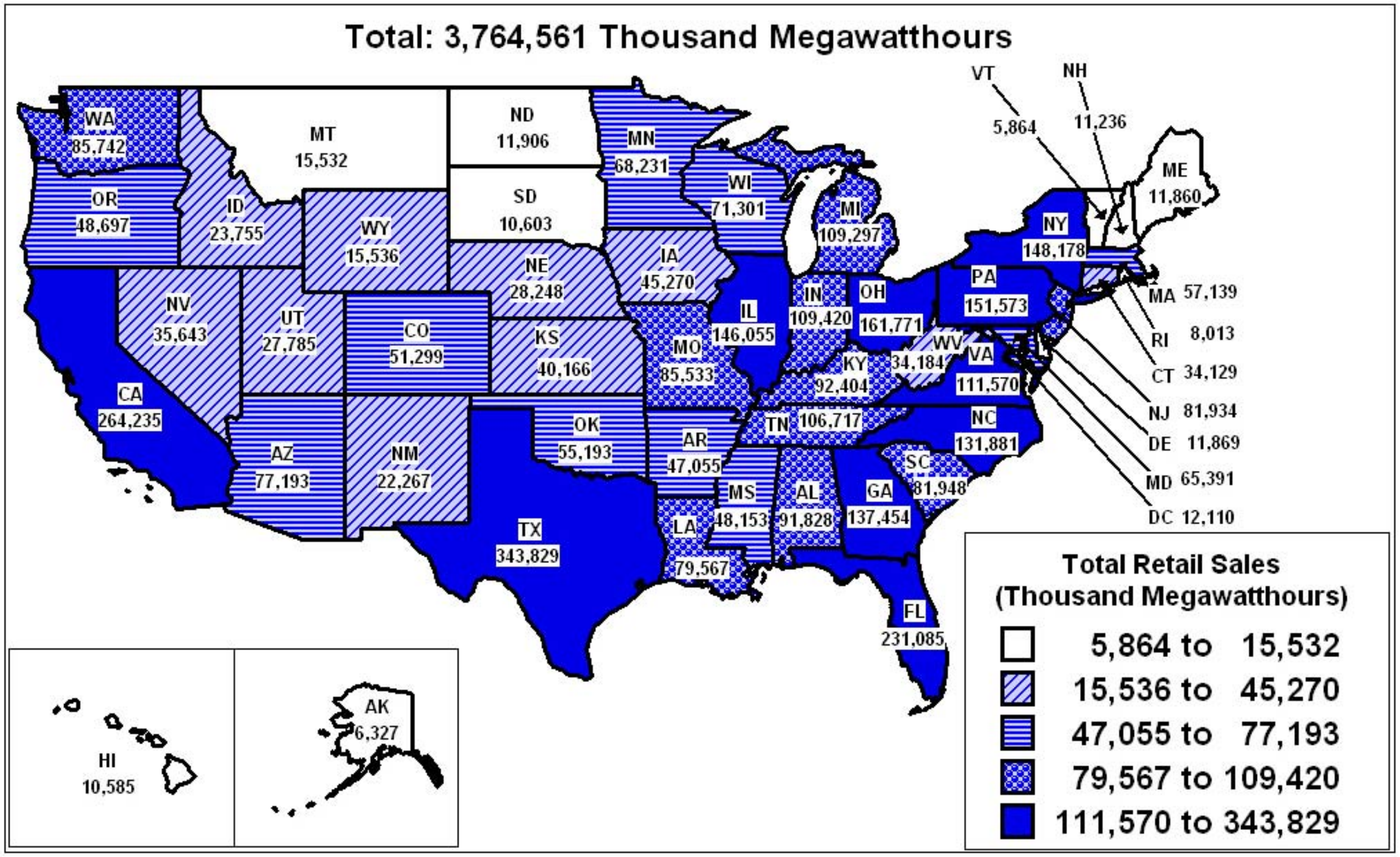
[2] Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas, all customers served by Retail Energy Providers must be provided fully-bundled energy and delivery services, so are included under "Full-Service Providers."

NA = Not available.

Notes: • See Technical Notes reference for definitions. • Full Service Providers sell bundled electricity services (e.g., both energy and delivery) to end users. Full Service Providers may purchase electricity from others (such as Independent Power Producers or other full service providers) prior to delivery. Direct sales from independent facility generators to end use consumers are reported under Full Service Providers. Energy-Only Providers sell energy to end use customers; incumbent utility distribution firms provide Delivery-Only Services for these customers.

Sources: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report;" Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including Form EIA-906, "Power Plant Report;" Form EIA-920, "Combined Heat and Power Plant Report."

Figure 7.2. U.S. Electric Industry Total Retail Sales by State, 2007



Note: Data are displayed as 5 groups of 10 States and the District of Columbia.
Source: Energy Information Administration, Form EIA-861. "Annual Electric Power Indsutry Report."

Table 7.3. Revenue from Retail Sales of Electricity to Ultimate Customers by Sector, by Provider, 1996 through 2007
(Million Dollars)

Period	Residential	Commercial	Industrial	Transportation	Other	All Sectors
Total Electric Industry						
1996	90,503	67,829	47,536	NA	6,741	212,609
1997	90,704	70,497	47,023	NA	7,110	215,334
1998	93,360	72,575	47,050	NA	6,863	219,848
1999	93,483	72,771	46,846	NA	6,796	219,896
2000	98,209	78,405	49,369	NA	7,179	233,163
2001	103,158	85,741	50,293	NA	8,151	247,343
2002	106,834	87,117	48,336	NA	7,124	249,411
2003	111,249	96,263	51,741	514	NA	259,767
2004	115,577	100,546	53,477	519	NA	270,119
2005	128,393	110,522	58,445	643	NA	298,003
2006	140,582	122,914	62,308	702	NA	326,506
2007	148,295	128,903	65,712	792	NA	343,703
Full-Service Providers[1]						
1996	90,501	67,827	47,385	NA	6,741	212,455
1997	90,694	70,482	46,772	NA	7,110	215,059
1998	93,164	71,769	46,550	NA	6,863	218,346
1999	93,142	70,492	45,056	NA	6,783	215,473
2000	97,086	73,704	46,465	NA	6,988	224,243
2001	101,541	81,385	48,182	NA	7,766	238,874
2002	104,814	80,573	44,826	NA	6,803	237,014
2003	109,165	87,764	46,686	226	NA	243,841
2004	113,306	89,597	47,993	238	NA	251,134
2005	125,983	97,405	52,113	249	NA	275,749
2006	138,608	107,432	56,385	257	NA	302,683
2007	145,642	109,703	56,950	232	NA	312,527
Unregulated Service Providers						
1996	2	2	151	NA	NA	154
1997	10	15	251	NA	NA	275
1998	196	806	500	NA	NA	1,502
1999	340	2,279	1,791	NA	13	4,423
2000	1,123	4,702	2,904	NA	191	8,920
2001	1,617	4,356	2,111	NA	385	8,469
2002	2,020	6,545	3,510	NA	321	12,396
2003	2,084	8,499	5,055	288	NA	15,926
2004	2,272	10,949	5,484	281	NA	18,985
2005	2,410	13,117	6,333	394	NA	22,254
2006	1,974	15,482	5,922	445	NA	23,823
2007	2,653	19,200	8,762	560	NA	31,176
Energy-Only Providers[2]						
1996	2	2	151	NA	0	154
1997	10	15	251	NA	0	275
1998	196	806	500	NA	0	1,502
1999	340	2,279	1,791	NA	13	4,423
2000	530	3,175	2,374	NA	75	6,153
2001	714	2,806	1,632	NA	237	5,390
2002	914	3,989	2,408	NA	143	7,454
2003	980	5,210	3,605	215	NA	10,011
2004	1,086	6,859	3,881	201	NA	12,027
2005	1,285	8,844	4,749	308	NA	15,186
2006	1,127	10,792	4,510	356	NA	16,784
2007	1,646	13,553	7,197	458	NA	22,854
Delivery-Only Service						
1996	--	--	--	--	--	--
1997	--	--	--	--	--	--
1998	--	--	--	--	--	--
1999	--	--	--	--	--	--
2000	593	1,527	531	NA	116	2,767
2001	903	1,551	479	NA	147	3,080
2002	1,106	2,556	1,102	NA	178	4,942
2003	1,104	3,289	1,450	72	NA	5,915
2004	1,186	4,090	1,603	79	NA	6,958
2005	1,125	4,273	1,584	86	NA	7,068
2006	847	4,690	1,412	90	NA	7,040
2007	1,007	5,647	1,565	102	NA	8,322

[1] Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas, all customers served by Retail Energy Providers must be provided fully-bundled energy and delivery services, so are included under "Full-Service Providers."

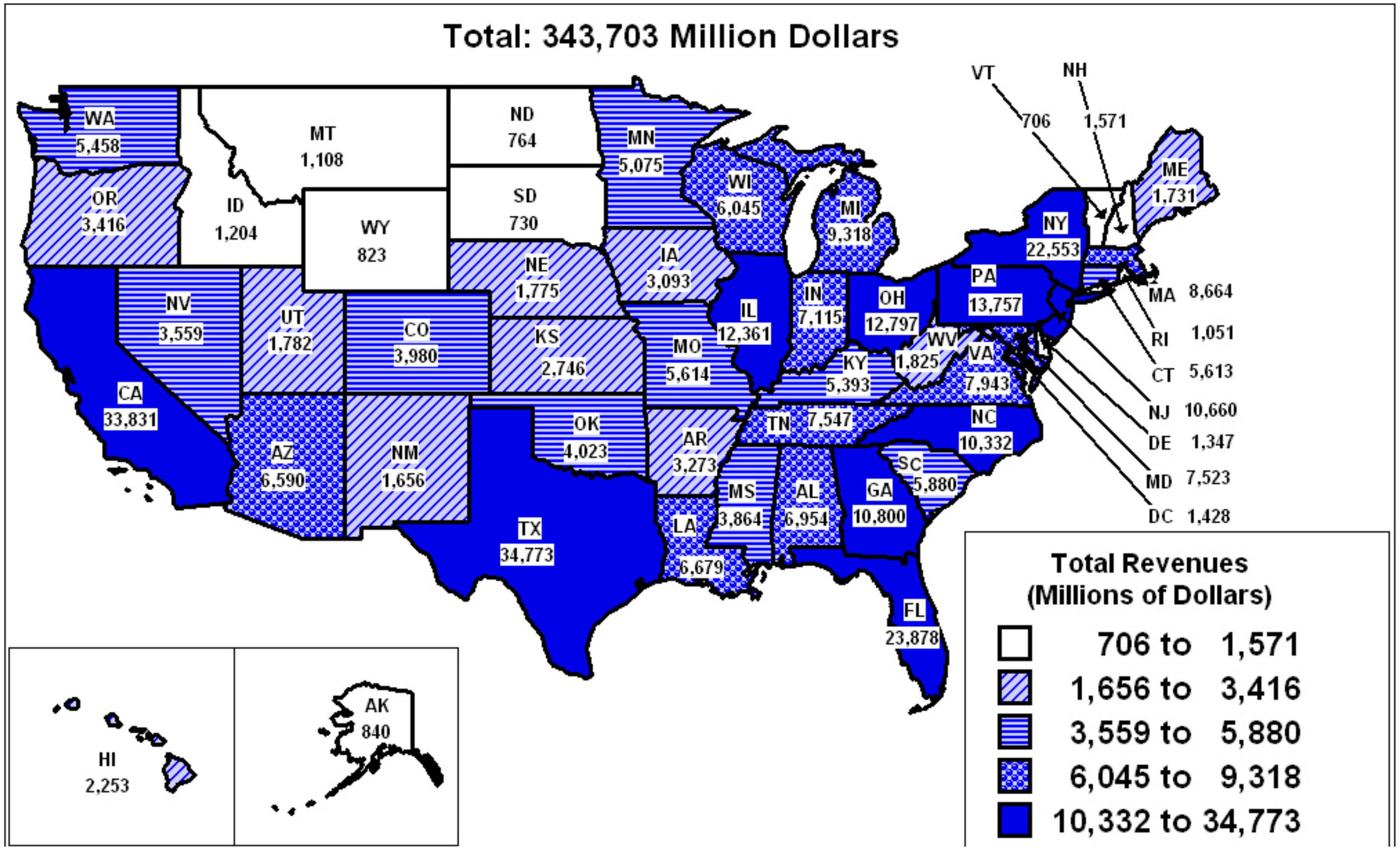
[2] From 1996 to 1999, revenue was estimated based on retail sales reported on the Form EIA-861.

NA = Not available.

Notes: • See Technical Notes reference for definitions. • Full Service Providers sell bundled electricity services (e.g., both energy and delivery) to end users. Full Service Providers may purchase electricity from others (such as Independent Power Producers or other full service providers) prior to delivery. Direct sales from independent facility generators to end use consumers are reported under Full Service Providers. Energy-Only Providers sell energy to end use customers; incumbent utility distribution firms provide Delivery-Only Services for these customers. Data reported under Unregulated Service Providers represent the sum of Energy-Only and Delivery-Only Services. • For historical data, see the State of California discussion in Technical Notes. • Totals may not equal sum of components because of independent rounding.

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

Figure 7.3.   U.S. Electric Industry Total Revenues by State, 2007



Note: Data are displayed as 5 groups of 10 States and the District of Columbia.
Source: Energy Information Administration, Form EIA-861. "Annual Electric Power Indsutry Report."

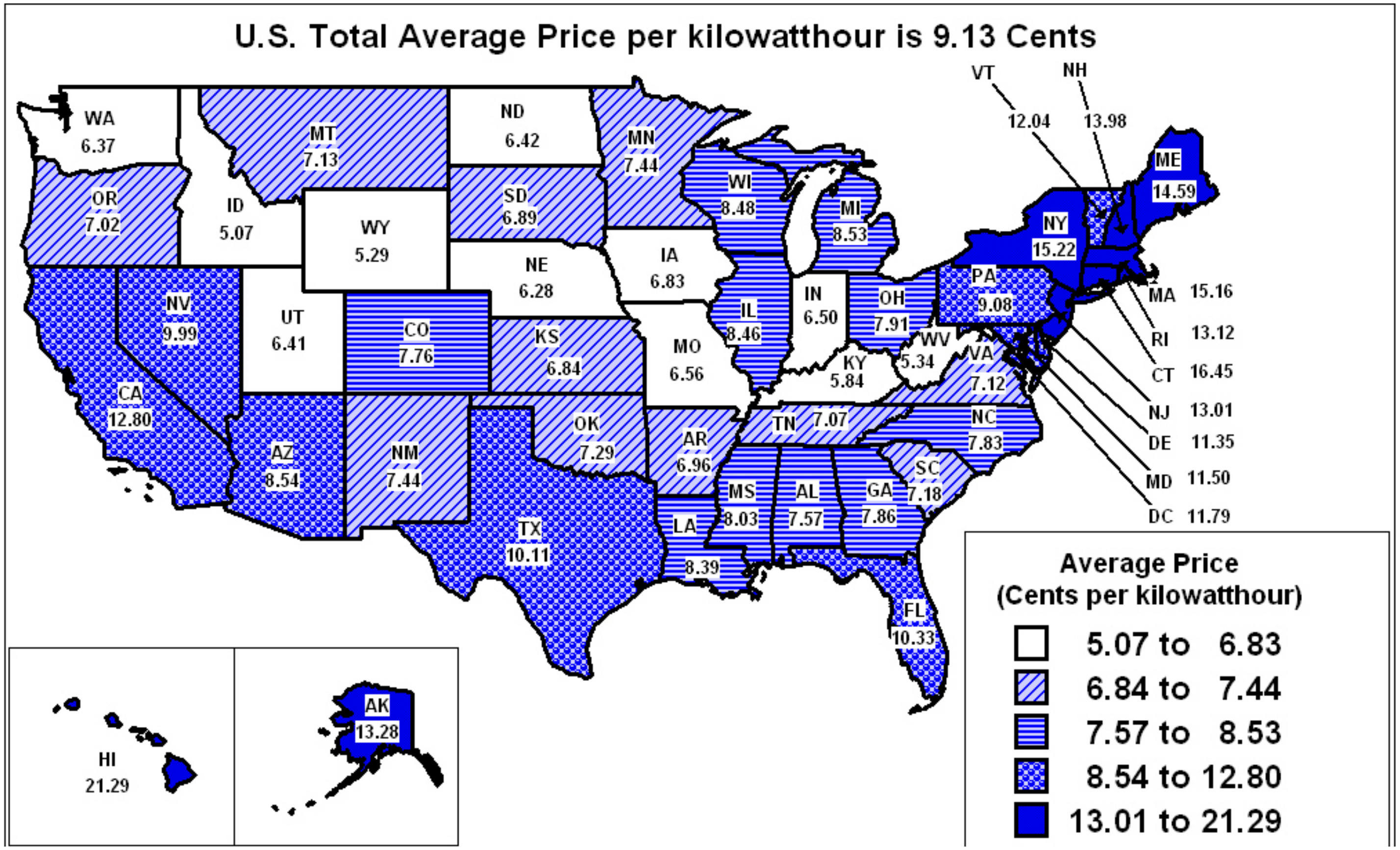
Table 7.4. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, 1996 through 2007

(Cents per kilowatthour)

Period	Residential	Commercial	Industrial	Transportation	Other	All Sectors
Total Electric Industry						
1996	8.36	7.64	4.60	NA	6.91	6.86
1997	8.43	7.59	4.53	NA	6.91	6.85
1998	8.26	7.41	4.48	NA	6.63	6.74
1999	8.16	7.26	4.43	NA	6.35	6.64
2000	8.24	7.43	4.64	NA	6.56	6.81
2001	8.58	7.92	5.05	NA	7.20	7.29
2002	8.44	7.89	4.88	NA	6.75	7.20
2003	8.72	8.03	5.11	7.54	NA	7.44
2004	8.95	8.17	5.25	7.18	NA	7.61
2005	9.45	8.67	5.73	8.57	NA	8.14
2006	10.40	9.46	6.16	9.54	NA	8.90
2007	10.65	9.65	6.39	9.70	NA	9.13
Full-Service Providers[1]						
1996	8.36	7.64	4.60	NA	6.91	6.86
1997	8.43	7.59	4.53	NA	6.91	6.85
1998	8.26	7.41	4.48	NA	6.63	6.74
1999	8.16	7.26	4.43	NA	6.35	6.66
2000	8.21	7.36	4.57	NA	6.48	6.78
2001	8.55	7.84	5.01	NA	7.15	7.25
2002	8.40	7.77	4.78	NA	6.65	7.13
2003	8.68	7.89	5.01	6.82	NA	7.38
2004	8.91	8.02	5.14	7.47	NA	7.55
2005	9.40	8.46	5.61	7.45	NA	8.05
2006	10.36	9.18	6.00	8.44	NA	8.77
2007	10.59	9.29	6.17	8.82	NA	8.98
Unregulated Service Providers						
1996	9.43	9.75	4.61	NA	NA	4.64
1997	8.43	7.59	4.53	NA	NA	4.71
1998	8.26	7.41	4.48	NA	NA	6.15
1999	8.17	7.26	4.43	NA	6.45	5.81
2000	12.07	8.65	6.24	NA	11.42	7.97
2001	12.08	9.67	6.07	NA	8.47	8.66
2002	12.00	9.61	6.61	NA	9.69	8.77
2003	11.54	9.82	6.26	8.23	NA	8.44
2004	11.51	9.61	6.50	6.95	NA	8.55
2005	12.26	10.60	7.08	9.47	NA	9.39
2006	14.43	11.99	8.21	10.32	NA	10.87
2007	15.80	12.35	8.37	10.11	NA	11.03
Energy-Only Providers[2]						
1996	9.43[R]	9.75[R]	4.61[R]	NA	--	4.64[R]
1997	8.43	7.59	4.53	NA	--	4.71[R]
1998	8.26	7.41	4.48	NA	--	6.15[R]
1999	8.17[R]	7.26	4.43	NA	6.45[R]	5.81[R]
2000	5.69[R]	5.84[R]	5.10[R]	NA	4.47[R]	5.50[R]
2001	5.34	6.22	4.69	NA	5.23	5.51
2002	5.43	5.86	4.53	NA	4.30	5.27
2003	5.43	6.02	4.47	6.16	NA	5.30
2004	5.50	6.02	4.60	4.99	NA	5.42
2005	6.54	7.15	5.31	7.40	NA	6.41
2006	8.23	8.36	6.25	8.24	NA	7.66
2007	9.80	8.71	6.87	8.28	NA	8.09
Delivery-Only Service						
1996	--	--	--	--	--	--
1997	--	--	--	--	--	--
1998	--	--	--	--	--	--
1999	--	--	--	--	--	--
2000	6.37[R]	2.81[R]	1.14[R]	--	6.95[R]	2.47[R]
2001	6.74	3.44	1.38	--	3.24	3.15
2002	6.57	3.75	2.08	--	5.39	3.50
2003	6.11	3.80	1.80	2.07	--	3.13
2004	6.00	3.59	1.90	1.96	NA	3.13
2005	5.72	3.45	1.77	2.07	NA	2.98
2006	6.19	3.63	1.96	2.08	NA	3.21
2007	6.00	3.63	1.50	1.84	NA	2.95

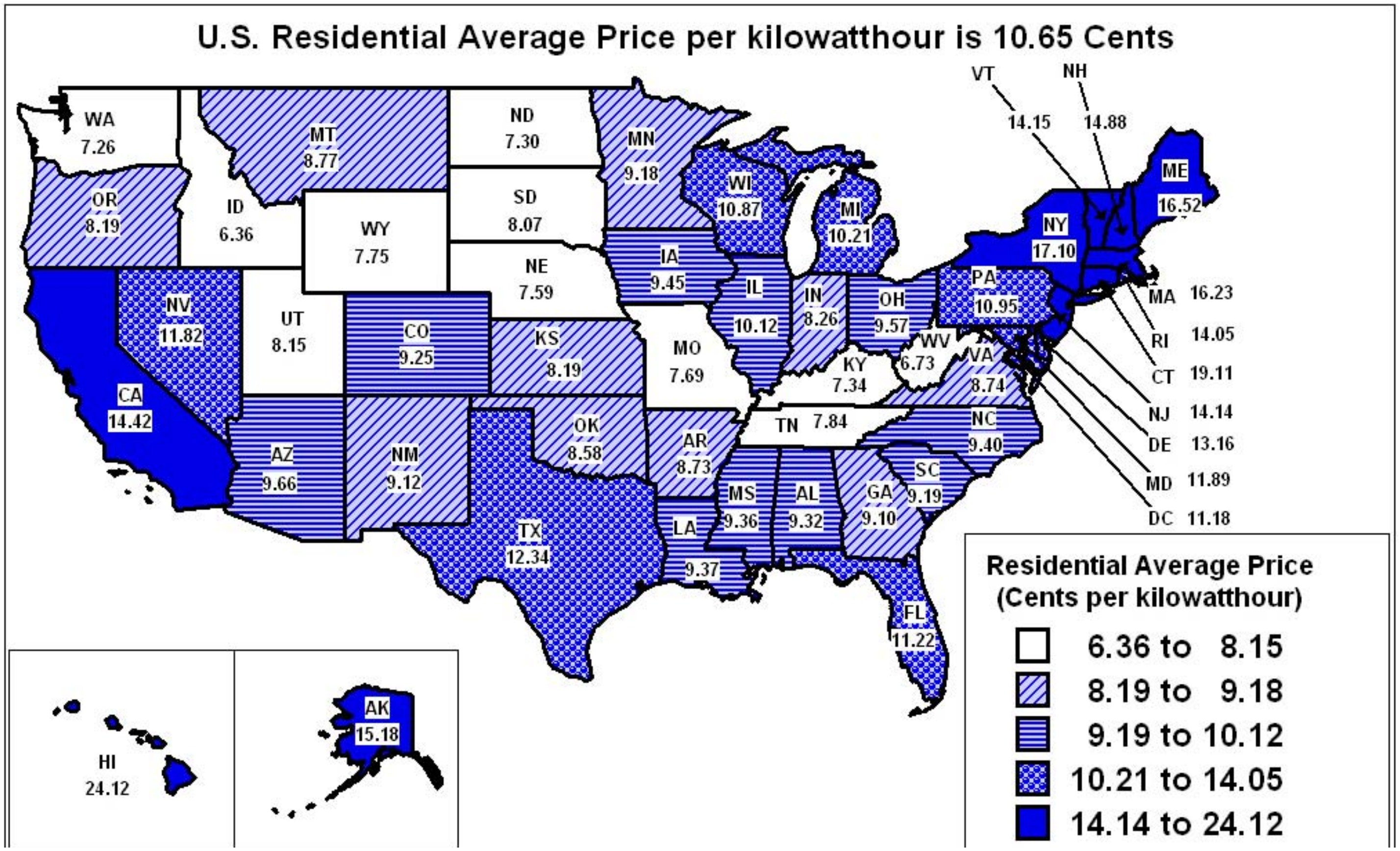
[1] Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas, all customers served by Retail Energy Providers must be provided fully-bundled energy and delivery services, so are included under "Full-Service Providers."
[2] From 1996 to 1999, average revenue was estimated based on retail sales reported on the Form EIA-861.
NA = Not available.
R = Revised.
Notes: • See Glossary reference for definitions • Full Service Providers sell bundled electricity services (e.g., both energy and delivery) to end users. Full Service Providers may purchase electricity from others (such as Independent Power Producers or other full service providers) prior to delivery. Direct sales from independent facility generators to end use consumers are reported under Full Service Providers. Energy-Only Providers sell energy to end use customers; incumbent utility distribution firms provide Delivery-Only Services for these customers. Data reported under Unregulated Service Providers represent the sum of Energy-Only and Delivery-Only Services.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Figure 7.4. Average Retail Price of Electricity by State, 2007



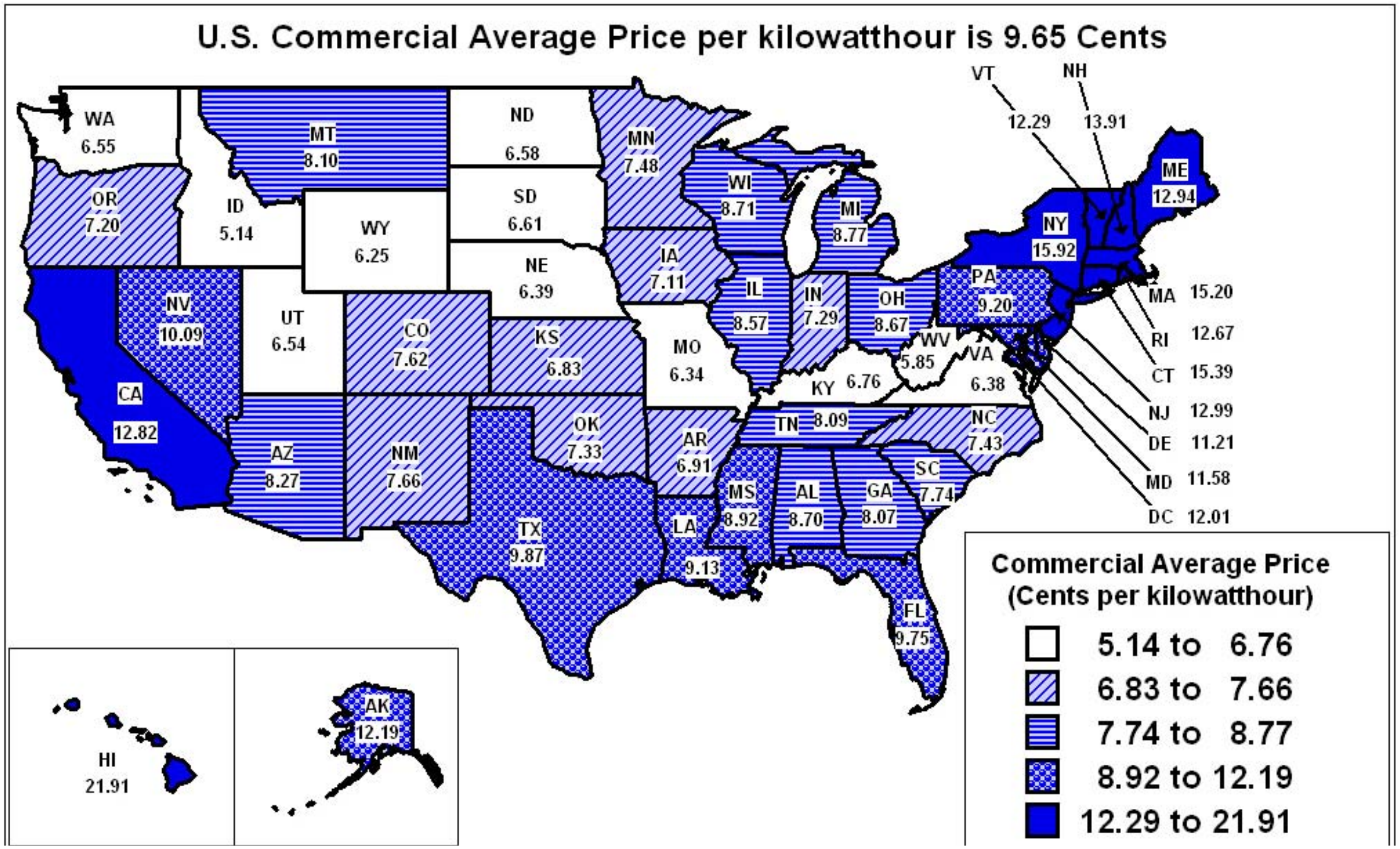
Note: Data are displayed as 5 groups of 10 States and the District of Columbia.
Source: Energy Information Administration, Form EIA-861. "Annual Electric Power Indsutry Report."

Figure 7.5. Average Residential Price of Electricity by State, 2007



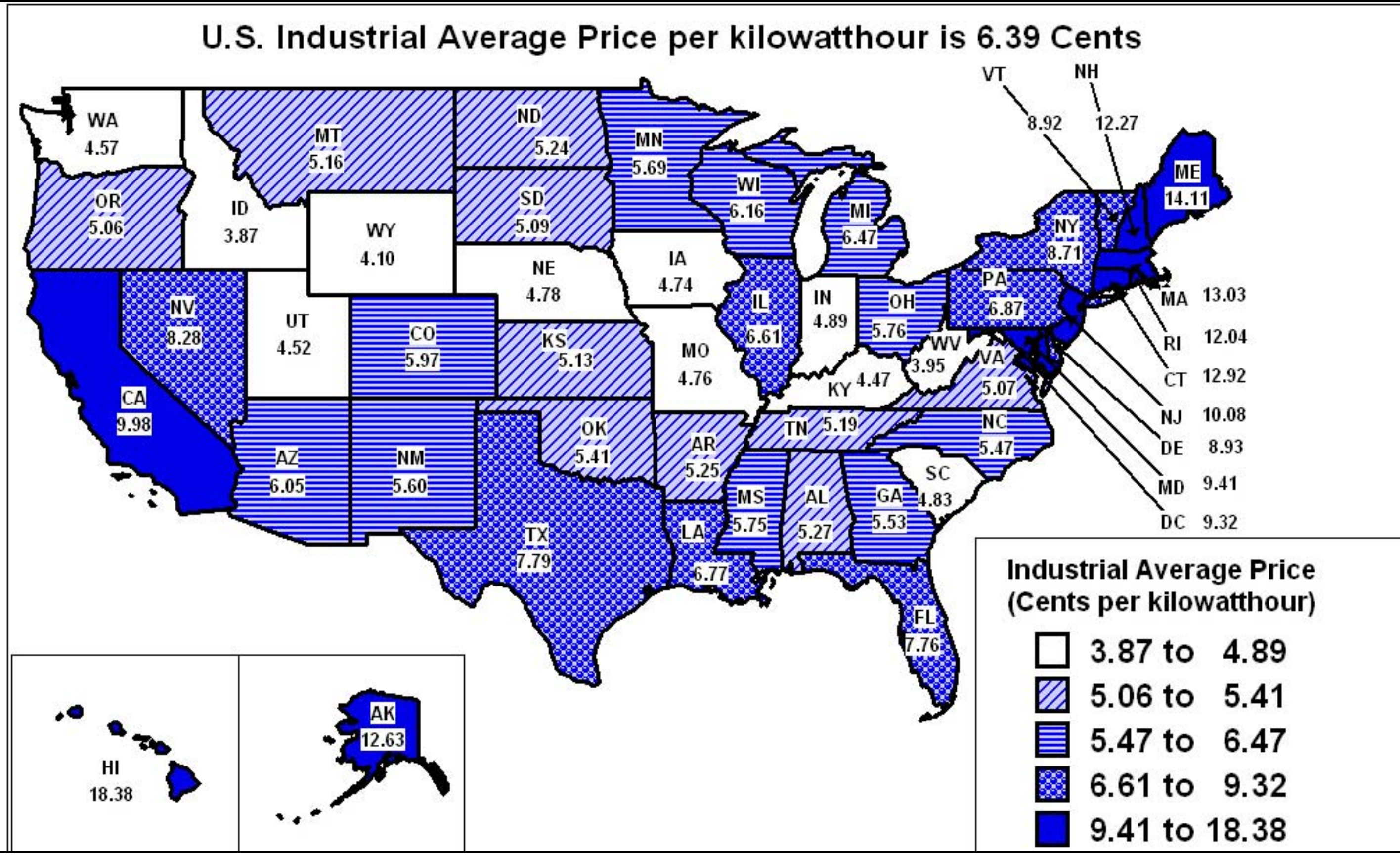
Note: Data are displayed as 5 groups of 10 States and the District of Columbia.
Source: Energy Information Administration, Form EIA-861. "Annual Electric Power Indsutry Report."

Figure 7.6. Average Commercial Price of Electricity by State, 2007



Note: Data are displayed as 5 groups of 10 States and the District of Columbia.
Source: Energy Information Administration, Form EIA-861. “Annual Electric Power Indsutry Report.”

Figure 7.7. Average Industrial Price of Electricity by State, 2007



Note: Data are displayed as 5 groups of 10 States and the District of Columbia.
Source: Energy Information Administration, Form EIA-861. "Annual Electric Power Indsutry Report."

Table 7.5. Net Metering and Green Pricing Customers by End Use Sector, 2002 - 2007

Year	Green Pricing			Net Metering		
	Residential	Non Residential	Total	Residential	Non Residential	Total
2002	688,069	23,481	711,550	3,559	913	4,472
2003	819,579	57,547	877,126	5,870	943	6,813
2004	864,794	63,539	928,333	14,114	1,712	15,826
2005	871,774	70,998	942,772	19,244	1,902	21,146
2006[1R]	606,919	35,937	642,856	30,689	2,930	33,619
2007	773,391	62,260	835,651	44,886	3,943	48,820

[1] In 2006 the single largest provider of green pricing services in the country discontinued service in two States. More than 297,600 customers in green pricing programs reverted to standard service tariffs, predominantly in Ohio and Pennsylvania.

R = Revised.

Notes: • Green Pricing programs allow electricity customers the opportunity to purchase electricity generated from renewable resources, thereby encouraging renewable energy development. Renewable resources include solar, wind, geothermal, hydroelectric power, and wood. • Net Metering arrangements permit facilities and residences (using a meter that reads inflows and outflows of electricity) to sell any excess power generated over its load requirement back to the distributor to offset consumption.

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

Chapter 8. Revenue and Expense Statistics

Table 8.1. Revenue and Expense Statistics for Major U.S. Investor-Owned Electric Utilities, 1996 through 2007
(Million Dollars)

Description	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
Utility Operating Revenues	**282,875**	**277,142**	**267,534**	**240,318**	**226,227**	**219,389**	**267,525**	**235,336**	**214,160**	**218,175**	**215,083**	**207,459**
Electric Utility	251,959	247,503	235,570	213,539	202,369	200,135	244,219	214,707	197,578	201,970	195,898	188,901
Other Utility	30,305	29,639	31,964	26,779	23,858	19,254	23,306	20,630	16,583	16,205	19,185	18,558
Utility Operating Expenses	**252,216**	**247,170**	**238,590**	**207,161**	**197,459**	**188,745**	**235,198**	**210,324**	**182,258**	**186,498**	**182,796**	**173,920**
Electric Utility	223,297	219,171	208,461	182,337	175,473	171,291	213,733	191,329	167,266	171,689	165,443	156,938
Operation	161,939	159,472	151,150	131,962	122,723	116,374	159,929	132,662	108,461	110,759	104,337	97,207
Production	128,914	128,016	121,058	104,287	96,181	90,649	136,089	107,352	83,555	85,956	80,153	73,437
Cost of Fuel	42,178	38,158	36,161	28,678	26,476	24,132	29,490	32,555	29,826	31,252	31,861	30,706
Purchased Power	78,124	79,485	78,279	67,354	62,173	58,828	98,231	61,969	43,258	42,612	37,991	32,987
Other	8,632	10,399	6,638	8,256	7,532	7,688	8,368	12,828	10,470	12,092	10,301	9,744
Transmission	6,095	6,185	5,687	4,519	3,585	3,494	2,365	2,699	2,423	2,197	1,915	1,503
Distribution	3,870	3,658	3,517	3,301	3,185	3,113	3,217	3,115	2,956	2,804	2,700	2,604
Customer Accounts	4,843	4,424	4,243	4,087	4,180	4,165	4,434	4,246	4,195	4,021	3,767	3,848
Customer Service	2,959	2,533	2,289	2,012	1,893	1,821	1,856	1,839	1,889	1,955	1,917	1,920
Sales	249	241	219	238	234	261	282	403	492	514	501	435
Administrative and General	14,933	14,618	14,113	13,519	13,466	12,872	11,686	13,009	12,951	13,311	13,384	13,458
Maintenance	13,675	12,879	12,058	11,774	11,141	10,843	11,167	12,185	12,276	12,486	12,368	12,050
Depreciation	18,662	17,438	17,177	16,373	16,962	17,319	20,845	22,761	23,968	24,122	23,072	21,194
Taxes and Other	27,839	28,187	26,848	22,228	24,648	26,755	21,792	23,721	22,561	24,322	25,667	26,488
Other Utility	28,347	27,999	30,129	24,823	21,986	17,454	21,465	18,995	14,992	14,809	17,353	16,983
Net Utility Operating Income	**30,659**	**29,972**	**28,944**	**33,158**	**28,768**	**30,644**	**32,327**	**25,012**	**31,902**	**31,677**	**32,286**	**33,539**

Note: Missing or erroneous respondent data may result in slight imbalances in some of the expense account subtotals. 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."

Table 8.2. Average Power Plant Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 1996 through 2007
(Mills per Kilowatthour)

Plant Type	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
Operation												
Nuclear	9.20	8.93	8.39	8.30	8.86	8.54	8.30	8.41	8.93	9.98	11.02	9.47
Fossil Steam	3.49	3.23	2.97	2.68	2.50	2.54	2.40	2.31	2.21	2.17	2.22	2.25
Hydroelectric[1]	7.71	5.11	5.26	5.05	4.50	5.07	5.79	4.74	4.17	3.85	3.29	3.87
Gas Turbine and Small Scale[2]	2.89	3.00	2.97	2.73	2.76	2.72	3.15	4.57	5.16	3.85	4.43	5.08
Maintenance												
Nuclear	5.79	5.68	5.23	5.38	5.23	5.04	5.01	4.93	5.13	5.79	6.90	5.68
Fossil Steam	3.39	3.19	2.96	2.96	2.73	2.68	2.61	2.45	2.38	2.41	2.43	2.49
Hydroelectric[1]	5.17	3.44	3.60	3.64	3.01	3.58	3.97	2.99	2.60	2.00	2.49	2.08
Gas Turbine and Small Scale[2]	2.53	2.29	2.15	2.16	2.26	2.38	3.33	3.50	4.80	3.43	3.43	4.98
Fuel												
Nuclear	5.01	4.85	4.54	4.58	4.60	4.60	4.67	4.95	5.17	5.39	5.42	5.50
Fossil Steam	24.02	23.17	21.77	18.21	17.35	16.11	18.13	17.69	15.62	15.94	16.80	16.51
Hydroelectric[1]	--	--	--	--	--	--	--	--	--	--	--	--
Gas Turbine and Small Scale[2]	56.69	52.46	53.73	45.20	43.91	31.82	43.56	39.19	28.72	23.02	24.94	30.58
Total												
Nuclear	20.00	19.46	18.16	18.26	18.69	18.18	17.98	18.28	19.23	21.16	23.33	20.65
Fossil Steam	30.89	29.59	27.69	23.85	22.59	21.32	23.14	22.44	20.22	20.52	21.45	21.25
Hydroelectric[1]	12.88	8.54	8.86	8.69	7.51	8.65	9.76	7.73	6.77	5.86	5.78	5.95
Gas Turbine and Small Scale[2]	62.11	57.75	58.85	50.10	48.93	36.93	50.04	47.26	38.68	30.30	32.80	40.64

[1] Conventional hydro and pumped storage.
[2] Gas turbine, internal combustion, photovoltaic, and wind plants.
Notes: • 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 one cent). • 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."

Table 8.3. Revenue and Expense Statistics for Major U.S. Publicly Owned Electric Utilities (With Generation Facilities), 1996 through 2007
(Million Dollars)

Description	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
Operating Revenue - Electric	**NA**	**NA**	**NA**	**NA**	**33,906**	**32,776**	**38,028**	**31,843**	**26,767**	**26,155**	**25,397**	**24,207**
Operating Expenses - Electric	**NA**	**NA**	**NA**	**NA**	**29,637**	**28,638**	**32,789**	**26,244**	**21,274**	**20,880**	**20,425**	**19,084**
Operation Including Fuel	**NA**	**NA**	**NA**	**NA**	**22,642**	**21,731**	**25,922**	**19,575**	**15,386**	**15,120**	**14,917**	**13,768**
Production	NA	NA	NA	NA	17,948	17,176	21,764	15,742	11,923	11,608	11,481	11,080
Transmission	NA	NA	NA	NA	872	858	785	781	732	773	725	344
Distribution	NA	NA	NA	NA	696	680	605	574	516	603	538	497
Customer Accounts	NA	NA	NA	NA	582	537	600	507	415	390	390	365
Customer Service	NA	NA	NA	NA	280	315	263	211	160	127	133	103
Sales	NA	NA	NA	NA	84	74	73	66	49	51	46	18
Administrative and General	NA	NA	NA	NA	2,180	2,090	1,832	1,695	1,591	1,567	1,602	1,360
Maintenance	**NA**	**NA**	**NA**	**NA**	**2,086**	**1,926**	**1,904**	**1,815**	**1,686**	**1,631**	**1,609**	**1,638**
Depreciation and Amortization	**NA**	**NA**	**NA**	**NA**	**3,844**	**3,907**	**4,009**	**3,919**	**3,505**	**3,459**	**3,239**	**3,160**
Taxes and Tax Equivalents	**NA**	**NA**	**NA**	**NA**	**1,066**	**1,074**	**954**	**936**	**697**	**670**	**660**	**662**
Net Electric Operating Income	**NA**	**NA**	**NA**	**NA**	**4,268**	**4,138**	**5,238**	**5,598**	**5,493**	**5,275**	**4,972**	**5,123**

NA = Not available.
Notes: • In 2004, Form EIA-412 was terminated. • Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, EIA Form-412, "Annual Electric Industry Financial Report," and predecessor forms.

Table 8.4. Revenue and Expense Statistics for Major U.S. Publicly Owned Electric Utilities (Without Generation Facilities), 1996 through 2007
(Million Dollars)

Description	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
Operating Revenue - Electric	**NA**	**NA**	**NA**	**NA**	**12,454**	**11,546**	**10,417**	**9,904**	**9,354**	**8,790**	**8,586**	**8,582**
Operating Expenses - Electric	**NA**	**NA**	**NA**	**NA**	**11,481**	**10,703**	**9,820**	**9,355**	**8,737**	**8,245**	**8,033**	**8,123**
Operation Including Fuel	**NA**	**NA**	**NA**	**NA**	**10,095**	**9,439**	**8,864**	**8,424**	**7,874**	**7,437**	**7,117**	**7,359**
Production	NA	NA	NA	NA	8,865	8,311	7,863	7,486	7,015	6,661	6,240	6,578
Transmission	NA	NA	NA	NA	105	93	61	64	48	44	57	51
Distribution	NA	NA	NA	NA	348	320	311	280	261	230	304	234
Customer Accounts	NA	NA	NA	NA	172	163	164	155	143	130	139	141
Customer Service	NA	NA	NA	NA	31	39	26	22	22	21	16	18
Sales	NA	NA	NA	NA	11	10	15	16	14	9	13	12
Administrative and General	NA	NA	NA	NA	562	504	423	402	371	342	348	325
Maintenance	**NA**	**NA**	**NA**	**NA**	**418**	**389**	**304**	**286**	**272**	**263**	**338**	**244**
Depreciation and Amortization	**NA**	**NA**	**NA**	**NA**	**711**	**631**	**405**	**394**	**369**	**330**	**354**	**322**
Taxes and Tax Equivalents	**NA**	**NA**	**NA**	**NA**	**257**	**244**	**247**	**251**	**223**	**215**	**225**	**206**
Net Electric Operating Income	**NA**	**NA**	**NA**	**NA**	**974**	**843**	**597**	**549**	**617**	**545**	**552**	**459**

NA = Not available.
Notes: • In 2004, Form EIA-412 was terminated. • Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, EIA Form-412, "Annual Electric Industry Financial Report," and predecessor forms.

Table 8.5. Revenue and Expense Statistics for U.S. Federally Owned Electric Utilities, 1996 through 2007
(Million Dollars)

Description	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
Operating Revenue - Electric	**NA**	**NA**	**NA**	**NA**	**11,798**	**11,470**	**12,458**	**10,685**	**10,186**	**9,780**	**8,833**	**9,082**
Operating Expenses - Electric	**NA**	**NA**	**NA**	**NA**	**8,763**	**8,665**	**10,013**	**8,139**	**7,775**	**7,099**	**5,999**	**6,390**
Operation Including Fuel	**NA**	**NA**	**NA**	**NA**	**6,498**	**6,419**	**7,388**	**5,873**	**5,412**	**5,184**	**4,073**	**4,514**
Production	NA	NA	NA	NA	5,175	5,236	6,247	5,497	4,890	4,735	3,686	4,109
Transmission	NA	NA	NA	NA	307	244	354	332	349	323	327	328
Distribution	NA	NA	NA	NA	1	1	1	2	2	2	1	1
Customer Accounts	NA	NA	NA	NA	4	10	16	6	1	1	1	3
Customer Service	NA	NA	NA	NA	63	60	60	48	50	51	42	46
Sales	NA	NA	NA	NA	20	6	6	10	28	14	13	7
Administrative and General	NA	NA	NA	NA	927	862	705	467	528	535	444	451
Maintenance	**NA**	**NA**	**NA**	**NA**	**600**	**566**	**521**	**488**	**436**	**476**	**441**	**432**
Depreciation and Amortization	**NA**	**NA**	**NA**	**NA**	**1,335**	**1,351**	**1,790**	**1,471**	**1,623**	**1,175**	**1,214**	**1,187**
Taxes and Tax Equivalents	**NA**	**NA**	**NA**	**NA**	**329**	**328**	**315**	**308**	**304**	**264**	**272**	**256**
Net Electric Operating Income	**NA**	**NA**	**NA**	**NA**	**3,035**	**2,805**	**2,445**	**2,546**	**2,411**	**2,681**	**2,834**	**2,692**

NA = Not available.
Notes: • In 2004, Form EIA-412 was terminated. • Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-412, "Annual Electric Industry Financial Report," and predecessor forms.

Table 8.6. Revenue and Expense Statistics for U.S. Cooperative Borrower Owned Electric Utilities, 1996 through 2007
(Million Dollars)

Description	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
Operating Revenue - Electric	**38,208**	**36,723[R]**	**34,088**	**30,650**	**29,228**	**27,458**	**26,458**	**25,629**	**23,824**	**23,988**	**23,321**	**24,424**
Operation and Maintenance Expenses	**34,843**	**33,550[R]**	**31,209**	**27,828**	**26,361**	**24,561**	**23,763**	**22,982**	**21,283**	**21,223**	**20,715**	**23,149**
Operation Including Fuel	**32,229**	**30,920[R]**	**28,723**	**25,420**	**24,076**	**22,383**	**21,703**	**20,942**	**19,336**	**19,280**	**18,405**	**20,748**
Production	26,929	25,799[R]	23,921	20,752	19,559	18,143	17,714	17,080	15,706	15,683	15,105	17,422
Transmission	754	748[R]	679	665	637	579	524	525	466	452	339	372
Distribution	2,161	2,037[R]	1,895	1,860	1,787	1,681	1,589	1,530	1,451	1,440	1,134	1,133
Customer Accounts	677	655[R]	612	595	579	545	532	487	455	446	382	375
Customer Service	163	158[R]	147	141	140	136	119	133	132	132	118	118
Sales	78	80	76	80	79	79	88	82	81	77	61	72
Administrative and General	1,468	1,444[R]	1,393	1,327	1,295	1,219	1,137	1,104	1,045	1,050	1,266	1,257
Depreciation and Amortization	**2,350**	**2,367[R]**	**2,253**	**2,182**	**2,076**	**1,992**	**1,895**	**1,820**	**1,747**	**1,732**	**1,727**	**1,787**
Taxes and Tax Equivalents	**264**	**262[R]**	**234**	**226**	**209**	**186**	**164**	**220**	**200**	**211**	**583**	**614**
Net Electric Operating Income	**3,365**	**3,173[R]**	**2,879**	**2,822**	**2,867**	**2,897**	**2,696**	**2,647**	**2,541**	**2,764**	**2,606**	**1,274[R]**

R = Revised.
Note: Totals may not equal sum of components because of independent rounding.
Source: U.S. Department of Agriculture, Rural Utilities Service (prior Rural Electrification Administration), Statistical Report, Rural Electric Borrowers publications, as compiled from RUS Form 7 and RUS Form 12.

Chapter 9. Demand-Side Management

Table 9.1. Demand-Side Management Actual Peak Load Reductions by Program Category, 1996 through 2007
(Megawatts)

Item	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
Total Actual Peak Load Reduction	**30,276**	**27,240**	**25,710**	**23,532**	**22,904**	**22,936**	**24,955**	**22,901**	**26,455**	**27,231**	**25,284**	**29,893**
Energy Efficiency	17,710	15,959	15,351	14,272	13,581	13,420	13,027	12,873	13,452	13,591	13,327	14,243
Load Management	12,566	11,281	10,359	9,260	9,323	9,516	11,928	10,027	13,003	13,640	11,958	15,650

Notes: • See Technical Notes for the Demand-Side Management definitions located within the Form EIA-861 section. • Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 9.2. Demand-Side Management Program Annual Effects by Program Category, 1996 through 2007

Item	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
	Annual Effects – Energy Efficiency											
Large Utilities												
Actual Peak Load Reduction (MW)	17,710	15,959	15,351	14,272	13,581	13,420	13,027	12,873	13,452	13,591	13,327	14,243
Energy Savings (Thousand MWh)	67,134	62,951	58,891	52,662	48,245	52,285	52,946	52,827	49,691	48,775	55,453	59,853
	Annual Effects – Load Management											
Large Utilities												
Actual Peak Load Reduction (MW)	12,566	11,281	10,359	9,260	9,323	9,516	11,928	10,027	13,003	13,640	11,958	15,650
Potential Peak Load Reductions (MW)	23,119	21,270	21,282	20,998	25,290	26,888	27,730	28,496	30,118	27,840	27,911	34,101
Energy Savings (Thousand MWh)	1,937	865	1,006	2,047	2,020	1,790	990	875	872	392	953	1,989

Notes: • See Technical Notes for the Demand-Side Management definitions located within the Form EIA-861 section. • Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 9.3. Demand-Side Management Program Incremental Effects by Program Category, 1996 through 2007

Item	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
	Incremental Effects – Energy Efficiency											
Large Utilities												
Actual Peak Load Reduction (MW)	1,649	1,177	1,403	1,521	945	1,054	999	720	695	796	1,065	1,381
Energy Savings (Thousand MWh)	7,426	5,385	5,872	4,522	2,939	3,543	4,402	3,284	3,027	3,324	4,661	6,361
Small Utilities												
Actual Peak Load Reduction (MW)	349	91	302	204	90	49	20	25	22	12	12	2
Energy Savings (Thousand MWh)	254	9	7	10	8	192	8	8	8	37	10	7
	Incremental Effects – Load Management											
Large Utilities												
Actual Peak Load Reduction (MW)	1,357	1,495	1,009	907	1,084	1,160	1,297	919	1,568	1,821	1,261	5,027
Potential Peak Load Reductions (MW)	3,343	2,544	2,005	2,622	1,981	2,655	2,448	2,439	6,457	2,832	2,475	2,309
Energy Savings (Thousand MWh)	137	95	133	2	29	65	79	63	67	37	171	482
Small Utilities												
Actual Peak Load Reduction (MW)	1,036	195	153	242	81	54	45	137	54	124	130	50
Potential Peak Load Reductions (MW)	1,423	273	218	422	131	76	177	190	84	160	183	90
Energy Savings (Thousand MWh)	5	4	5	4	4	2	4	9	2	7	19	6

Notes: • See Technical Notes for the Demand-Side Management definitions located within the Form EIA-861 section. • Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 9.4. Demand-Side Management Program Annual Effects by Sector, 1996 through 2007

Item	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
					Actual Peak Load Reductions (MW)							
Large Utilities												
Residential	13,192	10,730	9,432	8,870	9,431	9,137	9,619	9,446	9,976	9,327	10,799	11,471
Commercial	8,054	7,779	7,926	7,194	6,774	6,839	8,210	6,987	7,777	9,482	8,174	8,678
Industrial	9,013	8,692	8,343	7,454	6,594	6,500	6,553	6,141	6,360	7,927	5,812	9,083
Transportation	17	39	9	14	105	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	460	573	327	2,342	495	498	661
Total	**30,276**	**27,240**	**25,710**	**23,532**	**22,904**	**22,936**	**24,955**	**22,901**	**26,455**	**27,231**	**25,284**	**29,893**
					Potential Peak Load Reductions (MW)							
Large Utilities												
Residential	15,263	13,040	12,097	11,967	12,525	12,072	12,274	12,970	12,812	13,022	16,662	14,697
Commercial	10,201	10,006	10,214	9,624	8,943	9,298	10,469	9,114	8,868	12,210	12,896	12,452
Industrial	15,303	14,119	14,260	13,665	17,298	18,321	17,344	18,775	17,237	15,512	11,035	20,275
Transportation	62	64	62	14	105	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	617	670	510	4,653	686	644	921
Total	**40,829**	**37,229**	**36,633**	**35,270**	**38,871**	**40,308**	**40,757**	**41,369**	**43,570**	**41,430**	**41,237**	**48,344**
					Energy Savings (Thousand MWh)							
Large Utilities												
Residential	23,688	21,437	19,255	17,763	13,469	15,438	16,027	16,287	16,263	16,564	17,830	20,585
Commercial	30,725	28,982	28,416	24,624	25,089	24,391	24,217	25,660	23,375	25,125	27,898	29,186
Industrial	14,549	13,348	12,178	12,273	11,156	11,339	10,487	9,160	8,156	3,347	8,684	10,493
Transportation	109	50	48	51	551	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	2,907	3,206	2,593	2,770	831	1,694	1,578
Total	**69,071**	**63,817**	**59,897**	**54,710**	**50,265**	**54,075**	**53,936**	**53,701**	**50,563**	**49,167**	**56,406**	**61,842**

NA = Not available.

Notes: • See Technical Notes for the Demand-Side Management definitions located within the Form EIA-861 section. • Totals may not equal sum of components because of independent rounding.

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

Table 9.5. Demand-Side Management Program Incremental Effects by Sector, 1996 through 2007

Item	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
Actual Peak Load Reductions (MW)												
Large Utilities												
Residential	1,344	1,012	966	1,361	640	895	790	572	605	599	743	792
Commercial	983	759	715	560	528	527	742	515	684	1,176	699	935
Industrial	678	901	731	507	849	680	640	502	929	799	836	1,870
Transportation	1	0	0	0	12	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	112	124	50	45	43	48	93
Total	**3,006**	**2,672**	**2,412**	**2,428**	**2,029**	**2,214**	**2,296**	**1,640**	**2,263**	**2,617**	**2,326**	**3,690**
Small Utilities												
Residential	871	131	325	280	88	48	32	37	27	35	40	30
Commercial	342	63	71	126	58	41	15	37	22	34	21	9
Industrial	130	92	59	40	25	12	16	62	7	56	61	8
Transportation	42	0	0	0	0	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	0	0	26	19	10	20	5
Total	**1,385**	**286**	**455**	**446**	**171**	**101**	**63**	**162**	**76**	**136**	**142**	**52**
U.S. Total	**4,391**	**2,958**	**2,867**	**2,874**	**2,200**	**2,317**	**2,361**	**1,802**	**2,339**	**2,753**	**2,468**	**3,742**
Potential Peak Load Reductions (MW)												
Large Utilities												
Residential	2,374	1,406	1,311	1,680	752	1,311	900	699	753	751	960	950
Commercial	1,574	1,114	1,098	894	602	751	1,115	565	718	1,863	853	1,512
Industrial	1,043	1,201	999	1,569	1,551	1,506	1,277	1,815	5,612	1,438	1,669	3,800
Transportation	1	0	0	0	21	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	141	155	79	68	76	58	146
Total	**4,992**	**3,721**	**3,408**	**4,143**	**2,926**	**3,709**	**3,447**	**3,159**	**7,151**	**3,628**	**3,540**	**6,408**
Small Utilities												
Residential	962	164	367	395	116	64	158	55	41	49	59	46
Commercial	513	95	100	154	73	43	19	51	25	41	35	17
Industrial	243	105	53	77	32	15	18	64	9	70	72	16
Transportation	54	0	0	0	0	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	3	2	44	31	12	30	13
Total	**1,772**	**364**	**520**	**626**	**221**	**125**	**197**	**215**	**106**	**172**	**196**	**92**
U.S. Total	**6,764**	**4,085**	**3,928**	**4,769**	**3,147**	**3,834**	**3,644**	**3,374**	**7,257**	**3,800**	**3,736**	**6,500**
Energy Savings (Thousand MWh)												
Large Utilities												
Residential	3,515	2,141	2,276	1,842	868	1,203	1,365	856	990	909	1,055	1,179
Commercial	2,831	2,339	2,638	1,815	1,356	1,583	1,867	1,780	1,502	1,703	2,382	3,537
Industrial	1,203	999	1,090	867	732	706	872	547	475	645	1,059	1,787
Transportation	13	0	*	0	12	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	116	376	164	127	104	336	341
Total	**7,562**	**5,479**	**6,004**	**4,524**	**2,968**	**3,608**	**4,481**	**3,347**	**3,094**	**3,361**	**4,832**	**6,844**
Small Utilities												
Residential	157	9	6	6	7	45	5	9	4	8	10	7
Commercial	98	3	5	7	5	148	3	4	3	6	3	3
Industrial	4	1	*	2	1	2	2	1	1	3	8	2
Transportation	0	0	0	0	0	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	*	3	3	1	1	7	1
Total	**259**	**13**	**12**	**14**	**13**	**194**	**13**	**17**	**9**	**18**	**28**	**13**
U.S. Total	**7,821**	**5,492**	**6,016**	**4,539**	**2,981**	**3,802**	**4,492**	**3,364**	**3,103**	**3,379**	**4,860**	**6,857**

* = Value is less than half of the smallest unit of measure.

NA = Not available.

Notes: • See Technical Notes for the Demand-Side Management definitions located within the Form EIA-861 section. • Totals may not equal sum of components because of independent rounding.

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

Table 9.6. Demand-Side Management Program Energy Savings, 1996 through 2007
(Thousand Megawatthours)

Item	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
Total Energy Savings	**69,071**	**63,817**	**59,897**	**54,710**	**50,265**	**54,075**	**53,936**	**53,701**	**50,563**	**49,167**	**56,406**	**61,842**
Energy Efficiency	67,134	62,951	58,891	52,662	48,245	52,285	52,946	52,827	49,691	48,775	55,453	59,853
Load Management	1,937	865	1,006	2,047	2,020	1,790	990	875	872	392	953	1,989

Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Table 9.7. Demand-Side Management Program Direct and Indirect Costs, 1996 through 2007
(Thousand Dollars)

Item	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996
Direct Cost[1]	**2,368,466**	**1,923,891**	**1,794,809**	**1,425,172**	**1,159,540**	**1,420,937**	**1,455,602**	**1,384,232**	**1,250,689**	**1,233,018**	**1,347,245**	**1,623,588**
Energy Efficiency	1,664,563	1,258,158	1,169,241	910,115	807,403	1,007,323	1,097,504	938,666	820,108	766,384	892,468	1,051,922
Load Management	703,903	665,733	625,568	515,057	352,137	413,614	358,098	445,566	430,581	466,634	454,777	571,666
Indirect Cost[2]	**158,378**	**127,499**	**126,543**	**132,294**	**137,670**	**204,600**	**174,684**	**180,669**	**172,955**	**187,902**	**288,775**	**278,609**
Total DSM Cost[3]	**2,526,844**	**2,051,394**	**1,921,352**	**1,557,466**	**1,297,210**	**1,625,537**	**1,630,286**	**1,564,901**	**1,423,644**	**1,420,920**	**1,636,020**	**1,902,197**

[1] Reflects electric utility costs incurred during the year that are identified with one of the demand-side program categories.
[2] Reflects costs not directly attributable to specific programs.
[3] Reflects the sum of the total incurred direct and indirect cost for the year.
Notes: • Includes expenditures reported by large electric utilities, only. See the data files for Demand Side Management expenditures of small utilities. • Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

Appendices

Appendix A.
Technical Notes

This appendix describes how the Energy Information Administration (EIA) collects, estimates, and reports electric power data in the *Electric Power Annual*. Following is a description of the ongoing data quality efforts and sources of data for the *Electric Power Annual*.

Data Quality

The *Electric Power Annual* (EPA) is prepared by the Electric Power Division (EPD), Office of Coal, Nuclear, Electric and Alternate Fuels (CNEAF), Energy Information Administration (EIA), U.S. Department of Energy (DOE). EPD performs routine reviews of the data collected and the forms on which they are collected. Additionally, to assure that the data are collected from the complete set of respondents, CNEAF routinely reviews the frames for each data collection.

Unified Data Submission Process

Data are entered directly by respondents into the EPD e-filing system. A small number of hard copy forms are keyed by EPD. All data are subject to review via edits built into the system, additional quality assurance reports, and review by subject matter experts. Questionable data values are verified through contacts with respondents. Also, survey non-respondents are identified and contacted.

Initial edit checks of the data are performed through the system by the respondent. Other 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 staff or by further information obtained from a telephone call to the respondent company.

Those respondents unable to use the electronic reporting method provide the data in hard copy, typically via fax and e-mail. These data are manually entered into the computerized database and are subjected to the same data edits as those that are electronically submitted. Resolution of questionable data is accomplished via telephone or e-mail contact with the respondents.

Reliability of Data

Annual survey data have nonsampling errors. Non-sampling errors can be attributed to many sources: (1) inability to obtain complete information about all cases (i.e., nonresponse); (2) response errors; (3) definitional difficulties; (4) differences in the interpretation of questions; (5) mistakes in recording or coding the data; and (6) other errors of collection, response, coverage, and estimation for missing data.

Although no direct measurement of the biases due to nonsampling errors can be obtained, precautionary steps were taken in all phases of the frame development and data collection, processing, and tabulation processes, in an effort to minimize their influence.

Imputation. If the reported values appeared to be in error and the data issue could not be resolved with the respondent, or if the facility was a nonrespondent, a regression methodology was used to impute for the facility.[1,2,3,4,5] The regression methodology relies on other data to make estimates for erroneous or missing responses.

The basic technique employed is described in the paper "Model-Based Sampling and Inference[12]," on the EIA website. Additional references can be found on the InterStat website. The basis for the current methodology involves a 'borrowing of strength' technique for small domains.[1,6,7]

Data Revision Procedure

CNEAF has adopted the following procedures with respect to the revision of data disseminated in energy data products:

- Annual survey data are disseminated either as preliminary or final when first appearing in a data product. Data initially released as preliminary will be so noted in the data product. These data are typically released as

1 Knaub, J.R., Jr. (1999a), "Using Prediction-Oriented Software for Survey Estimation," InterStat, August 1999, http://interstat.statjournals.net/

2 Knaub, J.R. Jr. (1999b), "Model-Based Sampling, Inference and Imputation," EIA web site: http://www.eia.doe.gov/cneaf/electricity/forms/eiawebme.pdf

3 Knaub, J.R., Jr. (2005), "Classical Ratio Estimator," InterStat, October 2005, http://interstat.statjournals.net/.

4 Knaub, J.R., Jr. (2007a), "Cutoff Sampling and Inference," InterStat, April 2007, http://interstat.statjournals.net/.

5 Knaub, J.R., Jr. (2008), forthcoming. "Cutoff Sampling." Definition in Encyclopedia of Survey Research Methods, Editor: Paul J. Lavrakas, Sage, to appear.

6 Knaub, J.R., Jr. (2000), "Using Prediction-Oriented Software for Survey Estimation - Part II: Ratios of Totals," InterStat, June 2000, http://interstat.statjournals.net/

7 Knaub, J.R., Jr. (2001), "Using Prediction-Oriented Software for Survey Estimation - Part III: Full-Scale Study of Variance and Bias," InterStat, June 2001, http://interstat.statjournals.net/

final by the next dissemination of the same product; however, if final data are available at an earlier interval they may be released in another product.

- After data are disseminated as final, further revisions will be considered if they make a difference of 1 percent or greater at the national level. Revisions for differences that do not meet the 1 percent or greater threshold will be determined by the Office Director. In either case, the proposed revision will be subject to the EIA revision policy concerning how it affects other EIA products.
- The magnitudes of changes due to revisions experienced in the past will be included periodically in the data products, so that the reader can assess the accuracy of the data.

The *Electric Power Annual* 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.

Sensitive Data (Formerly Identified as Data Confidentiality). Most of the data collected on the electric power surveys are not considered business sensitive. However, the data that are classified as sensitive are handled by EPD consistent with EIA's "Policy on the Disclosure of Individually Identifiable Energy Information in the Possession of the EIA" (45 Federal Register 59812 (1980)).

Rounding and Percent Change Calculations

Rounding Rules for Data. To round a number to n digits (decimal places), add one unit to the nth digit if the (n+1) digit is 5 or larger and keep the nth digit unchanged if the (n+1) digit is less than 5. The symbol for a number rounded to zero is (*).

Percent Change. The following formula is used to calculate percent differences.

$$\text{Percent Change} = \left(\frac{x\ (t_2) - x\ (t_1)}{x\ (t_1)} \right) x\ 100,$$

where $x\ (t_1)$ and $x\ (t_2)$ denote the quantity at year t_1 and subsequent year t_2.

Data Sources for *Electric Power Annual*

Data published in the *Electric Power Annual* are compiled from forms filed annually or aggregated to an annual basis from monthly forms by electric utilities and electricity generators (see figure on EIA Electric Industry Data Collection on the next page.) The EIA forms used are:

- Form EIA-411, "Coordinated Bulk Power Supply Program Report;"
- Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report;" [Replaced]
- Form EIA-767, "Steam-Electric Plant Operation and Design Report;" [Replaced]
- Form EIA-860, "Annual Electric Generator Report;" [Modified]
- Form EIA-861, "Annual Electric Power Industry Report;"
- Form EIA-906, "Power Plant Report;" [Replaced] and
- Form EIA-920, "Combined Heat and Power Plant Report." [Replaced]
- Form EIA-923, "Power Plant Operations Report," [New]

These forms can be found on the EIA Internet website at:
http://www.eia.doe.gov/cneaf/electricity/page/forms.html.

The purpose of each form is summarized below.

Survey data from other Federal sources is also utilized for this publication. They include:

- Department of Energy Form OE-781R, "Annual Report of International Electric Export/Import Data" (Office of Electricity Delivery and Energy Reliability);
- Federal Energy Regulatory Commission Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others;"
- Rural Utility Services Form 7, "Financial and Statistical Report;" and
- Rural Utility Services Form 12, "Operating Report – Financial."

In addition to the above-named forms, the historical data published in the EPA are compiled from the following sources:

- Form EIA-412, "Annual Electric Industry Financial Report,"
- Federal Energy Regulatory Commission Form 423, "Cost and Quality of Fuels for Electric Plants,"
- Form EIA-759, "Monthly Power Plant Report,"

- Form EIA-860A, "Annual Electric Generator Report–Utility,"
- Form EIA-860B, "Annual Electric Generator Report–Nonutility,"
- Form EIA-900, "Monthly Nonutility Power Report,"

Additionally, some data reported in this publication were acquired from the National Energy Board of Canada.

Issues within Non-EIA Historical Data Series: Restructuring of the electric power industry has dramatically increased trade in various locations and altered trends. In California, with the changes initiated to establish electricity markets, the electricity imports and exports data are found on the California's Independent System Operator's web site[8] and are not reported to DOE.

Meanings of Symbols Appearing in Tables

Some symbols appearing in the data tables have further standardized to describe all data collected by the Electric Power Division of EIA. The meanings are indicated in footnotes on the applicable tables and include the following:

*	The value reported is less than half of the smallest unit of measure, but is greater than zero.
P	Usage of this symbol indicates a preliminary value. The P is defined in endnotes as "P=Preliminary data."
NM	Data value is not meaningful when compared to the same value for the previous month or the previous year. This symbol is also used to indicate a data value is not meaningful due to having a high Relative Standard Error (RSE).

Form EIA-411

The Form EIA-411 is filed as a mandatory report except for Schedule 7 (Transmission Outages) that is still voluntary reported. The information reported includes: (1) actual energy and peak demand for the preceding year and five 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. The report presents various North American Electric Reliability Corporation (NERC) regional council aggregate totals for their member electric utilities, with some nonmember information included. The eight NERC councils submit data for the Form EIA-411 to NERC. A joint response, through the NERC Headquarters, is filed annually on July 15. The forms are compiled from data furnished by electricity generators and electric utilities (members, associates, and nonmembers) within the council areas.

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. Until 2008, this form was 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 transferred to EIA for the reporting year 1996.

Issues within Historical Data Series

The Florida Reliability Coordinating Council (FRCC) separated itself from the Southeastern Electric Reliability Council (SERC) in the mid-1990s and all time series data have been adjusted. In 1998, several utilities realigned from Southwest Power Pool (SPP) to SERC. Adjustments were made to the information to account for the separation and to address the tracking of shared reserve capacity that was under long-term contracts with multiple members. Name changes altered both the Mid-Continent Area Power Pool (MAPP) to the Midwest Reliability Organization (MRO) and the Western Systems Coordinating Council (WSCC) to the Western Energy Coordinating Council (WECC). The MRO membership boundaries have altered over time, but WECC membership boundaries have not. The utilities in the associated regional entity identified as the Alaska System Coordination Council (ASCC) dropped their formal participation in NERC. Both the States of Alaska and Hawaii are not contiguous with the other continental States and have no electrical interconnections. At the close of calendar year 2005, the follow reliability regional councils were dissolved: East Central Area Reliability Coordinating Agreement (ECAR), Mid-Atlantic Area Council (MAAC), and Mid-America Interconnected Network (MAIN).

[8] For the reporting year 2001, California - ISO reported electricity purchases from Mexico of 98,645 MWh. They exported 65,475 MWh, thereby having a total net trade of 33,170 MWh of imported electricity in 2001. For the reporting year 2002, California - ISO reported electricity purchases from Mexico of 143,948 MWh. They exported 196,923 MWh, thereby having a total net trade of 52,975 MWh of exported electricity in 2002. In 2003, California - ISO reported electricity purchases of 971,278 MWh and sold 22,510 MWh. For 2004, California - ISO reported electricity purchases of 1,103,928 MWh and sold 48,074 MWh. For 2005, California ISO reported electricity purchases of 1,498,622 MWh and sales of 103,051 MWh. For 2006, California - ISO reported electric purchases of 1,048,610 MWh and sales of 498, 268 MWh. In 2007, the California – ISO reported electric purchases on 1,178,996 MWh and 216,496 MWh sales with Mexico.

On January 1, 2006, the Reliability*First* Corporation (RFC) came into existence as a new regional reliability council. Individual utility membership in the former ECAR, MAAC, and MAIN councils mostly shifted to RFC. However, adjustments in membership as utilities joined or left various reliability councils impacted MRO, SERC, and SPP. The Texas Regional Entity (TRE) was formed from a delegation of authority from NERC to handle the regional responsibilities of the Electric Reliability Council of Texas (ERCOT). The revised delegation agreements covering all the regions were approved by the Federal Energy Regulatory Commission on March 21, 2008. Reliability Councils that are unchanged include: Florida Reliability Coordinating Council (FRCC), Northeast Power Coordinating Council (NPCC), and the Western Energy Coordinating Council (WECC). The historical time series have not been adjusted to account for individual membership shifts.

The new NERC Regional Council names are as follows:

- Florida Reliability Coordinating Council (FRCC),
- Midwest Reliability Organization (MRO),
- Northeast Power Coordinating Council (NPCC),
- Reliability*First* Corporation (RFC),
- Southeastern Electric Reliability Council (SERC),
- Southwest Power Pool (SPP),
- Texas Regional Entity (TRE), and
- Western Energy Coordinating Council (WECC).

Concept of Demand within the EIA-411: Historically, the Form EIA-411 has used the electric power industry's methodology for examining aggregated supply and demand. To get to the megawatts of power that are determined to be available for planning purposes each year, different categories are subtracted from the theoretical true totals. The definitions for demand are as follows:

- **Net Internal Demand**: Internal Demand less Direct Control Load Management and Interruptible Demand.
- **Internal Demand**: To collect these data, NERC develops a Total Internal Demand that 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 nor are any requirement customer (utility) load or capacity found behind the line meters on the system.
- **Direct Control Load Management**: Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises; it does not included Interruptible Demand.
- **Interruptible Demand**: The magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted as the time of the NERC Council or Reporting party seasonal peak by direct control 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.

Sensitive Data (Formerly Identified as Data Confidentiality). Power flow cases and maps are considered business sensitive.

Form EIA-412 [Terminated]

The Form EIA-412 was 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 150,000 megawatthours of sales to ultimate consumers and/or 150,000 megawatthours of sales for resale for the two previous years, as reported on the Form EIA-861, "Annual Electric Utility Report," were required to submit the Form EIA-412. The Form EIA-412 was made available in January to collect data as of the end of the preceding calendar year. The completed surveys were due to EIA on or before April 30.

Instrument and Design History. The Federal Power Commission (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.

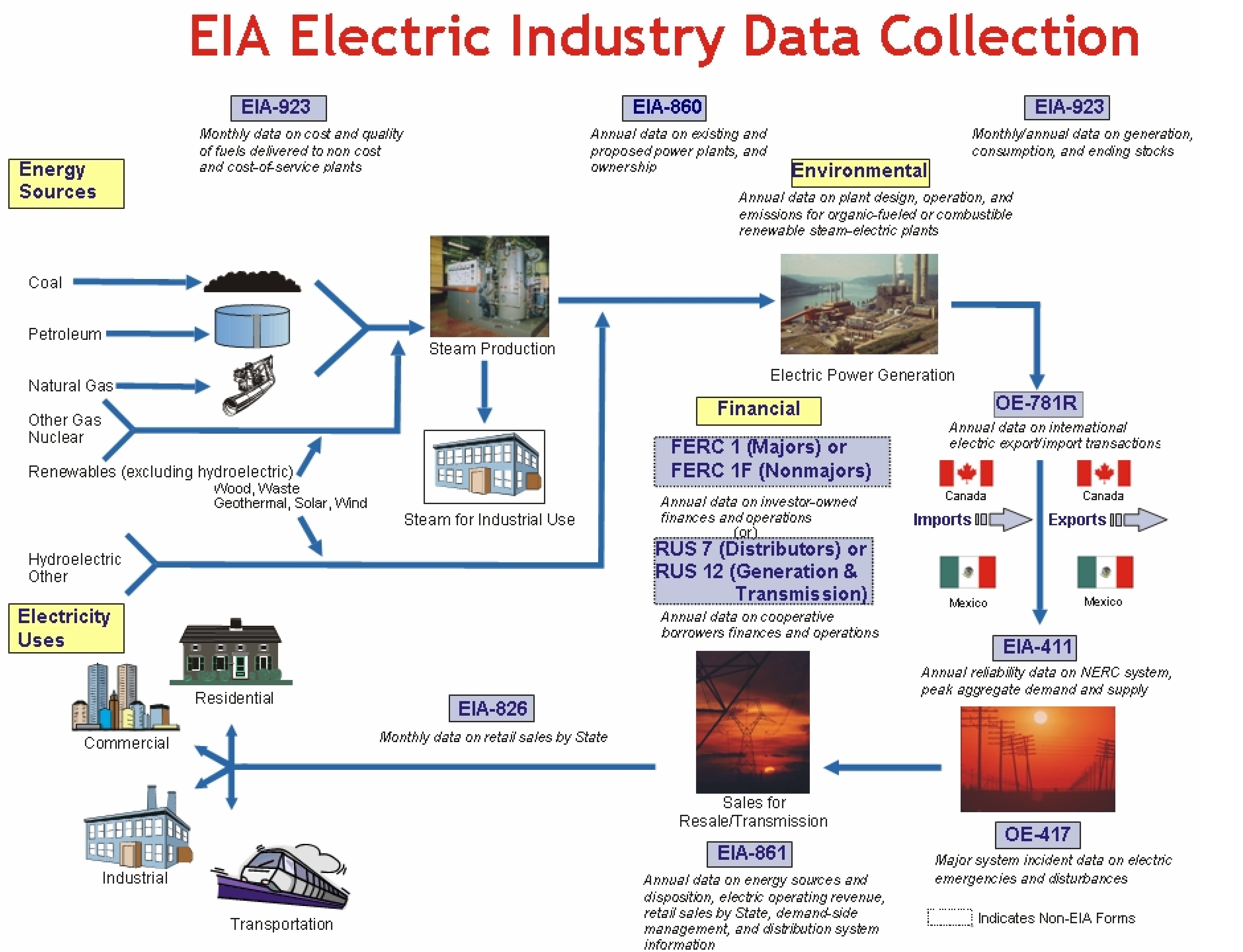
The 1996-1997 data represent those electric utilities meeting a threshold of 120,000 megawatthours for ultimate consumers' sales and/or resales. The criteria used to select the respondents for this survey fit approximately 500 publicly owned electric utilities. Federal electric utilities are required 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. Department of Interior, Bureau of Reclamation; and the U.S. International Boundary and Water Commission were collected on the Form EIA-412 from the Federal power marketing administrations. The form was terminated after the 2003 data year.

Issues within Historical Data Series

Beginning with the 2001 data collection, the plant statistics reported on Schedule 9 were also collected from unregulated entities that own plants with a nameplate capacity of 10 megawatts or greater. Also beginning with the 2003 collection, the transmission data reported in Schedules 10 and 11 were collected from each generation and transmission cooperative owning transmission lines having a nominal voltage of 132 kilovolts or greater.

For 2001 - 2003, California Department of Water Resources - Electric Energy Fund data were included in the EIA-412 data tables. In response to the energy shortfall in California, in 2001 the California State legislature authorized the California Department of Water Resources, using its undamaged borrowing capability, to enter the wholesale markets on behalf of the California retail customers effective on January 17, 2001 and for the period ending December 31, 2002. Their 2001 revenue collected was $5,501,000,000 with purchased power costs of $12,055,000,000. Their 2002 revenue collected was $4,210,000,000 with purchased power costs of $3,827,749,811. Their 2003 revenue collected was $4,627,000,000 with purchased power costs of $4,732,000,000. The California Public Utility Commission was required by statute to establish the procedures for retail revenue recovery mechanisms for their purchase power costs in the future.



EIA Electric Industry Data Collection
EIA-923
Monthly data on cost and quality of fuels delivered to non cost and cost-of-service plants
EIA-860
Annual data on existing and proposed power plants, and ownership
EIA-923
Monthly/annual data on generation, consumption, and ending stocks
Energy Sources
Environmental
Annual data on plant design, operation, and emissions for organic-fueled or combustible renewable steam-electric plants
Coal
Petroleum
Natural Gas
Other Gas
Nuclear
Renewables (excluding hydroelectric)
Wood, Waste
Geothermal, Solar, Wind
Steam Production
Steam for Industrial Use
Electric Power Generation
Hydroelectric
Other
Financial
FERC 1 (Majors) or
FERC 1F (Nonmajors)
Annual data on investor-owned finances and operations
(or)
RUS 7 (Distributors) or
RUS 12 (Generation & Transmission)
Annual data on cooperative borrowers finances and operations
OE-781R
Annual data on international electric export/import transactions
Canada
Canada
Imports
Exports
Mexico
Mexico
Electricity Uses
Residential
Commercial
Industrial
Transportation
EIA-826
Monthly data on retail sales by State
Sales for Resale/Transmission
EIA-861
Annual data on energy sources and disposition, electric operating revenue, retail sales by State, demand-side management, and distribution system information
EIA-411
Annual reliability data on NERC system, peak aggregate demand and supply
OE-417
Major system incident data on electric emergencies and disturbances
Indicates Non-EIA Forms

Sensitive Data (Formerly Identified as Data Confidentiality). The nonutility data collected on Schedule 9 "Electric Generating Plant Statistics" for "Cost of Plant" and "Production Expenses," are considered business sensitive.

Form EIA-423 [Replaced in 2008 by the Form EIA-923]

The Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report," collected information from selected electric generating plants in the United States. The data collected on this survey included the cost and quality of fossil fuels delivered to nonutility plants to produce electricity. These plants included independent power producers (including those facilities that formerly reported on the FERC Form 423) and commercial and industrial combined heat and power producers whose total fossil-fueled nameplate generating capacity is 50 or more megawatts.

Instrument and Design History. The Form EIA-423[1] was originally implemented in January 2002 to collect monthly cost and quality data for fossil fuel receipts from owners or operators of nonutility electricity generating plants. It was terminated on January 1, 2008, and replaced by the Form EIA-923, "Power Plant Operations Report."

Issues within Historical Data Series

Natural gas values for 2001 forward do not include blast furnace gas or other gas.

Sensitive Data (Formerly Identified as Data Confidentiality). Plant fuel cost data collected on the survey are considered business sensitive. State and national level aggregations will be published in this report if sufficient data are available to avoid disclosure of individual company and plant level costs.

FERC Form 423 [Replaced in 2008 by Form EIA-923]

The Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," was administered by FERC. The data were downloaded from the Commission's website into an EIA database. The Form was filed by approximately 600 regulated plants. To meet the old criteria for filing, a plant must have had a total steam turbine electric generating capacity and/or combined-cycle (gas turbine with associated steam turbine) generating capacity of 50 or more megawatts. Only fuel delivered for use in steam-turbine and combined-cycle units was reported. Fuel received for use in gas-turbine or internal-combustion units that was not associated with a combined-cycle operation is not reported. The 2007 data collection represents the last year where the information came from the FERC Form 423.

Instrument and Design History. On July 7, 1972, the Federal Power Commission (FPC) issued Order Number 453 enacting the New Code of Federal Regulations, Section 141.61, legally creating the FPC Form 423. Originally, the form was used to collect data only on fossil-steam plants, but was amended in 1974 to include data on internal-combustion and combustion-turbine units. The FERC Form 423 replaced the FPC Form 423 in January 1983. The FERC Form 423 eliminated peaking units, for which data were previously collected on the FPC Form 423. In addition, the generator nameplate capacity threshold was changed from 25 megawatts to 50 megawatts. This reduction in coverage eliminated approximately 50 utilities and 250 plants. All historical FPC Form 423 data in this publication were revised to reflect the new generator-nameplate-capacity threshold of 50 or more megawatts reported on the FERC Form 423. In January 1991, the collection of data on the FERC Form 423 was extended to include combined-cycle units. Historical data have not been revised to include these units. Starting with the January 1993 data, the FERC began to collect the data directly from the respondents. On January 1, 2008, EIA assumed took responsibility for collection and the information is now under the Form EIA-923, "Power Plant Operations Report."

Formulas and Methodologies. Data for the FERC Form 423 were collected at the plant level. These data were then used in the same formulas used by the Form EIA-423 to produce aggregates and averages for each fuel type at the State, Census division, and U.S. levels.

Issues within Historical Data Series. The FERC Form 423 data published by EIA have been reviewed for consistency between volumes and prices and for their consistency over time.

Receipts data for regulated utilities were compiled by EIA from data collected by the Federal Energy Regulatory Commission (FERC) on the FERC Form 423. These data were collected by FERC for regulatory rather than statistical and publication purposes. EIA did not attempt to resolve any late

[1] Due to the restructuring of the electric power industry, many plants which had historically submitted this information for utility plants on the FERC Form 423 (see subsequent section) were being transferred to the nonutility sector. As a result, a large percentage of fossil fuel receipts were no longer being reported. The Form EIA-423 was implemented to fill this void and to capture the data associated with existing nonregulated power producers. Its design closely follows that of the FERC Form 423.

filing issues in the FERC Form 423 data. Due to the estimation procedure discussed previously, 2003 and later data cannot be directly compared to previous years' data.

Sensitive Data (Formerly Identified as Data Confidentiality). Data collected on FERC Form 423 are not considered to be business sensitive.

Form EIA-767 [Replaced by Forms EIA-860 and EIA-923]

The Form EIA-767 was used to collect data annually on plant operations and equipment design, including boiler, generator, cooling system, air pollution control equipment, and stack characteristics. Data were collected from a mandatory restricted-universe census of all electric power plants with a total existing or planned organic-fueled or combustible renewable steam-electric generator nameplate rating of 10 or more megawatts. The entire form was filed by approximately 800 power plants with a nameplate capacity of 100 or more megawatts. An additional 600 power plants with a nameplate capacity under 100 megawatts submitted information only on fuel consumption and quality, boiler and generator configuration, and nitrogen oxides, mercury, particulate matter, and sulfur dioxide controls.

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 retitled 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. In 2002, the respondent universe was increased by almost 1,370 plants with the addition of non-utility plants. <u>Collection of data via the form was suspended for the 2006 data year</u>. Starting for the collection of 2007 calendar year data, most of the Form EIA-767 information is now collected on either the revised Form EIA-860, "Annual Electric Generator Report" or the new Form EIA-923, "Power Plant Operations Report."

Estimation of EIA-767 Data. No estimation of Form EIA-767 data was performed, as 100 percent of the forms were collected.

Issues within Historical Data Series

None.

Sensitive Data (Formerly Identified as Data Confidentiality). Historical latitude and longitude data collected on the Form EIA-767 are considered business sensitive.

Form EIA-860

The Form EIA-860 is a mandatory census of all existing and planned electric generating facilities in the United States with a total generator nameplate capacity of 1 or more megawatts. The survey is used to collect data on existing power plants and 5-year plans for constructing new plants, generating unit additions, modifications, and retirements in existing plants. Data on the survey are collected at the individual generator level. Certain power plant environmental related data are now collected at the boiler level. These data include environmental equipment design parameters and boiler air emission standards and boiler emission controls. The Form EIA-860 is made available in January to collect data for the previous year and is due to EIA by February 15 of each year.

Instrument and Design History. The Form EIA-860 was originally implemented in January 1985 to collect plant data on electric utilities as of year-end 1984. In January 1999, the Form EIA-860 was renamed the Form EIA-860A and was implemented to collect data as of January 1, 1999.

In 1989, the Form EIA-867, "Annual Nonutility Power Producer Report," was initiated to collect plant data on unregulated entities with a total generator nameplate capacity of 5 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. In 1998, the Form EIA-867, was renamed Form EIA-860B, "Annual Electric Generator Report – Nonutility." The Form EIA-860B was 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.

Beginning with data collected for the year 2001, the infrastructure data collected on the Form EIA-860A and the Form EIA-860B were combined into the new Form EIA-860 and the monthly and annual versions of the Form EIA-906. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data.

Starting with the 2007 data,, design parameters data formerly collected on Form EIA-767 are collected on

Form EIA-860. These include design parameters associated with certain steam-electric plants' boilers, cooling systems, flue gas particulate collectors, flue gas desulfurization units and stacks and flues.

Estimation of EIA-860 Data. Of the 17,344 existing generators in the 2007 Form EIA-860 frame, imputation was performed on 81 generators. These 81 generators account for less than one percent (.017 percent) of the existing capacity. Imputation was performed at the respondent-plant-generator levels, using the 2006 respondent data.

Issues within Historical Data Series

Categorization of Capacity by Business Sector: There is a small number of electric utility combined heat and power plants, as well as a small number of industrial and commercial generating facilities that are not combined heat and power. For the purposes of this report the data for these plants is included, respectively, in the following categories: "Electricity Generators, Electric Utilities," "Combined Heat and Power, Industrial," and "Combined Heat and Power, Commercial."

Some capacity in 2001 through 2004 is classified based on the operating company's classification as an electric utility or an independent power producer. Starting in the *Electric Power Annual 2006*, capacity by producer type was determined at the generating plant level for 2005 and 2006, based on whether the plant is an electric utility plant or an electric nonutility plant. Therefore, the revised capacity by producer type for 2005 is comparable to the capacity for 2006 and later years, by producer type. The previously published 2005 capacity by producer type was determined based on the operating company's classification of electric utility or electric nonutility.

Planned Capacity: Delays and cancellations may have occurred subsequent to respondent data reporting as of December 31 of the data year.

Capacity by Energy Source: Prior to the *Electric Power Annual* 2005, the capacity for generators for which natural gas or petroleum was the most predominant energy source was presented in the categories "petroleum only," "natural gas only" and "dual-fired." The "dual-fired" category, which was EIA's effort to infer which generators could fuel-switch between natural gas and fuel oil, included only the capacity of generators for which the most predominant energy source and second most predominant energy source were reported as natural gas or petroleum. Beginning with the *Electric Power Annual* 2005 capacity is assigned to energy source based solely on the most predominant (primary) energy source reported for a generator. The "dual-fired" category was eliminated. Separately, summaries of capacity associated with generators with fuel-switching capability are presented for 2005 and later years.. These summaries are based on data collected from new questions added to the Form EIA-860 survey that directly address the ability of generators to switch fuels and co-fire fuels.

In the *Electric Power Annual 2005*, certain petroleum-fired capacity was misclassified as natural gas-fired capacity for 1995 – 2003. This has been corrected in the *Electric Power Annual 2006*. Corrections were noted as revised data.

Sensitive Data (Formerly Identified as Data Confidentiality). The tested heat rate data collected on the Form EIA-860 are considered business sensitive.

Form EIA-861

The Form EIA-861 is a mandatory census of electric power industry participants in the United States. The survey is used to collect information on power production and sales data from approximately 3,300 respondents. About 3,200 are electric utilities, and the remainder are nontraditional entities such as energy service providers, or the unregulated subsidiaries of electric utilities and power marketers. The data collected are used to maintain and update the EPD electric power industry participant frame database. The Form EIA-861 is made available in January of each year to collect data as of the end of the preceding calendar year and is due by April 30.

Transportation Sector. Prior to 2003, sales of electric power to the Transportation sector of the U. S. economy were included in the Other sector, along with sales to customers for public buildings, traffic signals, public street lighting, and sales to irrigation consumers. Beginning with the 2003 collection cycle, sales to the Transportation sector are collected separately. Sales to public-sector customers for public buildings, traffic signals and street lighting, previously reported in the Other sector, were reclassified as Commercial sector sales. Sales to irrigation customers, where separately identified, were reclassified to the Industrial sector.

On the Form EIA-861, the Transportation sector is defined as electrified rail, primarily urban transit, light rail, automated guideway, and other rail systems whose primary propulsive energy source is electricity. Electricity sales to transportation sector consumers whose primary propulsive energy source is not electricity (i.e., gasoline, diesel fuel, etc.) are not included.

Benchmark statistics were reviewed from outside surveys, most notably the U.S. Department of Transportation, Federal Transit Administration's National Transportation Database, a source previously used by EIA to estimate electricity transportation consumption. The U.S. Department of Transportation (DOT) survey indicated the State and city locations of expected respondents. The EIA-861 survey methodology assumed that sales, revenue, and customer counts associated with these mass transit systems would be provided by the incumbent utilities in these areas, relying on information drawn routinely from rate schedules and classifications designed to serve the sector separately and distinctly. In 2007, 72 respondents reported transportation data in 28 States.

Imputation. The *Electric Power Annual* (EPA) reports total retail sales volumes (megawatthours) and customer counts in States with deregulated markets as the sum of bundled sales reported by full service providers and delivery reported by transmission and distribution utilities. EPD has concluded that the retail sales data reported by delivery utilities are more reliable than data reported by power marketers and Energy Service Providers (ESPs).

The reporting methodology change uses sales volumes and customer counts reported by distribution utilities, and add only an incremental revenue value, representing revenue associated with missing sales assumed to be attributable to the ESPs that were under-represented in the survey frame. In some cases, adjustments are also made to retail sales, revenue, and customer counts associated with underreporting of delivery volumes by one or more of the distribution utilities. In those cases, EIA assumes that total load served by those utilities is accurate, and that any underreporting of delivery volumes resulted from misclassifying actual delivery volumes as bundled sales. Therefore, in those instances EIA adjusted upwards the delivery volumes, revenues, and customer counts and made a corresponding equivalent offset (reduction) to the bundled sales by State and end-use sector.

Data for 2007 reflect imputed retail sales data to account for non-respondents on Form EIA-861. The imputation methodology used is the same as that used in preparing the *Electric Power Monthly* (whose retail sales data are drawn from Form EIA-826). Form EIA-826 is a monthly stratified sample of approximately 454 investor-owned and public utilities, as well as a census of energy service providers and power marketers. If an EIA-861 respondent did not file an annual form for 2007, their data were assumed to be the amount imputed during the year using the EIA-826 sample form collection and imputation process.

Instrument and Design History. The Form EIA-861 was implemented in January 1985 for collection of data as of year-end 1984. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data.

Data Reconciliation. The EPA reports total retail sales volumes (megawatthours) and customer counts in States with deregulated markets as the sum of bundled sales reported by full service providers and delivery reported by transmission and distribution utilities. EPD has concluded that the retail sales data reported by delivery utilities are more reliable than data reported by power marketers and ESPs.

Average Retail Price of Electricity. This represents the cost per unit of electricity sold and is calculated by dividing retail electric revenue by the corresponding sales of electricity. The average retail price of electricity is calculated for all consumers and for each end-use sector. State-level weighted average prices per unit of sales are calculated as the ratio of revenue to sales.

The electric revenue used to calculate the average retail price of electricity is the operating revenue reported by the electric power industry participant. Operating revenue includes energy charges, demand charges, consumer service charges, environmental surcharges, fuel adjustments, and other miscellaneous charges. Electric power industry participant operating revenues also include ratepayer reimbursements for State and Federal income taxes and taxes other than income taxes paid by the utility.

The average retail price of electricity reported in this publication by sector represents a weighted average of consumer revenue and sales within sectors and across sectors for all consumers, and does not reflect the per kWh rate charged by the electric power industry participant to the individual consumers. 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 power industry participant for providing electrical service.

Issues within Historical Data Series

Beginning in 2003 the Other sector has been eliminated. Data previously assigned to the Other sector have been reclassified as follows: lighting for public buildings, streets, and highways, interdepartmental sales, and other sales to public authorities are now included in the Commercial sector; agricultural and irrigation sales where separately identified are now included in the Industrial sector; and a new sector, Transportation, includes electrified rail and various urban transit systems (such as automated guideway, trolley, and cable) where the principal propulsive energy source is electricity. Comparisons of data across years should include consideration of these reclassification changes.
Changes from year to year in consumer counts, sales and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications. Utilities and energy service providers may classify commercial and industrial customers based on either NAICS codes or demands or usage falling within specified limits by rate schedule. Also, the number of ultimate customers is an average of the number of customers at the close of each month.

Demand-Side Management: The following definitions are supplied to assist in interpreting Tables 9.1 through 9.5. Utility costs reflect the total cash expenditures for the year, in nominal dollars, that flow out to support demand-side management (DSM) programs.

- **Actual Peak Load Reduction.** The actual reduction in annual peak load achieved by all program participants during the reporting year, at the time of annual peak load, as opposed to the installed peak load reduction capability (Potential Peak Load Reduction). Actual peak load reduction is reported by large utilities only.
- **Energy Savings.** The change in aggregate electricity use (measured in megawatthours) for consumers that participate in a utility DSM program. These savings represent changes at the consumer's 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.
- **Large Utilities.** Those electric utilities with annual sales to ultimate customers or sales for resale greater than or equal to 150 million kilowatthours in 1998-2008 and, for years prior, the threshold was set at 120 million kilowatthours.
- **Potential Peak Load Reductions.** The potential peak load reduction as a result of load management, and also the actual peak load reduction achieved by energy efficiency programs.

Wholesale Trade: Alaska and Hawaii are not included.

Sensitive Data (Formerly Identified as Data Confidentiality). Data collected on the Form EIA-861 are not considered to be business sensitive.

Form EIA-906 [Replaced in 2007 by Form EIA-923]

The Form EIA-906 was used to collect plant-level data on generation, fuel consumption, stocks, and fuel heat content, from electric utilities and nonutilities. Data were collected monthly from a model-based sample of approximately 1,700 utility and nonutility electric power plants. The form was also used to collect these statistics from another 2,667 plants (i.e., all other generators 1 MW or greater) on an annual basis. The 2007 data collection represents the last year where the information came from the Form EIA-906. Starting with the collection of 2008 calendar year data, the Form EIA-906 information is now collected on a replacement form (the Form EIA-923). The monthly data for Form EIA-906 is now being collected on the replacement form starting in January of 2008.

Instrument and Design History. The Bureau of Census and the U.S. Geological Survey collected, compiled, and published data on the electric power industry prior to 1936. After 1936, the Federal Power Commission (FPC) assumed all data collection and publication responsibilities for the electric power industry and implemented the Form FPC-4. The Federal Power Act, Section 311 and 312, and FPC Order 141 defined the legislative authority to collect power production data. The Form EIA-759 replaced the Form FPC-4 in January 1982. In 1996, the Form EIA-900 was initiated to collect sales for resale data from unregulated entities. In 1998, the form was modified to collect sales for resale, gross generation, and sales to end user data. In 1999, the form was modified to collect net generation, consumption, and ending stock data. In 2000, the form was modified to include useful thermal output data.

In January 2001, Form EIA-906 superseded Forms EIA-759 and EIA-900. In January 2004, Form EIA-920 superseded Form EIA-906 for those plants defined as combined heat and power plants; all other plants that generate electricity continue to report on Form EIA-906. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data. In January 2008, the Form EIA-923 superseded this form.

Issues within Historical Data Series

There were a small number of electric commercial and industrial- only plants that are included in the combined heat and power category. For the purposes of this report the data for these plants were included, respectively, in the following categories: "Electricity Generators, Electric Utilities," "Combined Heat and Power, Industrial," and "Combined Heat and Power, Commercial." No information on the production of Useful Thermal Output (UTO) or fuel consumption for UTO was collected or estimated for the electric utility combined heat and power plants.

Sensitive Data (Formerly Identified as Data Confidentiality). The only business sensitive data element collected on the Form EIA-906 is fuel stocks at the end of the reporting period.

Form EIA-920 [Replaced in 2007 by Form EIA-923]

The Form EIA-920, "Combined Heat and Power Plant Report" was used to collect plant-level data on generation, fuel consumption, stocks, and fuel heat content of combined heat and power (CHP) plants. Data were collected monthly from a sample of plants. The form was also used to collect the statistics from combined heat and power plants on an annual basis.

Instrument and Design History. In January 2004, Form EIA-920 superseded Form EIA-906 for those plants defined as combined heat and power plants; all other plants that generate electricity continue to report on Form EIA-906. Starting with the collection of 2007 calendar year data, the Form EIA-920 information is now collected on a replacement form (the Form EIA-923). The monthly data for Form EIA-920 began collection on the replacement form in January of 2008. (For further information on predecessor forms, see the discussion of the EIA-906 survey, above.) The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data.

Issues within Historical Data Series

There are a small number of electric commercial and industrial only plants that are included in the combined heat and power category. For the purposes of this report the data for these plants are included, respectively, in the following categories: "Electricity Generators, Electric Utilities," "Combined Heat and Power, Industrial," and "Combined Heat and Power, Commercial." No information on the production of UTO or fuel consumption for UTO was collected or estimated for the electric utility combined heat and power plants.

Sensitive Data (Formerly Identified as Data Confidentiality). The only business sensitive data element collected on the Form EIA-920 were fuel stocks at the end of the reporting period.

Form EIA-923 *[New]*

Form EIA-923, "Power Plant Operations Report," is used to collect information on receipts and cost of fossil fuels, fuel stocks, generation, consumption of fuel for generation, and environmental data (e.g., emission controls and cooling systems). Data are collected from a monthly sample of approximately 1,600 plants, which includes a census of nuclear and pumped storage hydroelectric plants. The plants in the monthly sample report their receipts, cost and stocks of fossil fuels, electric power generation, and the total consumption of fuels for both electric power generation and, if a combined heat and power plant, useful thermal output. At the end of the year, the monthly respondents report their annual source and disposition of electric power (nonutilities only), and if applicable, the environmental data on the Form EIA-923 Supplemental Form (Schedules 6, 7, and 8A to 8F). Approximately 3,300 plants, representing all generators not included in the monthly sample and with a nameplate capacity of 1 MW or more, report data on the entire form (Schedules 1 to 8F, as applicable) annually. In addition to electric power generating plants, respondents include fuel storage terminals without generating capacity that receives shipments of fossil fuels for eventual use in electric power generation. The monthly data are due by the last day of the month following the reporting period.

Receipts of fossil fuels, fuel cost and quality information, and fuel stocks at the end of the reporting period are all reported at the plant level. Fuel receipts and costs are collected from plants with a nameplate capacity of 50 MW or more and burn fossil fuels. Plants that burn organic fuels and have a steam turbine capacity of at least 10 megawatts report consumption at the boiler level and generation at the generator level for each month, regardless of whether the plant reports in the monthly sample or reports once a year (annually). For all other plants, consumption is reported at the prime-mover level. For these plants, generation is reported either at the prime-mover level or, for noncombustible sources (e.g., wind, nuclear), at the prime-move and energy source level (including generating unit for nuclear only). The source and disposition of electricity is reported annually for nonutilities at the plant level, as is revenue from sales for resale. Additional operational data, including environmental data, are collected annually from facilities that have a steam turbine capacity of at least 10 megawatts.

Instrument and Design History:

Receipts and Cost and Quality of Fossil Fuels

On July 7, 1972, the Federal Power Commission (FPC) issued Order Number 453 enacting the New Code of Federal Regulations, Section 141.61, legally creating the FPC Form 423. Originally, the form was used to collect data only on fossil-steam plants, but was amended in 1974 to include data on internal-combustion and combustion-turbine units. The FERC Form 423 replaced the FPC Form 423 in January 1983. The FERC Form 423 eliminated peaking units, for which data were previously collected on the FPC Form 423. In addition, the generator nameplate capacity threshold was changed from 25 megawatts to 50 megawatts. This reduction in coverage eliminated approximately 50 utilities and 250 plants. All historical FPC Form 423 data in this publication were revised to reflect the new generator-nameplate-capacity threshold of 50 or more megawatts reported on the FERC Form 423. In January 1991, the collection of data on the FERC Form 423 was extended to include combined-cycle units. Historical data have not been revised to include these units. Starting with the January 1993 data, the FERC began to collect the data directly from the respondents.

The Form EIA-423 was originally implemented in January 2002 to collect monthly cost and quality data for fossil fuel receipts from owners or operators of nonutility electricity generating plants. Due to the restructuring of the electric power industry, many plants which had historically submitted this information for utility plants on the FERC Form 423 (see above) were being transferred to the nonutility sector. As a result, a large percentage of fossil fuel receipts were no longer being reported. The Form EIA-423 was implemented to fill this void and to capture the data associated with existing non-regulated power producers. Its design closely followed that of the FERC Form 423.

Both the Form EIA-423 and FERC-423 were superseded by Form EIA-923 (Schedule 2) in January of 2008. The EIA-923 maintains the same 50 megawatt threshold for these data. However, not all data are collected monthly on the new form. Beginning with 2008 data, a sample of the respondents will report monthly, with the remainder reporting annually (monthly values will be imputed via regression). For 2007, Schedule 2 annual data will not be collected or imputed. Most of the plants required to report on Schedule 2 already submitted their 2007 receipts data on a monthly basis.

Generation and Consumption

The Bureau of Census and the U.S. Geological Survey collected, compiled, and published data on the electric power industry prior to 1936. After 1936, the Federal Power Commission (FPC) assumed all data collection and publication responsibilities for the electric power industry and implemented the Form FPC-4. The Federal Power Act, Section 311 and 312, and FPC Order 141 defined the legislative authority to collect power production data. The Form EIA-759 replaced the Form FPC-4 in January 1982.

In 1996, the Form EIA-900 was initiated to collect sales for resale data from unregulated entities[10]. In 1998, the form was modified to collect sales for resale, gross generation, and sales to end user data. In 1999, the form was modified to collect net generation, consumption, and ending stock data[11]. In 2000, the form was modified to include useful thermal output data.

In January 2001, Form EIA-906 superseded Forms EIA-759 and EIA-900. In January 2004, Form EIA-920 superseded Form EIA-906 for those plants defined as combined heat and power plants; all other plants that generate electricity continue to report on Form EIA-906. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data.

Forms EIA-906 and EIA-920 were superseded by survey form EIA-923 beginning in January 2008 with the collection of annual 2007 data and monthly 2008 data.

Steam Electric Plant Operational Data

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 retitled 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. In 2002, the respondent universe increased to above 1,370 plants plus the addition of non-utility plants. Collection of data via the Form EIA-767 was suspended for the 2006 data year, but was resumed on the Form EIA-923 for data year 2007. For respondents selected to be in the monthly sample for Form EIA-906 or EIA-920 in 2007, and were thus were not annual filers for Form EIA-923, this data was collected for 2007 via a one-time supplemental filing in 2008.

Data Processing and Data System Editing. Respondents are encouraged to enter data directly into a computerized database via the e-filing system. A variety of automated quality control mechanisms are run during this process, such as range checks and comparisons with historical data. These edit checks were performed as the data were provided, and many problems that are encountered are resolved during the reporting process. Those plants that are unable to use the electronic reporting medium provide the data in hard copy, typically via fax. These data were manually entered into the computerized database. The data were subjected to the same edits as those that were electronically submitted.

If the reported data appeared to be in error and the data issue could not be resolved by follow up contact with the respondent, or if a facility was a nonrespondent, a regression methodology was used to impute for the facility.

Imputation. For data collected monthly, regression prediction, or imputation, is done for all missing data including non-sampled units and any nonrespondents. For data collected annually, imputation is done for nonrespondents.

For gross generation and total fuel consumption, multiple regression is used for imputation. For gross generation, the regressors are prior year average generation for the same fuel, prior year average generation from other fuels, and nameplate capacity. Regressors for total fuel consumption are prior year average fuel consumption from the same fuel, prior year average consumption from other fuels, and nameplate capacity. For stocks, a linear combination of the prior month's ending stocks value and the current month's consumption and receipts values is used.

Only approximately 0.02% of the national total gross generation for 2007 reported here is imputed, although this will vary by State and energy source.

Net generation, where not reported, is estimated by using a fixed ratio to gross generation by prime-mover type.

Receipts of Fossil Fuels. Note that for 2007, this data was collected on Form EIA-423 and FERC Form 423.

Receipts data, including cost and quality of fuels, are collected at the plant level from selected electric generating plants and fossil-fuel storage terminals in the United States. These plants include independent power producers, electric utilities, and commercial and industrial combined heat and power producers whose total fossil-fueled nameplate capacity is 50 megawatts or more (excluding storage terminals, which do not produce electricity). The data on cost and quality of fuel shipments are then used in the following formulas to produce aggregates and averages for each fuel type at the State, Census division, and U.S. levels. For these formulas, receipts and average heat content are at the plant level. For each geographic region, the summation sign, $\sum$, represents the sum of all facilities in that geographic region.

For coal, units for receipts are in tons and units for average heat contents (A) are in million Btu per ton.

For petroleum, units for receipts are in barrels and units for average heat contents (A) are in million Btu per barrel.

For gas, units for receipts are in thousand cubic feet (Mcf) and units for average heat contents (A) are in million Btu per thousand cubic foot.

For each of the above fossil fuels:

$$\text{Total Btu} = \sum_i (R_i \ x \ A_i),$$

where i denotes a facility; R_i = receipts for facility i;

A_i = average heat content for receipts at facility i;

$$\text{Weighted Average Btu} = \frac{\sum_i (R_i \ x \ A_i)}{\sum_i R_i},$$

where i denotes a facility; R_i = receipts for facility i; and, A_i = average heat content for receipts at facility i.

The weighted average cost in cents per million Btu is calculated using the following formula:

$$\text{Weighted Average Cost} = \frac{\sum_i (R_i \times A_i \times C_i)}{\sum_i (R_i \times A_i)},$$

where i denotes a facility; R_i = receipts for facility i;

A_i average heat content for receipts at facility i;

and C_i = cost in cents per million Btu for facility i.

The weighted average cost in dollars per unit (i.e., tons, barrels, or Mcf) is calculated using the following formula:

$$\text{Weighted Average Cost} = \frac{\sum_i (R_i \times A_i \times C_i)}{10^2 \sum_i R_i},$$

where i denotes a facility; R_i = receipts for facility i;

A_i = average heat content for receipts at facility i;

and, C_i = cost in cents per million Btu for facility i.

Power Production, Fuel Stocks, and Fuel Consumption Data. The Bureau of Census and the U.S. Geological Survey collected, compiled, and published data on the electric power industry prior to 1936. After 1936, the Federal Power Commission (FPC) assumed all data collection and publication responsibilities for the electric power industry and implemented the Form FPC-4. The Federal Power Act, Section 311 and 312, and FPC Order 141 defined the legislative authority to collect power production data. The Form EIA-759 replaced the Form FPC-4 in January 1982.

In 1996, the Form EIA-900 was initiated to collect sales for resale data from unregulated entities. In 1998, the form was modified to collect sales for resale, gross generation, and sales to end user data. In 1999, the form was modified to collect net generation, consumption, and ending stock data. In 2000, the form was modified to include useful thermal output data.

In January 2001, Form EIA-906 superseded Forms EIA-759 and EIA-900. In January 2004, Form EIA-920 superseded Form EIA-906 for those plants defined as combined heat and power plants; all other plants that generate electricity continue to report on Form EIA-906. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data.

In January 2004, Form EIA-920 superseded Form EIA-906 for those plants defined as combined heat and power plants; all other plants that generate electricity continue to report on Form EIA-906. In January 2008, Form EIA-923 superseded both the EIA-906 and EIA-920 forms for the collection of these data.

Methodology to Estimate Biogenic and Non-biogenic Municipal Solid Waste. Municipal Solid Waste (MSW) consumption for generation of electric power is split into its biogenic and non-biogenic components beginning with 2001 data by the following methodology:

> The reported tonnage of MSW is reported on the Form EIA-923. The composition of MSW and categorization of the components were obtained from the Environmental Protection Agency publication, *Municipal Solid Waste in the United States: 2005 Facts and Figures.* The Btu contents of the components of MSW were obtained from various sources.[2]
>
> The potential quantities of combustible MSW discards (which include all MSW material available for combustion with energy recovery, discards to landfill, and other disposal) were multiplied by their respective Btu contents. The EPA-based categories of MSW were then classified into renewable and non-renewable groupings. From this, EIA calculated how much of the energy potentially consumed from MSW was attributed to biogenic components and how much to non-biogenic components (see Table 1 and 2, below).[3]

[10]See the following sources:

- ◊ Bahillo, A. et al. Journal of Energy Resources Technology, "NOx and N2O Emissions During Fluidized Bed Combustion of Leather Wastes." Volume 128, Issue 2, June 2006. pp. 99-103.
- ◊ Energy Information Administration. *Renewable Energy Annual 2004*. "Average Heat Content of Selected Biomass Fuels." Washington, DC, 2005
- ◊ Penn State Agricultural College Agricultural and Biological Engineering and Council for Solid Waste Solutions. Garth, J. and Kowal, P. *Resource Recovery, Turning Waste into Energy,* University Park, PA, 1993
- ◊ Utah State University Recycling Center Frequently Asked Questions. Published at http://www.usu.edu/recycle/faq.htm. Accessed December 2006

[3] Biogenic components include newsprint, paper, containers and packaging, leather, textiles, yard trimmings, food wastes, and wood. Non-biogenic components include plastics, rubber and other miscellaneous non-biogenic waste.

These values are used to allocate the net and gross generation published in the *Electric Power Monthly* and *Electric Power Annual* generation tables. The tons of biogenic and non-biogenic components were estimated with the assumption that glass and metals were removed prior to combustion. The average Btu/ton for the biogenic and non-biogenic components is estimated by dividing the total Btu consumption by the total tons. Published net generation attributed to biogenic MSW and non-biogenic MSW is classified under Other Renewables and Other, respectively.

Table 1. Btu Consumption for Biogenic and Non-biogenic Municipal Solid Waste (percent)

	2001	2002	2003	2004	2005	2006
Biogenic	57	56	55	55	56	56
Non-biogenic	43	44	45	45	44	44

Table 2. Tonnage Consumption for Biogenic and Non-biogenic Municipal Solid Waste (percent)

	2001	2002	2003	2004	2005	2006
Biogenic	77	77	76	76	75	75
Non-biogenic	23	23	24	24	25	25

Useful Thermal Output. With the implementation of the Form EIA-923, "Power Plant Operations Report," in 2008, combined heat and power (CHP) plants are required to report total fuel consumed and electric power generation[4]. Beginning with the January 2008 data, EIA will estimate the allocation of the total fuel consumed at CHP plants between electric power generation and useful thermal output.

First, an efficiency factor is determined for each plant and prime mover type. Based on data for electric power generation and useful thermal output (UTO) collected in 2003 (on Form EIA-906, "Power Plant Report") efficiency was calculated for each prime mover type at a plant. The efficiency factor is the total output in Btu, including electric power and useful thermal output (UTO), divided by the total input in Btu. Electric power is converted to Btu at 3,412 Btu per kilowatthour.

Second, to calculate the amount of fuel for electric power, the gross generation in Btu is divided by the efficiency factor. The fuel for UTO is the difference between the total fuel reported and the fuel for electric power generation. UTO is calculated by multiplying the fuel for UTO by the efficiency factor.

[4] See the section "Issues within Historical Data Series" for information on the handling of CHP plants prior to 2008.

In addition, if the total fuel reported is less than the estimated fuel for electric power generation, then the fuel for electric power generation is equal to the total fuel consumed, and the UTO will be zero.

Issues within Historical Data Series

Receipts and Cost and Quality of Fossil Fuels

Values for receipts of natural gas for 2001 forward do not include blast furnace gas or other gas.

Historical data collected on FERC Form 423 and published by EIA have been reviewed for consistency between volumes and prices and for their consistency over time. However, these data were collected by FERC for regulatory rather than statistical and publication purposes. EIA did not attempt to resolve any late filing issues in the FERC Form 423 data. In 2003, EIA introduced a procedure to estimate for late or non-responding entities who were required to report on the FERC Form 423. Due to the introduction of this procedure, 2003 and later data cannot be directly compared to previous years' data.

Generation and Consumption

Beginning in 2008, a new method of allocating fuel consumption between electric power generation and useful thermal output (UTO) was implemented (see above). This new methodology evenly distributes a combined heat and power (CHP) plant's losses between the two output products (electric power and UTO). In the historical data, UTO was consistently assumed to be 80 percent efficient and all other losses at the plant were allocated to electric power. This change causes the fuel for electric power to be lower while the fuel for UTO is higher as both are given the same efficiency. This results in the appearance of an increase in efficiency of production of electric power between periods.

Steam Electric Plant Operational Data

Due to suspension of Form EIA-767 in 2007, there is a one year break in this data series as data year 2006 could not be collected.

Sensitive Data (Formerly identified as Data Confidentiality). Most of the data collected on the Form EIA-923 are not considered business sensitive. However, the total delivered cost of fuel delivered to nonutilities, commodity cost of fossil fuels, and reported fuel stocks at the end of the reporting period are considered business sensitive. The release of these data must adhere to EIA's "Policy on the Disclosure of Individually Identifiable Energy Information in the

Possession of the EIA" (45Federal Register 59812 (1980)).

Air Emissions

This section describes the methodology for calculating estimated emissions of carbon dioxide (CO_2) from electric generating plants for 1989 through 2007, as well as the estimated emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) from electric generating plants for 2001 through 2007. For a description of the methodology used for other years, see the technical notes to the *Electric Power Annual 2003*.

Methodology Overview

Initial estimates of uncontrolled SO_2 and NO_x emissions for all plants are made by applying an emissions factor to fuel consumption data collected by EIA on the Forms EIA-906 and EIA-920. An emission factor is the average quantity of a pollutant released from a power plant when a unit of fuel is burned, assuming no use of pollution control equipment. The basic relationship is:

Emissions = Quantity of Fuel Consumed x Emission Factor

Quantity is defined in physical units (e.g., tons of solid fuels, million cubic feet of gaseous fuels, and thousands of barrels of liquid fuels) for determining NO_x and SO_2 emissions. As discussed below, physical quantities are converted to millions of Btus for calculating CO_2 emissions.

For some fuels, the calculation of SO_2 emissions requires including in the formula the sulfur content of the fuel measured in percentage of weight. Examples include coal and fuel oil. In these cases the formula is:

Emissions = Quantity of Fuel Consumed x Emission Factor x Sulfur Content

The fuels that require the percent sulfur as part of the emissions calculation are indicated in Table A1, which lists the SO_2 emission factors used for this report.

In the case of SO_2 and NO_x emissions, the factor applied to a fuel can also vary with the combustion system: either a steam-producing boiler, a combustion turbine, or an internal combustion engine. In the case of boilers, NO_x emissions can also vary with the firing configuration of a boiler and whether or not the boiler is a wet-bottom or dry-bottom design.[5] These distinctions are shown in Tables A1 and A2.

For SO_2 and NO_x, the initial estimate of uncontrolled emissions is reduced to account for the plant's operational pollution control equipment, when data on control equipment are available from the historic Form EIA-767 survey (i.e., data for the years 2005 and earlier). A special case for removal of SO_2 is the fluidized bed boiler, in which the sulfur removal process is integral with the operation of the boiler. The SO_2 emission factors shown in Table A1 for fluidized bed boilers already account for 90 percent removal of SO_2 since, in effect, the plant has no uncontrolled emissions of this pollutant.

Although SO_2 and NO_x emission estimates are made for all plants, in many cases the estimated emissions can be replaced with actual emissions data collected by the U.S. Environmental Protection Agency's Continuous Emissions Monitoring System (CEMS) program. (CEMS data for CO_2 are incomplete and are not used in this report.) The CEMS data account for the bulk of SO_2 and NO_x emissions from the electric power industry. For those plants for which CEMS data are available, the EIA estimates of SO_2 and NO_x emissions are employed for the limited purpose of allocating emissions by fuel, since the CEMS data itself do not provide a detailed breakdown of plant emissions by fuel. For plants for which CEMS data are unavailable, the EIA-computed values are used as the final emissions estimates.

The emissions estimation methodologies are described in more detail below.

CO_2 Emissions. CO_2 emissions are estimated using the information on fuel consumption in physical units and the heat content of fuel collected on the Forms EIA-920 (data for combined heat and power plants) and EIA-906 (all other power plants) for the years 1989 through 2006. In 2007, a new form was introduced, the Power Plant Operations Survey (Form EIA-923), which includes information on fuel consumption previously part of the Form EIA-906/EIA-920 Surveys. Fuel consumption data from the Form EIA-923 was used to estimate CO_2. The heat content information is used to convert physical units to millions of Btu (MMBtu) consumed. To estimate CO_2 emissions, the fuel-specific emission factor from Table A3 is multiplied by the fuel consumption in MMBtu

[5] A boiler's firing configuration relates to the arrangement of the fuel burners in the boiler, and whether the boiler is of conventional or cyclone design. Wet and dry-bottom boilers use different methods to collect a portion of the ash that results from burning coal. For information on wet and dry bottom boilers, see the EIA Glossary at http://www.eia.doe.gov/glossary/index.html. Additional information on wet and dry-bottom-boilers and on other aspects of boiler design and operation, including the differences between conventional and cyclone designs, can be found in Babcock and Wilcox, *Steam: Its Generation and Use*, 41st Edition, 2005.

and a factor that accounts for incomplete combustion. The incomplete combustion factor is 0.995 for natural gas and 0.99 for all other fuels.

The estimation procedure calculates uncontrolled CO_2 emissions. CO_2 control technologies are currently in the early stages of research and there are no operational systems installed. Therefore, no estimates of controlled CO_2 emissions are made.

SO_2 and NO_x Emissions. To comply with environmental regulations controlling SO_2 emissions, many coal-fired generating plants have installed flue gas desulfurization (FGD) units. Similarly, NO_x control regulations require many plants to install low-NO_x burners, selective catalytic reduction systems, or other technologies to reduce emissions. It is common for power plants to employ two or even three NO_x control technologies; accordingly, the NO_x emissions estimation approach accounts for the combined effect of the equipment (Table A4). However, control equipment information is available only for plants that reported on the Form EIA-923 and for historic data from the Form EIA-767. Both the EIA-923 and the historic EIA-767 surveys are limited to plants with boilers fired by combustible fuels[6] with a minimum generating capacity of 10 megawatts (nameplate). Pollution control equipment data are unavailable from EIA sources for plants that did not report on the historic EIA-767 survey.

The following method is used to estimate SO_2 and NO_x emissions:

- For steam electric plants that reported on the historic Form EIA-767, uncontrolled emissions are estimated using the emission factors shown in Tables A1 and A2 as well as reported data on fuel consumption, sulfur content, and boiler firing configuration. Controlled emissions are then determined when pollution control equipment is present. Although information on control equipment was unreported for the years 2006 and 2007, updates for new installations during this period were made based upon Environmental Protection Agency data. In the future, this data will be collected on the Form EIA-923. For SO_2, the reported efficiency of the plant's FGD units is used to convert uncontrolled to controlled emission estimates. For NO_x, the reduction percentages shown in Table A4 are applied to the uncontrolled estimates.

- For plants and prime movers not reported on the historic Form EIA-767 survey, uncontrolled emissions are estimated using the Table A1 and Table A2 emission factors and the following data and assumptions:
    - Fuel consumption is taken from the Form EIA-923 (for historic data, from the Form EIA-920 - for combined heat and power plants) or the Form EIA-906 - all other power plants).
    - The sulfur content of the fuel is estimated from fuel receipts for the plant reported the Form EIA-923 (for historic data, from either the Form EIA-423 or the FERC Form 423). When plant-specific sulfur content data are unavailable, the national average sulfur content for the fuel, computed from the Form EIA-923 (for historic data, from the Form EIA-423 and the FERC Form 423), is applied to the plant.
    - As noted earlier, the emission factor for plants with boilers depends in part on the type of combustion system, including whether a boiler is wet-bottom or dry-bottom, and the boiler firing configuration. However, this boiler information is unavailable for steam electric plants that did not report on the historic Form EIA-767. For these cases, the plant is assumed to have a dry-bottom, non-cyclone boiler using a firing method that falls into the "All Other" category shown on Table A1.[7]
    - For the plants that did not report on the historic Form EIA-767, pollution control equipment data are unavailable and the uncontrolled estimates are not reduced.

- If actual emissions of SO_2 or NO_x are reported in EPA's CEMS data, the EIA estimates are replaced with the CEMS values, using the EIA estimates to allocate the CEMS plant-level data by fuel. If CEMS data are unavailable, the EIA estimates are used as the final values.

[6] Boilers that rely entirely on waste heat to create steam, including the heat recovery portion of most combined cycle plants, did not report on the historic Form EIA-767.

[7] The "All Other" firing configuration category includes, for example, arch firing and concentric firing. For a full list of firing method options for reporting on the historic Form EIA-767, see the form instructions, page xi, at http://www.eia.doe.gov/cneaf/electricity/forms/eia767/eia767instr.pdf.

Conversion of Petroleum Coke to Liquid Petroleum

The quantity conversion is 5 barrels (of 42 U.S. gallons each) per short ton (2,000 pounds). Coke from petroleum has a heating value of 6.024 million Btu per barrel.

Relative Standard Error

The relative standard error (RSE) statistic, usually given as a percent, describes the magnitude of sampling error that might reasonably be incurred. The RSE is the square root of the estimated variance, divided by the variable of interest. The variable of interest may be the ratio of two variables, or a single variable.

The sampling error may be less than the nonsampling error. In fact, large RSE estimates found in preliminary work with these data have often indicated nonsampling errors, which were then identified and corrected. Nonsampling errors may be attributed to many sources, including the response errors, definitional difficulties, differences in the interpretation of questions, mistakes in recording or coding data obtained, and other errors of collection, response, or coverage. These nonsampling errors also occur in complete censuses. In a complete census, this problem may become unmanageable.

Using the Central Limit Theorem, which applies to sums and means such as are applicable here, there is approximately a 68-percent chance that the true total or mean is within one RSE of the estimated total. Note that reported RSEs are always estimates, themselves, and are usually, as here, reported as percents. As an example, suppose that a net generation from coal value is estimated to be 1,507 total million kilowatthours with an estimated RSE of 4.9 percent. This means that, ignoring any nonsampling error, there is approximately a 68-percent chance that the true million kilowatthour value is within approximately 4.9 percent of 1,507 million kilowatthours (that is, between 1,433 and 1,581 million kilowatthours). Also under the Central Limit Theorem, there is approximately a 95-percent chance that the true mean or total is within 2 RSEs of the estimated mean or total.

Note that there are times when a model may not apply, such as in the case of a substantial reclassification of sales, when the relationship between the variable of interest and the regressor data does not hold. In such a case, the new information represents only itself, and such numbers are added to model results when estimating totals. Further, there are times when sample data may be known to be in error, or are not reported. Such cases are treated as if they were never part of the model-based sample, and values are imputed.

Business Classification

Nonutility power producers consist of corporations, persons, agencies, authorities, or other legal entities that own or operate facilities for electric generation but are not required to meet all filing obligations of electric utilities to the Federal Energy Regulatory Commission. Included in this category are qualifying cogenerators, small power producer, and independent power producers. Furthermore, nonutility power producers do not have a designated franchised service area. In addition to entities whose primary business is the production and sale of electric power, entities with other primary business classifications can and do sell electric power. These can consist of manufacturing, agricultural, forestry, transportation, finance, service and administrative industries, based on the Office of Management and Budget's Standard Industrial Classification (SIC) Manual.17 In 1997, the SIC Manual name was changed to North American Industry Classification System (NAICS). The following is a list of the main classifications and the category of primary business activity within each classification.

Agriculture, Forestry, and Fishing

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

Mining

211	Oil and gas extraction
2121	Coal mining
2122	Metal mining
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
316	Leather and leather products
321	Lumber and wood products, except furniture
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)
32512	Industrial organic chemicals
325188	Industrial Inorganic Chemicals
325211	Plastics materials and resins
325311	Nitrogenous fertilizers
324	Petroleum refining and related industries (other than 32411)
32411	Petroleum refining
326	Rubber and miscellaneous plastic 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
3345	Measuring, analyzing, and controlling instruments, photographic, medical, and optical goods, watches and clocks
335	Electronic and other electrical equipment and components except computer equipment
336	Transportation equipment
337	Furniture and fixtures
339	Miscellaneous manufacturing industries

Transportation and Public Utilities

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

Wholesale Trade

421 to 422

Retail Trade

441 to 454

Finance, Insurance, and Real Estate

521 to 533

Services

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

Public Administration

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Table A1. Sulfur Dioxide Uncontrolled Emission Factors
(Units and Factors)

Fuel, Code, Source and Emission units			Combustion System Type/Firing Configuration							
Fuel And EIA Fuel Code	**Source and Tables (As appropriate)**	**Emissions Units** (Lbs = pounds, MMCF = million cubic feet, MG = thousand gallons)	Cyclone Boiler	Fluidized Bed Boiler	Opposed Firing Boiler	Spreader Stoker Boiler	Tangential Boiler	All Other Boiler Types	Combustion Turbine	Internal Combustion Engine
Agricultural Byproducts (AB)	Source: 1	Lbs per ton	0.08	0.01	0.08	0.08	0.08	0.08	NA	NA
Blast Furnace Gas (BFG)	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.6	0.06	0.6	0.6	0.6	0.6	0.6	0.6
Bituminous Coal (BIT)*	Source: 2, Table 1.1-3	Lbs per ton	38.00	3.8	38.00	38.00	38.00	38.00	NA	NA
Black Liquor (BLQ)	Source: 1	Lbs per ton **	7.00	0.70	7.00	7.00	7.00	7.00	NA	NA
Distillate Fuel Oil (DFO)*	Source: 2, Table 3.1-2a, 3.4-1 & 1.3-1	Lbs per MG	157.0	15.70	157.0	157.0	157.0	157.0	140.0	140.0
Jet Fuel (JF)*	Assumed to have emissions similar to DFO.	Lbs per MG	157.0	15.70	157.0	157.0	157.0	157.0	140.0	140.0
Kerosene (KER)*	Assumed to have emissions similar to DFO.	Lbs per MG	157.0	15.70	157.0	157.0	157.0	157.0	140.0	140.0
Landfill Gas (LFG)	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.6	0.06	0.6	0.6	0.6	0.6	0.6	0.6
Lignite Coal (LIG)*	Source: 2, Table 1.7-1	Lbs per ton	30.00	3.00	30.00	30.00	30.00	30.00	NA	NA
Municipal Solid Waste (MSW)	Source: 1	Lbs per ton	1.70	0.17	1.70	1.70	1.70	1.70	NA	NA
Natural Gas (NG)	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60	0.60
Other Biomass Gas (OBG)	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60	0.60
Other Biomass Liquids (OBL)*	Source: 1 (including footnotes 3 and 16 within source)	Lbs per MG	157.0	15.70	157.0	157.0	157.0	157.0	140.0	140.0
Other Biomass Solids (OBS)	Source: 1 (including footnote 11 within source)	Lbs per ton	0.23	0.02	0.23	0.23	0.23	0.23	NA	NA
Other Gases (OG)	Source: 1 (including footnote 7 within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60	0.60
Other (OTH)	Assumed to have emissions similar to NG.	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60	0.60
Petroleum Coke (PC)*	Source: 1	Lbs per ton	39.00	3.90	39.00	39.00	39.00	39.00	NA	NA
Propane Gas (PG)	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.60	0.06	0.60	0.60	0.60	0.60	0.60	0.60
Residual Fuel Oil (RFO)*	Source: 2, Table 1.3-1	Lbs per MG	157.00	15.70	157.00	157.00	157.00	157.00	NA	NA
Synthetic Coal (SC)*	Assumed to have the emissions similar to Bituminous Coal.	Lbs per ton	38.00	3.8	38.00	38.00	38.00	38.00	NA	NA
Sludge Waste (SLW)	Source: 1 (including footnote 11 within source)	Lbs per ton **	2.80	0.28	2.80	2.80	2.80	2.80	NA	NA
Subbituminous Coal (SUB)*	Source: 2, Table 1.1-3	Lbs per ton	35.00	3.5	35.00	38.00	35.00	35.00	NA	NA
Tire-Derived Fuel (TDF)*	Source: 1 (including footnote 13 within source)	Lbs per ton	38.00	3.80	38.00	38.00	38.00	38.00	NA	NA
Waste Coal (WC)*	Source: 1 (including footnote 20 within source)	Lbs per ton	30.00	3.00	30.00	30.00	30.00	30.00	NA	NA
Wood Waste Liquids (WDL)*	Source: 1 (including footnotes 3 and 16 within source)	Lbs per MG	157.0	15.70	157.0	157.0	157.0	157.0	140.0	140.0
Wood Waste Solids (WDS)	Source: 1	Lbs per ton	0.29	0.08	0.29	0.08	0.29	0.29	NA	NA
Waste Oil (WO)*	Source: 2, Table 1.11-2	Lbs per MG	147.00	14.70	147.00	147.00	147.00	147.00	NA	NA

Note: * For these fuels, emissions are estimated by multiplying the emissions factor by the physical volume of fuel and the sulfur percentage of the fuel (other fuels do not require the sulfur percentage in the calculation). Note that EIA data do not provide the sulfur content of TDF. The value used (1.56 percent) is from U.S. EPA, *Control of Mercury Emissions from Coal-Fired Electric Utility Boilers*, April 2002, EPA-600/R-01-109, Table A-11 (available at:http://www.epa.gov/appcdwww/aptb/EPA-600-R-01-109A.pdf).
** Although Sludge Waste and Black Liquor consist substantially of liquids, these fuels are measured and reported to EIA in tons.
Sources:

1. Eastern Research Group, Inc. and E.H. Pechan & Associates, Inc., *Documentation for the 2002 Electric Generating Unit National Emissions Inventory*, Table 6, September 2004. Prepared for the U.S. Environmental Protection Agency, Emission Factor and Inventory Group (D205-01), Emissions, Monitoring and Analysis Division, Research Triangle Park; and
2. U.S. Environmental Protection Agency, *AP 42, Fifth Edition (Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources)*; available at: http://www.epa.gov/ttn/chief/ap42/

Table A2. Nitrogen Oxides Uncontrolled Emission Factors
(Units and Factors)

Fuel, Code, Source, and Emission Units			Combustion System Type/Firing Configuration Factors for Wet-Bottom Boilers are in Brackets; All Other Boiler Factors are for Dry-Bottom							
Fuel And EIA Fuel Code	**Source and Tables (As appropriate)**	**Emissions Units** (Lbs = pounds, MMCF = million cubic feet, MG = thousand gallons)	Cyclone Boiler	Fluidized Bed Boiler	Opposed Firing Boiler	Spreader Stoker Boiler	Tangential Boiler	All Other Boiler Types	Combustion Turbine	Internal Combustion Engine
Agricultural Byproducts (AB)	Source: 1	Lbs per ton	1.20	1.20	1.20	1.20	1.20	1.20	NA	NA
Blast Furnace Gas (BFG)	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	15.40	15.40	15.40	15.40	15.40	15.40	30.40	256.55
Bituminous Coal (BIT)	Source: 2, Table 1.1-3	Lbs per ton	33.00	5.00	12 [31]	11.00	10.0 [14.0]	12.0 [31.0]	NA	NA
Black Liquor (BLQ)	Source: 1	Lbs per ton **	1.50	1.50	1.50	1.50	1.50	1.50	NA	NA
Distillate Fuel Oil (DFO)	Source: 2, Tables 3.4-1 & 1.3-1	Lbs per MG	24.00	24.00	24.00	24.00	24.00	24.00	122.0	443.8
Jet Fuel (JF)	Source: 2, Tables 3.1-2a, 3.4-1 & 1.3-1	Lbs per MG	24.00	24.00	24.00	24.00	24.00	24.00	118.0	432.0
Kerosene (KER)	Source: 2, Tables 3.1-2a, 3.4-1 & 1.3-1	Lbs per MG	24.00	24.00	24.00	24.00	24.00	24.00	118.0	432.0
Landfill Gas (LFG)	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	72.44	72.44	72.44	72.44	72.44	72.44	144.0	1215.22
Lignite Coal (LIG)	Source: 2, Table 1.7-1	Lbs per ton	15.00	3.60	6.3	5.80	7.10	6.3	NA	NA
Municipal Solid Waste (MSW)	Source: 1	Lbs per ton	5.0	5.0	5.0	5.0	5.0	5.0	NA	NA
Natural Gas (NG)	Source: 2, Tables 1.4-1, 3.1-1, and 3.4-1	Lbs per MMCF	280.00	280.00	280.00	280.00	170.00	280.00	328.00	2768.00
Other Biomass Gas (OBG)	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	112.83	112.83	112.83	112.83	112.83	112.83	313.60	2646.48
Other Biomass Liquids (OBL)	Source: 1 (including footnote 3 within source)	Lbs per MG	19.0	19.0	19.0	19.0	19.0	19.0	NA	NA
Other Biomass Solids (OBS)	Source: 1 (including footnote 11 within source)	Lbs per ton	2.0	2.0	2.0	2.0	2.0	2.0	NA	NA
Other Gases (OG)	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	152.82	152.82	152.82	152.82	152.82	152.82	263.82	2226.41
Other (OTH)	Assumed to have emissions similar to natural gas.	Lbs per MMCF	280.00	280.00	280.00	280.00	170.00	280.00	328.00	2768.00
Petroleum Coke (PC)	Source: 1 (including footnote 8 within source)	Lbs per ton	21.00	5.00	21.00	21.00	21.00	21.00	NA	NA
Propane Gas (PG)	Sources: 3; EIA estimates	Lbs per MMCF	215.00	215.00	215.00	215.00	215.00	215.00	330.75	2791.22
Residual Fuel Oil (RFO)	Source: 2, Table 1.3-1	Lbs per MG	47.00	47.00	47.00	47.00	32.00	47.00	NA	NA
Synthetic Coal (SC)	Assumed to have emissions similar to Bituminous Coal.	Lbs per ton	33.00	5.00	12 [31]	11.00	10.0 [14.0]	12.0 [31.0]	NA	NA
Sludge Waste (SLW)	Source: 1 (including footnote 11 within source)	Lbs per ton **	5.00	5.00	5.00	5.00	5.00	5.00	NA	NA
Subbituminous Coal (SUB)	Source: 2, Table 1.1-3	Lbs per ton	17.00	5.00	7.4 [24]	8.80	7.2	7.4 [24.0]	NA	NA
Tire-Derived Fuel (TDF)	Source: 1 (including footnote 13 within source)	Lbs per ton	33.00	5.00	12 [31]	11.00	10.0 [14.0]	12.0 [31.0]	NA	NA
Waste Coal (WC)	Source: 1 (including footnote 20 within source)	Lbs per ton	15.00	3.60	6.30	5.80	7.10	6.30	NA	NA
Wood Waste Liquids (WDL)	Source: 1 (including footnote 16 within source)	Lbs per MG	5.43	5.43	5.43	5.43	5.43	5.43	NA	NA
Wood Waste Solids (WDS)	Source: 1	Lbs per ton	2.51	2.00	2.51	1.50	2.51	2.51	NA	NA
Waste Oil (WO)	Source: 2, Table 1.11-2	Lbs per MG	19.00	19.00	19.00	19.00	19.00	19.00	NA	NA

Note: ** Although Sludge Waste and Black Liquor consist substantially of liquids, these fuels are measured and reported to EIA in tons.

Sources:

1. Eastern Research Group, Inc. and E.H. Pechan & Associates, Inc., *Documentation for the 2002 Electric Generating Unit National Emissions Inventory*, Table 6, September 2004. Prepared for the U.S. Environmental Protection Agency, Emission Factor and Inventory Group (D205-01); Emissions, Monitoring and Analysis Division, Research Triangle Park;
2. U.S. Environmental Protection Agency, *AP 42, Fifth Edition (Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources)*; available at: http://www.epa.gov/ttn/chief/ap42/; and
3. U.S. Environmental Protection Agency, *Factor Information Retrieval (FIRE) Database, Version 6.25*; available at: http://www.epa.gov/ttn/chief/software/fire/index.html

Table A3. Carbon Dioxide Uncontrolled Emission Factors
(Pounds of CO_2 per Million Btu)

Fuel, Code, Source, and Emission Factor		
Fuel And EIA Fuel Code	**Source and Tables (As appropriate)**	**Factor (Pounds of CO_2 Per Million Btu)*** **
Bituminous Coal (BIT)	Source: 1	205.300
Distillate Fuel Oil (DFO)	Source: 1	161.386
Geothermal (GEO)	Estimate from EIA, Office of Integrated Analysis and Forecasting	16.59983
Jet Fuel (JF)	Source: 1	156.258
Kerosene (KER)	Source: 1	159.535
Lignite Coal (LIG)	Source: 1	215.400
Municipal Solid Waste (MSW)	Source: 1 (including footnote 2 within source)	91.900
Natural Gas (NG)	Source: 1	117.080
Petroleum Coke (PC)	Source: 1	225.130
Propane Gas (PG)	Source: 1	139.178
Residual Fuel Oil (RFO)	Source: 1	173.906
Synthetic Coal (SC)	Assumed to have emissions similar to Bituminous Coal.	205.300
Subbituminous Coal (SUB)	Source: 1	212.700
Tire-Derived Fuel (TDF)	Source: 1	189.538
Waste Coal (WC)	Assumed to have emissions similar to Bituminous Coal.	205.300
Waste Oil (WO)	Source: 2, Table 1.11-3 (assumes typical heat content of 4.4 MMBtus per barrel)	210.000

Note: *** CO_2 factors do not vary by combustion system type or boiler firing configuration.
Sources: Energy Information Administration, Office of Integrated Analysis and Forecasting, Voluntary Reporting of Greenhouse Gases Program, *Table of Fuel and Energy Source: Codes and Emission Coefficients*; available at: http://www.eia.doe.gov/oiaf/1605/coefficients.html; and U.S. Environmental Protection Agency, *AP 42, Fifth Edition (Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources)*; available at: http://www.epa.gov/ttn/chief/ap42/.

Table A4. Nitrogen Oxides Control Technology Emissions Reduction Factors

Nitrogen Oxides Control Technology	EIA-Code(s)	Reduction Factor (Percent)
Advanced Overfire Air	AA	30[1]
Alternate Burners	BF	20
Flue Gas Recirculation	FR	40
Fluidized Bed Combustor	CF	20
Fuel Reburning	FU	30
Low Excess Air	LA	20
Low NO_x Burners	LN	30[1]
Other (or Unspecified)	OT	20
Overfire Air	OV	20[1]
Selective Catalytic Reduction	SR	70
Selective Catalytic Reduction With Low Nitrogen Oxide Burners	SR and LN	90
Selective Noncatalytic Reduction	SN	30
Selective Noncatalytic Reduction With Low NO_x Burners	SN and LN	50
Slagging	SC	20

1. Starting with 1995 data, reduction factors for advanced overfire air, low NO_x burners, and overfire air were reduced by 10 percent.
Sources: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report;" Babcock and Wilcox, Steam 41st Edition, 2005.

Table A5. Unit-of-Measure Equivalents

Unit	Equivalent	Unit
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.

Table A6. Average Capacity Factors by Energy Source, 1996 through 2007
(Percent)

Year	Coal	Petroleum	Natural Gas CC	Natural Gas Other	Nuclear	Hydroelectric Conventional	Other Renewables	All Energy Sources
1996	65.2	12.8	--	--	76.2	51.7	56.4	51.9
1997	67.2	14.6	--	--	72.0	51.2	57.4	52.4
1998	67.7	22.2	--	--	79.2	46.6	57.0	54.6
1999	68.1	22.4	--	--	85.3	45.9	56.9	54.9
2000	71.0	20.5	--	--	87.7	39.5	59.1	54.6
2001	69.2	21.5	--	--	89.4	31.4	50.2	51.4
2002	70.0	18.1	--	--	90.3	38.0	54.0	49.7
2003	72.0	22.4	33.5	12.1	87.9	40.0	50.0	47.7
2004	71.9	23.3	35.5	10.7	90.1	39.4	50.5	47.9
2005	73.3	23.8	36.8	10.6	89.3	39.8	47.0	48.3
2006	72.6	12.6	38.8	10.7	89.6	42.4	45.7	48.0
2007	73.6	13.4	42.0	11.4	91.8	36.3	40.0	48.7

Sources: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report;" Form EIA-860, "Annual Electric Generator Report." and predecessor forms.

Table A7. Average Heat Rates by Prime Mover and Energy Source, 2007
(Btu per kilowatthour)

Prime Mover	Coal	Petroleum	Natural Gas	Nuclear
Steam Turbine	10,114	10,400	10,466	10,488
Gas Turbine	--	13,216	11,459	--
Internal Combustion	--	10,149	9,923	--
Combined Cycle	W	11,015	7,445	--

W = Withheld to avoid disclosure of individual company data.
Notes: • See Glossary reference for definitions. • Totals may not equal sum of components because of independent rounding. • Heat rate is reported at full load conditions for electric utilities and independent power producers.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Glossary

The Office of Coal, Nuclear, Electric And Alternate Fuel's Master Glossary contains all references used in this publication.
Please use this URL:
http://www.eia.doe.gov/cneaf/electricity/page/glossary.html