Electric Power Annual 2005

DOE/EIA-0348(2005)

Electric Power Annual 2005

REVISED DATA

November 2006

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

This report is only available on the Web at:
http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html

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Preface

The Electric Power Annual 2005 summarizes electric power industry statistics at the national level. The publication seeks to provide 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 five surveys performed by other government organizations[1] and seven surveys completed annually or monthly by electric utilities and other electric power producers and submitted to the EIA. 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.

Note: Table ES1, 4.5, 4.6 and 4.7 were revised on November 9, 2006.

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Electric Power Industry 2005: Year in Review

Overview

The volume of electricity generation and sales in 2005 rose 2.1 percent and 3.2 percent, respectively, over the 2004 levels. Above average temperatures prevailed in most of the Nation, especially during the summer months, driving up peak demand (e.g. air conditioning loads), and increased total summer generation by approximately 6 percent over the previous summer.

Total net summer capacity increased 1.6 percent, a net increase of 15,078 megawatts, almost all in natural gas-fired combined cycle units. The capacity margin[1] dropped to 15.4 percent in 2005 from 20.9 percent in 2004.

Retail prices for electricity increased by 7.0 percent to an average of 8.14 cents per kilowatthour. Increasing costs for fossil fuels, most notably an increase of 37.9 percent in natural gas prices and 13.2 percent for delivered coal prices, contributed substantially to higher retail electricity rates.

The Energy Policy Act of 2005 (EPACT 2005) assigned the responsibility for overseeing operations, developing procedures, and enforcing mandatory standards in the electric power industry to an electricity reliability organization (ERO) under the general oversight of the Federal Energy Regulatory Commission. This was a significant change from the prior semi-voluntary system administered by the North American Electric Reliability Council.

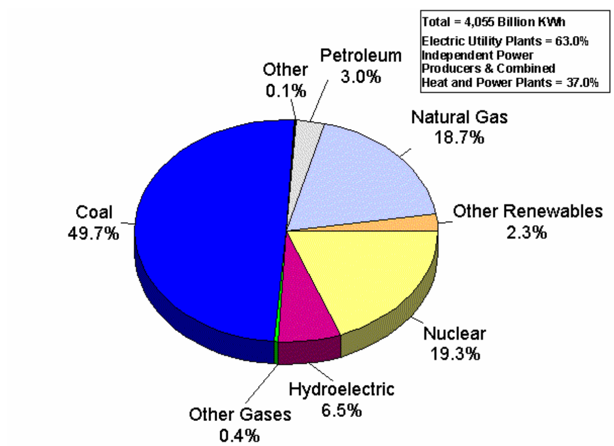
Generation

Net generation of electricity increased 2.1 percent from 2004 to 2005, reaching 4,055 billion kilowatthours. This rate of increase slightly exceeded the average for the 12-year period 1994 through 2005 of 2.0 percent per annum. In the summer months of 2005, which was one of the Nation's warmest years on record, net generation increased approximately 6 percent over the summer of 2004, and the warm temperatures created high summer peak demands. The summer increase in net generation was partially offset by lower net generation during the warmer winter months (e.g. less heating load).

Hurricane damage reduced generation in the Gulf Coast States of Louisiana and Alabama in September. The storms also disrupted natural gas supply and contributed to high natural gas prices and lower generation from natural gas in other Gulf coast States. However, the disruption to generation was short-lived, and all States except Louisiana, including Alabama, Florida, Mississippi, and Texas returned to more normal levels of natural gas-fired generation by November 2005.

[1] Capacity margin is the amount of unused available capability of an electric power system at peak load as a percentage of total capability.

Figure ES 1. U.S. Electric Power Industry Net Generation, 2005



2005 Weather Events

Because of hurricanes Katrina and Rita, electric power generation and sales were lower in both Louisiana and Mississippi in September 2005, compared to the previous year, in spite of above average temperatures. The storms disrupted power supply for over 1 million customers and caused long-term damage to distribution systems in the most severely affected areas. Although Florida was also hit repeatedly by hurricanes, it was spared the long-lasting destruction of large portions of its customer base and electrical infrastructure.

Record average temperatures were set in several Mid-Atlantic States, and near records in many other northeastern States. Nationally, cooling degree days were 14.9 percent higher than in 2004. The increased demand for air conditioning in summer months drives peak demands higher and is typically met with natural gas-fired peaking units. Large increases in natural gas prices in turn fueled higher retail power prices.

Drought conditions continued to improve in the northwestern region, although continued low reservoir levels and increased water demands held hydroelectric generation at nearly the same level as 2004.

Coal, natural gas, and nuclear generation have in combination consistently provided about 85 percent to 88 percent of total net generation during the period 1994 through 2005. However, the trends for these three major generation sources have been different. Coal generation in 2005 grew 1.7 percent over 2004 to 2,013 billion kilowatthours. This was less than the overall growth in generation, and coal's share of total net generation continued its slow decline, from 52.1 percent in 1994 to 49.7 percent in 2005.

In contrast, natural gas generation showed the highest rate of growth from 2004 to 2005 of the three major generation sources (coal, natural gas, and nuclear), 6.9 percent, reaching 758 billion kilowatthours. The gas-fired share of total generation has increased from 14.2 percent of the total in 1994 to 18.7 percent in 2005. Compared to a modest average annual growth of less than 2 percent for coal, nuclear, petroleum and hydroelectric generation, natural gas generation has increased an average of 4.6 percent since 1994. This reflects the enormous increases in natural gas-fired generating capacity, especially since 2000 (discussed further below). The recent increases in the price of natural gas, however, have made this capacity expensive to operate when compared to generation using coal.

Nuclear generation has essentially maintained its approximately 20 percent share of total net generation from 1994 through 2005 although no new nuclear units have been constructed. This has occurred because plant operators have improved the utilization of their plants and made incremental increases in the generating capacity of existing units. Despite more than a doubling in the spot price of uranium between the beginning of 2004 and the end of 2005[2], nuclear generation has remained relatively constant. This is because the fuel component of the overall nuclear generation cost is a relatively small percentage, and most uranium is purchased with long-term rather than spot market contracts. Net generation at nuclear plants decreased slightly (0.8 percent) in 2005, primarily due to more planned and forced outages and temporary derates than in 2004. Nevertheless, at 782 billion kilowatthours in 2005, nuclear generation was higher than any year other than 2004 (789 billion kWh).

Net generation from hydroelectric plants increased slightly over 2004, to 270 billion kilowatthours, although the level was still lower than the peak year for hydroelectric production over the past decade, when it reached 356 billion kilowatthours in 1997. During the period from 1999 through 2004 the western U.S. experienced one of the most severe droughts in its history. Beginning in spring 2005, precipitation levels improved in the Northwest, and reservoirs began to recover, but aggregated reservoir levels were still low at year end.[3] Hydroelectric power generation was 3.3 percent higher in 2005 than in 2004 in the Western and Northwestern regions of the Nation, including California, Oregon, Washington, Idaho, Wyoming, Utah, and Montana. California contributed the largest increase, 5.49 billion kilowatthours more than in 2004. Tennessee, Maryland, Kentucky, and Pennsylvania combined for a decrease in hydroelectric generation of 3.64 billion kilowatthours. In spite of heavy rains from hurricanes, some States in the southeast and northeast experienced one of the 10 driest periods on record for August and September.[4] With no growth in capacity, the share of net generation from hydroelectric plants continues to decline every year, reaching 6.6 percent of net generation in 2005, down from over 10 percent in 1997.

Petroleum accounted for 3.0 percent of generation. Petroleum-fired generation grew 1.6 percent, to 123 billion kilowatthours. Renewable energy, other than hydroelectric, grew 5.0 percent and accounted for 2.3 percent of net generation. Biomass contributed the majority of non-hydroelectric renewable generation; however, wind generation showed strong growth, 25.9 percent over 2004, contributing a record 17.8 billion kilowatthours out of 94.9 billion kilowatthours for biomass, wind, geothermal, and solar combined. Generation from other gases (refinery gases, blast furnace gas, etc.) and other miscellaneous sources accounted for the remaining generation.

Fossil Fuel Stocks at Electric Power Plants

End-of-year coal stocks declined for the third straight year in 2005. Stocks as of December 31 totaled 101.1 million tons, the lowest end-of-year point since 1997. Stocks of bituminous coal exceeded 2004 levels in most months of 2005, but rail transportation constraints on Powder River Basin (PRB) shipments of subbituminous coal drove down subbituminous stocks and influenced the overall decline in stocks. End-of-year subbituminous coal stocks were 17.2 percent below the 2004 level, while bituminous stocks were 9.7 percent higher.

[2] UX Consulting Company LLC, weekly market reports at http://www.uxc.com/review/uxc_g_price.html . The spot price of uranium went from around $15 per pound at the beginning of 2004 to about $36 per pound by the end of 2005.

[3] National Climate Data Center, "Climate of 2005 Annual Review U.S. Drought," http://www.ncdc.noaa.gov/oa/climate/research/2005/ann/drought-summary.html#regdrot

[4] Ibid.

The coal shipments from the PRB mines were disrupted beginning in mid-May 2005 when two major train derailments exposed a need for immediate major maintenance on the PRB rail lines. Extensive repair and rebuilding disrupted rail traffic flows and resulted in a shortfall in rail shipments, as much as 15 percent below the normal level. Rail shipments of coal were disrupted throughout the entire second half of 2005, and to a lesser extent into 2006. The Union Pacific Railroad, one of two railroads serving the PRB, advised coal plants to take measures to conserve coal.[5] Some operators reduced coal-fired generation and made up the difference by utilizing other units or buying power. In many cases the replacement power came from gas-fired plants with higher operating costs. The supply disruptions of PRB coal resulted in a drawdown of subbituminous coal inventories at some power plants and also reduced capacity utilization rate at other coal-fired plants.

In 2005, inventories of petroleum declined by 2.7 percent to 50.1 million barrels by year end. Lower levels of stocks during 2004 and 2005 were the result of increased petroleum product prices and the increased use of petroleum-fired generation to meet high summer peak demands.

Capacity

Total net summer generating capacity as of January 1, 2006 was 978,020 megawatts, an increase of 1.6 percent from January 1, 2005. New generating capacity added during 2005 totaled 17,622 megawatts while retirements totaled 3,172 megawatts. Natural gas-fired generating units accounted for 14,753 megawatts or 84 percent of capacity additions. Of that amount, 11,908 megawatts were highly efficient combined-cycle units. Since the late 1990's, natural gas has been the fuel of choice for the majority of new generating units, resulting in a nearly 81 percent increase in gas-fired capacity since 1999. The construction of natural gas plants began increasing in 1999, peaked during 2002 and 2003, and since then declined considerably.

On January 1, 2006, natural gas-fired generating capacity represented 383,061 megawatts or 39.2 percent of total net summer generating capacity (Figure ES1). Although new natural gas-fired combined-cycle plants produce electricity more efficiently than older fossil-fueled plants, high natural gas prices can prevent full utilization of these plants. Fuel costs for a new, efficient natural gas plant were about 6.4 cents per kilowatthour, by the end of 2005, compared to 1.5 cents for coal-fired plants.[6]

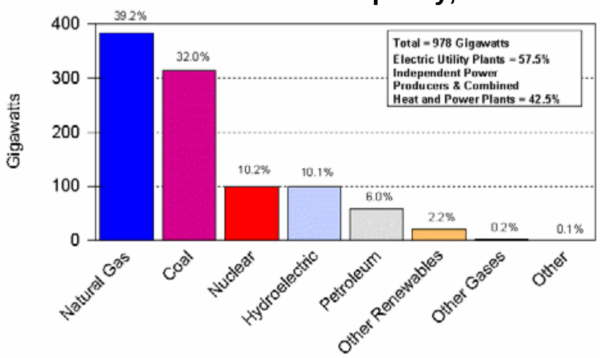
As of January 1, 2006, reported planned capacity additions that are scheduled to start commercial operation from 2006 through 2010 totaled 94,429 megawatts. This compares with 94,023 megawatts of planned capacity reported on January 1, 2005, for the five-year period through 2009. Planned natural gas-fired capacity totaled 56,925 megawatts or 60 percent of total planned capacity additions compared with 75,659 megawatts or 80 percent of total planned capacity reported in 2005. This reduction in planned natural gas capacity is due largely to high natural gas prices that have resulted in gas-fired plants being less economically attractive for generating electricity.

Coal-fired generating capacity remained relatively unchanged at 313,380 megawatts or 32 percent of total generating capacity. This share of total capacity represents a slight decline from 2004 due to the fact that capacity additions over the past year have been primarily natural gas-fired. During 2005, 415 megawatts of new coal-fired generators started commercial operation, while approximately 272 megawatts of older, inefficient coal-fired capacity were retired from service. Although coal-fired capacity has not changed significantly, generation by coal-fired plants was 19 percent higher in 2005 than in 1994. The utilization of coal-fired generators, a measure of actual generation compared to the hypothetical maximum output, has increased from 62 percent in 1994 to 73 percent in 2005. Planned coal-fired capacity on January 1, 2006, totaled 27,884 megawatts, up considerably from the 13,088 reported on January 1, 2005. Most of this proposed capacity is scheduled to start commercial operation in 2009 and 2010. Coal plants planned for Texas, Illinois, and Kentucky represent over one-half of all proposed coal-fired capacity additions.

[5] Union Pacific Railroad website; Southern Powder River Basin 2005 Updates, Notice Of Disruption On The Southern Powder River Basin Joint Line at http://www.uprr.com/customers/energy/sprb/updates_2005.shtml

[6] Statement of Howard Gruenspect, Deputy Administrator, EIA, before the Senate Committee on Energy and Natural Resources, May 25, 2006.

Figure ES 2. U.S. Electric Power Industry Net Summer Capacity, 2005



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

Wind plants accounted for most of the remaining new generating capacity with over 2,000 megawatts of capacity added during 2005, considerably above the levels of 2004. Texas and Oklahoma combined for over 800 megawatts of new wind capacity in 2005. This increase in wind capacity was stimulated in part by the scheduled December 31, 2005 expiration date for the production tax credit (PTC). The PTC, which encourages construction of wind plants, has since been extended until December 31, 2007. First enacted through the Energy Policy Act of 1992 to encourage construction of wind and qualifying biomass generating facilities, the PTC has expired and been renewed several times. The most recent renewal was enacted through the Energy Policy Act of 2005, (H.R. 6), Public Law 109-58. The growth in wind generating capacity is expected to continue, with over 5,000 megawatts of planned wind generating capacity proposed to begin operation during 2006 and 2007. Of this amount, over 1,500 megawatts is planned to come on line in Texas over the next two years. California, Colorado, Idaho, Iowa, New York, and Washington are also planning to add significant amounts of new wind generating capacity over the next five years.

Nuclear net summer generating capacity totaled 99,988 megawatts or 10.2 percent of total capacity, up slightly from 99,628 megawatts in 2004. This 360-megawatt increase in capacity was due to modifications and uprates[7] at existing nuclear units. Hydroelectric generating capacity accounted for 8 percent of total capacity with a summer net generating capacity of 77,541 megawatts. Like coal and nuclear, hydroelectric generating capacity has remained relatively unchanged over the last 10 years. The electric generating capacity from other renewable energy sources increased 13 percent from 2004 to 2005, due primary to an increase in wind generating capacity.

[7] Nuclear capacity increased 0.4 percent from 2004 to 2005, primarily due to uprates. This rate of capacity increase has ranged between 0.3 percent and 0.6 percent since 1999 and is expected to continue for the next five years.

Fuel Switching Capacity

New information on the available generating capacity capable of switching fuels between natural gas and fuel oil (see Tables 2.8 to 2.11)[8] is presented in the *Electric Power Annual 2005.* As of the end of 2005, the total net summer capacity reporting natural gas as the primary fuel was 383,061 megawatts, of which 118,216 megawatts (31 percent) reported a currently 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 oil-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 118,216 megawatts of gas-fired capacity that reported the ability to switch to oil, only 31,200 megawatts (26 percent) reported no environmental regulatory constraints on oil-fired operations.

"Switchable" capacity is spread across the major generating technologies. Combustion turbine peaking units account for 43 percent (50,764 megawatts) of this capacity. Steam-electric generators (33,193 megawatts) and combined cycle units (33,358 megawatts) each account for about 28 percent, and internal combustion engines make up the remaining 1 percent. Of the steam-electric capacity that is capable of switching from gas to oil, which tends to be older units, almost half reported no environmental regulatory restrictions on oil-fired operations. In contrast, only 33 percent of the combustion turbine and 12 percent of the combined-cycle capacity that are capable of switching fuels report no environmental regulatory restrictions on oil-fired operations.

The data show that most of the new gas-fired capacity added at the beginning of this decade cannot use oil as a backup or alternative fuel. During the period 2000 to 2005 total gas-fired net summer capacity increased from 219,605 to 383,061 megawatts, a gain of 163,456 megawatts. However, during this same period the

[8] Previous issues of the *Electric Power Annual* divided generators into natural gas, petroleum and dual-fueled categories. The dual-fuel designation was inferred from information reported to EIA on the primary and secondary fuels that a generator can use. The EIA-860 survey, "Annual Electric Generator Report," has now been revised to explicitly collect data on fuel switching capability, as reported in this issue of the *Electric Power Annual*. For additional information on the collection of fuel switching data see the Technical Notes.

amount of gas-fired capacity that can switch to fuel oil increased by only 42,518 megawatts, equivalent to about 26 percent of the increase in total gas-fired capacity. About 40 percent of the capacity capable of switching from natural gas to fuel oil was built prior to 1980 and close to two-thirds was built prior to 2000.

Fuel Costs

The average delivered cost for coal, petroleum, and natural gas used for electricity generation increased between 2004 and 2005. The average cost of natural gas to electricity generators increased from the previous record high of $5.96 per million Btu (MMBtu) established in 2004 to a new record level of $8.21 per MMBtu in 2005 (Figure ES 3). For the third year in a row, natural gas costs experienced a double-digit percentage increase, 37.8 percent from 2004 to 2005. Strong demand for natural gas, due in part to high demands for heating and high petroleum prices, as well as the natural gas production disruptions in and around the Gulf of Mexico caused by Hurricanes Katrina, Rita and Wilma in the second half of 2005 contributed to the overall increase in the price of natural gas for the year. As a result, the cost of natural gas for electricity generation in 2005 was 130.6 percent higher than in 2002.

The average delivered cost of coal increased 13.2 percent for the year, from $1.36 per MMBtu in 2004 to $1.54 per MMBtu in 2005. Coal costs in 2005 were 23.2 percent higher than in 2002. Coal prices were influenced by increases in operating costs associated with the extraction of coal. In 2005, coal mining operations experienced increases in the cost of mining equipment, electricity, diesel fuel and natural gas, all of which changed the price of coal.[9] Coal prices also increased in response to the supply/demand imbalance created by the rail transportation problems in the Powder River Basin. For the year, average petroleum costs increased 50.1 percent, from $4.29 per MMBtu in 2004 to $6.44 per MMBtu in 2005. Over the three year period from 2002 to 2005, petroleum costs have almost doubled, increasing by 92.8 percent. Overall, U.S. petroleum demand in 2005 was strong, and prices remained at historically high levels.

[9] U.S. Coal Supply and Demand: 2005 Review, Energy Information Administration, April 2006. See http://www.eia.doe.gov/cneaf/coal/page/special/feature.html

The average delivered cost for all fossil fuels used for electricity generation (coal, petroleum and natural gas combined) in 2005 was $3.26 per MMBtu (Table 4.5) as compared to $2.48 per MMBtu in 2004, an increase of 31.5 percent. The 2005 average combined cost for all fossil fuels was 114.5 percent higher than in 2002, contributing to the significant increases in the cost of electricity over that time period.

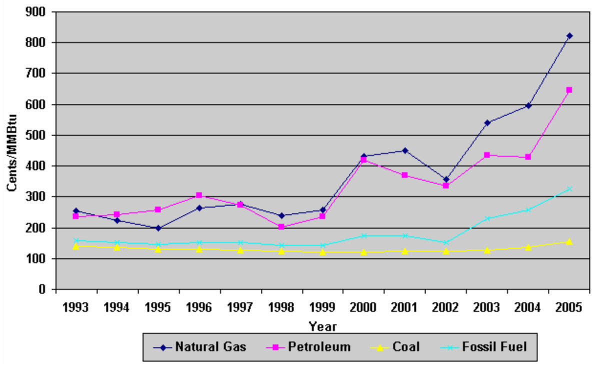
Emissions

The carbon dioxide, sulfur dioxide and nitrogen oxides emissions estimates for electricity reflect fuel consumed for electric power generation and, for combined heat and power plants, for the production of useful thermal output. In addition to the new 2005 estimates, the emissions estimates have been revised for all three types of emissions for 2001 through 2004. The revisions are primarily due to updates to the emissions factors used in the estimation methodology (see the discussion of Air Emissions in the Technical Notes and, in particular, Tables A1, A2, and A3).

Estimated carbon dioxide emissions by U.S. electric generators increased by 2.3 percent from 2004 to 2005 (from 2,457 million metric tons to 2,514 million metric tons). The increase reflects greater use of coal, petroleum products and natural gas. In contrast, estimated emissions of nitrogen oxides declined between 2004 and 2005 while emissions of sulfur dioxide were almost unchanged. Nitrogen oxide emissions dropped by 4.4 percent (from 4.143 to 3.961 million metric tons). Emissions of sulfur dioxide increased slightly, by 0.1 percent (from 10.309 to 10.340 million metric tons). The emissions estimates are shown in Table 5.1.

Emissions trends are driven by increased use of fossil fuels and the impact of Federal and State pollution control regulations on power plant operations, including required installations of new pollution control equipment. For example, between 1994 and 2005 the coal-fired generating capacity with equipment for removing sulfur dioxide (flue gas desulfurization units, also referred to as scrubbers) increased by 26 percent, from 80.6 to 101.6 gigawatts, 32 percent of total coal-fired capacity (see Table 5.2.). Another factor is changes in fuel mix, particularly the increased use of subbituminous coal. Because of its relatively low sulfur content and low combustion temperature, subbituminous coal generally emits less sulfur dioxide and nitrogen oxides when burned than other coals.

Figure ES 3. Fuel Costs for the Electric Power Industry, 1993 – 2005



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."

Trade

Institutional changes, covering the operational and planning oversight of electricity reliability, became more apparent at the end of 2005, when members of three North American Electric Reliability Regions[10] merged to establish the Reliability*First* region. (See Figures 6.1 and 6.2 for the historical and new regional reliability structure.) EPACT 2005 directed the Federal Energy Regulatory Commission (FERC) to provide general oversight of a new electricity reliability organization (ERO). The ERO will develop and oversee mandatory electric system reliability rules. Filings containing comments on the establishment of the ERO were presented to the FERC in the fall of 2005. On July 20, 2006, the FERC certified the North American Electric Reliability Council as the ERO. EPACT 2005 also gives the Federal government more influence and authority over electric transmission planning and approval.

Electric sales to utilities that resell to end-user customers grew to 3,246 billion kilowatthours in 2005. Most of those transactions are by power marketing companies, a class of electric utilities having market based rates that came into being during the late 1990s with the deregulation of the wholesale power markets. However, since 2002, their market share has declined from over 76 percent to 60.4 percent in 2005. Correspondingly, all of the traditional electric utility ownership classes have increased their market share of sales for resale. This is both an indication of tightening of market pricing and improved efficiencies by participating utilities. There has also been a drop-off in the count of power marketing companies participating in market trade during this period, from 2002 to 2005.[11]

[10] The on-going restructuring of the electric power industry has now changed the industry's operational framework for reliability oversight. The NERC Regions of ECAR, MAAC, and MAIN were dissolved at the end of 2005. Many of the former member utilities joined the new Reliability*First* reliability council. Other former member utilities joined neighboring reliability council regions.

In international electricity trade, Canada is the United States' major partner. Mexico's participation is limited to a small amount of transactions that cross the border with the States of California, Arizona, and Texas. Besides allowing international sales of electric power, an indirect benefit of the transmission ties across international boundaries is improved reliability of each country's power grids. International trade provides a source of inexpensive surplus power (mostly hydroelectric generation caused by heavy seasonal river flows) and also can mitigate risk by providing emergency support when generating capability is lost due to outages.

In Canada, particularly in the Province of Manitoba, improvements in the amount of available water for hydroelectric generation rose substantially above domestic needs.[12] As a result, sales to the United States reached 42.9 billion kilowatthours, substantially higher than the average of the prior 4 years. Total U.S. imports grew to 44.5 billion kilowatthours, and total exports decreased for the second straight year to 19.8 billion kilowatthours.

Revenue and Expense Statistics

In 2005, major investor-owned electric utility operating revenues (from sales to ultimate customers, sales for resale, and other electric income) were $268 billion, an 11 percent increase from 2004. These strong revenues, however, failed to keep pace with operating expenses. Expenses were $239 billion in 2005, a 15 percent increase from 2004. Consequently, net income declined to $29 billion in 2005.

Increases in operating expenses were driven by sharply increased costs for purchased power. In 2005, purchased power expenses were $78 billion, up 16 percent from $67 billion in 2004. Fuel costs also rose, from $29 billion to $36 billion, a 26 percent increase. Transmission expenses rose about $1 billion for the second consecutive year and distribution expenses increased only slightly from 2004. Average operating expenses for fuel at investor-owned fossil steam plants increased sharply in 2005, rising from about 18 mills per kilowatthour to nearly 22 mills per kilowatthour. Average maintenance expenses at plants were held in check, but average operating expenses rose slightly.

[11] Form EIA-861 Databases at http://www.eia.doe.gov/cneaf/electricity/page/eia861.html.
[12] Canadian National Energy Board, "Annual Report 2005 to Parliament" of March 20, 2006, pgs. 16, 30-31.

Electricity Prices and Sales

In 2005, the average retail price for all customers rose to 8.14 cents per kilowatthour, about a half cent (7.0 percent) increase from the 2004 price level. A similar magnitude increase last occurred in 2001, driven by the California electricity crisis, and prior to that in 1982.

Ten States and the District of Columbia saw the average price of electricity rise by more than 10 percent or more from 2004 to 2005. With the exception of Hawaii, these large price increases were found only in the Gulf Coast and the East Coast States. Another 16 States saw increases between 5 and 10 percent between 2004 and 2005.

Average industrial prices increased to 5.73 cents per kilowatthour, or 9.1 percent above 2004, the largest percentage increase among the three sectors (industrial, commercial, and residential) for the past 10 years. In Texas, industrial prices increased nearly 22 percent: nearly two-thirds of the industrial market in Texas is served by energy service providers,[13] and rising natural gas costs were passed on readily to their customers. Texas' industrial sector retail sales totaled 97 billion kilowatthours, almost 10 percent of the national total.

Residential prices increased to 9.45 cents per kilowatthour, almost half a cent, or 5.6 percent, between 2004 and 2005. Average residential prices rose sharply in New England and parts of the Middle Atlantic, as residential prices in Connecticut increased by 17 percent and in the District of Columbia by about 14 percent. Average residential prices in Texas grew by 12 percent.

[13] An energy service provider is an energy entity that provides service to a retail or end-use customer.

Total retail sales of electricity in 2005 were 3,661 billion kilowatthours. Annual growth in electricity sales in 2005 was 3.2 percent, showing much stronger growth than the 2.3 percent average since 1980. Sales to the residential sector increased by 5.2 percent from 2004 to 2005. Sales to the commercial sector increased by 3.6 percent, and sales to the industrial sector rose only slightly, by 0.1 percent. All sector sales increased by more than 5 percent in six States, led by Missouri which showed a 9 percent increase. Sales fell in only two States, Mississippi and Louisiana—primarily the result of Hurricane Katrina.

Demand-Side Management

In 2005, electricity providers reported total peak-load reductions of 25,710 megawatts resulting from demand-side management (DSM) programs, a 9.3 percent increase from the amount reported in 2004. Reported DSM costs increased to $1.9 billion, a 23.4 percent increase from costs reported in 2004. 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 show a direct relationship year to year. Nonetheless, nominal DSM expenditures have declined significantly over the last 10 years, in part due to elimination of some DSM requirements when States have moved to more competitive markets. At the same time, new programs designed to deliver real-time price signals to consumers may account for the recent cost increases over the last two years.

Table ES1. Summary Statistics for the United States, 1994 through 2005

Description	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
Net Generation (thousand megawatthours)												
Coal[1]	2,013,179	1,978,620	1,973,737	1,933,130	1,903,956	1,966,265	1,881,087	1,873,516	1,845,016	1,795,196	1,709,426	1,690,694
Petroleum[2]	122,522	120,646	119,406	94,567	124,880	111,221	118,061	128,800	92,555	81,411	74,554	105,901
Natural Gas	757,974	708,979	649,908	691,006	639,129	601,038	556,396	531,257	479,399	455,056	496,058	460,219
Other Gases[3]	16,317	16,766	15,600	11,463	9,039	13,955	14,126	13,492	13,351	14,356	13,870	13,319
Nuclear	781,986	788,528	763,733	780,064	768,826	753,893	728,254	673,702	628,644	674,729	673,402	640,440
Hydroelectric Conventional[4]	269,587	268,417	275,806	264,329	216,961	275,573	319,536	323,336	356,453	347,162	310,833	260,126
Other Renewables[5]	94,932	90,408	87,410	86,922	77,985	80,906	79,423	77,088	77,183	75,796	73,965	76,535
Pumped Storage[6]	-6,558	-8,488	-8,535	-8,743	-8,823	-5,539	-6,097	-4,467	-4,040	-3,088	-2,725	-3,378
Other[7]	4,749	6,679	6,121	5,714	4,690	4,794	4,024	3,571	3,612	3,571	4,104	3,667
All Energy Sources	**4,054,688**	**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**	**3,353,487**	**3,247,522**
Net Summer Generating Capacity (megawatts)												
Coal[1]	313,380	313,020	313,019	315,350	314,230	315,114	315,496	315,786	313,624	313,382	311,386	311,415
Petroleum[2]	58,548	59,119	60,680	59,583	66,086	61,822	43,299	42,989	45,723	45,267	44,725	43,976
Natural Gas[8]	383,061	371,011	355,492	312,580	252,909	219,605	211,889	203,580	203,211	201,385	196,379	192,514
Other Gases[3]	2,063	2,296	1,994	2,008	1,670	2,342	1,909	1,520	1,525	1,664	1,661	2,093
Nuclear	99,988	99,628	99,209	98,657	98,159	97,860	97,411	97,070	99,716	100,784	99,515	99,148
Hydroelectric Conventional[4]	77,541	77,641	78,694	79,356[R]	78,916[R]	79,359	79,393	79,151	79,415	76,437	78,562	78,041
Other Renewables[5]	21,251	18,763	18,199	16,755	16,180	15,572	15,942	15,444	15,351	15,309	15,300	15,021
Pumped Storage[9]	21,347	20,764	20,522	20,371[R]	19,664[R]	19,522	19,565	19,518	19,310	21,110	21,387	21,208
Other[7]	841	700	638	641	440	523	1,023	810	774	550	550	550
All Energy Sources	**978,020**	**962,942**	**948,446**	**905,301**	**848,254**	**811,719**	**785,927**	**775,868**	**778,649**	**775,890**	**769,463**	**763,967**
Demand, Capacity Resources, and Capacity Margins – Summer												
Net Internal Demand (megawatts)	746,470	692,908	696,752	696,376	674,833	680,941	653,857	638,086	618,389	602,438	589,860	578,640
Capacity Resources (megawatts)	882,125	875,870	856,131	833,380	788,990	808,054	765,744	744,670	737,855	730,376	727,481	711,583
Capacity Margins (percent)	15.4	20.9	18.6	16.4	14.5	15.7	14.6	14.3	16.2	17.5	18.9	18.7
Fuel												
Consumption of Fossil Fuels for Electricity Generation												
Coal (thousand tons)[1]	1,045,878	1,026,018[R]	1,014,058	987,583	972,691	994,933	949,802	946,295	931,949	907,209	860,594	848,796
Petroleum (thousand barrels)[2]	211,256	209,508[R]	206,653	168,597	216,672	195,228	207,871	222,640	159,715	144,626	132,578	183,618
Natural Gas (millions of cubic feet)	6,486,761	6,116,574[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	4,737,871	4,367,148
Other Gases (millions of Btu)[3]	176,906	186,796[R]	156,306	131,230	97,308	125,971	126,387	124,988	119,412	158,560	132,520	136,381
Consumption of Fossil Fuels for Thermal Output in Combined Heat and Power Facilities												
Coal (thousand tons)[1]	19,402	18,779[R]	17,720	17,561	18,944	20,466	20,373	20,320	21,005	20,806	20,418	20,609
Petroleum (thousand barrels)[2]	19,937	19,856[R]	17,939	14,811	18,268	22,266	26,822	28,845	28,802	27,873	25,562	27,929
Natural Gas (millions of cubic feet)	541,206	610,105[R]	721,267	860,019	898,286	985,263	982,958	949,106	868,569	865,774	834,382	784,015
Other Gases (millions of Btu)[3]	171,406	167,273[R]	137,837[R]	146,882	166,161	230,082	223,713	208,828	187,680	187,290	180,895	179,595
Consumption of Fossil Fuels for Electricity Generation and Useful Thermal Output												
Coal (thousand tons)[1]	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	881,012	869,405
Petroleum (thousand barrels)[2]	231,193	229,364[R]	224,593	183,408	234,940	217,494	234,694	251,486	188,517	172,499	158,140	211,547
Natural Gas (millions of cubic feet)	7,027,967	6,726,679[R]	6,337,402	6,986,081	6,730,591	6,676,744	6,304,942	6,030,490	5,433,338	5,178,232	5,572,253	5,151,163
Other Gases (millions of Btu)[3]	348,312	354,069[R]	294,143	278,111	263,469	356,053	350,100	333,816	307,092	345,850	313,415	315,976
Stocks at Electric Power Sector (year end)												
Coal (thousand tons)[10]	101,137	106,669	121,567	141,714	138,496	102,296	141,604	120,501	98,826	114,623	126,304	126,897
Petroleum (thousand barrels)[11]	50,062	51,434	53,170	52,490	57,031	40,932	54,109	56,591	51,138	48,146	50,821	63,333
Receipts of Fuel at Electricity Generators[12]												
Coal (thousand tons)[1]	1,021,437[R]	1,002,032	986,026	884,287	762,815	790,274	908,232	929,448	880,588	862,701	826,860	831,929
Petroleum (thousand barrels)[2]	194,733	186,655	185,567	120,851	124,618	108,272	145,939	181,276	128,749	113,678	89,908	149,258
Natural Gas (millions of cubic feet)[13]	6,191,389[R]	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	3,023,327	2,863,904
Cost of Fuel at Electricity Generators (cents per million Btu)[12]												
Coal[1]	154	136	128	125	123	120	122	125	127	129	132	136
Petroleum[2]	644	429	433	334	369	418	236	202	273	303	257	242
Natural Gas[13]	821	596	539	356	449	430	257	238	276	264	198	223
Emissions (thousand metric tons)												
Carbon Dioxide (CO_2)	2,513,609	2,456,934[R]	2,415,680[R]	2,395,048[R]	2,389,745[R]	2,429,394	2,326,559[R]	2,313,008[R]	2,223,348[R]	2,155,452[R]	2,079,761	2,063,788
Sulfur Dioxide (SO_2)	10,340	10,309[R]	10,646[R]	10,881[R]	11,174[R]	11,297	12,444[R]	12,509	13,520[R]	12,906[R]	11,896[R]	14,472[R]
Nitrogen Oxides (NO_X)	3,961	4,143[R]	4,532[R]	5,194[R]	5,290[R]	5,380	5,732	6,237[R]	6,324	6,282[R]	7,885	7,801[R]
Trade (million megawatthours)												
Purchases	2,847	2,829[R]	2,716[R]	2,705[R]	3,143[R]	2,346	2,040	2,021	1,966	1,798	1,618	1,528
Sales for Resale	3,246	3,013[R]	3,015[R]	2,811[R]	2,959[R]	2,355	1,998	1,922	1,839	1,656	1,495	1,388
Electricity Imports and Exports (thousand megawatthours)												
Imports	44,527	34,210[R]	30,390	36,779[R]	38,500	48,592	43,215	39,513	43,031	43,497	42,854	46,833
Exports	19,803	22,898[R]	23,972	15,796[R]	16,473	14,829	14,222	13,656	8,974	3,302	3,623	2,010
Retail Sales and Revenue Data – Bundled and Unbundled												
Number of Ultimate Customers (thousands)												
Residential	120,761	118,764	117,280	116,622	114,890	111,718	110,383	109,048	107,066	105,343	103,917	102,321
Commercial	16,872	16,607	16,550	15,334	14,867	14,349	14,074	13,887	13,542	13,181	12,949	12,733
Industrial	734	748	713	602	571	527	553	540	563	586	581	584
Transportation	1	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	1,067	1,030	974	935	933	952	894	882	851
All Sectors	138,367	136,119	134,544	133,624	131,359	127,568	125,945	124,408	122,123	120,004	118,330	116,489

See end of table for Notes and Sources.

Table ES1. Summary Statistics for the United States, 1994 through 2005 (Continued)

Description	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
Retail Sales and Revenue Data – Bundled and Unbundled (Continued)												
Sales to Ultimate Customers (thousand megawatthours)												
Residential	1,359,227	1,291,982[R]	1,275,824[R]	1,265,180[R]	1,201,607[R]	1,192,446	1,144,923	1,130,109	1,075,880	1,082,512	1,042,501	1,008,482
Commercial	1,275,079	1,230,425[R]	1,198,728[R]	1,104,497[R]	1,083,069[R]	1,055,232	1,001,996	979,401	928,633	887,445	862,685	820,269
Industrial	1,019,156	1,017,850[R]	1,012,373[R]	990,238[R]	996,609[R]	1,064,239	1,058,217	1,051,203	1,038,197	1,033,631	1,012,693	1,007,981
Transportation	7,506	7,224[R]	6,810	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	105,552[R]	113,174[R]	109,496	106,952	103,518	102,901	97,539	95,407	97,830
All Sectors	3,660,969	3,547,479[R]	3,493,734[R]	3,465,466[R]	3,394,458[R]	3,421,414	3,312,087	3,264,231	3,145,610	3,101,127	3,013,287	2,934,563
Direct Use[14]	154,700	168,470	168,295	166,184	162,649	170,943	171,629	160,866	156,239	152,638	150,677	146,325
Total Disposition	3,815,669	3,715,949[R]	3,662,029[R]	3,631,650[R]	3,557,107[R]	3,592,357	3,483,716	3,425,097	3,301,849	3,253,765	3,163,963	3,080,888
Revenue From Ultimate Customers (million dollars)												
Residential	128,393	115,577[R]	111,249[R]	106,834[R]	103,158[R]	98,209	93,483	93,360	90,704	90,503	87,610	84,552
Commercial	110,522	100,546[R]	96,263[R]	87,117[R]	85,741[R]	78,405	72,771	72,575	70,497	67,829	66,365	63,396
Industrial	58,445	53,477[R]	51,741[R]	48,336[R]	50,293[R]	49,369	46,846	47,050	47,023	47,536	47,175	48,069
Transportation	643	519[R]	514	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	7,124[R]	8,151[R]	7,179	6,796	6,863	7,110	6,741	6,567	6,689
All Sectors	298,003	270,119[R]	259,767	249,411[R]	247,343[R]	233,163	219,896	219,848	215,334	212,609	207,717	202,706
Average Retail Price (cents per kilowatthour)												
Residential	9.45	8.95[R]	8.72[R]	8.44[R]	8.58[R]	8.24	8.16	8.26	8.43	8.36	8.40	8.38
Commercial	8.67	8.17[R]	8.03[R]	7.89[R]	7.92[R]	7.43	7.26	7.41	7.59	7.64	7.69	7.73
Industrial	5.73	5.25[R]	5.11[R]	4.88[R]	5.05[R]	4.64	4.43	4.48	4.53	4.60	4.66	4.77
Transportation	8.57	7.18[R]	7.54[R]	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	6.75	7.20[R]	6.56	6.35	6.63	6.91	6.91	6.88	6.84
All Sectors	8.14	7.61[R]	7.44[R]	7.20[R]	7.29[R]	6.81	6.64	6.74	6.85	6.86	6.89	6.91
Revenue and Expense Statistics (million dollars)												
Major Investor Owned												
Utility Operating Revenues	267,534	240,318	226,227	219,389	267,525	235,336	214,160	218,175	215,083	207,459	199,967	196,282
Utility Operating Expenses	238,590	207,161	197,459	188,745	235,198	210,324	182,258	186,498	182,796	173,920	165,321	164,207
Net Utility Operating Income	28,944	33,158	28,768	30,644	32,327	25,012	31,902	31,677	32,286	33,539	34,646	32,074
Major Publicly Owned (with Generation Facilities)[15]												
Operating Revenues	NA	NA	33,906	32,776	38,028	31,843	26,767	26,155	25,397	24,207	23,473	23,267
Operating Expenses	NA	NA	29,637	28,638	32,789	26,244	21,274	20,880	20,425	19,084	18,959	18,649
Net Electric Operating Income	NA	NA	4,268	4,138	5,238	5,598	5,493	5,275	4,972	5,123	4,514	4,618
Major Publicly Owned (without Generation Facilities)[15]												
Operating Revenues	NA	NA	12,454	11,546	10,417	9,904	9,354	8,790	8,586	8,582	8,435	7,996
Operating Expenses	NA	NA	11,481	10,703	9,820	9,355	8,737	8,245	8,033	8,123	7,979	7,567
Net Electric Operating Income	NA	NA	974	843	597	549	617	545	552	459	457	429
Major Federally Owned[15]												
Operating Revenues	NA	NA	11,798	11,470	12,458	10,685	10,186	9,780	8,833	9,082	8,743	8,552
Operating Expenses	NA	NA	8,763	8,665	10,013	8,139	7,775	7,099	5,999	6,390	6,162	6,303
Net Electric Operating Income	NA	NA	3,035	2,805	2,445	2,546	2,411	2,681	2,834	2,692	2,581	2,249
Major Cooperative Borrower Owned												
Operating Revenues	34,088	30,650	29,228	27,458	26,458	25,629	23,824	23,988	23,321	24,424	24,609	23,777
Operating Expenses	31,209	27,828	26,361	24,561	23,763	22,982	21,283	21,223	20,715	23,149	21,741	20,993
Net Electric Operating Income	2,879	2,822	2,867	2,897	2,696	2,647	2,541	2,764	2,606	2,872	2,868	2,784
Demand-Side Management (DSM) Data												
Actual Peak Load Reductions (megawatts)												
Total Actual Peak Load Reduction	25,710	23,532	22,904	22,936	24,955	22,901	26,455	27,231	25,284	29,893	29,561	25,001
DSM Energy Savings (thousand megawatthours)												
Energy Efficiency	58,891	52,662	48,245	52,285	52,946	52,827	49,691	48,775	55,453	59,853	55,328	49,720
Load Management	1,006	2,047	2,020	1,790	990	875	872	392	953	1,989	2,093	2,763
DSM Cost (million dollars)												
Total Cost	1,921	1,557	1,297	1,626	1,630	1,565	1,424	1,421	1,636	1,902	2,421	2,716

[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] Wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, tires, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
[6] The generation from a hydroelectric pumped storage facility is the net value of production minus the energy used for pumping.
[7] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
[8] Includes a small number of generators for which waste heat is the primary energy source.
[9] 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.
[10] Anthracite, bituminous, subbituminous, lignite, and synthetic coal; excludes waste coal.
[11] 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.
[12] Beginning in 2002, includes data from the Form EIA-423 for independent power producers and combined heat and power producers.
[13] Natural gas, including a small amount of supplemental gaseous fuels that cannot be identified separately.
[14] 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.
[15] The Form EIA-412 was terminated in 2003.
NA = Not available.
R = Revised.
Notes: ·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 rounding.

Sources: Form EIA-411, "Coordinated Bulk Power Supply Program Report;" Form EIA-412, "Annual Electric Industry Financial Report;" Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report;" Form EIA-767, "Steam-Electric Plant Operation and Design Report;" Form EIA-860, " Annual Electric Generator Report;" Form EIA-861, "Annual Electric Power Industry Report;" Energy Information Administration, Form EIA-906, "Power Plant Report;" Energy Information Administration, Form EIA-920 "Combined Heat and Power Plant Report;" and 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;" FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," and predecessor forms; Rural Utility Services (RUS) Form 7, "Operating Report;" RUS Form 12, "Operating Report;" 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).

Table ES2. Supply and Disposition of Electricity, 1994 through 2005
(Million Megawatthours)

Category	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
Supply												
Generation												
Electric Utilities	2,554	2,505	2,462	2,549	2,630	3,015	3,174	3,212	3,123	3,077	2,995	2,911
Independent Power Producers	1,167	1,119	1,063	955	781	458	201	91	59	60	58	55
Combined Heat and Power, Electric	180	184	196	194	170	165	155	154	148	147	141	123
Electric Power Sector Generation Subtotal	3,901	3,808	3,721	3,698	3,580	3,638	3,530	3,457	3,329	3,284	3,194	3,089
Combined Heat and Power, Commercial	8	8	7	7	7	8	9	9	9	9	8	8
Combined Heat and Power, Industrial	145	154	155	153	149	157	156	154	154	151	151	151
Industrial and Commercial Generation Subtotal	153	162	162	160	157	165	165	163	163	160	159	159
Total Net Generation	4,055	3,971	3,883	3,858	3,737	3,802	3,695	3,620	3,492	3,444	3,353	3,248
Total Imports	45	34	30	37[R]	39	49	43	40	43	43	43	47
Total Supply	**4,099**	**4,005**	**3,914**	**3,895**	**3,775**	**3,851**	**3,738**	**3,660**	**3,535**	**3,488**	**3,396**	**3,294**
Disposition												
Retail Sales												
Full-Service Providers	3,413	3,318	3,285	3,324	3,297	3,310	3,236	3,240	3,140	3,098	3,013	2,935
Energy-Only Providers	237	222	189	141	98	112	76	24	6	3	--	--
Facility Direct Retail Sales	11	8	20	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Electric Industry Retail Sales	3,661	3,547[R]	3,494[R]	3,465[R]	3,394[R]	3,421	3,312	3,264	3,146	3,101	3,013	2,935
Direct Use	155	168	168	166	163	171	172	161	156	153	151	146
Total Exports	20	23	24	14	16	15	14	14	9	3	4	2
Losses and Unaccounted For	264	266	228	250	202	244	240	221	224	231	229	211
Total Disposition	**4,099**	**4,005**	**3,914**	**3,895**	**3,775**	**3,851**	**3,738**	**3,660**	**3,535**	**3,488**	**3,396**	**3,294**

Note: 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 include: (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-906, "Power Plant Report;" 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, 1994 through 2005
(Thousand Megawatthours)

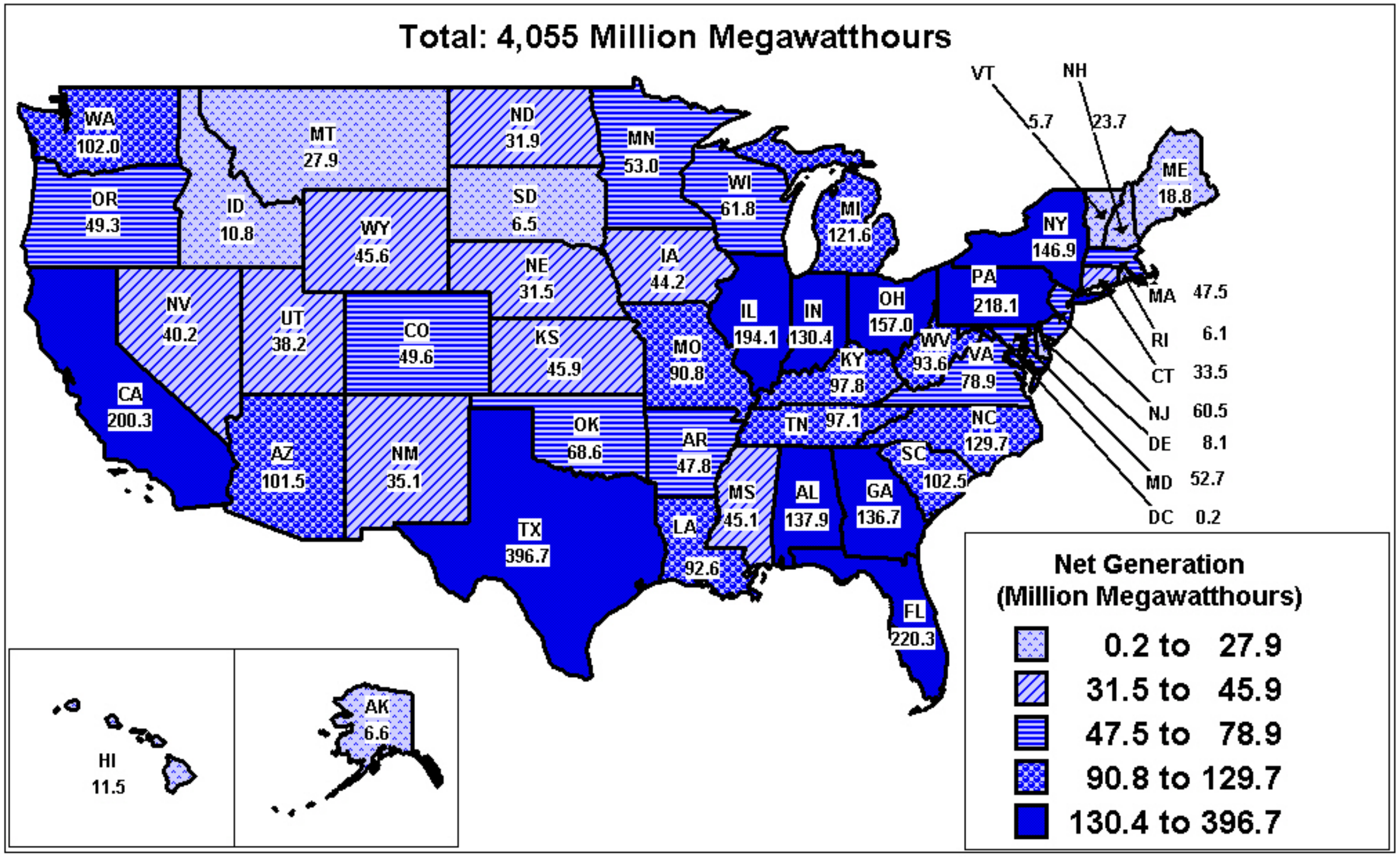
Period	Coal[1]	Petroleum [2]	Natural Gas	Other Gases[3]	Nuclear	Hydroelectric Conventional[4]	Other Renewables[5]	Hydroelectric Pumped Storage[6]	Other[7]	Total
Total (All Sectors)										
1994	1,690,694	105,901	460,219	13,319	640,440	260,126	76,535	-3,378	3,667	3,247,522
1995	1,709,426	74,554	496,058	13,870	673,402	310,833	73,965	-2,725	4,104	3,353,487
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	77,985	-8,823	4,690	3,736,644
2002	1,933,130	94,567	691,006	11,463	780,064	264,329	86,922	-8,743	5,714	3,858,452
2003	1,973,737	119,406	649,908	15,600	763,733	275,806	87,410	-8,535	6,121	3,883,185
2004	1,978,620	120,646	708,979	16,766	788,528	268,417	90,408	-8,488	6,679	3,970,555
2005	2,013,179	122,522	757,974	16,317	781,986	269,587	94,932	-6,558	4,749	4,054,688
Electricity Generators, Electric Utilities										
1994	1,635,493	91,039	291,115	--	640,440	247,071	8,933	-3,378	--	2,910,712
1995	1,652,914	60,844	307,306	--	673,402	296,378	6,409	-2,725	--	2,994,529
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	2,152	-7,704	--	2,629,946
2002	1,514,670	59,125	229,639	206	507,380	242,302	3,569	-7,434	--	2,549,457
2003	1,500,281	69,930	186,967	243	458,829	249,622	3,941	-7,532	--	2,462,281
2004	1,513,641	73,694	199,662	374	475,682	245,546	4,061	-7,526	98	2,505,231
2005	1,533,666	70,834	238,484	10	465,069	246,028	5,335	-5,630	253	2,554,050
Electricity Generators, Independent Power Producers										
1994	4,370	1,047	8,603	7	--	6,934	33,554	--	--	54,514
1995	5,044	1,162	10,136	6	--	9,033	32,841	--	--	58,222
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	42,661	-1,119	--	780,592
2002	366,535	24,150	227,155	29	272,684	18,189	46,456	-1,309	1,441	955,331
2003	415,498	38,571	234,240	13	304,904	21,890	47,753	-1,003	1,339	1,063,205
2004	407,418	35,665	291,527	7	312,846	19,518	51,483	-962	1,368	1,118,870
2005	421,847	40,374	314,690	3	316,917	20,268	53,860	-928	3	1,167,033
Combined Heat and Power, Electric power										
1994	26,414	6,592	85,971	1,085	--	--	3,199	--	239	123,500
1995	28,098	6,139	101,737	1,921	--	--	3,372	--	213	141,480
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	--	--	3,988	--	--	169,515
2002	29,408	6,458	150,889	1,734	--	--	4,565	--	615	193,670
2003	36,935	5,195	146,097	2,392	--	--	4,822	--	233	195,674
2004	36,134	5,208	136,331	2,645	--	--	3,578	--	364	184,259
2005	36,547	5,560	130,142	3,948	--	10	4,107	--	62	180,375
Combined Heat and Power, Commercial										
1994	850	417	4,929	115	--	93	1,216	--	--	7,619
1995	998	379	5,162	--	--	118	1,575	--	*	8,232
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	1,482	--	*	7,416
2002	992	431	4,310	*	--	13	1,585	--	84	7,415
2003	1,206	423	3,899	--	--	72	1,894	--	2	7,496
2004	1,323	469	4,051	--	--	105	2,321	--	1	8,270
2005	1,329	375	4,279	--	--	86	2,422	--	1	8,492
Combined Heat and Power, Industrial										
1994	23,568	6,808	69,600	12,112	--	6,028	29,633	--	3,428	151,178
1995	22,372	6,030	71,717	11,943	--	5,304	29,768	--	3,890	151,025
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	27,703	--	4,690	149,175
2002	21,525	4,403	79,013	9,493	--	3,825	30,747	--	3,574	152,580
2003	19,817	5,285	78,705	12,953	--	4,222	29,001	--	4,546	154,530
2004	20,103	5,610	77,409	13,740	--	3,248	28,965	--	4,849	153,925
2005	19,791	5,380	70,380	12,356	--	3,195	29,208	--	4,429	144,739

[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] Wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, tires, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy and wind.
[6] The quantity of output from a hydroelectric pumped storage facility represents production minus energy used for pumping.
[7] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
* = Value is less than half of the smallest unit of measure.

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

Source: Energy Information Administration, Form EIA-906, "Power Plant Report;" Energy Information Administration, Form EIA-920 "Combined Heat and Power Plant Report;" and predecessor forms.

Figure 1.1. U.S. Electric Industry Net Generation by State, 2005



Note: Data is displayed as 5 groups of 10 States and the District of Columbia.

Sources: Energy Information Administration, Form EIA-906, "Power Plant Report" and Form EIA-920, "Combined Heat and Power Plant Report."

Table 1.2. Useful Thermal Output by Energy Source by Combined Heat and Power Producers, 1994 through 2005
(Billion Btus)

Period	Coal[1]	Petroleum[2]	Natural Gas	Other Gases[3]	Other Renewables[4]	Other[5]	Total
Total Combined Heat and Power							
1994	387,604	132,528	645,561	143,682	767,417	42,129	2,118,921
1995	386,403	120,790	686,182	144,715	768,338	44,389	2,150,817
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	597,475	42,248	1,958,151
2002	336,848	72,826	708,738	117,513	584,976	34,796	1,855,697
2003	333,361	85,263	610,122	110,263	646,223	41,103	1,826,335
2004	346,083	96,439	504,548	133,821	696,936	26,851[R]	1,804,678[R]
2005	356,901	97,035	445,160	137,124	741,674	26,239	1,804,133
Combined Heat and Power, Electric Power							
1994	36,663	8,631	119,199	5,190	24,497	880	195,060
1995	40,427	13,044	117,994	4,344	26,910	249	202,968
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	16,019	--	242,508
2002	40,020	3,869	214,137	5,961	17,219	63	281,269
2003	38,249	7,379	200,077	9,282	22,760	321	278,068
2004	22,153	1,250	129,791	16,043	9,388	337	178,962
2005	25,273	1,162	118,313	31,932	12,296	361	189,337
Combined Heat and Power, Commercial							
1994	17,759	4,483	25,578	172	14,172	--	62,164
1995	16,718	2,877	28,574	--	15,223	1	63,393
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	--	14,024	--	71,560
2002	18,477	2,743	36,265	--	11,703	--	69,188
2003	22,780	2,716	16,955	--	14,438	--	56,889
2004	23,753	4,023	21,418	--	17,011	--	66,205
2005	21,088	3,412	22,218	--	13,469	--	60,187
Combined Heat and Power, Industrial							
1994	333,182	119,414	500,784	138,320	728,748	41,249	1,861,697
1995	329,258	104,869	539,614	140,371	726,205	44,139	1,884,456
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	567,432	42,248	1,644,083
2002	278,351	66,214	458,336	111,552	556,054	34,733	1,505,240
2003	272,332	75,168	393,090	100,981	609,025	40,782	1,491,378
2004	300,177	91,166	353,339	117,778	670,537	26,514[R]	1,559,511[R]
2005	310,540	92,461	304,629	105,192	715,909	25,878	1,554,609

[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)
[3] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[4] Wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, tires, agriculture byproducts, other biomass, and photovoltaic energy.
[5] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
* = 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.
Source: Energy Information Administration, Form EIA-906, "Power Plant Report;" Energy Information Administration, Form EIA-920 "Combined Heat and Power Plant Report;" and predecessor forms.

Chapter 2. Capacity

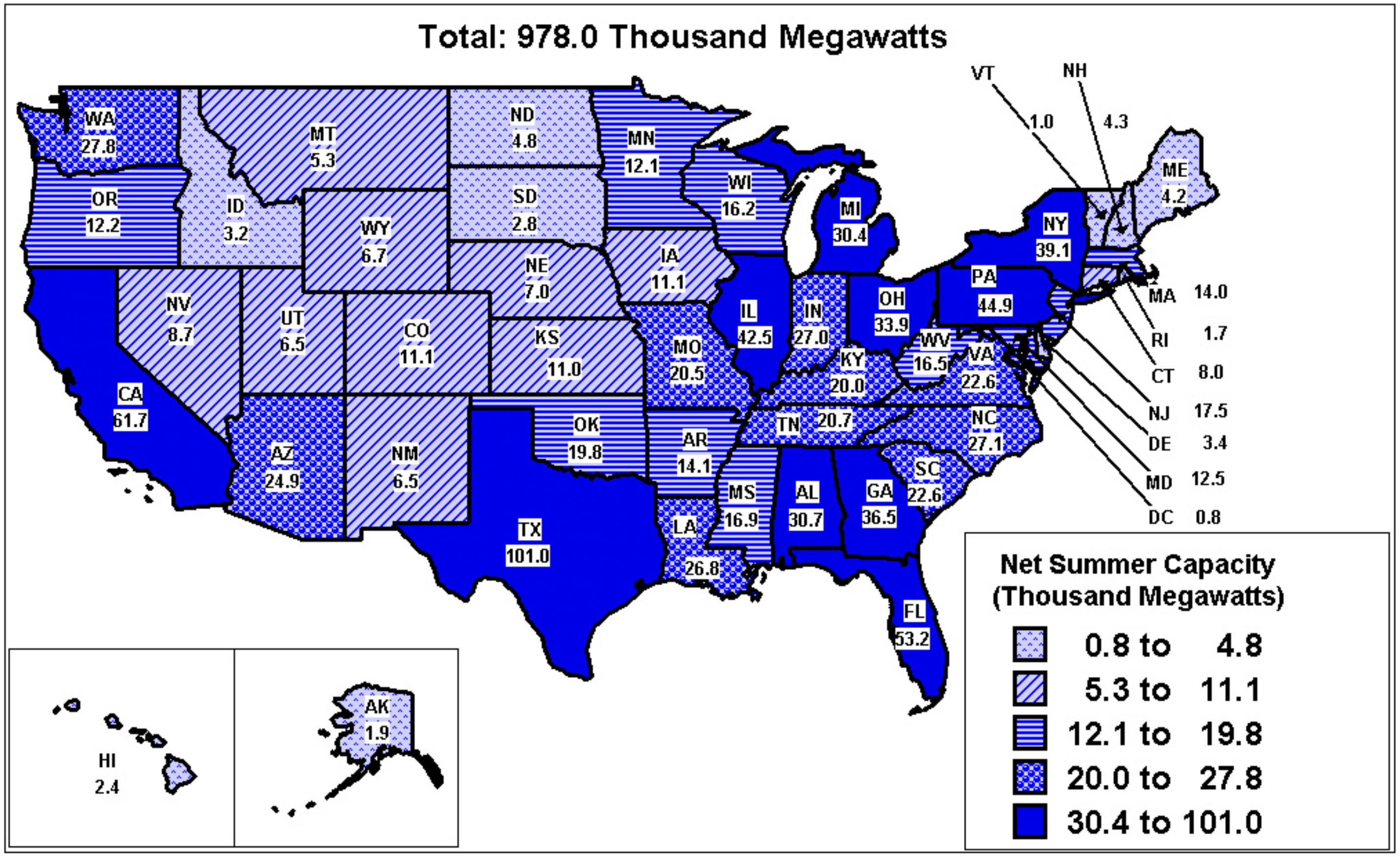
Table 2.1. Existing Net Summer Capacity by Energy Source and Producer Type, 1994 through 2005
(Megawatts)

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)										
1994	311,415	43,976	192,514	2,093	99,148	78,041	15,021	21,208	550	763,967
1995	311,386	44,725	196,379	1,661	99,515	78,562	15,300	21,387	550	769,463
1996	313,382	45,267	201,385	1,664	100,784	76,437	15,309	21,110	550	775,890
1997	313,624	45,723	203,211	1,525	99,716	79,415	15,351	19,310	774	778,649
1998	315,786	42,989	203,580	1,520	97,070	79,151	15,444	19,518	810	775,868
1999	315,496	43,299	211,889	1,909	97,411	79,393	15,942	19,565	1,023	785,927
2000	315,114	61,822	219,605	2,342	97,860	79,359	15,572	19,522	523	811,719
2001	314,230	66,086	252,909	1,670	98,159	78,916[R]	16,180	19,664[R]	440	848,254
2002	315,350	59,583	312,580	2,008	98,657	79,356[R]	16,755	20,371[R]	641	905,301
2003	313,019	60,680	355,492	1,994	99,209	78,694	18,199	20,522	638	948,446
2004	313,020	59,119	371,011	2,296	99,628	77,641	18,763	20,764	700	962,942
2005	313,380	58,548	383,061	2,063	99,988	77,541	21,251	21,347	841	978,020
Electricity Generators, Electric Utilities										
1994	300,941	41,815	161,354	698	99,148	74,787	2,278	21,208	--	702,229
1995	300,569	42,554	164,192	291	99,515	75,274	2,330	21,387	--	706,111
1996	302,420	43,170	167,187	63	100,784	73,129	2,079	21,110	--	709,942
1997	302,866	42,817	168,454	206	99,716	76,177	2,123	19,310	222	711,889
1998	299,739	39,412	153,697	55	97,070	75,525	2,067	18,898	229	686,692
1999	277,780	32,250	139,962	220	95,030	74,122	790	18,945	224	639,324
2000	260,990	41,017	123,680	57	85,968	73,738	837	18,020	13	604,319
2001	244,451	38,441	112,856	57	63,060	72,968	979	17,097	13	549,920
2002	244,056	33,876	127,692	61	63,202	73,391	989	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	236,225	30,992	144,622	104	58,762	71,550	1,496	18,630	39	562,420
Electricity Generators, Independent Power Producers										
1994	702	213	3,005	--	--	2,108	6,728	--	--	12,755
1995	719	221	2,987	--	--	2,151	6,887	--	--	12,964
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[R]	9,695[R]	2,567[R]	--	240,952[R]
2002	61,770	23,664	140,404	9[R]	35,455	4,911	10,435	2,564	35	279,246[R]
2003	66,538	26,028	178,624	6	38,244	5,058	11,832	2,719	--	329,049
2004	67,242	25,918	190,855	8	38,978	5,274	12,116	2,717	--	343,106
2005	67,272	25,715	192,480	12	41,226	5,301	13,979	2,717	--	348,702
Combined Heat and Power, Electric power										
1994	4,453	704	15,885	--	--	--	498	--	--	21,540
1995	4,756	754	16,614	--	--	--	610	--	--	22,733
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	910	21,287	287	--	1[R]	776[R]	--	28	27,917[R]
2002	5,222	1,016	28,523	182	--	--	555	--	--	35,499
2003	5,534	1,001	34,945	185	--	1	665	--	--	42,332
2004	5,609	677	32,600	289	--	1	555	--	--	39,731
2005	5,502	743	30,434	185	--	1	614	--	--	37,480
Combined Heat and Power, Commercial										
1994	287	215	1,227	--	--	32	297	--	--	2,057
1995	315	235	1,246	--	--	31	303	--	--	2,131
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[R]	348	--[R]	--	2,912
2002	292	301	1,216	--	--	22[R]	357	--[R]	--	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	--	26	435	--	--	2,220
Combined Heat and Power, Industrial										
1994	5,032	1,029	11,044	1,395	--	1,115	5,221	--	550	25,386
1995	5,028	961	11,339	1,370	--	1,106	5,171	--	550	25,524
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[R]	--	1,033	4,419	--	607	27,295[R]
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	764	14,501	1,757	--	662	4,727	--	802	27,198

[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, tires, 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 lower level.
[8] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, 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 Existing Capacity by State, 2005



Note: Data is displayed as 5 groups of 10 States and the District of Columbia.

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

Table 2.2. Existing Capacity by Energy Source, 2005
(Megawatts)

Energy Source	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Coal[1]	1,522	335,892	313,380	315,556
Petroleum[2]	3,753	64,845	58,548	63,171
Natural Gas[3]	5,467	436,991	383,061	412,241
Other Gases[4]	102	2,293	2,063	2,012
Nuclear	104	105,585	99,988	101,524
Hydroelectric Conventional[5]	3,993	77,354	77,541	77,130
Other Renewables[6]	1,671	23,553	21,251	21,477
Pumped Storage	150	19,569	21,347	21,253
Other[7]	45	928	841	863
Total	**16,807**	**1,067,010**	**978,020**	**1,015,227**

[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, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, tires, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
[7] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, 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.

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

Table 2.3. Existing Capacity by Producer Type, 2005
(Megawatts)

Producer Type	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Electric Power Sector				
Electric Utilities	9,129	603,299	562,420	578,958
Independent Power Producers	4,555	387,246	348,702	365,086
Total	**13,684**	**990,545**	**911,122**	**944,044**
Combined Heat and Power Sector				
Electric Power[1]	666	43,326	37,480	40,285
Commercial	636	2,533	2,220	2,315
Industrial	1,821	30,606	27,198	28,583
Total	**3,123**	**76,465**	**66,898**	**71,183**
Total All Sectors	**16,807**	**1,067,010**	**978,020**	**1,015,227**

[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.

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

Table 2.4. Planned Nameplate Capacity Additions from New Generators, by Energy Source, 2006 through 2010
(Megawatts)

Energy Source	2006	2007	2008	2009	2010
Coal[1]	602	1,589	1,056	15,287	9,350
Petroleum[2]	269	78	168	817	300
Natural Gas	10,657	16,892	15,050	8,511	5,815
Other Gases[3]	--	391	1,160	--	--
Nuclear	--	--	--	--	--
Hydroelectric Conventional	8	3	4	--	1
Other Renewables[4]	3,027	2,454	695	236	--
Pumped Storage	--	--	--	--	--
Other[5]	10	--	--	--	--
Total	**14,573**	**21,407**	**18,133**	**24,850**	**15,466**

[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] Wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, tires, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
[5] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, 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 January 1, 2006. • 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, 2006-2010
(Count, Megawatts)

Energy Source	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
		2006		
U.S. Total	**223**	**14,573**	**12,979**	**13,937**
Coal[1]	5	602	564	566
Petroleum[2]	48	269	245	261
Natural Gas	89	10,657	9,156	10,093
Other Gases[3]	--	--	--	--
Nuclear	--	--	--	--
Hydroelectric Conventional	2	8	8	8
Other Renewables[4]	78	3,027	2,996	3,000
Pumped Storage	--	--	--	--
Other[5]	1	10	9	9
		2007		
U.S. Total	**152**	**21,407**	**18,849**	**20,395**
Coal[1]	3	1,589	1,488	1,493
Petroleum[2]	2	78	71	73
Natural Gas	100	16,892	14,506	16,010
Other Gases[3]	2	391	336	370
Nuclear	--	--	--	--
Hydroelectric Conventional	1	3	3	3
Other Renewables[4]	44	2,454	2,445	2,447
Pumped Storage	--	--	--	--
Other[5]	--	--	--	--
		2008		
U.S. Total	**109**	**18,133**	**15,730**	**17,224**
Coal[1]	5	1,056	988	993
Petroleum[2]	4	168	142	164
Natural Gas	81	15,050	12,911	14,281
Other Gases[3]	4	1,160	999	1,095
Nuclear	--	--	--	--
Hydroelectric Conventional	1	4	4	4
Other Renewables[4]	14	695	685	687
Pumped Storage	--	--	--	--
Other[5]	--	--	--	--
		2009		
U.S. Total	**79**	**24,850**	**22,525**	**23,419**
Coal[1]	25	15,287	14,256	14,369
Petroleum[2]	2	817	751	772
Natural Gas	46	8,511	7,306	8,055
Other Gases[3]	--	--	--	--
Nuclear	--	--	--	--
Hydroelectric Conventional	--	--	--	--
Other Renewables[4]	6	236	212	223
Pumped Storage	--	--	--	--
Other[5]	--	--	--	--
		2010		
U.S. Total	**46**	**15,466**	**13,909**	**14,558**
Coal[1]	17	9,350	8,654	8,789
Petroleum[2]	1	300	255	294
Natural Gas	24	5,815	4,999	5,474
Other Gases[3]	--	--	--	--
Nuclear	--	--	--	--
Hydroelectric Conventional	4	1	1	1
Other Renewables[4]	--	--	--	--
Pumped Storage	--	--	--	--
Other[5]	--	--	--	--

[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, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, tires, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
[5] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, 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 January 1, 2006. • Totals may not equal sum of components because of independent rounding.

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

Table 2.6. Capacity Additions, Retirements and Changes by Energy Source, 2005
(Count, Megawatts)

Energy Source	Generator Additions				Generator Retirements				Updates and Revisions[1]		
	Number of Gene-rators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity	Number of Gene-rators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity (MW)
Coal[2]	4	478	415	415	13	330	272	292	501	218	70
Petroleum[3]	57	144	123	129	64	789	748	748	307	54	233
Natural Gas[4]	126	16,688	14,753	15,877	105	2,279	2,092	2,198	55	-611	-1,009
Other Gases[5]	4	113	97	111	2	20	19	19	-336	-310	-339
Nuclear	--	--	--	--	--	--	--	--	25	360	147
Hydroelectric	6	30	30	30	8	16	14	14	210	467	463
Other Renewables[6]	44	2,205	2,197	2,200	12	32	26	28	267	317	304
Other[7]	1	7	7	7	--	--	--	--	166	134	140
Total	**242**	**19,666**	**17,622**	**18,768**	**204**	**3,466**	**3,172**	**3,299**	**1,195**	**628**	**9**

[1] Generator re-ratings, re-powering, and revisions/corrections to previously reported data. There is not a direct correlation between these columns of data since this is a mixture of changes.
[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, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, tires, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
[7] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, 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.

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

Table 2.7.A. Capacity of Dispersed Generators by Technology Type, 2004 and 2005
(Count, Megawatts)

Period	Internal Combustion		Combustion Turbine		Steam Turbine		Hydroelectric		Wind and Other		Total	
	Number of Generators	Capacity	Number of Generators	Capacity	Number of Generators	Capacity	Number of Generators	Capacity	Number of Generators	Capacity	Number of Generators	Capacity
2004	NA	3,369	NA	210	NA	552	NA	26	NA	2	11,123	4,156
2005	NA	4,292	NA	334	NA	126	NA	2	NA	13	11,373	4,766

NA = Not available.

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: Form EIA-861, "Annual Electric Power Industry Report."

Table 2.7.B. Capacity of Distributed Generators by Technology Type, 2004 and 2005
(Count, Megawatts)

Period	Internal Combustion		Combustion Turbine		Steam Turbine		Hydroelectric		Wind and Other		Total	
	Number of Generators	Capacity	Number of Generators	Capacity	Number of Generators	Capacity	Number of Generators	Capacity	Number of Generators	Capacity	Number of Generators	Capacity
2004	NA	2,169	NA	1,028	NA	1,086	NA	1,003	NA	137	5,863	5,423
2005[1]	NA	4,024	NA	1,917	NA	1,831	NA	998	NA	994	17,371	9,766

[1] Distributed generator data in 2005 includes a significant number of generators reported by one respondent which may be for residential applications.

NA = Not available.

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: Form EIA-861, "Annual Electric Power Industry Report."

Table 2.7.C. Total Capacity of Dispersed and Distributed Generators by Technology Type, 2004 and 2005
(Count, Megawatts)

Period	Internal Combustion		Combustion Turbine		Steam Turbine		Hydroelectric		Wind and Other		Total	
	Number of Generators	Capacity	Number of Generators	Capacity	Number of Generators	Capacity	Number of Generators	Capacity	Number of Generators	Capacity	Number of Generators	Capacity
2004	NA	5,538	NA	1,238	NA	1,638	NA	1,029	NA	139	16,986	9,579
2005[1]	NA	8,316	NA	2,251	NA	1,957	NA	1,000	NA	1,007	28,744	14,532

[1] Distributed generator data in 2005 includes a significant number of generators reported by one respondent which may be for residential applications.

NA = Not available.

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: 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, 2005
(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 Reporting No Regulatory Limits on Use of Petroleum Liquids[1]
Electric Utility	144,622	70,268	48.6	67,747	23,099
Independent Power Producers	192,480	40,095	20.8	38,944	7,100
Combined Heat and Power, Electric Power[2]	30,434	6,386	21.0	6,261	698
Electric Power Sector Subtotal	**367,536**	**116,749**	**31.8**	**112,952**	**30,897**
Combined Heat and Power, Commercial	1,024	474	46.3	484	55
Combined Heat and Power, Industrial	14,501	993	6.8	894	248
All Sectors	**383,061**	**118,216**	**30.9**	**114,329**	**31,200**

[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, 2005
(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	30,992	10,231	33.0	9,714
Independent Power Producers	25,715	11,924	46.4	9,821
Combined Heat and Power Electric Power[2]	743	--	--	--
Electric Power Sector Subtotal	**57,450**	**22,156**	**38.6**	**19,535**
Combined Heat and Power Commercial	333	29	8.6	28
Combined Heat and Power Industrial	764	96	12.6	75
All Sectors	**58,548**	**22,281**	**38.1**	**19,639**

[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, 2005
(Count, Megawatts)

Prime Mover Type	Number of Generators	Net Summer Capacity	Net Summer Capacity Reported as Having No Regulatory Limits on use of Petroleum Liquids[1]
Steam Generator	244	33,193	15,553
Combined Cycle	388	33,358	4,058
Internal Combustion	324	900	293
Gas Turbine	899	50,764	11,295
All Fuel Switchable Prime Movers	1,855	118,216	31,200

[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, 2005
(Count, Megawatts)

Year of Commercial Operation	Number of Generators	Net Summer Capacity	Net Summer Capacity Reported as Having No Regulatory Limits on use of Petroleum Liquids[1]
pre-1970	412	17,648	8,520
1970-1974	381	19,087	7,228
1975-1979	118	10,549	4,679
1980-1984	45	2,810	2,056
1985-1989	127	3,355	308
1990-1994	223	12,875	1,741
1995-1999	137	9,373	2,269
2000-2004	383	38,696	3,407
2005	29	3,822	991
Total	1,855	118,216	31,200

[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 Power Industry 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, 2001 through 2010
(Megawatts)

North American Electric Reliability Council Region	Actual 2001	2002	2003	2004	2005
Summer					
ECAR[1]	100,235	102,996	98,487	95,300	NA
ERCOT	55,201	56,248	59,996	58,531	60,210
FRCC	39,062	40,696	40,475	42,383	46,396
MAAC[1]	54,015	55,569	53,566	52,049	NA
MAIN[1]	56,344	56,396	56,988	53,439	NA
MRO (U.S.) [2]	28,321	29,119	28,831	29,351	39,918
NPCC (U.S.)	55,949	56,012	55,018	52,549	58,960
Reliability*First*[3]	NA	NA	NA	NA	190,200
SERC	149,293	158,767	153,110	157,615	190,705
SPP	40,273	39,688	40,367	40,106	41,727
WECC (U.S.)	109,119	119,074	122,537	123,136	130,760
Contiguous U.S.	**687,812**	**714,565**	**709,375**	**704,459**	**758,876**
Winter					
ECAR[1]	85,485	87,300	86,332	91,800	NA
ERCOT	44,015	45,414	42,702	44,010	48,141
FRCC	40,922	45,635	36,841	44,839	42,657
MAAC[1]	39,458	46,551	45,625	45,905	NA
MAIN[1]	40,529	42,412	41,719	42,929	NA
MRO (U.S.) [2]	21,815	23,645	24,134	24,526	33,748
NPCC (U.S.)	42,670	46,009	48,079	48,176	46,828
Reliability*First*[3]	NA	NA	NA	NA	151,600
SERC	135,182	141,882	137,972	144,337	164,638
SPP	29,614	30,187	28,450	29,490	31,260
WECC (U.S.)	96,622	95,951	102,020	102,689	107,493
Contiguous U.S.	**576,312**	**604,986**	**593,874**	**618,701**	**626,365**

North American Electric Reliability Council Region	Projected 2006	2007	2008	2009	2010
Summer					
ECAR[1]	NA	NA	NA	NA	NA
ERCOT	61,656	63,222	64,318	65,950	67,548
FRCC	45,520	46,725	48,030	49,233	50,221
MAAC[1]	NA	NA	NA	NA	NA
MAIN[1]	NA	NA	NA	NA	NA
MRO (U.S.) [2]	41,623	42,300	43,205	44,024	44,843
NPCC (U.S.)	60,320	61,186	62,214	63,228	64,227
Reliability*First*[3]	191,600	193,900	198,600	201,900	204,800
SERC	188,763	192,895	198,263	201,787	205,804
SPP	41,747	42,539	43,276	43,985	44,747
WECC (U.S.)	130,999	134,215	137,396	140,804	143,878
Contiguous U.S.	**762,228**	**776,982**	**795,302**	**810,911**	**826,068**
Winter					
ECAR[1]	NA	NA	NA	NA	NA
ERCOT	44,715	45,334	46,536	47,564	48,460
FRCC	48,296	49,464	50,732	51,678	52,869
MAAC[1]	NA	NA	NA	NA	NA
MAIN[1]	NA	NA	NA	NA	NA
MRO (U.S.) [2]	34,113	34,629	35,511	36,109	36,739
NPCC (U.S.)	48,861	49,593	50,357	50,973	51,550
Reliability*First*[3]	154,800	157,300	159,900	162,200	164,700
SERC	167,811	172,167	175,045	177,190	180,906
SPP	29,788	30,431	31,001	31,607	32,159
WECC (U.S.)	107,213	109,443	111,677	114,281	116,508
Contiguous U.S.	**635,597**	**648,361**	**660,759**	**671,602**	**683,891**

[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 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.

Sources: 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, 1994 through 2005
(Megawatts)

Region and Item	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
ECAR[1]												
Net Internal Demand[2]	NA	95,300	98,487	101,251	100,235	98,651	94,072	92,359	91,103	88,573	85,643	84,967
Capacity Resources[3]	NA	127,919	123,755	119,736	113,136	115,379	107,451	105,545	105,106	104,953	103,003	101,605
Capacity Margin (percent)[4]	NA	25.5	20.4	15.4	11.4	14.5	12.5	12.5	13.3	15.6	16.9	16.4
ERCOT												
Net Internal Demand[2]	59,060	58,531	59,282	55,833	55,106	53,649	51,697	50,254	47,746	45,636	44,990	43,630
Capacity Resources[3]	66,724	73,850	74,764	76,849	70,797	69,622	65,423	59,788	55,771	55,230	55,074	54,219
Capacity Margin (percent)[4]	11.5	20.7	20.7	27.3	22.2	22.9	21.0	15.9	14.4	17.4	18.3	19.5
FRCC												
Net Internal Demand[2]	45,950	42,243	40,387	37,951	38,932	35,666	34,832	34,562	32,874	31,868	31,649	30,537
Capacity Resources[3]	50,200	48,579	46,806	43,342	42,290	43,083	40,645	39,708	39,613	38,237	38,282	37,577
Capacity Margin (percent)[4]	8.5	13.0	13.7	12.4	7.9	17.2	14.3	13.0	17.0	16.7	17.3	18.7
MAAC[1]												
Net Internal Demand[2]	NA	52,049	53,566	54,296	54,015	51,358	49,325	47,626	46,548	45,628	45,224	44,571
Capacity Resources[3]	NA	66,167	65,897	63,619	59,533	60,679	57,831	55,511	56,155	56,774	56,881	56,271
Capacity Margin (percent)[4]	NA	21.3	18.7	14.7	9.3	15.4	14.7	14.2	17.1	19.6	20.5	20.8
MAIN[1]												
Net Internal Demand[2]	NA	50,499	53,617	53,267	53,032	51,845	47,165	45,570	45,194	44,470	43,229	42,611
Capacity Resources[3]	NA	65,677	67,410	67,025	65,950	64,170	55,984	52,722	52,160	52,880	52,112	50,963
Capacity Margin (percent)[4]	NA	23.1	20.5	20.5	19.6	19.2	15.8	13.6	13.4	15.9	17.0	16.4
MRO (U.S.)[5]												
Net Internal Demand[2]	38,266	29,094	28,775	28,825	27,125	28,006	30,606	29,766	28,221	27,298	27,487	26,855
Capacity Resources[3]	46,792	35,830	33,287	34,259	32,271	34,236	35,373	34,773	34,027	33,121	32,665	32,267
Capacity Margin (percent)[4]	18.2	18.8	13.6	15.9	15.9	18.2	13.5	14.4	17.1	17.6	15.9	16.8
NPCC (U.S.)												
Net Internal Demand[2]	57,402	51,580	53,936	55,164	55,888	54,270	53,450	51,760	50,240	48,950	48,290	47,465
Capacity Resources[3]	72,258	71,532	70,902	66,208	63,760	63,376	63,077	60,439	60,729	58,592	62,368	61,906
Capacity Margin (percent)[4]	20.6	27.9	23.9	16.7	12.3	14.4	15.3	14.4	17.3	16.5	22.6	23.3
Reliability*First*[6]												
Net Internal Demand[2]	190,200	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Capacity Resources[3]	220,000	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Capacity Margin (percent)[4]	13.5	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
SERC												
Net Internal Demand[2]	186,049	153,024	148,380	154,459	144,399	151,527	142,726	138,146	134,968	109,270	105,785	101,885
Capacity Resources[3]	219,749	182,861	177,231	172,485	171,530	169,760	160,575	158,360	155,016	126,196	127,562	120,044
Capacity Margin (percent)[4]	15.3	16.3	16.3	10.5	15.8	10.7	11.1	12.8	12.9	13.4	17.1	15.1
SPP												
Net Internal Demand[2]	41,079	39,383	39,428	38,298	38,807	39,056	37,807	36,402	37,009	59,017	57,951	56,395
Capacity Resources[3]	46,376	48,000	45,802	47,233	45,530	46,109	43,111	42,554	43,591	69,344	69,354	69,198
Capacity Margin (percent)[4]	11.4	18.0	13.9	18.9	14.8	15.3	12.3	14.5	15.1	14.9	16.4	18.5
WECC (U.S.)												
Net Internal Demand[2]	128,464	121,205	120,894	117,032	107,294	116,913	112,177	111,641	104,486	101,728	99,612	99,724
Capacity Resources[3]	160,026	155,455	150,277	142,624	124,193	141,640	136,274	135,270	135,687	135,049	130,180	127,533
Capacity Margin (percent)[4]	19.7	22.0	19.6	17.9	13.6	17.5	17.7	17.5	23.0	24.7	23.5	21.8
Contiguous U.S.												
Net Internal Demand[2]	**746,470**	**692,908**	**696,752**	**696,376**	**674,833**	**680,941**	**653,857**	**638,086**	**618,389**	**602,438**	**589,860**	**578,640**
Capacity Resources[3]	**882,125**	**875,870**	**856,131**	**833,380**	**788,990**	**808,054**	**765,744**	**744,670**	**737,855**	**730,376**	**727,481**	**711,583**
Capacity Margin (percent)[4]	**15.4**	**20.9**	**18.6**	**16.4**	**14.5**	**15.7**	**14.6**	**14.3**	**16.2**	**17.5**	**18.9**	**18.7**

[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 represents the system demand that is planned for, which is set to equal Internal Demand less Direct Control Load Management and Interruptible Demand by the electric power industry`s reliability authority. See Technical Notes for detailed definitions.
[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.

Sources: 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, 2005 through 2010
(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]
	2005			2006		
ECAR[4]	NA	NA	NA	NA	NA	NA
ERCOT	59,060	66,724	11.5	60,506	70,182	13.8
FRCC	45,950	50,200	8.5	42,761	51,247	16.6
MAAC[4]	NA	NA	NA	NA	NA	NA
MAIN[4]	NA	NA	NA	NA	NA	NA
MRO (U.S.)[5]	38,266	46,792	18.2	39,958	46,954	14.9
NPCC (U.S.)	57,402	72,258	20.6	58,716	70,205	16.4
Reliability*First*[6]	190,200	220,000	13.5	187,500	222,395	15.7
SERC	186,049	219,749	15.3	183,783	221,246	16.9
SPP	41,079	46,376	11.4	40,939	47,847	14.4
WECC (U.S.)	128,464	160,026	19.7	128,225	162,009	20.9
Contiguous U.S.	**746,470**	**882,125**	**15.4**	**742,388**	**892,085**	**16.8**
	2007			2008		
ECAR[4]	NA	NA	NA	NA	NA	NA
ERCOT	62,072	70,384	11.8	63,168	70,191	10.0
FRCC	43,778	52,830	17.1	45,029	53,934	16.5
MAAC[4]	NA	NA	NA	NA	NA	NA
MAIN[4]	NA	NA	NA	NA	NA	NA
MRO (U.S.)[5]	40,630	47,440	14.4	41,526	48,117	13.7
NPCC (U.S.)	59,582	71,950	17.2	60,610	72,390	16.3
Reliability*First*[6]	189,900	220,980	14.1	194,500	220,144	11.6
SERC	187,982	223,103	15.7	193,706	226,119	14.3
SPP	41,694	47,960	13.1	42,399	49,221	13.9
WECC (U.S.)	131,418	162,566	19.2	134,576	162,595	17.2
Contiguous U.S.	**757,056**	**897,213**	**15.6**	**775,514**	**902,711**	**14.1**
	2009			2010		
ECAR[4]	NA	NA	NA	NA	NA	NA
ERCOT	64,800	70,124	7.6	66,398	70,310	5.6
FRCC	46,210	56,470	18.2	47,215	57,579	18.0
MAAC[4]	NA	NA	NA	NA	NA	NA
MAIN[4]	NA	NA	NA	NA	NA	NA
MRO (U.S.)[5]	42,342	48,160	12.1	43,142	48,311	10.7
NPCC (U.S.)	61,624	72,622	15.1	62,623	72,622	13.8
Reliability*First*[6]	197,800	220,144	10.1	200,700	220,066	8.8
SERC	197,248	230,978	14.6	201,233	236,518	14.9
SPP	43,057	48,998	12.1	43,810	51,155	14.4
WECC (U.S.)	137,957	162,588	15.1	141,008	162,553	13.3
Contiguous U.S.	**791,038**	**910,084**	**13.1**	**806,129**	**919,114**	**12.3**

[1] Net Internal Demand represents the system demand that is planned for, which is set to equal Internal Demand less Direct Control Load Management and Interruptible Demand by the electric power industry`s reliability authority. See Technical Notes for detailed definitions.
[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] ECAR, MAAC, and MAIN dissolved at the end-of-2005. Utility membership joined other reliability regional councils. Also, see Footnote 6.
[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: • 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.

Sources: 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, 2005 through 2010
(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]
	2005/ 2006			2006/ 2007		
ECAR[4]	NA	NA	NA	NA	NA	NA
ERCOT	46,991	61,003	23.0	43,565	71,672	39.2
FRCC	42,493	49,066	13.4	44,792	54,658	18.1
MAAC[4]	NA	NA	NA	NA	NA	NA
MAIN[4]	NA	NA	NA	NA	NA	NA
MRO (U.S.)[5]	32,854	44,620	26.4	33,206	44,480	25.3
NPCC (U.S.)	46,328	76,076	39.1	48,631	75,574	35.7
Reliability*First*[6]	151,600	229,000	33.8	152,600	225,023	32.2
SERC	160,054	224,652	28.8	163,098	226,258	27.9
SPP	30,857	47,578	35.1	29,350	48,258	39.2
WECC (U.S.)	105,670	152,211	30.6	105,272	153,973	31.6
Contiguous U.S.	**616,847**	**884,206**	**30.2**	**620,514**	**899,896**	**31.0**
	2007/ 2008			2008/ 2009		
ECAR[4]	NA	NA	NA	NA	NA	NA
ERCOT	44,184	72,642	39.2	45,386	73,329	38.1
FRCC	45,905	57,211	19.8	47,127	58,531	19.5
MAAC[4]	NA	NA	NA	NA	NA	NA
MAIN[4]	NA	NA	NA	NA	NA	NA
MRO (U.S.)[5]	33,717	45,078	25.2	34,592	45,788	24.5
NPCC (U.S.)	49,363	77,304	36.1	50,127	77,746	35.5
Reliability*First*[6]	155,100	224,216	30.8	157,700	223,380	29.4
SERC	167,660	228,036	26.5	170,498	230,521	26.0
SPP	29,973	48,421	38.1	30,540	49,682	38.5
WECC (U.S.)	107,500	155,499	30.9	109,731	155,257	29.3
Contiguous U.S.	**633,402**	**908,407**	**30.3**	**645,701**	**914,234**	**29.4**
	2009/ 2010			2010/ 2011		
ECAR[4]	NA	NA	NA	NA	NA	NA
ERCOT	46,414	72,961	36.4	47,310	72,783	35.0
FRCC	48,088	60,119	20.0	49,257	61,919	20.4
MAAC[4]	NA	NA	NA	NA	NA	NA
MAIN[4]	NA	NA	NA	NA	NA	NA
MRO (U.S.)[5]	35,190	46,370	24.1	35,805	46,566	23.1
NPCC (U.S.)	50,743	77,746	34.7	51,320	77,746	34.0
Reliability*First*[6]	160,100	223,302	28.3	162,600	223,242	27.2
SERC	172,617	235,361	26.7	176,646	238,933	26.1
SPP	31,144	50,221	38.0	31,691	51,495	38.5
WECC (U.S.)	112,330	155,269	27.7	114,553	154,710	26.0
Contiguous U.S.	**656,626**	**921,349**	**28.7**	**669,182**	**927,394**	**27.8**

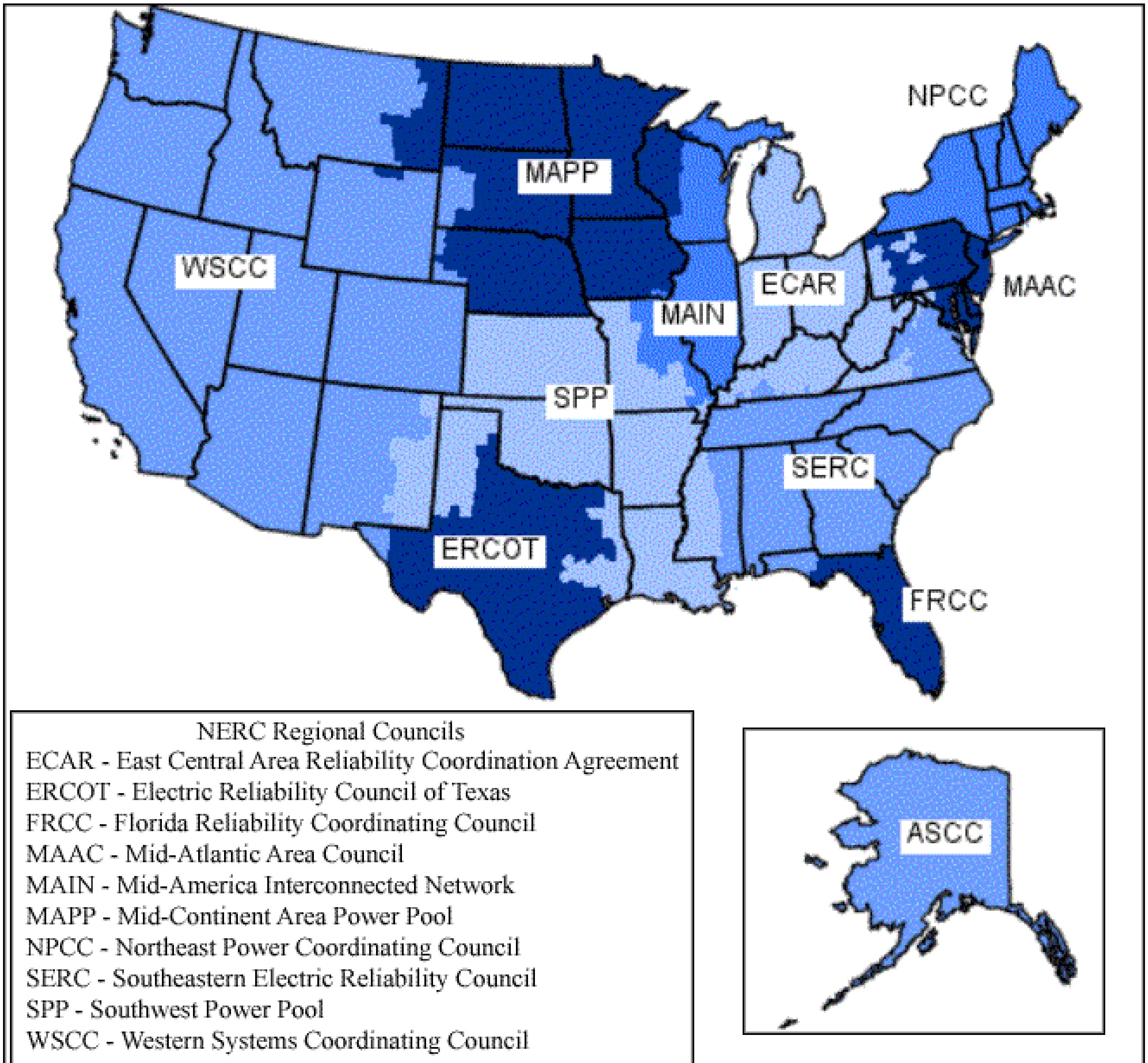
[1] Net Internal Demand represents the system demand that is planned for, which is set to equal Internal Demand less Direct Control Load Management and Interruptible Demand by the electric power industry`s reliability authority. See Technical Notes for detailed definitions.
[2] Capacity Resources: Utility- 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] ECAR, MAAC, and MAIN dissolved at the end-of-2005. Utility membership joined various other reliability regional councils.
[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: • 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 end-of-February of the following year. For example, winter 2004/2005 begins December 1, 2004, and extends 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.

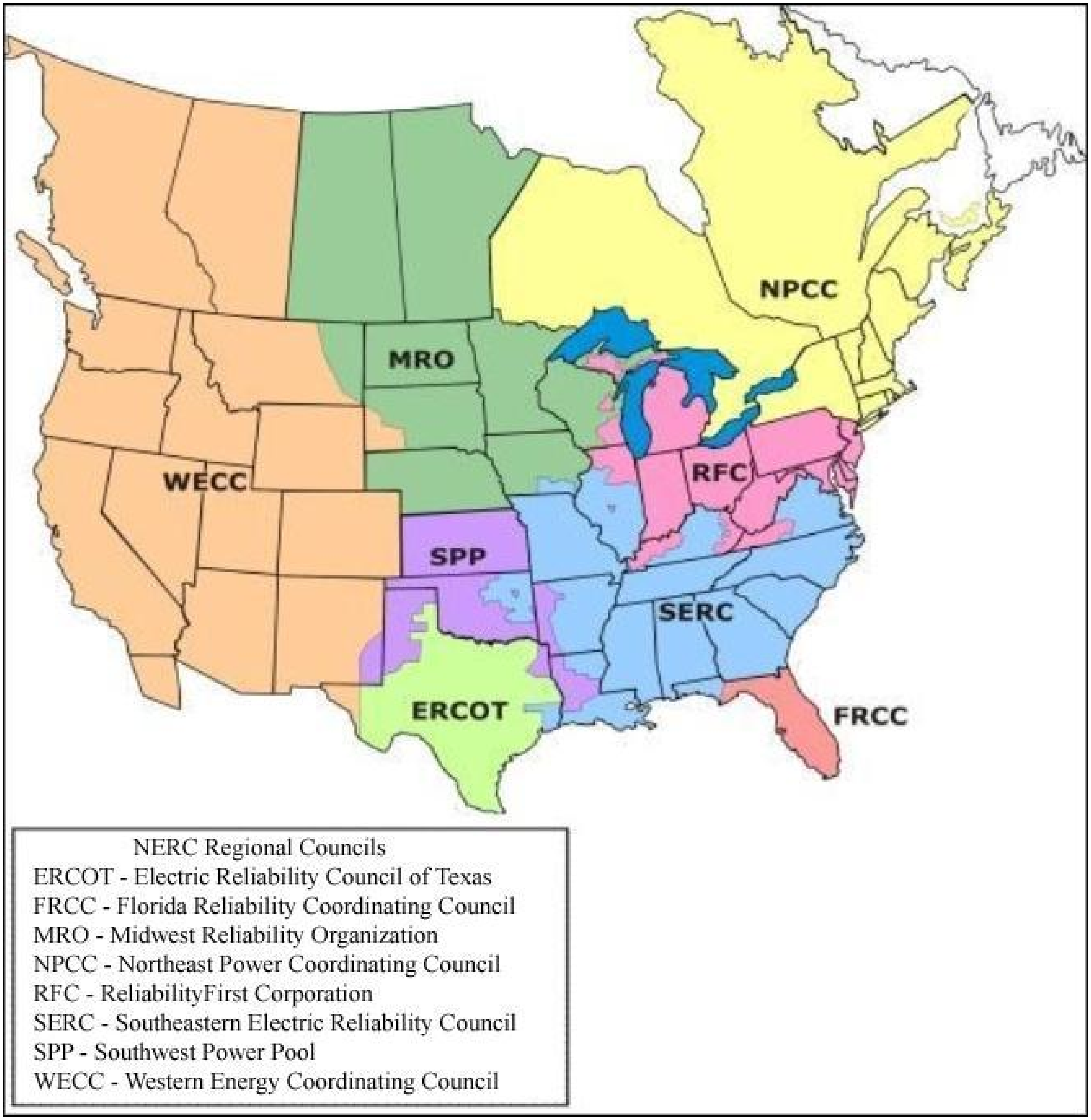
Sources: Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program."

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 Council Regions, 2006



Chapter 4. Fuel

Table 4.1. Consumption of Fossil Fuels for Electricity Generation by Type of Power Producer, 1994 through 2005

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)				
1994	848,796	183,618	4,367,148	136,381
1995	860,594	132,578	4,737,871	132,520
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]	1,026,018	209,508	6,116,574	186,796
2005	1,045,878	211,256	6,486,761	176,906
Electricity Generators, Electric Utilities				
1994	817,270	155,377	2,987,146	--
1995	829,007	105,956	3,196,507	--
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[R]	1,809,443[R]	5,163
2005	783,548	120,920	2,138,809	91
Electricity Generators, Independent Power Producers				
1994	3,939	1,998	77,414	96
1995	3,921	2,342	91,064	87
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[R]	63,060[R]	2,332,092[R]	86
2005	232,092	70,907	2,453,462	43
Combined Heat and Power, Electric Power				
1994	14,904	12,011	693,923	11,928
1995	14,926	11,366	806,202	18,080
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	20,306[R]	10,620[R]	1,164,328[R]	33,202
2005	20,500	10,099	1,132,641	43,941
Combined Heat and Power, Commercial				
1994	404	694	40,828	1,172
1995	569	649	42,700	--
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	602	1,188	45,883[R]	--
2005	770	939	47,851	--
Combined Heat and Power, Industrial				
1994	12,279	13,537	567,836	123,185
1995	12,171	12,265	601,397	114,353
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	10,337	10,100[R]	764,828[R]	148,345[R]
2005	8,969	8,392	713,999	132,831

[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.
* = Value is less than half of the smallest unit of measure.
R = Revised.
Note: See Glossary reference for definitions.
Sources: Energy Information Administration, Form EIA-906, "Power Plant Report;" Energy Information Administration, 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, 1994 through 2005

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				
1994	20,609	27,929	784,015	179,595
1995	20,418	25,562	834,382	180,895
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[R]
2004[R]	18,779	19,856	610,105	167,273
2005	19,402	19,937	541,206	171,406
Electric Power[4]				
1994	2,241	1,791	144,062	6,487
1995	2,376	2,784	142,753	5,430
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]	1,189	277	157,900	20,054[R]
2005	1,345	258	144,233	39,918
Commercial				
1994	940	931	31,457	215
1995	850	596	34,964	--
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	1,315	821	26,189[R]	--
2005	1,151	691	27,364	--
Industrial				
1994	17,428	25,207	608,496	172,893
1995	17,192	22,182	656,665	175,465
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[R]
2004	16,276	18,758	426,016[R]	147,219
2005	16,906	18,987	369,609	131,488

[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.

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

Sources: Energy Information Administration, Form EIA-906, "Power Plant Report;" Energy Information Administration, 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, 1994 through 2005

Period	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Natural Gas (Thousand Mcf)	Other Gases (Million Btu)[3]
Total (All Sectors)				
1994	869,405	211,547	5,151,163	315,976
1995	881,012	158,140	5,572,253	313,415
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	229,364R	6,726,679R	354,069R
2005	1,065,281	231,193	7,027,967	348,312
Electricity Generators, Electric Utilities				
1994	817,270	155,377	2,987,146	--
1995	829,007	105,956	3,196,507	--
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	5,182R
2003	757,384	118,087	1,763,764	6,078
2004	772,224	124,541R	1,809,443R	5,163
2005	783,548	120,920	2,138,809	91
Electricity Generators, Independent Power Producers				
1994	3,939	1,998	77,414	96R
1995	3,921	2,342	91,064	87R
1996	4,143	2,169	91,617	71R
1997	3,884	4,010	70,774	642R
1998	9,486	9,676	285,878	1,345R
1999	30,572	30,037	615,756	696R
2000	107,745	45,011	1,049,636	1,951R
2001	139,799	60,489	1,477,643	92R
2002	192,274	44,993	1,998,782	354R
2003	226,154	68,817	2,016,550	171
2004	222,550	63,060	2,332,092R	86
2005	232,092	70,907	2,453,462	43
Combined Heat and Power, Electric Power				
1994	17,145	13,803	837,985	18,415
1995	17,302	14,149	948,954	23,510
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	53,256R
2005	21,845	10,357	1,276,874	83,859
Combined Heat and Power, Commercial				
1994	1,344	1,625	72,285	1,387
1995	1,419	1,245	77,664	--
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	75,215	--
Combined Heat and Power, Industrial				
1994	29,707	38,744	1,176,332	296,078
1995	29,363	34,448	1,258,063	289,818
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	252,975R
2004	26,613	28,857	1,190,844R	295,564R
2005	25,875	27,380	1,083,607	264,319

[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.
* = 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-906, "Power Plant Report;" Energy Information Administration, 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, 1994 through 2005

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]
1994	126,897	63,333	126,897	63,333	NA	NA
1995	126,304	50,821	126,304	50,821	NA	NA
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	80,265	31,569	20,871	18,493

[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.

Source: Energy Information Administration, Form EIA-906, "Power Plant Report;" Energy Information Administration, 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, 1994 through 2005

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/ 10^6 Btu)	(dollars/ ton)		(thousand barrels)	(cents/ 10^6 Btu)	(dollars/ barrel)		(thousand Mcf)	(cents/ 10^6 Btu)	(cents/ 10^6 Btu)
1994	831,929	136	28.03	1.17	149,258	242	15.19	1.23	2,863,904	223	152
1995	826,860	132	27.01	1.08	89,908	257	16.10	1.21	3,023,327	198	145
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	152
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[R]
2005	1,021,437[R]	154	31.20[R]	.98	194,733	644	39.65	1.61	6,191,389[R]	821	326

[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 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 FERC Form 423.
R = Revised.
Notes: • 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, 1994 through 2005

Period	Anthracite[1]			Bituminous[1]			Subbituminous			Lignite		
	Receipts (Thousand Tons)	Sulfur percent by weight	Ash percent by weight	Receipts (Thousand Tons)	Sulfur percent by weight	Ash percent by weight	Receipts (Thousand Tons)	Sulfur percent by weight	Ash percent by weight	Receipts (Thousand Tons)	Sulfur percent by weight	Ash percent by weight
1994	689	.56	36.8	456,733	1.69	10.1	295,752	.41	6.9	78,756	.94	13.8
1995	857	.53	37.4	432,586	1.60	10.2	316,195	.39	6.7	77,222	.99	14.0
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[R]	.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[R]	1.55[R]	10.5[R]	456,856	.36	6.2	77,677	1.02	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 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 FERC Form 423.
R = Revised.
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, 1994 through 2005

Year	Coal[1]			Petroleum[2]		Natural Gas[3]
	Average Btu per Pound	Sulfur Percent by Weight	Ash Percent by Weight	Average Btu per Gallon	Sulfur Percent by Weight	Average Btu per Cubic Foot
1994	10,338	1.17	9.36	149,324	1.23	1,023
1995	10,248	1.08	9.23	149,371	1.21	1,019
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[R]	.94	8.74	147,902[R]	1.64	1,025[R]
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[R]	.98	9.02[R]	146,481	1.61	1,028

[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 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 FERC Form 423.
R = Revised.

Notes: • 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."

Chapter 5. Emissions

Table 5.1. Emissions from Energy Consumption at Conventional Power Plants and Combined-Heat-and-Power Plants, 1994 through 2005
(Thousand Metric Tons)

Emission	2005	2004[R]	2003[R]	2002[R]	2001[R]	2000	1999	1998	1997	1996[R]	1995	1994
Carbon Dioxide (CO_2)	2,513,609	2,456,934	2,415,680	2,395,048	2,389,745	2,429,394	2,326,559[R]	2,313,008[R]	2,223,348[R]	2,155,452	2,079,761	2,063,788
Sulfur Dioxide (SO_2)	10,340	10,309	10,646	10,881	11,174	11,297	12,444[R]	12,509	13,520[R]	12,906	11,896[R]	14,472[R]
Nitrogen Oxides (NO_x)	3,961	4,143	4,532	5,194	5,290	5,380	5,732	6,237[R]	6,324	6,282	7,885	7,801[R]

R = Revised.

Note: See Appendix A, Technical Notes, for a description of the sources and methodology used to develop the emissions estimates.

Table 5.2. Number and Capacity of Fossil-Fueled Steam-Electric Generators with Environmental Equipment, 1994 through 2005

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)
1994	168	80,617	1,135	351,180	480	165,452	1,309	376,899
1995	178	84,677	1,134	351,198	471	165,295	1,295	375,691
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

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

[2] Nameplate capacity

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 plant 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, 1994 through 2005

Year	Average Overhead & Maintenance Costs (mills per kilowatthour)[1]	Average Installed Capital Costs (dollars per kilowatt)
1994	1.14	127.00
1995	1.16	126.00
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

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

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 - Purchases, 1994 through 2005
(Thousand Megawatthours)

	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
U.S. Total	**2,847,195**	**2,829,350[R]**	**2,715,567[R]**	**2,704,648[R]**	**3,143,211[R]**	**2,345,540**	**2,039,969**	**2,020,622**	**1,966,447**	**1,797,720**	**1,617,715**	**1,528,222**
Electric Utilities	2,760,043	2,725,694[R]	2,610,525[R]	2,620,712[R]	3,045,854[R]	2,250,382	1,949,574	1,927,198	1,878,099	1,694,192	1,528,068	1,435,591
IPP	12,829	25,623	37,921	15,801	97,357	10,622	4,358	4,089	1,647	7,713	3,760	4,221
CHP	74,323	78,033	67,122	68,135	NA[1]	84,536	86,037	89,334	86,701	95,814	85,887	88,410

[1] For 2001, CHP purchases are combined with IPP data above.

NA = Not available. R = Revised.

Notes: • 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.

Sources: 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.

Table 6.2. Electric Power Industry - Sales for Resale, 1994 through 2005
(Thousand Megawatthours)

	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
U.S. Total	**3,246,376**	**3,012,730[R]**	**3,014,734[R]**	**2,811,395[R]**	**2,958,687[R]**	**2,355,154**	**1,998,090**	**1,921,858**	**1,838,539**	**1,656,090**	**1,495,015**	**1,387,966**
Electric Utilities	1,925,710	1,923,440[R]	1,824,030[R]	1,838,901[R]	2,146,689[R]	1,715,582	1,635,614	1,664,081	1,616,318	1,431,179	1,276,356	1,185,352
IPP	1,293,559	1,063,965	1,156,796	943,531	811,998	611,150	335,122	228,617	192,299	194,361	187,453	168,927
CHP	27,107	25,326	33,909	28,963	NA[1]	28,421	27,354	29,160	29,922	30,550	31,206	33,687

[1] For 2001, CHP sales are combined with IPP data above.

NA = Not available. R = Revised.

Notes: • 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.

Sources: 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.

Table 6.3. Electric Power Industry - U.S. Electricity Imports from and Electricity Exports to Canada and Mexico, 1994 through 2005
(Megawatthours)

Description	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
Electricity Imports and Exports												
Canada												
Imports	42,930,212	33,007,487[R]	29,319,707	36,536,479[R]	38,401,598	48,515,476	42,911,308	39,502,108	43,008,501	42,233,376	40,596,119	44,821,858
Exports	19,332,124	22,482,109	23,582,184	15,231,079[R]	16,105,612	12,684,706	12,953,488	11,683,276	7,470,332	1,986,361	2,468,244	941,214
Mexico												
Imports[1]	1,597,275	1,202,576	1,069,926	242,596[R]	98,649	76,800	303,439	11,249	22,729	1,263,152	2,257,411	2,011,319
Exports	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	1,154,421	1,068,668
Total Imports	**44,527,487**	**34,210,063[R]**	**30,389,633**	**36,779,077[R]**	**38,500,247**	**48,592,276**	**43,214,747**	**39,513,357**	**43,031,230**	**43,496,528**	**42,853,530**	**46,833,177**
Total Exports	**19,802,855**	**22,897,863**	**23,972,374**	**15,795,681[R]**	**16,473,292**	**14,829,382**	**14,221,772**	**13,656,479**	**8,974,039**	**3,301,986**	**3,622,665**	**2,009,882**

[1] Includes contract terminations in 1997 and 2000.

R = Revised.

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

Sources: Canada: National Energy Board of Canada; Mexico: Office of Fuels Programs, Fossil Energy, Form FE-781R, "Annual Report of International Electric Export/Import Data," Data provided by the California - ISO.

Chapter 7. Retail Customers, Sales, and Revenue

Table 7.1. Number of Ultimate Customers Served by Sector, by Provider, 1994 through 2005
(Number)

Period	Residential	Commercial	Industrial	Transportation	Other	All Sectors
Total Electric Industry						
1994	102,320,846	12,733,153	583,935	NA	850,770	116,488,704
1995	103,917,312	12,949,365	580,626	NA	882,422	118,329,725
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[R]	NA	136,119,176[R]
2005	120,760,839	16,871,940	733,862	518	NA	138,367,159
Full-Service Providers[1]						
1994	102,320,846	12,733,153	583,935	NA	850,770	116,488,704
1995	103,917,312	12,949,365	580,626	NA	882,422	118,329,725
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[R]	14,364,578[R]	553,280[R]	NA	1,004,027[R]	128,394,514[R]
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
Energy-Only Providers						
1994	--	--	--	--	--	--
1995	--	--	--	--	--	--
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[R]	502,912[R]	18,183[R]	NA	26,019[R]	2,964,725[R]
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[R]	NA	2,897,410[R]
2005	2,290,911	482,391	14,643	22	NA	2,787,967

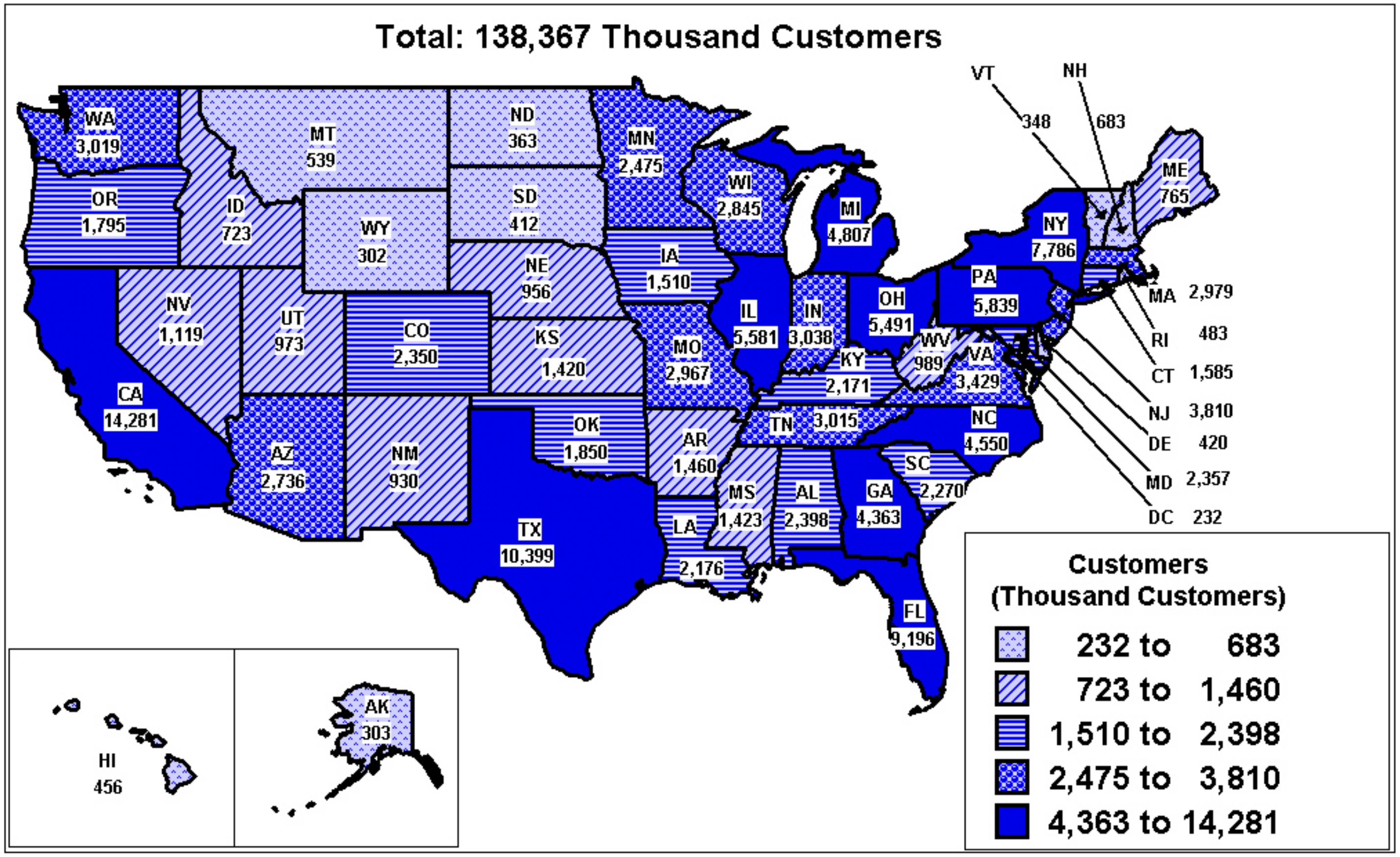
[1] Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas, all customers served by Retail Energy Providers must be provided fully-bundled energy and delivery services, so they are included under "Full-Service Providers."

NA = Not available. R = Revised.

Note: See Technical Notes reference for definitions.

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

Figure 7.1. U.S. Electric Industry Total Ultimate Customers by State, 2005



Note: Data is 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, 1994 through 2005
(Megawatthours)

Period	Sales						Direct Use[1]	Total End Use
	Residential	Commercial	Industrial	Trans-portation	Other	Total		
Total Electric Industry								
1994	1,008,481,682	820,269,462	1,007,981,245	NA	97,830,475	2,934,562,864	146,325,334	3,080,888,198
1995	1,042,501,471	862,684,775	1,012,693,350	NA	95,406,993	3,013,286,589	150,676,540	3,163,963,129
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 R	1,083,068,516 R	996,609,310 R	NA	113,173,685 R	3,394,458,104 R	162,648,615	3,557,106,719 R
2002	1,265,179,869 R	1,104,496,607 R	990,237,631 R	NA	105,551,904 R	3,465,466,011 R	166,184,296	3,631,650,307 R
2003	1,275,823,910 R	1,198,727,601 R	1,012,373,247 R	6,809,728	NA	3,493,734,486 R	168,294,526	3,662,029,012 R
2004	1,291,981,578 R	1,230,424,731 R	1,017,849,532 R	7,223,642 R	NA	3,547,479,483 R	168,470,002	3,715,949,485 R
2005	1,359,227,107	1,275,079,020	1,019,156,065	7,506,321	NA	3,660,968,513	154,700,367	3,815,668,880
Full-Service Providers[2]								
1994	1,008,481,682	820,269,462	1,007,981,245	NA	97,830,475	2,934,562,864	NA	2,934,562,864
1995	1,042,501,471	862,684,775	1,012,693,350	NA	95,406,993	3,013,286,589	NA	3,013,286,589
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 R	1,037,998,484 R	961,812,417 R	NA	108,632,086 R	3,296,662,577 R	NA	3,296,662,577 R
2002	1,248,349,458 R	1,036,366,268 R	937,138,192 R	NA	102,238,786 R	3,324,092,704 R	NA	3,324,092,704 R
2003	1,257,766,998 R	1,112,206,121 R	931,661,404 R	3,315,043	NA	3,304,949,566 R	NA	3,304,949,566 R
2004	1,272,237,425 R	1,116,497,417 R	933,529,502 R	3,188,466 R	NA	3,325,452,810 R	NA	3,325,452,810 R
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
Energy-Only Providers								
1994	--	--	--	--	--	--	--	--
1995	--	--	--	--	--	--	--	--
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 R	45,070,032 R	34,796,893 R	NA	4,541,599 R	97,795,527 R	NA	97,795,527 R
2002	16,830,411 R	68,130,339 R	53,099,439 R	NA	3,313,118 R	141,373,307 R	NA	141,373,307 R
2003	18,056,912 R	86,521,480 R	80,711,843 R	3,494,685	NA	188,784,920 R	NA	188,784,920 R
2004	19,744,153 R	113,927,314 R	84,320,030 R	4,035,176 R	NA	222,026,673 R	NA	222,026,673 R
2005	19,658,832	123,751,159	89,480,133	4,164,507	NA	237,054,631	NA	237,054,631

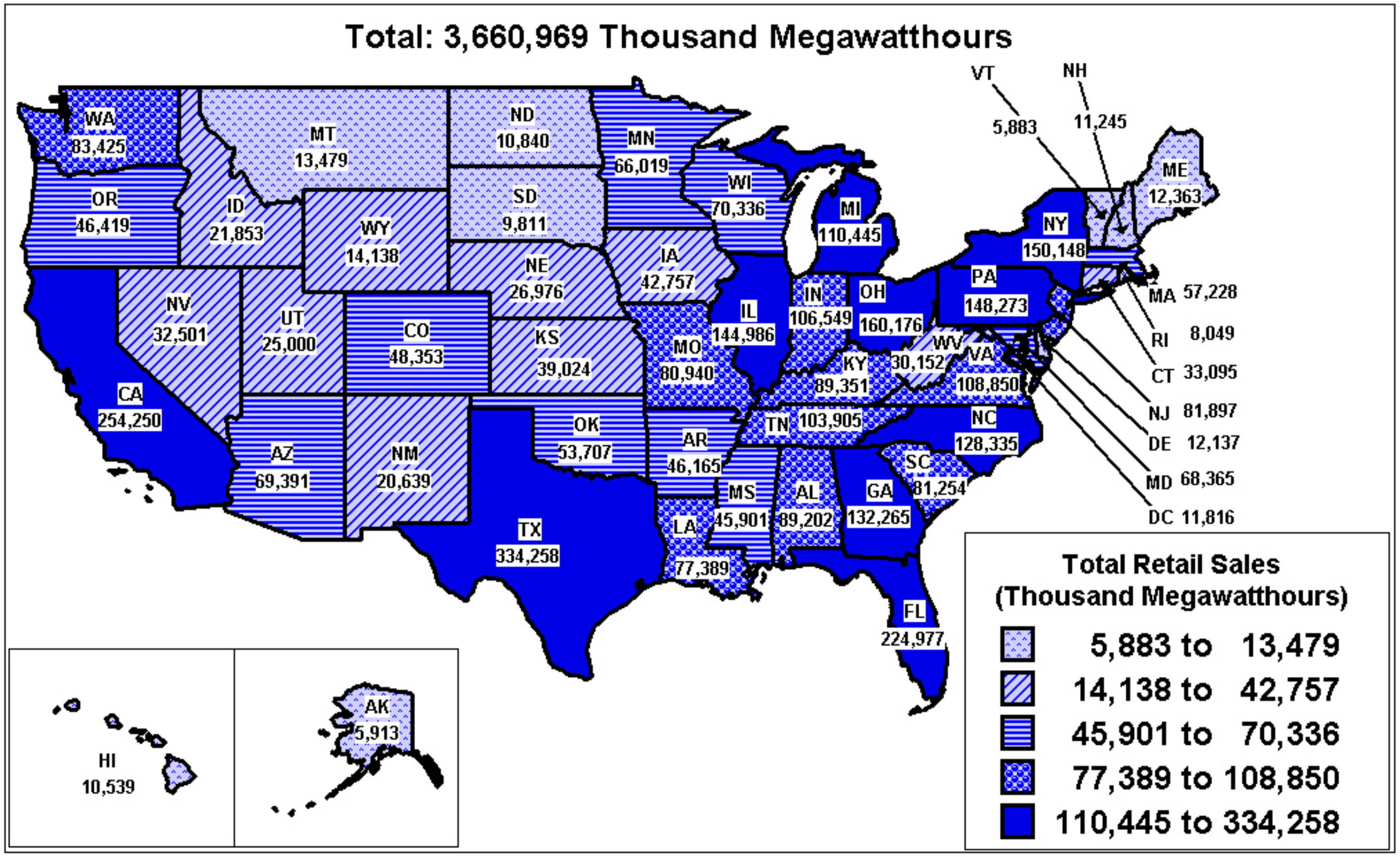
[1] Direct Use represents commercial and industrial facility use of onsite net electricity generation; and electricity sales or transfers to adjacent or co-located facilities for which revenue information is not available.
[2] Pursuant to applicable Texas statutes establishing competitive electricity 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. R = Revised.

Note: See Technical Notes reference for definitions.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report;" Energy Information Administration, Form EIA-906, "Power Plant Report;" Energy Information Administration, Forma EIA-920 "Combined Heat and Power Plant Report;"

Figure 7.2. U.S. Electric Industry Total Retail Sales by State, 2005



Note: Data is 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 7.3. Revenue from Retail Sales of Electricity to Ultimate Customers by Sector, by Provider, 1994 through 2005
(Million Dollars)

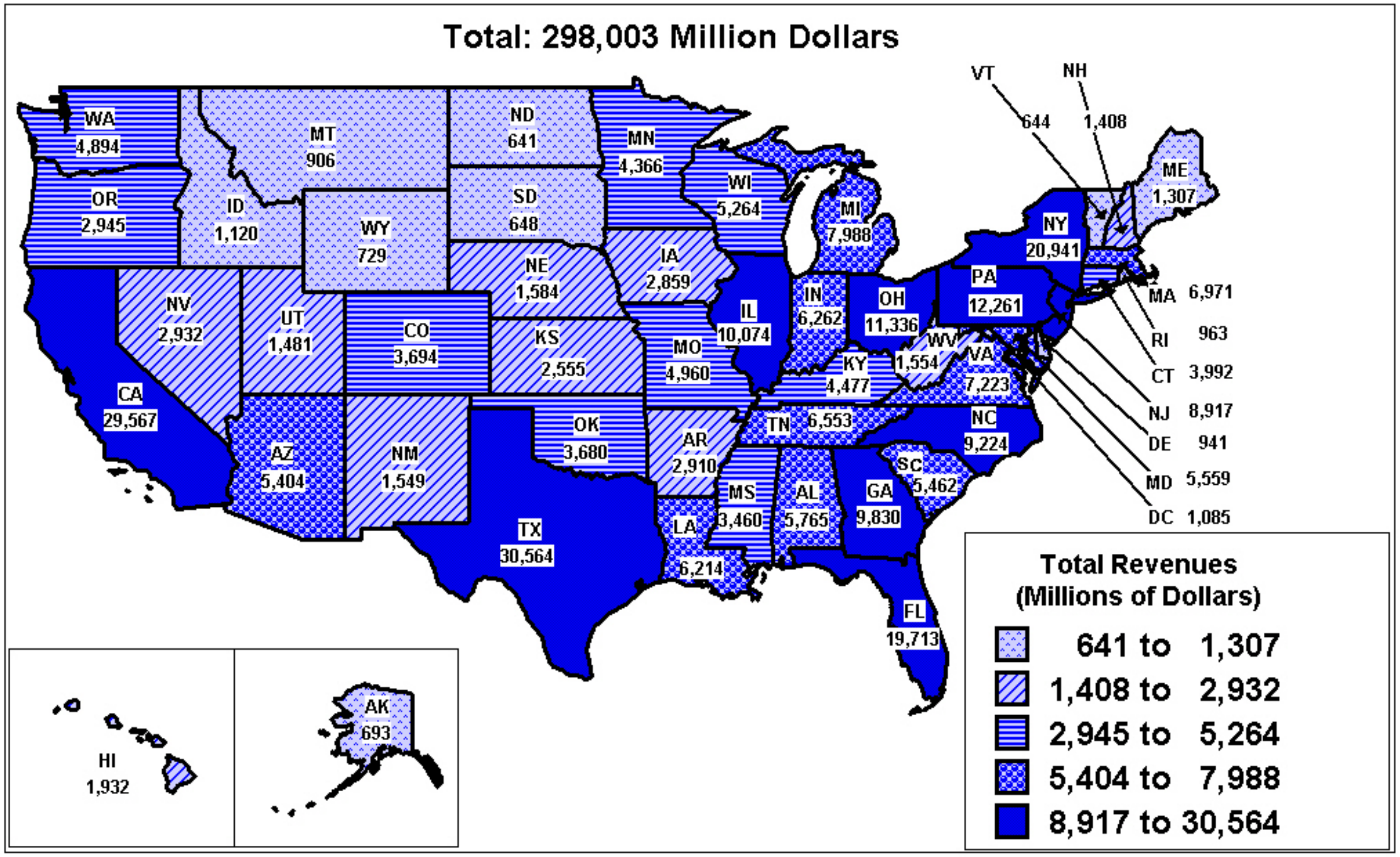
Period	Residential	Commercial	Industrial	Transportation	Other	All Sectors
Total Electric Industry						
1994	84,552	63,396	48,069	NA	6,689	202,706
1995	87,610	66,365	47,175	NA	6,567	207,717
1996	90,503	67,829	47,536	NA	6,741	212,609
1997	90,704	70,497	47,023	NA	7,110	215,334
1998	93,360	72,575	47,050	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	103,158R	85,741R	50,293R	NA	8,151R	247,343R
2002	106,834R	87,117R	48,336R	NA	7,124R	249,411R
2003	111,249R	96,263R	51,741R	514	NA	259,767R
2004	115,577R	100,546R	53,477R	519R	NA	270,119R
2005	128,393	110,522	58,445	643	NA	298,003
Full-Service Providers						
1994	84,552	63,396	48,069	NA	6,689	202,706
1995	87,610	66,365	47,175	NA	6,567	207,717
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	101,541R	81,385R	48,182R	NA	7,766R	238,874R
2002	104,814R	80,573R	44,826R	NA	6,803R	237,014R
2003	109,165R	87,764R	46,686R	226	NA	243,841R
2004[1]	113,306R	89,597R	47,993R	238R	NA	251,134R
2005	125,983	97,405	52,113	249	NA	275,749
Energy-Only Providers[2]						
1994	--	--	--	--	--	--
1995	--	--	--	--	--	--
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	714R	2,806R	1,632R	NA	237R	5,390R
2002	914R	3,989R	2,408R	NA	143R	7,454R
2003	980R	5,210R	3,605R	215R	NA	10,011R
2004	1,086R	6,859R	3,881R	201R	NA	12,027R
2005	1,285	8,844	4,749	308	NA	15,186
Delivery-Only Service						
1994	--	--	--	--	--	--
1995	--	--	--	--	--	--
1996	--	--	--	--	--	--
1997	--	--	--	--	--	--
1998	--	--	--	--	--	--
1999	--	--	--	--	--	--
2000	593	1,527	531	NA	116	2,767
2001	903R	1,551R	479R	NA	147R	3,080R
2002	1,106R	2,556R	1,102R	NA	178R	4,942R
2003	1,104R	3,289R	1,450R	72	NA	5,915R
2004	1,186R	4,090R	1,603R	79R	NA	6,958R
2005	1,125	4,273	1,584	86	NA	7,068

[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 estimated based on retail sales reported on the Form EIA-861.
NA = Not available. R = Revised.

Notes: • See Technical Notes reference for definitions. • 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, 2005



Note: Data is 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 7.4. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, 1994 through 2005

(Cents per kilowatthour)

Period	Residential	Commercial	Industrial	Transportation	Other	All Sectors
Total Electric Industry						
1994	8.38	7.73	4.77	NA	6.84	6.91
1995	8.40	7.69	4.66	NA	6.88	6.89
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[R]	7.92[R]	5.05[R]	NA	7.20[R]	7.29[R]
2002	8.44[R]	7.89[R]	4.88[R]	NA	6.75	7.20[R]
2003	8.72[R]	8.03[R]	5.11[R]	7.54[R]	NA	7.44[R]
2004	8.95[R]	8.17[R]	5.25[R]	7.18[R]	NA	7.61[R]
2005	9.45	8.67	5.73	8.57	NA	8.14
Full-Service Providers[1]						
1994	8.38	7.73	4.77	NA	6.84	6.91
1995	8.40	7.69	4.66	NA	6.88	6.89
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[R]	7.84	5.01[R]	NA	7.15[R]	7.25[R]
2002	8.40[R]	7.77[R]	4.78[R]	NA	6.65[R]	7.13[R]
2003	8.68[R]	7.89[R]	5.01[R]	6.82	NA	7.38[R]
2004	8.91[R]	8.02[R]	5.14[R]	7.47[R]	NA	7.55[R]
2005	9.40	8.46	5.61	7.45	NA	8.05
Energy-Only Providers[2]						
1994	--	--	--	--	--	--
1995	--	--	--	--	--	--
1996	8.36	7.64	4.60	NA	--	6.86
1997	8.43	7.59	4.53	NA	--	6.85
1998	8.26	7.41	4.48	NA	--	6.74
1999	8.16	7.26	4.43	NA	6.35	6.66
2000	12.07	8.65	6.24	NA	11.42	7.97
2001	5.34[R]	6.22[R]	4.69[R]	NA	5.23[R]	5.51[R]
2002	5.43[R]	5.86[R]	4.53[R]	NA	4.30[R]	5.27[R]
2003	5.43[R]	6.02[R]	4.47[R]	6.16[R]	NA	5.30[R]
2004	5.50[R]	6.02[R]	4.60[R]	4.99[R]	NA	5.42[R]
2005	6.54	7.15	5.31	7.40	NA	6.41
Delivery-Only Service						
1994	--	--	--	--	--	--
1995	--	--	--	--	--	--
1996	--	--	--	--	--	--
1997	--	--	--	--	--	--
1998	--	--	--	--	--	--
1999	--	--	--	--	--	--
2000	--	--	--	--	--	--
2001	6.74[R]	3.44[R]	1.38[R]	--	3.24[R]	3.15[R]
2002	6.57[R]	3.75[R]	2.08[R]	--	5.39[R]	3.50[R]
2003	6.11[R]	3.80[R]	1.80[R]	2.07	--	3.13[R]
2004	6.00[R]	3.59[R]	1.90[R]	1.96[R]	NA	3.13[R]
2005	5.72	3.45	1.77	2.07	NA	2.98

[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."

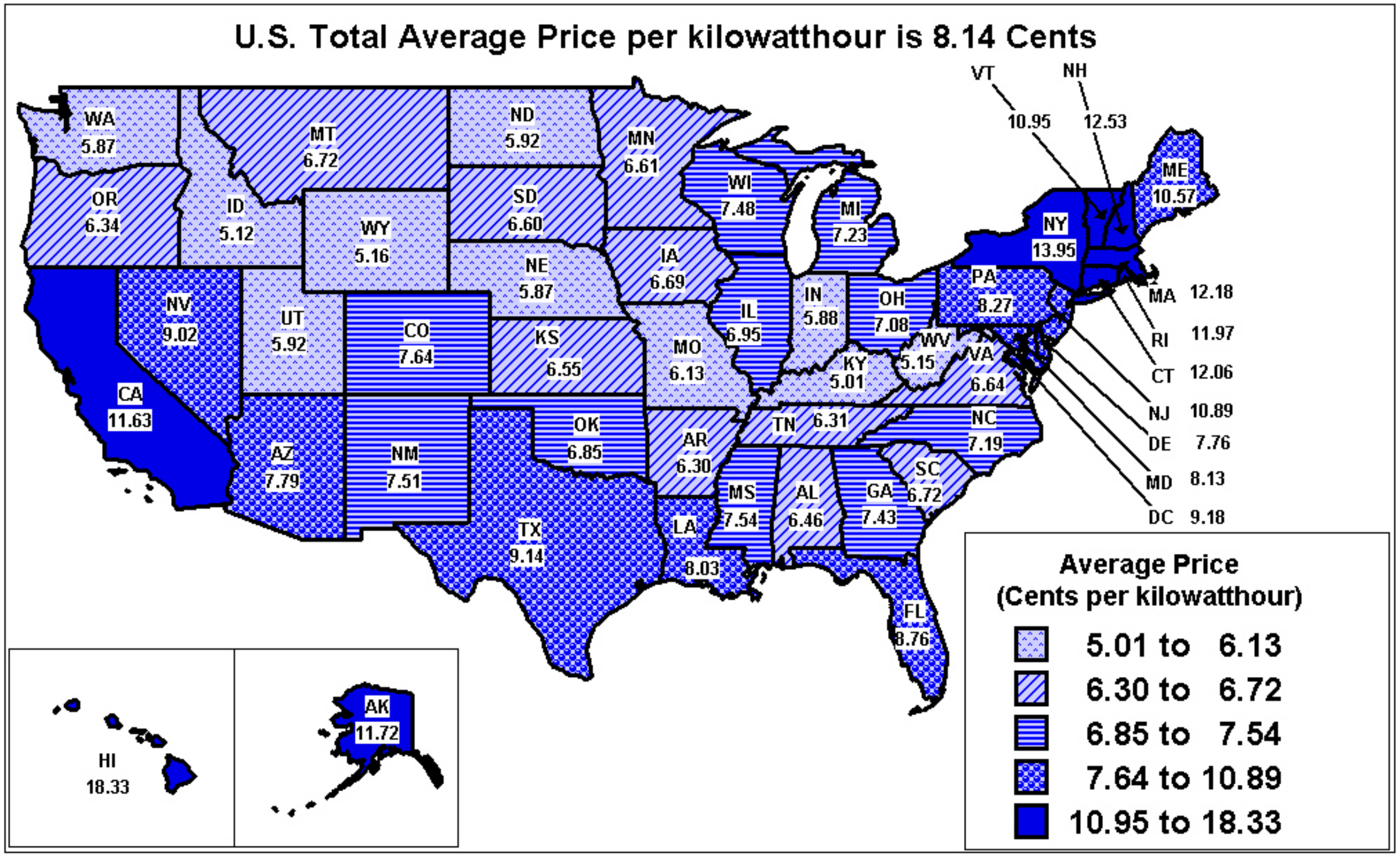
[2] From 1996 to 1999, average revenue estimated based on retail sales reported on the Form EIA-861.

NA = Not available. R = Revised.

Note: See Glossary reference for definitions.

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

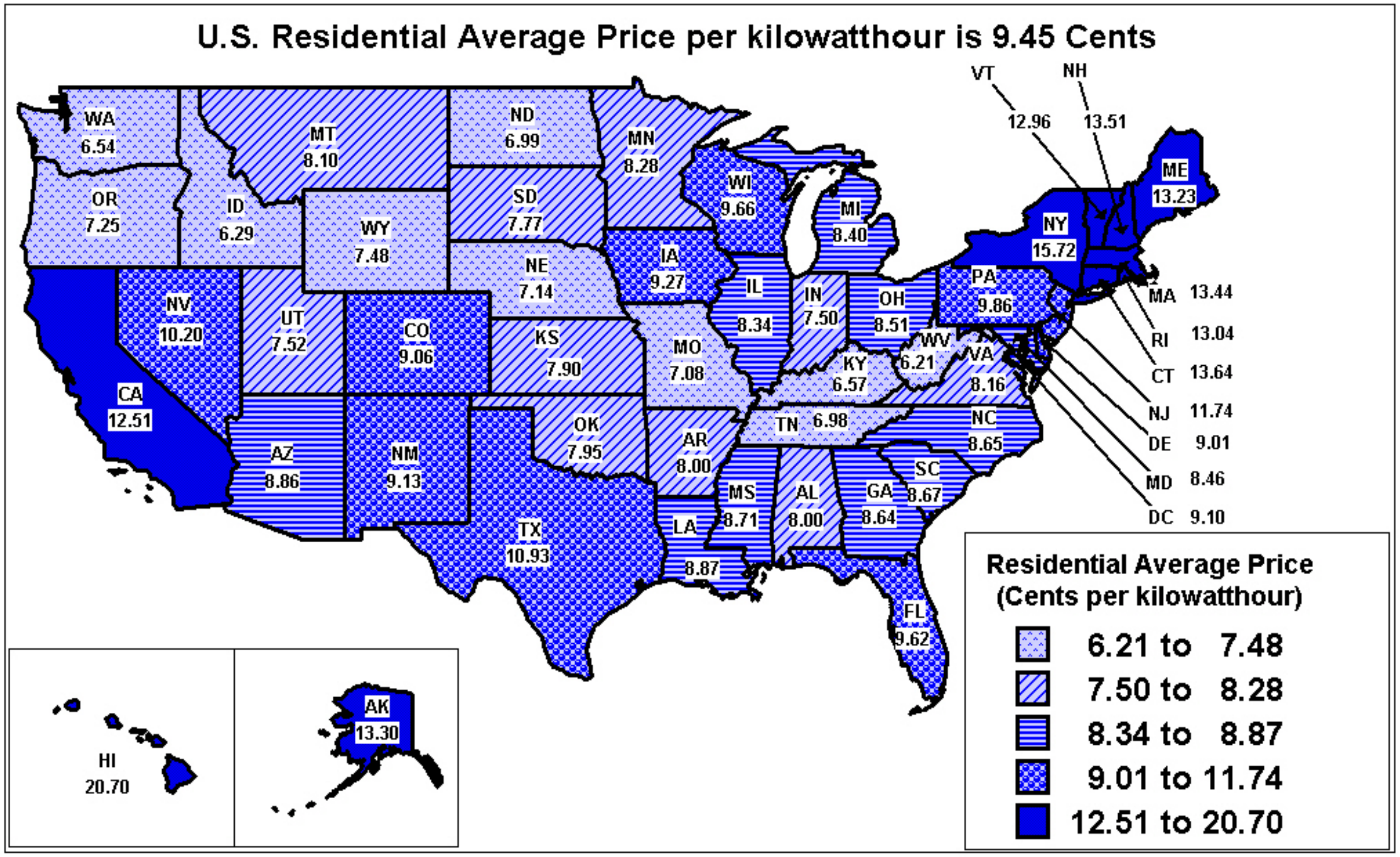
Figure 7.4. Average Retail Price of Electricity by State, 2005



Note: Data is displayed as 5 groups of 10 States and the District of Columbia.

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

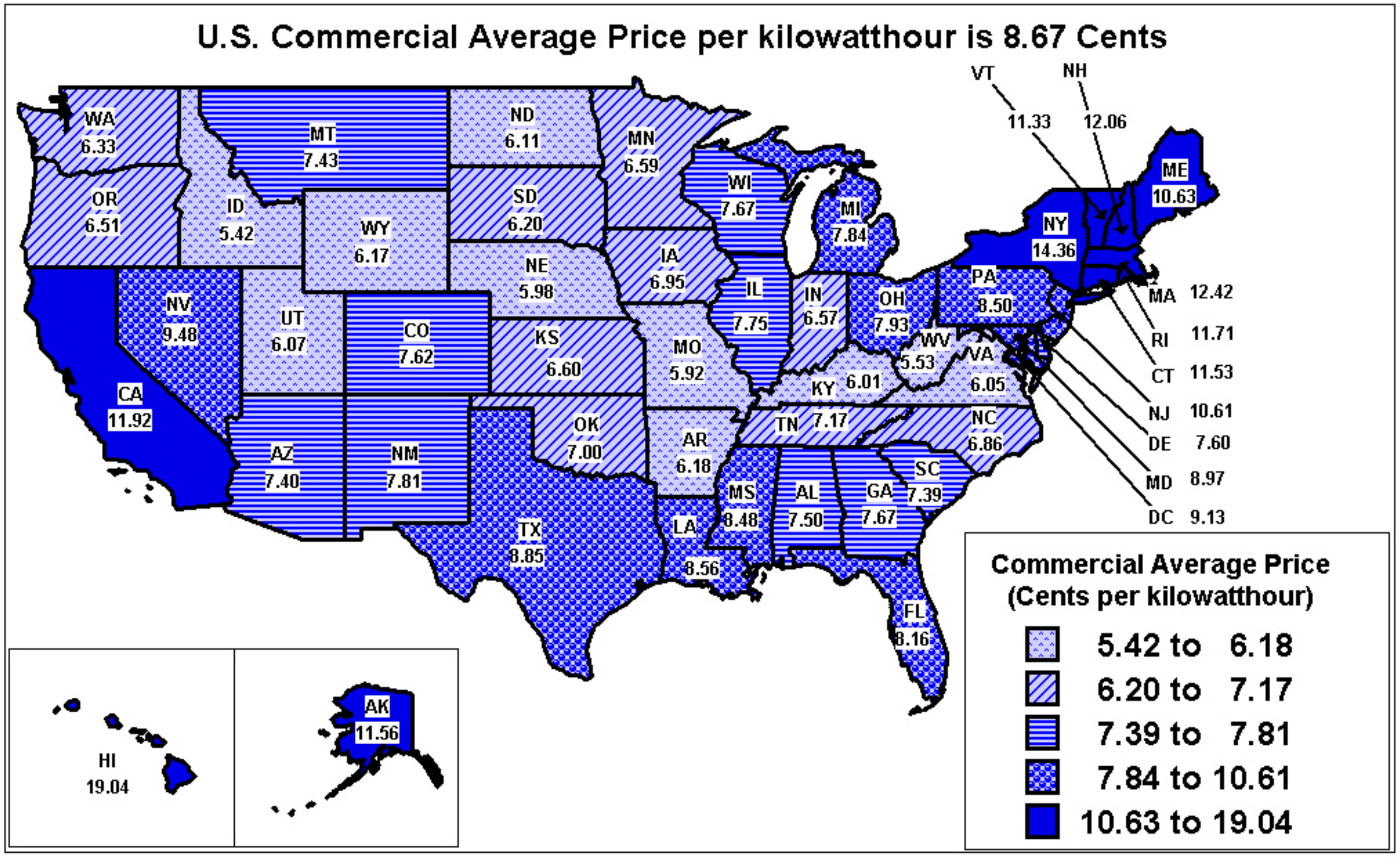
Figure 7.5. Average Residential Price of Electricity by State, 2005



Note: Data is displayed as 5 groups of 10 States and the District of Columbia.

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

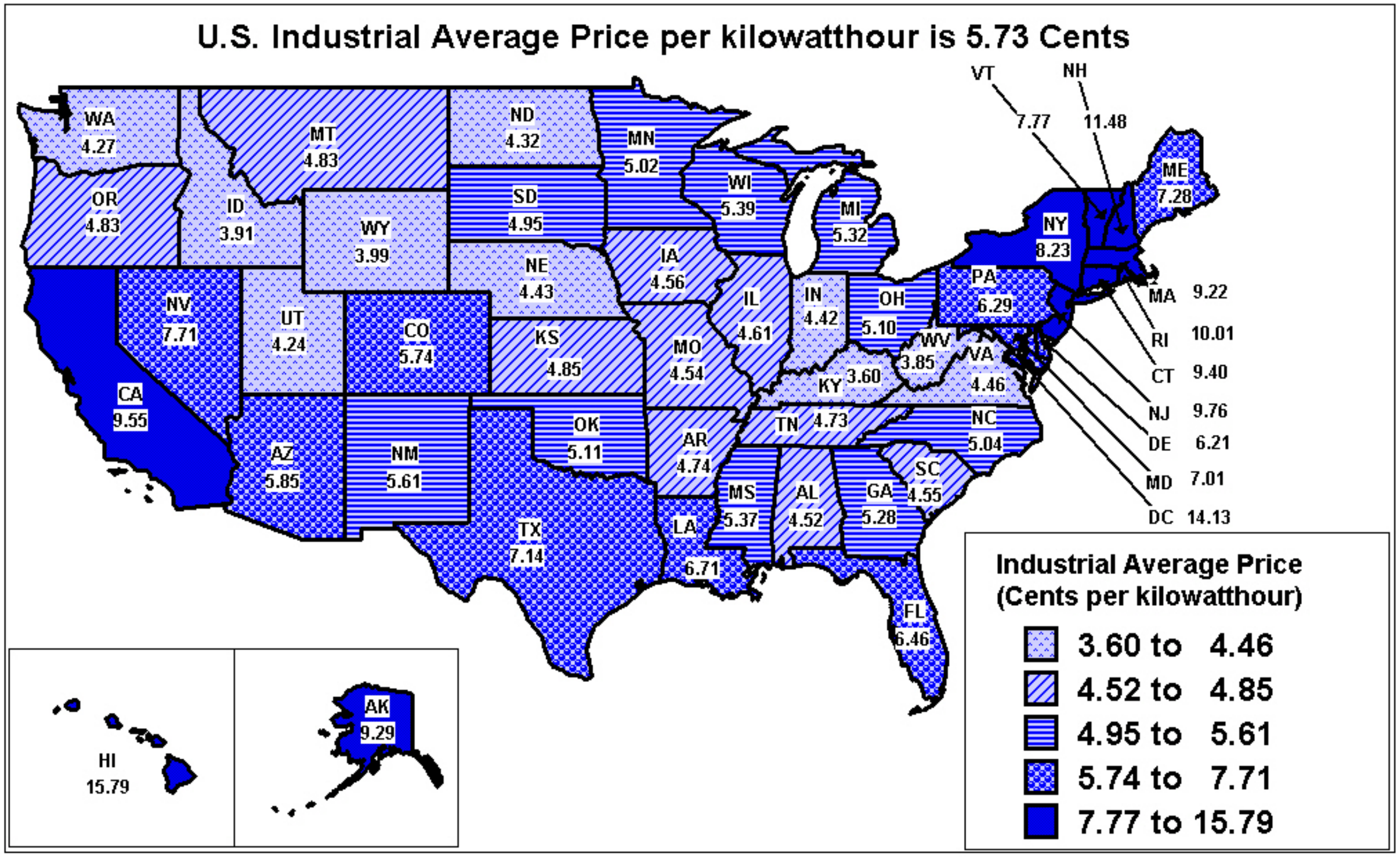
Figure 7.6.   Average Commercial Price of Electricity by State, 2005



Note: Data is displayed as 5 groups of 10 States and the District of Columbia.

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

Figure 7.7. Average Industrial Price of Electricity by State, 2005



Note: Data is 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 7.5. Net Metering and Green Pricing Customers by End Use Sector, 2002 - 2005

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

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, 1994 through 2005
(Million Dollars)

Description	2005[1]	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
Utility Operating Revenues	**267,534**	**240,318**	**226,227**	**219,389**	**267,525**	**235,336**	**214,160**	**218,175**	**215,083**	**207,459**	**199,967**	**196,282**
Electric Utility	235,570	213,539	202,369	200,135	244,219	214,707	197,578	201,970	195,898	188,901	183,655	179,307
Other Utility	31,964	26,779	23,858	19,254	23,306	20,630	16,583	16,205	19,185	18,558	16,312	16,974
Utility Operating Expenses	**238,590**	**207,161**	**197,459**	**188,745**	**235,198**	**210,324**	**182,258**	**186,498**	**182,796**	**173,920**	**165,321**	**164,207**
Electric Utility	208,461	182,337	175,473	171,291	213,733	191,329	167,266	171,689	165,443	156,938	150,599	148,663
Operation	151,150	131,962	122,723	116,374	159,929	132,662	108,461	110,759	104,337	97,207	91,881	93,108
Production	121,058	104,287	96,181	90,649	136,089	107,352	83,555	85,956	80,153	73,437	68,983	69,269
Cost of Fuel	36,161	28,678	26,476	24,132	29,490	32,555	29,826	31,252	31,861	30,706	29,122	30,108
Purchased Power	78,279	67,354	62,173	58,828	98,231	61,969	43,258	42,612	37,991	32,987	29,981	29,213
Other	6,638	8,256	7,532	7,688	8,368	12,828	10,470	12,092	10,301	9,744	9,880	9,948
Transmission	5,687	4,519	3,585	3,494	2,365	2,699	2,423	2,197	1,915	1,503	1,425	1,361
Distribution	3,517	3,301	3,185	3,113	3,217	3,115	2,956	2,804	2,700	2,604	2,561	2,581
Customer Accounts	4,243	4,087	4,180	4,165	4,434	4,246	4,195	4,021	3,767	3,848	3,613	3,546
Customer Service	2,289	2,012	1,893	1,821	1,856	1,839	1,889	1,955	1,917	1,920	1,922	1,956
Sales	219	238	234	261	282	403	492	514	501	435	348	232
Administrative and General	14,113	13,519	13,466	12,872	11,686	13,009	12,951	13,311	13,384	13,458	13,028	14,163
Maintenance	12,058	11,774	11,141	10,843	11,167	12,185	12,276	12,486	12,368	12,050	11,767	12,022
Depreciation	17,177	16,373	16,962	17,319	20,845	22,761	23,968	24,122	23,072	21,194	19,885	18,679
Taxes and Other	26,848	22,228	24,648	26,755	21,792	23,721	22,561	24,322	25,667	26,488	27,065	24,854
Other Utility	30,129	24,823	21,986	17,454	21,465	18,995	14,992	14,809	17,353	16,983	14,722	15,544
Net Utility Operating Income	**28,944**	**33,158**	**28,768**	**30,644**	**32,327**	**25,012**	**31,902**	**31,677**	**32,286**	**33,539**	**34,646**	**32,074**

[1] Missing respondent data in several accounts results in slight imbalances in some of the 2005 expenses subtotals. Column values do not add to summary total. Errors in respondent submission have not been revised by filer.

Note: 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, 1994 through 2005
(Mills per Kilowatthour)

Plant Type	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
Operation												
Nuclear	8.39	8.30	8.86	8.54	8.30	8.41	8.93	9.98	11.02	9.47	9.43	9.79
Fossil Steam	2.97	2.68	2.50	2.54	2.40	2.31	2.21	2.17	2.22	2.25	2.38	2.32
Hydroelectric[1]	5.26	5.05	4.50	5.07	5.79	4.74	4.17	3.85	3.29	3.87	3.69	4.53
Gas Turbine and Small Scale[2]	2.97	2.73	2.76	2.72	3.15	4.57	5.16	3.85	4.43	5.08	3.57	4.58
Maintenance												
Nuclear	5.23	5.38	5.23	5.04	5.01	4.93	5.13	5.79	6.90	5.68	5.21	5.20
Fossil Steam	2.96	2.96	2.73	2.68	2.61	2.45	2.38	2.41	2.43	2.49	2.65	2.82
Hydroelectric[1]	3.60	3.64	3.01	3.58	3.97	2.99	2.60	2.00	2.49	2.08	2.19	2.90
Gas Turbine and Small Scale[2]	2.15	2.16	2.26	2.38	3.33	3.50	4.80	3.43	3.43	4.98	4.28	5.39
Fuel												
Nuclear	4.54	4.58	4.60	4.60	4.67	4.95	5.17	5.39	5.42	5.50	5.75	5.87
Fossil Steam	21.77	18.21	17.35	16.11	18.13	17.69	15.62	15.94	16.80	16.51	16.07	16.67
Hydroelectric[1]	--	--	--	--	--	--	--	--	--	--	--	--
Gas Turbine and Small Scale[2]	53.73	45.20	43.91	31.82	43.56	39.19	28.72	23.02	24.94	30.58	20.83	22.19
Total												
Nuclear	18.16	18.26	18.69	18.18	17.98	18.28	19.23	21.16	23.33	20.65	20.39	20.86
Fossil Steam	27.69	23.85	22.59	21.32	23.14	22.44	20.22	20.52	21.45	21.25	21.11	21.80
Hydroelectric[1]	8.86	8.69	7.51	8.65	9.76	7.73	6.77	5.86	5.78	5.95	5.89	7.43
Gas Turbine and Small Scale[2]	58.85	50.10	48.93	36.93	50.04	47.26	38.68	30.30	32.80	40.64	28.67	32.16

[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), 1994 through 2005
(Million Dollars)

Description	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
Operating Revenue - Electric	**NA**	**NA**	**33,906**	**32,776**	**38,028**	**31,843**	**26,767**	**26,155**	**25,397**	**24,207**	**23,473**	**23,267**
Operating Expenses - Electric	**NA**	**NA**	**29,637**	**28,638**	**32,789**	**26,244**	**21,274**	**20,880**	**20,425**	**19,084**	**18,959**	**18,649**
Operation Including Fuel	**NA**	**NA**	**22,642**	**21,731**	**25,922**	**19,575**	**15,386**	**15,120**	**14,917**	**13,768**	**13,653**	**13,578**
Production	NA	NA	17,948	17,176	21,764	15,742	11,923	11,608	11,481	11,080	10,385	10,445
Transmission	NA	NA	872	858	785	781	732	773	725	344	628	610
Distribution	NA	NA	696	680	605	574	516	603	538	497	426	430
Customer Accounts	NA	NA	582	537	600	507	415	390	390	365	323	317
Customer Service	NA	NA	280	315	263	211	160	127	133	103	102	104
Sales	NA	NA	84	74	73	66	49	51	46	18	20	22
Administrative and General	NA	NA	2,180	2,090	1,832	1,695	1,591	1,567	1,602	1,360	1,769	1,651
Maintenance	**NA**	**NA**	**2,086**	**1,926**	**1,904**	**1,815**	**1,686**	**1,631**	**1,609**	**1,638**	**1,575**	**1,584**
Depreciation and Amortization	**NA**	**NA**	**3,844**	**3,907**	**4,009**	**3,919**	**3,505**	**3,459**	**3,239**	**3,160**	**2,934**	**2,721**
Taxes and Tax Equivalents	**NA**	**NA**	**1,066**	**1,074**	**954**	**936**	**697**	**670**	**660**	**662**	**797**	**766**
Net Electric Operating Income	**NA**	**NA**	**4,268**	**4,138**	**5,238**	**5,598**	**5,493**	**5,275**	**4,972**	**5,123**	**4,514**	**4,618**

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), 1994 through 2005
(Million Dollars)

Description	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
Operating Revenue - Electric	**NA**	**NA**	**12,454**	**11,546**	**10,417**	**9,904**	**9,354**	**8,790**	**8,586**	**8,582**	**8,435**	**7,996**
Operating Expenses - Electric	**NA**	**NA**	**11,481**	**10,703**	**9,820**	**9,355**	**8,737**	**8,245**	**8,033**	**8,123**	**7,979**	**7,567**
Operation Including Fuel	**NA**	**NA**	**10,095**	**9,439**	**8,864**	**8,424**	**7,874**	**7,437**	**7,117**	**7,359**	**7,173**	**6,858**
Production	NA	NA	8,865	8,311	7,863	7,486	7,015	6,661	6,240	6,578	6,422	6,185
Transmission	NA	NA	105	93	61	64	48	44	57	51	35	34
Distribution	NA	NA	348	320	311	280	261	230	304	234	204	190
Customer Accounts	NA	NA	172	163	164	155	143	130	139	141	125	119
Customer Service	NA	NA	31	39	26	22	22	21	16	18	18	17
Sales	NA	NA	11	10	15	16	14	9	13	12	10	10
Administrative and General	NA	NA	562	504	423	402	371	342	348	325	358	303
Maintenance	**NA**	**NA**	**418**	**389**	**304**	**286**	**272**	**263**	**338**	**244**	**250**	**234**
Depreciation and Amortization	**NA**	**NA**	**711**	**631**	**405**	**394**	**369**	**330**	**354**	**322**	**313**	**274**
Taxes and Tax Equivalents	**NA**	**NA**	**257**	**244**	**247**	**251**	**223**	**215**	**225**	**206**	**244**	**201**
Net Electric Operating Income	**NA**	**NA**	**974**	**843**	**597**	**549**	**617**	**545**	**552**	**459**	**457**	**429**

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, 1994 through 2005
(Million Dollars)

Description	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
Operating Revenue - Electric	**NA**	**NA**	**11,798**	**11,470**	**12,458**	**10,685**	**10,186**	**9,780**	**8,833**	**9,082**	**8,743**	**8,552**
Operating Expenses - Electric	**NA**	**NA**	**8,763**	**8,665**	**10,013**	**8,139**	**7,775**	**7,099**	**5,999**	**6,390**	**6,162**	**6,303**
Operation Including Fuel	**NA**	**NA**	**6,498**	**6,419**	**7,388**	**5,873**	**5,412**	**5,184**	**4,073**	**4,514**	**4,615**	**4,877**
Production	NA	NA	5,175	5,236	6,247	5,497	4,890	4,735	3,686	4,109	4,219	4,464
Transmission	NA	NA	307	244	354	332	349	323	327	328	290	304
Distribution	NA	NA	1	1	1	2	2	2	1	1	2	2
Customer Accounts	NA	NA	4	10	16	6	1	1	1	3	2	4
Customer Service	NA	NA	63	60	60	48	50	51	42	46	29	28
Sales	NA	NA	20	6	6	10	28	14	13	7	41	9
Administrative and General	NA	NA	927	862	705	467	528	535	444	451	431	442
Maintenance	**NA**	**NA**	**600**	**566**	**521**	**488**	**436**	**476**	**441**	**432**	**398**	**377**
Depreciation and Amortization	**NA**	**NA**	**1,335**	**1,351**	**1,790**	**1,471**	**1,623**	**1,175**	**1,214**	**1,187**	**896**	**746**
Taxes and Tax Equivalents	**NA**	**NA**	**329**	**328**	**315**	**308**	**304**	**264**	**272**	**256**	**252**	**56**
Net Electric Operating Income	**NA**	**NA**	**3,035**	**2,805**	**2,445**	**2,546**	**2,411**	**2,681**	**2,834**	**2,692**	**2,581**	**2,249**

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, 1994 through 2005
(Million Dollars)

Description	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
Operating Revenue - Electric	**34,088**	**30,650**	**29,228**	**27,458**	**26,458**	**25,629**	**23,824**	**23,988**	**23,321**	**24,424**	**24,609**	**23,777**
Operation and Maintenance Expenses	**31,209**	**27,828**	**26,361**	**24,561**	**23,763**	**22,982**	**21,283**	**21,223**	**20,715**	**23,149**	**21,741**	**20,993**
Operation Including Fuel	**28,723**	**25,420**	**24,076**	**22,383**	**21,703**	**20,942**	**19,336**	**19,280**	**18,405**	**20,748**	**19,334**	**18,650**
Production	23,921	20,752	19,559	18,143	17,714	17,080	15,706	15,683	15,105	17,422	15,907	15,471
Transmission	679	665	637	579	524	525	466	452	339	372	366	322
Distribution	1,895	1,860	1,787	1,681	1,589	1,530	1,451	1,440	1,134	1,133	1,127	1,053
Customer Accounts	612	595	579	545	532	487	455	446	382	375	383	374
Customer Service	147	141	140	136	119	133	132	132	118	118	112	105
Sales	76	80	79	79	88	82	81	77	61	72	72	61
Administrative and General	1,393	1,327	1,295	1,219	1,137	1,104	1,045	1,050	1,266	1,257	1,367	1,265
Depreciation and Amortization	**2,253**	**2,182**	**2,076**	**1,992**	**1,895**	**1,820**	**1,747**	**1,732**	**1,727**	**1,787**	**1,778**	**1,742**
Taxes and Tax Equivalents	**234**	**226**	**209**	**186**	**164**	**220**	**200**	**211**	**583**	**614**	**628**	**601**
Net Electric Operating Income	**2,879**	**2,822**	**2,867**	**2,897**	**2,696**	**2,647**	**2,541**	**2,764**	**2,606**	**2,872**	**2,868**	**2,784**

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, 1994 through 2005
(Megawatts)

Item	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
Total Actual Peak Load Reduction	**25,710**	**23,532**	**22,904**	**22,936**	**24,955**	**22,901**	**26,455**	**27,231**	**25,284**	**29,893**	**29,561**	**25,001**
Energy Efficiency	15,351	14,272	13,581	13,420	13,027	12,873	13,452	13,591	13,327 R	14,243	13,212	11,662
Load Management	10,359	9,260	9,323	9,516	11,928	10,027	13,003	13,640	11,958	15,650	16,347	13,340

R = Revised.

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, 1994 through 2005

Item	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
	Annual Effects – Energy Efficiency											
Large Utilities												
Actual Peak Load Reduction (MW)	15,351	14,272	13,581	13,420	13,027	12,873	13,452	13,591	13,327	14,243	13,212	11,662
Energy Savings (Thousand MWh)	58,891	52,662	48,245	52,285	52,946	52,827	49,691	48,775	55,453	59,853	55,328	49,720
	Annual Effects – Load Management											
Large Utilities												
Actual Peak Load Reduction (MW)	10,359	9,260	9,323	9,516	11,928	10,027	13,003	13,640	11,958	15,650	16,347 R	13,340 R
Potential Peak Load Reductions (MW)	21,282	20,998	25,290	26,888	27,730	28,496	30,118	27,840	27,911	34,101	33,817	31,255
Energy Savings (Thousand MWh)	1,006	2,047	2,020	1,790	990	875	872	392	953	1,989	2,093	2,763

R = Revised.

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, 1994 through 2005

Item	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
	Incremental Effects – Energy Efficiency											
Large Utilities												
Actual Peak Load Reduction (MW)	1,403	1,521	945	1,054	999	720	695	796	1,065	1,381	1,561	1,751
Energy Savings (Thousand MWh)	5,872	4,522	2,939	3,543	4,402	3,284	3,027	3,324	4,661	6,361	7,901	8,054
Small Utilities												
Actual Peak Load Reduction (MW)	302	204	90	49	20	25	22	12	12	2	7	9
Energy Savings (Thousand MWh)	7	10	8	192	8	8	8	37	10	7	16	11
	Incremental Effects – Load Management											
Large Utilities												
Actual Peak Load Reduction (MW)	1,009	907	1,084	1,160	1,297	919	1,568	1,821	1,261	5,027	3,039	1,418
Potential Peak Load Reductions (MW)	2,005	2,622	1,981	2,655	2,448	2,439	6,457	2,832	2,475	2,309	4,930	5,153
Energy Savings (Thousand MWh)	133	2	29	65	79	63	67	37	171	482	321	178
Small Utilities												
Actual Peak Load Reduction (MW)	153	242	81	54	45	137	54	124	130	50	29	56
Potential Peak Load Reductions (MW)	218	422	131	76	177	190	84	160	183	90	41	81
Energy Savings (Thousand MWh)	5	4	4	2	4	9	2	7	19	6	3	8

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, 1994 through 2005

Item	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
	Actual Peak Load Reductions (MW)											
Large Utilities												
Residential	9,432	8,870	9,431	9,137	9,619	9,446	9,976	9,327	10,799	11,471	10,930	9,638
Commercial	7,926	7,194	6,774	6,839	8,210	6,987	7,777	9,482	8,174	8,678	8,057	6,927
Industrial	8,343	7,454	6,594	6,500	6,553	6,141	6,360	7,927	5,812	9,083	10,033	7,977
Transportation	9	14	105	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	460	573	327	2,342	495	498	661	545	460
Total	**25,710**	**23,532**	**22,904**	**22,936**	**24,955**	**22,901**	**26,455**	**27,231**	**25,284**	**29,893**	**29,561**	**25,001**
	Potential Peak Load Reductions (MW)											
Large Utilities												
Residential	12,097	11,967	12,525	12,072	12,274	12,970	12,812	13,022	16,662	14,697	14,047	13,851
Commercial	10,214	9,624	8,943	9,298	10,469	9,114	8,868	12,210	12,896	12,452	11,495	9,915
Industrial	14,260	13,665	17,298	18,321	17,344	18,775	17,237	15,512	11,035	20,275	20,715	18,271
Transportation	62	14	105	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	617	670	510	4,653	686	644	921	772	881
Total	**36,633**	**35,270**	**38,871**	**40,308**	**40,757**	**41,369**	**43,570**	**41,430**	**41,237**	**48,344**	**47,029**	**42,917**
	Energy Savings (Thousand MWh)											
Large Utilities												
Residential	19,255	17,763	13,469	15,438	16,027	16,287	16,263	16,564	17,830	20,585	20,253	21,028
Commercial	28,416	24,624	25,089	24,391	24,217	25,660	23,375	25,125	27,898	29,186	26,187	21,773
Industrial	12,178	12,273	11,156	11,339	10,487	9,160	8,156	3,347	8,684	10,493	9,620	8,568
Transportation	48	51	551	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	2,907	3,206	2,593	2,770	831	1,694	1,578	1,360	1,114
Total	**59,897**	**54,710**	**50,265**	**54,075**	**53,936**	**53,701**	**50,563**	**49,167**	**56,406**	**61,842**	**57,421**	**52,483**

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, 1994 through 2005

Item	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
	Actual Peak Load Reductions (MW)											
Large Utilities												
Residential	966	1,361	640	895	790	572	605	599	743	792	860	1,083
Commercial	715	560	528	527	742	515	684	1,176	699	935	1,176	1,244
Industrial	731	507	849	680	640	502	929	799	836	1,870	2,426	785
Transportation	0	0	12	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	112	124	50	45	43	48	93	139	57
Total	**2,412**	**2,428**	**2,029**	**2,214**	**2,296**	**1,640**	**2,263**	**2,617**	**2,326**	**3,690**	**4,601**	**3,169**
Small Utilities												
Residential	325	280	88	48	32	37	27	35	40	30	20	27
Commercial	71	126	58	41	15	37	22	34	21	9	10	7
Industrial	59	40	25	12	16	62	7	56	61	8	4	24
Transportation	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	0	0	26	19	10	20	5	2	6
Total	**455**	**446**	**171**	**101**	**63**	**162**	**76**	**136**	**142**	**52**	**36**	**65**
U.S. Total	**2,867**	**2,874**	**2,200**	**2,317**	**2,361**	**1,802**	**2,339**	**2,753**	**2,468**	**3,742**	**4,637**	**3,234**
	Potential Peak Load Reductions (MW)											
Large Utilities												
Residential	1,311	1,680	752	1,311	900	699	753	751	960	950	1,231	1,467
Commercial	1,098	894	602	751	1,115	565	718	1,863	853	1,512	1,697	2,115
Industrial	999	1,569	1,551	1,506	1,277	1,815	5,612	1,438	1,669	3,800	3,368	1,997
Transportation	0	0	21	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	141	155	79	68	76	58	146	195	326
Total	**3,408**	**4,143**	**2,926**	**3,709**	**3,447**	**3,159**	**7,151**	**3,628**	**3,540**	**6,408**	**6,491**	**5,905**
Small Utilities												
Residential	367	395	116	64	158	55	41	49	59	46	27	38
Commercial	100	154	73	43	19	51	25	41	35	17	13	12
Industrial	53	77	32	15	18	64	9	70	72	16	6	31
Transportation	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	3	2	44	31	12	30	13	2	8
Total	**520**	**626**	**221**	**125**	**197**	**215**	**106**	**172**	**196**	**92**	**48**	**89**
U.S. Total	**3,928**	**4,769**	**3,147**	**3,834**	**3,644**	**3,374**	**7,257**	**3,800**	**3,736**	**6,500**	**6,539**	**5,994**
	Energy Savings (Thousand MWh)											
Large Utilities												
Residential	2,276	1,842	868	1,203	1,365	856	990	909	1,055	1,179	1,630	2,194
Commercial	2,638	1,815	1,356	1,583	1,867	1,780	1,502	1,703	2,382	3,537	4,594	4,449
Industrial	1,090	867	732	706	872	547	475	645	1,059	1,787	1,678	1,325
Transportation	*	0	12	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	116	376	164	127	104	336	341	320	262
Total	**6,004**	**4,524**	**2,968**	**3,608**	**4,481**	**3,347**	**3,094**	**3,361**	**4,832**	**6,844**	**8,222**	**8,230**
Small Utilities												
Residential	6	6	7	45	5	9	4	8	10	7	9	13
Commercial	5	7	5	148	3	4	3	6	3	3	5	3
Industrial	*	2	1	2	2	1	1	3	8	2	5	1
Transportation	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	*	3	3	1	1	7	1	2	1
Total	**12**	**14**	**13**	**194**	**13**	**17**	**9**	**18**	**28**	**13**	**21**	**18**
U.S. Total	**6,016**	**4,539**	**2,981**	**3,802**	**4,492**	**3,364**	**3,103**	**3,379**	**4,860**	**6,857**	**8,243**	**8,248**

* = 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, 1994 through 2005
(Thousand Megawatthours)

Item	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
Total Energy Savings	**59,897**	**54,710**	**50,265**	**54,075**	**53,936**	**53,701**	**50,563**	**49,167**	**56,406**	**61,842**	**57,421**	**52,483**
Energy Efficiency	58,891	52,662	48,245	52,285	52,946	52,827	49,691	48,775	55,453	59,853	55,328	49,720
Load Management	1,006	2,047	2,020	1,790	990	875	872	392	953	1,989	2,093	2,763

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, 1994 through 2005
(Thousand Dollars)

Item	2005	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
Direct Cost[1]	**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**	**2,004,942**	**2,254,059**
Energy Efficiency	1,169,241	910,115	807,403	1,007,323	1,097,504	938,666	820,108	766,384	892,468	1,051,922	1,408,542	1,592,125
Load Management	625,568	515,057	352,137	413,614	358,098	445,566	430,581	466,634	454,777	571,666	596,400	661,934
Indirect Cost[2]	**126,543**	**132,294**	**137,670**	**204,600**	**174,684**	**180,669**	**172,955**	**187,902**	**288,775**	**278,609**	**416,342**	**461,598**
Total DSM Cost[3]	**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**	**2,421,284**	**2,715,657**

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

Unified Data Submission Process

Data are either received on paper forms or entered directly by respondents into CNEAF's Internet Data Collection System (IDC). Hard copy forms are keyed by EIA into the IDC. All data are subject to review via edits built into the IDC, 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 IDC 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 email. 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 email 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.

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 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.
- All monthly survey data are first disseminated as preliminary. These data are revised only after the completion of the 12-month cycle of the data. No revisions are made to the published data before this unless significant errors are discovered. In that case, determination as to whether the data should be revised is described in a later bullet.
- Any CNEAF data released as preliminary or estimated will be revised, if necessary, and disseminated as final at the same levels of aggregation in a future data 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 stages of the data (e.g., preliminary, estimated, final, revised) will be so designated in table/figure titles, headers, or footnotes, or in the accompanying text.
- 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. On a chapter basis, the status (preliminary versus final) of the data contained in the EPA follows:

- **Chapter 1, Generation and Useful Thermal Output** Based on data from the Forms EIA-906 and EIA-920. All data are final.
- **Chapter 2, Capacity** Based on data from the Form EIA-860. All data are final.
- **Chapter 3, Demand, Capacity Resources, and Capacity Margins** Based on data from the Form EIA-411. All data are final.
- **Chapter 4, Fuel** Based on data from the Form EIA-906, EIA-920, EIA-423 and FERC Form 423. All data are final.
- **Chapter 5, Emissions** Based on data from the Form EIA-767, EIA-906, and EIA-920 and on data extracted from the U.S. Environmental protection Agency's Continuous Emission Monitoring System database. All data are final.
- **Chapter 6, Trade** Based on data from the Form EIA-861 and on import/export data from the National Energy Board of Canada and the Office of Fuels Programs, Fossil Energy, Form FE-781R. All data are final.
- **Chapter 7, Retail Customers, Sales, and Revenues** Based on data on sales, revenue, and calculated average retail price of electricity from the Form EIA-861. All data are final.
- **Chapter 8, Revenue and Expense Statistics** Based on financial data from the Federal Energy Regulatory Commission Form 1, Form EIA-412, and Rural Utility Services Form 7 and Form 12. All data are final.
- **Chapter 9, Demand-Side Management** Based on data on demand-side management from the Form EIA-861. All data are final.

Imputation. If the reported electric generation 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 generation for the facility. The same procedure is used to estimate ("predict") data for facilities not in the monthly sample. The regression methodology relied on 2004 data for other facilities to make estimates for erroneous or missing responses. The basic technique employed is described in the paper "Model-Based Sampling and Inference," available on the EIA web site at http://www.eia.doe.gov/cneaf/electricity/page/forms.html. Also see reference "Practical Methods for Electric Power Survey Data," in InterStat, July 2002, article # 1, available at http://interstat.statjournals.net/YEAR/2002/articles/0207001.pdf. The basis for the current methodology, which involves a 'borrowing of strength' technique for small domains, is found in "Using Prediction-Oriented Software for Survey Estimation," at http://interstat.statjournals.net/YEAR/1999/abstracts/9908001.php?Name=908001 in InterStat, August 1999, article # 1 and also highly relevant is "The Classical Ratio Estimator," http://interstat.statjournals.net/YEAR/2005/abstracts/0510004.php?Name=510004, in InterStat, October 2005, article # 4.

Data Confidentiality. Most of the data collected on the Electric Power Surveys are not considered confidential. However, the data that are classified confidential are handled by EIA 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-412, "Annual Electric Industry Financial Report;" [Terminated]

- Form EIA-423, “Monthly Cost and Quality of Fuels for Electric Plants Report;”
- Form EIA-767, “Steam-Electric Plant Operation and Design Report;”
- Form EIA-860, “Annual Electric Generator Report;”
- Form EIA-861, “Annual Electric Power Industry Report;” and
- Form EIA-906, “Power Plant Report.”
- Form EIA-920, “Combined Heat and Power Plant Report.”

A brief description of each of these forms can be found on the EIA website on the Internet with the following URL: http://www.eia.doe.gov/cneaf/electricity/page/forms.html.

Each of these forms is summarized below.

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

- Fossil Energy Form FE-781R, “Annual Report of International Electric Export/Import Data;” (Department of Energy, Office of Emergency Planning Department of Energy, Office of Fuels Programs);
- Federal Energy Regulatory Commission Form 1, “Annual Report of Major Electric Utilities, Licensees, and Others;”
- Federal Energy Regulatory Commission Form 423, “Cost and Quality of Fuels for Electric Plants;”
- 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-759, “Monthly Power Plant Report,” Form EIA-860A, “Annual Electric Generator Report–Utility,” Form EIA-860B, “Annual Electric Generator Report–Nonutility,” and 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[1] and are not reported to DOE.

Form EIA-411

The Form EIA-411 is filed as a voluntary report. 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 present various North American Electric Reliability Council (NERC) regional council aggregate totals for their member electric utilities, with some nonmember information included. The 8 North American Electric Reliability Councils submit data for the Form EIA-411 to the North American Electric Reliability Council (NERC). A joint response, through the NERC Headquarters, is filed annually on June 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. This form is considered voluntary under the authority of the Federal Power Act (Public Law 88-280), The Federal Energy Administration Act of 1974 (Public Law 93-275), and the Department of Energy Organization Act (Public Law 95-91). The responsibility for collecting these data had been delegated to the Office of Emergency Planning and Operations within the Department of Energy and was 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 Mid-Continent Area Power Pool (MAPP) to Midwest Reliability Organization (MRO) and

[1] 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.

the Western Systems Coordinating Council (WSCC) to Western Energy Coordinating Council (WECC). The MRO membership boundaries have altered over time, but WECC has not. The utilities in the associated regional entity identified as the Alaska System Coordination Council (ASCC) dropped their formal participation in NERC. The State of Alaska is not contiguous with the other continental States and has 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). 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 the Midwest Reliability Organization (MRO), SERC, and SPP. Reliability Councils that are unchanged include: Electric Reliability Council of Texas (ERCOT), 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:

- Electric Reliability Council of Texas (ERCOT),
- 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), and the
- Western Energy Coordinating Council (WECC).

<u>Concept of Demand and Supply within the EIA-411</u>: Historically, the voluntarily filed 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 this 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.

Confidentiality of the Data. Power flow cases and maps are considered confidential.

Form EIA-412 [Terminated]

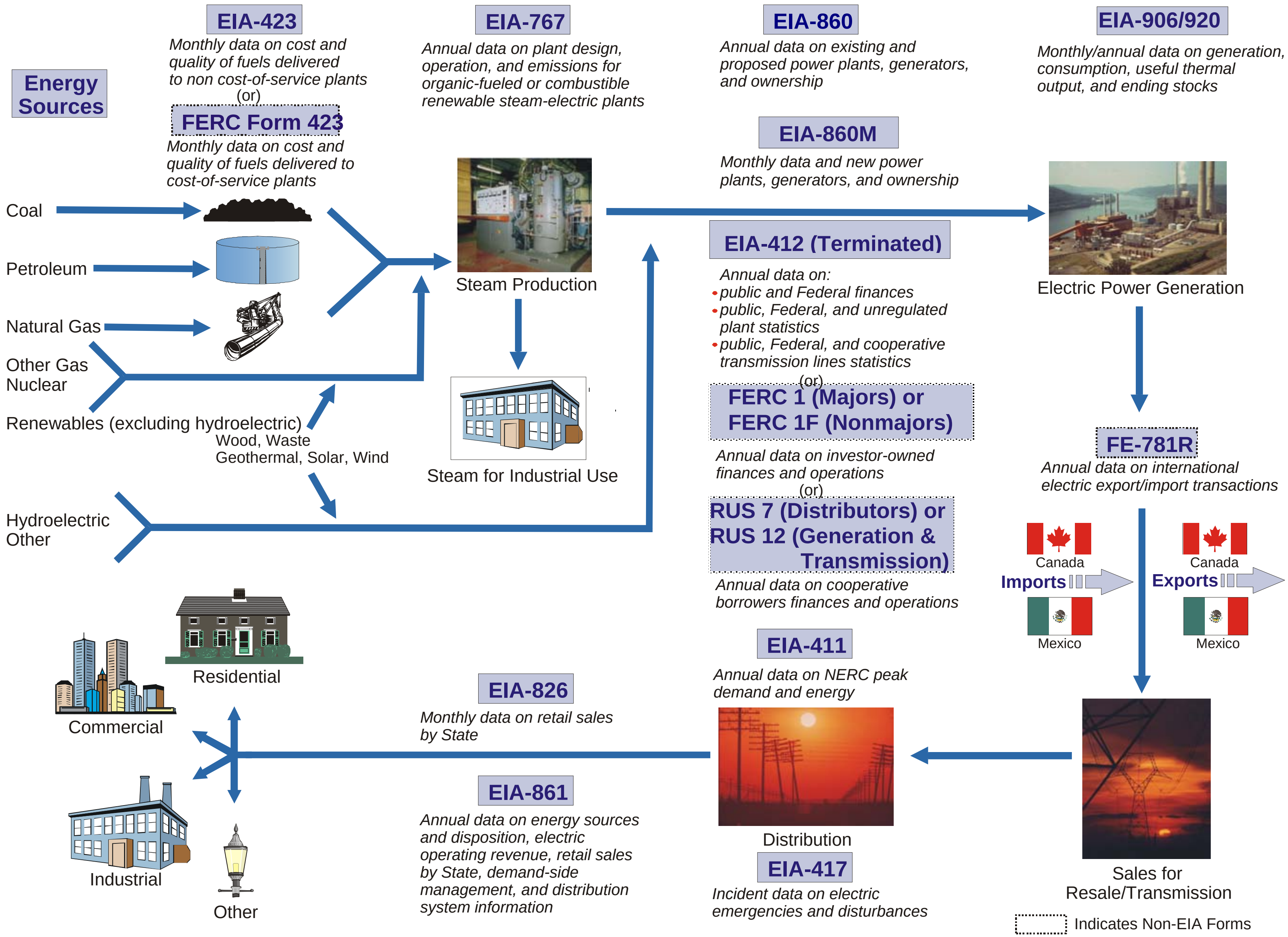
The Form EIA-412 is a restricted-universe census (no companies that fall below a pre-determined threshold are required to file) used annually to collect accounting, financial, and operating data from major publicly owned electric utilities in the United States. Those publicly owned electric utilities 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," must 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.

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 were $5,501,000,000 with purchased power costs of $12,055,000,000. Their 2002 revenue collected were $4,210,000,000 with purchased power costs of $3,827,749,811. Their 2003 revenue collected were $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



The 1993-1997 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.

Confidentiality of the Data. The nonutility data collected on Schedule 9 "Electric Generating Plant Statistics" for "Cost of Plant" and "Production Expenses," are considered confidential.

Form EIA-423

The Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report," collects information from selected electric generating plants in the United States. The data collected on this survey include the cost and quality of fossil fuels delivered to nonutility plants to produce electricity. These plants include 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. The Form EIA-423 survey respondents are required to submit their data by the 45th calendar day following the close of the month.

Instrument and Design History. 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 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.

Formulas and Methodologies. Data for the Form EIA-423 are collected at the plant level. These data are then used in the following formulas to produce aggregates and averages for each fuel type at the State, Census Division, and U.S. 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, units for average heat contents (A) are in million Btu per ton.

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

For gas, units for receipts are in thousand cubic feet (Mcf), 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:

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

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

A_i average heat content for receipts at facility *i*;

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:

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

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*.

Issues within Historical Data Series. Natural gas values for 2001 forward do not include blast furnace gas or other gas.

Confidentiality of the Data. Plant fuel cost data collected on the survey are considered confidential. 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

The Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," is administered by FERC. The data are downloaded from the Commission's website into an EIA database. The Form is due to FERC no later than 45 days after the end of the report month and is filed by approximately 600 regulated plants. To meet the criteria for filing, a plant must have 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 is reported. Fuel received for use in gas-turbine or internal-combustion units that is not associated with a combined-cycle operation is not reported.

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.

Data Processing and Data System Editing. The FERC posts a monthly file on their website: http://www.ferc.gov/docs-filing/eforms.asp#423. The EIA downloads the file and reviews the data for accuracy. Edit checks of the data are performed through computer programs. These 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 other data elements in the file.

Estimation for FERC Form 423 Data. In order to address FERC Form 423 fuel receipts data that were determined to either be out of range (+/- 20 percent) or missing due to non-response beginning in 2003, a procedure was utilized to estimate fuel receipts for the affected plants on a monthly basis. For missing or out-of-range natural gas receipts, the monthly consumption value from the Form EIA-906, "Power Plant Report," was used as a proxy for the monthly receipts. For missing or out-of-range coal and petroleum receipts, the estimated monthly fuel receipts were calculated using the Form EIA-906 data (where receipts were estimated to be equal to the monthly fuel consumption plus the difference between ending and beginning fuel stocks).

The associated fuel quality and cost information for each facility was estimated using the State weighted average for the electric power industry for the year (FERC Form 423 and Form EIA-423). In the event that no values were available at the State level, national averages for the electric power industry for the year were used.

Beginning in 2005, the procedure used the state or national averages for fuel quality and cost information only in the event of non-response. For out of range receipts the reported fuel quality and cost information for each facility was retained.

Formulas and Methodologies. Data for the FERC Form 423 are collected at the plant level. These data are then used in the same formulas shown under the "Formulas and Methodologies" section for 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 are compiled by EIA from data collected by the Federal Energy Regulatory Commission (FERC) on the FERC Form 423. These data are collected by FERC for regulatory rather than statistical and publication purposes. EIA does not attempt to resolve any late 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.

Confidentiality of the Data. Data collected on FERC Form 423 are not considered to be confidential.

Form EIA-767

The Form EIA-767 is used to collect data annually on plant operations and equipment design, including boiler, generator, cooling system, air pollution control equipment, and stack characteristics. Data are 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 is 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 submit information only on fuel consumption and quality, boiler and generator configuration, and nitrogen oxide, mercury, particulate matter, and sulfur dioxide controls. The Form EIA-767 is made available in January to collect data as of the end of the preceding calendar year. The completed forms are to be submitted to the EIA by April 30.

Instrument and Design History. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data. The predecessor form, FPC-67, “Steam-Electric Plant Air and Water Quality Control Data,” was used to collect data from 1969 to 1980, when the form number was changed to Form EIA-767. In 1982, the form was completely redesigned and given the name Form EIA-767, “Steam-Electric Plant Operation and Design Report.” In 1986, the respondent universe of 700 was increased to 900 to include plants with nameplate capacity from 10 megawatts to 100 megawatts. In 2002, the respondent universe increased to above 1,370 plants plus the addition of non-utility plants.

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

Issues within Historical Data Series. None.

Confidentiality of the Data. Latitude and longitude data collected on the Form EIA-767 are considered confidential.

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. 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 - Non-utility." 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.

Estimation of EIA-860 Data. Of the 16,807 existing generators in the 2005 Form EIA-860 frame, imputation was performed for 48 generators. These 48 generators account for 0.1 percent of the existing 2005 electric generating capacity. Imputation was performed at the respondent - plant - generator levels, using the 2004 respondent data.

Issues within Historical Data Series.

<u>Categorization of Capacity by Business Sector</u>: There are a small number of electric utility combined heat and power plants, and 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 2005 is classified based on the operating company's classification as an electric utility or an independent power producer.

<u>Planned Capacity</u>: Delays and cancellations may have occurred subsequent to respondent data reporting as of January 1 of the reporting 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 is eliminated. Separately, summaries of capacity associated with generators with fuel-switching capability are presented for the current data year. These summaries are based on data collected from new questions added to the EIA-860 survey that directly address the ability of generators to switch fuels and co-fire fuels.

Confidentiality of the Data. The plant latitude and longitude and tested heat rate data collected on the Form EIA-860 are considered confidential.

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 3,400 respondents. About 3,200 are electric utilities, and the remainder are nontraditional entities such as independent power producers, energy service providers, or the unregulated subsidiaries of electric utilities and power marketers. The data collected are used to maintain and update the EIA's 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 to estimate electricity transportation consumption by EIA. 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 2005, 58 respondents reported transportation data in 27 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. EIA 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 adds 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.

As in 2004, data for 2005 reflects 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 is drawn from Form EIA-826). Form EIA-826 is a monthly-stratified sample of approximately 450 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 2005, their data was assumed to be the amount imputed during the year using the EIA-826 sample form collection and imputation process. No special imputation process was implemented to account for differences in the EIA-861 and EIA-826 submitted forms. For 2005, the EPA reflects imputed retail sales volumes equivalent to about 260 million kilowatthours, or less than a hundredth of a percent of the total reported retail sales volume.

The Demand-Side Management data for 2005 reflects imputed information to account for a small set of missing values not included by respondents on their Form EIA-861 filings. No special imputation process was needed to account for missing value differences for EIA-861 filings in prior years.

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

Data 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. EIA has concluded that the retail sales data reported by delivery utilities are more reliable than data reported by power marketers and ESPs.

The reporting methodology change uses sales volumes and customer counts reported by distribution utilities, and adds 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.

As in 2004, data for 2005 reflects 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 is drawn from Form EIA-826). Form EIA-826 is a monthly-stratified sample of approximately 450 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 2005, their data was assumed to be the amount imputed during the year using the EIA-826 sample form collection and imputation process. No special imputation process was implemented to account for differences in the EIA-861 and EIA-826 submitted forms. For 2005, the EPA reflects imputed retail sales volumes equivalent to about 277 million megawatthours, or less than 0.01 percent of the total reported retail sales volume.

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.

California. Data for sales and revenue have been revised in EPA 2005 to restate the character of the California Department of Water and Power's intervention in the State's electricity market in early 2001 and their participation in the years since 2001.

In 2000 and 2001, unrecoverable high average wholesale power costs reduced the credit ratings of California's three major investor-owned utilities below investment grade by early 2001. The rapid and dramatic decline in the credit-worthiness of California's major investor-owned utilities virtually eliminated their ability to obtain wholesale power to meet the requirements of their retail consumers. In response to the looming energy shortfall, the California State legislature authorized the California Department of Water Resources (CDWR), using its undamaged borrowing capability, to enter the wholesale markets on behalf of the California retail consumer effective on January 17, 2001, and for the period ending December 31, 2002. Also the California Public Utility Commission (CPUC) was required by statute to establish the procedures for facilitating the CDWR's participation in California retail sales, as well as retail revenue recovery mechanisms. CDWR's continued commitment to the California ratepayers is related to long-term contracts for resources that will last for years.

Because the California statute called for a direct retail relationship between the CDWR and retail consumers in California, energy provided by the CDWR and delivered by the major investor-owned utilities in California had been treated as deregulated sales and reported under "Energy Only Providers." In the years since 2001 however, a direct retail relationship between CDWR and California consumers has not developed. CDWR continues to obtain large volumes on the wholesale market, delivering these volumes to the three investor-owned utilities for final distribution to end-use consumers. As such, the distribution utilities have continued to maintain direct retail contact with California consumers. For this reason, retail sales and associated revenue formerly associated with CDWR for the years 2001 through 2004 are now reported as Full Service activities by the three investor-owned utilities. Slight revisions to sales, revenue, and prices, both in California and the nation, ensue from this methodological change. Large revisions in the magnitude of activities of "Energy Only Providers" should be noted, both in the State of California and the United States.

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 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 (demand-side management) 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 1998-2005 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 includes the actual peak load reduction achieved by energy efficiency programs.

Wholesale Trade: Alaska and Hawaii are not included.

Confidentiality of the Data. Data collected on the Form EIA-861 are not considered to be confidential.

Form EIA-906

The Form EIA-906 is used to collect plant-level data on generation, fuel consumption, stocks, and fuel heat content, from electric utilities and nonutilities. Data are collected monthly from a model-based sample of approximately 1,600 utility and nonutility electric power plants. The form is also used to collect these statistics from another 2,689 plants (i.e., all other generators 1 MW or greater) on an annual basis. The monthly data are due by the last day of the month following the end of the reporting month and the annual data are due by March 1.

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.

Estimation of EIA-906 Data. Of the approximately 4,300 plants in the Form EIA-906 frame for 2005, some estimation was performed for 33 plants. These plants account for 0.01 percent of national total generation (i.e., the total for plants reporting on either the EIA-906 or EIA-920 surveys) and 0.02 percent of the national total fuel consumption. Considering just those plants that are part of the EIA-906 survey frame, the plants with some estimation accounted for 0.01 percent of generation and 0.02 percent of fuel consumption.

Finalization of the Monthly Data and Annual Totals. The EIA-906 data is finalized once data has been collected from the annual respondents who are not part of the monthly sample. The data from annual responses that pass edit checks are proportioned to the months (by State, fuel and sector) using the ratio of the monthly data actually collected to the sum of that monthly data. In the case of annual facilities that are non-respondents, or whose data fails edit checks and have data problems that cannot be resolved, generation and consumption is imputed monthly. The sum of the revised monthly data are the final annual totals for each State, fuel and sector combination.

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 is included, respectively, in the following categories: "Electricity Generators, Electric Utilities," "Combined Heat and Power, Industrial," and Combined Heat and Power, Commercial." Data for these types of plants is collected on the Form EIA-906. No information on the production of UTO or fuel consumption for UTO is collected or estimated for the electric utility combined heat and power plants

Confidentiality of the Data. The only confidential data element collected on the Form EIA-906 is fuel stocks at the end of the reporting period.

Form EIA-920

The Form EIA-920, "Combined Heat and Power Plant Report" is used to collect plant-level data on generation, fuel consumption, stocks, and fuel heat content of combined heat and power (CHP) plants. Data is collected monthly from a model-based sample of approximately 300 plants. The form is also used to collect these statistics from about 600 combined heat and power plants on an annual basis. The data are due by the last day of the month following the end of the reporting month and the annual data are due by March 1.

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. (For further information on predecessor forms, see the discussion of the EIA-906 survey, above.) The Federal Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data.

Estimation of EIA-920 Data.

<u>Routine Estimation of Useful Thermal Output and Fuel for Useful Thermal Output</u>

Useful thermal output (UTO) is the thermal energy, usually in the form of steam, produced by a CHP system for use in any commercial or industrial application other than electric power generation. As discussed above, UTO was previously collected on the Form EIA-906. However, on the new EIA-920 form UTO is no longer collected. The Form EIA-920 asks for total fuel consumption and fuel consumption for electricity production. Fuel consumption to produce UTO can then be estimated by subtraction (i.e., fuel consumption for UTO = total consumption – consumption for generation). UTO itself is then estimated by multiplying fuel consumption for UTO by an assumed thermal conversion factor of 80 percent.

Imputation for Annual Respondents and Non-Respondents

Fuel consumption data is imputed for non-respondents, including out-of-sample annual respondents until their data is collected after the end of the calendar year. As discussed elsewhere in these Technical Notes, generation is imputed using statistical techniques. Given imputed generation, consumption for generation is estimated by multiplying generation by the plant's prior year heat rate. UTO is estimated by:

- Converting the plant's generation to a heat equivalent, computed as 3412 btus per kilowatthour.

- Dividing the heat equivalent of generation by the plant's historical power-to-steam ratio. The power-to-steam ratio is the ratio of the heat equivalent of the plant's generation divided by MMBtus of UTO produced by the plant.

Fuel for UTO is then computed by dividing UTO by the assumed estimated thermal conversion factor of 80 percent.

Reallocation of Fuel for Plants with Out-of-Range Reported Data

In addition to the imputation of missing values, consumption for generation is estimated for respondents reporting an unusually high allocation of total fuel to power production. Specifically, with the change in survey instruments in January 2004 from the Form EIA-906 to the Form EIA-920, a significant number of CHP respondents began reporting a much larger allocation of fuel to power production – and therefore, by implication, a much smaller allocation of fuel to UTO production – than in 2003 and earlier years. Increased allocation of fuel to generation implies that these facilities are less efficient producers of electricity than they previously appeared and have an overall thermal efficiency lower than expected for CHP plants. In some cases plants allocated 100 percent of their fuel consumed to power generation.

EIA made two types of adjustments to the fuel consumption of CHP plants reporting an unusually high allocation of fuel to generation:

- For steam electric plants reporting either a 100 percent allocation or a very large allocation of fuel to generation, the allocation of fuel between generation and UTO was re-computed to be consistent with the plant's power to steam ratio or with the industry average power to steam ratio if the plant's value also seemed questionable.

- The same type of adjustment was made to fuel consumption for the combustion turbine part of combined cycle CHP plants, but only if the plant reported allocating all of its fuel to generation.

The adjustments, which were designed to modify reported values for the least ambiguous instances of possible over-allocation of fuel to generation, are provisional pending further research.

Portion of Fuel Consumption and Generation Data that is Estimated for the Form EIA-920

For 2005 data, the allocation of fuel between generation and production of UTO was adjusted for about 226 plants in some or all months of the year. These plants accounted for 13 percent of all generation and 21 percent of all fuel consumption data collected by the EIA-920 survey. They account for 1 percent of total national generation and 2.6 percent of total national fuel consumption in 2005.

Imputation of generation and fuel consumption was performed for 37 non-respondents for some or all months of the year. The imputed data accounts for 0.6 percent of all generation and 2.0 percent of all fuel consumption data collected by the EIA-920 survey. They account for less than a tenth of a percent of total national generation and fuel consumption in 2005.

Finalization of the Monthly Data and Annual Totals. The EIA-920 data is finalized once data has been collected from the annual respondents who are not part of the monthly sample. The data from annual responses that pass edit checks are proportioned to the months (by State, fuel and sector) using the ratio of the monthly data actually collected to the sum of that monthly data. In the case of annual facilities that are non-respondents, or whose data fails edit checks and have data problems that cannot be resolved, generation and consumption is imputed monthly. The sum of the revised monthly data are the final annual totals for each State, fuel and sector combination.

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 is included, respectively, in the following categories: "Electricity Generators, Electric Utilities," "Combined Heat and Power, Industrial," and Combined Heat and Power, Commercial." Data for these types of plants is collected on the Form EIA-906. No information on the production of UTO or fuel consumption for UTO is collected or estimated for the electric utility combined heat and power plants.

Confidentiality of the Data. The only confidential data element collected on the Form EIA-920 is fuel stocks at the end of the reporting period.

Air Emissions

This section describes the methodology for calculating estimated emissions of carbon dioxide (CO_2), sulfur dioxide (SO_2), and nitrogen oxides (NO_X) from electric generating plants for 2001 through 2005. 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 NOx emissions for all plants are made by applying an emissions factor to fuel consumption data collected by EIA on the 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 NOx 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, NOx 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.[1] These distinctions are shown in Tables A1 and A2.

For SO_2 and NOx, the initial estimate of uncontrolled emissions is reduced to account for the plant's operational pollution control equipment, when data on control equipment is available from the EIA-767 survey. 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 NOx 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 is incomplete and is not used in this report.). The CEMS data account for the bulk of SO_2 and NOx emissions from the electric power industry. For those plants for which CEMS data is available, the EIA estimates of SO_2 and NOx emissions are employed for the limited purpose of allocating emissions by fuel, since the CEMS data itself does not provide a detailed breakdown of plant emissions by fuel. For plants for which CEMS data is 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 CO2 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). The heat content information is used to convert physical units to millions of Btu (MMBtu) consumed. To estimate CO2 emissions, the fuel-specific emission factor from Table A3 is multiplied by the fuel consumption in MMBtu 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, NOx control regulations require many plants to install low-NOx 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

[1] 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/glossary_main_page.htm. 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.

NOx emissions estimation approach accounts for the combined effect of the equipment (Table A4). However, control equipment information is available only for plants that report on the Form EIA-767. The EIA-767 survey is limited to plants with boilers fired by combustible fuels[2] with a minimum generating capacity of 10 megawatts (nameplate). Pollution control equipment data is unavailable from EIA sources for plants that do not report on the EIA-767 survey.

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

- For steam electric plants that report on the Form EIA-767, uncontrolled emissions are estimated using the emission factors shown in Tables A1 A2 and reported data on fuel consumption, sulfur content, and boiler firing configuration. Controlled emissions are then determined when pollution control equipment is present. For SO_2, the reported efficiency of the plant's FGD units is used to convert uncontrolled to controlled emission estimates. For NOx, the reduction percentages shown in Table A3 are applied to the uncontrolled estimates.
- For plants and prime movers not reported on the 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-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 on either the Form EIA-423 or the FERC Form 423. When plant-specific sulfur content data is unavailable, the national average sulfur content for the fuel, computed from the Form EIA-423 and the FERC Form 423 data, is applied to the plant.
    - As noted earlier, the emission factor for plants using 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 do not report on the 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.[3]
    - For the plants that do not report on the Form EIA-767, pollution control equipment data is unavailable and the uncontrolled estimates are not reduced.
- If actual emissions of SO_2 or NOx 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.

[2] Boilers that rely entirely on waste heat to boil water, including the heat recovery portion of most combined cycle plants, do not report on the Form EIA-767.

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,

[3] 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 Form EIA-767, see the form instructions, page xi, at http://www.eia.doe.gov/cneaf/electricity/forms/eia767/eia767instr.pdf.

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

The nonutility industry consists of all manufacturing, agricultural, forestry, transportation, finance, service and administrative industries, based on the Office of Management and Budget's Standard Industrial Classification (SIC) Manual. 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
2121 Coal mining
211 Oil and gas extraction
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)
325188 Industrial Inorganic Chemicals
325211 Plastics materials and resins
32512 Industrial organic chemicals
325311 Nitrogenous fertilizers
324 Petroleum refining and related industries (other than 32411)
32411 Petroleum refining
326 Rubber and miscellaneous plastic products
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
92

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.

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 Oxide 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.

Source:

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/
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: *** CO2 factors do not vary by combustion system type or boiler firing configuration.

Source:

1. 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.

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 A4. Nitrogen Oxide Control Technology Emissions Reduction Factors

Nitrogen Oxide Control Technology	EIA-767 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 Nitrogen Oxide 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 Nitrogen Oxide Burners	SN and LN	50
Slagging	SC	20

1. Starting with 1995 data, reduction factors for advanced overfire air, low nitrogen oxide burners and overfire air were reduced by 10 percent.
Source: Babcox and Wilcox, *Steam: Its Generation and Use*, 40th Edition, 1992.

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.

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