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Contacts

General information regarding this publication may be obtained from:		
Name and Title	Phone Number	Internet Address
Robert M. Schnapp, Director Electric Power Division	(202) 426-1211	robert.schnapp@eia.doe.gov
Betsy O'Brien, Chief Electric Market Assessment Team	(202) 426-1180	betsy.obrien@eia.doe.gov

Specific questions on the preparation and content of this report may be obtained from:		
Dean Fennell, Project Leader	(202) 426-1157	dean.fennell@eia.doe.gov
Channele Carner	(202) 426-1270	channele.donald@eia.doe.gov
Sandra R. Smith	(202) 426-1173	sandra.smith@eia.doe.gov

Technical information regarding the sources and quality of the data in this report is available in the *Electric Power Monthly*, DOE/EIA-0226, Technical Notes. This report is accessible via the Internet at: http://www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html.

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Preface

Section 205(A)(2) of the Department of Energy Organization Act of 1977 (Public Law 95-91) requires the Administrator of the Energy Information Administration (EIA) to carry out a central, comprehensive, and unified energy data information program. Under this program, the EIA will collect, evaluate, assemble, analyze, and disseminate data and information relevant to energy resources, reserves, production, demand, technology, and related economic and statistical information.

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The purpose of this report, *Electric Power Annual 1998 Volume I* (EPAVI), is to provide a comprehensive overview of the electric power industry during the most recent year for which data have been collected, with an emphasis on the major changes that occurred. In response to the changes of 1998, this report has been expanded in scope. It begins with a general review of the year and incorporates new data on nonutility capacity and generation, transmission information, futures prices from the Commodity Futures Trading Commission, and wholesale spot market prices from the Pennsylvania-New Jersey-Maryland Independent System Operator and the California Power Exchange. Electric utility statistics at the Census division and State levels on generation, fuel consumption, stocks, delivered cost of fossil fuels, sales to ultimate customers, average revenue per kilowatthour of electricity sold, and revenues from those retail sales can be found in Appendix A. The EPAVI is intended for a wide audience, including Congress, Federal and State agencies, the electric power industry, and the general public.

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Electric Power Industry: 1998 Review

Overview

The year 1998 was a time of major change for the electric power industry and strong growth in electricity generation and retail sales (Table 1). The most significant change occurred on March 31, 1998, when retail customers of investor-owned utilities in California (approximately three-fourths of the State's customers) were allowed direct access to an alternative energy (electricity) service provider. In addition, the legislatures and/or public utility commissions in 17 other States also approved or implemented plans to move toward retail competition.[1] In response, many electric utilities began restructuring their companies and selling their generating assets primarily to nonutility companies, causing a shift in the ownership patterns of power plants.

The structure of the industry also continued to evolve in 1998 as regional independent transmission system operators (or ISOs), power exchanges, and additional futures markets began operating. June of 1998 produced a shock for the industry: a wholesale price spike. It resulted from record high temperatures in a large part of the Midwest and the East, power plant and transmission line outages, and defaults on contract deliveries. Finally, events external to the electric power industry, lower petroleum and natural gas prices, and less water availability for hydropower caused a change in the fuels used to generate electricity in 1998.

Table 1. Summary of U.S. Electric Power Statistics, 1997 and 1998

Item	1997	1998
Capability (percent share)		
Utility	91	88
Nonutility	9	12
Net Generation (billion kWh)		
Utility	3,123	3,212
Nonutility[1]	371	407
Total	3,494	3,620
Retail Sales (billion kWh)	3,140	3,220
Retail Prices (cents/kWh)	6.85	6.75
Utility Fossil Fuel Consumption		
Coal (million short tons)	900	911
Petroleum (million barrels)[2]	125	179
Natural Gas (Bcf)	2,968	3,258
Utility Fossil Cost ($ per million Btu)		
Coal	1.27	1.25
Petroleum	2.88	2.14
Natural Gas	2.76	2.38

[1]Nonutility generation for 1998 is estimated.
[2]Excludes petroleum coke.
Note: •Bcf = billion cubic feet, Btu = British Thermal Unit, and kWh = kilowatthour. •Totals may not equal sum of components due to independent rounding.
Source: Energy Information Administration, Coal, Nuclear, Electric and Alternate Fuels, Electric Power Division.

Electricity Production

Generating Capability

Ownership of electric generating units has historically been dominated by utilities. As of January 1, 1998, 15,533 generating units with a net summer capability[2] of 778,513 megawatts (MW) existed to supply electricity in the United States. At that time, the electric utility sector owned 10,421 units with a capability of 711,889 MW, accounting for approximately 91 percent of the total.[3] During the year, however, the share of the total industry capability owned by nonutilities rose from 9 to 12 percent, primarily as a consequence of the sale of generating units by utilities to nonutility companies.

The amount of capability which was sold to nonutilities during 1998 was 23,397 MW (Table 2). Although the effect of the shift from utility to nonutility ownership of generating units in 1998 was relatively small at the national level, it can be observed more strongly at the State level when restructuring legislation required or encouraged divestiture of the utility's generating assets (Figure 1). This shift in ownership shares reflects the

[1] For more detailed information on the changing electric power industry see the Energy Information Administration Website at: www.eia.doe.gov/cneaf/electricity/page/restructure.html.
[2] All capability values shown in this report are net summer and all capacity shown is installed nameplate.
[3] For detailed statistics see *Inventory of Power Plants in the United States, As of January 1, 1998.*

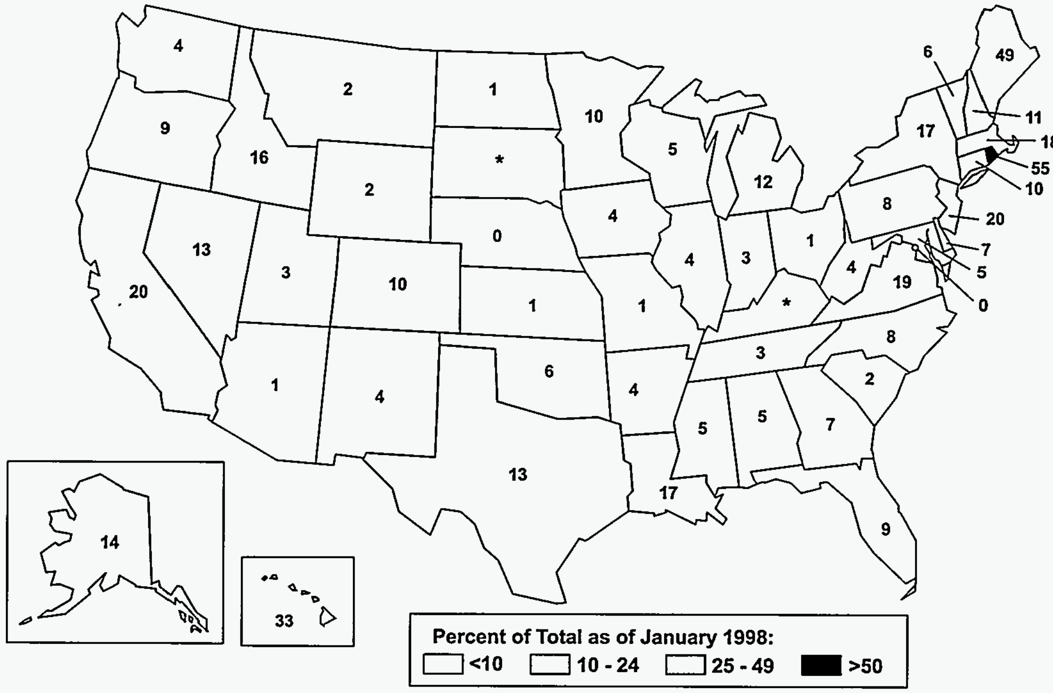
Table 2. U.S. Electric Utility Plants That Have Been Sold and Reclassified as Nonutility Plants, 1998

Seller	Plant	State	Net Summer Capability (megawatts)	Date[1]	Buyer
Commonwealth Edison Co. IN, Inc.	State Line	IN	409	January	Southern Energy
City of Fairbanks	Chena	AK	54	January	Aurora Energy
Commonwealth Edison Co., Inc.	Kincaid	IL	1,108	February	Dominion Energy
Southern California Edison Co.	Long Beach	CA	531	March	NRG/Destec Energy
Southern California Edison Co.	Cool Water	CA	628	April	Houston Industries
Southern California Edison Co.	El Segundo	CA	1,020	April	NRG/Destec Energy
Southern California Edison Co.	Ellwood	CA	48	April	Houston Industries
Southern California Edison Co.	Etiwanda	CA	1,030	April	Houston Industries
Southern California Edison Co.	Highgrove	CA	154	April	Thermo Electron
Southern California Edison Co.	Mandalay	CA	570	April	Houston Industries
Southern California Edison Co.	San Bernardino	CA	126	April	Thermo Electron
Boston Edison	Edgar	MA	20	May	Sithe Energy
Boston Edison	Framingham	MA	32	May	Sithe Energy
Boston Edison	L Street	MA	17	May	Sithe Energy
Boston Edison	Mystic	MA	978	May	Sithe Energy
Boston Edison	New Boston	MA	760	May	Sithe Energy
Boston Edison	West Medway	MA	125	May	Sithe Energy
Southern California Edison Co.	Alamitos	CA	2,083	May	AES Corporation
Southern California Edison Co.	Huntington Beach	CA	1,003	May	AES Corporation
Southern California Edison Co.	Redondo Beach	CA	1,602	May	AES Corporation
Pacific Gas & Electric Co.	Morro Bay	CA	1,002	July	Duke Energy
Pacific Gas & Electric Co.	Moss Landing	CA	1,478	July	Duke Energy
Pacific Gas & Electric Co.	Oakland	CA	165	July	Duke Energy
Sacramento Municipal Utility District	Smud Geo	CA	72	July	Calpine Geysers Co.
Southern California Edison Co.	Ormond Beach	CA	1,500	July	Houston Industries
Big Rivers Electric Corp.	Coleman	KY	455	August	LG&E Energy[2]
Big Rivers Electric Corp.	Green	KY	454	August	LG&E Energy[2]
Big Rivers Electric Corp.	HMP&L Station 2	KY	315	August	LG&E Energy[2]
Big Rivers Electric Corp.	Reid	KY	130	August	LG&E Energy[2]
Big Rivers Electric Corp.	Wilson	KY	420	August	LG&E Energy[2]
New England Power Company	Comerford	NH	164	September	U.S. Generating Co.
New England Power Company	Mcindoes	NH	13	September	U.S. Generating Co.
New England Power Company	S.C. Moore	VT	192	September	U.S. Generating Co.
New England Power Company	Wilder	NH	42	September	U.S. Generating Co.
New England Power Company	Bellows FLS	VT	49	September	U.S. Generating Co.
New England Power Company	Harriman	VT	40	September	U.S. Generating Co.
New England Power Company	Searsburg	VT	5	September	U.S. Generating Co.
New England Power Company	Vernon	VT	24	September	U.S. Generating Co.
New England Power Company	Deerfield	MA	34	September	U.S. Generating Co.
New England Power Company	Sherman	MA	7	September	U.S. Generating Co.
New England Power Company	Brayton Pt	MA	1,550	September	U.S. Generating Co.
New England Power Company	Salem Harbor	MA	712	September	U.S. Generating Co.
New England Power Company	Fife Brook	MA	10	September	U.S. Generating Co.
New England Power Company	Bear Swamp	MA	572	September	U.S. Generating Co.
New England Power Company	Manchester St	RI	420	September	U.S. Generating Co.
Fitchburg Gas & Electric Lt.	Fitchburg	MA	20	September	Fleet Leasing[3]
Cambridge Electric	Kendall Sq	MA	99	December	Southern Energy
Canal Electric	Canal	MA	1,143	December	Southern Energy
Commonwealth Electric Company	Oak Bluffs	MA	6	December	Southern Energy
Commonwealth Electric Company	W. Tisbury	MA	6	December	Southern Energy
Total			23,397		

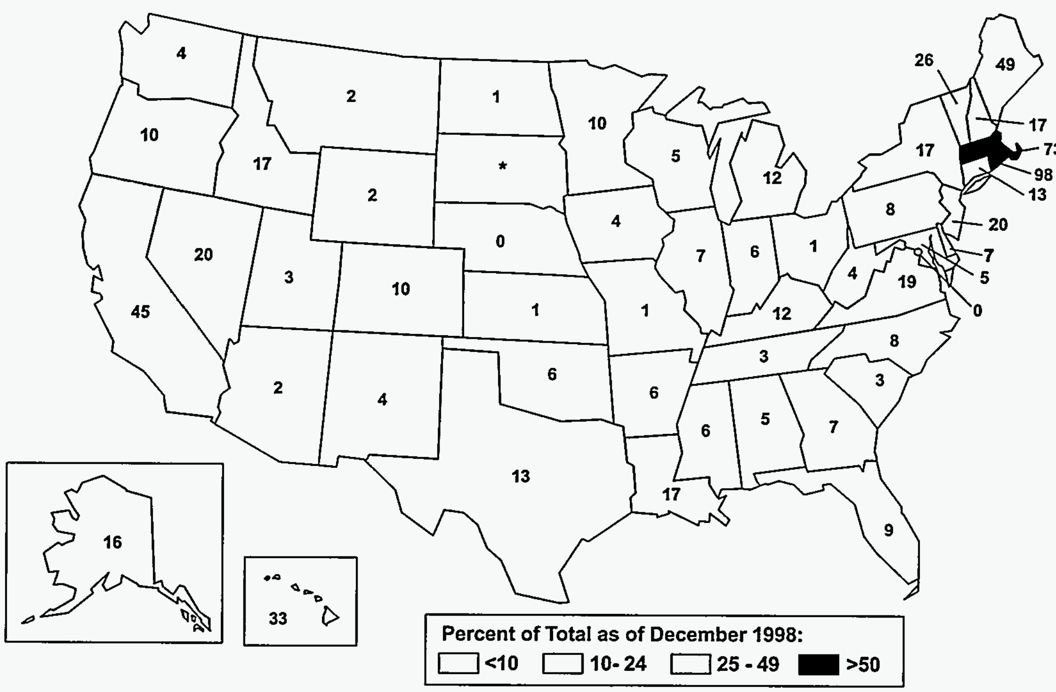
[1] Start date for facility to begin reporting as a nonutility generator.
[2] Plants leased to LG&E energy for 25 years.
[3] Unit returned to lessor.
Note: Not shown in the table is the sale by Wisconsin Power & Light Co. of its 480-kilowatt hydroelectric unit in April 1998.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, U.S. Department of Energy.

Figure 1. U.S. Nonutility Share of Total Capability by State, 1998

January



December



* = Less than 1 percent.
Note: December 1998 values are estimated.
Sources: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report," and Form EIA-867, "Annual Nonutility Power Producer Report."

sale of plants, as well as unit additions and retirements during the year. By the end of 1998, 4 States had over 45 percent of their capability owned by nonutility companies—California, Maine, Massachusetts, and Rhode Island.

Electric utilities added 458 MW of new capability (Table 3) and retired 2,867 MW during 1998 (Table 4). In addition, nonutility companies added 3,002 MW of new capability. Most of the new utility-owned units that came on-line during the year were located in the South (Florida, Mississippi, and Alabama) and the Midwest (Iowa, Illinois, Ohio, Minnesota, and Nebraska). Of the 30 new units, most are small units (less than 10 MW) that use petroleum as their primary fuel; however, 3 of the new units are larger (at least 100 MW)—2 burn natural gas and 1 uses waste heat.

The largest share (40 percent) of the Nation's generating capability is in coal-fired plants (Figure 2). Gas-fired plants represent 21 percent of the total U.S. capability, while hydroelectric facilities and nuclear plants each provide a 13-percent share.

Table 3. U.S. Electric Utility Generating Unit Additions, 1998

Month/ Company	Plant	State	Generating Unit Number	Net Summer Capability (megawatts)	Energy Source	Unit Type Code
January						
Durant City of	Durant	IA	7	1.9	Petroleum	IC
Cascade City of	Cascade	IA	3A	1.9	Petroleum	IC
Florida Keys El Coop Assn	Marathon	FL	10	3.5	Petroleum	IC
Mountain Lake City of	Mountain Lake	MN	7	1.8	Petroleum	IC
February						
Mountain Lake City of	Mountain Lake	MN	6	1.8	Petroleum	IC
American Municipal Power-Ohio	Prospect Mun. Elec.	OH	1	1.8	Petroleum	IC
Nantucket Electric Co	Nantucket	MA	16, 17	5.0	Petroleum	IC
March						
None	--	--	--	--	--	--
April						
Osage City of	Osage	IA	8	3.6	Petroleum	IC
Gulf Power Co	Pea Ridge	FL	1	14.3	Gas	GT
May						
Geneseo City of	Geneseo	IL	9	3.9	Petroleum	IC
June						
Montezuma City of	Montezuma	IA	8	1.8	Petroleum	IC
Alabama Electric Coop Inc	McIntosh	AL	2	113.0	Gas	CT
Alabama Electric Coop Inc	McIntosh	AL	3	114.0	Gas	GT
Tennessee Valley Authority	Meridian	MS	1, 2, 3, 4, 5	8.9	Petroleum	IC
July						
Public Service Co of Colorado	Fort St. Vrain	CO	CW1	100.0	Waste Heat	CW
August						
Nebraska City of	Nebraska City #2	NE	11,12	9.2	Gas	IC
September						
None	--	--	--	--	--	--
October						
Ketchikan City of	SW Bailey	AK	4	10.5	Petroleum	IC
Key West City of	Stock Island	FL	GT2, GT3	32.0	Petroleum	GT
November						
Nebraska City of	Nebraska City #2	NE	13	4.6	Petroleum	IC
December						
Janesville City of	Janesville	MN	4	1.8	Petroleum	IC
La Plata City of	La Plata	MO	8,9	2.0	Petroleum	IC
Maui Electric Co	Maalaea	HI	17	20.0	Petroleum	CT
Total				457.5		

Notes: Net summer capability is estimated. Totals may not equal sum of components because of independent rounding. Data are preliminary. Final data for the year are to be released in the *Inventory of Power Plants in the United States* (DOE/EIA-0095). Unit Type Codes are: CT = Combined Cycle Combustion Turbine, CW = Combined Cycle Steam Turbine - Waste Heat Boiler only, GT = Combustion (gas) Turbine, IC = Internal Combustion.

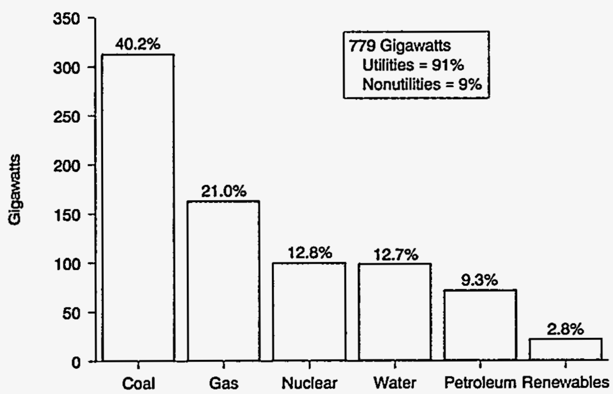
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 4. Retirements at U.S. Electric Utilities, 1998

State	Utility/Unit	Net Summer Capability (Megawatts)	Primary Fuel Source
Connecticut	Northeast Nuclear Energy Company/		
	Millstone 1	641.0	Uranium
Illinois	Commonwealth Edison Company/		
	Zion 1	1,040.0	Uranium
	Zion 2	1,040.0	Uranium
	City of Geneseo/		
	Geneseo 6	0.8	Fuel Oil No. 2
Texas	Texas Utilities Company/		
	Dallas 3	75.0	Natural Gas
	Dallas 9	70.0	Natural Gas
Total		2,866.8	

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

Figure 2. Share of U.S. Net Summer Capability by Energy Source, as of January 1, 1998



Note: •Total value includes multifuel capability (209 megawatts), petroleum/natural gas combined (8,541 megawatts), and expander turbine fueled by hot nitrogen (13 megawatts). •Data on electric power industry capability are final. •Totals may not equal sum of components due to independent rounding.

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report," and Form EIA-867, "Annual Nonutility Power Producer Report."

Generation

The industry generating capability produced a total of 3,620 billion kilowatthours (kWh) of electricity in 1998, compared with 3,494 billion kWh in 1997 to meet a 2.6-percent increase in demand. Electricity production by all energy sources increased from the 1997 levels except for generation with renewable resources (Table 5). The majority of the renewable resources are hydroelectric. The electric utilities experienced the largest decreases in hydroelectric generation in Washington (24 billion kWh) and Oregon (7 billion kWh), where the mountain snowpack in January 1998 was less than 70 percent of the long-term average levels, as compared with 130 percent of the average in January 1997.[4] Precipitation levels were also lower than 1997 throughout much of the year. In contrast, hydroelectric generation in California increased by 9 billion kWh because of above normal precipitation in 1998. Utilities in most other areas of the country, except for the South Atlantic Census Division,

Table 5. Net Generation in the U.S. Electric Power Industry by Energy Source, 1997 and 1998
(Million Kilowatthours)

Energy Source	1997	1998
Coal[1]	1,843,831	1,872,186
Petroleum[2]	92,727	129,104
Natural Gas[3]	497,430	544,765
Nuclear	628,644	673,702
Renewable		
Hydroelectric (conventional)	358,949	328,581
Other[4]	73,763	72,867
Hydroelectric Pumped Storage	-4,040	-4,478
Other[5]	3,137	2,905
Total	3,494,441	3,619,632

[1]Includes coal, anthracite, culm, coke breeze, fine coal, waste coal, bituminous gob, and lignite waste.
[2]Includes petroleum, petroleum coke, diesel, kerosene, liquid butane, liquid propane, oil waste, and tar oil.
[3]Includes natural gas, waste heat, waste gas, butane, methane, propane, and other gas.
[4]Includes geothermal, biomass (wood, wood waste, peat, wood liquors, railroad ties, pitch, wood sludge, municipal solid waste, agricultural byproducts, straw, tires, landfill gases, and fish oils), wind, solar, and photovoltaic.
[5]Includes hydrogen, sulfur, batteries, chemicals, and purchased steam.
Notes: •Data for 1997 and for 1998 utility generation are final. •Values for 1998 are estimated. Nonutility generation numbers have been projected on the basis of the two most recent "growth" periods, i.e., 1995 to 1996 and 1996 to 1997. The average growth rates for each fuel type from those periods were applied to 1997 numbers to obtain 1998 generation numbers. There was an additional adjustment made because some utilities changed status from "utility" to "nonutility" during the year. The industry generation numbers are derived by adding the corresponding utility and "nonutility" numbers. •Totals may not equal sum of components because of independent rounding.
Sources: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," Form EIA-867, "Annual Nonutility Power Producer Report."

[4] Information on snowpack was prepared by USDA, Natural Resources Conservation Service, National Water and Climate Center, Portland, Oregon.

also produced less electricity with conventional hydroelectric power in 1998.

Nuclear-powered generation during 1998 (674 billion kWh) returned to the record levels produced in 1995 (673 billion kWh) and 1996 (675 billion kWh) after a decline to 629 billion kWh in 1997. Seven units, that had been out of service for an extended period of time, were restarted during 1998. The units were Salem 1 in New Jersey, Quad Cities 1 and 2 and LaSalle 1 in Illinois, Millstone 3 in Connecticut, and Beaver Valley 1 and 2 in Pennsylvania. In addition, the average capacity factor[5] for all nuclear units increased from 71 percent in 1997 to 78 percent in 1998—many individual units achieved a 90-percent or higher efficiency.[6]

Among the fossil energy sources used within the utility sector, petroleum showed the largest increase, up by 32 billion kWh from the 1997 level to 110 billion kWh, reflecting the 26-percent drop in cost to 214 cents per million Btu from the prior year. This was the lowest price in more than 20 years (the 1976 price was 199 cents per million Btu). Over 90 percent of the increase occurred in only six States—Florida, Maryland, Mississippi, New York, Pennsylvania, and Virginia. The average delivered cost of petroleum declined in every State between 1997 and 1998, although it was still higher than the average delivered cost of natural gas in the majority of States. The increased petroleum-fired generation displaced natural gas-fired generation primarily in New York and Florida with five other States also following the same trend (Connecticut, Pennsylvania, New Hampshire, Delaware, and Alaska). However, gas-fired generation by utilities (309 billion kWh) was the highest it has been since 1981 (when it was 346 billion kWh). This level was achieved in 1998 because of the high demand for electricity.

Coal-fired generation by utilities increased by 1 percent in 1998 to 1,807 billion kWh. In the New England Census Division States that use coal (Connecticut, Massachusetts, and New Hampshire) and in New Jersey, electric utilities reported a decline in coal-fired generation (down by 31 and 18 percent, respectively) primarily due to the increased nuclear-powered generation and the sale of two large coal-fired plants in Massachusetts to a nonutility operator. In Illinois and Kentucky, coal-fired generation reported by utilities also declined from 1997 levels, by 8 and 6 percent, respectively, as a result of the sale of several large coal-fired power plants to nonutilities. In the Western States, the reverse trend occurred. Coal-fired generation by utilities replaced the lower hydroelectric generation in 1998, increasing by more than 4 billion kWh in Washington and Oregon combined and by nearly 13 billion kWh across States that comprise the Mountain Census Division.

Detailed statistics at the State and Census division levels on utility generation can be found in Appendix A. When comparing the State or Census division data for 1998 with 1997, however, it is important to note that sometimes a decline in generation by a certain fuel type or limited growth may be due, in part, to the sale of plants that are listed in Table 2.

Fossil Fuel Consumption, Stocks, and Costs

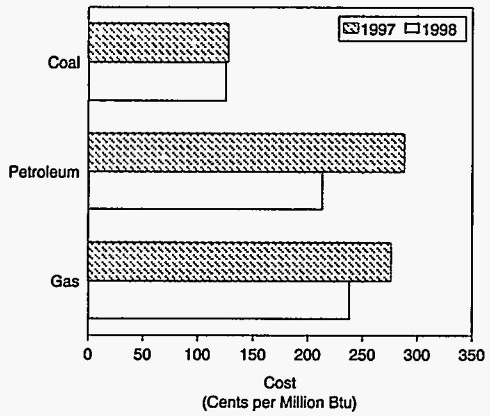
The record level generation by electric utilities also resulted in high levels of fossil fuel consumption. Electric utilities consumed a record level of 911 million short tons of coal in 1998, even with the sale of 4,664 MW of coal-fired capacity to nonutility companies during the year. Utilities received 929 million short tons of coal, 48 million short tons more than in 1997. The average cost of coal delivered for the year was $1.25 per million Btu—compared with $1.27 per million Btu in 1997 (Figure 3). Part of this increase in coal receipts by utilities went toward rebuilding their stockpiles starting in October. By year's end, stocks rose to 121 million short tons. On the other hand, the use of more petroleum by utilities, up 53 million barrels (or 43 percent) from 1997, was an indication of substantially lower petroleum costs during the year ($2.14 per million Btu in 1998, compared with $2.88 per million Btu in 1997). The 1998 consumption level for petroleum was the highest since 1991. Utility petroleum purchases amounted to 165 million barrels (up 40 percent from the prior year). Petroleum stocks also increased by the end of 1998 to 54 million barrels.

Gas consumption by electric utilities increased to 3,258 billion cubic feet, the highest level since 1981. During the year, 2,920 billion cubic feet (Bcf) of gas were delivered to utilities, 155 Bcf more than for the prior year. The cost for that gas was $2.38 per million Btu (14 percent lower than in 1997). Although the sale of gas-fired plants to the nonutility sector during 1998 contributed to lower utility receipts in three States (California,

[5] Capacity factor is the ratio of the electricity produced by a generating unit, for the period of time considered, to the energy that could have been produced at continuous full-power operation during the same period.

[6] Energy Information Administration, *Monthly Energy Review*, March 1999, DOE/EIA-0035(99/03), Table 8.1, p. 105; *Nucleonics Week*, McGraw-Hill Companies, New York, (February 11, 1999), p.22.

Figure 3. Average Cost of Fossil Fuels at U.S. Electric Utilities, 1997 and 1998



Notes: •Data for 1997 are final; data for 1998 are preliminary. •Data are for electric generating plants with a total steam-electric and combined cycle nameplate capacity of 50 or more megawatts. •Data do not include petroleum coke.

Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Massachusetts, and Rhode Island), a substantial increase in utility receipts in the West South Central Census Division led to a higher overall total gas receipts than for 1997. In the West South Central Census Division, gas receipts rose from 1,446 Bcf in 1997 to 1,712 Bcf during the year. On the other hand, gas receipts fell by 108 Bcf in California where the nonreporting status of several plants owned by Southern California Edison Company (SCE) and Pacific Gas & Electric Company (PG&E) likely affected reported totals for the State.[7]

Market Transactions

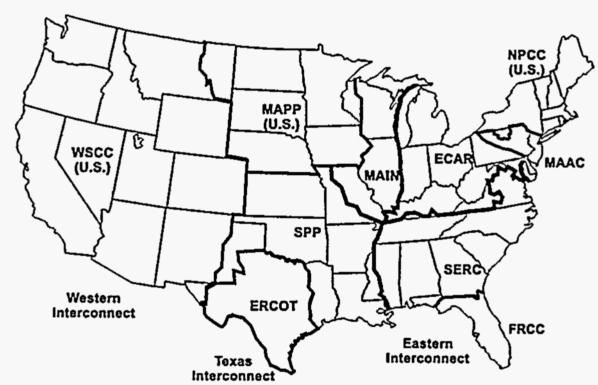
Wholesale Market

The volume of wholesale trade in the electric power industry has been increasing. Wholesale trade was constrained prior to opening access to transmission lines; subsequently, the number of companies participating in the market has grown and electricity trading is now considered similar to other commodity trading. Wholesale transactions include daily, monthly, and long-term bilateral contracts, sales and purchases through power exchanges, and financial transactions such as futures and options. The expansion of the market led to increased price volatility in 1998.

Abnormal Spike in Midwest Wholesale Prices. During the week of June 22-26, 1998, wholesale prices of electricity rose to $7,500 per megawatthour (MWh) in the Midwest as compared to an average price of $25 per MWh.[8] Although this anomaly was short-lived, it represented unprecedented volatility in market prices for electricity. The price spikes resulted from a combination of several unusual occurrences.

While some large utilities in the Midwest had planned outages of some generators for maintenance, several other generators were down due to unplanned outages. High outages of generating capability were present in two North American Electric Reliability Council (NERC) regions: ECAR and MAIN (Figure 4). The outages for

Figure 4. North American Electric Reliability Council Region Map



ECAR - East Central Area Reliability Coordination Agreement
ERCOT - Electric Reliability Council of Texas
FRCC - Florida Reliability Coordinating Council
MACC - Mid-Atlantic Area Council
MAIN - Mid-America Interconnected Network
MAPP - Mid-Continent Area Power Pool
NPCC - Northeast Power Coordinating Committee
SERC - Southeastern Electric Reliability Council
SPP - Southwest Power Pool
WSCC - Western Systems Coordinating Committee

Source: North American Electric Reliability Council.

[7] During 1998, several Southern California Edison and Pacific Gas &Electric plants were sold and are now operating as nonutility power plants and are, therefore, no longer required to report fuels receipts on FERC Form 423.

[8] Federal Energy Regulatory Commission, "Staff Report to the Federal Energy Regulatory Commission on the Causes of Wholesale Electric Pricing Abnormalities in the Midwest During June 1998." September 22, 1998, Washington, DC.

both of these councils were well beyond planned estimates.[9]

These outages coincided with a week of unseasonably high temperatures throughout ECAR, MAIN, and the SPP. During this period, temperatures were in the low 90s for MAIN and ECAR, and SPP averaged 95 degrees. Neighboring council regions, the SERC and the MAAC, also had temperatures that averaged more than 90 degrees. The unusually high temperatures brought about an unexpected period of high demand for electricity in the Midwest. In addition to those unplanned outages and high temperatures, transmission lines were damaged as a result of severe thunderstorms that passed through the region during this period. For example, one of the storms produced tornadoes that took down some 345-kilovolt lines and caused a nuclear powerplant to shutdown. This further affected electrical operations within ECAR, by reducing both generation and transmission capacity. While thunderstorms in MAAC produced similar damage, they also reduced the demand for electricity.

Utilities and power marketers located in ECAR and MAIN that buy nonfirm and surplus energy from suppliers in MAAC were notified early on June 24 that these transactions would be terminated. This occurred so that MAAC could meet a projected all-time high demand on its own system. Some contract transactions were also terminated, reducing the likelihood for importing additional power and further diminished the availability of functionally operating generation. (However, during this same period, utilities in SERC, MAIN, ECAR, NPCC, and nonutility generators were experiencing high demand and had variable amounts of surplus energy not under contract or committed to reserves that could be made available for sale during different parts of the day.)

Another, and perhaps the major, contributor to the dramatic increase in wholesale prices was the default of a power marketer in the delivery of firm power. To meet deficiencies resulting from those contract defaults, purchasers depending on these deliveries had to locate other sources of electricity in a market already affected by high demand and capacity shortages in the Midwest. Utilities operating in the area affected by these unusual conditions were obligated to meet customer demand, thus maintaining reliability. The problem of finding and securing power supplies—*at any cost*—in order to comply with the requirement to serve customers caused prices to skyrocket. On June 22, supply and transmission constraints pushed prices in the ECAR Region to about $400 per MWh, compared with an average price of $81 per MWh during the peak hours of the day.[10] With no apparent relief in sight, prices jumped to more than $1,000 per MWh the following day. On June 25, wholesale electricity prices began at $1,400 per MWh and by noon had reached around $4,000 per MWh. As the scramble for power continued, prices escalated hourly, finally soaring to an astronomical $7,500 per MWh.

Importantly, those high prices in the Midwest occurred only in the wholesale market for electricity. None of the five States in the Midwest (Illinois, Indiana, Michigan, Ohio, or Wisconsin), which are part of the MAIN and ECAR Regions, were operating in retail competitive markets in 1998. Retail rates in these States were still regulated by each of the State's utility commissions. As a result, the estimated losses of more than $500 million suffered by the electric utilities that week[11] could not be automatically passed onto the retail customers.

Wholesale Purchases Through Power Exchanges. Besides the traditional bilateral contracts or agreements, wholesale auctions of electricity occurred for the first time during 1998. These transactions took place in California and in the Pennsylvania, New Jersey, Maryland (PJM) control area. Although the wholesale auction of the California Power Exchange (CalPX) differs from that within the PJM-ISO and the pricing policies are

[9] Multi-regional operational issues arise in the electrical system when there are extreme temperature variations (very high or very low) spread across several reliability regions for lengthy periods. The operators of electrical systems, electric utilities or Independent System Operators must make sure that they have generating and transmission resources available, first, to meet their internal needs. Correspondingly, the responsibility for problems rests first within a reliability region. But if generation supply is unavailable or insufficient from within or outside the region, then that region must take responsibility and drop customer load along with other relief actions in order to avoid harming the electrical operations of the other systems. The expectation was that all the planned generating capacity should be available to meet the normal high-peak demand periods of July and August. However, the first summer peak occurred in June. Reaching peak load should not be considered an unanticipated event. The country has seen considerable economic growth since the last period of setting new multi-regional peak demand levels, so it should not be unexpected to anticipate a growth in electrical demand plus additional increases during an extended period of rising temperatures. Some utilities could not have all their powerplants available because of actions taken by the Nuclear Regulatory Commission to address compliance issues on operating nuclear power plants.

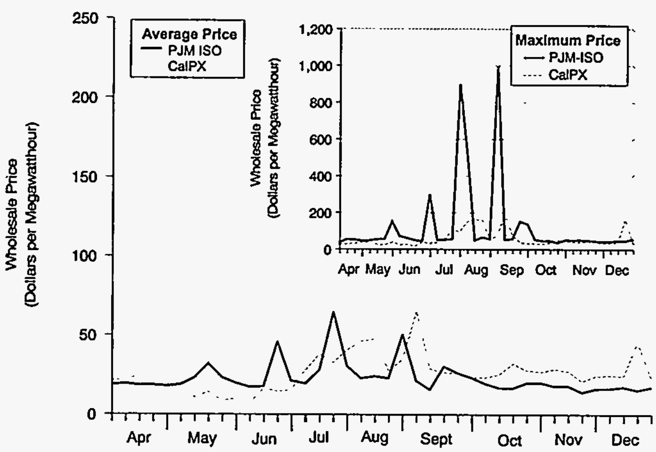
[10] Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, "Briefing Book: Midwest Electricity Price Spike in June 1998" (Draft: September 15, 1998).

[11] *Wall Street Journal*, September 1, 1998, p. 1.

derived differently in each of the two entities, there are some similarities. Suppliers submit bids for providing electricity for each hour of the following day and purchasers submit demands for power hour by hour. The intersection of the supply and demand curves for each hour produces the market clearing price (MCP). Under unconstrained transmission conditions, the wholesale price of electricity is the MCP. When transmission is constrained and congestion occurs a different price is paid. Zonal prices are derived in California, whereas within the PJM-ISO, the locational marginal price (LMP) is used.[12]

For comparison purposes, the hourly day ahead MCPs at the CalPX were averaged to derive weekly average prices (Figure 5) for the period, April 1 through December 31, 1998. Average weekly prices ranged from a low of $6.87 per MWh during the first full week of June (June 7 through June 13) to a high of $65.19 per MWh during the week from August 30 through September 5 (Table 6). Although there is little variability among the monthly prices, the largest monthly average price occurred in August at $39.52 per MWh. The maximum day ahead prices for California represent the largest hourly day ahead MCP price for a given week and month.

Figure 5. Wholesale Hourly Price of Electricity at the California Power Exchange and the Pennsylvania-New Jersey-Maryland Independent System Operator, April Through December 1998



Sources: California Power Exchange (CalPX) and the Pennsylvania-New Jersey-Maryland Independent System Operator (PJM-ISO), Western Interface prices.

During 1998, the largest maximum day ahead price at the CalPX was $190.94 per MWh, which also occurred during the week from August 30 through September 5. In addition, there were five other weeks during the period (April through December) in which the maximum day ahead price exceeded $100.00 per MWh in California. For the most part, however, the maximum day ahead prices ranged from $20.00 to $40.00 per MWh.

For the PJM-ISO's Western Interface, the price (MCPs and LMPs)[13] on a MWh basis was used to identify the maximum hourly price and the average hourly price for April through December 1998 (Figure 5). Average prices in the Western Interface (Table 7) ranged from a low of $14.13 per MWh (November 22-28) to a high of $64.93 per MWh (July 19-25). It is important to note however that the average monthly LMP did not exceed $34.19 per MWh nor fall below $16.75 per MWh. Maximum prices, per MWh, ranged from a low of $36.55 (October 18-24) to a high of $999.00 during the week of August 23-29. During the week of June 21-27, the week of the Midwest price spike, the maximum price at the PJM-ISO was $300.10.

Futures Contracts. During 1998, five new electricity futures and options contracts began trading. They expand the futures market from the original two futures contracts that were begun by the New York Mercantile Exchange (NYMEX) for delivery of electricity at two locations adjacent to the California market: the California-Oregon Border (COB) and the Palo Verde switchyard in Arizona. The original electricity futures contract markets both began trading in the spring of 1996 (March 29 for futures and April 26 for options). The following are the new futures contract markets and the date they began trading: NYMEX (Cinergy Contract) July 10, 1998 and (Entergy Contract) July 10, 1998; Chicago Board of Trade (Commonwealth Edison Hub) September 11, 1998 and (TVA Hub) September 11, 1998; and the Minneapolis Grain Exchange (Twin Cities) September 14, 1998.

Power marketers, utilities, power producers, buyers, and investors can use electricity futures to lock in a sales price for power, protect a purchase price, mitigate price risk, and protect revenue targets. Prices for electricity futures are quoted for precise specifications delivered to a specific location at a specified point in time. Because electricity futures trading is conducted in an anonymous

[12] In addition to the day ahead prices, the PX began an hour ahead market, which was implemented in August 1998. Due to the lateness of the implementation of this market during the year, hour ahead prices, which are determined in the same manner as the day ahead prices, are not included in this report.

[13] Prior to April 1, the market clearing prices are shown, while the locational marginal prices are presented as of April 1.

Table 6. Wholesale Hourly Price of Electricity at the California Power Exchange, April Through December 1998
(Dollars per Megawatthour)

Time Interval	Day Ahead	
	Average Price	Maximum Price
Apr 1 - Apr 4	21.36	26.83
Apr 5 - Apr 11	21.40	27.39
Apr 12 - Apr 18	24.52	31.22
Apr 19 - Apr 25	23.05	36.74
Apr 26 - May 2	19.84	35.98
May 3 - May 9	13.93	25.33
May 10 - May 16	10.67	23.31
May 17 - May 23	13.98	37.37
May 24 - May 30	8.58	25.00
May 31 - Jun 6	9.74	26.39
Jun 7 - Jun 13	6.87	15.02
Jun 14 - Jun 20	16.24	38.02
Jun 21 - Jun 27	14.54	32.46
Jun 28 - Jul 4	15.21	37.01
Jul 5 - Jul 11	27.86	58.00
Jul 12 - Jul 18	38.16	102.17
Jul 19 - Jul 25	32.78	97.78
Jul 26 - Aug 1	40.84	151.10
Aug 2 - Aug 8	46.19	163.01
Aug 9 - Aug 15	47.63	159.95
Aug 16 - Aug 22	27.82	52.36
Aug 23 - Aug 29	34.63	75.00
Aug 30 - Sep 5	65.19	190.94
Sep 6 - Sep 12	28.83	77.93
Sep 13 - Sep 19	26.38	37.50
Sep 20 - Sep 26	26.24	31.75
Sep 27 - Oct 3	23.44	31.02
Oct 4 - Oct 10	23.28	29.25
Oct 11 - Oct 17	25.23	34.76
Oct 18 - Oct 24	32.08	47.84
Oct 25 - Oct 31	27.84	44.99
Nov 1 - Nov 7	26.82	39.29
Nov 8 - Nov 14	28.63	38.43
Nov 15 - Nov 21	27.28	43.93
Nov 22 - Nov 28	21.03	39.13
Nov 29 - Dec 5	24.24	33.00
Dec 6 - Dec 12	24.71	35.74
Dec 13 - Dec 19	24.17	35.22
Dec 20 - Dec 26	45.73	164.63
Dec 27 - Dec 31	23.45	35.02
1998		
April	22.62	36.74
May	11.73	37.37
June	12.54	38.02
July	32.46	151.10
August	39.52	163.01
September	34.01	190.94
October	26.66	47.84
November	25.74	43.93
December	29.13	164.63

Notes: Average is the arithmetic average of the clearing prices.
Source: California Power Exchange.

Table 7. Wholesale Hourly Price of Electricity at the Pennsylvania-New Jersey-Maryland Independent System Operator, 1998 (Dollars per Megawatthour)

Time Interval	Day Ahead	
	Average Price	Maximum Price
Jan 1 - Jan 3	18.69	72.20
Jan 4 - Jan 10	14.31	54.80
Jan 11 - Jan 17	17.69	55.20
Jan 18 - Jan 24	16.33	52.00
Jan 25 - Jan 31	16.37	51.30
Feb 1 - Feb 7	18.09	50.30
Feb 8 - Feb 14	18.07	50.60
Feb 15 - 21	16.36	40.00
Feb 22 - Feb 28	14.51	31.60
Mar 1 - Mar 7	16.24	39.90
Mar 8 - Mar 14	22.21	59.90
Mar 15 - Mar 21	19.81	60.30
Mar 22 - Mar 28	19.63	57.20
Mar 29 - Mar 31	17.84	55.60
Apr 1 - Apr 4	18.67	37.11
Apr 5 - Apr 11	19.36	54.08
Apr 12 - Apr 18	18.35	51.30
Apr 19 - Apr 25	18.44	45.73
Apr 26 - May 2	17.86	47.55
May 3 - May 9	18.78	53.97
May 10 - May 16	23.15	55.57
May 17 - May 23	31.98	152.00
May 24 - May 30	23.17	71.33
May 31 - Jun 6	19.69	60.44
Jun 7 - Jun 13	17.27	49.20
Jun 14 - Jun 20	17.62	44.72
Jun 21 - Jun 27	45.97	300.10
Jun 28 - Jul 4	21.24	51.06
Jul 5 - Jul 11	19.57	52.15
Jul 12 - Jul 18	28.14	55.33
Jul 19 - Jul 25	64.93	900.00
Jul 26 - Aug 1	30.55	518.11
Aug 2 - Aug 8	22.94	49.10
Aug 9 - Aug 15	24.16	65.60
Aug 16 - Aug 22	22.95	56.30
Aug 23 - Aug 29	50.72	999.00
Aug 30 - Sep 5	21.37	53.05
Sep 6 - Sep 12	15.83	55.77
Sep 13 - Sep 19	30.36	152.00
Sep 20 - Sep 26	26.19	137.90
Sep 27 - Oct 3	23.29	52.81
Oct 4 - Oct 10	19.52	46.02
Oct 11 - Oct 17	16.88	46.48
Oct 18 - Oct 24	16.79	36.55
Oct 25 - Oct 31	19.95	51.00
Nov 1 - Nov 7	20.18	50.58
Nov 8 - Nov 14	18.00	51.00
Nov 15 - Nov 21	18.13	49.25
Nov 22 - Nov 28	14.13	45.26
Nov 29 - Dec 5	16.30	42.45
Dec 6 - Dec 12	16.53	42.75
Dec 13 - Dec 19	17.45	47.90
Dec 20 - Dec 26	15.46	45.90
Dec 27 - Dec 31	17.33	57.23
1998		
January	16.42	72.20
February	16.76	50.60
March	19.32	60.30
April	18.69	54.08
May	23.95	152.00
June	24.93	300.10
July	34.19	900.00
August	29.59	999.00
September	23.66	152.00
October	18.24	51.00
November	17.35	51.00
December	16.75	57.23

Notes: Average is the arithmetic average of the hourly prices.
Source: Pennsylvania, New Jersey, Maryland-Independent System Operator, Western Interface prices.

public auction with prices displayed for all to see, the market performs the important function of price discovery.

An electricity futures contract at NYMEX consists of 736 megawatthours delivered over a monthly period. Delivery is 2 MW for each hour of the 16-hour on-peak delivery period during the business days of the month. The highest daily settlement price during 1998 for delivery one month in the future at Palo Verde was $59.75 per megawatthour, and the peak price at the COB was $45.28 per megawatthour—both occurred in July for August delivery (Figures 6 and 7). The meaningfulness of these prices is diminished by the low volume of trading in these newly established futures markets. As trading volumes increase, prices should more accurately reflect wholesale prices in the spot market.

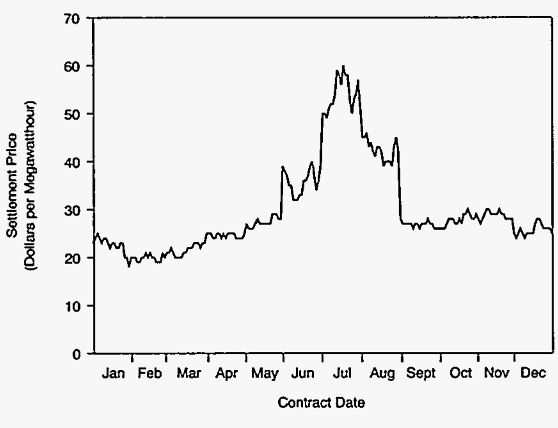
The average monthly settlement prices on 1998 futures contracts at Palo Verde, COB, Cinergy, and Entergy are highest for delivery in June through September (Tables 8 through 11). The futures contracts settled in July, October, November and December of 1998 at Cinergy for delivery in July and August of 1999 all have average settlement prices over $100 per megawatthour. These expectations may reflect the experience of the price spike of June 1998 and continued concerns about availability of supply. Similarly, the futures contracts settled in October, November, and December of 1998 at Entergy for delivery in July and August of 1999 also have average settlement prices over $100 per megawatthour.

Data are not provided for transactions at the three sites run by the Chicago Board of Trade and the Minneapolis Grain Exchange because of limited activity during 1998. The specifications for a futures contract at the Chicago Board of Trade consists of 1,680 megawatthours delivered over a monthly period at a rate of 5 MW for each hour of its 16-hour on-peak delivery during the business days of the month.

Retail Sales

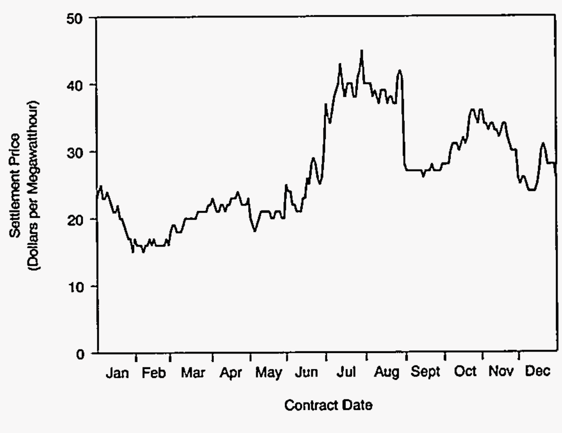
In 1998, the estimated quantity of electricity sold in the retail market (that is, to ultimate consumers) rose to 3,220 billion kWh, 2.6 percent higher than the 1997 level (3,140 billion kWh) to meet higher demand.[14] As a result of deregulation occurring in several States, total sales in the retail market by all energy service providers have not been captured. Consequently, the growth in sales is likely underestimated, in particular for the commercial and industrial sectors. In addition, estimates for nonutility retail sales for 1998 are not available yet (1997 nonutility sales were estimated at 18 billion kWh).[15] The growth in retail electricity sales occurred because of an estimated 3.6-percent growth in Gross Domestic Product (GDP)[16] and warmer weather. The increase in retail sales maintains an upward trend established at least as

Figure 6. Daily Settlement Prices for Month Ahead Futures at NYMEX Palo Verde, 1998



Source: Commodity Futures Trading Commission.

Figure 7. Daily Settlement Prices for Month Ahead Futures at NYMEX California Oregon Border, 1998



Source: Commodity Futures Trading Commission.

[14] Data on electric utility retail sales are in Appendix A, Table A11.
[15] Energy Information Administration, *Electric Power Annual 1997 Volume II*, DOE/EIA-0348(97)/2, Table 51, p. 87.
[16] U.S. Department of Commerce, Bureau of Economic Analysis.

Table 8. Average Monthly Settlement Prices for Electricity Futures at NYMEX Palo Verde, 1998

Delivery Date	1998 Contract Date											
	January	February	March	April	May	June	July	August	September	October	November	December
1998												
January	NA	--	--	--	--	--	--	--	--	--	--	--
February	22.82	--	--	--	--	--	--	--	--	--	--	--
March	21.55	19.88	--	--	--	--	--	--	--	--	--	--
April	21.45	19.95	21.58	--	--	--	--	--	--	--	--	--
May	23.45	23.11	23.64	24.56	--	--	--	--	--	--	--	--
June	26.50	26.26	27.55	28.57	27.35	--	--	--	--	--	--	--
July	32.60	34.68	39.00	39.95	39.45	35.79	--	--	--	--	--	--
August	36.65	40.16	45.45	47.10	46.75	46.50	48.81	--	--	--	--	--
September	33.60	36.16	39.73	40.43	41.15	42.05	47.50	42.33	--	--	--	--
October	26.30	28.42	29.23	29.62	29.50	29.82	31.14	28.81	24.10	--	--	--
November	25.70	26.53	27.23	28.57	29.10	29.32	28.73	25.52	25.14	27.79	--	--
December	27.75	28.26	28.09	29.24	29.75	30.09	31.14	29.38	27.52	29.18	28.75	--
1999												
January	25.95	26.11	26.18	26.05	26.35	26.32	26.73	24.95	25.19	27.32	27.84	25.68
February	24.25	24.11	24.14	23.95	23.80	23.86	23.95	22.86	23.67	25.23	26.95	24.50
March	22.90	22.63	22.09	21.86	21.75	21.55	21.86	21.10	22.05	24.05	25.63	22.91
April	21.83	20.79	20.41	20.81	19.80	19.68	21.18	21.33	22.24	22.82	23.84	20.86
May	24.00	23.00	23.14	23.71	22.55	22.05	22.73	22.00	22.24	23.00	23.32	22.27
June	27.61	26.95	27.50	27.90	27.60	27.55	29.00	28.10	28.05	28.50	31.05	31.00
July	33.80	34.84	38.41	39.86	39.25	37.59	39.91	37.76	37.62	41.50	47.32	46.59
August	46.59	40.54	44.59	46.33	46.00	47.45	52.73	52.48	53.19	57.50	62.47	63.23
September	--	--	39.44	40.57	40.00	41.55	44.91	42.52	41.95	46.77	51.63	51.36
October	--	--	--	--	--	--	--	--	--	--	--	--
November	--	--	--	--	--	--	--	--	--	--	--	--
December	--	--	--	--	--	--	--	--	--	--	--	--

NA = Not available.

Notes: • Prices are arithmetic averages of daily settlement prices. • Shaded values are Average Month Ahead Future Price.

Source: Commodity Futures Trading Commission.

Table 9. Average Monthly Settlement Prices for Electricity Futures at NYMEX California Oregon Border, 1998

Delivery Date	1998 Contract Date											
	January	February	March	April	May	June	July	August	September	October	November	December
1998												
January	NA	--	--	--	--	--	--	--	--	--	--	--
February	21.29	--	--	--	--	--	--	--	--	--	--	--
March	18.65	16.13	--	--	--	--	--	--	--	--	--	--
April	17.60	16.21	19.79	--	--	--	--	--	--	--	--	--
May	17.85	16.79	18.82	22.28	--	--	--	--	--	--	--	--
June	18.65	17.74	19.68	22.24	20.24	--	--	--	--	--	--	--
July	22.95	22.21	25.55	28.19	27.40	24.68	--	--	--	--	--	--
August	27.00	27.16	30.86	33.43	33.85	33.68	39.16	--	--	--	--	--
September	26.40	27.16	30.95	32.81	32.85	32.32	37.18	38.89	--	--	--	--
October	24.70	25.32	27.36	28.76	29.40	29.00	29.32	27.67	27.06	--	--	--
November	26.20	26.53	27.27	28.76	29.60	30.14	30.18	29.24	28.19	32.16	--	--
December	28.75	28.68	30.23	31.76	30.75	31.59	32.36	31.62	30.33	33.55	32.56	--
1999												
January	24.90	24.79	27.23	28.81	28.10	27.64	27.41	26.90	28.00	32.23	31.74	26.58
February	23.20	22.95	24.32	24.76	23.85	24.09	24.00	23.71	25.10	28.27	28.32	24.18
March	19.55	19.00	20.05	20.05	18.90	18.91	20.05	20.48	21.57	22.95	22.95	21.45
April	18.05	16.58	17.77	18.19	18.15	18.77	20.00	18.86	18.29	19.73	22.00	20.23
May	18.65	17.00	17.95	18.95	17.95	17.95	19.14	18.29	18.19	19.36	19.47	17.82
June	19.45	17.95	19.00	19.95	19.40	18.68	19.05	18.62	18.95	19.91	20.05	18.36
July	23.75	22.89	24.86	26.76	26.80	26.50	27.77	28.00	28.52	30.95	31.58	29.41
August	--	--	--	32.05	32.75	34.82	37.86	37.10	38.24	41.45	43.74	42.95
September	--	--	--	32.05	33.00	33.05	36.23	35.90	36.57	39.64	42.42	40.86
October	--	--	--	--	--	29.84	29.83	29.05	28.00	29.86	31.00	28.41
November	--	--	--	--	--	30.53	30.33	30.10	29.10	31.09	32.53	30.14
December	--	--	--	--	--	31.63	31.50	31.90	31.00	32.86	33.21	30.86

NA = Not available.

Notes: • Prices are arithmetic averages of daily settlement prices. • Shaded values are Average Month Ahead Future Price.

Source: Commodity Futures Trading Commission.

Table 10. Average Monthly Settlement Prices for Electricity Futures at NYMEX Cinergy, 1998

Delivery Date	1998 Contract Date											
	January	February	March	April	May	June	July	August	September	October	November	December
1998												
January	NA	NA	NA	NA	NA	NA	--	--	--	--	--	--
February ...	NA	NA	NA	NA	NA	NA	--	--	--	--	--	--
March	NA	NA	NA	NA	NA	NA	--	--	--	--	--	--
April	NA	NA	NA	NA	NA	NA	--	--	--	--	--	--
May	NA	NA	NA	NA	NA	NA	--	--	--	--	--	--
June	NA	NA	NA	NA	NA	NA	--	--	--	--	--	--
July	NA	NA	NA	NA	NA	NA	--	--	--	--	--	--
August	NA	NA	NA	NA	NA	NA	--	--	--	--	--	--
September	NA	NA	NA	NA	NA	NA	44.56	31.39	--	--	--	--
October	NA	NA	NA	NA	NA	NA	25.19	24.24	24.78	--	--	--
November ..	NA	NA	NA	NA	NA	NA	25.44	24.95	25.71	24.58	--	--
December ..	NA	NA	NA	NA	NA	NA	26.88	25.81	26.48	26.45	24.44	--
1999												
January	NA	NA	NA	NA	NA	NA	29.81	28.90	30.29	33.41	30.26	26.00
February ...	NA	NA	NA	NA	NA	NA	28.43	27.62	29.33	31.82	28.89	25.68
March	NA	NA	NA	NA	NA	NA	24.71	24.52	25.19	25.59	24.53	24.14
April	NA	NA	NA	NA	NA	NA	25.00	24.67	24.52	24.91	23.63	23.45
May	NA	NA	NA	NA	NA	NA	25.00	26.10	27.90	33.55	32.79	28.82
June	NA	NA	NA	NA	NA	NA	50.57	42.38	50.10	70.82	74.79	63.50
July	NA	NA	NA	NA	NA	NA	105.56	79.38	91.52	131.64	147.58	124.68
August	NA	NA	NA	NA	NA	NA	105.56	77.86	86.05	122.82	136.05	116.59
September	NA	NA	NA	NA	NA	NA	37.87	33.14	35.90	41.32	39.84	37.14
October	NA	NA	NA	NA	NA	NA	--	--	--	--	--	--
November ..	NA	NA	NA	NA	NA	NA	--	--	--	--	--	--
December ..	NA	NA	NA	NA	NA	NA	--	26.00	26.00	26.00	25.68	24.77

NA = Not available.

Notes: • Prices are arithmetic averages of daily settlement prices. • Shaded values are Average Month Ahead Future Price.

Source: Commodity Futures Trading Commission.

Table 11. Average Monthly Settlement Prices for Electricity Futures at NYMEX Entergy, 1998

Delivery Date	1998 Contract Date											
	January	February	March	April	May	June	July	August	September	October	November	December
1998												
January	NA	NA	NA	NA	NA	NA	--	--	--	--	--	--
February ...	NA	NA	NA	NA	NA	NA	--	--	--	--	--	--
March	NA	NA	NA	NA	NA	NA	--	--	--	--	--	--
April	NA	NA	NA	NA	NA	NA	--	--	--	--	--	--
May	NA	NA	NA	NA	NA	NA	--	--	--	--	--	--
June	NA	NA	NA	NA	NA	NA	--	--	--	--	--	--
July	NA	NA	NA	NA	NA	NA	--	--	--	--	--	--
August	NA	NA	NA	NA	NA	NA	--	--	--	--	--	--
September	NA	NA	NA	NA	NA	NA	47.56	32.61	--	--	--	--
October	NA	NA	NA	NA	NA	NA	25.63	24.67	23.37	--	--	--
November ..	NA	NA	NA	NA	NA	NA	25.63	24.90	25.33	23.20	--	--
December ..	NA	NA	NA	NA	NA	NA	27.87	26.52	26.38	26.14	21.22	--
1999												
January	NA	NA	NA	NA	NA	NA	30.00	28.76	30.05	32.32	28.68	23.84
February ...	NA	NA	NA	NA	NA	NA	27.67	26.81	28.10	29.82	27.32	23.91
March	NA	NA	NA	NA	NA	NA	24.08	24.52	24.38	24.64	23.68	23.09
April	NA	NA	NA	NA	NA	NA	24.69	24.90	24.48	24.64	23.74	22.55
May	NA	NA	NA	NA	NA	NA	25.92	26.19	28.00	33.59	32.89	28.36
June	NA	NA	NA	NA	NA	NA	48.00	42.48	49.05	70.14	73.95	60.50
July	NA	NA	NA	NA	NA	NA	88.85	74.95	85.24	119.36	136.05	115.77
August	NA	NA	NA	NA	NA	NA	88.62	74.62	83.38	115.00	128.63	109.77
September	NA	NA	NA	NA	NA	NA	--	33.00	36.05	41.23	39.26	36.23
October	NA	NA	NA	NA	NA	NA	--	--	--	--	24.00	23.32
November ..	NA	NA	NA	NA	NA	NA	--	--	--	--	--	--
December ..	NA	NA	NA	NA	NA	NA	--	--	26.00	26.00	25.05	24.32

NA = Not available.

Notes: • Prices are arithmetic averages of daily settlement prices. • Shaded values are Average Month Ahead Future Price.

Source: Commodity Futures Trading Commission.

early as 1949, with the exception of 1982, when retail sales fell by 2.8 percent due to economic factors.[17]

Utilities' retail sales of electricity increased from the prior year in all major end-use sectors. In the residential sector, where a total of 1,124 billion kWh of electricity were sold, a 4.5-percent increase from the 1997 volume was reported. In the commercial and industrial sectors, sales increased by 2.2 and 1.4 percent, respectively, in 1998 from 1997. Temperatures across the Nation during the summer months (June, July, and August) were considerably warmer than normal (Figure 8) and warmer than for the same period in the prior year. The occurrence of substantially warmer temperatures so early in the summer had a greater impact on retail sales in June than in July or August, because demand for electricity usually peaks during the latter two months. Retail sales rose across all sectors during the warm spell, but affected sales in the residential sector more than in the commercial and industrial sectors.

Figure 8. Above Normal Temperatures in the United States, 1998

Source: National Climatic Data Center, National Oceanic and Atmospheric Administration.

Temperatures in June were 21 percent higher than in June of 1997. In response, the use of electricity during the month by residential customers rose by 17 percent; usage by commercial and industrial customers also increased (5 and 1 percent, respectively). Although temperatures in July were only 10 percent higher than for the comparable month a year ago, sales of electricity to residential customers set a monthly record at 121 billion kWh (11 percent). Again, consumption of electricity in the commercial and industrial sectors also rose mildly (2 and 1 percent, respectively). August temperatures were 26 percent higher in 1998 than in 1997. In response, sales of electricity to residential customers were 12 percent more than the August 1997 sales—nearly matching the record set in July 1998. Consumption of electricity by commercial and industrial customers was also up (7 and 3 percent, respectively), compared with August 1997.

In the South Atlantic Census Division, which represents 21 percent of total U.S. retail sales, 676 billion kWh of electricity were sold in 1998–the most of any Census division in the country. Temperatures were warmer than normal during June, July, and August in the division. Utilities in Florida (with a 28-percent share of the division's sales) reported the second largest State-level increase (12 billion kWh or 7 percent) for the Nation. About two-thirds of that increase was in residential sales and at least 3 billion kWh of the overall increase occurred during June, July, and August in response to the warmer temperatures.

Retail sales in the West South Central Census Division, which represents 14 percent of the U.S. total, increased 5 percent from 1997 to 465 billion kWh. Residential customers bought 14 billion kWh (or 9 percent) more electricity in 1998 than in 1997—in part, due to the warmer temperatures. Utilities in Texas sold more electricity (301 billion kWh) than in any of the 50 States, as well as had the largest increase (15 billion kWh) from 1997.

In the Pacific Contiguous Census Division, 364 billion kWh of electricity were sold in 1998, slightly less than in 1997. Retail sales at 224 billion kWh in California (which has a 61-percent share of the division's total sales) represented the second largest quantity of State-level sales in the Nation, surpassed only by Texas. Nonetheless, California also had the largest quantitative (4 billion kWh) decrease in sales from 1997. The decline in retail sales by utilities occurred primarily in the industrial sector. In 1998, industrial customers took advantage of the option to choose an alternative energy service provider more than the residential and commercial customers. On the other hand, in the State of Washington, which provides 25 percent of the division's sales and where competition had not been started, retail sales in 1998 were 92 billion kWh (up by 4 percent from 1997). Industrial sales in the State grew 11 percent in 1998 from the 1997 level (35 billion kWh).

The 1998 share of total U.S. retail sales represented by the East North Central Census Division was 17 percent. Sales in the division (540 billion kWh) increased by 2 percent from 1997. During June, demand for electricity

[17] Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384 (97) (Washington, DC), Table 8.9, p. 225.

in the East North Central Census Division rose substantially due to high temperatures. In order to meet that increased demand, June retail sales in the division were 6 percent higher than in June 1997, accounting for 29 percent of the increase in the division's annual sales of 9 billion kWh. Nearly two-thirds of the rise in June sales for this division occurred in Illinois. Utility sales in Illinois, as well as other States in the Midwest, were affected by the situation surrounding the abnormal June spike in wholesale prices.

The East South Central Census Division sales rose 2 percent in 1998 from the 1997 level. A significant drop in commercial sales (down by 15 billion kWh or 24 percent) and substantially growth in the industrial sector (up by 15 billion kWh or 13 percent) occurred mainly due to a reclassification in Tennessee of retail sales from commercial to industrial–this did little to affect overall sales in the division. However, as might be expected, residential sales were up by 6 billion kWh or 6 percent, likely a result of the warm summer.

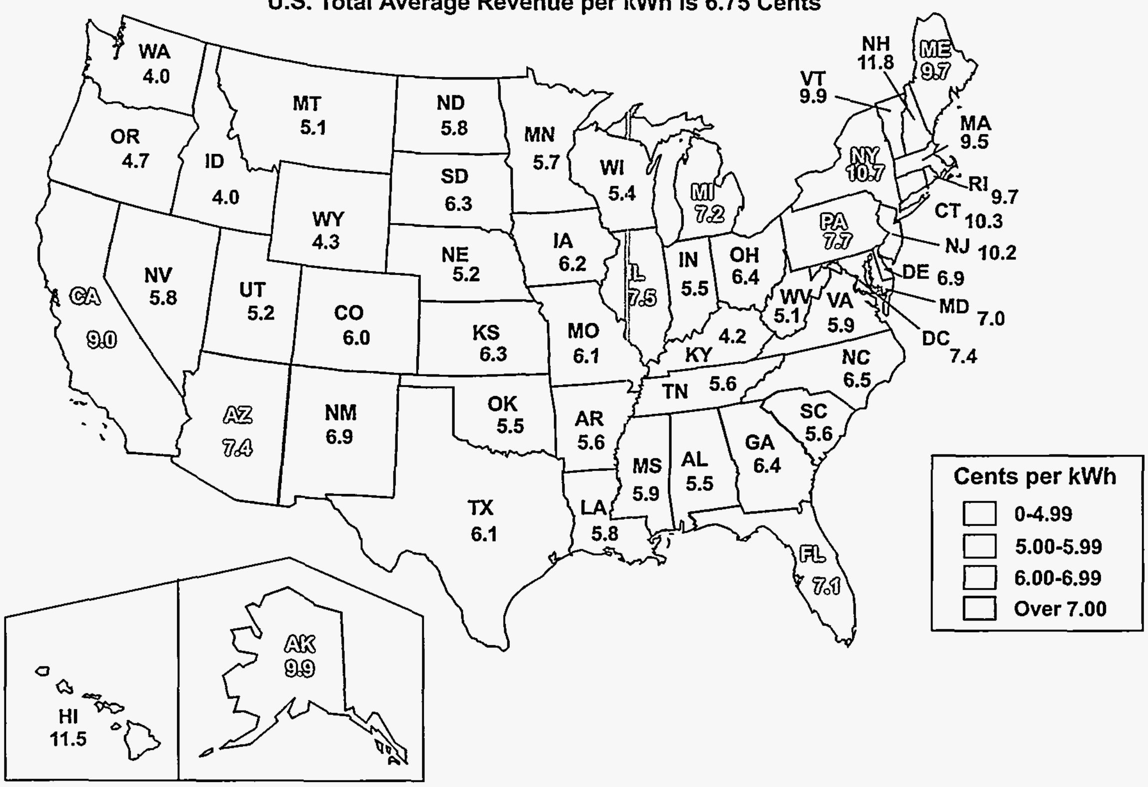
On a national level, the price of electricity sold by utilities in 1998 averaged 6.75 cents per kilowatthour, a decrease of 1.5 percent, compared with the 1997 national average of 6.85 cents per kilowatthour (Figure 9). In the residential sector, on a cents-per- kilowatthour basis, the price fell to 8.27 cents during the year from 8.43 cents in 1997. Both the commercial and the industrial reported lower electricity prices in 1998 at 7.43 and 4.50 cents per kilowatthour sold, respectively, compared with 7.59 and 4.53 cents per kilowatthour, respectively, in 1997. This decline in the price of electricity was a result of the lower cost for fossil fuels and rate reductions in response to the emerging environment of competition in the industry.

Transmission

As we began 1998, more than 200,000 circuit miles of high-voltage transmission lines existed, carrying

Figure 9. Estimated Average Revenue per Kilowatthour for All Sectors at U.S. Electric Utilities by State, 1998

U.S. Total Average Revenue per kWh is 6.75 Cents



kWh = Kilowatthour.

Note: •Estimates are preliminary. •The average revenue per kilowatthour of electricity sold is calculated by dividing revenue by sales.

Source: Energy information Administration, Form EIA-826, "Monthly Electric Utility Sales and Revenue Report with State Distributions."

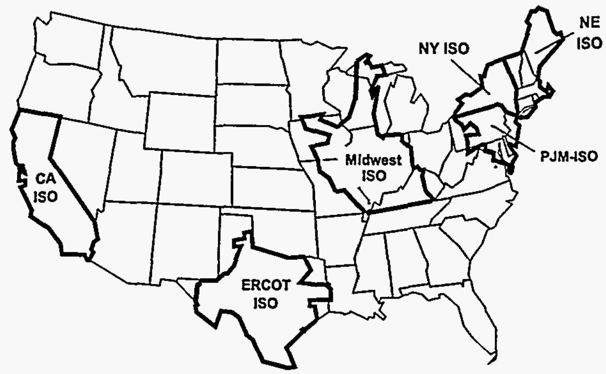
electricity from the generating plants to the various points of delivery.[18] These transmission lines make up three distinct power grids: Western, Eastern, and Texas, which are comprised of 10 NERC regions for the secure reliable operation of the transmission system (Figure 4). The access to and availability of sufficient transmission line capacity is important for a competitive wholesale market for electricity to flourish.

Independent System Operators (ISOs)

Companies referred to as Independent System Operators were established by the industry to operate the electric power transmission system in an open, non-discriminatory way for all participants in the wholesale market for electricity. In 1998, four ISOs began operating in the United States (Figure 10).[19] The Pennsylvania-New Jersey-Maryland Independent System Operator (PJM-ISO) was approved in November 1997 and began operations on April 1, 1998; the California ISO (CA-ISO) was approved October 1997 and began operation on March 31, 1998; New England ISO was approved in July 1997, and began operations in the last part of 1998; and the New York ISO was conditionally approved by FERC in June 1998 and is just beginning its operations. The Midwest ISO was also conditionally approved by FERC on September 16, 1998, but is not yet operating. Additionally, the Texas Public Utility Commission approved the ERCOT ISO in 1996, and it began operations in 1997 (ERCOT is not under FERC jurisdiction).

PJM-ISO. PJM's stated objectives are to ensure reliability of the bulk power transmission system and to facilitate an open, competitive wholesale electric market. To achieve these objectives, PJM manages the PJM Open Access Transmission Tariff, which provides comparative pricing and access to the transmission system. It also operates the PJM Interchange Energy Market, which is the region's power exchange (spot market) for wholesale electricity. That is, the ISO and PX (power exchange) in PJM are operated together. The PJM-ISO also provides ancillary services[20] for its transmission customers and provides transmission planning for the region. PJM operates one centrally dispatched control area, the largest in the United States. The prior existence of the PJM Interconnection as a tight power pool and a control area eased the transition to the PJM-ISO. PJM covers all

Figure 10. U.S. Independent System Operators in Operation, 1998



Notes: The ISOs in operation have been conditionally approved by the Federal Energy Regulatory Commission and/or the State public utility commission. ISO control of the transmission grid is incomplete in many of the regions shown on the map. Full implementation will be completed in phases. Data are not available to show specific areas covered within regions. For example, the California ISO currently controls approximately 75 percent of the power grid in California.

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

or part of six States: Pennsylvania, New Jersey, Maryland, Delaware, Virginia, and the District of Columbia.

Transmission access charges in PJM are based on 10 zones. The customer pays the price according to the zone where the energy was delivered. The zonal system eliminates paying a separate transmission charge for using each system in wheeling electricity over several control areas (often referred to as "pancaking"), thus achieving one of FERC's objectives to price transmission more efficiently and fairly. To further the idea of price fairness, efficiency, and comparability, the FERC has asked PJM to file a single system-wide rate proposal by July 2002. To account for congestion charges for transmission, PJM employs a system of locational marginal pricing (LMP). There are 1,600 designated locations (referred to as "nodes") on the PJM system grid. The price of energy at each node is determined each hour, and customers pay the LMP according to the node where the power was taken off the grid. Each of the 1,600 nodes has a LMP that can include congestion

[18] Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

[19] For a comprehensive discussion of the development of the concept of Independent System Operators and the ISO principles contained in Order 888, see the Changing Structure of the Electric Power Industry: Selected Issues, 1998, DOE/EIA-0562(98). Also available on EIA's World Wide Web Site at http:\\www.eia.doe.gov.

[20] Necessary services that must be provided in the generation and delivery of electricity.

charges for that location. In the absence of congestion, each of the 1,600 nodes would have the same LMP.

California ISO. The concept of separating the operator from the owner of a transmission system began in the California debate on industry restructuring. The FERC endorsed the idea, and California's restructuring legislation required the formation of an ISO and a separate power exchange (PX). The CA-ISO was approved by the FERC in October 1997, and began operating March 31, 1998, when the transmission owning investor-owned utilities formally transferred control of their systems to the ISO, coinciding with the opening of the California retail electricity market. The ISO controls the transmission grid, and the PX, which in California is a separate entity, operates a competitive auction for wholesale electricity. The CA-ISO controls approximately 75 percent of the transmission in the State.

New York ISO (NYISO). In June 1998, FERC authorized the NYISO, the fourth ISO approved. NYISO evolved from the New York Power Pool, which was established in 1966 and has operated as a single control area serving transmission and generation owning utilities in the State of New York. The membership encompasses the members of the New York Power Pool: Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Long Island Lighting Company, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., Rochester Gas and Electric Corporation, and the nonprofit New York Power Authority. The principle mission of NYISO will be to maintain reliability of the bulk power system and provide transmission service on a comparable and nondiscriminatory basis. In the proposal authorized by the FERC, New York will form two additional entities: a New York State Reliability Council to develop bulk power reliability standards, and a New York Power Exchange to facilitate transactions open to all market participants. Most recently, in January 1999, FERC approved the NYISO's proposed tariffs, market rules, and market-based rates. This action brings the NYISO closer to operational reality. Additionally, NYISO was directed to provide a market monitoring plan for detecting and mitigating market power.

ISO New England. The ISO New England was formed out of the New England Power Pool (NEPOOL), approved by the FERC, and established on July 1, 1997. Membership in ISO New England includes transmission owning entities in the six New England States: Maine, New Hampshire, Vermont, Massachusetts, Connecticut, and Rhode Island. NEPOOL has operated as a tight power pool with a control center for central dispatch of the bulk power system since 1971 in the New England States. The mission of newly formed ISO New England is "to promote a healthy and competitive wholesale electricity marketplace while maintaining the highest standards of reliability, independence and fairness." ISO New England assumes the responsibility for the management of the New England region's electric bulk power generation and transmission systems and administering the region's open access transmission tariff.

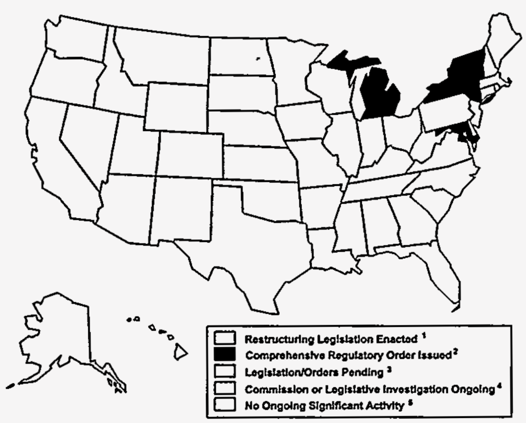
Electric Reliability Council of Texas ISO (ERCOT ISO). ERCOT ISO was given authority in three major areas of responsibility by the Public Utilities Commission of Texas: security operations of the bulk electric system in ERCOT; facilitation of the efficient use of the electric transmission system by all market participants including administration of the ERCOT OASIS; and coordination of future transmission planning in ERCOT. The ERCOT ISO is not responsible for power pool activities such as generation dispatch, matching buyers and sellers, providing ancillary services, or establishing pricing other than the cost of any redispatch needed to allow transactions to occur. The ISO does not have direct control of the system generation or transmission. That control is still the responsibility of the ERCOT control areas.

Midwest Independent System Operator (MISO). On September 16, 1998, the FERC conditionally approved the Midwest ISO. Membership includes: Cincinnati Gas & Electric Company, Commonwealth Edison Company, Commonwealth Edison Company of Indiana, Illinois Power Company, PSI Energy, Inc., Wisconsin Electric Power Company, Union Electric Company, Central Illinois Public Service Company, Louisville Gas & Electric Company, and Kentucky Utilities Company. Additionally, Hoosier Energy Rural Electric Cooperative, Inc., Wabash Valley Power Association, Inc., Allegheny Energy Inc., Duquesne Light Company, Alliant Corporation, and Central Illinois Light Company have signed the Midwest ISO Agreement. MISO covers parts of 13 States from the Mid-Atlantic to the Midwest. MISO differs from the other four ISO's approved by the FERC in that it will not operate a single control area, but the individual existing control area operators will continue to perform some of the traditional control area functions. The proposed regional rate, a single rate for the entire system, was accepted by the FERC, while a hearing was set to address several rate issues. Conditions imposed on FERC approval include submitting an assessment on the competitive and reliability effects of allowing control area operators to perform some control area functions and monitoring the relationship between control areas and the ISO. Another condition directs MISO to consider monitoring Midwest energy markets in the future.

Restructuring in the States

Many of the changes of 1998 have been a result of the movement toward restructuring the electric power industry in many States (Figure 11). Once competition in the wholesale market was made possible through Federal legislation, interest was formed in retail competition, especially in regions of the country where prices are significantly above the national average (i.e., California and the New England States). As of the end of 1998, 13 States had enacted legislation and 5 others issued final regulatory orders that deregulate their electric power industry and will eventually allow retail customers their choice of where to purchase electricity. (Currently, through April 1999, 19 States have legislation or a final regulatory order that allows retail competition). During 1998, California, Massachusetts, and Rhode Island opened their retail electricity markets. A number of States also allowed limited retail competition under pilot programs to facilitate the eventual transition to competition. In these competitive environments, customers may choose to buy their power from unregulated competitive suppliers. However, delivery of the power and the function of the incumbent utility remain regulated. The transition to competition will take years as issues such as stranded costs, public benefits, and tax policies are resolved and consumers become educated shoppers for electricity.

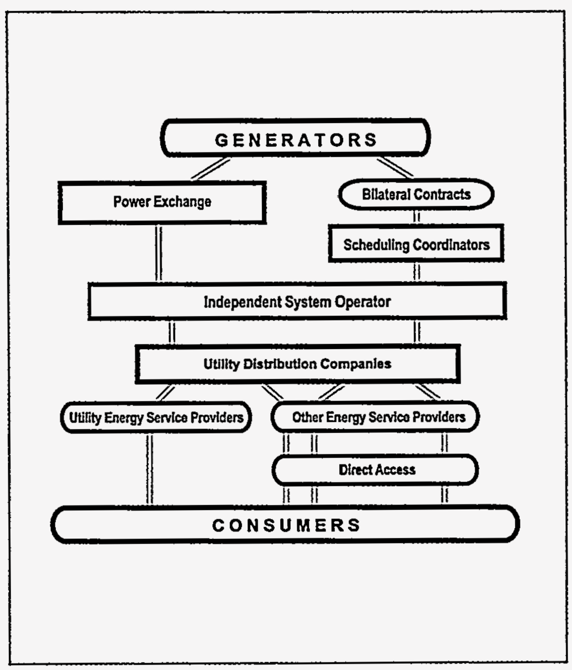
Figure 11. Status of State Electric Utility Deregulation Activity, as of April 1, 1999



[1]Arizona, California, Connecticut, Delaware, Illinois, Maine, Massachusetts, Montana, Nevada, New Hampshire, New Jersey, New Mexico, Oklahoma, Pennsylvania, Rhode Island, and Virginia.
[2]Maryland, Michigan, New York, and Vermont.
[3]Arkansas, Ohio, South Carolina, and Texas.
[4]Alabama, Alaska, Colorado, District of Columbia, Georgia, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Nebraska, North Carolina, North Dakota, Oregon, Tennessee, Utah, Washington, West Virginia, Wisconsin, and Wyoming.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Monthly updates available at: http://www.eia.doe.gov/cneaf/electricity chg_str/tab5rev.html.

California. In September 1996, California enacted legislation to deregulate their electric power industry (Figure 12). The law required a plan to allow retail competition by 1998. To achieve an open competitive market for electricity, the law required: (1) formation of an Independent System Operator to operate the transmission system independently from the generation of power and in accordance with FERC regulations on open transmission access[21] and (2) formation of a

Figure 12. California's Competitive Electricity Market Structure



Source: California Power Exchange.

[21] Energy Information Administration, *The Changing Structure of the Electric Power Industry: Selected Issues, 1998,* DOE/EIA-0562(98) (Washington, DC, July 1998), Chapter 3, p. 37.

wholesale power exchange where electricity could be sold to competitive suppliers in an open market. The law addressed the issue of stranded costs, i.e., those costs incurred and planned for recovery under regulated rates that may not be recoverable in a deregulated competitive industry. In California, stranded costs are being recovered through a charge paid by consumers from 1998 through 2002, as determined by the public utility commission. Investor-owned utilities were required to sell a percentage of their generation assets to mitigate stranded costs and given the option of using securitization to pay off stranded investments. The secured bonds issued by the utilities to pay these debts are also funded by charges paid by consumers. An opposition movement to restructuring put a proposition on the November 1998 ballot in California. The focus of the opposition was the recovery of stranded costs funded by charges on consumer bills. The proposition was defeated and the restructuring law remains unchanged.

The retail electricity market officially was opened for all consumers in California on March 31, 1998. Consumers' interest in actually switching to alternative suppliers in California has been slow, especially in the residential sector, where savings are relatively small compared with industrials. The restructuring law included a 10-percent rate reduction for residential consumers who remained with their incumbent utility. Some of the consumers who have chosen alternative suppliers are paying premium prices for selecting a "green power" choice: power produced using renewable resources. The transition to a truly competitive environment will likely take place over many years, as stranded costs are paid off and consumers become educated in choosing electricity suppliers.

As of the end of 1998, about 1 percent of California's three investor-owned utilities' customers, representing approximately 11.6 percent of retail load, have switched to competitive suppliers. About 1 percent of residential consumers are using direct access suppliers. About 18 percent of large industrial consumers have opted for direct access, representing 27 percent of the large industrial consumer load. According to data collected by the California Energy Commission, direct access is attracting large users of electricity in all sectors in California.

New England. Electricity prices in the New England States have been well above the national average, spurring interest in retail competition. In 1998, competition was implemented in Massachusetts, Rhode Island, and New York. New Hampshire was scheduled to open its retail electricity market in 1998, but most of the State has had the implementation of retail access delayed until a dispute is settled concerning stranded cost recovery by the Public Service of New Hampshire. Maine and Connecticut have enacted legislation that will open their markets in the future, and Vermont's public utility commission has issued an order to deregulate the industry, but the necessary legislation has not yet been enacted. In the New England States as a result of restructuring, most of the generating capacity has been offered for sale. Utilities either were required by restructuring laws to divest their generation assets or chose to do so to mitigate stranded costs. The Connecticut restructuring law requires all generation, including nuclear, to be sold.

Other States in the region have varying requirements for divestiture, mostly fossil-fueled plants. Many utilities have divested their entire generation portfolio and are concentrating on the business of power delivery and customer service. Proceeds from these sales will lower stranded costs. Rhode Island enacted legislation to deregulate its electric power industry in August 1996, and during 1997, became the first State to begin phasing-in retail competition. All consumers were allowed to choose generation suppliers in 1998; however, the public utility commission has set the standard offer rate low enough for customers remaining with their incumbent utility that few, if any, competitors have offered lower rates to entice consumers to switch. The standard offer rates are scheduled to gradually increase, and the public utility commission lately approved an increase for at least one utility which may enable competitors to enter the market. As in California, competition will be an ongoing process over the next several years, as stranded costs are recovered and utilities make the transition to a deregulated environment for generation. Massachusetts enacted legislation in November 1997 and implemented retail access in March 1998. Rate reductions of 10 percent were given initially, and another 5-percent reduction is due in 1999. As in other States, the move toward a competitive environment is an evolving one. Like California, a ballot initiative to repeal the restructuring law was put to a vote in November and defeated.

New York. The PUC in New York issued a decision to restructure the electric power industry in May 1996. Utilities were asked to file restructuring plans, with the goal of implementing retail access by 1998. The utilities responded with plans for retail access, divestiture of assets, and stranded costs recovery. During 1997 and 1998, the investor-owned utilities' restructuring plans were approved and retail access began to be phased in. Most utilities now have target dates ranging from the end of 1999 to 2002 to full retail access in their service territories. Legislation for restructuring has not yet been passed in New York, but has been proposed to give statewide restructuring more consistency. Meanwhile, each utility is restructuring according to approved plans: offering retail choice, divesting generation assets, and recovering stranded costs.

Other States. As of the end of 1998, several more States were planning to open their retail electricity markets in the coming year. Pennsylvania opened its market to two- thirds of its retail customers on January 1, 1999. In Arizona, the Salt River Project opened 20 percent of their market to retail competition as of December 31, 1998. However, the investor-owned utilities in Arizona that were scheduled to begin retail access have delayed its start; at issue is stranded cost recovery for Arizona Public Service Company and Tucson Electric Power Company. Connecticut is scheduled to begin direct access in January 2000, and Maine by March 2000.

Illinois customers received a rate reduction in August 1998 as part of the restructuring legislation that will open retail markets to all consumers by May 2002. The PUC in Michigan is moving ahead with its plan to allow retail access by 2002, but the necessary legislation was not passed in last year's session.

Some large consumers in Montana have retail choice, and all consumers are scheduled for access by July 2002. Nevada restructuring law calls for retail access by December 1999, but the PUC has called for a delay in order to resolve some issues.

Oklahoma has legislation to allow retail access by July 2002, and Virginia has a schedule to go to retail competition by 2004. A recently passed bill expected to be enacted into law in Virginia sets out the details of restructuring and confirms the plan to begin phasing in retail access in January 2002. Vermont's PUC had called for competition to begin by 1998, but no legislation was enacted to implement the plan.

Additionally, New Jersey enacted restructuring legislation in February 1999, Delaware in March, and Arkansas, Maryland, and New Mexico in April. Also, Texas and Ohio are debating legislation that has strong support for passage to open their retail electricity markets. All the other States are in some stage of investigating restructuring their electric power industries to allow retail competition.

Appendix A. U.S. Electric Utility Statistics by Census Division and State

Technical information regarding the sources and quality of the data in this report is available in the *Electric Power Monthly,* DOE/EIA-0226, Technical Notes. This report is accessible via the Internet at: http://www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html.

Table A1. Net Generation from U.S. Electric Utilities by Selected Prime Mover, Census Division, and State, 1997 and 1998
(Million Kilowatthours)

Census Division State	Total		Fossil Steam		Gas Turbine/Internal Combustion	
	1997	1998	1997	1998	1997	1998
New England	**73,500**	**65,401**	**47,333**	**36,770**	**4,625**	**3,013**
Connecticut	13,228	15,123	12,289	11,001	246	67
Maine	3,223	3,549	1,441	1,726	2	3
Massachusetts	33,899	26,037	28,487	19,177	801	830
New Hampshire	14,264	14,238	5,116	4,865	4	11
Rhode Island	3,563	2,061	0	0	3,563	2,061
Vermont	5,323	4,394	*	1	10	41
Middle Atlantic	**309,027**	**325,655**	**165,945**	**174,646**	**3,002**	**3,405**
New Jersey	23,761	35,911	8,710	7,477	1,273	1,448
New York	108,099	115,840	49,169	56,438	1,431	1,502
Pennsylvania	177,167	173,903	108,067	110,731	297	455
East North Central	**520,978**	**528,169**	**422,923**	**428,647**	**1,505**	**2,313**
Illinois	131,138	131,274	79,875	75,306	154	321
Indiana	110,466	112,772	109,756	111,927	149	366
Michigan	89,565	85,146	66,912	72,053	80	247
Ohio	141,249	146,448	125,195	129,117	216	449
Wisconsin	48,560	52,529	41,185	40,245	905	929
West North Central	**253,841**	**265,766**	**193,310**	**206,162**	**1,440**	**2,863**
Iowa	34,064	37,085	28,959	32,107	139	299
Kansas	37,844	41,481	29,080	30,586	333	484
Minnesota	40,303	43,977	28,127	30,827	229	359
Missouri	71,073	74,894	60,115	62,776	483	1,255
Nebraska	28,388	28,720	17,317	18,551	129	227
North Dakota	29,720	30,519	26,394	28,220	6	3
South Dakota	12,450	9,089	3,317	3,095	121	236
South Atlantic	**633,982**	**684,168**	**428,650**	**452,870**	**21,389**	**26,495**
Delaware	6,579	6,318	5,226	5,248	1,353	1,070
District of Columbia	71	244	53	213	17	31
Florida	147,984	169,447	107,637	118,678	17,137	19,456
Georgia	101,780	108,717	66,499	70,902	449	1,409
Maryland	44,553	48,514	29,155	32,672	597	771
North Carolina	107,371	113,112	70,342	69,181	428	1,042
South Carolina	78,374	84,397	31,174	32,601	238	523
Virginia	58,986	63,815	30,656	34,132	1,170	2,193
West Virginia	88,284	89,605	87,907	89,244	0	0
East South Central	**329,763**	**325,679**	**238,144**	**231,649**	**2,283**	**4,724**
Alabama	113,684	113,394	71,928	72,154	662	2,013
Kentucky	91,558	86,151	88,039	82,594	139	441
Mississippi	31,228	31,992	19,191	21,692	1,224	1,109
Tennessee	93,293	94,143	58,986	55,209	258	1,161
West South Central	**429,480**	**453,829**	**346,981**	**367,207**	**9,302**	**10,459**
Arkansas	42,790	43,199	25,060	26,953	10	35
Louisiana	61,120	66,107	46,795	48,931	814	749
Oklahoma	48,380	51,454	42,079	44,298	3,477	3,736
Texas	277,190	293,068	233,047	247,026	5,000	5,938
Mountain	**281,927**	**294,206**	**201,779**	**215,800**	**3,931**	**6,254**
Arizona	78,060	81,299	35,495	38,272	850	1,487
Colorado	34,376	35,471	32,281	33,435	159	644
Idaho	13,512	11,978	—	—	*	*
Montana	27,807	27,617	14,435	16,538	24	25
Nevada	22,870	26,553	17,698	20,399	2,604	3,002
New Mexico	30,568	31,428	30,132	30,241	177	951
Utah	33,969	35,160	32,353	33,558	117	144
Wyoming	40,765	44,699	39,384	43,357	0	0
Pacific Contiguous	**278,704**	**258,406**	**43,350**	**38,806**	**3,088**	**5,014**
California	112,183	114,926	34,559	24,473	1,884	2,034
Oregon	49,068	46,352	1,819	5,035	967	1,813
Washington	117,453	97,128	6,973	9,297	238	1,167
Pacific Noncontiguous	**11,321**	**10,891**	**5,711**	**5,548**	**4,492**	**4,216**
Alaska	5,108	4,590	795	597	3,214	2,880
Hawaii	6,213	6,301	4,916	4,950	1,278	1,337
U.S. Total	**3,122,523**	**3,212,171**	**2,094,127**	**2,158,105**	**55,057**	**68,755**

* =Value less than 0.5 million kilowatthours.

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

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Table A2. Net Generation from U.S. Electric Utilities by Energy Source, Census Division, and State, 1997 and 1998
(Million Kilowatthours)

Census Division State	Coal		Petroleum[1]		Gas	
	1997	1998	1997	1998	1997	1998
New England	**19,124**	**13,164**	**22,494**	**21,759**	**10,340**	**4,859**
Connecticut	2,558	1,483	8,431	8,608	1,546	977
Maine	—	—	1,443	1,729	—	—
Massachusetts	12,489	8,169	11,586	10,020	5,213	1,819
New Hampshire	4,077	3,513	1,008	1,353	35	10
Rhode Island	—	—	17	9	3,546	2,053
Vermont	—	—	10	41	*	1
Middle Atlantic	**134,019**	**135,607**	**10,834**	**19,106**	**24,094**	**23,339**
New Jersey	6,822	5,586	384	485	2,777	2,854
New York	21,752	23,503	8,142	14,524	20,706	19,913
Pennsylvania	105,446	106,517	2,307	4,097	611	572
East North Central	**416,285**	**418,627**	**2,147**	**3,216**	**5,996**	**9,117**
Illinois	76,092	70,306	495	838	3,442	4,483
Indiana	108,912	110,696	607	822	386	775
Michigan	65,552	69,143	602	1,005	838	2,152
Ohio	124,910	128,696	273	351	228	519
Wisconsin	40,820	39,786	170	200	1,101	1,188
West North Central	**189,797**	**201,886**	**1,204**	**1,307**	**3,749**	**5,832**
Iowa	28,739	31,884	82	110	277	412
Kansas	27,236	28,024	110	122	2,068	2,924
Minnesota	27,081	29,884	764	650	512	652
Missouri	59,903	62,489	125	310	570	1,232
Nebraska	17,209	18,336	31	42	206	400
North Dakota	26,314	28,176	86	47	*	*
South Dakota	3,314	3,094	7	27	117	211
South Atlantic	**382,150**	**390,087**	**29,754**	**49,880**	**38,136**	**39,397**
Delaware	3,926	3,812	833	1,234	1,820	1,272
District of Columbia	—	—	71	244	—	—
Florida	66,035	65,470	25,742	40,953	32,998	31,711
Georgia	66,180	69,871	201	671	568	1,769
Maryland	27,394	29,077	1,479	3,312	879	1,054
North Carolina	70,181	69,001	212	286	377	936
South Carolina	31,043	32,378	188	331	181	415
Virginia	29,676	31,471	858	2,655	1,292	2,199
West Virginia	87,715	89,008	171	194	21	42
East South Central	**230,861**	**220,738**	**3,070**	**6,504**	**6,495**	**9,131**
Alabama	71,586	71,457	119	260	885	2,449
Kentucky	87,875	82,412	126	127	177	496
Mississippi	12,501	11,748	2,633	5,418	5,281	5,635
Tennessee	58,899	55,120	193	699	152	551
West South Central	**212,447**	**207,556**	**913**	**888**	**142,924**	**169,222**
Arkansas	22,761	23,140	67	144	2,243	3,704
Louisiana	20,953	20,762	646	600	26,010	28,318
Oklahoma	33,037	31,027	13	8	12,507	17,000
Texas	135,696	132,627	188	137	102,164	120,201
Mountain	**194,420**	**207,005**	**233**	**260**	**11,058**	**14,788**
Arizona	34,219	36,225	61	61	2,065	3,472
Colorado	32,002	33,079	15	37	424	964
Idaho	—	—	*	*	—	—
Montana	14,410	16,508	17	14	32	41
Nevada	15,251	17,161	31	50	5,021	6,190
New Mexico	27,079	27,537	21	23	3,210	3,631
Utah	32,144	33,207	29	31	297	463
Wyoming	39,315	43,287	59	43	10	27
Pacific Contiguous	**8,467**	**12,639**	**169**	**193**	**37,803**	**30,988**
California	—	—	142	121	36,301	26,385
Oregon	1,501	3,348	11	33	1,273	3,467
Washington	6,966	9,290	16	39	229	1,135
Pacific Noncontiguous	**237**	**171**	**6,935**	**7,044**	**3,031**	**2,549**
Alaska	237	171	741	757	3,031	2,549
Hawaii	—	—	6,194	6,287	—	—
U.S. Total	**1,787,806**	**1,807,480**	**77,753**	**110,158**	**283,625**	**309,222**

See notes and footnotes at end of table.

Table A2. Net Generation from U.S. Electric Utilities by Energy Source, Census Division, and State, 1997 and 1998 (Continued)
(Million Kilowatthours)

Census Division State	Nuclear		Hydroelectric[2]		Renewable[3]	
	1997	1998	1997	1998	1997	1998
New England	16,432	20,686	4,508	4,359	601	573
Connecticut	−125	3,243	367	385	451	427
Maine	0	0	1,780	1,820	—	—
Massachusetts	4,310	5,698	300	331	—	—
New Hampshire	7,979	8,387	1,165	975	—	—
Rhode Island	—	—	0	0	—	—
Vermont	4,267	3,358	896	848	150	145
Middle Atlantic	111,132	119,595	28,930	28,004	18	5
New Jersey	13,908	27,132	−130	−146	—	—
New York	29,570	31,314	27,912	26,582	18	5
Pennsylvania	67,655	61,149	1,148	1,568	—	—
East North Central	92,229	93,963	3,926	2,806	395	441
Illinois	51,069	55,596	17	51	24	0
Indiana	—	—	562	479	—	—
Michigan	21,914	12,494	658	352	—	—
Ohio	15,331	16,476	507	406	—	—
Wisconsin	3,916	9,397	2,182	1,518	372	441
West North Central	41,622	42,598	16,975	13,593	494	549
Iowa	4,149	3,768	795	893	22	19
Kansas	8,430	10,411	—	—	—	—
Minnesota	10,819	11,644	697	695	429	451
Missouri	8,955	8,517	1,478	2,269	42	78
Nebraska	9,269	8,259	1,672	1,683	1	1
North Dakota	—	—	3,320	2,296	—	—
South Dakota	—	—	9,012	5,758	—	—
South Atlantic	171,048	190,598	12,895	14,205	0	0
Delaware	—	—	—	—	—	—
District of Columbia	—	—	—	—	—	—
Florida	22,968	31,115	241	199	—	—
Georgia	30,414	31,380	4,418	5,026	—	—
Maryland	13,213	13,331	1,588	1,740	—	—
North Carolina	32,453	38,778	4,148	4,111	—	—
South Carolina	44,916	48,759	2,047	2,513	—	—
Virginia	27,084	27,234	76	256	0	0
West Virginia	—	—	377	361	—	—
East South Central	65,033	66,241	24,302	23,066	—	—
Alabama	29,573	28,663	11,521	10,565	—	—
Kentucky	—	—	3,380	3,116	—	—
Mississippi	10,813	9,191	—	—	—	—
Tennessee	24,648	28,388	9,401	9,385	—	—
West South Central	65,077	68,210	8,120	7,953	*	*
Arkansas	14,208	13,097	3,511	3,114	—	—
Louisiana	13,511	16,428	—	—	—	—
Oklahoma	—	—	2,824	3,420	—	—
Texas	37,358	38,685	1,785	1,419	*	*
Mountain	29,314	30,301	46,735	41,692	169	160
Arizona	29,314	30,301	12,401	11,239	—	—
Colorado	—	—	1,935	1,392	0	0
Idaho	—	—	13,512	11,978	—	—
Montana	—	—	13,348	11,054	—	—
Nevada	—	—	2,567	3,151	—	—
New Mexico	—	—	259	236	—	—
Utah	—	—	1,331	1,299	169	160
Wyoming	—	—	1,381	1,342	—	—
Pacific Contiguous	36,756	41,510	189,725	167,598	5,785	5,478
California	30,512	34,594	39,797	48,684	5,431	5,141
Oregon	—	—	46,283	39,504	0	0
Washington	6,244	6,916	103,645	79,410	353	337
Pacific Noncontiguous	—	—	1,118	1,127	—	*
Alaska	—	—	1,099	1,113	—	—
Hawaii	—	—	19	14	—	*
U.S. Total	628,644	673,702	337,234	304,403	7,462	7,206

1 Includes petroleum coke.
2 Station losses include energy used for pumped storage. Energy used in 1998 for pumping was 28,872 million kilowatthours and in 1997 was 28,342 million kilowatthours.
3 Includes geothermal, biomass, wind, solar thermal, and photovoltaic (excludes hydroelectric).
* =Value less than 0.5 million kilowatthours.

Notes: •Data are final. •Negative generation denotes that electric power consumed for plant use exceeds gross generation. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Table A3. Petroleum-Fired Net Generation from U.S. Electric Utilities by Selected Prime Mover, Census Division, and State, 1997 and 1998
(Million Kilowatthours)

Census Division State	Total[1]		Steam		Gas Turbine/Internal Combustion	
	1997	1998	1997	1998	1997	1998
New England	22,494	21,759	22,273	21,473	221	286
Connecticut	8,431	8,608	8,403	8,581	29	27
Maine	1,443	1,729	1,441	1,726	2	3
Massachusetts	11,586	10,020	11,424	9,815	162	205
New Hampshire	1,008	1,353	1,005	1,352	3	1
Rhode Island	17	9	0	0	17	9
Vermont	10	41	*	*	10	41
Middle Atlantic	10,834	19,106	10,193	18,191	641	914
New Jersey	384	485	275	339	109	146
New York	8,142	14,524	7,771	14,048	371	476
Pennsylvania	2,307	4,097	2,147	3,805	161	292
East North Central	2,147	3,216	1,931	2,856	216	360
Illinois	495	838	445	759	51	79
Indiana	607	822	596	800	11	21
Michigan	602	1,005	575	944	27	61
Ohio	273	351	219	253	54	98
Wisconsin	170	200	96	100	74	100
West North Central	1,204	1,307	984	810	220	497
Iowa	82	110	25	21	57	89
Kansas	110	122	82	66	28	57
Minnesota	764	650	722	602	42	48
Missouri	125	310	62	64	63	246
Nebraska	31	42	11	12	20	30
North Dakota	86	47	80	44	6	3
South Dakota	7	27	3	2	4	24
South Atlantic	29,754	49,880	28,698	47,613	1,056	2,267
Delaware	833	1,234	809	1,211	24	23
District of Columbia	71	244	53	213	17	31
Florida	25,742	40,953	25,181	39,740	561	1,213
Georgia	201	671	98	226	102	445
Maryland	1,479	3,312	1,317	3,149	162	163
North Carolina	212	286	135	138	77	148
South Carolina	188	331	111	180	77	151
Virginia	858	2,655	823	2,561	35	93
West Virginia	171	194	171	194	0	0
East South Central	3,070	6,504	2,910	5,706	161	798
Alabama	119	260	89	96	30	164
Kentucky	126	127	105	104	21	23
Mississippi	2,633	5,418	2,629	5,417	4	1
Tennessee	193	699	87	89	106	610
West South Central	913	888	893	831	19	57
Arkansas	67	144	56	108	10	35
Louisiana	646	600	645	599	*	1
Oklahoma	13	8	10	5	2	2
Texas	188	137	181	118	7	19
Mountain	233	260	221	218	12	42
Arizona	61	61	57	50	4	11
Colorado	15	37	10	10	5	27
Idaho	*	*	—	—	*	*
Montana	17	14	17	14	1	*
Nevada	31	50	31	51	*	*
New Mexico	21	23	20	23	1	*
Utah	29	31	27	28	2	3
Wyoming	59	43	59	43	0	0
Pacific Contiguous	169	193	41	19	128	174
California	142	121	26	6	116	116
Oregon	11	33	10	9	*	24
Washington	16	39	5	4	12	34
Pacific Noncontiguous	6,935	7,044	4,921	4,952	2,013	2,092
Alaska	741	757	5	2	736	755
Hawaii	6,194	6,287	4,916	4,950	1,278	1,337
U.S. Total	77,753	110,158	73,065	102,669	4,688	7,489

[1] Includes petroleum coke.
* =Value less than 0.5 million kilowatthours.
Notes: •Data are final. •Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Table A4. Gas-Fired Net Generation from U.S. Electric Utilities by Selected Prime Mover, Census Division, and State, 1997 and 1998
(Million Kilowatthours)

Census Division State	Total		Steam		Gas Turbine/Internal Combustion	
	1997	1998	1997	1998	1997	1998
New England	**10,340**	**4,859**	**5,936**	**2,133**	**4,404**	**2,726**
Connecticut	1,546	977	1,329	938	217	39
Maine	—	—	—	—	—	—
Massachusetts	5,213	1,819	4,574	1,194	639	625
New Hampshire	35	10	34	0	1	10
Rhode Island	3,546	2,053	0	0	3,546	2,053
Vermont	*	1	*	1	—	—
Middle Atlantic	**24,094**	**23,339**	**21,732**	**20,848**	**2,361**	**2,491**
New Jersey	2,777	2,854	1,613	1,552	1,164	1,302
New York	20,706	19,913	19,645	18,887	1,060	1,027
Pennsylvania	611	572	474	410	137	162
East North Central	**5,996**	**9,117**	**4,707**	**7,164**	**1,289**	**1,953**
Illinois	3,442	4,483	3,339	4,240	104	243
Indiana	386	775	248	430	138	345
Michigan	838	2,152	785	1,967	53	185
Ohio	228	519	66	168	162	351
Wisconsin	1,101	1,188	270	359	831	829
West North Central	**3,749**	**5,832**	**2,529**	**3,466**	**1,220**	**2,366**
Iowa	277	412	194	202	82	210
Kansas	2,068	2,924	1,763	2,497	305	427
Minnesota	512	652	324	341	188	311
Missouri	570	1,232	150	224	420	1,009
Nebraska	206	400	97	203	109	197
North Dakota	*	*	*	0	*	*
South Dakota	117	211	*	–1	117	212
South Atlantic	**38,136**	**39,397**	**17,803**	**15,170**	**20,333**	**24,228**
Delaware	1,820	1,272	492	224	1,329	1,047
District of Columbia	—	—	—	—	—	—
Florida	32,998	31,711	16,422	13,468	16,576	18,243
Georgia	568	1,769	221	805	347	964
Maryland	879	1,054	444	445	435	609
North Carolina	377	936	26	43	351	893
South Carolina	181	415	21	43	160	372
Virginia	1,292	2,199	157	99	1,135	2,100
West Virginia	21	42	21	42	—	—
East South Central	**6,495**	**9,131**	**4,373**	**5,205**	**2,122**	**3,925**
Alabama	885	2,449	253	601	632	1,848
Kentucky	177	496	59	78	118	418
Mississippi	5,281	5,635	4,062	4,527	1,220	1,109
Tennessee	152	551	0	0	152	551
West South Central	**142,924**	**169,222**	**133,641**	**158,821**	**9,283**	**10,402**
Arkansas	2,243	3,704	2,243	3,704	0	0
Louisiana	26,010	28,318	25,197	27,570	814	748
Oklahoma	12,507	17,000	9,032	13,266	3,475	3,734
Texas	102,164	120,201	97,170	114,281	4,994	5,920
Mountain	**11,058**	**14,788**	**7,138**	**8,577**	**3,919**	**6,211**
Arizona	2,065	3,472	1,219	1,997	846	1,475
Colorado	424	964	269	346	154	617
Idaho	—	—	—	—	—	—
Montana	32	41	8	16	24	25
Nevada	5,021	6,190	2,417	3,187	2,603	3,003
New Mexico	3,210	3,631	3,033	2,681	177	951
Utah	297	463	182	323	116	140
Wyoming	10	27	10	27	—	—
Pacific Contiguous	**37,803**	**30,988**	**34,843**	**26,148**	**2,960**	**4,840**
California	36,301	26,385	34,533	24,467	1,768	1,918
Oregon	1,273	3,467	307	1,678	966	1,789
Washington	229	1,135	2	2	226	1,133
Pacific Noncontiguous	**3,031**	**2,549**	**553**	**425**	**2,478**	**2,124**
Alaska	3,031	2,549	553	425	2,478	2,124
Hawaii	—	—	—	—	—	—
U.S. Total	**283,625**	**309,222**	**233,256**	**247,956**	**50,369**	**61,266**

* =Value less than 0.5 million kilowatthours.

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

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Table A5. Consumption of Fossil Fuels at U.S. Electric Utilities by Census Division and State, 1997 and 1998

Census Division State	Coal (thousand short tons)		Petroleum[1] (thousand barrels)		Gas (million cubic feet)	
	1997	1998	1997	1998	1997	1998
New England	**7,583**	**5,184**	**35,897**	**36,001**	**96,010**	**45,073**
Connecticut	1,058	590	14,043	14,605	16,761	10,718
Maine	—	—	2,517	2,973	—	—
Massachusetts	4,826	3,129	17,436	15,923	51,490	18,428
New Hampshire	1,699	1,465	1,843	2,372	564	149
Rhode Island	0	0	27	20	27,159	15,589
Vermont	—	—	31	107	36	188
Middle Atlantic	**54,179**	**54,738**	**18,024**	**32,173**	**254,408**	**246,232**
New Jersey	2,851	2,357	705	1,085	29,534	30,994
New York	8,726	9,410	13,836	24,350	217,504	208,348
Pennsylvania	42,602	42,971	3,483	6,738	7,370	6,890
East North Central	**204,251**	**204,721**	**3,626**	**4,819**	**101,815**	**137,765**
Illinois	41,017	38,255	1,128	1,338	44,607	56,337
Indiana	54,845	55,086	322	447	4,661	9,095
Michigan	31,928	34,021	1,339	2,087	33,286	48,322
Ohio	52,893	54,456	574	635	3,485	7,663
Wisconsin	23,568	22,903	263	312	15,775	16,348
West North Central	**123,967**	**130,374**	**1,197**	**1,709**	**47,898**	**74,521**
Iowa	18,194	20,031	211	269	4,124	5,947
Kansas	17,534	17,627	252	298	25,822	36,894
Minnesota	17,490	17,902	186	177	6,098	7,738
Missouri	35,193	37,165	300	714	7,465	16,034
Nebraska	10,796	11,505	72	93	2,656	5,044
North Dakota	22,754	24,278	153	89	1	0
South Dakota	2,005	1,866	23	68	1,731	2,865
South Atlantic	**155,500**	**157,764**	**46,881**	**78,581**	**350,376**	**366,270**
Delaware	1,685	1,592	1,435	2,111	16,092	11,135
District of Columbia	—	—	197	566	—	—
Florida	27,372	27,542	39,156	62,048	296,900	281,351
Georgia	30,631	30,731	451	1,591	7,343	22,369
Maryland	10,417	10,968	3,018	6,159	11,007	12,302
North Carolina	27,206	26,834	467	635	4,512	12,417
South Carolina	12,096	12,664	457	809	2,731	5,893
Virginia	11,605	12,300	1,408	4,338	11,572	20,386
West Virginia	34,487	35,132	292	324	219	417
East South Central	**99,620**	**96,320**	**4,956**	**10,560**	**86,911**	**113,878**
Alabama	30,841	31,473	230	472	9,997	25,545
Kentucky	38,281	35,842	266	265	2,194	5,760
Mississippi	6,035	5,684	4,086	8,376	73,084	76,361
Tennessee	24,464	23,321	375	1,448	1,636	6,213
West South Central	**144,217**	**141,671**	**1,617**	**1,617**	**1,487,614**	**1,776,119**
Arkansas	13,772	14,276	127	279	24,805	40,574
Louisiana	13,807	13,850	1,111	1,050	277,438	318,394
Oklahoma	20,101	18,884	30	18	128,819	174,575
Texas	96,537	94,661	349	271	1,056,552	1,242,575
Mountain	**105,217**	**111,787**	**455**	**515**	**118,667**	**156,012**
Arizona	17,504	18,316	110	117	23,385	38,674
Colorado	17,116	17,663	38	83	5,536	10,627
Idaho	—	—	*	1	—	—
Montana	9,286	10,627	39	33	420	522
Nevada	7,261	7,961	69	99	51,777	60,939
New Mexico	15,802	15,883	42	45	33,375	39,035
Utah	14,252	14,664	52	58	4,079	5,945
Wyoming	23,996	26,674	105	80	95	271
Pacific Contiguous	**5,592**	**8,148**	**379**	**420**	**391,245**	**313,399**
California	—	—	317	278	377,947	271,163
Oregon	822	2,037	23	59	10,681	28,884
Washington	4,771	6,111	39	83	2,618	13,352
Pacific Noncontiguous	**235**	**162**	**12,114**	**12,220**	**33,510**	**28,785**
Alaska	235	162	1,321	1,355	33,510	28,785
Hawaii	—	—	10,793	10,864	—	—
U.S. Total	**900,361**	**910,867**	**125,146**	**178,614**	**2,968,453**	**3,258,054**

[1] Does not include petroleum coke. Petroleum coke consumption in 1998 was 1,769 thousand short tons and in 1997 was 1,400 thousand short tons.
* =Value less than 0.5 thousand barrels or 0.5 million cubic feet.
Notes: •Data are final. •Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Table A6. Petroleum Consumption at U.S. Electric Utilities by Selected Prime Mover, Census Division, and State, 1997 and 1998
(Thousand Barrels)

Census Division State	Total		Steam		Gas Turbine/Internal Combustion	
	1997	1998	1997	1998	1997	1998
New England	**35,897**	**36,001**	**35,399**	**35,360**	**497**	**641**
Connecticut	14,043	14,605	13,967	14,530	76	75
Maine	2,517	2,973	2,509	2,964	7	9
Massachusetts	17,436	15,923	17,088	15,491	348	432
New Hampshire	1,843	2,372	1,833	2,368	10	4
Rhode Island	27	20	0	0	27	20
Vermont	31	107	2	6	29	101
Middle Atlantic	**18,024**	**32,173**	**16,287**	**29,769**	**1,736**	**2,404**
New Jersey	705	1,085	361	680	344	405
New York	13,836	24,350	12,887	23,126	949	1,224
Pennsylvania	3,483	6,738	3,040	5,963	444	775
East North Central	**3,626**	**4,819**	**2,951**	**3,864**	**676**	**955**
Illinois	1,128	1,338	951	1,094	177	245
Indiana	322	447	285	390	37	57
Michigan	1,339	2,087	1,240	1,887	99	200
Ohio	574	635	436	448	138	188
Wisconsin	263	312	39	46	225	265
West North Central	**1,197**	**1,709**	**568**	**456**	**629**	**1,252**
Iowa	211	269	52	46	159	223
Kansas	252	298	173	121	79	177
Minnesota	186	177	49	55	136	122
Missouri	300	714	130	127	169	587
Nebraska	72	93	21	23	51	70
North Dakota	153	89	137	80	17	10
South Dakota	23	68	6	5	17	63
South Atlantic	**46,881**	**78,581**	**44,213**	**72,956**	**2,668**	**5,625**
Delaware	1,435	2,111	1,378	2,052	57	59
District of Columbia	197	566	133	471	64	95
Florida	39,156	62,048	37,893	59,274	1,264	2,774
Georgia	451	1,591	207	401	244	1,190
Maryland	3,018	6,159	2,553	5,760	464	398
North Carolina	467	635	234	221	233	414
South Carolina	457	809	191	308	266	501
Virginia	1,408	4,338	1,332	4,144	77	195
West Virginia	292	324	292	324	0	0
East South Central	**4,956**	**10,560**	**4,604**	**8,911**	**352**	**1,649**
Alabama	230	472	159	171	70	301
Kentucky	266	265	219	215	47	50
Mississippi	4,086	8,376	4,078	8,374	8	2
Tennessee	375	1,448	149	152	226	1,296
West South Central	**1,617**	**1,617**	**1,574**	**1,482**	**42**	**135**
Arkansas	127	279	103	189	24	90
Louisiana	1,111	1,050	1,109	1,044	2	5
Oklahoma	30	18	27	14	3	4
Texas	349	271	336	235	13	36
Mountain	**455**	**515**	**418**	**415**	**37**	**101**
Arizona	110	117	102	88	8	29
Colorado	38	83	21	23	17	60
Idaho	*	1	—	—	*	1
Montana	39	33	37	32	2	1
Nevada	69	99	65	97	4	3
New Mexico	42	45	39	43	2	2
Utah	52	58	49	51	4	7
Wyoming	105	80	105	80	0	0
Pacific Contiguous	**379**	**420**	**75**	**38**	**304**	**382**
California	317	278	44	10	273	268
Oregon	23	59	22	20	1	39
Washington	39	83	9	8	30	76
Pacific Noncontiguous	**12,114**	**12,220**	**8,604**	**8,570**	**3,510**	**3,650**
Alaska	1,321	1,355	16	7	1,304	1,349
Hawaii	10,793	10,864	8,587	8,563	2,206	2,301
U.S. Total	**125,146**	**178,614**	**114,695**	**161,821**	**10,451**	**16,793**

* =Value less than 0.5.

Notes: •Data are final. •Totals may not equal sum of components because of independent rounding. •Does not include petroleum coke. Petroleum coke consumption in 1998 was 1,769 thousand short tons and in 1997 was 1,400 thousand short tons.

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Table A7. Gas Consumption at U.S. Electric Utilities by Selected Prime Mover, Census Division, and State, 1997 and 1998
(Million Cubic Feet)

Census Division State	Total		Steam		Gas Turbine/Internal Combustion	
	1997	1998	1997	1998	1997	1998
New England	**96,010**	**45,073**	**60,448**	**22,965**	**35,562**	**22,107**
Connecticut	16,761	10,718	14,497	10,251	2,264	467
Maine	—	—	—	—	—	—
Massachusetts	51,490	18,428	45,502	12,527	5,988	5,901
New Hampshire	564	149	413	0	151	149
Rhode Island	27,159	15,589	0	0	27,159	15,589
Vermont	36	188	36	188	—	—
Middle Atlantic	**254,408**	**246,232**	**227,241**	**217,968**	**27,167**	**28,264**
New Jersey	29,534	30,994	14,831	15,296	14,703	15,699
New York	217,504	208,348	206,776	197,751	10,728	10,596
Pennsylvania	7,370	6,890	5,635	4,920	1,736	1,970
East North Central	**101,815**	**137,765**	**82,285**	**108,974**	**19,529**	**28,791**
Illinois	44,607	56,337	42,769	51,988	1,837	4,349
Indiana	4,661	9,095	2,668	4,664	1,993	4,432
Michigan	33,286	48,322	32,461	45,714	825	2,608
Ohio	3,485	7,663	801	1,963	2,685	5,700
Wisconsin	15,775	16,348	3,587	4,645	12,189	11,703
West North Central	**47,898**	**74,521**	**31,593**	**42,727**	**16,305**	**31,793**
Iowa	4,124	5,947	2,838	2,803	1,286	3,143
Kansas	25,822	36,894	21,897	30,787	3,925	6,107
Minnesota	6,098	7,738	3,920	3,926	2,179	3,811
Missouri	7,465	16,034	1,764	2,785	5,701	13,248
Nebraska	2,656	5,044	1,156	2,419	1,500	2,625
North Dakota	1	0	1	0	*	0
South Dakota	1,731	2,865	17	7	1,714	2,858
South Atlantic	**350,376**	**366,270**	**181,569**	**153,400**	**168,808**	**212,870**
Delaware	16,092	11,135	5,786	3,029	10,306	8,106
District of Columbia	—	—	—	—	—	—
Florida	296,900	281,351	165,706	133,367	131,194	147,984
Georgia	7,343	22,369	2,829	10,220	4,514	12,149
Maryland	11,007	12,302	5,536	4,987	5,471	7,316
North Carolina	4,512	12,417	0	0	4,512	12,417
South Carolina	2,731	5,893	220	446	2,511	5,447
Virginia	11,572	20,386	1,273	935	10,299	19,451
West Virginia	219	417	219	417	—	—
East South Central	**86,911**	**113,878**	**47,257**	**56,470**	**39,653**	**57,408**
Alabama	9,997	25,545	2,625	5,769	7,372	19,776
Kentucky	2,194	5,760	609	806	1,585	4,953
Mississippi	73,084	76,361	44,024	49,895	29,060	26,466
Tennessee	1,636	6,213	0	0	1,636	6,213
West South Central	**1,487,614**	**1,776,119**	**1,385,644**	**1,662,272**	**101,969**	**113,847**
Arkansas	24,805	40,574	24,805	40,574	0	0
Louisiana	277,438	318,394	267,400	309,853	10,038	8,541
Oklahoma	128,819	174,575	97,380	141,219	31,439	33,356
Texas	1,056,552	1,242,575	996,060	1,170,626	60,492	71,949
Mountain	**118,667**	**156,012**	**77,398**	**92,664**	**41,268**	**63,348**
Arizona	23,385	38,674	14,103	22,748	9,283	15,926
Colorado	5,536	10,627	3,618	4,665	1,919	5,961
Idaho	—	—	—	—	—	—
Montana	420	522	93	172	327	350
Nevada	51,777	60,939	26,207	32,206	25,571	28,733
New Mexico	33,375	39,035	31,077	28,855	2,298	10,180
Utah	4,079	5,945	2,207	3,747	1,872	2,198
Wyoming	95	271	95	271	—	—
Pacific Contiguous	**391,245**	**313,399**	**359,244**	**260,597**	**32,001**	**52,802**
California	377,947	271,163	356,812	248,559	21,135	22,604
Oregon	10,681	28,884	2,407	12,013	8,273	16,871
Washington	2,618	13,352	25	25	2,593	13,327
Pacific Noncontiguous	**33,510**	**28,785**	**0**	**0**	**33,510**	**28,785**
Alaska	33,510	28,785	0	0	33,510	28,785
Hawaii	—	—	—	—	—	—
U.S. Total	**2,968,453**	**3,258,054**	**2,452,679**	**2,618,037**	**515,774**	**640,017**

* =Value less than 0.5.
Notes: •Data are final. •Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Table A8. Coal and Petroleum Stocks at U.S. Electric Utilities by Census Division and State, as of December 31, 1997 and 1998

Census Division State	Coal (thousand short tons)		Petroleum[1] (thousand barrels)	
	1997	1998	1997	1998
New England	754	575	4,490	3,555
Connecticut	66	134	1,803	2,093
Maine	—	—	265	487
Massachusetts	389	163	1,993	521
New Hampshire	298	278	375	415
Rhode Island	0	0	16	3
Vermont	—	—	38	38
Middle Atlantic	9,175	10,232	10,667	12,356
New Jersey	566	663	1,628	1,823
New York	819	1,128	7,220	7,827
Pennsylvania	7,790	8,441	1,819	2,705
East North Central	28,051	34,128	2,547	3,625
Illinois	4,828	6,572	1,058	1,249
Indiana	5,822	8,198	129	184
Michigan	7,222	8,776	646	1,444
Ohio	6,066	5,902	411	449
Wisconsin	4,113	4,679	303	298
West North Central	13,707	17,961	1,612	2,002
Iowa	2,447	3,788	204	170
Kansas	2,282	3,168	606	740
Minnesota	1,737	2,093	166	189
Missouri	3,670	5,032	357	480
Nebraska	1,596	2,096	142	243
North Dakota	1,755	1,580	44	57
South Dakota	219	204	94	123
South Atlantic	16,141	20,938	12,880	15,559
Delaware	319	470	703	741
District of Columbia	—	—	117	121
Florida	3,441	4,565	7,629	9,396
Georgia	2,278	3,424	569	715
Maryland	1,188	1,157	1,528	1,651
North Carolina	1,912	3,622	342	420
South Carolina	1,809	2,539	447	470
Virginia	1,152	1,370	1,393	1,892
West Virginia	4,042	3,791	150	155
East South Central	9,329	10,808	2,153	2,946
Alabama	2,609	3,195	254	358
Kentucky	4,475	4,668	205	222
Mississippi	614	820	1,344	1,684
Tennessee	1,630	2,124	351	681
West South Central	11,050	14,396	6,550	7,087
Arkansas	934	1,107	253	332
Louisiana	1,248	2,157	1,299	1,725
Oklahoma	2,516	3,349	385	440
Texas	6,352	7,784	4,613	4,590
Mountain	9,667	10,404	931	939
Arizona	1,386	1,855	420	408
Colorado	2,458	2,840	142	173
Idaho	—	—	*	*
Montana	410	335	18	15
Nevada	812	881	215	178
New Mexico	795	789	74	75
Utah	2,309	2,461	26	54
Wyoming	1,498	1,243	35	36
Pacific Contiguous	951	1,060	5,674	4,592
California	—	—	5,414	4,375
Oregon	83	196	199	144
Washington	868	864	62	72
Pacific Noncontiguous	*	0	1,289	1,128
Alaska	*	0	272	243
Hawaii	—	—	1,017	885
U.S. Total	98,826	120,501	48,792	53,790

[1] Does not include petroleum coke. Petroleum coke stocks at the end of 1998 were 559 thousand short tons and in 1997 were 469 thousand short tons.

* =Value less than 0.5.

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

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Table A9. Fossil Fuel Receipts at U.S. Electric Utilities by Census Division and State, 1997 and 1998

Census Division State	Coal (thousand short tons)		Petroleum[1] (thousand barrels)		Gas (million cubic feet)	
	1997	1998	1997	1998	1997	1998
New England	7,125	5,538	36,176	36,174	95,374	44,730
Connecticut	952	657	13,901	14,192	13,738	10,396
Maine	—	—	2,335	3,204	—	—
Massachusetts	4,545	3,473	18,344	15,733	50,755	18,560
New Hampshire	1,628	1,408	1,594	2,427	302	—
Rhode Island	—	—	—	—	30,544	15,586
Vermont	—	—	2	4	34	187
Middle Atlantic	54,185	55,557	19,139	31,690	236,208	225,794
New Jersey	2,087	2,312	1,516	1,781	17,920	16,374
New York	8,277	9,296	14,556	22,710	215,276	204,614
Pennsylvania	43,821	43,948	3,067	7,199	3,012	4,807
East North Central	202,401	208,749	3,108	4,675	79,833	102,227
Illinois	40,750	39,867	895	1,241	44,986	51,887
Indiana	53,353	57,091	390	501	2,631	4,258
Michigan	32,145	34,906	1,288	2,400	28,208	40,444
Ohio	52,743	53,446	467	491	719	1,310
Wisconsin	23,410	23,438	67	41	3,289	4,328
West North Central	120,150	134,490	976	659	29,509	43,557
Iowa	16,675	21,730	88	121	2,748	3,182
Kansas	16,672	18,419	490	248	20,050	30,228
Minnesota	17,591	17,915	39	45	2,768	2,176
Missouri	33,553	38,589	202	158	2,889	5,984
Nebraska	10,638	11,940	21	15	1,053	1,981
North Dakota	23,087	24,199	134	72	1	1
South Dakota	1,934	1,699	—	—	—	5
South Atlantic	149,311	159,840	44,613	74,500	310,596	285,398
Delaware	1,682	1,744	1,706	2,116	15,997	11,148
District of Columbia	—	—	139	446	—	—
Florida	27,595	27,904	38,320	59,812	276,254	241,059
Georgia	28,346	31,737	279	738	3,074	10,682
Maryland	10,139	10,845	1,985	6,005	4,864	4,988
North Carolina	26,151	27,818	350	406	1,220	1,879
South Carolina	11,835	12,945	137	109	196	435
Virginia	11,930	12,716	1,361	4,543	8,619	14,859
West Virginia	31,633	34,130	336	324	372	348
East South Central	102,352	99,759	4,697	9,007	49,081	56,595
Alabama	30,378	29,902	218	112	1,194	1,731
Kentucky	39,550	36,938	237	208	576	805
Mississippi	6,043	5,886	4,081	8,534	47,311	54,059
Tennessee	26,381	27,034	161	152	—	—
West South Central	135,858	144,423	1,458	1,607	1,445,739	1,711,874
Arkansas	11,879	14,388	73	90	17,490	22,561
Louisiana	13,167	14,043	846	1,264	264,879	289,495
Oklahoma	18,378	19,747	39	7	133,617	178,090
Texas	92,435	96,244	500	246	1,029,752	1,221,728
Mountain	103,539	112,418	363	364	111,722	134,733
Arizona	16,788	18,826	123	144	22,010	35,888
Colorado	16,711	18,061	—	—	2,361	3,544
Idaho	—	—	—	—	—	—
Montana	9,160	10,512	16	14	103	199
Nevada	6,851	8,280	38	30	52,189	51,812
New Mexico	15,775	15,841	45	53	32,753	39,169
Utah	15,053	14,869	23	42	2,207	4,045
Wyoming	23,201	26,029	117	81	98	77
Pacific Contiguous	5,667	8,120	33	124	385,685	295,927
California	—	—	—	103	374,700	267,010
Oregon	875	2,014	17	6	10,969	28,915
Washington	4,792	6,106	15	15	15	2
Pacific Noncontiguous	—	—	7,227	6,916	20,989	18,887
Alaska	—	—	—	—	20,989	18,887
Hawaii	—	—	7,227	6,916	—	—
U. S. Total	880,588	928,893	117,789	165,099	2,764,734	2,919,721

[1] Does not include petroleum coke. Petroleum coke receipts in 1998 were 3.207 million short tons and in 1997 were 2.192 million short tons.

Notes: •Data for 1997 are final; data for 1998 are preliminary. •Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. •Totals may not equal sum of components because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table A10. Average Delivered Cost of Fossil Fuel Receipts at U.S. Electric Utilities by Census Division and State, 1997 and 1998

Census Division State	Coal[1]			Petroleum[2]			Gas		
	1997	1998		1997	1998		1997	1998	
	(cents per 10^6 Btu)	(cents per 10^6 Btu)	($ per short ton)	(cents per 10^6 Btu)	(cents per 10^6 Btu)	($ per barrel)	(cents per 10^6 Btu)	(cents per 10^6 Btu)	($ per Mcf)
New England	**171.2**	**167.6**	**42.94**	**274.3**	**203.5**	**12.97**	**300.6**	**282.8**	**2.91**
Connecticut	190.5	181.1	47.59	292.7	218.7	13.98	242.1	236.9	2.44
Maine	—	—	—	278.9	202.1	12.84	—	—	—
Massachusetts	169.9	167.6	42.30	260.7	192.6	12.25	301.0	270.1	2.78
New Hampshire	163.2	161.2	42.35	263.6	187.2	11.94	266.6	—	—
Rhode Island	—	—	—	—	—	—	326.4	328.5	3.38
Vermont	—	—	—	453.5	327.1	18.70	312.1	286.1	2.90
Middle Atlantic	**138.3**	**137.6**	**34.33**	**285.3**	**210.6**	**13.30**	**282.2**	**251.8**	**2.59**
New Jersey	175.6	159.0	41.71	298.7	242.2	15.12	295.1	262.0	2.74
New York	142.4	143.4	37.44	284.1	203.5	12.88	281.0	249.5	2.57
Pennsylvania	135.5	135.0	33.28	284.7	225.7	14.19	292.5	316.5	3.26
East North Central	**130.7**	**129.9**	**27.51**	**382.3**	**288.6**	**17.69**	**259.7**	**230.1**	**1.91**
Illinois	155.4	155.7	30.22	375.0	275.2	17.19	251.4	220.7	2.25
Indiana	116.4	112.3	23.63	453.1	319.4	18.42	316.3	280.5	2.88
Michigan	136.9	133.4	28.19	345.1	280.2	17.43	256.3	230.6	1.24
Ohio	132.1	136.5	32.52	437.0	332.6	19.24	362.9	315.9	3.24
Wisconsin	109.0	107.4	19.97	462.6	348.9	20.52	314.7	264.1	2.68
West North Central	**91.7**	**88.9**	**14.92**	**346.5**	**293.1**	**17.49**	**267.8**	**224.0**	**2.25**
Iowa	93.7	87.6	15.12	445.2	332.9	19.45	339.8	306.2	3.07
Kansas	102.1	98.4	17.11	282.1	265.5	16.14	258.4	213.5	2.14
Minnesota	109.5	106.9	19.00	483.2	352.7	20.41	243.6	233.8	2.36
Missouri	93.4	91.7	16.40	364.5	277.0	16.68	279.4	223.3	2.26
Nebraska	58.5	58.6	10.07	450.3	354.5	20.49	287.1	242.7	2.40
North Dakota	77.8	76.2	10.01	459.2	311.9	18.19	322.0	369.3	3.88
South Dakota	92.0	92.7	16.19	—	—	—	—	176.7	1.77
South Atlantic	**147.6**	**144.7**	**35.58**	**276.1**	**209.2**	**13.27**	**302.9**	**279.2**	**2.93**
Delaware	157.1	156.3	40.52	277.9	214.7	13.61	304.7	297.7	2.89
District of Columbia	—	—	—	357.7	252.9	15.20	—	—	—
Florida	172.5	164.8	40.03	270.2	205.9	13.11	304.3	276.2	2.91
Georgia	158.6	154.5	36.32	420.8	327.6	19.06	265.5	312.8	3.21
Maryland	150.0	145.7	37.63	296.4	211.5	13.39	285.3	263.2	2.75
North Carolina	142.9	143.8	35.66	427.7	310.5	18.02	310.7	267.9	2.81
South Carolina	144.7	144.7	37.05	454.1	327.6	19.01	397.6	353.4	3.62
Virginia	139.3	137.8	34.73	281.9	203.7	12.85	274.0	295.4	3.10
West Virginia	123.7	122.2	30.06	464.0	370.9	21.68	335.1	328.9	3.29
East South Central	**123.9**	**125.3**	**28.91**	**289.8**	**205.6**	**13.50**	**263.4**	**224.5**	**2.33**
Alabama	153.6	156.0	35.90	405.2	287.6	16.85	277.2	247.5	2.59
Kentucky	104.6	105.9	24.52	482.9	383.3	22.43	337.3	331.9	3.40
Mississippi	154.7	153.8	32.51	269.1	199.2	13.16	262.2	222.1	2.31
Tennessee	112.5	112.5	26.39	439.0	304.5	17.89	—	—	—
West South Central	**126.7**	**123.4**	**19.34**	**361.5**	**250.1**	**15.80**	**266.7**	**227.0**	**2.33**
Arkansas	164.0	147.1	25.50	470.2	370.8	21.99	261.9	224.0	2.29
Louisiana	147.9	142.9	23.15	301.8	222.3	14.32	269.3	227.4	2.37
Oklahoma	91.8	91.0	15.74	409.2	292.2	17.42	287.8	241.2	2.48
Texas	125.9	123.9	18.61	453.6	362.1	21.12	263.3	224.9	2.30
Mountain	**110.7**	**107.4**	**20.85**	**532.9**	**423.9**	**24.69**	**245.5**	**230.8**	**2.36**
Arizona	142.5	133.0	27.10	531.8	429.0	25.02	294.4	239.1	2.42
Colorado	100.9	98.7	19.41	—	—	—	317.5	300.3	2.98
Idaho	—	—	—	—	—	—	—	—	—
Montana	68.3	67.3	11.36	529.4	466.0	27.60	NM	NM	NM
Nevada	139.2	131.1	29.33	507.6	379.6	22.14	211.9	230.2	2.38
New Mexico	133.6	130.6	23.72	574.6	439.3	25.09	259.2	220.0	2.22
Utah	111.3	115.0	25.94	583.6	439.6	25.80	203.0	202.5	2.11
Wyoming	80.6	78.6	13.83	517.0	405.5	23.70	NM	NM	NM
Pacific Contiguous	**154.5**	**138.4**	**23.07**	**494.4**	**292.4**	**17.69**	**298.0**	**261.5**	**2.67**
California	—	—	—	—	274.7	16.71	302.2	273.0	2.79
Oregon	113.9	108.9	18.92	490.2	331.9	19.52	147.6	154.1	1.56
Washington	162.6	148.7	24.44	499.1	405.3	23.82	NM	NM	NM
Pacific Noncontiguous	**—**	**—**	**—**	**364.3**	**261.5**	**16.39**	**174.0**	**179.8**	**1.80**
Alaska	—	—	—	—	—	—	174.0	179.8	1.80
Hawaii	—	—	—	364.3	261.5	16.39	—	—	—
U. S. Total	**127.3**	**125.1**	**25.61**	**288.0**	**213.6**	**13.55**	**276.0**	**238.4**	**2.44**

[1] Some coal delivered to Alabama, Florida, Kentucky, and Tennessee is reported on FERC Form 423 as delivered to storage facilities. The cost reported for this coal does not include transportation costs incurred later in transporting the coal to the plant.

[2] Does not include petroleum coke. Petroleum coke cost in 1998 was 71.3 cents per million Btu and in 1997 was 91.2 cents per million Btu.

Mcf = thousand cubic feet.

NM = Not Meaningful.

Notes: •Data for 1997 are final; data for 1998 are preliminary. •Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts. •Totals may not equal sum of components because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table A11. Retail Sales of Electricity by U.S. Electric Utilities to Ultimate Consumers by Sector, Census Division, and State, 1998
(Million Kilowatthours)

Census Division and State	All Sectors	Residential	Commercial	Industrial	Other[1]
New England	**109,891**	**38,483**	**44,170**	**25,859**	**1,379**
Connecticut	28,924	10,933	11,675	5,940	377
Maine	11,568	3,619	3,309	4,582	58
Massachusetts	48,292	16,204	21,449	10,050	589
New Hampshire	9,253	3,390	3,319	2,400	144
Rhode Island	6,578	2,404	2,617	1,380	177
Vermont	5,277	1,933	1,802	1,507	35
Middle Atlantic	**327,668**	**105,366**	**120,240**	**87,163**	**14,899**
New Jersey	68,811	23,578	30,955	13,774	504
New York	131,375	40,168	52,896	25,197	13,115
Pennsylvania	127,482	41,621	36,389	48,192	1,279
East North Central	**540,313**	**159,769**	**146,650**	**218,824**	**15,069**
Illinois	130,646	39,450	39,754	42,700	8,742
Indiana	90,822	26,973	18,826	44,497	526
Michigan	100,373	30,061	34,128	35,313	870
Ohio	156,282	44,066	37,682	70,337	4,197
Wisconsin	62,190	19,219	16,259	25,978	734
West North Central	**234,622**	**84,353**	**65,664**	**78,850**	**5,755**
Iowa	36,432	11,811	7,705	15,612	1,304
Kansas	33,715	11,887	11,768	9,678	382
Minnesota	56,233	17,580	10,767	27,174	712
Missouri	68,958	28,219	23,887	15,849	1,004
Nebraska	23,397	8,245	6,654	6,944	1,555
North Dakota	8,073	3,280	2,569	1,785	440
South Dakota	7,813	3,331	2,314	1,809	359
South Atlantic	**675,997**	**273,777**	**217,615**	**163,660**	**20,945**
Delaware	10,322	3,326	3,191	3,752	52
District of Columbia	10,281	1,596	8,051	262	372
Florida	186,905	95,610	67,982	17,555	5,758
Georgia	108,445	40,864	32,273	33,999	1,309
Maryland	57,786	22,460	24,147	10,421	758
North Carolina	113,353	42,811	33,092	35,387	2,062
South Carolina	72,431	23,665	16,565	31,291	909
Virginia	89,935	34,390	26,107	19,808	9,630
West Virginia	26,539	9,056	6,205	11,184	94
East South Central	**283,932**	**99,625**	**48,131**	**130,645**	**5,530**
Alabama	77,866	26,880	14,820	35,583	583
Kentucky	73,994	21,242	11,515	38,067	3,170
Mississippi	41,480	16,042	9,347	15,405	686
Tennessee	90,591	35,461	12,449	41,590	1,091
West South Central	**464,846**	**169,799**	**115,918**	**159,505**	**19,624**
Arkansas	39,034	14,502	8,150	15,720	662
Louisiana	77,103	26,419	17,201	30,780	2,704
Oklahoma	47,451	19,406	12,499	12,842	2,704
Texas	301,257	109,472	78,069	100,163	13,554
Mountain	**204,923**	**65,032**	**64,584**	**67,568**	**7,739**
Arizona	55,367	21,660	18,514	12,810	2,384
Colorado	39,477	12,637	15,992	9,818	1,030
Idaho	21,320	6,611	5,984	8,405	318
Montana	13,146	3,736	3,408	5,759	243
Nevada	24,852	7,925	5,683	10,306	938
New Mexico	17,854	4,562	5,690	6,030	1,571
Utah	20,757	5,783	6,737	7,436	802
Wyoming	12,151	2,118	2,576	7,004	454
Pacific Contiguous	**363,560**	**123,402**	**120,859**	**110,593**	**8,707**
California	223,583	74,656	84,800	59,778	4,348
Oregon	48,146	17,512	13,838	16,131	665
Washington	91,831	31,233	22,220	34,683	3,695
Pacific Noncontiguous	**14,369**	**4,397**	**5,073**	**4,678**	**221**
Alaska	5,113	1,756	2,298	895	164
Hawaii	9,256	2,641	2,775	3,783	57
U.S. Total	**3,220,121**	**1,124,004**	**948,904**	**1,047,346**	**99,868**

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

Notes: •Values for 1998 are preliminary, based on revised Form EIA-826 estimates. •Revenue and average revenue per kilowatthour do not include taxes such as sales and excise taxes that are assessed on the consumer and collected through the utility. •Weather-related phenomena, reclassification of retail sales, changes in number of customers, prior period adjustments, and changes in billing procedures may contribute to substantial year-to-year changes in the data in this table. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-826, "Monthly Electric Utility Sales and Revenue Report with State Distributions."

Table A12. Estimated Coefficients of Variation for U.S. Electric Utility Retail Sales of Electricity by Census Division and State, 1998
(Percent)

Census Division and State	All Sectors	Residential	Commercial	Industrial	Other[1]
New England	0.2	0.2	0.2	0.3	0.5
Connecticut	.1	.1	.1	.2	.8
Maine	.1	.3	1.0	.8	4.2
Massachusetts	.5	.5	.4	.5	1.1
New Hampshire	.3	.3	.1	.7	1.0
Rhode Island	.1	.2	.1	.2	.3
Vermont	.3	.4	2.3	1.8	2.9
Middle Atlantic	.2	.7	.3	.5	.3
New Jersey	.1	.2	.1	.3	.2
New York	.4	.7	.4	.5	.3
Pennsylvania	.5	1.6	.6	.9	.5
East North Central	.3	.3	.3	.6	.5
Illinois	.7	.5	.8	.6	.4
Indiana	.5	.8	.6	.9	1.1
Michigan	.4	.2	.9	2.3	1.8
Ohio	.6	.7	.3	1.2	1.3
Wisconsin	.3	.4	.4	.4	1.4
West North Central	.2	.4	.3	.3	2.0
Iowa	.4	.9	.7	.4	.6
Kansas	.3	.5	.4	.3	1.2
Minnesota	.6	.7	1.2	.6	1.6
Missouri	.4	.8	.3	.7	1.1
Nebraska	.6	1.0	.4	.6	7.2
North Dakota	.5	.8	1.2	1.2	1.6
South Dakota	.5	.9	.5	.9	3.5
South Atlantic	.2	.2	.2	.2	.3
Delaware	.2	.1	.2	.5	.6
District of Columbia	—	—	—	—	—
Florida	.2	.3	.3	.6	1.1
Georgia	.6	.9	.5	.3	1.2
Maryland	.2	.3	.3	.2	.8
North Carolina	.3	.7	.4	.3	.9
South Carolina	1.6	.9	.8	.6	.5
Virginia	.3	.6	.2	.3	.2
West Virginia	.2	.5	.4	.3	1.8
East South Central	.8	.5	.4	.5	1.2
Alabama	.5	1.0	1.1	.9	1.4
Kentucky	2.7	1.2	.4	1.3	.3
Mississippi	.9	.8	.9	1.0	.9
Tennessee	.6	1.0	.7	.5	5.8
West South Central	.3	.5	.2	.4	.5
Arkansas	.6	.9	.6	.9	2.1
Louisiana	1.0	.7	.4	1.1	.8
Oklahoma	.7	1.2	.8	.7	2.2
Texas	.3	.7	.3	.5	.6
Mountain	.2	.2	.2	.4	1.4
Arizona	.3	.4	.5	1.3	2.6
Colorado	.4	.5	.3	.4	4.7
Idaho	.4	.6	.9	.7	4.2
Montana	.9	.8	1.0	3.6	.9
Nevada	.6	1.1	.6	.3	.8
New Mexico	.7	.7	.7	.8	3.1
Utah	.2	.4	.6	.1	1.0
Wyoming	.6	1.2	1.1	.4	12.2
Pacific Contiguous	.3	.3	.3	.6	2.1
California	.3	.5	.4	.8	4.0
Oregon	.7	.8	.5	1.4	4.7
Washington	1.1	.6	.4	1.5	1.4
Pacific Noncontiguous	.3	.2	.2	.8	2.8
Alaska	.7	.4	.3	4.0	3.8
Hawaii	.1	.1	.1	.1	.1
U.S. Total	.1	.1	.1	.2	.3

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

Notes: •It should be noted that such things as large changes in retail sales, reclassification of retail sales, or changes in billing procedures can contribute unusually high coefficients of variation.

Sources: Energy Information Administration, Form EIA-826, "Monthly Electric Utility Sales and Revenue Report with State Distributions."

Table A13. Revenue from Retail Sales by U.S. Electric Utilities to Ultimate Consumers by Sector, Census Division, and State, 1998
(Million Dollars)

Census Division and State	All Sectors	Residential	Commercial	Industrial	Other[1]
New England	**10,960**	**4,423**	**4,340**	**2,002**	**195**
Connecticut	2,978	1,305	1,168	452	53
Maine	1,125	467	349	295	15
Massachusetts	4,605	1,695	2,011	816	82
New Hampshire	1,090	463	383	224	20
Rhode Island	639	266	246	107	20
Vermont	522	227	182	108	6
Middle Atlantic	**30,943**	**12,272**	**12,227**	**5,046**	**1,399**
New Jersey	6,998	2,742	3,087	1,080	89
New York	14,076	5,484	6,176	1,258	1,158
Pennsylvania	9,870	4,046	2,963	2,709	152
East North Central	**35,351**	**13,683**	**10,779**	**9,826**	**1,063**
Illinois	9,758	3,878	3,097	2,185	597
Indiana	4,984	1,952	1,172	1,807	52
Michigan	7,223	2,647	2,688	1,790	99
Ohio	10,003	3,823	2,868	3,050	262
Wisconsin	3,382	1,382	954	992	54
West North Central	**13,943**	**6,175**	**4,023**	**3,393**	**352**
Iowa	2,243	1,001	524	634	85
Kansas	2,124	906	742	439	36
Minnesota	3,220	1,290	667	1,208	55
Missouri	4,176	1,990	1,424	701	61
Nebraska	1,225	533	360	251	81
North Dakota	465	213	153	79	20
South Dakota	492	242	153	81	15
South Atlantic	**43,770**	**21,495**	**14,028**	**6,956**	**1,292**
Delaware	716	305	228	176	7
District of Columbia	762	128	598	11	24
Florida	13,247	7,611	4,360	882	394
Georgia	6,974	3,158	2,245	1,460	111
Maryland	4,053	1,897	1,654	433	69
North Carolina	7,370	3,457	2,102	1,664	146
South Carolina	4,026	1,784	1,039	1,149	54
Virginia	5,279	2,588	1,457	756	478
West Virginia	1,343	568	344	423	9
East South Central	**14,897**	**6,420**	**2,987**	**5,151**	**338**
Alabama	4,319	1,874	981	1,420	44
Kentucky	3,093	1,204	597	1,144	148
Mississippi	2,440	1,118	611	655	56
Tennessee	5,045	2,224	798	1,932	91
West South Central	**27,664**	**12,605**	**7,422**	**6,420**	**1,217**
Arkansas	2,189	1,058	467	621	43
Louisiana	4,470	1,890	1,125	1,288	168
Oklahoma	2,599	1,283	711	472	133
Texas	18,406	8,374	5,119	4,040	873
Mountain	**12,250**	**4,922**	**4,151**	**2,766**	**411**
Arizona	4,089	1,882	1,439	653	115
Colorado	2,366	943	907	433	84
Idaho	859	350	259	234	16
Montana	676	250	205	201	19
Nevada	1,436	555	369	475	37
New Mexico	1,229	412	450	276	90
Utah	1,071	395	384	256	36
Wyoming	524	135	137	237	16
Pacific Contiguous	**26,050**	**10,444**	**9,967**	**5,148**	**491**
California	20,109	7,830	8,201	3,754	325
Oregon	2,274	1,039	696	505	35
Washington	3,667	1,575	1,071	890	132
Pacific Noncontiguous	**1,572**	**566**	**555**	**421**	**31**
Alaska	506	202	214	66	24
Hawaii	1,066	364	340	355	7
U.S. Total	**217,401**	**93,005**	**70,478**	**47,129**	**6,790**

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

Notes: •Values for 1998 are preliminary, based on revised Form EIA-826 estimates. •Revenue and average revenue per kilowatthour do not include taxes such as sales and excise taxes that are assessed on the consumer and collected through the utility. •Weather-related phenomena, reclassification of retail sales, changes in number of customers, prior period adjustments, and changes in billing procedures may contribute to substantial year-to-year changes in the data in this table. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-826, "Monthly Electric Utility Sales and Revenue Report with State Distributions,"

Table A14. Estimated Coefficients of Variation of Revenue from Retail Sales by U.S. Electric Utilities by Census Division and State, 1998
(Percent)

Census Division and State	All Sectors	Residential	Commercial	Industrial	Other[1]
New England	0.3	0.2	0.5	0.5	0.6
Connecticut	.2	.2	.2	.2	1.1
Maine	.2	.1	.9	1.0	2.0
Massachusetts	.8	.5	1.0	1.1	.8
New Hampshire	.3	.3	.5	.3	3.5
Rhode Island	.1	.2	.1	.2	.2
Vermont	.5	.5	2.0	2.8	2.3
Middle Atlantic	.3	.7	.3	.5	.3
New Jersey	.2	.3	.1	.3	.1
New York	.4	.6	.3	.5	.4
Pennsylvania	.8	2.1	.8	.8	.3
East North Central	.2	.3	.3	.6	.4
Illinois	.3	.5	.3	.7	.3
Indiana	.6	.8	.6	1.0	1.0
Michigan	.5	.3	1.0	2.5	1.0
Ohio	.4	.6	.3	.7	1.6
Wisconsin	.6	.8	.7	.6	1.5
West North Central	.3	.4	.3	.4	1.4
Iowa	.4	.7	.6	.6	.5
Kansas	.6	.8	.7	.5	2.7
Minnesota	.8	.9	1.0	.8	.8
Missouri	.7	.9	.6	.7	3.1
Nebraska	.8	1.2	.8	1.2	5.5
North Dakota	.5	.6	.9	1.2	1.3
South Dakota	.7	1.0	.5	1.0	1.6
South Atlantic	.2	.3	.2	.2	.4
Delaware	.1	.1	.3	.4	.3
District of Columbia	—	—	—	—	—
Florida	.4	.4	.4	1.0	1.1
Georgia	.8	1.4	.4	.3	1.2
Maryland	.5	.6	.4	.5	.4
North Carolina	.4	.7	.6	.5	1.0
South Carolina	1.0	1.4	.9	.8	.7
Virginia	.5	.8	.2	.8	.2
West Virginia	.2	.5	.4	.2	1.0
East South Central	.4	.6	.5	.4	1.1
Alabama	.8	1.2	1.3	.6	1.1
Kentucky	.9	1.6	.7	1.0	.4
Mississippi	.6	.9	1.0	.8	1.1
Tennessee	.6	1.0	.8	.7	3.8
West South Central	.4	.6	.4	.5	.6
Arkansas	1.2	.8	1.5	1.5	3.5
Louisiana	.9	1.0	.6	1.1	2.0
Oklahoma	1.0	1.4	1.1	.6	1.8
Texas	.6	.9	.5	.7	.7
Mountain	.2	.2	.2	.4	1.1
Arizona	.4	.4	.4	1.2	2.7
Colorado	.7	.5	.5	.7	1.5
Idaho	.6	.6	1.1	1.1	2.7
Montana	.5	1.0	.7	2.5	1.2
Nevada	.7	1.0	.5	.8	.8
New Mexico	.8	.9	.6	1.4	2.9
Utah	.2	.4	.6	.1	1.1
Wyoming	.6	1.3	1.1	.5	6.2
Pacific Contiguous	.4	.4	.5	.8	2.6
California	.4	.5	.6	.9	3.9
Oregon	.9	1.0	.9	1.9	1.5
Washington	1.1	.6	.5	2.6	2.2
Pacific Noncontiguous	.3	.3	.3	.7	2.7
Alaska	.6	.6	.7	3.9	3.4
Hawaii	.3	.3	.3	.4	.3
U.S. Total	.1	.2	.1	.2	.3

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

Notes: •It should be noted that such things as large changes in retail sales, reclassification of retail sales, or changes in billing procedures can contribute unusually high coefficients of variation.

Sources: Energy Information Administration, Form EIA-826, "Monthly Electric Utility Sales and Revenue Report with State Distributions."

Table A15. Average Revenue per Kilowatthour for U.S. Electric Utilities by Sector, Census Division, and State, 1998
(Cents)

Census Division and State	All Sectors	Residential	Commercial	Industrial	Other[1]
New England	**10.0**	**11.5**	**9.8**	**7.7**	**14.1**
Connecticut	10.3	11.9	10.0	7.6	14.2
Maine	9.7	12.9	10.5	6.4	25.3
Massachusetts	9.5	10.5	9.4	8.1	13.9
New Hampshire	11.8	13.7	11.6	9.3	13.6
Rhode Island	9.7	11.1	9.4	7.8	11.2
Vermont	9.9	11.7	10.1	7.1	16.2
Middle Atlantic	**9.4**	**11.6**	**10.2**	**5.8**	**9.4**
New Jersey	10.2	11.6	10.0	7.8	17.7
New York	10.7	13.7	11.7	5.0	8.8
Pennsylvania	7.7	9.7	8.1	5.6	11.9
East North Central	**6.5**	**8.6**	**7.4**	**4.5**	**7.1**
Illinois	7.5	9.8	7.8	5.1	6.8
Indiana	5.5	7.2	6.2	4.1	9.9
Michigan	7.2	8.8	7.9	5.1	11.4
Ohio	6.4	8.7	7.6	4.3	6.2
Wisconsin	5.4	7.2	5.9	3.8	7.3
West North Central	**5.9**	**7.3**	**6.1**	**4.3**	**6.1**
Iowa	6.2	8.5	6.8	4.1	6.5
Kansas	6.3	7.6	6.3	4.5	9.4
Minnesota	5.7	7.3	6.2	4.4	7.7
Missouri	6.1	7.1	6.0	4.4	6.1
Nebraska	5.2	6.5	5.4	3.6	5.2
North Dakota	5.8	6.5	6.0	4.5	4.4
South Dakota	6.3	7.3	6.6	4.5	4.2
South Atlantic	**6.5**	**7.9**	**6.4**	**4.3**	**6.2**
Delaware	6.9	9.2	7.1	4.7	13.2
District of Columbia	7.4	8.0	7.4	4.4	6.6
Florida	7.1	8.0	6.4	5.0	6.8
Georgia	6.4	7.7	7.0	4.3	8.5
Maryland	7.0	8.4	6.9	4.2	9.0
North Carolina	6.5	8.1	6.4	4.7	7.1
South Carolina	5.6	7.5	6.3	3.7	5.9
Virginia	5.9	7.5	5.6	3.8	5.0
West Virginia	5.1	6.3	5.5	3.8	9.1
East South Central	**5.2**	**6.4**	**6.2**	**3.9**	**6.1**
Alabama	5.5	7.0	6.6	4.0	7.5
Kentucky	4.2	5.7	5.2	3.0	4.7
Mississippi	5.9	7.0	6.5	4.2	8.2
Tennessee	5.6	6.3	6.4	4.6	8.3
West South Central	**6.0**	**7.4**	**6.4**	**4.0**	**6.2**
Arkansas	5.6	7.3	5.7	3.9	6.5
Louisiana	5.8	7.2	6.5	4.2	6.2
Oklahoma	5.5	6.6	5.7	3.7	4.9
Texas	6.1	7.6	6.6	4.0	6.4
Mountain	**6.0**	**7.6**	**6.4**	**4.1**	**5.3**
Arizona	7.4	8.7	7.8	5.1	4.8
Colorado	6.0	7.5	5.7	4.4	8.2
Idaho	4.0	5.3	4.3	2.8	4.9
Montana	5.1	6.7	6.0	3.5	7.7
Nevada	5.8	7.0	6.5	4.6	3.9
New Mexico	6.9	9.0	7.9	4.6	5.7
Utah	5.2	6.8	5.7	3.4	4.4
Wyoming	4.3	6.4	5.3	3.4	3.5
Pacific Contiguous	**7.2**	**8.5**	**8.2**	**4.7**	**5.6**
California	9.0	10.5	9.7	6.3	7.5
Oregon	4.7	5.9	5.0	3.1	5.2
Washington	4.0	5.0	4.8	2.6	3.6
Pacific Noncontiguous	**10.9**	**12.9**	**10.9**	**9.0**	**14.0**
Alaska	9.9	11.5	9.3	7.3	14.6
Hawaii	11.5	13.8	12.3	9.4	12.2
U.S. Average	**6.75**	**8.27**	**7.43**	**4.50**	**6.80**

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

Notes: •Values for 1998 are preliminary, based on revised Form EIA-826 estimates. •Revenue and average revenue per kilowatthour do not include taxes such as sales and excise taxes that are assessed on the consumer and collected through the utility. •Weather-related phenomena, reclassification of retail sales, changes in number of customers, prior period adjustments, and changes in billing procedures may contribute to substantial year-to-year changes in the data in this table. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-826, "Monthly Electric Utility Sales and Revenue Report with State Distributions,"

Table A16. Estimated Coefficients of Variation for Average Revenue per Kilowatthour for U.S. Electric Utilities by Sector, Census Division, and State, 1998
(Percent)

Census Division and State	All Sectors	Residential	Commercial	Industrial	Other[1]
New England	0.3	0.3	0.4	0.5	0.6
Connecticut	.1	.1	.1	.2	.6
Maine	.2	.3	.2	.3	2.1
Massachusetts	.8	.7	.9	1.2	1.3
New Hampshire	.5	.5	.5	.6	2.8
Rhode Island	.1	.1	.1	.2	.3
Vermont	.5	.5	.4	1.3	1.4
Middle Atlantic	.2	.3	.2	.3	.2
New Jersey	.1	.1	.1	.1	.2
New York	.4	.5	.5	.4	.3
Pennsylvania	.5	.9	.4	.4	.5
East North Central	.2	.2	.2	.3	.2
Illinois	.6	.3	.6	.6	.3
Indiana	.3	.4	.3	.5	1.0
Michigan	.5	.3	.5	.5	1.0
Ohio	.5	.3	.3	.6	.5
Wisconsin	.7	.6	.7	.7	1.5
West North Central	.3	.3	.3	.2	1.2
Iowa	.5	.8	.6	.5	.4
Kansas	.4	.5	.5	.4	2.2
Minnesota	.4	.3	.7	.3	1.3
Missouri	.7	.8	.7	.7	2.7
Nebraska	.7	.6	.6	1.1	3.9
North Dakota	.3	.4	.5	.4	1.0
South Dakota	.5	.4	.5	.6	2.8
South Atlantic	.2	.2	.1	.1	.1
Delaware	.2	.1	.3	.3	.5
District of Columbia	—	—	—	—	—
Florida	.2	.2	.2	.6	.3
Georgia	.5	.9	.4	.2	1.1
Maryland	.3	.4	.4	.4	.6
North Carolina	.3	.3	.4	.3	.5
South Carolina	1.8	.8	.7	.4	.6
Virginia	.3	.3	.2	.6	.1
West Virginia	.1	.1	.1	.1	1.8
East South Central	.7	.2	.2	.4	.3
Alabama	.6	.4	.3	.9	.6
Kentucky	2.4	.6	.4	1.1	.4
Mississippi	.8	.8	.5	.7	1.0
Tennessee	.3	.4	.2	.4	2.2
West South Central	.3	.3	.3	.4	.5
Arkansas	.8	.5	1.1	1.5	1.6
Louisiana	.5	.7	.5	.4	2.2
Oklahoma	.5	.5	.6	.8	.7
Texas	.4	.4	.5	.5	.5
Mountain	.2	.1	.2	.4	1.2
Arizona	.3	.2	.4	1.5	2.4
Colorado	.3	.3	.5	.5	4.0
Idaho	.3	.3	.3	.8	3.3
Montana	.9	.6	.6	1.2	.9
Nevada	.2	.2	.2	.6	1.1
New Mexico	.6	.6	.3	1.1	3.2
Utah	.1	.1	.1	.1	.4
Wyoming	.2	1.1	.5	.4	6.0
Pacific Contiguous	.4	.3	.5	.6	1.9
California	.5	.3	.6	.7	3.6
Oregon	.5	.3	.8	1.1	3.4
Washington	.9	.3	.4	1.8	1.3
Pacific Noncontiguous	.3	.2	.3	.4	1.6
Alaska	.6	.4	.6	1.2	2.2
Hawaii	.2	.1	.2	.3	.2
U.S. Average	.1	.1	.1	.1	.2

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

Notes: •*It should be noted that such things as large changes in retail sales, reclassification of retail sales, or changes in billing procedures can contribute unusually high coefficients of variation.*

Sources: Energy Information Administration, Form EIA-826, "Monthly Electric Utility Sales and Revenue Report with State Distributions."

Glossary

Acid Rain: Also called acid precipitation or acid deposition, acid rain is precipitation containing harmful amounts of nitric and sulfuric acids formed primarily by nitrogen oxides and sulfur oxides released into the atmosphere when fossil fuels are burned. It can be wet precipitation (rain, snow, or fog) or dry precipitation (absorbed gaseous and particulate matter, aerosol particles or dust). Acid rain has a pH below 5.6. Normal rain has a pH of about 5.6, which is slightly acidic. The term pH is a measure of acidity or alkalinity and ranges from 0 to 14. A pH measurement of 7 is regarded as neutral. Measurements below 7 indicate increased acidity, while those above indicate increased alkalinity.

Adjustment Bid: A bid that is used by the Independent System Operator to adjust supply or demand when congestion on the transmission system is anticipated.

Aggregator: Any marketer, broker, public agency, city, county, or special district that combines the loads of multiple end-use customers in facilitating the sale and purchase of electric energy, transmission, and other services on behalf of these customers.

Ampere: The unit of measurement of electrical current produced in a circuit by 1 volt acting through a resistance of 1 ohm.

Ancillary Services: Necessary services that must be provided in the generation and delivery of electricity. As defined by the Federal Energy Regulatory Commission, they include: coordination and scheduling services (load following, energy imbalance service, control of transmission congestion); automatic generation control (load frequency control and the economic dispatch of plants); contractual agreements (loss compensation service); and support of system integrity and security (reactive power, or spinning and operating reserves).

Anthracite: The highest rank of coal; used primarily for residential and commercial space heating. It is hard, brittle, and black lustrous coal, often referred to as hard coal, containing a high percentage of fixed carbon and a low percentage of volatile matter. The moisture content of fresh-mined anthracite generally is less than 15 percent. The heat content of anthracite ranges from 22 to 28 million Btu per ton on a moist, mineral-matter-free basis. The heat content of anthracite coal consumed in the United States averages 25 million Btu per ton, on the as-received basis (i.e., containing both inherent moisture and mineral matter). *Note*: Since the 1980's, anthracite refuse or mine waste has been used for steam electric power generation. This fuel typically has a heat content of 15 million Btu per ton or less.

Ash: Impurities consisting of silica, iron, alumina, and other noncombustible matter that are contained in coal. Ash increases the weight of coal, adds to the cost of handling, and can affect its burning characteristics. Ash content is measured as a percent by weight of coal on an "received" or a "dry" (moisture-free, usually part of a laboratory analysis) basis.

Available but not Needed Capability: Net capability of main generating units that are operable but not considered necessary to carry load, and cannot be connected to load within 30 minutes.

Average Revenue per Kilowatthour: The average revenue per kilowatthour of electricity sold by sector (residential, commercial, industrial, or other) and geographic area (State, Census division, and national), is calculated by dividing the total monthly revenue by the corresponding total monthly sales for each sector and geographic area.

Barrel: A volumetric unit of measure for crude oil and petroleum products equivalent to 42 U.S. gallons.

Base Bill: A charge calculated through multiplication of the rate from the appropriate electric rate schedule by the level of consumption.

Baseload: The minimum amount of electric power delivered or required over a given period of time at a steady rate.

Baseload Capacity: The generating equipment normally operated to serve loads on an around-the-clock basis.

Baseload Plant: A plant, usually housing high-efficiency steam-electric units, which is normally operated to take all or part of the minimum load of a system, and which consequently produces electricity at an essentially constant rate and runs continuously. These units are operated to maximize system mechanical and thermal efficiency and minimize system operating costs.

Bbl: The abbreviation for barrel.

Bcf: The abbreviation for 1 billion cubic feet.

Bilateral Agreement: Written statement signed by a pair of communicating parties that specifies what data may be exchanged between them.

Bilateral Contract: A direct contract between the power producer and user or broker outside of a centralized power pool or power exchange.

Bituminous Coal: A dense coal, usually black, sometimes dark brown, often with well-defined bands of bright and dull material, used primarily as fuel in steam-electric power generation, with substantial quantities also used for heat and power applications in manufacturing and to make coke. Bituminous coal is the most abundant coal in active U.S. mining regions. Its moisture content usually is less then 20 percent. The heat content of bituminous coal ranges from 21 to 30 million Btu per ton on a moist, mineral-matter-free basis. The heat content of bituminous coal consumed in the United States averages 24 million Btu per ton, on the as-received basis (i.e., containing both inherent moisture and mineral matter).

Boiler: A device for generating steam for power, processing, or heating purposes or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes in the boiler shell. This fluid is delivered to an end-use at a desired pressure, temperature, and quality.

Broker: An entity that arranges the sale and purchase of electric energy, transmission, and other services between buyers and sellers, but does not take title to any of the power sold.

Btu (British Thermal Unit): A standard unit for measuring the quantity of heat energy equal to the quantity of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit.

Bundled Utility Service: All generation, transmission, and distribution services provided by one entity for a single charge. This would include ancillary services and retail services.

California Power Exchange: The California Power Exchange Corporation, a State chartered, non-profit corporation charged with providing Day-Ahead and Hour-Ahead markets for energy and ancillary services, if it chooses to self-provide, in accordance with the power exchange tariff. The power exchange is a Scheduling Coordinator and is independent of both the Independent System Operator and all other market participants.

Capability: The maximum load that a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time without exceeding approved limits of temperature and stress.

Capacity: The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer.

Capacity (Purchased): The amount of energy and capacity available for purchase from outside the system.

Capacity Charge: An element in a two-part pricing method used in capacity transactions (energy charge is the other element). The capacity charge, sometimes called Demand Charge, is assessed on the amount of capacity being purchased.

Census Divisions: The nine geographic divisions of the United States established by the Bureau of the Census, U.S. Department of Commerce, for the purpose of statistical analysis. The boundaries of Census divisions coincide with State boundaries. The Pacific Division is subdivided into the Pacific Contiguous and Pacific Noncontiguous areas.

Circuit: A conductor or a system of conductors through which electric current flows.

Coal: A readily combustible black or brownish-black rock whose composition, including inherent moisture, consists of more than 50 percent by weight and more than 70 percent by volume of carbonaceous material. It is formed from plant remains that have been compacted, hardened, chemically altered, and metamorphosed by heat and pressure over geologic time.

Cogenerator: A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes. To receive status as a qualifying facility (QF) under the Public Utility Regulatory Policies Act (PURPA), the facility must produce electric energy and "another form of useful thermal energy through the sequential use of energy," and meet certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC). (See the Code of Federal Regulations, Title 18, Part 292.)

Coincidental Demand: The sum of two or more demands that occur in the same time interval.

Coincidental Peak Load: The sum of two or more peakloads that occur in the same time interval.

Coke (Petroleum): A residue high in carbon content and low in hydrogen that is the final product of thermal decomposition in the condensation process in cracking. This product is reported as marketable coke or catalyst coke. The conversion is 5 barrels (of 42 U.S. gallons each) per short ton. Coke from petroleum has a heating value of 6.024 million Btu per barrel.

Combined Cycle: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Combined Cycle Unit: An electric generating unit that consists of one or more combustion turbines and one or more boilers with a portion of the required energy input to the boiler(s) provided by the exhaust gas of the combustion turbine(s).

Combined Pumped-Storage Plant: A pumped-storage hydroelectric power plant that uses both pumped water and natural streamflow to produce electricity.

Commercial: The commercial sector is generally defined as nonmanufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, retail stores, and health, social, and educational institutions. The utility may classify commercial service as all consumers whose demand or annual use exceeds some specified limit. The limit may be set by the utility based on the rate schedule of the utility.

Commercial Operation: Commercial operation begins when control of the loading of the generator is turned over to the system dispatcher.

Competitive Transition Charge: A non-bypassable charge levied on each customer of a distribution utility, including those who are served under contracts with nonutility suppliers, for recovery of a utility's transition costs.

Congestion: A condition that occurs when insufficient transfer capacity is available to implement all of the preferred schedules for electricity transmission simultaneously.

Consumption (Fuel): The amount of fuel used for gross generation, providing standby service, start-up and/or flame stabilization.

Contract Price: Price of fuels marketed on a contract basis covering a period of 1 or more years. Contract prices reflect market conditions at the time the contract was negotiated and therefore remain constant throughout the life of the contract or are adjusted through escalation clauses. Generally, contract prices do not fluctuate widely.

Contract Receipts: Purchases based on a negotiated agreement that generally covers a period of 1 or more years.

Cooperative Electric Utility: An electric utility legally established to be owned by and operated for the benefit of those using its service. The utility company will generate, transmit, and/or distribute supplies of electric energy to a specified area not being serviced by another utility. Such ventures are generally exempt from Federal income tax laws. Most electric cooperatives have been initially financed by the Rural Electrification Administration, U.S. Department of Agriculture.

Cost: The amount paid to acquire resources, such as plant and equipment, fuel, or labor services.

Cost-of-Service Regulation: Traditional electric utility regulation under which a utility is allowed to set rates based on the cost of providing service to customers and the right to earn a limited profit.

Current (Electric): A flow of electrons in an electrical conductor. The strength or rate of movement of the electricity is measured in amperes.

Customer Choice: Allowing all customers to purchase kilowatthours of electricity from any of a number of companies that compete with each other.

Day-Ahead Market: The forward market for energy and ancillary services to be supplied during the settlement period of a particular trading day that is conducted by the Independent System Operator, the power exchange, and other Scheduling Coordinators. This market closes with the Independent System Operator's acceptance of the final day-ahead schedule.

Day-Ahead Schedule: A schedule prepared by a Scheduling Coordinator or the Independent System Operator before the beginning of a trading day. This schedule indicates the levels of generation and demand scheduled for each settlement period that trading day.

Demand: The rate at which energy is delivered to loads and scheduling points by generation, transmission, and distribution facilities.

Demand (Electric): The rate at which electric energy is delivered to or by a system, part of a system, or piece of equipment, at a given instant or averaged over any designated period of time.

Demand Bid: A bid into the power exchange indicating a quantity of energy or an ancillary service that an eligible customer is willing to purchase and, if relevant, the maximum price that the customer is willing to pay.

Demand-Side Management: The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. It refers only to energy and load-shape modifying activities that are undertaken in response to utility-administered programs. It does not refer to energy and load-shape changes arising from the normal operation of the marketplace or from government-mandated energy-efficiency standards. Demand-Side Management (DSM) covers the complete range of load-shape objectives, including strategic conservation and load management, as well as strategic load growth.

Deregulation: The elimination of regulation from a previously regulated industry or sector of an industry.

Direct Access: The ability of a retail customer to purchase commodity electricity directly from the wholesale market rather than through a local distribution utility.

Distillate Fuel Oil: A general classification for one of the petroleum fractions produced in conventional distillation operations. It is used primarily for space heating, on-and-off-highway diesel engine fuel (including railroad engine fuel and fuel for agriculture machinery), and electric power generation. Included are Fuel Oils No. 1, No. 2, and No. 4; and Diesel Fuels No. 1, No. 2, and No. 4.

Distribution: The delivery of electricity to retail customers (including homes, businesses, etc.).

Distribution System: The portion of an electric system that is dedicated to delivering electric energy to an end user.

Divestiture: The stripping off of one utility function from the others by selling (spinning-off) or in some other way changing the ownership of the assets related to that function. Stripping off is most commonly associated with spinning-off generation assets so they are no longer owned by the shareholders that own the transmission and distribution assets.

Electric Plant (Physical): A facility containing prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or fission energy into electric energy.

Electric Rate Schedule: A statement of the electric rate and the terms and conditions governing its application, including attendant contract terms and conditions that have been accepted by a regulatory body with appropriate oversite authority.

Electric Service Provider: An entity that provides electric service to a retail or end-use customer.

Electric Utility: A corporation, person, agency, authority, or other legal entity or instrumentality that owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public and files forms listed in the Code of Federal Regulations, Title 18, Part 141. Facilities that qualify as cogenerators or small power producers under the Public Utility Regulatory Policies Act (PURPA) are not considered electric utilities.

Energy: The capacity for doing work as measured by the capability of doing work (potential energy) or the conversion of this capability to motion (kinetic energy). Energy has several forms, some of which are easily convertible and can be changed to another form useful for work. Most of the world's convertible energy comes from fossil fuels that are burned to produce heat that is then used as a transfer medium to mechanical or other means in order to accomplish tasks. Electrical energy is usually measured in kilowatthours, while heat energy is usually measured in British thermal units.

Energy Charge: That portion of the charge for electric service based upon the electric energy (kWh) consumed or billed.

Energy Deliveries: Energy generated by one electric utility system and delivered to another system through one or more transmission lines.

Energy Efficiency: Refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption (reported in megawatthours), often without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems.

Energy Receipts: Energy generated by one electric utility system and received by another system through one or more transmission lines.

Energy Source: The primary source that provides the power that is converted to electricity through chemical, mechanical, or other means. Energy sources include coal, petroleum and petroleum products, gas, water, uranium, wind, sunlight, geothermal, and other sources.

EPACT: The Energy Policy Act of 1992 addresses a wide variety of energy issues. The legislation creates a new class of power generators, exempt wholesale generators, that are exempt from the provisions of the Public Holding Company Act of 1935 and grants the authority to the Federal Energy Regulatory Commission to order and condition access by eligible parties to the interconnected transmission grid.

Exempt Wholesale Generator: Created under the 1992 Energy Policy Act, these wholesale generators are exempt from certain financial and legal restrictions stipulated in the Public Utilities Holding Company Act of 1935.

Facility: An existing or planned location or site at which prime movers, electric generators, and/or equipment for converting mechanical, chemical, and/or nuclear energy into electric energy are situated, or will be situated. A facility may contain more than one generator of either the same or different prime mover type. For a cogenerator, the facility includes the industrial or commercial process.

Federal Energy Regulatory Commission (FERC): A quasi-independent regulatory agency within the Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification.

Federal Power Act: Enacted in 1920, and amended in 1935, the Act consists of three parts. The first part incorporated the Federal Water Power Act administered by the former Federal Power Commission, whose activities were confined almost entirely to licensing non-Federal hydroelectric projects. Parts II and III were added with the passage of the Public Utility Act. These parts extended the Act's jurisdiction to include regulating the interstate transmission of electrical energy and rates for its sale as wholesale in interstate commerce. The Federal Energy Regulatory Commission is now charged with the administration of this law.

Federal Power Commission: The predecessor agency of the Federal Energy Regulatory Commission. The Federal Power Commission (FPC) was created by an Act of Congress under the Federal Water Power Act on June 10, 1920. It was charged originally with regulating the electric power and natural gas industries. The FPC was abolished on September 20, 1977, when the Department of Energy was created. The functions of the FPC were divided between the Department of Energy and the Federal Energy Regulatory Commission.

FERC: The Federal Energy Regulatory Commission.

Firm Gas: Gas sold on a continuous and generally long-term contract.

Firm Power: Power or power-producing capacity intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions.

Flue Gas Desulfurization Unit (Scrubber): Equipment used to remove sulfur oxides from the combustion gases of a boiler plant before discharge to the atmosphere. Chemicals, such as lime, are used as the scrubbing media.

Flue Gas Particulate Collectors: Equipment used to remove fly ash from the combustion gases of a boiler plant before discharge to the atmosphere. Particulate collectors include electrostatic precipitators, mechanical collectors (cyclones), fabric filters (baghouses), and wet scrubbers.

Fly Ash: Particulate matter from coal ash in which the particle diameter is less than 1×10^{-4} meter. This is removed from the flue gas using flue gas particulate collectors such as fabric filters and electrostatic precipitators.

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

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

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

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

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

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

Futures Market: Arrangement through a contract for the delivery of a commodity at a future time and at a price specified at the time of purchase. The price is based on an auction or market basis. This is a standardized, exchange-traded, and government regulated hedging mechanism.

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

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

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

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

Generation Company: A regulated or non-regulated entity (depending upon the industry structure) that operates and maintains existing generating plants. The generation company may own the generation plants or interact with the short-term market on behalf of plant owners. In the context of restructuring the market for electricity, the generation company is sometimes used to describe a specialized "marketer" for the generating plants formerly owned by a vertically-integrated utility.

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

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

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

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

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

Gigawatt (GW): One billion watts.

Gigawatthour (GWh): One billion watthours.

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

Grid: The layout of an electrical distribution system.

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

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

Hedging Contracts: Contracts which establish future prices and quantities of electricity independent of the short-term market. Derivatives may be used for this purpose.

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

Independent Power Producers: Entities that are also considered nonutility power producers in the United States. These facilities are wholesale electricity producers that operate within the franchised service territories of host utilities and are usually authorized to sell at market-based rates. Unlike traditional electric utilities, Independent Power Producers do not possess transmission facilities or sell electricity in the retail market.

Independent System Operators: An independent, Federally-regulated entity that coordinates regional transmission in a non-discriminatory manner and ensures the safety and reliability of the electric system.

Industrial: The industrial sector is generally defined as manufacturing, construction, mining agriculture, fishing and forestry establishments Standard Industrial Classification (SIC) codes 01-39. The utility may classify industrial service using the SIC codes, or based on demand or annual usage exceeding some specified limit. The limit may be set by the utility based on the rate schedule of the utility.

Intermediate Load (Electric System): The range from base load to a point between base load and peak. This point may be the midpoint, a percent of the peakload, or the load over a specified time period.

Internal Combustion Plant: A plant in which the prime mover is an internal combustion engine. An internal combustion engine has one or more cylinders in which the process of combustion takes place, converting energy released from the rapid burning of a fuel-air mixture into mechanical energy. Diesel or gas-fired engines are the principal types used in electric plants. The plant is usually operated during periods of high demand for electricity.

Interruptible Gas: Gas sold to customers with a provision that permits curtailment or cessation of service at the discretion of the distributing company under certain circumstances, as specified in the service contract.

Interruptible Load: Refers to program activities that, in accordance with contractual arrangements, can interrupt consumer load at times of seasonal peak load by direct control of the utility system operator or by action of the consumer at the direct request of the system operator. It usually involves commercial and industrial consumers. In some instances the load reduction may be affected by direct action of the system operator (remote tripping) after notice to the consumer in accordance with contractual provisions. For example, loads that can be interrupted to fulfill planning or operation reserve requirements should be reported as Interruptible Load. Interruptible Load as defined here excludes Direct Load Control and Other Load Management. (Interruptible Load, as reported here, is synonymous with Interruptible Demand reported to the North American Electric Reliability Council on the voluntary Office of Energy Emergency Operations Form OE-411, "Coordinated Regional Bulk Power Supply Program Report," with the exception that annual peakload effects are reported on the Form EIA-861 and seasonal (i.e., summer and winter) peakload effects are reported on the OE-411).

Investor-Owned Utility: A class of utility whose stock is publicly traded and which is organized as a tax-paying business, usually financed by the sale of securities in the capital market. It is regulated and authorized to achieve an allowed rate of return.

Kilowatt (kW): One thousand watts.

Kilowatthour (kWh): One thousand watthours.

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

Lignite: The lowest rank of coal, often referred to as brown coal, used almost exclusively as fuel for steam-electric power generation. It is brownish-black and has a high inherent moisture content, sometimes as high as 45 percent. The heat content of lignite ranges from 9 to 17 million Btu per ton on a moist, mineral-matter-free basis. The heat content of lignite consumed in the United States averages 13 million Btu per ton, on the as-received basis (i.e., containing both inherent moisture and mineral matter).

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

Market-Based Pricing: Electric service prices determined in an open market system of supply and demand under which the price is set solely by agreement as to what a buyer will pay and a seller will accept. Such prices could recover less or more than full costs, depending upon what the buyer and seller see as their relevant opportunities and risks.

Market Clearing Price: The price at which supply equals demand for the Day Ahead and/or Hour Ahead Markets.

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

Mcf: One thousand cubic feet.

Megawatt (MW): One million watts.

Megawatthour (MWh): One million watthours.

MMcf: One million cubic feet.

Monopoly: One seller of electricity with control over market sales.

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

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

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

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

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

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

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

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

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

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

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

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

Open Access: A regulatory mandate to allow others to use a utility's transmission and distribution facilities to move bulk power from one point to another on a nondiscriminatory basis for a cost-based fee.

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

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

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

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

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

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

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

Petroleum Coke: See Coke (Petroleum).

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

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

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

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

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

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

Power Exchange: The entity that will establish a competitive spot market for electric power through day- and/or hour-ahead auction of generation and demand bids.

Power Exchange Generation: Generation being scheduled by the power exchange.

Power Exchange Load: Load that has been scheduled by the power exchange and which is received through the use of transmission or distribution facilities owned by participating transmission owners.

Power Marketers: Business entities engaged in buying, selling, and marketing electricity. Power marketers do not usually own generating or transmission facilities. Power marketers, as opposed to brokers, take ownership of the electricity and are involved in interstate trade. These entities file with the Federal Energy Regulatory Commission for status as a power marketer.

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

Price: The amount of money or consideration-in-kind for which a service is bought, sold, or offered for sale.

Prime Mover: The engine, turbine, water wheel, or similar machine that drives an electric generator; or, for reporting purposes, a device that converts energy to electricity directly (e.g., photovoltaic solar and fuel cell(s)).

Profit: The income remaining after all business expenses are paid.

Public Authority Service to Public Authorities: Public authority service includes electricity supplied and services rendered to municipalities or divisions or agencies of State or Federal governments, under special contracts or agreements or service classifications applicable only to public authorities.

Public Street and Highway Lighting: Public street and highway lighting includes electricity supplied and services rendered for the purposes of lighting streets, highways, parks, and other public places; or for traffic or other signal system service, for municipalities, or other divisions or agencies of State or Federal governments.

Pumped-Storage Hydroelectric Plant: A plant that usually generates electric energy during peak-load periods by using water previously pumped into an elevated storage reservoir during off-peak periods when excess generating capacity is available to do so. When additional generating capacity is needed, the water can be released from the reservoir through a conduit to turbine generators located in a power plant at a lower level.

Purchased Power Adjustment: A clause in a rate schedule that provides for adjustments to the bill when energy from another electric system is acquired and it varies from a specified unit base amount.

Pure Pumped-Storage Hydroelectric Plant: A plant that produces power only from water that has previously been pumped to an upper reservoir.

PURPA: The Public Utility Regulatory Policies Act of 1978, passed by the U.S. Congress. This statute requires States to implement utility conservation programs and create special markets for co-generators and small producers who meet certain standards, including the requirement that States set the prices and quantities of power the utilities must buy from such facilities.

Qualifying Facility (QF): A cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC) pursuant to the Public Utility Regulatory Policies Act (PURPA).

Railroad and Railway Services: Railroad and railway services include electricity supplied and services rendered to railroads and interurban and street railways, for general railroad use, including the propulsion of cars or locomotives, where such electricity is supplied under separate and distinct rate schedules.

Rate Base: The value of property upon which a utility is permitted to earn a specified rate of return as established by a regulatory authority. The rate base generally represents the value of property used by the utility in providing service and may be calculated by any one or a combination of the following accounting methods: fair value, prudent investment, reproduction cost, or original cost. Depending on which method is used, the rate base includes cash, working capital, materials and supplies, and deductions for accumulated provisions for depreciation, contributions in aid of construction, customer advances for construction, accumulated deferred income taxes, and accumulated deferred investment tax credits.

Ratemaking Authority: A utility commission's legal authority to fix, modify, approve, or disapprove rates, as determined by the powers given the commission by a State or Federal legislature.

Receipts: Purchases of fuel.

Regional Transmission Group: A utility industry concept that the Federal Energy Regulatory Commission embraced for the certification of voluntary groups that would be responsible for transmission planning and use on a regional basis.

Regulation: The governmental function of controlling or directing economic entities through the process of rulemaking and adjudication.

Reliability: Electric system reliability has two components—adequacy and security. Adequacy is the ability of the electric system to supply to aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system facilities. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer services.

Renewable Resources: Naturally, but flow-limited resources that can be replenished. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Some (such as geothermal and biomass) may be stock-limited in that stocks are depleted by use, but on a time scale of decades, or perhaps centuries, they can probably be replenished. Renewable energy resources include: biomass, hydro, geothermal, solar and wind. In the future, they could also include the use of ocean thermal, wave, and tidal action technologies. Utility renewable resource applications include bulk electricity generation, on-site electricity generation, distributed electricity generation, non-grid-connected generation, and demand-reduction (energy efficiency) technologies.

Reregulation: The design and implementation of regulatory practices to be applied to the remaining regulated entities after restructuring of the vertically-integrated electric utility. The remaining regulated entities would be those that continue to exhibit characteristics of a natural monopoly, where imperfections in the market prevent the realization of more competitive results, and where, in light of other policy considerations, competitive results are unsatisfactory in one or more respects. Regulation could employ the same or different regulatory practices as those used before restructuring.

Reserve Margin (Operating): The amount of unused available capability of an electric power system at peakload for a utility system as a percentage of total capability.

Residential: The residential sector is defined as private household establishments which consume energy primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking and clothes drying. The classification of an individual consumer's account, where the use is both residential and commercial, is based on principal use. For the residential class, do not duplicate consumer accounts due to multiple metering for special services (water, heating, etc.). Apartment houses are also included.

Residual Fuel Oil: The topped crude of refinery operation, includes No. 5 and No. 6 fuel oils as defined in ASTM Specification D396 and Federal Specification VV-F-815C; Navy Special fuel oil as defined in Military Specification MIL-F-859E including Amendment 2 (NATO Symbol F-77); and Bunker C fuel oil. Residual fuel oil is used for the production of electric power, space heating, vessel bunkering, and various industrial purposes. Imports of residual fuel oil include imported crude oil burned as fuel.

Restricted-Universe Census: This is the complete enumeration of data from a specifically defined subset of entities including, for example, those that exceed a given level of sales or generator nameplate capacity.

Restructuring: The process of replacing a monopoly system of electric utilities with competing sellers, allowing individual retail customers to choose their electricity supplier but still receive delivery over the power lines of the local utility. It includes the reconfiguration of the vertically-integrated electric utility.

Retail: Sales covering electrical energy supplied for residential, commercial, and industrial end-use purposes. Other small classes, such as agriculture and street lighting, also are included in this category.

Retail Competition: The concept under which multiple sellers of electric power can sell directly to end-use customers and the process and responsibilities necessary to make it occur.

Retail Market: A market in which electricity and other energy services are sold directly to the end-use customer.

Retail Wheeling: The process of moving electric power from a point of generation across one or more utility-owned transmission and distribution systems to a retail customer.

Revenue: The total amount of money received by a firm from sales of its products and/or services, gains from the sales or exchange of assets, interest and dividends earned on investments, and other increases in the owner's equity except those arising from capital adjustments.

Running and Quick-Start Capability: The net capability of generating units that carry load or have quick-start capability. In general, quick-start capability refers to generating units that can be available for load within a 30-minute period.

Sales: The amount of kilowatthours sold in a given period of time; usually grouped by classes of service, such as residential, commercial, industrial, and other. Other sales include public street and highway lighting, other sales to public authorities and railways, and interdepartmental sales.

Sales for Resale: Energy supplied to other electric utilities, cooperatives, municipalities, and Federal and State electric agencies for resale to ultimate consumers.

Scheduling Coordinators: Entities certified by the Federal Energy Regulatory Commission that act as a go-between with the Independent System Operator on behalf of generators, supply aggregators (wholesale marketers), retailers, and customers to schedule the distribution of electricity.

Scheduled Outage: The shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule.

Securitization: A proposal for issuing bonds that would be used to buy down existing power contracts or other obligations. The bonds would be repaid by designating a portion of future customer bill payments. Customer bills would be lowered, since the cost of bond payments would be less than the power contract costs that would be avoided.

Securitize: The aggregation of contracts for the purchase of the power output from various energy projects into one pool which then offers shares for sale in the investment market. This strategy diversifies project risks from what they would be if each project were financed individually, thereby reducing the cost of financing. Fannie Mae performs such a function in the home mortgage market.

Short Ton: A unit of weight equal to 2,000 pounds.

Small Power Producer (SPP): Under the Public Utility Regulatory Policies Act (PURPA), a small power production facility (or small power producer) generates electricity using waste, renewable (water, wind and solar), or geothermal energy as a primary energy source. Fossil fuels can be used, but renewable resource must provide at least 75 percent of the total energy input. (See Code of Federal Regulations, Title 18, Part 292.)

Spinning Reserve: That reserve generating capacity running at a zero load and synchronized to the electric system.

Spot Purchases: A single shipment of fuel or volumes of fuel, purchased for delivery within 1 year. Spot purchases are often made by a user to fulfill a certain portion of energy requirements, to meet unanticipated energy needs, or to take advantage of low-fuel prices.

Stability: The property of a system or element by virtue of which its output will ultimately attain a steady state. The amount of power that can be transferred from one machine to another following a disturbance. The stability of a power system is its ability to develop restoring forces equal to or greater than the disturbing forces so as to maintain a state of equilibrium.

Standard Industrial Classification (SIC): A set of codes developed by the Office of Management and Budget, which categorizes business into groups with similar economic activities.

Standby Facility: A facility that supports a utility system and is generally running under no-load. It is available to replace or supplement a facility normally in service.

Standby Service: Support service that is available, as needed, to supplement a consumer, a utility system, or to another utility if a schedule or an agreement authorizes the transaction. The service is not regularly used.

Steam-Electric Plant (Conventional): A plant in which the prime mover is a steam turbine. The steam used to drive the turbine is produced in a boiler where fossil fuels are burned.

Stocks: A supply of fuel accumulated for future use. This includes coal and fuel oil stocks at the plant site, in coal cars, tanks, or barges at the plant site, or at separate storage sites.

Stranded Benefits: Benefits associated with regulated retail electric service which may be at risk under open market retail competition. Examples are conservation programs, fuel diversity, reliability of supply, and tax revenues based on utility revenues.

Stranded Costs: Prudent costs incurred by a utility which may not be recoverable under market-based retail competition. Examples are undepreciated generating facilities, deferred costs, and long-term contract costs.

Subbituminous Coal: A coal whose properties range from those of lignite to those of bituminous coal and are used primarily as fuel for steam-electric power generation. It may be dull, dark brown to black, soft and crumbly at the lower end of the range, to bright, jet black, hard, and relatively strong at the upper end. Subbituminous coal contains 20 to 30 percent inherent moisture by weight. The heat content of subbituminous coal ranges from 17 to 24 million Btu per ton on a moist, mineral-matter-free basis. The heat content of subbituminous coal consumed in the United States averages 17 to 18 million Btu per ton, on the as-received basis (i.e., containing both inherent moisture and mineral matter).

Substation: Facility equipment that switches, changes, or regulates electric voltage.

Sulfur: One of the elements present in varying quantities in coal which contributes to environmental degradation when coal is burned. In terms of sulfur content by weight, coal is generally classified as low (less than or equal to 1 percent), medium (greater than 1 percent and less than or equal to 3 percent), and high (greater than 3 percent). Sulfur content is measured as a percent by weight of coal on an "as received" or a "dry" (moisture-free, usually part of a laboratory analysis) basis.

Switching Station: Facility equipment used to tie together two or more electric circuits through switches. The switches are selectively arranged to permit a circuit to be disconnected, or to change the electric connection between the circuits.

System (Electric): Physically connected generation, transmission, and distribution facilities operated as an integrated unit under one central management, or operating supervision.

Transformer: An electrical device for changing the voltage of alternating current.

Transmission: The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

Transmission System (Electric): An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers, or is delivered to other electric systems.

Transmitting Utility: This is a regulated entity which owns, and may construct and maintain, wires used to transmit wholesale power. It may or may not handle the power dispatch and coordination functions. It is regulated to provide non-discriminatory connections, comparable service, and cost recovery. According to EPACT, this includes any electric utility, qualifying cogeneration facility, qualifying small power production facility, or Federal power marketing agency which owns or operates electric power transmission facilities which are used for the sale of electric energy at wholesale.

Turbine: A machine for generating rotary mechanical power from the energy of a stream of fluid (such aswater, steam, or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction, or a mixture of the two.

Unbundling: The separating of the total process of electric power service from generation to metering into its component parts for the purpose of separate pricing or service offerings.

Uniform System of Accounts: Prescribed financial rules and regulations established by the Federal Energy Regulatory Commission for utilities subject to its jurisdiction under the authority granted by the Federal Power Act.

Useful Thermal Output: The thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical generation.

Utility Distribution Companies: The entities that will continue to provide regulated services for the distribution of electricity to customers and serve customers who do not choose direct access. Regardless of where a consumer chooses to purchase power, the customer's current utility, also known as the utility distribution company, will deliver the power to the consumer's home, business, or farm.

Vertical Integration: An arrangement whereby the same company owns all the different aspects of making, selling, and delivering a product or service. In the electric industry, it refers to the historically common arrangement whereby a utility would own its own generating plants, transmission system, and distribution lines to provide all aspects of electric service.

Voltage Reduction: Any intentional reduction of system voltage by 3 percent or greater for reasons of maintaining the continuity of service of the bulk electric power supply system.

Volumetric Wires Charge: A type of charge for using the transmission and/or distribution system that is based on the volume of electricity that is transmitted.

Watt: The electrical unit of power. The rate of energy transfer equivalent to 1 ampere flowing under a pressure of 1 volt at unity power factor.

Watthour (Wh): An electrical energy unit of measure equal to 1 watt of power supplied to, or taken from, an electric circuit steadily for 1 hour.

Wheeling Service: The movement of electricity from one system to another over transmission facilities of intervening systems. Wheeling service contracts can be established between two or more systems.

Wholesale Competition: A system whereby a distributor of power would have the option to buy its power from a variety of power producers, and the power producers would be able to compete to sell their power to a variety of distribution companies.

Wholesale Sales: Energy supplied to other electric utilities, cooperatives, municipals, and Federal and State electric agencies for resale to ultimate consumers.

Wholesale Power Market: The purchase and sale of electricity from generators to resellers (who sell to retail customers), along with the ancillary services needed to maintain reliability and power quality at the transmission level.

Wholesale Transmission Services: The transmission of electric energy sold, or to be sold, at wholesale in interstate commerce (from EPACT).

Wires Charge: A broad term which refers to charges levied on power suppliers or their customers for the use of the transmission or distribution wires.

Zone: A portion of the Independent System Operator-controlled grid within which congestion is expected to be small or to occur infrequently.