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U.S. Energy Information Administration

Electric Power Annual 2010

November 2011

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Table ES1. Summary Statistics for the United States, 1999 through 2010

Description	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
Net Generation (thousand megawatthours)												
Coal[1]	1,847,290	1,755,904	1,985,801	2,016,456	1,990,511	2,012,873	1,978,301	1,973,737	1,933,130	1,903,956	1,966,265	1,881,087
Petroleum[2]	37,061	38,937	46,243	65,739	64,166	122,225	121,145	119,406	94,567	124,880	111,221	118,061
Natural Gas[3]	987,697	920,979	882,981	896,590	816,441	760,960	710,100	649,908	691,006	639,129	601,038	556,396
Other Gases[4]	11,313	10,632	11,707	13,453	14,177	13,464	15,252	15,600	11,463	9,039	13,955	14,126
Nuclear	806,968	798,855	806,208	806,425	787,219	781,986	788,528	763,733	780,064	768,826	753,893	728,254
Hydroelectric Conventional[5]	260,203	273,445	254,831	247,510	289,246	270,321	268,417	275,806	264,329	216,961	275,573	319,536
Other Renewables[6]	167,173	144,279	126,101[R]	105,238	96,525	87,329	83,067	79,487	79,109	70,769	80,906	79,423
Wind	94,652	73,886	55,363	34,450	26,589	17,811	14,144	11,187	10,354	6,737	5,593	4,488
Solar Thermal and Photovoltaic	1,212	891	864	612	508	550	575	534	555	543	493	495
Wood and Wood Derived Fuels[7]	37,172	36,050	37,300	39,014	38,762	38,856	38,117	37,529	38,665	35,200	37,595	37,041
Geothermal	15,219	15,009	14,840[R]	14,637	14,568	14,692	14,811	14,424	14,491	13,741	14,093	14,827
Other Biomass[8]	18,917	18,443	17,734	16,525	16,099	15,420	15,421	15,812	15,044	14,548	23,131	22,572
Pumped Storage[9]	-5,501	-4,627	-6,288	-6,896	-6,558	-6,558	-8,488	-8,535	-8,743	-8,823	-5,539	-6,097
Other[10]	12,855	11,928	11,804[R]	12,231	12,974	12,821	14,232	14,045	13,527	11,906	4,794	4,024
All Energy Sources	**4,125,060**	**3,950,331**	**4,119,388**	**4,156,745**	**4,064,702**	**4,055,423**	**3,970,555**	**3,883,185**	**3,858,452**	**3,736,644**	**3,802,105**	**3,694,810**
Net Summer Generating Capacity (megawatts)												
Coal[1]	316,800	314,294	313,322	312,738	312,956	313,380	313,020	313,019	315,350	314,230	315,114	315,496
Petroleum[2]	55,647	56,781	57,445	56,068	58,097	58,548	59,119	60,730	59,651	66,162	61,837	60,069
Natural Gas[3]	407,028	401,272	397,460[R]	392,876	388,294	383,061	371,011	355,442	312,512	252,832	219,590	195,119
Other Gases[4]	2,700	1,932	1,995	2,313	2,256	2,063	2,296	1,994	2,008	1,670	2,342	1,909
Nuclear	101,167	101,004	100,755	100,266	100,334	99,988	99,628	99,209	98,657	98,159	97,860	97,411
Hydroelectric Conventional[5]	78,825	78,518	77,930	77,885	77,821	77,541	77,641	78,694	79,356	78,916	79,359	79,393
Other Renewables[6]	53,886	48,552	38,466[R]	30,069	24,113	21,205	18,717	18,153	16,710	16,101	15,572	15,942
Wind	39,135	34,296	24,651	16,515	11,329	8,706	6,456	5,995	4,417	3,864	2,377	2,252
Solar Thermal and Photovoltaic	941	619	536	502	411	411	398	397	397	392	386	389
Wood and Wood Derived Fuels[7]	7,037	6,939	6,864	6,704	6,372	6,193	6,182	5,871	5,844	5,882	6,147	6,795
Geothermal	2,405	2,382	2,229[R]	2,214	2,274	2,285	2,152	2,133	2,252	2,216	2,793	2,846
Other Biomass[11]	4,369	4,317	4,186	4,134	3,727	3,609	3,529	3,758	3,800	3,748	3,869	3,660
Pumped Storage[9]	22,199	22,160	21,858	21,886	21,461	21,347	20,764	20,522	20,371	19,664	19,522	19,565
Other[12]	884	888	942	788	882	887	746	684	686	519	523	1,023
All Energy Sources	**1,039,137**	**1,025,400**	**1,010,171**	**994,888**	**986,215**	**978,020**	**962,942**	**948,446**	**905,301**	**848,254**	**811,719**	**785,927**
Demand, Capacity Resources, and Capacity Margins – Summer												
Net Internal Demand (megawatts)	747,836	713,106	744,151[R]	766,786[R]	776,479	746,470	692,908	696,752	696,376	674,833	680,941	653,857
Capacity Resources (megawatts)	924,922	916,449	909,504[R]	914,397[R]	891,226	882,125	875,870	856,131	833,380	788,990	808,054	765,744
Capacity Margins (percent)	19.2	22.2	18.2	16.1	12.9	15.4	20.9	18.6	16.4	14.5	15.7	14.6
Fuel												
Consumption of Fossil Fuels for Electricity Generation												
Coal (thousand tons)[1]	979,684	934,683	1,042,335	1,046,795	1,030,556	1,041,448	1,020,523	1,014,058	987,583	972,691	994,933	949,802
Petroleum (thousand barrels)[2]	65,071	67,668	80,932	112,615	110,634	206,785	203,494	206,653	168,597	216,672	195,228	207,871
Natural Gas (millions of cubic feet)[3]	7,680,185	7,121,069	6,895,843	7,089,342	6,461,615	6,036,370	5,674,580	5,616,135	6,126,062	5,832,305	5,691,481	5,321,984
Other Gases (millions of Btu)[4]	90,058	83,593	96,757	114,904	114,665	109,916	135,144	156,306	131,230	97,308	125,971	126,387
Consumption of Fossil Fuels for Thermal Output in Combined Heat and Power Facilities												
Coal (thousand tons)[1]	21,727	20,507	22,168	22,810	23,227	23,833	24,275	17,720	17,561	18,944	20,466	20,373
Petroleum (thousand barrels)[2]	10,161	13,161	12,016	19,775	20,371	24,408	25,870	17,939	14,811	18,268	22,266	26,822
Natural Gas (millions of cubic feet)[3]	821,775	816,787	793,537	872,579	942,817	984,340	1,052,100	721,267	860,019	898,286	985,263	982,958
Other Gases (millions of Btu)[4]	172,081	175,671	203,236	214,321	226,464	238,396	218,295	137,837	146,882	166,161	230,082	223,713
Consumption of Fossil Fuels for Electricity Generation and Useful Thermal Output												
Coal (thousand tons)[1]	1,001,411	955,190	1,064,503	1,069,606	1,053,783	1,065,281	1,044,798	1,031,778	1,005,144	991,635	1,015,398	970,175
Petroleum (thousand barrels)[2]	75,231	80,830	92,948	132,389	131,005	231,193	229,364	224,593	183,408	234,940	217,494	234,694
Natural Gas (millions of cubic feet)[3]	8,501,960	7,937,856	7,689,380	7,961,922	7,404,432	7,020,709	6,726,679	6,337,402	6,986,081	6,730,591	6,676,744	6,304,942
Other Gases (millions of Btu)[4]	262,138	259,265	299,993	329,225	341,129	348,312	353,438	294,143	278,111	263,469	356,053	350,100

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Description	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
Stocks at Electric Power Sector Facilities (year end)												
Coal (thousand tons)[13]	174,917	189,467	161,589	151,221	140,964	101,137	106,669	121,567	141,714	138,496	102,296	141,604
Petroleum (thousand barrels)[14]	40,800	46,181	44,498	47,203	51,583	50,062	51,434	53,170	52,490	57,031	40,932	54,109
Receipts of Fuel at Electricity Generators[15]												
Coal (thousand tons)[1]	979,918	981,477	1,069,709	1,054,664	1,079,943	1,021,437	1,002,032	986,026	884,287	762,815	790,274	908,232
Petroleum (thousand barrels)[2]	75,285	88,951	96,341	88,347	100,965	194,733	186,655	185,567	120,851	124,618	108,272	145,939
Natural Gas (millions of cubic feet)[16]	8,673,070	8,118,550	7,879,046	7,200,316	6,675,246	6,181,717	5,734,054	5,500,704	5,607,737	2,148,924	2,629,986	2,809,455
Cost of Fuel at Electricity Generators (cents per million Btu)[15]												
Coal[1]	227	221	207	177	169	154	136	128	125	123	120	122
Petroleum[2]	954	702	1,087	717	623	644	429	433	334	369	418	236
Natural Gas[16]	509	474	902	711	694	821	596	539	356	449	430	257
Emissions (thousand metric tons)												
Carbon Dioxide (CO2)	2,388,662	2,269,508	2,484,012[R]	2,547,032[R]	2,488,918[R]	2,543,838[R]	2,486,982[R]	2,445,094[R]	2,423,963[R]	2,418,607[R]	2,470,834[R]	2,366,302[R]
Sulfur Dioxide (SO2)	5,401	5,970	7,830	9,042	9,524	10,340	10,309	10,646	10,881	11,174	11,963	12,843
Nitrogen Oxides (NOX)	2,491	2,395	3,330	3,650	3,799	3,961	4,143	4,532	5,194	5,290	5,638	5,955
Trade (million megawatthours)												
Purchases	5,750	5,029	5,613	5,411	5,503	6,092	6,999	6,980	8,755	7,555	2,346	2,040
Sales for Resale	5,929	5,065	5,681	5,479	5,493	6,072	6,759	6,921	8,569	7,345	2,355	1,998
Electricity Imports and Exports (thousand megawatthours)												
Imports	45,083	52,191	57,019[R]	51,396	42,691	43,929[R]	34,210	30,395	36,779	38,500	48,592	43,215
Exports	19,106	18,138	24,198[R]	20,144	24,271	19,151[R]	22,898	23,975	15,796	16,473	14,829	14,222
Retail Sales and Revenue Data – Bundled and Unbundled												
Number of Ultimate Customers (thousands)												
Residential	125,718	125,177	124,937	123,950	122,471	120,761	118,764	117,280	116,622	114,890	111,718	110,383
Commercial	17,674	17,562	17,563	17,377	17,172	16,872	16,607	16,550	15,334	14,867	14,349	14,074
Industrial	748	758	775	794	760	734	748	713	602	571	527	553
Transportation	0	1	1	1	1	1	1	1	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	NA	NA	1,067	1,030	974	935
All Sectors	144,140	143,497	143,276	142,122	140,404	138,367	136,119	134,544	133,624	131,359	127,568	125,945
Sales to Ultimate Customers (thousand megawatthours)												
Residential	1,445,708	1,364,474	1,379,981	1,392,241	1,351,520	1,359,227	1,291,982	1,275,824	1,265,180	1,201,607	1,192,446	1,144,923
Commercial	1,330,199	1,307,168	1,335,981	1,336,315	1,299,744	1,275,079	1,230,425	1,198,728	1,104,497	1,083,069	1,055,232	1,001,996
Industrial	970,873	917,442	1,009,300	1,027,832	1,011,298	1,019,156	1,017,850	1,012,373	990,238	996,609	1,064,239	1,058,217
Transportation	7,712	7,781	7,700	8,173	7,358	7,506	7,224	6,810	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	NA	NA	105,552	113,174	109,496	106,952
All Sectors	3,754,493	3,596,865	3,732,962	3,764,561	3,669,919	3,660,969	3,547,479	3,493,734	3,465,466	3,394,458	3,421,414	3,312,087
Direct Use	131,910	126,938	132,197[R]	125,670[R]	146,927	150,016	168,470	168,295	166,184	162,649	170,943	171,629
Total Disposition	3,886,403	3,723,803	3,865,159[R]	3,890,231[R]	3,816,845	3,810,984	3,715,949	3,662,029	3,631,650	3,557,107	3,592,357	3,483,716
Revenue From Ultimate Customers (million dollars)												
Residential	166,782	157,008	155,433	148,295	140,582	128,393	115,577	111,249	106,834	103,158	98,209	93,483
Commercial	135,559	132,940	138,469	128,903	122,914	110,522	100,546	96,263	87,117	85,741	78,405	72,771
Industrial	65,750	62,504	68,920	65,712	62,308	58,445	53,477	51,741	48,336	50,293	49,369	46,846
Transportation	815	828	827	792	702	643	519	514	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	NA	NA	7,124	8,151	7,179	6,796
All Sectors	368,906	353,280	363,650	343,703	326,506	298,003	270,119	259,767	249,411	247,343	233,163	219,896
Average Retail Price (cents per kilowatthour)												
Residential	11.54	11.51	11.26	10.65	10.4	9.45	8.95	8.72	8.44	8.58	8.24	8.16
Commercial	10.19	10.17	10.36	9.65	9.46	8.67	8.17	8.03	7.89	7.92	7.43	7.26
Industrial	6.77	6.81	6.83	6.39	6.16	5.73	5.25	5.11	4.88	5.05	4.64	4.43
Transportation	10.57	10.65	10.74	9.7	9.54	8.57	7.18	7.54	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	NA	NA	6.75	7.2	6.56	6.35
All Sectors	9.83	9.82	9.74	9.13	8.9	8.14	7.61	7.44	7.2	7.29	6.81	6.64
Revenue and Expense Statistics (million dollars)												
Major Investor Owned												
Utility Operating Revenues	284,373	276,124	298,962	270,964	275,501	265,652	238,759	230,151	219,609	267,276	233,915	213,090
Utility Operating Expenses	250,122	244,243	267,263	241,198	245,589	236,786	206,960	201,057	189,062	234,910	210,250	180,467
Net Utility Operating Income	34,251	31,881	31,699	29,766	29,912	28,866	31,799	29,094	30,548	32,366	23,665	32,623

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Description	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
Major Publicly Owned (with Generation Facilities)												
Operating Revenues	NA	NA	NA	NA	NA	NA	NA	33,906	32,776	38,028	31,843	26,767
Operating Expenses	NA	NA	NA	NA	NA	NA	NA	29,637	28,638	32,789	26,244	21,274
Net Electric Operating Income	NA	NA	NA	NA	NA	NA	NA	4,268	4,138	5,238	5,598	5,493
Major Publicly Owned (without Generation Facilities)												
Operating Revenues	NA	NA	NA	NA	NA	NA	NA	12,454	11,546	10,417	9,904	9,354
Operating Expenses	NA	NA	NA	NA	NA	NA	NA	11,481	10,703	9,820	9,355	8,737
Net Electric Operating Income	NA	NA	NA	NA	NA	NA	NA	974	843	597	549	617
Major Federally Owned												
Operating Revenues	NA	NA	NA	NA	NA	NA	NA	11,798	11,470	12,458	10,685	10,186
Operating Expenses	NA	NA	NA	NA	NA	NA	NA	8,763	8,665	10,013	8,139	7,775
Net Electric Operating Income	NA	NA	NA	NA	NA	NA	NA	3,035	2,805	2,445	2,546	2,411
Major Cooperative Borrower Owned												
Operating Revenues	NA	42,189	42,087	38,208	36,723	34,088	30,650	29,228	27,458	26,458	25,629	23,824
Operating Expenses	NA	38,337	38,511	34,843	33,550	31,209	27,828	26,361	24,561	23,763	22,982	21,283
Net Electric Operating Income	NA	3,852	3,576	3,365	3,173	2,879	2,822	2,867	2,897	2,696	2,647	2,541
Demand-Side Management (DSM) Data[17]												
Actual Peak Load Reductions (megawatts)												
Total Actual Peak Load Reduction	33,283	31,682	31,735	30,253	27,240	25,710	23,532	22,904	22,936	24,955	22,901	26,455
DSM Energy Savings (thousand megawatthours)												
Energy Efficiency	86,926	76,891	74,861	67,134	62,951	58,891	52,662	48,245	52,285	52,946	52,827	49,691
Load Management	913	1,015	1,813	1,857	865	1,006	2,047	2,020	1,790	990	875	872
DSM Cost (million dollars)												
Total Cost	4,220	3,594	3,175	2,523	2,051	1,921	1,557	1,297	1,626	1,630	1,565	1,424

[1] Includes anthracite, bituminous, subbituminous and lignite coal. Waste and synthetic coal are included starting in 2002.

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

[3] Includes a small number of generators for which waste heat is the primary energy source.

[4] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.

[5] Conventional hydroelectric power excluding pumped storage facilities.

[6] Other renewables represents the summation of the sub-categories of Wind, Solar Thermal and Photovoltaic, Wood and Wood Derived Fuels, Geothermal, and Other Biomass.

[7] Wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

[8] Biogenic municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

[9] Pumped storage is the capacity to generate electricity from water previously pumped to an elevated reservoir and then released through a conduit to turbine generators located at a lower level. The generation from a hydroelectric pumped storage facility is the net value of production minus the energy used for pumping..

[10] Non-biogenic municipal solid waste, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.

[11] Municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

[12] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.

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

conversion methodology). Data prior to 2004 includes small quantities of waste oil.

[15] For 2002 through 2007, includes data from the Form EIA-423 for independent power producers, and commercial and industrial power-producing facilities. Beginning in 2008, data are collected on the Form EIA-923 for utilities, independent power producers, and commerical and industrial power-producing facilities. Reciepts, cost, and quality data are collected from plants above a 50 MW threshold, and imputed for plants between 1 and 50 MW. Therefore, there may be a notable increase in fuel reciepts beginning with 2008 data. Receipts of coal include imported coal.

[16] Natural gas, including a small amount of supplemental gaseous fuels that cannot be identified separately.

[17] Data presented are reflective of large utilities.

NA = Not available.

R = Revised.

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

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

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Table ES2. Supply and Disposition of Electricity, 1999 through 2010
(Million Megawatthours)

Category	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
Supply												
Generation												
Electric Utilities	2,472	2,373	2,475	2,504	2,484	2,475	2,505	2,462	2,549	2,630	3,015	3,174
Independent Power Producers	1,339	1,278	1,332	1,324	1,259	1,247	1,119	1,063	955	781	458	201
Combined Heat and Power, Electric	162	159	167	177	165	180	184	196	194	170	165	155
Electric Power Sector Generation Subtotal	3,972	3,810	3,974	4,005	3,908	3,902	3,808	3,721	3,698	3,580	3,638	3,530
Combined Heat and Power, Commercial	9	8	8	8	8	8	8	7	7	7	8	9
Combined Heat and Power, Industrial	144	132	137	143	148	145	154	155	153	149	157	156
Industrial and Commercial Generation Subtotal	153	140	145	151	157	153	162	162	160	157	165	165
Total Net Generation	4,125	3,950	4,119	4,157	4,065	4,055	3,971	3,883	3,858	3,737	3,802	3,695
Total Imports	45	52	57	51	43	44	34	30	37	39	49	43
Total Supply	**4,170**	**4,003**	**4,176**	**4,208**	**4,107**	**4,099**	**4,005**	**3,914**	**3,895**	**3,775**	**3,851**	**3,738**
Disposition												
Retail Sales												
Full-Service Providers	3,365	3,289	3,434	3,468	3,438	3,413	3,318	3,285	3,324	3,297	3,310	3,236
Energy-Only Providers	379	295	286	283	219	237	222	189	141	98	112	76
Facility Direct Retail Sales	10	13	14	14	12	11	8	20	NA	NA	NA	NA
Total Electric Industry Retail Sales	3,754	3,597	3,733	3,765	3,670	3,661	3,547	3,494	3,465	3,394	3,421	3,312
Direct Use	132	127	132	126	147	150	168	168	166	163	171	172
Total Exports	19	18	24	20	24	19	23	24	16	16	15	14
Losses and Unaccounted For	265	261	287	298	266	269	266	228	248	202	244	240
Total Disposition	**4,170**	**4,003**	**4,176**	**4,208**	**4,107**	**4,099**	**4,005**	**3,914**	**3,895**	**3,775**	**3,851**	**3,738**

NA = Not available.
R = Revised.

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

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

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Table 1.1.A. Existing Net Summer Capacity by Energy Source and Producer Type, 2000 through 2010
(Megawatts)

Period	Coal[1]	Petroleum [2]	Natural Gas[3]	Other Gases[4]	Nuclear	Hydroelectric Conventional[5]	Other Renew-ables[6]	Hydroelectric Pumped Storage[7]	Other[8]	Total
Total (All Sectors)										
2000	315,114	61,837	219,590	2,342	97,860	79,359	15,572	19,522	523	811,719
2001	314,230	66,162	252,832	1,670	98,159	78,916	16,101	19,664	519	848,254
2002	315,350	59,651	312,512	2,008	98,657	79,356	16,710	20,371	686	905,301
2003	313,019	60,730	355,442	1,994	99,209	78,694	18,153	20,522	684	948,446
2004	313,020	59,119	371,011	2,296	99,628	77,641	18,717	20,764	746	962,942
2005	313,380	58,548	383,061	2,063	99,988	77,541	21,205	21,347	887	978,020
2006	312,956	58,097	388,294	2,256	100,334	77,821	24,113	21,461	882	986,215
2007	312,738	56,068	392,876	2,313	100,266	77,885	30,069	21,886	788	994,888
2008	313,322	57,445	397,460	1,995	100,755	77,930	38,466	21,858	942	1,010,171
2009	314,294	56,781	401,272	1,932	101,004	78,518	48,552	22,160	888	1,025,400
2010	316,800	55,647	407,028	2,700	101,167	78,825	53,811[R]	22,199	884	1,039,062[R]
Electricity Generators, Electric Utilities										
2000	260,990	41,032	123,665	57	85,968	73,738	837	18,020	13	604,319
2001	244,451	38,456	112,841	57	63,060	72,968	979	17,097	13	549,920
2002	244,056	33,876	127,692	61	63,202	73,391	989	17,807	--	561,074
2003	236,473	32,570	125,612	61	60,964	72,827	925	17,803	13	547,249
2004	235,976	31,415	131,734	58	60,651	71,696	960	18,048	13	550,550
2005	229,705	30,867	147,752	--	56,564	71,568	1,545	18,195	39	556,235
2006	230,644	30,419	157,742	104	56,143	71,840	2,291	18,301	39	567,523
2007	231,289	29,115	162,756	104	54,211	72,186	2,806	18,693	39	571,200
2008	231,857	30,657	173,106	--	54,376	72,142	4,066	18,664	39	584,908
2009	234,397	30,174	180,571	--	54,355	72,690	5,614	18,930	39	596,769
2010	235,707	28,972	184,231	539	54,369	72,974	6,316[R]	18,969	--	602,076[R]
Electricity Generators, Independent Power Producers										
2000	44,164	18,771	60,327	--	11,892	4,509	8,994	1,502	--	150,159
2001	60,701	25,311	102,693	--	35,099	4,885	9,894	2,567	79	241,230
2002	61,770	23,664	140,404	9	35,455	4,911	10,390	2,564	80	279,246
2003	66,538	26,028	178,624	6	38,244	5,058	11,786	2,719	46	329,049
2004	67,242	25,918	190,855	8	38,978	5,274	12,070	2,717	46	343,106
2005	73,734	26,041	188,043	12	43,424	5,284	13,864	3,152	46	353,601
2006	72,730	25,384	184,196	20	44,190	5,263	15,865	3,160	46	350,854
2007	71,943	24,818	184,888	8	46,055	5,346	21,002	3,193	26	357,278
2008	71,864	24,823	179,169	--	46,379	5,433	28,139	3,193	46	359,044
2009	70,123	24,657	176,035	8	46,649	5,470	36,556	3,230	46	362,773
2010	71,214	24,867	178,190	8	46,798	5,489	41,014	3,230	77	370,887
Combined Heat and Power, Electric Power										
2000	5,044	907	20,704	262	--	--	736	--	--	27,653
2001	4,628	972	21,226	287	--	1	498	--	28	27,639
2002	5,222	1,084	28,455	182	--	--	555	--	--	35,499
2003	5,534	1,051	34,895	185	--	1	665	--	--	42,332
2004	5,609	677	32,600	289	--	1	555	--	--	39,731
2005	5,560	530	31,740	289	--	1	614	--	--	38,735
2006	5,837	970	30,031	325	--	1	628	--	--	37,793
2007	5,885	907	29,468	339	--	--	656	--	--	37,254
2008	5,927	900	29,575	206	--	--	701	--	--	37,309
2009	5,940	897	28,875	206	--	--	740	--	--	36,658
2010	5,451	766	29,006	182	--	--	846	--	--	36,250
Combined Heat and Power, Commercial[9]										
2000	314	308	1,186	--	--	33	399	--	--	2,240
2001	295	299	1,950	--	--	22	348	--	--	2,912
2002	292	301	1,216	--	--	22	357	--	--	2,188
2003	347	343	994	--	--	22	371	--	--	2,077
2004	368	321	1,069	5	--	22	404	--	--	2,188
2005	397	333	1,024	5	--	25	435	--	--	2,219
2006	428	341	1,040	5	--	25	433	--	--	2,272
2007	428	348	1,064	5	--	22	443	--	3	2,312
2008	428	352	1,059	5	--	22	444	--	3	2,312
2009	424	348	1,105	5	--	22	480	--	3	2,386
2010	418	368	1,155	5	--	22	520	--	3	2,490
Combined Heat and Power, Industrial[9]										
2000	4,601	818	13,708	2,023	--	1,079	4,607	--	510	27,348
2001	4,156	1,124	14,123	1,327	--	1,041	4,382	--	399	26,553
2002	4,010	726	14,745	1,756	--	1,033	4,419	--	607	27,295
2003	4,127	738	15,316	1,742	--	786	4,406	--	625	27,740
2004	3,825	789	14,753	1,937	--	648	4,728	--	687	27,367
2005	3,984	777	14,501	1,757	--	662	4,747	--	802	27,230
2006	3,317	983	15,285	1,802	--	693	4,896	--	797	27,773
2007	3,194	880	14,699	1,858	--	331	5,163	--	720	26,844
2008	3,246	713	14,551	1,784	--	334	5,116	--	854	26,599
2009	3,412	704	14,686	1,714	--	337	5,162	--	800	26,815
2010	4,010	674	14,447	1,967	--	341	5,116	--	804	27,359

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

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

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

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Table 1.1.B. Existing Net Summer Capacity of Other Renewables by Producer Type, 2000 through 2010
(Megawatts)

Period	Wind	Solar Thermal and Photovoltaic	Wood and Wood-Derived Fuels[1]	Geothermal	Other Biomass[2]	Total (Other Renewables)
Total (All Sectors)						
2000	2,377	386	6,147	2,793	3,869	15,572
2001	3,864	392	5,882	2,216	3,748	16,101
2002	4,417	397	5,844	2,252	3,800	16,710
2003	5,995	397	5,871	2,133	3,758	18,153
2004	6,456	398	6,182	2,152	3,529	18,717
2005	8,706	411	6,193	2,285	3,609	21,205
2006	11,329	411	6,372	2,274	3,727	24,113
2007	16,515	502	6,704	2,214	4,134	30,069
2008	24,651	536	6,864	2,229	4,186	38,466
2009	34,296	619	6,939	2,382	4,317	48,552
2010	39,135	866[R]	7,037	2,405	4,369	53,811[R]
Electricity Generators, Electric Utilities						
2000	54	5	259	273	247	837
2001	60	4	309	271	335	979
2002	111	9	248	271	350	989
2003	140	9	268	162	346	925
2004	326	10	313	152	160	960
2005	765	11	391	242	136	1,545
2006	1,441	11	428	240	172	2,291
2007	1,928	12	418	158	290	2,806
2008	3,190	14	427	159	276	4,066
2009	4,655	42	431	159	327	5,614
2010	5,338	79[R]	414	159	325	6,316[R]
Electricity Generators, Independent Power Producers						
2000	2,323	382	1,227	2,520	2,543	8,994
2001	3,804	388	1,178	1,945	2,580	9,894
2002	4,305	388	1,162	1,981	2,553	10,390
2003	5,855	388	1,121	1,972	2,450	11,786
2004	6,130	388	1,138	2,000	2,414	12,070
2005	7,941	400	1,033	2,044	2,447	13,864
2006	9,888	400	1,037	2,034	2,505	15,865
2007	14,587	489	1,066	2,056	2,803	21,002
2008	21,461	521	1,196	2,070	2,891	28,139
2009	29,640	575	1,220	2,223	2,898	36,556
2010	33,784	780	1,275	2,246	2,930	41,014
Combined Heat and Power, Electric Power						
2000	--	--	242	--	494	736
2001	--	--	144	--	354	498
2002	--	--	144	--	411	555
2003	--	--	204	--	461	665
2004	--	--	179	--	375	555
2005	--	--	218	--	395	614
2006	--	--	212	--	416	628
2007	--	--	210	--	446	656
2008	--	--	223	--	478	701
2009	--	--	237	--	503	740
2010	--	--	393	--	453	846
Combined Heat and Power, Commercial[3]						
2000	--	--	7	--	392	399
2001	--	--	6	--	342	348
2002	--	--	6	--	351	357
2003	--	--	7	--	364	371
2004	--	--	7	--	397	404
2005	--	--	7	--	428	435
2006	--	--	7	--	426	433
2007	--	--	8	--	435	443
2008	--	*	8	--	436	444
2009	1	*	8	--	471	480
2010	11	6	8	--	496	520
Combined Heat and Power, Industrial[3]						
2000	--	--	4,413	--	194	4,607
2001	--	--	4,245	--	138	4,382
2002	--	--	4,285	--	134	4,419
2003	--	--	4,271	--	136	4,406
2004	--	--	4,545	--	183	4,728
2005	--	--	4,545	--	202	4,747
2006	--	--	4,688	--	208	4,896
2007	--	1	5,002	--	160	5,163
2008	--	1	5,010	--	105	5,116
2009	--	1	5,043	--	118	5,162
2010	2	1	4,948	--	165	5,116

[1] Wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.
[2] Municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).
[3] Small number of electricity-only, non-Combined Heat and Power plants may be included.
[R] Revised.
* = Value is less than half of the smallest unit of measure.
Notes: • See Glossary reference for definitions. • Totals may not equal sum of components because of independent rounding. • Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator.
Source: U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

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Table 1.2. Existing Capacity by Energy Source, 2010
(Megawatts)

Energy Source	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Coal[1]	1,396	342,296	316,800	319,186
Petroleum[2]	3,779	62,504	55,647	59,577
Natural Gas[3]	5,529	467,214	407,028	438,727
Other Gases[4]	106	3,130	2,700	2,691
Nuclear	104	106,731	101,167	102,984
Hydroelectric Conventional[5]	4,020	78,204	78,825	78,468
Wind	689	39,516	39,135	39,185
Solar Thermal and Photovoltaic[R]	180	912	866	771
Wood and Wood Derived Fuels[6]	346	7,949	7,037	7,094
Geothermal	225	3,498	2,405	2,590
Other Biomass[7]	1,574	5,043	4,369	4,440
Pumped Storage	151	20,538	22,199	22,064
Other[8]	51	1,027	884	896
Total[R]	**18,150**	**1,138,563**	**1,039,062**	**1,078,673**

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

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

[3] Includes a small number of generators for which waste heat is the primary energy source.

[4] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.

[5] The net summer capacity and/or the net winter capacity may exceed nameplate capacity due to upgrades to and overload capability of hydroelectric generators.

[6] Wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

[7] Municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

[8] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.

[R] Revised.

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

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

Table 1.3. Existing Capacity by Producer Type, 2010
(Megawatts)

Producer Type	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Electric Power Sector				
Electric Utilities[R]	9,519	654,884	602,076	622,251
Independent Power Producers	5,708	407,978	370,887	385,804
Total [R]	**15,227**	**1,062,862**	**972,963**	**1,008,055**
Combined Heat and Power Sector				
Electric Power[1]	628	41,613	36,250	39,129
Commercial[2]	683	2,796	2,490	2,596
Industrial[2]	1,612	31,294	27,359	28,893
Total	**2,923**	**75,702**	**66,099**	**70,618**
Total All Sectors[R]	**18,150**	**1,138,563**	**1,039,062**	**1,078,673**

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

[2] Small number of electricity-only, non-Combined Heat and Power plants may be included.

[R] Revised.

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

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

Table 1.4. Planned Generating Capacity Additions from New Generators, by Energy Source, 2011-2015
(Count, Megawatts)

Energy Source	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
2011				
U.S. Total	**521**	**25,602**	**23,733**	**24,565**
Coal[1]	8	4,873	4,563	4,595
Petroleum[2]	26	548	516	519
Natural Gas	89	11,256	9,988	10,792
Other Gases[3]	--	--	--	--
Nuclear	--	--	--	--
Hydroelectric Conventional[4]	26	33	33	33
Wind	92	7,972	7,763	7,763
Solar Thermal and Photovoltaic	171	586	577	569
Wood and Wood Derived Fuels[5]	9	155	129	127
Geothermal	7	31	21	22
Other Biomass[6]	92	128	123	124
Pumped Storage	--	--	--	--
Other[7]	1	20	20	20
2012				
U.S. Total	**295**	**23,506**	**22,042**	**22,670**
Coal[1]	7	4,304	4,105	4,181
Petroleum[2]	14	70	60	68
Natural Gas	65	8,756	7,967	8,401
Other Gases[3]	4	808	597	638
Nuclear	1	1,270	1,122	1,164
Hydroelectric Conventional[4]	6	155	146	146
Wind	49	4,711	4,711	4,711
Solar Thermal and Photovoltaic	107	2,717	2,711	2,700
Wood and Wood Derived Fuels[5]	15	485	443	454
Geothermal	7	144	104	130
Other Biomass[6]	20	86	77	77
Pumped Storage	--	--	--	--
Other[7]	--	--	--	--
2013				
U.S. Total	**143**	**12,001**	**11,375**	**11,652**
Coal[1]	1	290	290	290
Petroleum[2]	--	--	--	--
Natural Gas	40	6,028	5,529	5,803
Other Gases[3]	1	4	3	3
Nuclear	--	--	--	--
Hydroelectric Conventional[4]	6	224	222	222
Wind	20	2,221	2,221	2,221
Solar Thermal and Photovoltaic	59	2,673	2,606	2,606
Wood and Wood Derived Fuels[5]	3	206	185	185
Geothermal	5	185	160	162
Other Biomass[6]	8	171	161	162
Pumped Storage	--	--	--	--
Other[7]	--	--	--	--
2014				
U.S. Total	**63**	**8,199**	**7,351**	**7,707**
Coal[1]	2	515	482	489
Petroleum[2]	--	--	--	--
Natural Gas	30	4,291	3,888	4,214
Other Gases[3]	3	840	593	596
Nuclear	--	--	--	--
Hydroelectric Conventional[4]	10	263	262	262
Wind	4	349	349	349
Solar Thermal and Photovoltaic	12	1,848	1,692	1,712
Wood and Wood Derived Fuels[5]	--	--	--	--
Geothermal	--	--	--	--
Other Biomass[6]	2	93	85	85
Pumped Storage	--	--	--	--
Other[7]	--	--	--	--

Table Continued on Next Page

Table 1.4. Planned Generating Capacity Additions from New Generators, by Energy Source, 2011-2015 (Cont'd)
(Count, Megawatts)

Energy Source	Number of Generators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
2015				
U.S. Total	**49**	**8,446**	**7,772**	**8,157**
Coal[1]	1	41	41	41
Petroleum[2]	--	--	--	--
Natural Gas	34	7,387	6,780	7,140
Other Gases[3]	--	--	--	--
Nuclear	--	--	--	--
Hydroelectric Conventional[4]	1	22	22	22
Wind	--	--	--	--
Solar Thermal and Photovoltaic	3	471	471	471
Wood and Wood Derived Fuels[5]	--	--	--	--
Geothermal	7	460	400	425
Other Biomass[6]	3	65	58	58
Pumped Storage	--	--	--	--
Other[7]	--	--	--	--

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

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

[3] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.

[4] Conventional hydroelectric power excluding pumped storage facilities; includes ocean power technology (wave energy).

[5] Wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

[6] Municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

[7] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.

Notes: • Projected data are updated annually, so revision superscript is not used. • Capacity by energy source is based on the capacity associated with the energy source reported as the most predominant (primary) one, where more than one energy source is associated with a generator. These data reflect plans as of December 31, 2010. • Totals may not equal sum of components because of independent rounding. • In some reporting of capacity data, such as for wind, solar and wave energy sites, the capacity for multiple generators is reported in a single generator record and is presented as a single generator in the count of number of generators.

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

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Table 1.5. Capacity Additions, Retirements and Changes by Energy Source, 2010
(Count, Megawatts)

Energy Source	Generator Additions				Generator Retirements				Changes to Existing Capacity[1]		
	Number of Gene-rators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity	Number of Gene-rators	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity	Generator Nameplate Capacity	Net Summer Capacity	Net Winter Capacity
Coal[2]	9	5,836	5,246	5,268	35	1,678	1,528	1,529	-585	-1,213	-916
Petroleum[3]	53	1,001	804	806	59	1,114	1,043	1,046	-636	-895	-1,061
Natural Gas[4]	106	7,544	6,543	7,206	67	2,333	2,168	2,236	2,201	1,382	1,447
Other Gases[5]	2	101	101	101	2	8	6	6	820	673	696
Nuclear	--	--	--	--	--	--	--	--	113	164	495
Hydroelectric Conventional	7	22	21	19	2	1	1	1	274	287	324
Wind	69	4,565	4,545	4,546	2	2	2	2	271	296	291
Solar Thermal and Photovoltaic	61	337	313	300	--	--	--	--	11	10	10
Wood and Wood Derived Fuels[6]	3	94	74	78	9	96	97	97	122	121	121
Geothermal	2	24	13	19	--	--	--	--	54	10	10
Other Biomass[7]	105	139	129	133	32	38	32	34	-64	-45	-40
Pumped Storage	--	--	--	--	--	--	--	--	--	39	1
Other[8]	1	1	1	1	2	50	39	39	34	34	34
Total	**418**	**19,661**	**17,789**	**18,477**	**210**	**5,321**	**4,916**	**4,989**	**2,612**	**863**	**1,412**

[1] Generator re-ratings, re-powering, and revisions/corrections to previously reported data.

[2] Anthracite, bituminous coal, subbituminous coal, lignite, and waste coal.

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

[4] Includes a small number of generators for which waste heat is the primary energy source.

[5] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.

[6] Wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

[7] Municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

[8] Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.

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

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

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Table 1.6.A. Capacity of Dispersed Generators by Technology Type, 2005 through 2010

(Count, Megawatts)

Period	Internal Combustion (MW)	Combustion Turbine (MW)	Steam Turbine (MW)	Hydroelectric (MW)	Wind and Other (MW)	Wind (MW)	Photovoltaic (MW)	Storage (MW)	Other (MW)	Total	
										Number of	(MW)
2005*	4290	335	126	2	13					11,373	4,766
2006*	6524	346	157	3	8					9,536	7,037
2007*	7866	268	102	31	30					11,057	8,297
2008*	9335	86	248	34	70					12,262	9,773
2009*	9751	329	204	81	108					13,928	10,475
2010	2771	64	14	8		6	95	7	18	16,874	2,984

Note: Dispersed generators are commercial and industrial generators which are not connected to the grid. They may be installed at or near a customer`s site, or at other locations. They may be owned by either the customers of the distribution utility or by the utility. Other includes generators for which technology is not specified.

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

* During these years, generators above 1 MW were also counted. This changed in 2010 when only generators smaller than 1 MW were counted.

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Table 1.6.B. Capacity of Distributed Generators by Technology Type, 2005 through 2010
(Count, Megawatts)

Period	Internal Combustion (MW)	Combustion Turbine (MW)	Steam Turbine (MW)	Hydroelectric (MW)	Wind and Other (MW)	Wind (MW)	Photovoltaic (MW)	Storage (MW)	Other (MW)	Total	
										Number of	(MW)
2005[1]*	4025	1917	1830	999	995					17,371	9,766
2006*	3646	1298	2582	806	1081					5,044	9,411
2007*	4624	1990	3596	1051	1441					7,103	12,702
2008*	5112	1949	3060	1154	1588					9,591	12,863
2009*	4339	4147	4621	1166	1729					13,006	16,002
2010	887	186	110	97		99	236	0	373	15,630	1,988

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

Note: Distributed generators are commercial and industrial generators which are connected to the grid. They may be installed at or near a customer`s site, or at other locations. They may be owned by either the customers of the distribution utility or by the utility. Other includes generators for which technology is not specified.

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

* During these years, generators above 1 MW were also counted. This changed in 2010 when only generators smaller than 1 MW were counted.

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Table 1.6.C. Total Capacity of Dispersed and Distributed Generators by Technology Type, 2005 through 2010

(Count, Megawatts)

Period	Internal Combustion (MW)	Combustion Turbine (MW)	Steam Turbine (MW)	Hydroelectric (MW)	Wind and Other (MW)	Wind (MW)	Photovoltaic (MW)	Storage (MW)	Other (MW)	Total	
										Number of	(MW)
2005[1]*	8315	2252	1956	1001	1008					28,744	14,532
2006*	10169	1644	2739	809	1088					14,580	16,448
2007*	12490	2258	3698	1082	1471					18,160	20,999
2008*	14447	2035	3308	1188	1658					21,853	22,636
2009*	14090	4476	4825	1248	1838					26,934	26,477
2010	3658	250	124	106		105	332	7	391	32,504	4,972

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

Note: Dispersed and distributed generators are commercial and industrial generators. Dispersed generators are not connected to the grid. Distributed generators are connected to the grid. Both types of generators may be installed at or near a customer`s site, or at other locations, and both types of generators may be owned by either the customers of the distribution utility or by the utility. Other includes generators for which technology is not specified.

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

* During these years, generators above 1 MW were also counted. This changed in 2010 when only generators smaller than 1 MW were counted.

Table 1.7. Fuel Switching Capacity of Operable Generators Reporting Natural Gas as the Primary Fuel, by Producer Type, 2010
(Megawatts, Percent)

Producer Type	Total Net Summer Capacity of All Generators Reporting Natural Gas as the Primary Fuel	Fuel-Switchable Part of Total			
		Net Summer Capacity of Natural Gas-Fired Generators Reporting the Ability to Switch to Petroleum Liquids[1]	Fuel Switchable Capacity as Percent of Total	Maximum Achievable Net Summer Capacity Using Petroleum Liquids	Fuel Switchable Net Summer Capacity Reported to Have No Factors that Limit the Ability to Switch to Petroleum Liquids
Electric Utility	184,231	76,469	41.5	74,390	25,957
Independent Power Producers	178,190	39,897	22.4	38,967	11,057
Combined Heat and Power, Electric Power[2]	29,006	6,282	21.7	6,013	572
Electric Power Sector Subtotal	**391,427**	**122,648**	**31.3**	**119,370**	**37,586**
Combined Heat and Power, Commercial[3]	1,155	524	45.3	512	134
Combined Heat and Power, Industrial[3]	14,447	1,241	8.6	1,190	262
All Sectors	**407,028**	**124,412**	**30.6**	**121,072**	**37,982**

[1] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, and waste oil.
[2] Electric Utility Combined Heat and Power plants are included in Electric Utilities.
[3] Small number of electricity-only, non-Combined Heat and Power plants may be included.
Source: U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 1.8. Fuel-Switching Capacity of Operable Generators: From Natural Gas to Petroleum Liquids by Type of Prime Mover, 2010
(Megawatts, Percent)

Producer Type	Total Net Summer Capacity of All Generators Reporting Petroleum as the Primary Fuel[1]	Fuel-Switchable Part of Total		
		Net Summer Capacity of Petroleum-Fired Generators Reporting the Ability to Switch to Natural Gas	Fuel Switchable Capacity as Percent of Total	Maximum Achievable Net Summer Capacity Using Natural Gas
Electric Utility	28,972	9,606	33.2	9,206
Independent Power Producers	24,867	12,240	49.2	10,469
Combined Heat and Power Electric Power[2]	766	450	58.7	450
Electric Power Sector Subtotal	**54,605**	**22,296**	**40.8**	**20,124**
Combined Heat and Power Commercial[3]	368	19	5.3	19
Combined Heat and Power Industrial[3]	674	44	6.5	35
All Sectors	**55,647**	**22,359**	**40.2**	**20,178**

[1] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, and waste oil.
[2] Electric Utility Combined Heat and Power plants are included in Electric Utilities.
[3] Small number of electricity-only, non-Combined Heat and Power plants may be included.
Source: U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 1.9. Fuel-Switching Capacity of Operable Generators: From Natural Gas to Petroleum Liquids by Type of Prime Mover, 2010
(Count, Megawatts)

Prime Mover Type	Number of Generators	Net Summer Capacity	Fuel Switchable Net Summer Capacity Reported to Have No Factors that Limit the Ability to Switch to Petroleum Liquids[1]
Steam Generator	196	27,441	17,135
Combined Cycle	401	41,684	7,288
Internal Combustion	331	1,054	335
Gas Turbine	927	54,234	13,224
All Fuel Switchable Prime Movers	1,855	124,412	37,982

[1] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, and waste oil.

Notes: • A small number of generators for which waste heat is the primary energy source may be included.

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

Table 1.10. Fuel-Switching Capacity of Operable Generators: From Natural Gas to Petroleum Liquids, by Year of Initial Commercial Operation, 2010
(Count, Megawatts)

Year of Initial Commercial Operation	Number of Generators	Net Summer Capacity	Fuel Switchable Net Summer Capacity Reported to Have No Factors that Limit the Ability to Switch to Petroleum Liquids[1]
pre-1970	363	14,248	9,585
1970-1974	387	17,937	9,599
1975-1979	105	10,353	5,971
1980-1984	48	969	131
1985-1989	110	3,346	461
1990-1994	210	12,873	2,141
1995-1999	133	9,933	2,191
2000-2004	373	39,072	5,819
2005-2009	105	14,424	2,064
2010	21	1,257	20
Total	1,855	124,412	37,982

[1] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, and waste oil.

Notes: • A small number of generators for which waste heat is the primary energy source may be included.

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

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Table 1.11. Interconnection Cost and Capacity for New Generators, by Producer Type, 2009 and 2010

Sector	Units[1]	Nameplate Capacity (megawatts)[1]	Cost (thousand dollars)[1]
2009			
Total	382	23,144	819,680
Electric Utilities[2]	106	10,939	237,751
Independent Power Producers[3]	244	11,590	561,057
Commercial[4]	20	58	10,587
Industrial[4]	12	557	10,285
2010			
Total	418	19,661	493,909
Electric Utilities[2]	155	9,199	129,232
Independent Power Producers[3]	213	9,335	323,909
Commercial[4]	37	205	26,926
Industrial[4]	13	922	13,842

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

Table 1.12. Interconnection Cost and Capacity for New Generators, by Grid Voltage Class, 2009 and 2010

Voltage Group	Units[1]	Nameplate Capacity[1] (megawatts)	Cost[1] (thousand dollars)
2009			
Total	**382**	**23,144**	**819,680**
Less than 100 kV	207	1,831	96,452
Between 100 kV and 199 kV	78	6,086	268,834
Greater than 200 kV	97	15,227	454,394
2010			
Total	**418**	**19,661**	**493,909**
Less than 100 kV	287	2,223	66,801
Between 100 kV and 199 kV	69	4,305	145,940
Greater than 200 kV	62	13,133	281,168

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

Notes: • Totals may not equal sum of components because of independent rounding. • In some reporting of capacity data, such as for wind, solar and wave energy sites, the capacity for multiple generators is reported in a single generator record and is presented as a single generator in the count of number of generators. • In 2010, EIA changed the voltage groupings to ones that are more commonly used by stakeholders.
Source: U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

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Table 2.1.A Net Generation by Energy Source by Type of Producer, 1999 through 2010

(Thousand Megawatthours)

Period	Coal [1]	Petroleum [2]	Natural Gas	Other Gases [3]	Nuclear	Hydroelectric Conventional [4]	Other Renewables [5]	Hydroelectric Pumped Storage [6]	Other [7]	Total
Total (All Sectors)										
1999	1,881,087	118,061	556,396	14,126	728,254	319,536	79,423	-6,097	4,024	3,694,810
2000	1,966,265	111,221	601,038	13,955	753,893	275,573	80,906	-5,539	4,794	3,802,105
2001	1,903,956	124,880	639,129	9,039	768,826	216,961	70,769	-8,823	11,906	3,736,644
2002	1,933,130	94,567	691,006	11,463	780,064	264,329	79,109	-8,743	13,527	3,858,452
2003	1,973,737	119,406	649,908	15,600	763,733	275,806	79,487	-8,535	14,045	3,883,185
2004	1,978,301	121,145	710,100	15,252	788,528	268,417	83,067	-8,488	14,232	3,970,555
2005	2,012,873	122,225	760,960	13,464	781,986	270,321	87,329	-6,558	12,821	4,055,423
2006	1,990,511	64,166	816,441	14,177	787,219	289,246	96,525	-6,558	12,974	4,064,702
2007	2,016,456	65,739	896,590	13,453	806,425	247,510	105,238	-6,896	12,231	4,156,745
2008	1,985,801	46,243	882,981	11,707	806,208	254,831	126,101	-6,288	11,804	4,119,388
2009	1,755,904	38,937	920,979	10,632	798,855	273,445	144,279	-4,627	11,928	3,950,331
2010	1,847,290	37,061	987,697	11,313	806,968	260,203	167,173	-5,501	12,855	4,125,060
Electricity Generators, Electric Utilities										
1999	1,767,679	86,929	296,381	--	725,036	299,914	3,716	-5,982	--	3173674
2000	1,696,619	72,180	290,715	--	705,433	253,155	2,241	-4,960	--	3015383
2001	1,560,146	78,908	264,434	--	534,207	197,804	1,666	-7,704	486	2629946
2002	1,514,670	59,125	229,639	206	507,380	242,302	3,089	-7,434	480	2549457
2003	1,500,281	69,930	186,967	243	458,829	249,622	3,421	-7,532	519	2462281
2004	1,513,641	73,694	199,662	374	475,682	245,546	3,692	-7,526	467	2505231
2005	1,484,855	69,722	238,204	10	436,296	245,553	4,945	-5,383	643	2474846
2006	1,471,421	40,903	282,088	30	425,341	261,864	6,588	-5,281	700	2483656
2007	1,490,985	40,719	313,785	141	427,555	226,734	8,953	-5,328	586	2504131
2008	1,466,395	28,124	320,190	46	424,256	229,645	11,308	-5,143	545	2475367
2009	1,322,092	25,217	349,166	96	417,275	247,198	14,617	-3,369	483	2372776
2010	1,378,028	26,065	392,616	52	424,843	236,104	17,927	-4,466	462	2,471,632
Electricity Generators, Independent Power Producers										
1999	64,387	17,906	60,264	36	3,218	14,749	40,460	-115	--	200905
2000	213,956	25,795	108,712	181	48,460	18,183	42,831	-579	--	457540
2001	291,678	34,257	162,540	10	234,619	15,945	37,200	-1,119	5,460	780,592
2002	366,535	24,150	227,155	29	272,684	18,189	40,729	-1,309	7,168	955,331
2003	415,498	38,571	234,240	13	304,904	21,890	42,058	-1,003	7,035	1,063,205
2004	407,418	35,665	291,527	7	312,846	19,518	45,743	-962	7,108	1,118,870
2005	470,658	41,485	314,970	3	345,690	21,477	48,294	-1,174	5,569	1,246,971
2006	462,302	14,340	335,898	3	361,877	24,383	55,890	-1,277	5,646	1,259,062
2007	470,978	16,189	372,523	3	378,869	19,103	62,301	-1,569	5,458	1,323,856
2008	465,558	11,145	363,138	1	381,952	23,444	82,358	-1,145	5,616	1,332,068
2009	389,783	6,684	373,554	1	381,579	24,304	97,928	-1,259	5,341	1,277,916
2010	419,459	6,312	386,755	15	382,126	22,351	117,201	-1,035	5,529	1,338,712
Combined Heat and Power, Electric Power [8]										
1999	26,551	6,704	116,351	1,571	--	--	4,088	--	139	155404
2000	32,536	7,217	118,551	1,847	--	--	4,330	--	125	164606
2001	31,003	5,984	127,966	576	--	--	3,393	--	595	169515
2002	29,408	6,458	150,889	1,734	--	--	3,737	--	1,444	193,670
2003	36,935	5,195	146,097	2,392	--	--	4,002	--	1,053	195,674
2004	36,128	5,320	135,983	3,187	--	--	2,893	--	747	184259
2005	36,541	5,275	130,655	3,765	--	10	3,415	--	716	180375
2006	36,014	4,465	116,430	4,220	--	8	3,456	--	766	165359
2007	36,428	4,398	128,444	3,898	--	6	3,450	--	733	177356
2008	36,884	3,612	119,043	3,153	--	6	3,417	--	798	166915
2009	29,248	3,910	118,286	2,961	--	4	3,932	--	805	159146
2010	30,250	2,302	122,019	2,901	--	--	3,754	--	816	162,042
Combined Heat and Power, Commercial [9]										
1999	995	434	4,607	*	--	115	2,412	--	*	8563
2000	1,097	432	4,262	*	--	100	2,012	--	*	7903
2001	995	438	4,434	*	--	66	1,025	--	457	7416
2002	992	431	4,310	*	--	13	1,065	--	603	7415
2003	1,206	423	3,899	--	--	72	1,302	--	594	7496
2004	1,340	499	3,969	--	--	105	1,575	--	781	8270
2005	1,353	375	4,249	--	--	86	1,673	--	756	8492
2006	1,310	235	4,355	*	--	93	1,619	--	758	8371
2007	1,371	189	4,257	--	--	77	1,614	--	764	8273
2008	1,261	142	4,188	--	--	60	1,555	--	720	7926
2009	1,096	163	4,225	--	--	71	1,769	--	842	8165

2010	1,111	124	4,725	3	--	80	1,714	--	834	8,592
Combined Heat and Power, Industrial[9]										
1999	21,474	6,088	78,793	12,519	--	4,758	28,747	--	3,885	156,264
2000	22,056	5,597	78,798	11,927	--	4,135	29,491	--	4,669	156,673
2001	20,135	5,293	79,755	8,454	--	3,145	27,485	--	4,908	149,175
2002	21,525	4,403	79,013	9,493	--	3,825	30,489	--	3,832	152,580
2003	19,817	5,285	78,705	12,953	--	4,222	28,704	--	4,843	154,530
2004	19,773	5,967	78,959	11,684	--	3,248	29,164	--	5,129	153,925
2005	19,466	5,368	72,882	9,687	--	3,195	29,003	--	5,137	144,739
2006	19,464	4,223	77,669	9,923	--	2,899	28,972	--	5,103	148,254
2007	16,694	4,243	77,580	9,411	--	1,590	28,919	--	4,690	143,128
2008	15,703	3,219	76,421	8,507	--	1,676	27,462	--	4,125	137,113
2009	13,686	2,963	75,748	7,574	--	1,868	26,033	--	4,457	132,329
2010	18,441	2,258	81,583	8,343	--	1,668	26,576	--	5,214	144,082

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

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

[3] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.

[4] Conventional hydroelectric power excluding pumped storage facilities.

[5] Other renewables represents the summation of the sub-categories of Wind, Solar Thermal and Photovoltaic, Wood and Wood Derived Fuels, Geothermal, and Other Biomass.

[6] The quantity of output from a hydroelectric pumped storage facility represents production minus energy used for pumping.

[7] Non-biogenic municipal solid waste, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.

[8] Electric utility CHP plants are included in Electricity Generators, Electric Utilities.

[9] Small number of electricity-only, non-Combined Heat and Power plants may be included.

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

R = Revised.

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

Sources: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report," and predecessor form(s) including U.S. Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report;" Form EIA-860, "Annual Electric Generator Report.

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Table 2.1.B. Net Generation by Selected Renewables by Type of Producer, 1999 through 2010

(Thousand Megawatthours)

Period	Wind	Solar Thermal and Photovoltaic	Wood and Wood-Derived Fuels [1]	Geothermal	Other Biomass [2]	Total (Other Renewables)
Total (All Sectors)						
1999	4,488	495	37,041	14,827	22,572	79,423
2000	5,593	493	37,595	14,093	23,131	80,906
2001	6,737	543	35,200	13,741	14,548	70,769
2002	10,354	555	38,665	14,491	15,044	79,109
2003	11,187	534	37,529	14,424	15,812	79,487
2004	14,144	575	38,117	14,811	15,421	83,067
2005	17,811	550	38,856	14,692	15,420	87,329
2006	26,589	508	38,762	14,568	16,099	96,525
2007	34,450	612	39,014	14,637	16,525	105,238
2008	55,363	864	37,300	14,840	17,734	126,101
2009	73,886	891	36,050	15,009	18,443	144,279
2010	94,652	1,212	37,172	15,219	18,917	167,173
Electricity Generators, Electric Utilities						
1999	23	3	684	1,698	1,307	3,716
2000	29	3	700	151	1,358	2,241
2001	135	3	560	152	815	1,666
2002	213	3	709	1,402	761	3,089
2003	354	2	882	1,249	934	3,421
2004	405	6	1,209	1,248	824	3,692
2005	1,046	16	1,829	1,126	929	4,945
2006	2,351	15	1,937	1,162	1,123	6,588
2007	4,361	11	2,226	1,139	1,217	8,953
2008	6,899	17	1,888	1,197	1,307	11,308
2009	10,348	28	1,748	1,182	1,312	14,617
2010	13,089	101	2,328	1,118	1,291	17,927
Electricity Generators, Independent Power Producers						
1999	4,465	492	6,569	13,129	15,805	40,460
2000	5,565	491	6,601	13,942	16,234	42,831
2001	6,602	539	6,011	13,588	10,460	37,200
2002	10,141	552	6,556	13,089	10,391	40,729
2003	10,834	532	6,520	13,175	10,998	42,058
2004	13,739	569	6,940	13,563	10,932	45,743
2005	16,764	535	6,668	13,566	10,761	48,294
2006	24,238	493	6,374	13,406	11,379	55,890
2007	30,089	601	6,451	13,498	11,662	62,301
2008	48,464	847	6,746	13,643	12,659	82,358
2009	63,538	863	6,733	13,826	12,968	97,928
2010	81,547	1,105	7,007	14,101	13,441	117,201
Combined Heat and Power, Electric Power [3]						
1999	--	--	1,707	--	2,381	4,088
2000	--	--	1,615	--	2,715	4,330
2001	--	--	1,723	--	1,669	3,393
2002	--	--	1,744	--	1,993	3,737
2003	--	--	2,126	--	1,876	4,002
2004	--	--	1,588	--	1,306	2,893
2005	--	--	2,073	--	1,341	3,415
2006	--	--	2,030	--	1,426	3,456
2007	--	--	2,034	--	1,416	3,450

2008	--	--	2,004	--	1,413	3,417
2009	--	--	2,258	--	1,674	3,932
2010	--	--	2,111	--	1,644	3,754
Combined Heat and Power, Commercial [4]						
1999	--	--	20	--	2,393	2,412
2000	--	--	27	--	1,985	2,012
2001	--	--	18	--	1,007	1,025
2002	--	--	13	--	1,053	1,065
2003	--	--	13	--	1,289	1,302
2004	--	--	13	--	1,562	1,575
2005	--	--	16	--	1,657	1,673
2006	--	--	21	--	1,599	1,619
2007	--	--	15	--	1,599	1,614
2008	--	*	21	--	1,534	1,555
2009	*	*	20	--	1,748	1,769
2010	16	5	21	--	1,672	1,714
Combined Heat and Power, Industrial [4]						
1999	--	--	28,060	--	686	28,747
2000	--	--	28,652	--	839	29,491
2001	--	--	26,888	--	596	27,485
2002	--	--	29,643	--	846	30,489
2003	--	--	27,988	--	715	28,704
2004	--	--	28,367	--	797	29,164
2005	--	--	28,271	--	733	29,003
2006	--	--	28,400	--	572	28,972
2007	--	--	28,287	--	631	28,919
2008	--	--	26,641	--	821	27,462
2009	--	--	25,292	--	740	26,033
2010	--	2	25,706	--	869	26,576

[1] Wood/wood waste solids (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids), wood waste liquids (red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids), and black liquor.

[2] Biogenic municipal solid waste, landfill gas, sludge waste, agricultural byproducts, other biomass solids, other biomass liquids, and other biomass gases (including digester gases, methane, and other biomass gases).

[3] Electric utility CHP plants are included in Electricity Generators, Electric Utilities.

[4] Small number of electricity-only, non-Combined Heat and Power plants may be included.

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

R = Revised.

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

Sources: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report," and predecessor form(s) including U.S. Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report;" Form EIA-860, "Annual Electric Generator Report.

Table 2.2. Useful Thermal Output by Energy Source by Combined Heat and Power Producers, 1999 through 2010
(Billion Btus)

Period	Coal [1]	Petroleum [2]	Natural Gas	Other Gases [3]	Other Renewables [4]	Other [5]	Total
Total Combined Heat and Power							
1999	385,926	125,486	810,918	178,971	744,470	47,871	2,293,642
2000	383,687	108,045	812,036	184,062	763,674	50,459	2,301,963
2001	354,204	90,308	740,979	132,937	584,560	55,162	1,958,151
2002	336,848	72,826	708,738	117,513	571,507	48,264	1,855,697
2003	333,361	85,263	610,122	110,263	632,368	54,960	1,826,335
2004	351,871	97,484	654,242	126,157	667,341	45,456	1,942,550
2005	341,806	92,383	624,008	138,469	664,691	41,400	1,902,757
2006	332,548	78,232	603,288	126,049	689,549	49,308	1,878,973
2007	326,803	76,255	554,394	116,313	651,230	46,822	1,771,816
2008	315,244	47,817	509,330	110,680	610,131	23,729	1,616,931
2009	281,557	52,899	513,002	99,556	546,974	33,287	1,527,276
2010	300,303	41,361	524,494	91,439	581,310	28,755	1,567,662
Combined Heat and Power, Electric Power							
1999	52,061	6,718	145,525	3,548	30,172	28	238,052
2000	53,329	6,610	157,886	5,312	25,661	39	248,837
2001	51,515	6,087	164,206	4,681	12,676	3,343	242,508
2002	40,020	3,869	214,137	5,961	12,550	4,732	281,269
2003	38,249	7,379	200,077	9,282	19,786	3,296	278,068
2004	39,014	8,217	239,416	18,200	17,347	3,822	326,017
2005	39,652	7,809	239,324	36,694	18,240	3,884	345,605
2006	38,133	7,065	207,095	22,567	17,284	4,435	296,579
2007	38,260	7,156	212,705	20,473	19,166	4,459	302,219
2008	37,220	6,832	204,167	22,109	17,052	4,854	292,234
2009	38,015	6,786	190,875	19,830	17,625	5,055	278,187
2010	38,325	5,810	186,772	19,707	17,589	5,040	273,244
Combined Heat and Power, Commercial							
1999	20,479	3,298	36,857	--	17,145	--	77,779
2000	21,001	3,827	39,293	--	17,613	--	81,734
2001	18,495	4,118	34,923	--	8,253	5,770	71,560
2002	18,477	2,743	36,265	--	6,901	4,801	69,188
2003	22,780	2,716	16,955	--	8,297	6,142	56,889
2004	22,450	4,283	21,851	--	8,936	6,350	63,871
2005	22,601	3,684	20,227	--	8,647	5,921	61,081
2006	22,186	2,264	19,370	--	9,359	6,242	59,422
2007	22,595	1,861	20,040	--	6,651	3,983	55,131
2008	22,991	1,999	20,183	--	8,863	6,054	60,091
2009	20,057	1,250	25,902	--	8,450	5,761	61,420
2010	19,216	1,061	29,791	13	7,917	5,333	63,330
Combined Heat and Power, Industrial							
1999	313,386	115,470	628,536	175,423	697,153	47,843	1,977,811
2000	309,357	97,608	614,857	178,750	720,400	50,420	1,971,392
2001	284,194	80,103	541,850	128,256	563,631	46,049	1,644,083
2002	278,351	66,214	458,336	111,552	552,056	38,731	1,505,240
2003	272,332	75,168	393,090	100,981	604,285	45,522	1,491,378
2004	290,407	84,984	392,974	107,956	641,058	35,284	1,552,663
2005	279,552	80,889	364,457	101,775	637,803	31,594	1,496,071
2006	272,229	68,903	376,822	103,481	662,906	38,630	1,522,971
2007	265,948	67,238	321,648	95,840	625,413	38,380	1,414,466
2008	255,032	38,986	284,980	88,571	584,216	12,821	1,264,606
2009	223,485	44,863	296,225	79,726	520,898	22,471	1,187,669
2010	242,762	34,490	307,931	71,719	555,803	18,382	1,231,088

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

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

[3] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.

[4] Other renewables represents the summation of the sub-categories of Wind, Solar Thermal and Photovoltaic, Wood and Wood Derived Fuels, Geothermal, and Other Biomass.

[5] Non-biogenic municipal solid waste, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies.

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

Sources: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report," and predecessor form(s) including U.S. Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report;" Form EIA-860, "Annual Electric Generator Report.

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Table 3.1. Consumption of Fossil Fuels for Electricity Generation by Type of Power Producer, 1999 through 2010

Type of Power Producer and Period	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Natural Gas (Thousand Mcf)	Other Gases (Billion Btu)[3]
Total (All Sectors)				
1999	949,802	207,871	5,321,984	126,387
2000	994,933	195,228	5,691,481	125,971
2001	972,691	216,672	5,832,305	97,308
2002	987,583	168,597	6,126,062	131,230
2003	1,014,058	206,653	5,616,135	156,306
2004	1,020,523	203,494	5,674,580	135,144
2005	1,041,448	206,785	6,036,370	109,916
2006	1,030,556	110,634	6,461,615	114,665
2007	1,046,795	112,615	7,089,342	114,904
2008	1,042,335	80,932	6,895,843	96,757
2009	934,683	67,668	7,121,069	83,593
2010	979,684	65,071	7,680,185	90,058
Electricity Generators, Electric Utilities				
1999	894,120	151,868	3,113,419	--
2000	859,335	125,788	3,043,094	--
2001	806,269	133,456	2,686,287	--
2002	767,803	99,219	2,259,684	5,182
2003	757,384	118,087	1,763,764	6,078
2004	772,224	124,541	1,809,443	5,163
2005	761,349	118,874	2,134,859	91
2006	753,390	71,624	2,478,396	358
2007	764,765	70,950	2,736,418	1,523
2008	760,326	50,475	2,730,134	1,818
2009	695,615	45,651	2,911,279	2,209
2010	721,431	47,431	3,290,993	771
Electricity Generators, Independent Power Producers				
1999	30,572	30,037	615,756	696
2000	107,745	45,011	1,049,636	1,951
2001	139,799	60,489	1,477,643	92
2002	192,274	44,993	1,998,782	354
2003	226,154	68,817	2,016,550	171
2004	222,550	63,060	2,332,092	86
2005	254,291	72,953	2,457,412	43
2006	251,379	26,873	2,612,653	49
2007	258,075	29,868	2,875,183	62
2008	257,480	21,284	2,790,358	19
2009	217,951	12,547	2,839,310	16
2010	233,082	12,471	2,948,473	241
Combined Heat and Power, Electric Power[4]				
1999	13,197	12,440	914,600	13,627
2000	15,634	13,147	921,341	16,871
2001	15,455	11,175	978,563	9,352
2002	15,174	11,942	1,149,812	19,958
2003	19,498	8,431	1,128,935	23,317
2004	17,685	8,209	933,804	21,899
2005	17,927	7,933	892,509	24,289
2006	18,033	6,738	800,173	27,173
2007	18,506	6,498	890,012	25,428
2008	19,085	5,389	821,839	21,513
2009	16,126	5,953	816,402	19,098
2010	16,731	2,575	845,950	18,579
Combined Heat and Power, Commercial[5]				

1999	481	931	39,045	*
2000	514	823	37,029	*
2001	532	1,023	36,248	*
2002	477	834	32,545	*
2003	582	894	38,480	--
2004	377	766	32,839	--
2005	377	585	33,785	--
2006	347	333	34,623	--
2007	361	258	34,087	--
2008	369	166	33,403	--
2009	317	190	34,279	--
2010	314	172	39,462	12
Combined Heat and Power, Industrial[5]				
1999	11,432	12,595	639,165	112,064
2000	11,706	10,459	640,381	107,149
2001	10,636	10,530	653,565	87,864
2002	11,855	11,608	685,239	105,737
2003	10,440	10,424	668,407	126,739
2004	7,687	6,919	566,401	107,995
2005	7,504	6,440	517,805	85,492
2006	7,408	5,066	535,770	87,084
2007	5,089	5,041	553,643	87,892
2008	5,075	3,617	520,109	73,407
2009	4,674	3,328	519,799	62,269
2010	8,125	2,422	555,307	70,454

[1] Includes anthracite, bituminous, subbituminous and lignite coal. Waste and synthetic coal were included starting in 2002.

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

[3] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.

[4] Electric utility CHP plants are included in Electricity Generators, Electric Utilities.

[5] Small number of electricity-only, non-Combined Heat and Power plants may be included.

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

Notes: • See Glossary reference for definitions • A new method of allocating fuel consumption between electric power generation and useful thermal output (UTO) was implemented with publication of the preliminary 2008 data, and retroactively applied to 2004-2007 data. The new methodology evenly distributes a combined heat and power (CHP) plant`s losses between the two output products (electric power and UTO). In the historical data, UTO was consistently assumed to be 80 percent efficient and all other losses at the plant were allocated to electric power. This change results in the fuel for electric power to be lower while the fuel for UTO is higher than the prior set of data as both are given the same efficiency. This results in the appearance of an increase in efficiency of production of electric power after 2003.

Sources: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report," and predecessor form(s) including U.S. Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report;" Form EIA-860, "Annual Electric Generator Report.

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Table 3.2. Consumption of Fossil Fuels for Useful Thermal Output by Type of Combined Heat and Power Producers, 1999 through 2010

Type of Power Producer and Year	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Natural Gas (Thousand Mcf)	Other Gases (Billion Btu)[3]
Total Combined Heat and Power				
1999	20,373	26,822	982,958	223,713
2000	20,466	22,266	985,263	230,082
2001	18,944	18,268	898,286	166,161
2002	17,561	14,811	860,019	146,882
2003	17,720	17,939	721,267	137,837
2004	24,275	25,870	1,052,100	218,295
2005	23,833	24,408	984,340	238,396
2006	23,227	20,371	942,817	226,464
2007	22,810	19,775	872,579	214,321
2008	22,168	12,016	793,537	203,236
2009	20,507	13,161	816,787	175,671
2010	21,727	10,161	821,775	172,081
Electric Power[4]				
1999	3,033	1,423	175,757	4,435
2000	3,107	1,412	192,253	6,641
2001	2,910	1,171	199,808	5,849
2002	2,255	841	263,619	7,448
2003	2,080	1,596	225,967	11,601
2004	3,809	2,688	388,424	31,132
2005	3,918	2,424	384,365	59,569
2006	3,834	2,129	330,878	36,963
2007	3,795	2,114	339,796	34,384
2008	3,689	1,907	326,048	37,899
2009	3,935	1,930	305,542	33,812
2010	3,808	1,578	301,769	32,609
Commercial				
1999	1,009	682	44,991	--
2000	1,034	792	47,844	--
2001	916	809	42,407	--
2002	929	416	41,430	--
2003	1,234	555	19,973	--
2004	1,540	1,243	39,233	--
2005	1,544	1,045	34,172	--
2006	1,539	601	33,112	1
2007	1,566	494	35,987	--
2008	1,652	504	32,813	--
2009	1,481	331	41,275	--
2010	1,406	265	46,324	16
Industrial				
1999	16,330	24,718	762,210	219,278
2000	16,325	20,062	745,165	223,441
2001	15,119	16,287	656,071	160,312
2002	14,377	13,555	554,970	139,434
2003	14,406	15,788	475,327	126,236
2004	18,926	21,939	624,443	187,162
2005	18,371	20,940	565,803	178,827
2006	17,854	17,640	578,828	189,501
2007	17,449	17,166	496,796	179,937
2008	16,827	9,605	434,676	165,337
2009	15,091	10,900	469,970	141,859
2010	16,513	8,318	473,683	139,456

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

Notes: • Totals may not equal sum of components because of independent rounding. • A new method of allocating fuel consumption between electric power generation and useful thermal output (UTO) was implemented with publication of the preliminary 2008 data, and retroactively applied to 2004-2007 data. The new methodology evenly distributes a combined heat and power (CHP) plant`s losses between the two output products (electric power and UTO). In the historical data, UTO was consistently assumed to be 80 percent efficient and all other losses at the plant were allocated to electric power. This change results in the fuel for electric power to be lower while the fuel for UTO is higher than the prior set of data as both are given the same efficiency. This results in the appearance of an increase in efficiency of production of electric power after 2003.

Sources: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report," and predecessor form(s) including U.S. Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report;" Form EIA-860, "Annual Electric Generator Report.

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Table 3.3. Consumption of Fossil Fuels for Electricity Generation and for Useful Thermal Output, 1999 through 2010

Period	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Natural Gas (Thousand Mcf)	Other Gases (Billion Btu)[3]
Total (All Sectors)				
1999	970,175	234,694	6,304,942	350,100
2000	1,015,398	217,494	6,676,744	356,053
2001	991,635	234,940	6,730,591	263,469
2002	1,005,144	183,408	6,986,081	278,111
2003	1,031,778	224,593	6,337,402	294,143
2004	1,044,798	229,364	6,726,679	353,438
2005	1,065,281	231,193	7,020,709	348,312
2006	1,053,783	131,005	7,404,432	341,129
2007	1,069,606	132,389	7,961,922	329,225
2008	1,064,503	92,948	7,689,380	299,993
2009	955,190	80,830	7,937,856	259,265
2010	1,001,411	75,231	8,501,960	262,138
Electricity Generators, Electric Utilities				
1999	894,120	151,868	3,113,419	--
2000	859,335	125,788	3,043,094	--
2001	806,269	133,456	2,686,287	--
2002	767,803	99,219	2,259,684	5,182
2003	757,384	118,087	1,763,764	6,078
2004	772,224	124,541	1,809,443	5,163
2005	761,349	118,874	2,134,859	91
2006	753,390	71,624	2,478,396	358
2007	764,765	70,950	2,736,418	1,523
2008	760,326	50,475	2,730,134	1,818
2009	695,615	45,651	2,911,279	2,209
2010	721,431	47,431	3,290,993	771
Electricity Generators, Independent Power Producers				
1998	9,486	9,676	285,878	1,345
1999	30,572	30,037	615,756	696
2000	107,745	45,011	1,049,636	1,951
2001	139,799	60,489	1,477,643	92
2002	192,274	44,993	1,998,782	354
2003	226,154	68,817	2,016,550	171
2004	222,550	63,060	2,332,092	86
2005	254,291	72,953	2,457,412	43
2006	251,379	26,873	2,612,653	49
2007	258,075	29,868	2,875,183	62
2008	257,480	21,284	2,790,358	19
2009	217,951	12,547	2,839,310	16
2010	233,082	12,471	2,948,473	241
Combined Heat and Power, Electric Power[4]				
1999	16,230	13,864	1,090,356	18,062
2000	18,741	14,559	1,113,595	23,512
2001	18,365	12,346	1,178,371	15,201
2002	17,430	12,783	1,413,431	27,406
2003	21,578	10,028	1,354,901	34,918
2004	21,494	10,897	1,322,228	53,031
2005	21,845	10,357	1,276,874	83,858
2006	21,867	8,867	1,131,051	64,136
2007	22,301	8,613	1,229,808	59,812
2008	22,774	7,296	1,147,887	59,412
2009	20,061	7,883	1,121,944	52,911
2010	20,539	4,153	1,147,719	51,188

Combined Heat and Power, Commercial[5]				
1999	1,490	1,613	84,037	*
2000	1,547	1,615	84,874	*
2001	1,448	1,832	78,655	*
2002	1,405	1,250	73,975	*
2003	1,816	1,449	58,453	--
2004	1,917	2,009	72,072	--
2005	1,922	1,630	67,957	--
2006	1,886	935	67,735	1
2007	1,927	752	70,074	--
2008	2,021	671	66,216	--
2009	1,798	521	75,555	--
2010	1,720	437	85,786	28
Combined Heat and Power, Industrial[5]				
1999	27,763	37,312	1,401,374	331,342
2000	28,031	30,520	1,385,546	330,590
2001	25,755	26,817	1,309,636	248,176
2002	26,232	25,163	1,240,209	245,171
2003	24,846	26,212	1,143,734	252,975
2004	26,613	28,857	1,190,844	295,158
2005	25,875	27,380	1,083,607	264,319
2006	25,262	22,706	1,114,597	276,585
2007	22,537	22,207	1,050,439	267,829
2008	21,902	13,222	954,785	238,744
2009	19,766	14,228	989,769	204,128
2010	24,638	10,740	1,028,990	209,910

[1] Includes anthracite, bituminous, subbituminous and lignite coal. Waste and synthetic coal were included starting in 2002.
[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum, see Technical Notes for conversion methodology), and waste oil.
[3] Blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[4] Electric utility CHP plants are included in Electricity Generators, Electric Utilities.
[5] Small number of electricity-only, non-Combined Heat and Power plants may be included.
* = Value is less than half of the smallest unit of measure.
Note: Totals may not equal sum of components because of independent rounding.
Sources: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report," and predecessor form(s) including U.S. Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report;" Form EIA-860, "Annual Electric Generator Report.

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Table 3.4. End-of-Year Stocks of Coal and Petroleum by Type of Producer, 1999 through 2010

Period	Electric Power Sector		Electric Utilities		Independent Power Producers	
	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Coal (Thousand Tons)[1]	Petroleum (Thousand Barrels)[2]	Coal (Thousand Tons)	Petroleum (Thousand Barrels)
1999	141,604	54,109	129,041	46,169	12,563	7,940
2000	102,296	40,932	90,115	30,502	12,180	10,430
2001	138,496	57,031	117,147	37,308	21,349	19,723
2002	141,714	52,490	116,952	31,243	24,761	21,247
2003	121,567	53,170	97,831	29,953	23,736	23,218
2004	106,669	51,434	84,917	32,281	21,751	19,153
2005	101,137	50,062	77,457	31,400	23,680	18,661
2006	140,964	51,583	110,277	32,082	30,688	19,502
2007	151,221	47,203	120,504	29,297	30,717	17,906
2008	161,589	44,498	127,463	28,450	34,126	16,048
2009	189,467	46,181	154,815	31,778	34,652	14,402
2010	174,917	40,800	143,744	29,050	31,173	11,750

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

[2] Distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid

NA = Not available.

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

Sources: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report," and predecessor form(s) including U.S. Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report;" Form EIA-860, "Annual Electric Generator Report.

Table 3.5. Receipts, Average Cost, and Quality of Fossil Fuels for the Electric Power Industry, 1999 through 2010

Period	Coal [1]				Petroleum [2]				Natural Gas [3]		All Fossil Fuels
	Receipts (thousand tons)	Avg. Sulfur Percent by Weight	Average Cost		Receipts (thousand barrels)	Avg. Sulfur Percent by Weight [4]	Average Cost		Receipts (thousand Mcf)	Average Cost	Average Cost
			(cents per MMBtu)	(dollars/ton)			(cents per MMBtu)	(dollars/ barrel)		(cents per MMBtu)	(cents per MMBtu)
1999	908,232	1.01	122	24.72	145,939	1.51	236	14.81	2,809,455	257	144
2000	790,274	0.93	120	24.28	108,272	1.33	418	26.30	2,629,986	430	174
2001	762,815	0.89	123	24.68	124,618	1.42	369	23.20	2,148,924	449	173
2002 [5]	884,287	0.94	125	25.52	120,851	1.64	334	20.77	5,607,737	356	186
2003	986,026	0.97	128	26.00	185,567	1.53	433	26.78	5,500,704	539	228
2004	1,002,032	0.97	136	27.42	186,655	1.66	429	26.56	5,734,054	596	248
2005	1,021,437	0.98	154	31.20	194,733	1.61	644	39.65	6,181,717	821	325
2006	1,079,943	0.97	169	34.09	100,965	2.31	623	37.66	6,675,246	694	302
2007	1,054,664	0.96	177	35.48	88,347	2.10	717	43.50	7,200,316	711	323
2008	1,069,709	0.97	207	41.14	96,341	2.21	1,087	64.89	7,879,046	902	411
2009	981,477	1.01	221	43.74	88,951	2.14	702	41.64	8,118,550	474	304
2010	979,918	1.04	227	44.64	75,285	2.20	954	56.35	8,673,070	509	326

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

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

[3] Natural gas, including a small amount of supplemental gaseous fuels that cannot be identified separately. Natural gas values for 2001 forward do not include blast furnace gas or other gas.

[4] Beginning in 2006, receipts of petroleum liquids went down substantially, while the receipts of petroleum coke remained the nearly the same. The Average Sulfur Percent by Weight is higher beginning in 2006 as a result of the greater influence by petroleum coke receipts, which have a higher sulfur content than the petroleum liquid receipts.

[5] Beginning in 2002, data from the historical Form EIA-423 for independent power producers and combined heat and power producers are included in this table. Prior to 2002, these data were not collected; the data for 2001 and previous years include only data collected from electric utilities via the historical FERC Form 423.

Notes: • Mcf equals 1,000 cubic feet. Totals may not equal sum of components because of independent rounding. • Beginning in 2008 with the Form EIA-923, fuel receipts, cost, and quality data are imputed for plants between 1 and 50 MW and are included in the data collected from plants at or above the 50 MW threshold. Therefore, there may be a notable increase in fuel receipts beginning with 2008 data.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report" and Federal Energy Regulatory Commission (FERC), FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 3.6. Receipts and Quality of Coal Delivered for the Electric Power Industry, 1999 through 2010

Period	Anthracite			Bituminous			Subbituminous			Lignite		
	Receipts (thousand tons)	Avg. Sulfur Percent by Weight	Avg. Ash Percent by Weight	Receipts (thousand tons)	Avg. Sulfur Percent by Weight	Avg. Ash Percent by Weight	Receipts (thousand tons)	Avg. Sulfur Percent by Weight	Avg. Ash Percent by Weight	Receipts (thousand tons)	Avg. Sulfur Percent by Weight	Avg. Ash Percent by Weight
1999	137	0.64	37.8	444,399	1.57	10.2	386,271	0.38	6.6	77,425	0.90	14.2
2000	11	0.64	37.2	375,673	1.45	10.1	341,242	0.35	6.3	73,349	0.91	14.2
2001 [1]	--	--	--	348,703	1.42	10.4	349,340	0.35	6.1	64,772	0.98	13.9
2002 [2]	--	--	--	412,589	1.47	10.1	391,785	0.36	6.2	65,555	0.93	13.3
2003	--	--	--	436,809	1.49	9.9	432,513	0.38	6.4	79,869	1.03	14.4
2004	--	--	--	441,186	1.50	10.3	445,603	0.36	6.0	78,268	1.05	14.2
2005	--	--	--	451,680	1.55	10.5	456,856	0.36	6.2	77,677	1.02	14.0
2006	--	--	--	462,992	1.57	10.5	504,947	0.35	6.1	75,742	0.95	14.4
2007	--	--	--	439,154	1.61	10.3	505,155	0.34	6.0	71,930	0.90	14.0
2008	--	--	--	463,943	1.68	10.6	522,228	0.34	5.8	68,945	0.86	13.8
2009	--	--	--	418,688	1.77	10.5	484,007	0.34	5.8	64,966	0.95	14.0
2010	--	--	--	403,619	1.90	10.5	491,425	0.33	5.8	71,416	0.92	14.2

[1] Beginning in 2001, anthracite coal receipts were no longer reported separately. From 2001 forward, all anthracite coal receipts have been combined with bituminous coal receipts.

[2] Beginning in 2002, data from the historical Form EIA-423 for independent power producers and combined heat and power producers are included in this table. Prior to 2002, these data were not collected; the data for 2001 and previous years include only data collected from electric utilities via the historical FERC Form 423.

Notes: • Totals may not equal sum of components because of independent rounding. • Beginning in 2008 with the Form EIA-923, fuel receipts, cost, and quality data are imputed for plants between 1 and 50 MW and are included in the data collected from plants at or above the 50 MW threshold. Therefore, there may be a notable increase in fuel receipts beginning with 2008 data.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report" and Federal Energy Regulatory Commission (FERC), FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

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Table 3.7. Average Quality of Fossil Fuel Receipts for the Electric Power Industry, 1999 through 2010

Year	Coal [1]			Petroleum [2]		Natural Gas [3]
	Average Btu per Pound	Average Sulfur Percent by Weight	Average Ash Percent by Weight	Average Btu per Gallon	Average Sulfur Percent by Weight	Average Btu per Cubic Foot
1999	10,163	1.01	9.0	149,407	1.51	1,019
2000	10,115	0.93	8.8	149,857	1.33	1,020
2001	10,200	0.89	8.8	147,857	1.42	1,020
2002 [4]	10,168	0.94	8.7	147,902	1.64	1,025
2003	10,137	0.97	9.0	147,086	1.53	1,030
2004	10,074	0.97	9.0	147,286	1.66	1,027
2005	10,107	0.98	9.0	146,481	1.61	1,028
2006	10,063	0.97	9.0	143,883	2.31	1,027
2007	10,028	0.96	8.8	144,545	2.10	1,027
2008	9,947	0.97	9.0	142,205	2.21	1,027
2009	9,902	1.01	8.9	141,321	2.14	1,025
2010	9,842	1.04	8.9	140,598	2.20	1,022

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

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

[3] Natural gas, including a small amount of supplemental gaseous fuels that cannot be identified separately. Natural gas values for 2001 forward do not include blast furnace gas or other gas.

[4] Beginning in 2002, data from the historical Form EIA-423 for independent power producers and combined heat and power producers are included in this table. Prior to 2002, these data were not collected; the data for 2001 and previous years include only data collected from electric utilities via the historical FERC Form 423.

Note: Totals may not equal sum of components because of independent rounding. Beginning in 2008 with the Form EIA-923, fuel receipts, cost, and quality data are imputed for plants between 1 and 50 MW and are included in the data collected from plants at or above the 50 MW theshold. Therefore, there may be a notable increase in fuel receipts beginning with 2008 data.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report" and Federal Energy Regulatory Commission (FERC), FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 3.8. Weighted Average Cost of Fossil Fuels for the Electric Power Industry, 1999 through 2010

Year	Coal								Petroleum		Natural Gas		Total Fossil Fuels	
	Bituminous		Subbituminous		Lignite		All Coal Ranks							
	Receipts (trillion Btu)	Average Cost (cents per MMBtu)	Receipts (trillion Btu)	Average Cost (cents per MMBtu)	Receipts (trillion Btu)	Average Cost (cents per MMBtu)	Receipts (trillion Btu)	Average Cost (cents per MMBtu)	Receipts (trillion Btu)	Average Cost (cents per MMBtu)	Receipts (trillion Btu)	Average Cost (cents per MMBtu)	Receipts (trillion Btu)	Average Cost (cents per MMBtu)
1999	10,722	131	6,740	110	996	93	18,461	122	916	236	2,862	257	22,238	144
2000	9,050	130	5,991	108	947	94	15,988	120	681	418	2,682	430	19,351	174
2001	8,312	139	6,134	104	839	109	15,286	123	783	369	2,209	449	18,278	173
2002	9,932	142	6,878	105	851	104	17,982	125	751	334	5,750	356	24,483	186
2003	10,543	144	7,598	110	1,026	103	19,990	128	1,146	433	5,663	539	26,799	228
2004	10,538	156	7,817	112	1,012	106	20,189	136	1,155	429	5,891	596	27,234	248
2005	10,833	184	8,004	119	1,008	107	20,647	154	1,198	644	6,357	821	28,202	325
2006	11,129	204	8,842	131	982	115	21,735	169	610	623	6,856	694	29,201	302
2007	10,580	208	8,826	145	925	128	21,152	177	536	717	7,396	711	29,085	323
2008	11,110	250	9,087	162	896	141	21,280	207	575	1,087	8,089	902	29,945	411
2009	10,010	275	8,421	164	835	158	19,438	221	528	702	8,319	474	28,285	304
2010	9,652	281	8,545	173	925	162	19,290	227	445	954	8,867	509	28,602	326

Notes: • Totals may not equal sum of components because of independent rounding. • Beginning in 2008 with the Form EIA-923, receipts, cost, and quality data are imputed for plants between 1 and 50 MW, in addition to the data collected from plants above the 50 MW threshold. Therefore, there may be a notable increase in fuel receipts beginning with 2008 data.

Sources: U.S. Energy Information Administration (EIA), Form EIA-923, "Power Plant Operations Report" and predecessor form(s) including Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report" and Federal Energy Regulatory Commission (FERC), FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

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Table 3.9. Emissions from Energy Consumption at Conventional Power Plants and Combined-Heat-and-Power Plants, 1999 through 2010
(Thousand Metric Tons)

Emission	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
Carbon Dioxide (CO_2)	2,388,596	2,269,508	2,484,012	2,547,032	2,488,918	2,543,838	2,486,982	2,445,094	2,423,963	2,418,607	2,470,834	2,366,302
Sulfur Dioxide (SO_2)	5,401	5,970	7,830	9,042	9,524	10,340	10,309	10,646	10,881	11,174	11,904	12,843
Nitrogen Oxides (NO_x)	2,491	2,395	3,330	3,650	3,799	3,961	4,143	4,532	5,194	5,290	5,638	5,955

Notes: • The emissions data presented include total emissions from both electricity generation and the production of useful thermal output. • See Appendix A, Technical Notes, for a description of the sources and methodology used to develop the emissions estimates. • CO2 emissions for the historical years 1998-2008 have been revised due to changes in emission factors. Total year 2000 sulfur dioxide emissions were revised downward from 11,963 thousand metric tons to 11,904 thousand metric tons in March 2012.

Source: Calculations made by the Office of Electricity, Renewables, and Uranium Statistics, U.S. Energy Information Administration.

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Table 3.10. Number and Capacity of Existing Fossil-Fuel Steam-Electric Generators with Environmental Equipment, 1991 through 2010

Year	Flue Gas Desulfurization (Scrubbers)		Particulate Collectors		Cooling Towers		Total[1]	
	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity (megawatts)
1999	192	89,666	1,148	353,480	505	175,520	1,343	387,192
2000	192	89,675	1,141	352,727	505	175,520	1,336	386,438
2001	236	97,988	1,273	360,762	616	189,396	1,485	390,821
2002	243	98,673	1,256	359,338	670	200,670	1,522	401,341
2003	246	99,567	1,244	358,009	695	210,928	1,546	409,954
2004	248	101,492	1,217	355,782	732	214,989	1,536	409,769
2005	248	101,648	1,216	355,599	730	217,646	1,535	411,840
2006	NA	NA	NA	NA	NA	NA	NA	NA
2007	278	119,024	1,188	354,407	771	228,704	1,547	421,120
2008	327	140,223	1,187	355,517	789	234,254	1,556	426,073
2009	384	167,517	1,188	358,342	818	241,347	1,573	430,956
2010[R]	432	188,327	1,183	363,116	825	242,998	1,579	435,915

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

[2] Nameplate capacity.

[R] Revised.

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

Notes: • Data for 2007 through 2009 reflect a minor revision to the aggregation methodology as compared to previous years. The new methodology takes generator status into account where previously the data only reflected boiler and flue gas desulfurization unit statuses. • Data for Independent Power Producer and Combined Heat and Power plants are included beginning with 2001 data. • Totals may not equal sum of components because of independent rounding.

Sources: Through 2005, U.S. Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report;" and from 2007 forward, U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

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Table 3.11. Average Costs of Existing Flue Gas Desulfurization Units, 1999 through 2010

Year	Average Operation & Maintenance Costs (mills per kilowatthour)[1]	Average Installed Capital Costs (dollar per kilowatt)
1999	1.13	125
2000	0.96	124
2001	1.27	130.8
2002	1.11	124.18
2003	1.23	123.75
2004	1.38	144.64
2005	1.23	141.34
2006	NA	NA
2007	1.51	135.29
2008	1.55	150.74
2009	1.61	186.73
2010[R]	1.61	206.27

[1] A mill is one tenth of one cent.
[R] Revised.
NA = Not available. Form EIA-767 data collection was suspended in the data year 2006.
Notes: • Data for 2007 through 2009 reflect a minor revision to the aggregation methodology as compared to previous years. The new methodology takes generator status into account where previously the data only reflected boiler and flue gas desulfurization unit statuses. • Data for Independent Power Producer and Combined Heat and Power plants are included beginning with 2001 data. • Totals may not equal sum of components because of independent rounding.
Sources: Through 2005, U.S. Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report;" and from 2007 forward, U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report" for Average Installed Capital Costs, and Form EIA-923, "Power Plant Operations Report" for Average Operation & Maintenance Costs.

Table 4.1.A. Noncoincident Peak Load by North American Electric Reliability Corporation Assessment Area, 1999-2010 Actual
(Megawatts)

Interconnection	NERC Regional Assesment Area	Summer											
		1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
	FRCC	**37,493**	**37,194**	**39,062**	**40,696**	**40,475**	**42,383**	**46,396**	**45,751**	**46,676**	**44,836**	**46,550**	**45,722**
	NPCC	**52,855**	**50,057**	**55,949**	**56,012**	**55,018**	**52,549**	**58,960**	**63,241**	**58,314**	**58,543**	**55,944**	**60,554**
	Balance of Eastern Region	**422,616**	**418,954**	**428,481**	**442,535**	**431,349**	**427,860**	**462,550**	**476,048**	**475,660**	**452,087**	**431,701**	**466,543**
	ECAR	99,239	92,033	100,235	102,996	98,487	95,300	NA	NA	NA	NA	NA	NA
	MAAC	51,645	49,477	54,015	55,569	53,566	52,049	NA	NA	NA	NA	NA	NA
	MAIN	51,535	52,552	56,344	56,396	56,988	53,439	NA	NA	NA	NA	NA	NA
Eastern Interconnection	MAPP	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	4,598
	MISO	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	108,346
	MRO	31,903	28,605	28,321	29,119	28,831	29,351	39,918	42,194	41,684	39,677	37,963	NA
	PJM	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	136,465
	RFC	NA	NA	NA	NA	NA	NA	190,200	191,920	181,700	169,155	161,241	NA
	SERC	149,685	156,088	149,293	158,767	153,110	157,615	190,705	199,052	209,109	199,779	191,032	164,058
	SPP	38,609	40,199	40,273	39,688	40,367	40,106	41,727	42,882	43,167	43,476	41,465	53,077
ERCOT	**TRE**	**55,529**	**57,606**	**55,201**	**56,248**	**59,996**	**58,531**	**60,210**	**62,339**	**62,188**	**62,174**	**63,518**	**65,776**
Western Interconnection	**WECC**	**113,629**	**114,602**	**109,119**	**119,074**	**122,537**	**123,136**	**130,760**	**142,096**	**139,389**	**134,829**	**128,245**	**129,352**
All Interconnections	**Contiguous U.S.**	**682,122**	**678,413**	**687,812**	**714,565**	**709,375**	**704,459**	**758,876**	**789,475**	**782,227**	**752,470**	**725,958**	**767,948**

Interconnection	NERC Regional Assesment Area	Winter											
		1999/2000	2000/2001	2001/2002	2002/2003	2003/2004	2004/2005	2005/2006	2006/2007	2007/2008	2008/2009	2009/2010	2010/2011
	FRCC	**40,178**	**38,606**	**40,922**	**45,635**	**36,841**	**44,839**	**42,657**	**42,526**	**41,701**	**45,275**	**53,022**	**46,135**
	NPCC	**45,227**	**43,852**	**42,670**	**46,009**	**48,079**	**48,176**	**46,828**	**46,697**	**46,795**	**46,043**	**44,864**	**45,712**
	Balance of Eastern Region	**347,266**	**364,003**	**352,083**	**371,977**	**364,232**	**378,987**	**381,246**	**390,263**	**386,301**	**390,829**	**405,176**	**400,589**
	ECAR	86,239	84,546	85,485	87,300	86,332	91,800	NA	NA	NA	NA	NA	NA
	MAAC	40,220	43,256	39,458	46,551	45,625	45,905	NA	NA	NA	NA	NA	NA
	MAIN	39,081	41,943	40,529	42,412	41,719	42,929	NA	NA	NA	NA	NA	NA
Eastern Interconnection	MAPP	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	5,069
	MISO	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	86,728
	MRO	25,200	24,536	21,815	23,645	24,134	24,526	33,748	34,677	33,191	36,029	35,351	NA
	PJM	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	115,535
	RFC	NA	NA	NA	NA	NA	NA	151,600	149,631	141,900	142,395	143,827	NA
	SERC	128,563	139,146	135,182	141,882	137,972	144,337	164,638	175,163	179,888	179,596	193,135	152,030
	SPP	27,963	30,576	29,614	30,187	28,450	29,490	31,260	30,792	31,322	32,809	32,863	41,226
ERCOT	**TRE**	**39,164**	**44,641**	**44,015**	**45,414**	**42,702**	**44,010**	**48,141**	**50,402**	**50,408**	**47,806**	**56,191**	**57,315**
Western Interconnection	**WECC**	**99,080**	**97,324**	**96,622**	**95,951**	**102,020**	**102,689**	**107,493**	**111,093**	**112,700**	**113,605**	**109,565**	**101,668**
All Grids	**Contiguous U.S.**	**570,915**	**588,426**	**576,312**	**604,986**	**593,874**	**618,701**	**626,365**	**640,981**	**637,905**	**643,557**	**668,818**	**651,418**

Notes: • NERC region and reliability assessment area maps are provided on EIA's Electricity Reliability web page:
http://www.eia.gov/cneaf/electricity/page/eia411/eia411.html
• Peak load represents an hour of a day during the associated peak period.
• The Summer peak period begins on June1 and extends through September 30.
• The Winter peak period begins October 1 and extends through May 31.
• Historically the MRO, RFC, SERC, and SPP regional boundaries were altered as utilities changed reliability organizations. The historical data series for these regions have not been adjusted. Instead, the Balance of Eastern Region category was introduced to to provide a consistent trend of the Eastern interconnection.
• ECAR, MAAC, and MAIN dissolved at the end-of-2005. Many of the former utility members joined RFC. ReliabilityFirst Corporation (RFC) came into existence on January 1, 2006. RFC submitted a consolidated filing covering the historical NERC regions of ECAR, MAAC, and MAIN.
• NA - Not Available
Source: U.S. Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply and Demand Program Report."

Table 4.1.B. Noncoincident Peak Load by North American Electric Reliability Corporation Assessment Area, 2010 Actual, 2011-2015 Projected
(Megawatts)

Interconnection	NERC Regional Assesment Area	Summer					
		Actual	Projected				
		2010	2011E	2012E	2013E	2014E	2015E
Eastern Interconnection	**FRCC**	**45,722**	**46,091**	**46,658**	**47,446**	**48,228**	**49,278**
Eastern Interconnection	**NPCC**	**60,554**	**60,262**	**61,277**	**61,958**	**62,579**	**63,058**
Eastern Interconnection	**Balance of Eastern Region**	**466,543**	**469,412**	**477,274**	**487,587**	**493,523**	**498,194**
Eastern Interconnection	MAPP	4,598	4,810	5,036	5,331	5,401	5,497
Eastern Interconnection	MISO	108,346	98,068	92,976	94,834	95,227	95,947
Eastern Interconnection	PJM	136,465	148,941	158,603	162,489	164,772	166,506
Eastern Interconnection	SERC	164,058	164,510	167,027	169,783	172,637	174,688
Eastern Interconnection	SPP	53,077	53,084	53,632	55,149	55,485	55,556
ERCOT	**TRE**	**65,776**	**63,770**	**65,406**	**67,362**	**70,004**	**71,910**
Western Interconnection	**WECC**	**129,352**	**130,962**	**132,422**	**134,252**	**136,138**	**138,497**
All Grids	**Contiguous U.S.**	**767,948**	**770,497**	**783,037**	**798,605**	**810,472**	**820,937**

Interconnection	NERC Regional Assesment Area	Winter					
		Actual	Projected				
		2010/2011	2011/2012E	2012/2013E	2013/2014E	2014/2015E	2015/2016E
Eastern Interconnection	**FRCC**	**46,135**	**47,613**	**48,276**	**48,889**	**49,534**	**50,148**
Eastern Interconnection	**NPCC**	**45,712**	**46,788**	**47,058**	**47,271**	**47,440**	**47,578**
Eastern Interconnection	**Balance of Eastern Region**	**400,589**	**410,168**	**411,679**	**418,406**	**420,899**	**425,399**
Eastern Interconnection	MAPP	5,069	5,118	5,066	5,316	5,368	5,459
Eastern Interconnection	MISO	86,728	79,052	75,208	77,410	77,725	78,574
Eastern Interconnection	PJM	115,535	130,711	133,594	135,529	136,948	137,985
Eastern Interconnection	SERC	152,030	154,150	156,118	157,978	158,766	160,721
Eastern Interconnection	SPP	41,226	41,138	41,693	42,173	42,092	42,660
ERCOT	**TRE**	**57,315**	**51,642**	**51,343**	**53,472**	**55,126**	**56,398**
Western Interconnection	**WECC**	**101,668**	**106,717**	**108,157**	**110,259**	**112,231**	**113,971**
All Interconnections	**Contiguous U.S.**	**651,418**	**662,928**	**666,513**	**678,297**	**685,230**	**693,494**

Notes: • NERC region and reliability assessment area maps are provided on EIA's Electricity Reliability web page:
http://www.eia.gov/cneaf/electricity/page/eia411/eia411.html
• Projected data are updated annually.
• Peak load represents an hour of a day during the associated peak period.
• The Summer peak period begins on June1 and extends through September 30.
• The Winter peak period begins October 1 and extends through May 31.
• Historically the MRO, RFC, SERC, and SPP regional boundaries were altered as utilities changed reliability organizations. The historical data series for these regions have not been adjusted. Instead, the Balance of Eastern Region category was introduced to to provide a consistent trend of the Eastern interconnection.
• ECAR, MAAC, and MAIN dissolved at the end-of-2005. Many of the former utility members joined RFC. ReliabilityFirst Corporation (RFC) came into existence on January 1, 2006. RFC submitted a consolidated filing covering the historical NERC regions of ECAR, MAAC, and MAIN.
• E - Estimate; NA - Not Available
Source: U.S. Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply and Demand Program Report."

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Table 4.2.A. Net Energy for Load by North American Electric Reliability Corporation Assessment Area, 1999-2010 Actual
(Thousands of Megawatthours)

Interconnection	NERC Regional Assesment Area	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Eastern Interconnection	**FRCC**	**188,598**	**196,561**	**200,134**	**211,116**	**219,021**	**220,335**	**226,544**	**230,115**	**232,405**	**226,874**	**225,966**	**233,034**
	NPCC	**277,902**	**281,518**	**282,670**	**286,199**	**288,791**	**292,725**	**303,607**	**294,319**	**301,766**	**297,362**	**285,625**	**294,276**
	Balance of Eastern Region	**2,147,860**	**2,210,739**	**2,203,509**	**2,301,321**	**2,255,233**	**2,313,180**	**2,385,461**	**2,361,721**	**2,432,475**	**2,406,730**	**2,293,617**	**2,456,553**
	ECAR	547,846	545,958	546,167	567,897	545,109	553,236	NA	NA	NA	NA	NA	NA
	MAAC	255,741	262,320	263,841	273,907	276,600	283,646	NA	NA	NA	NA	NA	NA
	MAIN	243,278	259,608	271,053	279,264	267,068	274,760	NA	NA	NA	NA	NA	NA
	MAPP	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	30,691
	MISO	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	585,274
	MRO	152,350	145,981	144,893	150,058	153,918	152,975	216,633	222,748	217,602	227,536	213,797	NA
	PJM	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	712,731
	RFC	NA	NA	NA	NA	NA	NA	1,005,226	926,279	954,700	936,201	880,377	NA
	SERC	768,408	803,211	787,139	835,319	826,964	856,734	962,054	1,011,173	1,049,298	1,035,390	997,142	870,367
	SPP	180,237	193,661	190,416	194,876	185,574	191,829	201,548	201,521	210,875	207,603	202,301	257,491
ERCOT	**TRE**	**268,622**	**286,313**	**278,226**	**280,269**	**283,868**	**289,146**	**299,225**	**305,672**	**307,064**	**312,401**	**308,278**	**319,097**
Western Interconnection	**WECC**	**635,503**	**663,913**	**638,746**	**666,696**	**664,754**	**682,053**	**685,624**	**720,087**	**739,018**	**745,691**	**718,694**	**713,177**
All Interconnections	**Contiguous U.S.**	**3,518,485**	**3,639,044**	**3,603,285**	**3,745,601**	**3,711,667**	**3,797,439**	**3,900,461**	**3,911,914**	**4,012,728**	**3,989,058**	**3,832,180**	**4,016,137**

Notes: • NERC region and reliability assessment area maps are provided on EIA's Electricity Reliability web page:
http://www.eia.gov/cneaf/electricity/page/eia411/eia411.html
• Peak load represents an hour of a day during the associated peak period.
• Net Energy for Load represents net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to other Balancing Authority Areas through interchange.
• Historically the MRO, RFC, SERC, and SPP regional boundaries were altered as utilities changed reliability organizations. The historical data series for these regions have not been adjusted. Instead, the Balance of Eastern Region category was introduced to to provide a consistent trend of the Eastern interconnection.
• ECAR, MAAC, and MAIN dissolved at the end-of-2005. Many of the former utility members joined RFC. ReliabilityFirst Corporation (RFC) came into existence on January 1, 2006. RFC submitted a consolidated filing covering the historical NERC regions of ECAR, MAAC, and MAIN.
• NA - Not Available
Source: U.S. Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply and Demand Program Report."

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Table 4.2.B. Net Energy for Load by North American Electric Reliability CorporationAssessment Area, 2010 Actual, 2011-2015 Projected
(Thousands of Megawatthours)

Interconnection	NERC Regional Assesment Area	Actual	Projected				
		2010	2011E	2012E	2013E	2014E	2015E
Eastern Interconnection	**FRCC**	**233,034**	**225,325**	**229,230**	**234,208**	**238,618**	**242,420**
	NPCC	**294,276**	**297,702**	**302,476**	**303,826**	**305,678**	**307,140**
	Balance of Eastern Region	**2,456,553**	**2,377,560**	**2,451,847**	**2,514,769**	**2,548,867**	**2,571,918**
	MAPP	30,691	33,507	34,448	35,679	36,226	36,652
	MISO	585,274	497,080	466,383	476,183	480,432	486,274
	PJM	712,731	762,050	842,634	860,521	874,144	883,516
	SERC	870,367	825,261	842,397	872,236	885,180	892,373
	SPP	257,491	259,661	265,985	270,150	272,885	273,103
ERCOT	**TRE**	**319,097**	**319,403**	**330,034**	**339,616**	**352,294**	**362,841**
Western Interconnection	**WECC**	**713,177**	**732,710**	**742,148**	**752,650**	**763,397**	**773,510**
All Interconnections	**Contiguous U.S.**	**4,016,137**	**3,952,699**	**4,055,735**	**4,145,069**	**4,208,854**	**4,257,828**

Notes: • NERC region and reliability assessment area maps are provided on EIA's Electricity Reliability web page:
http://www.eia.gov/cneaf/electricity/page/eia411/eia411.html
• Projected data are updated annually.
• Peak load represents an hour of a day during the associated peak period.
• Net Energy for Load represents net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to other Balancing Authority Areas through interchange.
• Historically the MRO, RFC, SERC, and SPP regional boundaries were altered as utilities changed reliability organizations. The historical data series for these regions have not been adjusted. Instead, the Balance of Eastern Region category was introduced to to provide a consistent trend of the Eastern interconnection.
• E - Estimate; NA - Not Available
Source: U.S. Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply and Demand Program Report."

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Table 4.3.A. Summer Net Internal Demand, Capacity Resources, and Capacity Margins by North American Electric Reliability Assessment Area, 1999-2010 Actual
(Megawatts and Percent)

Interconnection	NERC Regional Assesment Area	Net Internal Demand (MW)[1] -- Summer											
		1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Eastern Interconnection	**FRCC**	**34,832**	**35,666**	**38,932**	**37,951**	**40,387**	**42,243**	**45,950**	**45,345**	**46,434**	**44,660**	**46,263**	**45,522**
	NPCC	**53,450**	**54,270**	**55,888**	**55,164**	**53,936**	**51,580**	**57,402**	**60,879**	**58,221**	**59,896**	**55,730**	**56,232**
	Balance of Eastern Region	**401,701**	**420,443**	**417,613**	**430,396**	**422,253**	**419,349**	**455,594**	**469,639**	**465,229**	**447,629**	**424,714**	**454,759**
	ECAR	94,072	98,651	100,235	101,251	98,487	95,300	NA	NA	NA	NA	NA	NA
	MAAC	49,325	51,358	54,015	54,296	53,566	52,049	NA	NA	NA	NA	NA	NA
	MAIN	47,165	51,845	53,032	53,267	53,617	50,499	NA	NA	NA	NA	NA	NA
	MAPP	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	4,493
	MISO	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	100,963
	MRO	30,606	28,006	27,125	28,825	28,775	29,094	38,266	40,661	40,249	38,857	35,849	NA
	PJM	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	136,465
	RFC	NA	NA	NA	NA	NA	NA	190,200	190,800	177,200	169,155	161,241	NA
	SERC	142,726	151,527	144,399	154,459	148,380	153,024	186,049	196,196	205,321	196,711	186,507	160,896
	SPP	37,807	39,056	38,807	38,298	39,428	39,383	41,079	41,982	42,459	42,906	41,117	51,942
ERCOT	**TRE**	**51,697**	**53,649**	**55,106**	**55,833**	**59,282**	**58,531**	**59,060**	**61,214**	**61,063**	**61,049**	**63,518**	**64,378**
Western Interconnection	**WECC**	**112,177**	**116,913**	**107,294**	**117,032**	**120,894**	**121,205**	**128,464**	**139,402**	**135,839**	**130,916**	**122,881**	**126,944**
All Interconnections	**Contiguous U.S.**	**653,857**	**680,941**	**674,833**	**696,376**	**696,752**	**692,908**	**746,470**	**776,479**	**766,786**	**744,151**	**713,106**	**747,836**

Interconnection	NERC Regional Assesment Area	Capacity Resources (MW)[2] -- Summer											
		1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Eastern Interconnection	**FRCC**	**40,645**	**43,083**	**42,290**	**43,342**	**46,806**	**48,579**	**50,200**	**50,909**	**53,027**	**51,541**	**49,239**	**53,370**
	NPCC	**63,077**	**63,376**	**63,760**	**66,208**	**70,902**	**71,532**	**72,258**	**73,095**	**73,771**	**75,894**	**78,639**	**67,569**
	Balance of Eastern Region	**460,325**	**490,333**	**487,950**	**504,357**	**513,382**	**526,454**	**532,917**	**534,270**	**543,608**	**539,936**	**559,823**	**571,719**
	ECAR	107,451	115,379	113,136	119,736	123,755	127,919	NA	NA	NA	NA	NA	NA
	MAAC	57,831	60,679	59,533	63,619	65,897	66,167	NA	NA	NA	NA	NA	NA
	MAIN	55,984	64,170	65,950	67,025	67,410	65,677	NA	NA	NA	NA	NA	NA
	MAPP	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	7,210
	MISO	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	131,691
	MRO	35,373	34,236	32,271	34,259	33,287	35,830	46,792	50,116	47,259	48,180	47,529	NA
	PJM	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	168,970
	RFC	NA	NA	NA	NA	NA	NA	220,000	214,693	213,544	215,477	215,700	NA
	SERC	160,575	169,760	171,530	172,485	177,231	182,861	219,749	223,630	234,232	228,169	247,400	200,511
	SPP	43,111	46,109	45,530	47,233	45,802	48,000	46,376	45,831	48,573	48,110	49,194	63,337
ERCOT	**TRE**	**65,423**	**69,622**	**70,797**	**76,849**	**74,764**	**73,850**	**66,724**	**70,664**	**75,912**	**74,274**	**76,280**	**73,857**
Western Interconnection	**WECC**	**136,274**	**141,640**	**124,193**	**142,624**	**150,277**	**155,455**	**160,026**	**162,288**	**168,080**	**167,860**	**152,467**	**158,407**
All Interconnections	**Contiguous U.S.**	**765,744**	**808,054**	**788,990**	**833,380**	**856,131**	**875,870**	**882,125**	**891,226**	**914,397**	**909,504**	**916,449**	**924,922**

Interconnection	NERC Regional Assesment Area	Capacity Margin (percent)[3] -- Summer											
		1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Eastern Interconnection	**FRCC**	**14.3**	**17.2**	**7.9**	**12.4**	**13.7**	**13.0**	**8.5**	**10.9**	**12.4**	**13.4**	**6.0**	**14.7**
	NPCC	**15.3**	**14.4**	**12.3**	**16.7**	**23.9**	**27.9**	**20.6**	**16.7**	**21.1**	**21.1**	**29.1**	**16.8**
	Balance of Eastern Region	**12.7**	**14.3**	**14.4**	**14.7**	**17.8**	**20.3**	**14.5**	**12.1**	**14.4**	**17.1**	**24.1**	**20.5**
	ECAR	12.5	14.5	11.4	15.4	20.4	25.5	NA	NA	NA	NA	NA	NA
	MAAC	14.7	15.4	9.3	14.7	18.7	21.3	NA	NA	NA	NA	NA	NA
	MAIN	15.8	19.2	19.6	20.5	20.5	23.1	NA	NA	NA	NA	NA	NA
	MAPP	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	37.7
	MISO	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	23.3
	MRO	13.5	18.2	15.9	15.9	13.6	18.8	18.2	18.9	14.8	19.3	24.6	NA
	PJM	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	19.2
	RFC	NA	NA	NA	NA	NA	NA	13.5	11.1	17.0	21.5	25.2	NA
	SERC	11.1	10.7	15.8	10.5	16.3	16.3	15.3	12.3	12.3	13.8	24.6	19.8
	SPP	12.3	15.3	14.8	18.9	13.9	18.0	11.4	8.4	12.6	10.8	16.4	18.0
ERCOT	**TRE**	**21.0**	**22.9**	**22.2**	**27.3**	**20.7**	**20.7**	**11.5**	**13.4**	**19.6**	**17.8**	**16.7**	**12.8**
Western Interconnection	**WECC**	**17.7**	**17.5**	**13.6**	**17.9**	**19.6**	**22.0**	**19.7**	**14.1**	**19.2**	**22.0**	**19.4**	**19.9**
All Interconnections	**Contiguous U.S.**	**14.6**	**15.7**	**14.5**	**16.4**	**18.6**	**20.9**	**15.4**	**12.9**	**16.1**	**18.2**	**22.2**	**19.1**

[1] Net Internal Demand represent the system demand that is planned for by the electric power industry`s reliability authority and is equal to Internal Demand less Direct Control Load Management and Interruptible Demand.
[2] Capacity Resources: Utility and nonutility-owned generating capacity that is existing or in various stages of planning or construction, less inoperable capacity, plus planned capacity purchases from other resources, less planned capacity sales.
[3] Capacity Margin is the amount of unused available capability of an electric power system at peak load as a percentage of capacity resources.
Notes: • NERC region and reliability assessment area maps are provided on EIA's Electricity Reliability web page:
http://www.eia.gov/cneaf/electricity/page/eia411/eia411.html
• Peak load represents an hour of a day during the associated peak period.
• The Summer peak period begins on June1 and extends through September 30.
• Historically the MRO, RFC, SERC, and SPP regional boundaries were altered as utilities changed reliability organizations. The historical data series for these regions have not been adjusted. Instead, the Balance of Eastern Region category was introduced to to provide a consistent trend of the Eastern interconnection.
• ECAR, MAAC, and MAIN dissolved at the end-of-2005. Many of the former utility members joined RFC. ReliabilityFirst Corporation (RFC) came into existence on January 1, 2006. RFC submitted a consolidated filing covering the historical NERC regions of ECAR, MAAC, and MAIN.
• NA - Not Available
Source: U.S. Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply and Demand Program Report."

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Table 4.3.B. Summer Net Internal Demand, Capacity Resources, and Capacity Margins by North American Electric Reliability Corporation Assessment Area, 2010 Actual, 2011-2015 Projected
(Megawatts)

Interconnection	NERC Regional Assesment Area	Net Internal Demand (MW)[1] -- Summer					
		Actual	Projected				
		2010	2011E	2012E	2013E	2014E	2015E
Eastern Interconnection	**FRCC**	**45,522**	**42,945**	**43,389**	**44,056**	**44,787**	**45,770**
	NPCC	**56,232**	**56,174**	**56,618**	**56,902**	**57,127**	**57,606**
	Balance of Eastern Region	**454,759**	**442,400**	**454,051**	**461,791**	**467,431**	**471,764**
	MAPP	4,493	4,704	4,926	5,216	5,285	5,379
	MISO	100,963	90,249	85,157	87,015	87,408	88,128
	PJM	136,465	137,341	151,780	153,510	155,793	157,527
	SERC	160,896	158,323	159,852	162,247	164,805	166,467
	SPP	51,942	51,783	52,337	53,802	54,140	54,263
ERCOT	**TRE**	**64,378**	**62,286**	**63,880**	**65,790**	**68,381**	**70,231**
Western Interconnection	**WECC**	**126,944**	**126,586**	**127,446**	**128,925**	**130,801**	**133,139**
All Grids	**Contiguous U.S.**	**747,836**	**730,391**	**745,384**	**757,464**	**768,528**	**778,510**

Interconnection	NERC Regional Assesment Area	Capacity Resources (MW)[2] -- Summer					
		Actual	Projected				
		2010	2011E	2012E	2013E	2014E	2015E
Eastern Interconnection	**FRCC**	**53,370**	**53,538**	**54,695**	**54,815**	**56,242**	**57,253**
	NPCC	**67,569**	**71,943**	**72,333**	**74,119**	**74,761**	**74,254**
	Balance of Eastern Region	**571,719**	**569,691**	**575,220**	**579,720**	**581,186**	**578,986**
	MAPP	7,210	6,563	6,516	6,326	6,321	6,371
	MISO	131,691	111,945	106,631	106,690	106,709	106,732
	PJM	168,970	181,740	189,601	191,265	191,425	192,011
	SERC	200,511	203,220	205,834	207,560	208,362	205,988
	SPP	63,337	66,224	66,638	67,879	68,369	67,884
ERCOT	**TRE**	**73,857**	**73,199**	**74,902**	**75,063**	**77,223**	**78,003**
Western Interconnection	**WECC**	**158,407**	**171,032**	**180,001**	**186,410**	**188,386**	**191,799**
All Grids	**Contiguous U.S.**	**924,922**	**939,403**	**957,151**	**970,127**	**977,798**	**980,295**

Interconnection	NERC Regional Assesment Area	Capacity Margin (percent)[3] -- Summer					
		Actual	Projected				
		2010	2011E	2012E	2013E	2014E	2015E
Eastern Interconnection	**FRCC**	**14.7**	**19.8**	**20.7**	**19.6**	**20.4**	**20.1**
	NPCC	**16.8**	**21.9**	**21.7**	**23.2**	**23.6**	**22.4**
	Balance of Eastern Region	**20.5**	**22.3**	**21.1**	**20.3**	**19.6**	**18.5**
	MAPP	37.7	28.3	24.4	17.5	16.4	15.6
	MISO	23.3	19.4	20.1	18.4	18.1	17.4
	PJM	19.2	24.4	19.9	19.7	18.6	18.0
	SERC	19.8	22.1	22.3	21.8	20.9	19.2
	SPP	18.0	21.8	21.5	20.7	20.8	20.1
ERCOT	**TRE**	**12.8**	**14.9**	**14.7**	**12.4**	**11.4**	**10.0**
Western Interconnection	**WECC**	**19.9**	**26.0**	**29.2**	**30.8**	**30.6**	**30.6**
All Grids	**Contiguous U.S.**	**19.1**	**22.2**	**22.1**	**21.9**	**21.4**	**20.6**

[1] Net Internal Demand represent the system demand that is planned for by the electric power industry`s reliability authority and is equal to Internal Demand less Direct Control Load Management and Interruptible Demand.
[2] Capacity Resources: Utility and nonutility-owned generating capacity that is existing or in various stages of planning or construction, less inoperable capacity, plus planned capacity purchases from other resources, less planned capacity sales.
[3] Capacity Margin is the amount of unused available capability of an electric power system at peak load as a percentage of capacity resources.
Notes: • NERC region and reliability assessment area maps are provided on EIA's Electricity Reliability web page:
http://www.eia.gov/cneaf/electricity/page/eia411/eia411.html
• Projected data are updated annually.
• Peak load represents an hour of a day during the associated peak period.
• The Winter peak period begins October 1 and extends through May 31.
• Historically the MRO, RFC, SERC, and SPP regional boundaries were altered as utilities changed reliability organizations. The historical data series for these regions have not been adjusted. Instead, the Balance of Eastern Region category was introduced to to provide a consistent trend of the Eastern interconnection.
• E - Estimate
Source: U.S. Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply and Demand Program Report."

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Table 4.4.A. Winter Net Internal Demand, Capacity Resources, and Capacity Margins by North American Electric Reliability Assessment Areas, 2001-2010 Actual
(Megawatts and Percent)

Interconnection	NERC Regional Assesment Area	Net Internal Demand (MW)[1] -- Winter									
		2001/2002	2002/2003	2003/2004	2004/2005	2005/2006	2006/2007	2007/2008	2008/2009	2009/2010	2010/ 2011
Eastern Interconnection	**FRCC**	**39,699**	**42,001**	**36,229**	**41,449**	**42,493**	**45,993**	**46,093**	**45,042**	**51,703**	**45,954**
	NPCC	**42,551**	**45,980**	**47,850**	**47,859**	**46,328**	**48,394**	**46,185**	**47,151**	**44,864**	**44,172**
	Balance of Eastern Region	**341,158**	**360,748**	**357,026**	**371,011**	**375,365**	**385,887**	**383,779**	**384,495**	**399,204**	**389,351**
	ECAR	82,831	84,844	86,332	91,800	NA	NA	NA	NA	NA	NA
	MAAC	39,458	46,159	45,625	45,565	NA	NA	NA	NA	NA	NA
	MAIN	38,412	39,974	39,955	40,618	NA	NA	NA	NA	NA	NA
	MAPP	MRO	MRO	MRO	NA	NA	NA	NA	NA	NA	4,877
	MISO	NA	NA	NA	NA	NA	NA	NA	NA	NA	80,311
	MRO	21,575	23,090	24,042	24,446	32,854	34,582	34,358	34,539	33,983	NA
	PJM	NA	NA	NA	NA	NA	NA	NA	NA	NA	115,535
	RFC	NA	NA	NA	NA	151,600	147,800	141,200	142,395	143,827	NA
	SERC	130,311	137,541	133,244	139,486	160,054	173,036	176,766	175,199	188,653	148,062
	SPP	28,571	29,140	27,828	29,096	30,857	30,469	31,455	32,362	32,741	40,566
ERCOT	**TRE**	**43,908**	**44,719**	**41,988**	**44,010**	**46,991**	**46,038**	**46,068**	**46,747**	**56,191**	**55,917**
Western Interconnection	**WECC**	**95,395**	**94,554**	**100,337**	**101,002**	**105,670**	**107,586**	**113,504**	**110,977**	**106,256**	**99,515**
All Interconnections	**Contiguous U.S.**	**562,711**	**588,002**	**583,430**	**605,331**	**616,847**	**633,898**	**635,629**	**634,412**	**658,219**	**634,909**

Interconnection	NERC Regional Assesment Area	Capacity Resources[2] -- Winter									
		2001/2002	2002/2003	2003/2004	2004/2005	2005/2006	2006/2007	2007/2008	2008/2009	2009/2010	2010/ 2011
Eastern Interconnection	**FRCC**	**44,336**	**46,219**	**50,010**	**51,196**	**49,066**	**56,896**	**57,510**	**53,278**	**52,751**	**57,358**
	NPCC	**66,314**	**68,884**	**73,123**	**74,277**	**76,076**	**76,110**	**75,772**	**79,394**	**78,992**	**70,557**
	Balance of Eastern Region	**488,418**	**511,642**	**524,995**	**538,041**	**545,850**	**547,005**	**537,094**	**545,843**	**567,746**	**595,627**
	ECAR	115,926	123,823	129,351	131,187	NA	NA	NA	NA	NA	NA
	MAAC	63,604	66,143	68,134	69,604	NA	NA	NA	NA	NA	NA
	MAIN	63,209	66,694	68,942	66,414	NA	NA	NA	NA	NA	NA
	MAPP	NA	NA	NA	NA	NA	NA	NA	NA	NA	6,941
	MISO	NA	NA	NA	NA	NA	NA	NA	NA	NA	129,241
	MRO	30,809	33,224	32,769	34,371	44,620	46,959	44,987	47,343	46,422	NA
	PJM	NA	NA	NA	NA	NA	NA	NA	NA	NA	190,000
	RFC	NA	NA	NA	NA	229,000	220,930	212,257	215,477	215,700	NA
	SERC	169,580	174,925	179,810	186,784	224,652	231,917	229,627	234,797	255,527	207,558
	SPP	45,290	46,833	45,989	49,681	47,578	47,199	50,223	48,226	50,097	61,888
ERCOT	**TRE**	**72,644**	**73,335**	**77,111**	**71,902**	**61,003**	**71,451**	**75,504**	**73,910**	**69,490**	**77,660**
Western Interconnection	**WECC**	**119,254**	**132,278**	**152,158**	**149,360**	**152,211**	**166,362**	**167,770**	**167,312**	**151,022**	**156,413**
All Interconnections	**Contiguous U.S.**	**790,966**	**832,358**	**877,397**	**884,776**	**884,206**	**917,824**	**913,650**	**919,736**	**920,002**	**957,615**

Interconnection	NERC Regional Assesment Area	Capacity Margin (percent)[3] -- Winter									
		2001/2002	2002/2003	2003/2004	2004/2005	2005/2006	2006/2007	2007/2008	2008/2009	2009/2010	2010/ 2011
Eastern Interconnection	**FRCC**	**10.5**	**9.1**	**27.6**	**19.0**	**13.4**	**19.2**	**19.9**	**15.5**	**2.0**	**19.9**
	NPCC	**35.8**	**33.3**	**34.6**	**35.6**	**39.1**	**36.4**	**39.0**	**40.6**	**43.2**	**37.4**
	Balance of Eastern Region	**30.2**	**29.5**	**32.0**	**31.0**	**31.2**	**29.5**	**28.5**	**29.6**	**29.7**	**34.6**
	ECAR	28.5	31.5	33.3	30.0	NA	NA	NA	NA	NA	NA
	MAAC	38.0	30.2	33.0	34.5	NA	NA	NA	NA	NA	NA
	MAIN	39.2	40.1	42.0	38.8	NA	NA	NA	NA	NA	NA
	MAPP	NA	NA	NA	NA	NA	NA	NA	NA	NA	29.7
	MISO	NA	NA	NA	NA	NA	NA	NA	NA	NA	37.9
	MRO	30.0	30.5	26.6	28.9	26.4	26.4	23.6	27.0	26.8	NA
	PJM	NA	NA	NA	NA	NA	NA	NA	NA	NA	39.2
	RFC	NA	NA	NA	NA	33.8	33.1	33.5	33.9	33.3	NA
	SERC	23.2	21.4	25.9	25.3	28.8	25.4	23.0	25.4	26.2	28.7
	SPP	36.9	37.8	39.5	41.4	35.1	35.4	37.4	32.9	34.6	34.5
ERCOT	**TRE**	**39.6**	**39.0**	**45.5**	**38.8**	**23.0**	**35.6**	**39.0**	**36.8**	**19.1**	**28.0**
Western Interconnection	**WECC**	**20.0**	**28.5**	**34.1**	**32.4**	**30.6**	**35.3**	**32.3**	**33.7**	**29.6**	**36.4**
All Interconnections	**Contiguous U.S.**	**28.9**	**29.4**	**33.5**	**31.6**	**30.2**	**30.9**	**30.4**	**31.0**	**28.5**	**33.7**

[1] Net Internal Demand represent the system demand that is planned for by the electric power industry`s reliability authority and is equal to Internal Demand less Direct Control Load Management and Interruptible Demand.
[2] Capacity Resources: Utility and nonutility-owned generating capacity that is existing or in various stages of planning or construction, less inoperable capacity, plus planned capacity purchases from other resources, less planned capacity sales.
[3] Capacity Margin is the amount of unused available capability of an electric power system at peak load as a percentage of capacity resources.
Notes: • NERC region and reliability assessment area maps are provided on EIA's Electricity Reliability web page:
http://www.eia.gov/cneaf/electricity/page/eia411/eia411.html
• Peak load represents an hour of a day during the associated peak period.
• The Winter peak period begins October 1 and extends through May 31.
• Historically the MRO, RFC, SERC, and SPP regional boundaries were altered as utilities changed reliability organizations. The historical data series for these regions have not been adjusted. Instead, the Balance of Eastern Region category was introduced to to provide a consistent trend of the Eastern interconnection.
• ECAR, MAAC, and MAIN dissolved at the end-of-2005. Many of the former utility members joined RFC. ReliabilityFirst Corporation (RFC) came into existence on January 1, 2006. RFC submitted a consolidated filing covering the historical NERC regions of ECAR, MAAC, and MAIN.
• NA - Not Available
Source: U.S. Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply and Demand Program Report."

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Table 4.4.B. Winter Net Internal Demand, Capacity Resources, and Capacity Margins by North American Electric Reliability Corporation Assessment Area, 2010 Actual, 2011-2015 Projected
(Megawatts)

Interconnection	NERC Regional Assesment Area	Net Internal Demand[1] -- Winter					
		Actual	Projected				
		2010/2011	2011/2012E	2012/2013E	2013/2014E	2014/2015E	2015/2016E
Eastern Interconnection	**FRCC**	**45,954**	**44,196**	**44,750**	**45,350**	**45,923**	**46,503**
	NPCC	**44,172**	**44,924**	**44,637**	**44,422**	**44,216**	**44,354**
	Balance of Eastern Region	**389,351**	**384,993**	**390,736**	**394,849**	**396,861**	**401,086**
	MAPP	4,877	4,746	4,686	4,929	4,977	5,062
	MISO	80,311	71,233	67,389	69,591	69,906	70,755
	PJM	115,535	119,806	127,464	127,243	128,662	129,699
	SERC	148,062	148,990	150,504	151,921	152,244	153,879
	SPP	40,566	40,218	40,693	41,165	41,073	41,691
ERCOT	**TRE**	**55,917**	**50,158**	**49,817**	**51,900**	**53,503**	**54,719**
Western Interconnection	**WECC**	**99,515**	**104,740**	**105,879**	**107,570**	**109,542**	**111,261**
All Grids	**Contiguous U.S.**	**634,909**	**629,011**	**635,819**	**644,091**	**650,044**	**657,923**

Interconnection	NERC Regional Assesment Area	Capacity Resources[2] -- Winter					
		Actual	Projected				
		2010/2011	2011/2012E	2012/2013E	2013/2014E	2014/2015E	2015/2016E
Eastern Interconnection	**FRCC**	**57,358**	**55,786**	**57,282**	**58,030**	**61,245**	**60,543**
	NPCC	**70,557**	**74,946**	**75,937**	**77,155**	**77,850**	**77,706**
	Balance of Eastern Region	**595,627**	**570,224**	**578,991**	**581,968**	**582,872**	**580,949**
	MAPP	6,941	7,078	7,038	7,118	7,118	7,088
	MISO	129,241	107,051	101,737	101,796	101,815	101,838
	PJM	190,000	182,643	189,777	191,426	192,016	192,022
	SERC	207,558	208,978	214,974	215,492	215,346	213,657
	SPP	61,888	64,474	65,466	66,137	66,577	66,345
ERCOT	**TRE**	**77,660**	**77,256**	**78,440**	**78,535**	**80,695**	**82,095**
Western Interconnection	**WECC**	**156,413**	**161,583**	**168,816**	**172,598**	**175,807**	**176,112**
All Grids	**Contiguous U.S.**	**957,615**	**939,795**	**959,466**	**968,287**	**978,469**	**977,406**

Interconnection	NERC Regional Assesment Area	Capacity Margin (percent)[3] -- Winter					
		Actual	Projected				
		2010/2011	2011/2012E	2012/2013E	2013/2014E	2014/2015E	2015/2016E
Eastern Interconnection	**FRCC**	**19.9**	**20.8**	**21.9**	**21.9**	**25.0**	**23.2**
	NPCC	**37.4**	**40.1**	**41.2**	**42.4**	**43.2**	**42.9**
	Balance of Eastern Region	**34.6**	**32.5**	**32.5**	**32.2**	**31.9**	**31.0**
	MAPP	29.7	32.9	33.4	30.7	30.1	28.6
	MISO	37.9	33.5	33.8	31.6	31.3	30.5
	PJM	39.2	34.4	32.8	33.5	33.0	32.5
	SERC	28.7	28.7	30.0	29.5	29.3	28.0
	SPP	34.5	37.6	37.8	37.8	38.3	37.2
ERCOT	**TRE**	**28.0**	**35.1**	**36.5**	**33.9**	**33.7**	**33.3**
Western Interconnection	**WECC**	**36.4**	**35.2**	**37.3**	**37.7**	**37.7**	**36.8**
All Grids	**Contiguous U.S.**	**33.7**	**33.1**	**33.7**	**33.5**	**33.6**	**32.7**

[1] Net Internal Demand represent the system demand that is planned for by the electric power industry`s reliability authority and is equal to Internal Demand less Direct Control Load Management and Interruptible Demand.
[2] Capacity Resources: Utility and nonutility-owned generating capacity that is existing or in various stages of planning or construction, less inoperable capacity, plus planned capacity purchases from other resources, less planned capacity sales.
[3] Capacity Margin is the amount of unused available capability of an electric power system at peak load as a percentage of capacity resources.
Notes: • NERC region and reliability assessment area maps are provided on EIA's Electricity Reliability web page:
http://www.eia.gov/cneaf/electricity/page/eia411/eia411.html
• Projected data are updated annually.
• Peak load represents an hour of a day during the associated peak period.
• The Winter peak period begins October 1 and extends through May 31.
• Historically the MRO, RFC, SERC, and SPP regional boundaries were altered as utilities changed reliability organizations. The historical data series for these regions have not been adjusted. Instead, the Balance of Eastern Region category was introduced to to provide a consistent trend of the Eastern interconnection.
• E - Estimate
Source: U.S. Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply and Demand Program Report."

Table 4.5.A. Existing Transmission Capacity by High-Voltage Size, 2010
(Circuit Miles of Transmission)

Voltage		Circuit Miles								
Type	Operating (kV)	FRCC	MRO	NPCC	RFC	SERC	SPP	TRE	WECC	Contigious U.S.
AC	100-199	-	-	-	-	-	-	-	-	-
AC	200-299	5,922	7,241	1,521	6,949	21,100	2,776	-	36,810	82,319
AC	300-399	-	11,468	5,064	13,610	3,538	4,934	9,500	10,301	58,415
AC	400-599	1,201	473	-	2,551	8,617	47	-	12,729	25,618
AC	600+	-	-	190	2,226	-	-	-	-	2,416
AC Total		**7,123**	**19,182**	**6,774**	**25,336**	**33,255**	**7,757**	**9,500**	**59,840**	**168,768**
DC	100-199	-	-	48	-	-	-	-	-	48
DC	200-299	-	930	-	-	-	-	-	-	930
DC	300-399	-	-	-	-	-	-	-	-	-
DC	400-499	-	872	-	-	-	-	-	-	872
DC	500-599	-	-	-	66	-	-	-	2,137	2,203
DC	600+	-	-	-	-	-	-	-	-	-
DC Total		**-**	**1,802**	**48**	**66**	**-**	**-**	**-**	**2,137**	**4,053**
Grand Total		**7,123**	**20,984**	**6,822**	**25,402**	**33,255**	**7,757**	**9,500**	**61,977**	**172,820**

Notes: • NERC region and reliability assessment area maps are provided on EIA's Electricity Reliability web page: http://www.eia.gov/cneaf/electricity/page/eia411/eia411.html
• Circuit miles do not equal physical miles on the ground; the reference terminology for that concept is structural mile.
• Some structures were designed and then built to carry future transmission circuits in order to handle expected growth in new capability requirements.
• Lines are taken out of service for a variety of reasons including intentional changes to the right-of-way to better use available land for different levels of voltage and types of poles and towers.
Source: U.S. Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program Report."

Table 4.5.B. Proposed Transmission Capacity Additions by High-Voltage Size, 2011-2017
(Circuit Miles of Transmission)

Voltage		Circuit Miles							
Type	Operating (kV)	2011	2012	2013	2014	2015	2016	2017	All Years
AC	100-199	1,164	1,749	932	738	466	368	214	5,630
AC	200-299	1,007	1,091	708	822	895	241	157	4,922
AC	300-399	555	1,336	4,934	1,234	699	476	1,156	10,390
AC	400-599	116	695	633	782	2,802	1,438	440	6,906
AC	600+	-	-	-	-	275	-	-	275
AC Total		**2,841**	**4,871**	**7,208**	**3,577**	**5,137**	**2,524**	**1,967**	**28,124**
DC	100-199	-	-	-	-	-	-	-	-
DC	200-299	-	-	-	-	-	-	-	-
DC	300-399	-	-	-	-	140	-	-	140
DC	400-599	-	-	-	-	60	640	-	700
DC	600+	-	-	-	-	142	-	-	142
DC Total		**-**	**-**	**-**	**-**	**342**	**640**	**-**	**982**
Grand Total		**2,841**	**4,871**	**7,208**	**3,577**	**5,479**	**3,164**	**1,967**	**29,106**
Lines taken out of service		**99**	**180**	**21**	**121**	**33**	**134**	**-**	**587**

Notes: • NERC region and reliability assessment area maps are provided on EIA's Electricity Reliability web page: http://www.eia.gov/cneaf/electricity/page/eia411/eia411.html
• Circuit miles do not equal physical miles on the ground; the reference terminology for that concept is structural mile.
• Some structures were designed and then built to carry future transmission circuits in order to handle expected growth in new capability requirements.
• Lines are taken out of service for a variety of reasons including intentional changes to the right-of-way to better use available land for different levels of voltage and types of poles and towers.
Source: U.S. Energy Information Administration, Form EIA-411, "Coordinated Bulk Power Supply Program Report."

Table 5.1. Count of Electric Power Industry Power Plants, by Sector, by Predominant Energy Sources within Plant, 2002 through 2010
(Count)

Period	Coal	Petroleum	Natural Gas	Other Gases	Nuclear	Hydroelectric Conventional	Other Renewables	Hydroelectric Pumped Storage	Other
Total (All Sectors)									
2002	633	1,147	1,649	40	66	1,426	682	38	28
2003	629	1,166	1,693	40	66	1,425	741	38	27
2004	625	1,143	1,670	46	66	1,425	749	39	28
2005	619	1,133	1,664	44	66	1,422	781	39	29
2006	616	1,148	1,659	46	66	1,421	843	39	29
2007	606	1,163	1,659	46	66	1,424	929	39	25
2008	598	1,170	1,655	43	66	1,423	1,076	39	29
2009	593	1,168	1,652	43	66	1,427	1,219	39	28
2010	580	1,169	1,657	48	66	1,432	1,356	39	32
Electricity Generators, Electric Utilities									
2002	363	811	699	1	37	913	57	33	0
2003	359	827	715	1	37	912	64	33	1
2004	357	816	722	2	37	908	65	34	1
2005	353	813	743	1	37	906	71	34	1
2006	353	832	758	1	37	905	84	34	1
2007	351	851	767	1	37	904	93	34	1
2008	348	866	774	0	37	902	107	34	1
2009	346	861	776	0	37	903	132	34	1
2010	339	861	781	3	37	904	159	34	0
Electricity Generators, Independent Power Producers									
2002	106	180	326	1	29	455	430	5	4
2003	99	182	350	0	29	456	468	5	2
2004	100	173	355	1	29	457	478	5	2
2005	101	170	357	2	29	456	502	5	2
2006	101	166	356	2	29	458	552	5	2
2007	101	166	364	1	29	462	625	5	1
2008	99	166	365	0	29	464	751	5	2
2009	97	169	369	1	29	468	866	5	2
2010	99	171	374	1	29	472	964	5	6
Combined Heat and Power, Electric Power									
2002	44	15	169	2	0	0	28	0	0
2003	49	17	187	3	0	0	34	0	0
2004	48	15	180	3	0	0	30	0	0
2005	48	14	177	3	0	0	33	0	0
2006	50	15	173	4	0	0	32	0	0
2007	48	12	170	4	0	0	32	0	0
2008	47	12	169	3	0	0	36	0	0
2009	49	10	165	3	0	0	39	0	0
2010	45	10	161	2	0	0	41	0	0
Combined Heat and Power, Commercial[1]									
2002	22	63	122	0	0	9	41	0	0
2003	22	65	121	0	0	9	44	0	0
2004	21	65	121	1	0	9	46	0	0
2005	20	64	113	1	0	9	48	0	0
2006	22	62	109	1	0	9	47	0	0
2007	20	64	106	1	0	9	47	0	1
2008	20	62	106	1	0	9	49	0	1
2009	18	66	107	1	0	9	48	0	1
2010	17	67	110	1	0	9	57	0	1
Combined Heat and Power, Industrial[1]									
2002	98	71	317	36	0	49	125	0	24
2003	100	71	310	36	0	48	130	0	24
2004	99	74	292	39	0	51	130	0	25
2005	97	72	274	37	0	51	127	0	26
2006	90	73	263	38	0	49	128	0	26
2007	86	70	252	39	0	49	132	0	22
2008	84	64	241	39	0	48	133	0	25
2009	83	62	235	38	0	47	134	0	24
2010	80	60	231	41	0	47	135	0	25

[1] Small number of electricity-only non-Combined Heat and Power plants may be included.

Note: The number of power plants for each energy source is the number of sites for which the respective energy source was reported as the most predominant energy source for at least one of its generators. If all generators for a site have the same energy source reported as the most predominant, that site will be counted once under that energy source. However, if the most predominant energy source is not the same for all generators within a site, the site is counted more than once, based on the number of most predominant energy sources for generators at a site. In general, this table translates the number of generators by energy source (Table 1.2) into the number of sites represented by the generators for an energy source. Therefore, the count for Total (All Sectors) above is the sum of the counts for each sector by energy source and does not necessarily represent unique site. In addition, changes to predominant energy sources and status codes from year to year may result in changes to previously-posted data.

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

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Table 5.3. Average Operating Heat Rate for Selected Energy Sources, 2001 through 2010

(Btu per Kilowatthour)

Period	Coal [1]	Petroleum [2]	Natural Gas	Nuclear
2001	10,378	10,742	10,051	10,443
2002	10,314	10,641	9,533	10,442
2003	10,297	10,610	9,207	10,421
2004	10,331	10,571	8,647	10,427
2005	10,373	10,631	8,551	10,436
2006	10,351	10,809	8,471	10,436
2007	10,375	10,794	8,403	10,485
2008	10,378	11,015	8,305	10,453
2009 [R]	10,414	10,923	8,160	10,460
2010	10,415	10,984	8,185	10,452

[1] Includes anthracite, bituminous, subbituminous and lignite coal. Waste coal and synthetic coal are included starting in 2002.

[2] Includes distillate fuel oil (all diesel and No. 1 and No. 2 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil, jet fuel, kerosene, petroleum coke, and waste oil.

Notes: • 2009 natural gas heat rate is revised •Included in the calculation for coal, petroleum, and natural gas average operating heat rate are electric power plants in the utility and independent power producer sectors. • Combined heat and power plants, and all plants in the commercial and industrial sectors are excluded from the calculations. • The nuclear average heat rate is the weighted average tested heat rate for nuclear units as reported on the Form EIA-860.

Sources: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report," and predecessor form(s) including U.S. Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report;" Form EIA-860, "Annual Electric Generator Report."

Table 5.4. Average Heat Rates by Prime Mover and Energy Source, 2010
(Btu per Kilowatthour)

Prime Mover	Coal	Petroleum	Natural Gas[1]	Nuclear
Steam Turbine	10,142	10,249	10,416	10,452
Gas Turbine[2]	--	13,386	11,590	--
Internal Combustion	--	10,429	9,917	--
Combined Cycle	W	10,474	7,619	--

[1] Includes a small number of generators for which waste heat is the primary energy source.

[2] Includes binary turbines.

W = Withheld to avoid disclosure of individual company data.

Notes: • See Glossary reference for definitions. • Totals may not equal sum of components because of independent rounding. • Heat rate is reported at full load conditions for electric utilities and independent power producers. • The average heat rates above are weighted by Net Summer Capacity. • In 2010, EIA changed the way it treated blank values in its methodology for calculating average heat rates.

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

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Table 6.1. Electric Power Industry - Electricity Purchases, 1999 through 2010
(Thousand Megawatthours)

	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
U.S. Total	**5,770,134**	**5,028,647**	**5,612,781**	**5,411,422**	**5,502,584**	**6,092,285**	**6,998,549**	**6,979,669**	**8,754,807**	**7,555,276**	**2,345,540**	**2,039,969**
Electric Utilities	2,353,086	2,364,648	2,483,927	2,504,002	2,605,315	2,760,043	2,725,694	2,610,525	2,620,712	3,045,854	2,250,382	1,949,574
Energy-Only Providers	3,319,211	2,564,407	3,024,730	2,805,833	2,793,288	3,250,298	4,170,331	4,264,102	6,050,159	4,412,064	NA	NA
IPP	23,976	27,922	25,431	24,942	26,628	12,201	24,258	37,921	15,801	97,357[1]	10,622	4,358
CHP	73,861	71,669	78,693	76,646	77,353	69,744	78,267	67,122	68,135	NA	84,536	86,037

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

NA = Not available.

R = Revised.

Notes: • Energy-only providers are wholesale and retail power marketers. • IPP are independent power producers and CHP are combined heat and power producers. • Totals may not equal sum of components because of independent rounding. • The data collection instrument was changed in 2001 to collect data at the corporate level, rather than the plant level. As a result, comparisons with data prior to 2001 and after 2001 should be done with caution.

Sources: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report." For unregulated entities prior to 2001. Form EIA-860B, "Annual Electric Generator Report - Nonutility," and predecessor forms; and Form EIA-923, "Power Plant Operations Report" for 2007 and predecessor form(s) for earlier years.

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Table 6.2. Electric Power Industry - Electricity Sales for Resale, 1999 through 2010
(Thousand Megawatthours)

	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
U.S. Total	**5,929,211**	**5,065,031**	**5,680,733**	**5,479,394**	**5,493,473**	**6,071,659**	**6,758,975**	**6,920,954**	**8,568,678**	**7,345,319**	**2,355,154**	**1,998,090**
Electric Utilities	1,541,554	1,495,636	1,576,976	1,603,179	1,698,389	1,925,710	1,923,440	1,824,030	1,838,901	2,146,689	1,715,582	1,635,614
Energy-Only Providers	2,946,452	2,240,399	2,718,661	2,476,740	2,446,104	2,867,048	3,756,175	3,906,220	5,757,283	4,386,632	NA	NA
IPP	1,404,137	1,295,857	1,355,017	1,368,310	1,321,342	1,252,796	1,053,364	1,156,796	943,531	811,998[1]	611,150	335,122
CHP	37,068	33,139	30,079	31,165	27,638	26,105	25,996	33,909	28,963	NA	28,421	27,354

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

NA = Not available.

R = Revised.

Notes: • Energy-only providers are wholesale and retail power marketers. • IPP are independent power producers and CHP are combined heat and power producers. • The data collection instrument was changed in 2001 to collect data at the corporate level, rather than the plant level. As a result, comparisons with data prior to 2001, and after 2001 should be done with caution. • Totals may not equal sum of components because of independent rounding.

Sources: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report." For unregulated entities prior to 2001. Form EIA-860B, "Annual Electric Generator Report - Nonutility," and predecessor forms; and Form EIA-923, "Power Plant Operations Report" for 2007 and predecessor form(s) for earlier years.

Table 6.3. Electric Power Industry - U.S. Electricity Imports from and Electricity Exports to Canada and Mexico, 1999-2010
(Megawatthours)

Trading Partner	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
	U.S. Electricity Imports and Exports											
Canada												
Imports from ……………	43,763,091	51,108,502	55,732,400	50,118,056	41,544,052	42,332,039	33,007,487	29,324,625	36,536,479	38,401,598	48,515,476	42,911,308
Exports to ………………	18,481,678	17,490,264	23,499,445	19,559,417	23,405,387	18,680,237	22,482,109	23,584,513	15,231,079	16,105,612	12,684,706	12,953,488
Mexico												
Imports from ……………	1,320,095	1,082,093	1,286,981	1,277,644	1,147,258	1,597,275	1,202,576	1,069,926	242,596	98,649	76,800	303,439
Exports to ………………	624,502	647,720	698,714	584,176	865,948	470,731	415,754	390,190	564,603	367,680	2,144,676	1,268,284
U.S. Total												
Imports	**45,083,186**	**52,190,595**	**57,019,381**	**51,395,702**	**42,691,310**	**43,929,314**	**34,210,063**	**30,394,551**	**36,779,077**	**38,500,247**	**48,592,276**	**43,214,747**
Exports	**19,106,180**	**18,137,984**	**24,198,159**	**20,143,592**	**24,271,335**	**19,150,968**	**22,897,863**	**23,974,703**	**15,795,681**	**16,473,292**	**14,829,382**	**14,221,772**

Sources:
National Energy Board of Canada; DOE, Office of Electricity Delivery and Energy Reliability, Form OE-781R, "Annual Report of International Electric Export/Import Data," predecessor forms.
To estimate electricity trade with Mexico, for 2001 forward data from the California Independent System Operator are used in combination with the Form OE-781R values.

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Table 7.1. Number of Ultimate Customers Served by Sector, by Provider, 1999 through 2010
(Count)

Period	Residential	Commercial	Industrial	Transportation	Other	All Sectors
Total Electric Industry						
1999	110,383,238	14,073,764	552,690	NA	935,311	125,945,003
2000	111,717,711	14,349,067	526,554	NA	974,185	127,567,517
2001	114,890,240	14,867,490	571,463	NA	1,030,046	131,359,239
2002	116,622,037	15,333,700	601,744	NA	1,066,554	133,624,035
2003	117,280,481	16,549,519	713,221	1,127	NA	134,544,348
2004	118,763,768	16,606,783	747,600	1,025	NA	136,119,176
2005	120,760,839	16,871,940	733,862	518	NA	138,367,159
2006	122,471,071	17,172,499	759,604	791	NA	140,403,965
2007	123,949,916	17,377,219	793,767	750	NA	142,121,652
2008	124,937,469	17,562,726	774,713	727	NA	143,275,635
2009	125,177,175	17,561,661	757,519	705	NA	143,497,060
2010	125,717,935	17,674,338	747,746	239	NA	144,140,258
Full-Service Providers[1]						
1999	109,817,057	13,963,937	527,329	NA	934,260	125,242,583
2000	110,505,820	14,058,271	512,551	NA	953,756	126,030,398
2001	112,472,629	14,364,578	553,280	NA	1,004,027	128,394,514
2002	113,790,812	14,899,747	586,217	NA	1,035,604	130,312,380
2003	115,029,545	16,136,616	695,616	1,042	NA	131,862,819
2004	116,325,747	16,161,269	733,809	941	NA	133,221,766
2005	118,469,928	16,389,549	719,219	496	NA	135,579,192
2006	120,677,627	16,673,766	745,645	764	NA	138,097,802
2007	121,782,003	16,767,635	771,637	710	NA	139,321,985
2008	122,595,644	16,952,660	756,294	664	NA	140,305,262
2009	122,533,214	16,860,320	736,751	666	NA	140,130,951
2010	121,555,089	16,675,341	718,651	198	NA	138,949,279
Energy-Only Providers						
1999	566,181	109,827	25,361	NA	1,051	702,420
2000	1,211,891	290,796	14,003	NA	20,429	1,537,119
2001	2,417,611	502,912	18,183	NA	26,019	2,964,725
2002	2,831,225	433,953	15,527	NA	30,950	3,311,655
2003	2,250,936	412,903	17,605	85	NA	2,681,529
2004	2,438,021	445,514	13,791	84	NA	2,897,410
2005	2,290,911	482,391	14,643	22	NA	2,787,967
2006	1,793,444	498,733	13,959	27	NA	2,306,163
2007	2,167,913	609,584	22,130	40	NA	2,799,667
2008	2,341,825	610,066	18,419	63	NA	2,970,373
2009	2,643,961	701,341	20,768	39	NA	3,366,109
2010	4,162,846	998,997	29,095	41	NA	5,190,979

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

NA = Not available.

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

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

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Table 7.2. Retail Sales and Direct Use of Electricity to Ultimate Customers by Sector, by Provider, 1999 through 2010
(Megawatthours)

Period	Sales						Direct Use[1]	Total
	Residential	Commercial	Industrial	Trans- portation	Other	Total		End Use
Total Electric Industry								
1999	1,144,923,069	1,001,995,720	1,058,216,608	NA	106,951,684	3,312,087,081	171,629,285	3,483,716,366
2000	1,192,446,491	1,055,232,090	1,064,239,393	NA	109,496,292	3,421,414,266	170,942,509	3,592,356,775
2001	1,201,606,593	1,083,068,516	996,609,310	NA	113,173,685	3,394,458,104	162,648,615	3,557,106,719
2002	1,265,179,869	1,104,496,607	990,237,631	NA	105,551,904	3,465,466,011	166,184,296	3,631,650,307
2003	1,275,823,910	1,198,727,601	1,012,373,247	6,809,728	NA	3,493,734,486	168,294,526	3,662,029,012
2004	1,291,981,578	1,230,424,731	1,017,849,532	7,223,642	NA	3,547,479,483	168,470,002	3,715,949,485
2005	1,359,227,107	1,275,079,020	1,019,156,065	7,506,321	NA	3,660,968,513	150,015,531	3,810,984,044
2006	1,351,520,036	1,299,743,695	1,011,297,566	7,357,543	NA	3,669,918,840	146,926,612	3,816,845,452
2007	1,392,240,996	1,336,315,196	1,027,831,925	8,172,595	NA	3,764,560,712	125,670,185[R]	3,890,230,897[R]
2008	1,379,981,104	1,335,981,135	1,009,300,309	7,699,632	NA	3,732,962,180	132,196,685[R]	3,865,158,865[R]
2009	1,364,474,417	1,307,167,813	917,442,063	7,780,573	NA	3,596,864,866	126,937,958	3,723,802,824
2010	1,445,708,403	1,330,199,364	970,872,874	7,712,412	NA	3,754,493,053	131,910,249	3,886,403,302
Full-Service Providers[2]								
1999	1,140,761,016	970,600,943	1,017,783,037	NA	106,754,043	3,235,899,039	NA	3,235,899,039
2000	1,183,137,429	1,000,865,367	1,017,722,945	NA	107,824,323	3,309,550,064	NA	3,309,550,064
2001	1,188,219,590	1,037,998,484	961,812,417	NA	108,632,086	3,296,662,577	NA	3,296,662,577
2002	1,248,349,458	1,036,366,268	937,138,192	NA	102,238,786	3,324,092,704	NA	3,324,092,704
2003	1,257,766,998	1,112,206,121	931,661,404	3,315,043	NA	3,304,949,566	NA	3,304,949,566
2004	1,272,237,425	1,116,497,417	933,529,502	3,188,466	NA	3,325,452,810	NA	3,325,452,810
2005	1,339,568,275	1,151,327,861	929,675,932	3,341,814	NA	3,423,913,882	NA	3,423,913,882
2006	1,337,837,993	1,170,661,399	939,194,648	3,040,062	NA	3,450,734,102	NA	3,450,734,102
2007	1,375,450,126	1,180,789,042	923,148,031	2,635,498	NA	3,482,022,697	NA	3,482,022,697
2008	1,362,811,730	1,152,674,093	929,246,647	2,515,304	NA	3,447,247,774	NA	3,447,247,774
2009	1,345,125,375	1,140,767,357	813,292,567	2,453,843	NA	3,301,639,142	NA	3,301,639,142
2010	1,409,355,244	1,123,328,313	840,091,476	2,440,567	NA	3,375,215,600	NA	3,375,215,600
Energy-Only Providers								
1999	4,162,053	31,394,777	40,433,571	NA	197,641	76,188,042	NA	76,188,042
2000	9,309,062	54,366,723	46,516,448	NA	1,671,969	111,864,202	NA	111,864,202
2001	13,387,003	45,070,032	34,796,893	NA	4,541,599	97,795,527	NA	97,795,527
2002	16,830,411	68,130,339	53,099,439	NA	3,313,118	141,373,307	NA	141,373,307
2003	18,056,912	86,521,480	80,711,843	3,494,685	NA	188,784,920	NA	188,784,920
2004	19,744,153	113,927,314	84,320,030	4,035,176	NA	222,026,673	NA	222,026,673
2005	19,658,832	123,751,159	89,480,133	4,164,507	NA	237,054,631	NA	237,054,631
2006	13,682,043	129,082,296	72,102,918	4,317,481	NA	219,184,738	NA	219,184,738
2007	16,790,870	155,526,154	104,683,894	5,537,097	NA	282,538,015	NA	282,538,015
2008	17,169,374	183,307,042	80,053,662	5,184,328	NA	285,714,406	NA	285,714,406
2009	19,349,042	166,400,456	104,149,496	5,326,730	NA	295,225,724	NA	295,225,724
2010	36,353,159	206,871,051	130,781,398	5,271,845	NA	379,277,453	NA	379,277,453

[1] Direct Use represents commercial and industrial facility use of onsite net electricity generation; and electricity sales or transfers to adjacent or co-located facilities for which revenue information is not available.
[2] These data include Facility Direct Retail Sales.Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas, all customers served by Retail Energy Providers must be provided bundled energy and delivery services, so are included under "Full-Service Providers."
NA = Not available.
R = Revised.
Notes: • See Technical Notes reference for definitions. • Full-Service Providers sell bundled electricity services (e.g., both energy and delivery) to end users. Full-Service Providers
Sources: U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report;" Form EIA-923, "Power Plant Operations Report" and predecessor

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Table 7.3. Revenue from Retail Sales of Electricity to Ultimate Customers by Sector, by Provider, 1999 through 2010
(Million Dollars)

Period	Residential	Commercial	Industrial	Transportation	Other	All Sectors
Total Electric Industry[1]						
1999	93,483	72,771	46,846	NA	6,796	219,896
2000	98,209	78,405	49,369	NA	7,179	233,163
2001	103,158	85,741	50,293	NA	8,151	247,343
2002	106,834	87,117	48,336	NA	7,124	249,411
2003	111,249	96,263	51,741	514	NA	259,767
2004	115,577	100,546	53,477	519	NA	270,119
2005	128,393	110,522	58,445	643	NA	298,003
2006	140,582	122,914	62,308	702	NA	326,506
2007	148,295	128,903	65,712	792	NA	343,703
2008	155,433	138,469	68,920	827	NA	363,650
2009	157,008	132,940	62,504	828	NA	353,280
2010	166,782	135,559	65,750	815	NA	368,906
Full-Service Providers[2]						
1999	93,142	70,492	45,056	NA	6,783	215,473
2000	97,086	73,704	46,465	NA	6,988	224,243
2001	101,541	81,385	48,182	NA	7,766	238,874
2002	104,814	80,573	44,826	NA	6,803	237,014
2003	109,165	87,764	46,686	226	NA	243,841
2004	113,306	89,597	47,993	238	NA	251,134
2005	125,983	97,405	52,113	249	NA	275,749
2006	138,608	107,432	56,385	257	NA	302,683
2007	145,642	109,703	56,950	232	NA	312,527
2008	152,429	115,062	61,286	250	NA	329,027
2009	153,723	112,111	53,345	226	NA	319,405
2010	161,221	110,298	54,561	233	NA	326,312
Restructured Retail Service Providers[3]						
1999	340	2,279	1,791	NA	13	4,423
2000	1,123	4,702	2,904	NA	191	8,920
2001	1,617	4,356	2,111	NA	385	8,469
2002	2,020	6,545	3,510	NA	321	12,396
2003	2,084	8,499	5,055	288	NA	15,926
2004	2,272	10,949	5,484	281	NA	18,985
2005	2,410	13,117	6,333	394	NA	22,254
2006	1,974	15,482	5,922	445	NA	23,823
2007	2,653	19,200	8,762	560	NA	31,176
2008	3,004	23,407	7,635	577	NA	34,622
2009	3,286	20,828	9,159	602	NA	33,875
2010	5,560	25,261	11,190	582	NA	42,593

Energy-Only Providers[4]						
1999	340	2,279	1,791	NA	13	4,423
2000	530	3,175	2,374	NA	75	6,153
2001	714	2,806	1,632	NA	237	5,390
2002	914	3,989	2,408	NA	143	7,454
2003	980	5,210	3,605	215	NA	10,011
2004	1,086	6,859	3,881	201	NA	12,027
2005	1,285	8,844	4,749	308	NA	15,186
2006	1,127	10,792	4,510	356	NA	16,784
2007	1,646	13,553	7,197	458	NA	22,854
2008	1,873	17,126	6,212	455	NA	25,667
2009	1,877	14,271	7,205	460	NA	23,813
2010	3,230	16,999	8,664	425	NA	29,318
Delivery-Only Service						
1999	--	--	--	--	--	--
2000	593	1,527	531	NA	116	2,767
2001	903	1,551	479	NA	147	3,080
2002	1,106	2,556	1,102	NA	178	4,942
2003	1,104	3,289	1,450	72	NA	5,915
2004	1,186	4,090	1,603	79	NA	6,958
2005	1,125	4,273	1,584	86	NA	7,068
2006	847	4,690	1,412	90	NA	7,040
2007	1,007	5,647	1,565	102	NA	8,322
2008	1,131	6,281	1,422	121	NA	8,956
2009	1,409	6,557	1,954	143	NA	10,062
2010	2,330	8,262	2,526	157		13,276

[1] Sum of Full-Service Providers and Restructured Retail Service Providers.

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

[3] Sum of Energy-Only Providers and Delivery-Only Service.

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

NA = Not available.

Notes: • See Technical Notes reference for definitions. • Full-Service Providers sell bundled electricity services (e.g., both energy and

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

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Table 7.4. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, 1999 through 2010
(Cents per kilowatthour)

Period	Residential	Commercial	Industrial	Transportation	Other	All Sectors
Total Electric Industry[1]						
1999	8.16	7.26	4.43	NA	6.35	6.64
2000	8.24	7.43	4.64	NA	6.56	6.81
2001	8.58	7.92	5.05	NA	7.2	7.29
2002	8.44	7.89	4.88	NA	6.75	7.2
2003	8.72	8.03	5.11	7.54	NA	7.44
2004	8.95	8.17	5.25	7.18	NA	7.61
2005	9.45	8.67	5.73	8.57	NA	8.14
2006	10.4	9.46	6.16	9.54	NA	8.9
2007	10.65	9.65	6.39	9.7	NA	9.13
2008	11.26	10.36	6.83	10.74	NA	9.74
2009	11.51	10.17	6.81	10.65	NA	9.82
2010	11.54	10.19	6.77	10.57	NA	9.83
Full-Service Providers[2]						
1999	8.16	7.26	4.43	NA	6.35	6.66
2000	8.21	7.36	4.57	NA	6.48	6.78
2001	8.55	7.84	5.01	NA	7.15	7.25
2002	8.4	7.77	4.78	NA	6.65	7.13
2003	8.68	7.89	5.01	6.82	NA	7.38
2004	8.91	8.02	5.14	7.47	NA	7.55
2005	9.4	8.46	5.61	7.45	NA	8.05
2006	10.36	9.18	6	8.44	NA	8.77
2007	10.59	9.29	6.17	8.82	NA	8.98
2008	11.18	9.98	6.6	9.96	NA	9.54
2009	11.43	9.83	6.56	9.2	NA	9.67
2010	11.44	9.82	6.49	9.55	NA	9.67
Restructured Retail Service Providers[3]						
1999	8.17	7.26	4.43	NA	6.45	5.81
2000	12.07	8.65	6.24	NA	11.42	7.97
2001	12.08	9.67	6.07	NA	8.47	8.66
2002	12	9.61	6.61	NA	9.69	8.77
2003	11.54	9.82	6.26	8.23	NA	8.44
2004	11.51	9.61	6.5	6.95	NA	8.55
2005	12.26	10.6	7.08	9.47	NA	9.39
2006	14.43	11.99	8.21	10.32	NA	10.87
2007	15.8	12.35	8.37	10.11	NA	11.03
2008	17.49	12.77	9.54	11.12	NA	12.12
2009	16.98	12.52	8.79	11.31	NA	11.47
2010	15.30	12.21	8.56	11.04	NA	11.23

Energy-Only Providers[4]						
1999	8.17	7.26	4.43	NA	6.45	5.81
2000	5.69	5.84	5.1	NA	4.47	5.5
2001	5.34	6.22	4.69	NA	5.23	5.51
2002	5.43	5.86	4.53	NA	4.3	5.27
2003	5.43	6.02	4.47	6.16	NA	5.3
2004	5.5	6.02	4.6	4.99	NA	5.42
2005	6.54	7.15	5.31	7.4	NA	6.41
2006	8.23	8.36	6.25	8.24	NA	7.66
2007	9.8	8.71	6.87	8.28	NA	8.09
2008	10.91	9.34	7.76	8.79	NA	8.98
2009	9.7	8.58	6.92	8.63	NA	8.07
2010	8.88	8.22	6.62	8.06	NA	7.73
Delivery-Only Service						
1999	--	--	--	--	--	--
2000	6.37	2.81	1.14	--	6.95	2.47
2001	6.74	3.44	1.38	--	3.24	3.15
2002	6.57	3.75	2.08	--	5.39	3.5
2003	6.11	3.8	1.8	2.07	--	3.13
2004	6	3.59	1.9	1.96	NA	3.13
2005	5.72	3.45	1.77	2.07	NA	2.98
2006	6.19	3.63	1.96	2.08	NA	3.21
2007	6	3.63	1.5	1.84	NA	2.95
2008	6.59	3.43	1.78	2.34	NA	3.13
2009	7.28	3.94	1.88	2.68	NA	3.41
2010	6.41	3.99	1.93	2.98	NA	3.50

[1] Weighted average of Full-Service Providers and Restructured Retail Service Providers.

[2] Pursuant to applicable Texas statutes establishing competitive electricity markets within the Electric Reliability Council of Texas

[3] Sum of Energy-Only Providers and Delivery-Only Service.

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

NA = Not available.

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

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

Table 7.5. Net Metering and Green Pricing Customers by End Use Sector, 2003 - 2010
(Count)

Period	Green Pricing			Net Metering		
	Residential	Non Residential	Total	Residential	Non Residential	Total
2003	819,579	57,547	877,126	5,870	943	6,813
2004	864,794	63,539	928,333	14,114	1,712	15,826
2005	871,774	70,998	942,772	19,244	1,902	21,146
2006[1]	606,919	35,937	642,856	30,689	2,930	33,619
2007	773,391	62,260	835,651	44,886	3,943	48,829
2008	918,284	64,711	982,995	64,400	5,609	70,009
2009	1,058,185	65,593	1,123,778	88,222	8,284	96,506
2010	1,137,047	79,535	1,216,582	141,844	13,997	155,841

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

Notes: • Green Pricing programs allow electricity customers the opportunity to purchase electricity generated from renewable resources, thereby encouraging renewable energy devel

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

Table 8.1. Revenue and Expense Statistics for Major U.S. Investor-Owned Electric Utilities, 1999 through 2010
(Million Dollars)

Description	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
Utility Operating Revenues	**284,373**	**276,124**	**298,962**	**270,964**	**275,501**	**265,652**	**238,759**	**230,151**	**219,609**	**267,276**	**233,915**	**213,090**
Electric Utility	260,113	249,303	266,124	240,864	246,736	234,909	213,012	206,268	200,360	243,982	213,634	197,010
Other Utility	24,260	26,822	32,838	30,100	28,765	30,743	25,747	23,883	19,250	23,294	20,281	16,081
Utility Operating Expenses	**250,122**	**244,243**	**267,263**	**241,198**	**245,589**	**236,786**	**206,960**	**201,057**	**189,062**	**234,910**	**210,250**	**180,467**
Electric Utility	226,845	219,544	236,572	213,076	218,445	207,830	183,121	179,044	171,604	213,458	191,564	165,942
Operation	159,585	154,925	175,887	153,885	158,893	150,645	131,560	125,436	116,660	161,233	132,607	107,686
Production	128,808	118,816	140,974	121,700	127,494	120,586	103,871	98,305	90,715	135,791	107,554	82,791
Cost of Fuel	44,115	40,242	47,337	39,548	37,945	36,106	28,544	26,871	24,149	29,434	32,407	29,605
Purchased Power	67,284	67,630	84,724	74,112	79,205	77,902	67,126	63,749	58,810	98,020	62,608	42,663
Other	13,013	10,970	8,937	8,058	10,371	6,599	8,226	7,709	7,776	8,359	12,561	10,551
Transmission	6,948	6,742	6,950	6,051	6,179	5,664	4,531	3,653	3,560	3,385	2,713	2,480
Distribution	4,007	3,947	3,997	3,765	3,640	3,502	3,287	3,214	3,117	3,208	3,092	2,959
Customer Accounts	5,091	5,203	5,286	4,652	4,409	4,229	4,077	4,262	4,168	4,432	4,239	4,190
Customer Service	4,741	3,857	3,567	2,939	2,536	2,291	2,013	1,902	1,820	1,855	1,826	1,854
Sales	185	178	225	239	240	219	237	238	264	282	405	474
Administrative and General	17,115	15,991	14,718	14,346	14,580	14,130	13,537	13,863	13,018	12,292	12,768	12,950
Maintenance	14,962	14,092	14,192	13,181	12,838	12,033	11,743	11,340	10,861	11,154	12,064	12,359
Depreciation	20,930	20,095	19,049	17,936	17,373	17,123	16,322	15,981	16,199	17,476	20,636	20,232
Taxes and Other	27,646	29,081	26,202	27,000	28,149	26,805	22,190	25,027	26,716	21,765	24,479	23,786
Other Utility	23,277	24,698	30,692	28,122	27,143	28,956	23,839	22,013	17,457	21,452	18,686	14,525
Net Utility Operating Income	**34,251**	**31,881**	**31,699**	**29,766**	**29,912**	**28,866**	**31,799**	**29,094**	**30,548**	**32,366**	**23,665**	**32,623**

Notes: • 2007 financial data does not include information on Entergy Gulf State Louisiana LLC and Entergy Texas Inc. as both were not reported on the FERC Form for that year. • Missing or erroneous respondent data may result in slight imbalances in some of the expense account subtotals. Totals may not equal sum of components because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others, via Ventyx Global Energy Velocity Suite."

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Table 8.2. Average Power Plant Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 1999 through 2010
(Mills per Kilowatthour)

Plant Type	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
Operation												
Nuclear	10.50	10	9.89	9.54	9.03	8.26	8.97	9.12	9	8.44	6.03	8.17
Fossil Steam	4.04	4.23	3.72	3.63	3.57	3.21	3.13	2.74	2.59	2.47	2.17	2.16
Hydroelectric[1]	5.33	4.88	5.78	5.44	3.76	3.95	3.83	3.47	3.71	4.27	3.52	3.35
Gas Turbine and Small	2.79	3.05	3.77	3.26	3.51	3.69	4.27	3.5	3.26	3.65	3.93	5.01
Maintenance												
Nuclear	6.80	6.34	6.2	5.79	5.69	5.27	5.38	5.23	5.04	5.02	4.96	5.01
Fossil Steam	3.99	3.96	3.59	3.37	3.19	2.98	2.96	2.72	2.67	2.61	2.42	2.46
Hydroelectric[1]	3.81	3.5	3.89	3.87	2.7	2.73	2.76	2.32	2.62	2.89	2.22	2.03
Gas Turbine and Small	2.73	2.58	2.72	2.42	2.16	1.89	2.14	2.26	2.38	3.33	3.26	4.78
Fuel												
Nuclear	6.68	5.35	5.29	4.99	4.85	4.63	4.58	4.6	4.6	4.67	4.9	5.16
Fossil Steam	27.73	32.3	28.43	23.88	23.09	21.69	18.21	17.29	16.09	18.15	17.73	15.5
Hydroelectric[1]	--	--	--	--	--	--	--	--	--	--	--	--
Gas Turbine and Small	43.21	51.93	64.23	58.75	53.89	55.52	45.18	43.89	31.84	43.55	41.76	27.95
Total												
Nuclear	23.98	21.69	21.37	20.32	19.57	18.15	18.93	18.95	18.65	18.13	15.89	18.35
Fossil Steam	35.76	40.48	35.75	30.88	29.85	27.88	24.31	22.75	21.36	23.23	22.32	20.12
Hydroelectric[1]	9.15	8.38	9.67	9.32	6.46	6.68	6.6	5.79	6.33	7.16	5.74	5.38
Gas Turbine and Small	48.74	57.55	70.72	64.43	59.56	61.1	51.59	49.66	37.47	50.53	48.94	37.74

[1] Conventional hydro and pumped storage.

[2] Gas turbine, internal combustion, photovoltaic, and wind plants.

Notes: • Expenses are average expenses weighted by net generation. • A mill is a monetary cost and billing unit equal to 1/1000 of the U.S. dollar (equivalent to 1/10 of one cent). • Totals may not equal sum of components because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others via Ventyx Global Energy Velocity Suite."

Table 8.3. Revenue and Expense Statistics for Major U.S. Publicly Owned Electric Utilities (With Generation Facilities), 1999 through 2010
(Million Dollars)

Description	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
Operating Revenue - Electric	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**33,906**	**32,776**	**38,028**	**31,843**	**26,767**
Operating Expenses - Electric	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**29,637**	**28,638**	**32,789**	**26,244**	**21,274**
Operation Including Fuel	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**22,642**	**21,731**	**25,922**	**19,575**	**15,386**
Production	NA	NA	NA	NA	NA	NA	NA	17,948	17,176	21,764	15,742	11,923
Transmission	NA	NA	NA	NA	NA	NA	NA	872	858	785	781	732
Distribution	NA	NA	NA	NA	NA	NA	NA	696	680	605	574	516
Customer Accounts	NA	NA	NA	NA	NA	NA	NA	582	537	600	507	415
Customer Service	NA	NA	NA	NA	NA	NA	NA	280	315	263	211	160
Sales	NA	NA	NA	NA	NA	NA	NA	84	74	73	66	49
Administrative and General	NA	NA	NA	NA	NA	NA	NA	2,180	2,090	1,832	1,695	1,591
Maintenance	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**2,086**	**1,926**	**1,904**	**1,815**	**1,686**
Depreciation and Amortization	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**3,844**	**3,907**	**4,009**	**3,919**	**3,505**
Taxes and Tax Equivalents	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**1,066**	**1,074**	**954**	**936**	**697**
Net Electric Operating Income	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**4,268**	**4,138**	**5,238**	**5,598**	**5,493**

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

Table 8.4. Revenue and Expense Statistics for Major U.S. Publicly Owned Electric Utilities (Without Generation Facilities), 1999 through 2010
(Million Dollars)

Description	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
Operating Revenue - Electric	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**12,454**	**11,546**	**10,417**	**9,904**	**9,354**
Operating Expenses - Electric	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**11,481**	**10,703**	**9,820**	**9,355**	**8,737**
Operation Including Fuel	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**10,095**	**9,439**	**8,864**	**8,424**	**7,874**
Production	NA	NA	NA	NA	NA	NA	NA	8,865	8,311	7,863	7,486	7,015
Transmission	NA	NA	NA	NA	NA	NA	NA	105	93	61	64	48
Distribution	NA	NA	NA	NA	NA	NA	NA	348	320	311	280	261
Customer Accounts	NA	NA	NA	NA	NA	NA	NA	172	163	164	155	143
Customer Service	NA	NA	NA	NA	NA	NA	NA	31	39	26	22	22
Sales	NA	NA	NA	NA	NA	NA	NA	11	10	15	16	14
Administrative and General	NA	NA	NA	NA	NA	NA	NA	562	504	423	402	371
Maintenance	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**418**	**389**	**304**	**286**	**272**
Depreciation and Amortization	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**711**	**631**	**405**	**394**	**369**
Taxes and Tax Equivalents	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**257**	**244**	**247**	**251**	**223**
Net Electric Operating Income	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**974**	**843**	**597**	**549**	**617**

NA = Not available.

Notes: • In 2004, Form EIA-412 was terminated. • Totals may not equal sum of components because of independent rounding.

Source: U.S. Energy Information Administration, EIA Form-412, "Annual Electric Industry Financial Report," and predecessor forms.

Table 8.5. Revenue and Expense Statistics for U.S. Federally Owned Electric Utilities, 1999 through 2010
(Million Dollars)

Description	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
Operating Revenue - Electric	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**11,798**	**11,470**	**12,458**	**10,685**	**10,186**
Operating Expenses - Electric	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**8,763**	**8,665**	**10,013**	**8,139**	**7,775**
Operation Including Fuel	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**6,498**	**6,419**	**7,388**	**5,873**	**5,412**
Production	NA	NA	NA	NA	NA	NA	NA	5,175	5,236	6,247	5,497	4,890
Transmission	NA	NA	NA	NA	NA	NA	NA	307	244	354	332	349
Distribution	NA	NA	NA	NA	NA	NA	NA	1	1	1	2	2
Customer Accounts	NA	NA	NA	NA	NA	NA	NA	4	10	16	6	1
Customer Service	NA	NA	NA	NA	NA	NA	NA	63	60	60	48	50
Sales	NA	NA	NA	NA	NA	NA	NA	20	6	6	10	28
Administrative and General	NA	NA	NA	NA	NA	NA	NA	927	862	705	467	528
Maintenance	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**600**	**566**	**521**	**488**	**436**
Depreciation and Amortization	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**1,335**	**1,351**	**1,790**	**1,471**	**1,623**
Taxes and Tax Equivalents	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**329**	**328**	**315**	**308**	**304**
Net Electric Operating Income	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**3,035**	**2,805**	**2,445**	**2,546**	**2,411**

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

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Table 9.1. Demand-Side Management Actual Peak Load Reductions by Program Category, 1999 through 2010

(Megawatts)

Item	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
Total Actual Peak Load Reduction	**33,283**	**31,682**	**31,735**	**30,253**	**27,240**	**25,710**	**23,532**	**22,904**	**22,936**	**24,955**	**22,901**	**26,455**
Energy Efficiency	20,808	19,766	19,707	17,710	15,959	15,351	14,272	13,581	13,420	13,027	12,873	13,452
Load Management	12,475	11,916	12,028	12,543	11,281	10,359	9,260	9,323	9,516	11,928	10,027	13,003

Notes: • Data presented are reflective of large utilities. • See Technical Notes for the Demand-Side Management definitions located within the Form EIA-861 section. • Totals may not equal sum of

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

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Table 9.2. Demand-Side Management Program Annual Effects by Program Category, 1999 through 2010
(MW, MWh)

Item	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
Annual Effects – Energy Efficiency												
Large Utilities												
Actual Peak Load Reduction (MW)	20,808	19,766	19,707	17,710	15,959	15,351	14,272	13,581	13,420	13,027	52,827	49,691
Energy Savings (Thousand MWh)	86,926	76,891	74,861	67,134	62,951	58,891	52,662	48,245	52,285	52,946	12,873	13,452
Annual Effects – Load Management												
Large Utilities												
Actual Peak Load Reduction (MW)	12,475	11,916	12,028	12,543	11,281	10,359	9,260	9,323	9,516	11,928	10,027	13,003
Potential Peak Load Reductions (MW)	25,880	26,178	26,246	23,087	21,270	21,282	20,998	25,290	26,888	27,730	28,496	30,118
Energy Savings (Thousand MWh)	913	1,015	1,813	1,857	865	1,006	2,047	2,020	1,790	990	875	872

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

Table 9.3. Demand-Side Management Program Incremental Effects by Program Category, 1999 through 2010
(MW, MWh)

Item	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
Incremental Effects – Energy Efficiency												
Large Utilities												
Actual Peak Load Reduction (MW)	4,736	2,941	5,764	1,649	1,177	1,403	1,521	945	1,054	999	720	695
Energy Savings (Thousand MWh)	13,560	12,698	10,407	7,426	5,385	5,872	4,522	2,939	3,543	4,402	3,284	3,027
Small Utilities												
Actual Peak Load Reduction (MW)	28	777	567	349	91	302	204	90	49	20	25	22
Energy Savings (Thousand MWh)	32	209	21	254	9	7	10	8	192	8	8	8
Incremental Effects – Load Management												
Large Utilities												
Actual Peak Load Reduction (MW)	2,601	2,152	2,923	1,356	1,495	1,009	907	1,084	1,160	1,297	919	1,568
Potential Peak Load Reductions (MW)	4,987	5,811	6,636	3,342	2,544	2,005	2,622	1,981	2,655	2,448	2,439	6,457
Energy Savings (Thousand MWh)	49	65	167	132	95	133	2	29	65	79	63	67
Small Utilities												
Actual Peak Load Reduction (MW)	108	75	371	1,036	195	153	242	81	54	45	137	54
Potential Peak Load Reductions (MW)	246	232	620	1,423	273	218	422	131	76	177	190	84
Energy Savings (Thousand MWh)	1	1	1	5	4	5	4	4	2	4	9	2

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

Table 9.4. Demand-Side Management Program Annual Effects by Sector, 1999 through 2010
(MW, Thousand MWh)

Item	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
Actual Peak Load Reductions (MW)												
Large Utilities												
Residential	14,094	12,605	12,910	13,192	10,730	9,432	8,870	9,431	9,137	9,619	9,446	9,976
Commercial	10,882	11,399	11,097	8,054	7,779	7,926	7,194	6,774	6,839	8,210	6,987	7,777
Industrial	8,160	7,666	7,602	8,990	8,692	8,343	7,454	6,594	6,500	6,553	6,141	6,360
Transportation	147	12	126	17	39	9	14	105	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	NA	NA	460	573	327	2,342
Total	**33,283**	**31,682**	**31,735**	**30,253**	**27,240**	**25,710**	**23,532**	**22,904**	**22,936**	**24,955**	**22,901**	**26,455**
Potential Peak Load Reductions (MW)												
Large Utilities												
Residential	17,293	15,986	16,831	15,263	13,040	12,097	11,967	12,525	12,072	12,274	12,970	12,812
Commercial	14,060	14,366	13,850	10,201	10,006	10,214	9,624	8,943	9,298	10,469	9,114	8,868
Industrial	15,053	15,502	15,103	15,271	14,119	14,260	13,665	17,298	18,321	17,344	18,775	17,237
Transportation	282	90	169	62	64	62	14	105	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	NA	NA	617	670	510	4,653
Total	**46,688**	**45,944**	**45,953**	**40,797**	**37,229**	**36,633**	**35,270**	**38,871**	**40,308**	**40,757**	**41,369**	**43,570**
Energy Savings (Thousand MWh)												
Large Utilities												
Residential	32,436	27,811	26,534	23,688	21,437	19,255	17,763	13,469	15,438	16,027	16,287	16,263
Commercial	37,659	35,019	34,869	30,725	28,982	28,416	24,624	25,089	24,391	24,217	25,660	23,375
Industrial	17,655	15,002	15,196	14,470	13,348	12,178	12,273	11,156	11,339	10,487	9,160	8,156
Transportation	89	76	76	109	50	48	51	551	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	NA	NA	2,907	3,206	2,593	2,770
Total	**87,839**	**77,907**	**76,674**	**68,992**	**63,817**	**59,897**	**54,710**	**50,265**	**54,075**	**53,936**	**53,701**	**50,563**

NA = Not available.

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

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

Table 9.5. Demand-Side Management Program Incremental Effects by Sector, 1999 through 2010

(MW, Thousand MWh)

Item	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
Actual Peak Load Reductions (MW)												
Large Utilities												
Residential	1,986	2,055	5,507	1,344	1,012	966	1,361	640	895	790	572	605
Commercial	3,512	1,598	2,329	983	759	715	560	528	527	742	515	684
Industrial	1,838	1,436	849.0	677	901	731	507	849	680	640	502	929
Transportation	1	4	2	1	0	0	0	12	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	NA	NA	112	124	50	45
Total	**7,337**	**5,093**	**8,687**	**3,005**	**2,672**	**2,412**	**2,428**	**2,029**	**2,214**	**2,296**	**1,640**	**2,263**
Small Utilities												
Residential	58	586	220	871	131	325	280	88	48	32	37	27
Commercial	38	226	287	342	63	71	126	58	41	15	37	22
Industrial	40	40	431	130	92	59	40	25	12	16	62	7
Transportation	0	0	0	42	0	0	0	0	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	NA	NA	0	0	26	19
Total	**136**	**852**	**938**	**1,385**	**286**	**455**	**446**	**171**	**101**	**63**	**162**	**76**
U.S. Total	**7,473**	**5,945**	**9,625**	**4,390**	**2,958**	**2,867**	**2,874**	**2,200**	**2,317**	**2,361**	**1,802**	**2,339**
Potential Peak Load Reductions (MW)												
Large Utilities												
Residential	3,234	3,118	7,246	2,374	1,406	1,311	1,680	752	1,311	900	699	753
Commercial	3,715	2,762	3,025	1,574	1,114	1,098	894	602	751	1,115	565	718
Industrial	2,774	2,849	2,127	1,042	1,201	999	1,569	1,551	1,506	1,277	1,815	5,612
Transportation	1	23	2	1	0	0	0	21	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	NA	NA	141	155	79	68
Total	**9,724**	**8,752**	**12,400**	**4,991**	**3,721**	**3,408**	**4,143**	**2,926**	**3,709**	**3,447**	**3,159**	**7,151**
Small Utilities												
Residential	120	653	315	962	164	367	395	116	64	158	55	41
Commercial	58	251	304	513	95	100	154	73	43	19	51	25
Industrial	96	105	568	243	105	53	77	32	15	18	64	9
Transportation	0	0	0	54	0	0	0	0	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	NA	NA	3	2	44	31
Total	**274**	**1,009**	**1,187**	**1,772**	**364**	**520**	**626**	**221**	**125**	**197**	**215**	**106**
U.S. Total	**9,998**	**9,761**	**13,587**	**6,763**	**4,085**	**3,928**	**4,769**	**3,147**	**3,834**	**3,644**	**3,374**	**7,257**
Energy Savings (Thousand MWh)												
Large Utilities												
Residential	6,496	4,867	4,584	3,515	2,141	2,276	1,842	868	1,203	1,365	856	990
Commercial	5,338	4,975	4,440	2,831	2,339	2,638	1,815	1,356	1,583	1,867	1,780	1,502
Industrial	1,770	2,920	1,549	1,199	999	1,090	867	732	706	872	547	475
Transportation	5	1	1	13	0	*	0	12	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	NA	NA	116	376	164	127
Total	**13,609**	**12,763**	**10,574**	**7,558**	**5,479**	**6,004**	**4,524**	**2,968**	**3,608**	**4,481**	**3,347**	**3,094**
Small Utilities												
Residential	13	197	16	157	9	6	6	7	45	5	9	4
Commercial	6	5	4	98	3	5	7	5	148	3	4	3
Industrial	13	8	2	4	1	*	2	1	2	2	1	1
Transportation	*	*	*	0	0	0	0	0	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	NA	NA	*	3	3	1
Total	**33**	**210**	**22**	**259**	**13**	**12**	**14**	**13**	**194**	**13**	**17**	**9**
U.S. Total	**13,641**	**12,972**	**10,596**	**7,817**	**5,492**	**6,016**	**4,539**	**2,981**	**3,802**	**4,492**	**3,364**	**3,103**

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

NA = Not available.

R = Revised.

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

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

Table 9.6. Demand-Side Management Program Energy Savings, 1999 through 2010

(Thousand Megawatthours)

Item	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
Total Energy Savings	**87,839**	**77,907**	**76,674**	**68,992**	**63,817**	**59,897**	**54,710**	**50,265**	**54,075**	**53,936**	**53,701**	**50,563**
Energy Efficiency	86,926	76,891	74,861	67,134	62,951	58,891	52,662	48,245	52,285	52,946	52,827	49,691
Load Management	913	1,015	1,813	1,857	865	1,006	2,047	2,020	1,790	990	875	872

Notes: • Data presented are reflective of large utilities. • Totals may not equal sum of components because of independent rounding.

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

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Table 9.7. Demand-Side Management Program Direct and Indirect Costs, 1999 through 2010

(Thousand Dollars)

Item	2010	2009	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
Direct Cost[1]	**3,946,541**	**3,199,568**	**2,994,280**	**2,364,739**	**1,923,891**	**1,794,809**	**1,425,172**	**1,159,540**	**1,420,937**	**1,455,602**	**1,384,232**	**1,250,689**
Energy Efficiency	2,902,086	2,255,451	2,158,242	1,664,563	1,258,158	1,169,241	910,115	807,403	1,007,323	1,097,504	938,666	820,108
Load Management	1,044,455	944,117	836,038	700,176	665,733	625,568	515,057	352,137	413,614	358,098	445,566	430,581
Indirect Cost[2]	**273,523**	**394,182**	**181,131**	**158,378**	**127,499**	**126,543**	**132,294**	**137,670**	**204,600**	**174,684**	**180,669**	**172,955**
Total DSM Cost[3]	**4,220,064**	**3,593,750**	**3,175,410**	**2,523,117**	**2,051,394**	**1,921,352**	**1,557,466**	**1,297,210**	**1,625,537**	**1,630,286**	**1,564,901**	**1,423,644**

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

[2] Reflects costs not directly attributable to specific programs.

[3] Reflects the sum of the total incurred direct and indirect cost for the year.

Notes: • Data presented are reflective of large utilities. • Includes expenditures reported by large electric utilities, only. See the data files for Demand Side Management expenditures of small utilities. • Totals may not equal sum of components because of independent rounding.

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

Appendix A.

Technical Notes

This appendix describes how the U.S. Energy Information Administration collects, estimates, and reports electric power data in the *Electric Power Annual*.

Data Quality and Submission

The *Electric Power Annual* (*EPA*) is prepared by the Office of Electricity, Renewables, and Uranium Statistics (ERUS), U.S. Energy Information Administration (EIA), U.S. Department of Energy (DOE). ERUS performs routine reviews of the data collection respondent frames, survey forms, and reviews the quality of the data received.

Data are entered directly by respondents into the ERUS Internet Data Collection (IDC) system. A small number of hard copy forms are keyed into the system by ERUS personnel. All data are subject to review via interactive edits built into the IDC system, internal quality assurance reports, and review by ERUS subject matter experts. Questionable data values are verified through contacts with respondents, and survey non-respondents are identified and contacted.

IDC edits include both deterministic checks, in which records are checked for the presence of data in required fields, and statistical checks, in which the data are checked against a range of values based on historical data values and for logical or mathematical consistency with data elements reported in the survey. Discrepancies found in the data, as a result of these checks, must either be corrected by the respondent or the respondent must enter an explanation as to why the data are correct. If these explanations are unsatisfactory the respondent is contacted by EIA for clarification or corrected data.

Those respondents unable to use the electronic reporting method provide the data in hard copy, typically via fax and email. These data are manually entered into the computerized database and are subjected to the same data edits as those performed during e-filing by the respondent.

Reliability of Data

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

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

Imputation: If the reported values appear to be in error and the data issue cannot be resolved with the respondent, or if the facility is a non-respondent, a regression methodology is used to impute for the facility. The regression methodology relies on other data to make estimates for erroneous or missing responses. The basis for the current methodology involves a 'borrowing of strength' technique for small domains.[1]

Data Revision Procedure

The *EPA* presents the most current and complete data available to the EIA. The statistics may differ from those published previously in EIA publications due to corrections, revisions, or other adjustments to the data subsequent to its original release.

After data are disseminated as final, revisions will be considered if a correction would make a difference of 1 percent or greater at the national level. Revisions for differences that do not meet the 1 percent or greater threshold will be determined by the Office Director. In either case, the proposed revision will be subject to the EIA revision policy concerning how it affects other EIA products.

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

Rounding and Percent Change Calculations

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

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

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

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

Data Sources for *Electric Power Annual*

Data published in the *EPA* are compiled from forms filed annually or aggregated to an annual basis from monthly forms (see figure on EIA Electric Industry Data Collection in Appendix A). The respondents to these forms include electric utilities, other generators and sellers of electricity, and North American Electric Reliability Corporation (NERC) reliability entities. The EIA forms used are:

- Form EIA-411, "Coordinated Bulk Power Supply Program Report;"
- Form EIA-860, "Annual Electric Generator Report;"
- Form EIA-861, "Annual Electric Power Industry Report;"
- Form EIA-923, "Power Plant Operations Report."

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

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

- DOE Form OE-781R, "Annual Report of International Electric Export/Import Data" (Office of Electricity Delivery and Energy Reliability);
- FERC Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others;"
- U. S. Department of Agriculture (USDA) Rural Utility Service Form 7, "Financial and Statistical Report;" and
- USDA Rural Utility Service Form 12, "Operating Report – Financial."

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

- Form EIA-412, "Annual Electric Industry Financial Report," FERC Form 423, "Cost and Quality of Fuels for Electric Plants,"
- Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report;"
- Form EIA-759, "Monthly Power Plant Report,"
- Form EIA-767, "Steam-Electric Plant Operation and Design Report;"
- Form EIA-860A, "Annual Electric Generator Report–Utility,"
- Form EIA-860B, "Annual Electric Generator Report–Nonutility,"
- Form EIA-867, "Annual Nonutility Power Producer Report,"
- Form EIA-900, "Monthly Nonutility Power Report,"
- Form EIA-906, "Power Plant Report;" and
- Form EIA-920, "Combined Heat and Power Plant Report."

Additionally, some data reported in this publication were acquired from public reports of the National Energy Board of Canada on electricity imports and exports.

Meanings of Symbols Appearing in Tables

The following symbols have the meaning described below:

*	The value reported is less than half of the smallest unit of measure, but is greater than zero.
P	Indicates a preliminary value.
NM	Data value is not meaningful, either (1) when compared to the same value for the previous time period, or (2) when a data value is not meaningful due to having a high Relative Standard Error (RSE).
(*)	Usage of this symbol indicates a number rounded to zero.

Form EIA-411

The information reported on the mandatory Form EIA-411 includes: (1) actual energy and peak demand for the preceding year and five additional years; (2) existing and future generating capacity and capacity reserve margins; (3) scheduled capacity transfers; (4) projections of capacity, demand, purchases, sales, and scheduled maintenance; (5) power flow cases; and (6) bulk power system maps. The data is collected for EIA by NERC from NERC regional reliability entities, which in turn aggregate reports from regional members. Non-member data is also included. The compiled data is reviewed and edited by NERC and submitted to EIA annually on July 15. The data undergoes additional review by EIA. EIA resolves any quality issues with NERC.

Instrument and Design History: The Form EIA-411 program was initiated under the Federal Power Commission (FPC) Docket R-362, Reliability and Adequacy of Electric Service, and Orders 383-2, 383-3, and 383-4. The DOE, established in October 1977, assumed the responsibility for this activity. The responsibility for collecting these data was delegated to the Office of Emergency Planning and Operations within the DOE and was transferred to EIA for the reporting year 1996. Until 2008, this form was voluntary, The data is collected under the authority of the Federal Power Act (Public Law 88-280), the

Federal Energy Administration Act of 1974 (Public Law 93-275), and the DOE Organization Act (Public Law 95-91).

Issues within Historical Data Series: The Florida Reliability Coordinating Council (FRCC) separated itself from the Southeastern Electric Reliability Council (SERC) in the mid-1990s and all time series data have been adjusted. In 1998, several utilities realigned from Southwest Power Pool (SPP) to SERC. Adjustments were made to the information to account for the separation and to address the tracking of shared reserve capacity that was under long-term contracts with multiple members. Name changes altered the Mid-Continent Area Power Pool (MAPP) to the Midwest Reliability Organization (MRO) and the Western Systems Coordinating Council (WSCC) to the Western Electricity Coordinating Council (WECC). The MRO membership boundaries have altered over time, but WECC membership boundaries have not. The utilities in the associated regional entity identified as the Alaska System Coordination Council (ASCC) dropped their formal participation in NERC. (Alaska and, obviously, Hawaii are electrically interconnected with the coterminous 48 States).

At the close of calendar year 2005, the following reliability regional councils were dissolved: East Central Area Reliability Coordination Agreement (ECAR), Mid-Atlantic Area Council (MAAC), and Mid-America Interconnected Network (MAIN). On January 1, 2006, the Reliability*First* Corporation (RFC) came into existence as a new regional reliability council. Individual utility membership in the former ECAR, MAAC, and MAIN councils mostly shifted to RFC. However, adjustments in membership, as utilities joined or left various reliability councils, impacted MRO, SERC, and SPP. The Texas Regional Entity (TRE) was formed to handle the regional reliability responsibilities of the Electric Reliability Council of Texas (ERCOT). The revised delegation agreements covering all the regions were approved by the FERC on March 21, 2008. Reliability Councils that are unchanged include: Florida Reliability Coordinating Council (FRCC), Northeast Power Coordinating Council (NPCC), and the Western Electricity Coordinating Council (WECC). The historical time series have not been adjusted to account for individual membership shifts.

The current NERC regional entity names are as follows:

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

Changes Introduced in 2011: Starting in 2011, NERC modified the bulk power system *reporting* regions (in contrast to regional reliability entity *organizational* boundaries) to align them with electric market operations. Consequently, reliability data will be reported for the PJM and MISO regional transmission organization areas and the MAPP area rather than for the MRO and RFC regional areas.. This new framework, along with the other NERC regions, now forms the bulk power system reliability assessment areas.

Historically the MRO, RFC, SERC, and SPP regional boundaries were altered as utilities changed reliability organizations. In published EIA reports the historical data series for these regions have not been adjusted. Instead, starting in 2011, EIA has introduced the Balance of Eastern Region category to provide a consistent trend for the Eastern interconnection.

Concept of Demand within the EIA-411: The EIA-411 uses the following categorization of electricity demand:

- **Net Internal Demand**: Internal Demand less Direct Control Load Management and Interruptible Demand.
- **Internal Demand**: To collect these data, NERC develops a Total Internal Demand that is the sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demand of station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) is not included nor are any requirement customer (utility) load or capacity found behind the line meters on the system.
- **Direct Control Load Management**: Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises; it does not included Interruptible Demand.
- **Interruptible Demand**: The magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Council's seasonal peak by direct control of the System

Operator or by action of the customer at the direct request of the System Operator.

For additional information on demand, refer to the NERC's Long-Term Reliability Assessments at **http://www.nerc.com/page.php?cid=4|61.**

Sensitive Data: Power flow cases and maps are considered business sensitive.

Form EIA-412 (Terminated)

The Form EIA-412 was used annually to collect accounting, financial, and operating data from publicly owned electric utilities engaged in the generation, transmission, or distribution of electricity which had 150,000 megawatthours of sales to ultimate consumers and/or 150,000 megawatthours of sales for resale for the two previous years. Data was collected annually.

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

Instrument and Design History: The FPC created the FPC Form 1M in 1961 as a mandatory survey. It became the responsibility of the EIA in October 1977 when the FPC was merged with DOE and renamed the Federal Energy Regulatory Commission (FERC). In 1979, the FPC Form 1M was superseded by the Economic Regulatory Administration (ERA) Form ERA-412 and in January 1980 by the Form EIA-412.

The criteria used to select the respondents for this survey fit approximately 500 publicly owned electric utilities. Federal electric utilities were required to file the Form EIA-412. The financial data for the U.S. Army Corps of Engineers (except for Saint Mary's Falls at Sault Ste. Marie, Michigan); the U.S. Department of Interior, Bureau of Reclamation; and the U.S. International Boundary and Water Commission were collected on the Form EIA-412 from the Federal power marketing administrations. The form was terminated after the 2003 data year.

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

Sensitive Data: The nonutility data collected on Schedule 9 "Electric Generating Plant Statistics" for "Cost of Plant" and "Production Expenses," are considered business sensitive.

Form EIA-423 (Replaced in 2008 by the Form EIA-923)

The Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report," collected the cost and quality of fossil fuels delivered to nonutility plants to produce electricity. These plants included independent power producers (including those facilities that formerly reported on the FERC Form 423) and commercial and industrial combined heat and power (CHP) producers whose total fossil-fueled nameplate generating capacity was 50 or more megawatts (MW). (CHP plants are sometimes referred to as co-generators. They produce heat, such as steam for use in a manufacturing process, along with electricity).

Instrument and Design History: The Form EIA-423[2] was implemented in January 2002 to collect monthly cost and quality data for fossil fuel receipts from owners or operators of nonutility electricity generating plants. It was terminated on January 1, 2008, and replaced by the Form EIA-923, "Power Plant Operations Report."

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

Sensitive Data: Plant fuel cost data collected on the survey are considered business sensitive. State- and national-level aggregations are published if sufficient data are available to avoid disclosure of individual company and plant level costs.

FERC Form 423 (Replaced in 2008 by Form EIA-923)

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

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was not reported. The FERC Form 423 was replaced after 2007 by the Form EIA-923.

Instrument and Design History: On July 7, 1972, the FPC issued Order Number 453 enacting the New Code of Federal Regulations, Section 141.61, creating the FPC Form 423. Originally, the form was used to collect data only on fossil-steam plants, but was amended in 1974 to include data on internal-combustion and combustion-turbine units. When DOE was formed in 1977, most of FPC became FERC. The FERC Form 423 replaced the FPC Form 423 in January 1983. The FERC Form 423 dropped stand-alone combustion turbines. In addition, the generator nameplate capacity threshold was changed from 25 megawatts to 50 megawatts. This reduction in coverage eliminated approximately 50 utilities and 250 plants. All historical FPC Form 423 data in this publication were revised to reflect the new generator-nameplate-capacity threshold of 50 or more megawatts reported on the FERC Form 423. In January 1991, the collection of data on the FERC Form 423 was extended to include combined cycle units. Historical data have not been revised to include these units. On January 1, 2008, EIA assumed responsibility for collection of these data and both the utility and nonutility plants began to report their cost and quality of fuels information on Schedule 2 of Form EIA-923, "Power Plant Operations Report."

Issues within Historical Data Series: These data were collected by FERC for regulatory rather than statistical and publication purposes. EIA did not attempt to resolve any late filing issues in the FERC Form 423 survey. The data were quality reviewed by EIA and when possible quality issues were resolved with FERC.

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

Due to the estimation procedure described below in the discussion of the Form EIA-923, 2003 and later data cannot be directly compared to previous years' data.

Sensitive Data: Data collected on FERC Form 423 are not business sensitive.

Form EIA-767 (Replaced by Forms EIA-860 and EIA-923)

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

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

Collection of data via the form was suspended for the 2006 data year. Starting with the collection of 2007 calendar year data, most of the Form EIA-767 information is now collected on either the revised Form EIA-860, "Annual Electric Generator Report" or the new Form EIA-923, "Power Plant Operations Report."

Estimation of EIA-767 Data: No estimation of Form EIA-767 data was performed. Normally the survey had no non-response.

Issues within Historical Data Series: As noted above, no data were collected for calendar year 2006.

Sensitive Data: Latitude and longitude data collected on the Form EIA-767 were considered business sensitive.

Form EIA-860

The Form EIA-860 is a mandatory annual census of all existing and planned electric generating facilities in the United States with a total generator nameplate capacity of 1 or more megawatts. The survey is used to collect data on existing power plants and 10-year plans for constructing new plants, as well as generating unit additions, modifications, and retirements in existing plants. Data on the survey are collected at the individual generator level. Certain power plant environmental-related data are now collected at the boiler level. These data include environmental equipment design parameters and boiler air emission standards and boiler emission controls.

Instrument and Design History: The Form EIA-860 was originally implemented in January 1985 to collect plant data on electric utilities as of year-end 1984. It was preceded by several Federal Power Commission (FPC) forms including the FPC Form 4, Form 12 and 12E, Form 67, and Form 411. In January 1999, the

Form EIA-860 was renamed the Form EIA-860A and was implemented to collect data as of January 1, 1999.

In 1989, the Form EIA-867, "Annual Nonutility Power Producer Report," was initiated to collect plant data on unregulated entities with a total generator nameplate capacity of 5 or more megawatts. In 1992, the reporting threshold of the Form EIA-867 was lowered to include all facilities with a combined nameplate capacity of 1 or more megawatts. Previously, data were collected every 3 years from facilities with a nameplate capacity between 1 and 5 megawatts. In 1998, the Form EIA-867, was renamed Form EIA-860B, "Annual Electric Generator Report – Nonutility." The Form EIA-860B was a mandatory survey of all existing and planned nonutility electric generating facilities in the United States with a total generator nameplate capacity of 1 or more megawatts.

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

Starting with 2007, design parameters data formerly collected on Form EIA-767 were collected on Form EIA-860. These include design parameters associated with certain steam-electric plants' boilers, cooling systems, flue gas particulate collectors, flue gas desulfurization units, and stacks and flues.

Estimation of EIA-860 Data: EIA received forms form all 18,151 existing generators in the 2010 EIA-860 frame, so no imputation was required.

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

Some capacity in 2001 through 2004 is classified based on the *operating company's* classification as an electric utility or an independent power producer. Starting in the *EPA 2006*, capacity by producer type was determined at the *power plant level* for 2005 and all subsequent data collections. This change required revisions to the original published 2005 data.

Issues within Historical Data Series Regarding Planned Capacity: Delays and cancellations may have occurred subsequent to respondent data reporting as of December 31 of the data year.

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

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

Sensitive Data: The tested heat rate data collected on the Form EIA-860 are considered business sensitive.

Form EIA-861

The Form EIA-861 is a mandatory annual census of electric power industry participants in the United States. The survey is used to collect information on power sales and revenue data from approximately 3,300 respondents. About 3,200 are electric utilities, and the remainders are nontraditional entities such as energy service providers or the unregulated subsidiaries of electric utilities and power marketers.

Transportation Sector: Prior to 2003, sales of electric power for transportation (e.g., city subway systems) were included in the Other Sector, along with sales to customers for public buildings, traffic signals, public street lighting, and sales to irrigation consumers. Beginning with the 2003 data collection sales to the Transportation Sector were collected separately. The balance of the Other Sector was reclassified as Commercial Sector sales except that sales to irrigation customers, where separately identified, were reclassified to the Industrial Sector.

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

Benchmark statistics were reviewed from outside surveys, most notably the U.S. Department of Transportation (DOT) Federal Transit Administration's National Transportation Database, a source previously used by EIA to estimate electricity transportation consumption. The DOT survey indicated the State and City locations of expected respondents. The Form EIA-861 survey methodology assumed that sales, revenue, and customer counts associated with these mass transit systems would be provided by the incumbent utilities in these areas, relying on information drawn routinely from rate schedules and classifications designed to serve the sector separately and distinctly. In 2010, 64 respondents reported transportation data in 28 States.

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

The reporting methodology change uses sales volumes and a customer count reported by distribution utilities, and modifies only an incremental revenue value, representing revenue associated with misreported sales assumed to be attributable to the ESPs that were under-represented in the survey frame.

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

Average Retail Price of Electricity: This value represents the cost per unit of electricity sold and is calculated by dividing retail electric revenue by the corresponding sales of electricity. The average retail price of electricity is calculated for all consumers and for each end-use sector.

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

This computed average retail price of electricity reported in this publication by is a weighted average of consumer revenue and sales and does not equal the per kWh rate charged by the electric power industry participant to the individual consumers. Electric utilities typically employ a number of rate schedules within a single sector. These alternative rate schedules reflect the varying consumption levels and patterns of consumers and their associated impact on the costs of the electric power industry participant for providing electrical service.

Issues within Historical Data Series: Changes from year to year in consumer counts, sales and revenues, particularly involving the commercial and industrial consumer sectors, may result from respondent implementation of changes in the definitions of consumers, and reclassifications. Utilities and energy service providers may classify commercial and industrial customers based on either NAICS codes or demands or usage falling within specified limits by rate schedule. The number of ultimate customers is an average of the number of customers at the close of each month. Also see the discussion of the Transportation Sector, above.

Demand-Side Management (DSM): The following definitions are supplied to assist in interpreting DSM data. Utility costs reflect the total cash expenditures for the year, in nominal dollars, that used to support DSM programs.

- **Actual Peak Load Reduction** is the actual reduction in annual peak load achieved by all program participants during the reporting year, at the time of annual peak load, as opposed to the installed peak load reduction capability (potential peak load reduction). Actual peak load reduction is reported by large utilities only.
- **Energy Savings** is the change in aggregate electricity use (measured in megawatthours) for consumers that participate in a utility DSM program. These savings represent changes at the consumer's meter (i.e., exclude transmission and distribution effects) and reflect only activities that are undertaken specifically in response to utility-administered programs, including those activities implemented by third parties under contract to the utility.
- **Large Utilities** are those electric utilities with annual sales to ultimate customers or sales for resale greater than or equal to 150 million kilowatthours in 1998-2009 and, for years prior, the threshold was set at 120 million kilowatthours.
- **Potential Peak Load Reduction is t**he potential peak load reduction as a result of load management, and also the actual peak load reduction achieved by energy efficiency programs.

Sensitive Data: None.

Forms EIA-906 and EIA-920 (Replaced in 2008 by Form EIA-923)

The Form EIA-906 was used to collect plant-level data on generation, fuel consumption, stocks, and fuel heat content, from electric utilities and nonutilities. Data were collected monthly from a model-based sample of approximately 1,700 utility and nonutility electric power plants. The form was also used to collect these statistics from another 2,667 plants (i.e., all other generators 1 MW or greater) on an annual basis. The form was ended after the 2007 data collection and replaced by the Form EIA-923.

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

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

Issues within Historical Data Series: A relatively small number electric commercial- and industrial-only plants are, for the purposes of this report, are included in the CHP data categories. The small number of electric utility plants that are CHP units are reported together with other utility plants. No information on the production of useful thermal output (UTO) or fuel consumption for UTO was collected or estimated for the electric utility CHP plants.

Sensitive Data: The only business sensitive data element collected on the Forms EIA-906 and EIA-920 was fuel stocks at the end of the reporting period.

Form EIA-923

Form EIA-923, "Power Plant Operations Report," is used to collect information on receipts and cost of fossil fuels, fuel stocks, generation, consumption of fuel for generation, and environmental data (e.g., emission controls and cooling systems).[3] Data are collected from a monthly sample of approximately 1,900 plants, which includes a census of nuclear and pumped-storage hydroelectric plants. The plants in the monthly sample report their receipts, cost and stocks of fossil fuels, electric power generation, and the total consumption of fuels for both electric power generation and, if a CHP plant, useful thermal output. At the end of the year, the monthly respondents report their annual source and disposition of electric power (nonutilities only), and if applicable, the environmental data on the Form EIA-923 Supplemental Form (Schedules 6, 7, and 8A to 8F). Approximately 3,900 plants, representing all generators not included in the monthly sample and with a nameplate capacity of 1 MW or more, report data on the entire form annually. In addition to electric power generating plants, respondents include fuel storage terminals without generating capacity that receive shipments of fossil fuel for eventual use in electric power generation. The monthly data are due by the last day of the month following the reporting period.

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

Instrument and Design History: See discussion of predecessor forms (EIA-906, -920, -767, and -423, and FERC Form 423).

Imputation: For data collected monthly, regression prediction, or imputation, is done for all missing data including non-sampled units and any non-respondents. For data collected annually, imputation is performed for non-respondents. For gross generation and total fuel consumption, multiple regression is used for imputation (see discussion, above). Only approximately 0.02 percent of the national total generation for 2010 is imputed, although this will vary by State and energy source.

When gross generation is reported and net generation is not available, net generation is estimated by using a fixed ratio to gross generation by prime-mover type and installed environmental equipment. These ratios are:

Net Generation = (Factor) x Gross Generation
Prime Movers:
Combined Cycle Steam - 0.97
Combined Cycle Single Shaft - 0.97
Combined Cycle Combustion Turbine - 0.97
Compressed Air - 0.97
Fuel Cell - 0.99
Gas Turbine - 0.98
Hydroelectric Turbine - 0.99
Hydroelectric Pumped Storage - 0.99
Internal Combustion Engine - 0.98
Other - 0.97
Photovoltaic - 0.99
Steam Turbine - 0.97
Wind Turbine - 0.99
Environmental Equipment:
Flue Gas Desulfurization - 0.97
Flue Gas Particulate 0.99
All Others - 0.97

For stocks, a linear combination of the prior month's ending stocks value and the current month's consumption and receipts values is used.

Receipts of Fossil Fuels: Receipts data, including cost and quality of fuels, are collected at the plant level from selected electric generating plants and fossil-fuel storage terminals in the United States. These plants include independent power producers, electric utilities, and commercial and industrial CHP producers whose total fossil-fueled nameplate capacity is 50 megawatts or more (excluding storage terminals, which do not produce electricity). The data on cost and quality of fuel shipments are then used to produce aggregates and weighted averages for each fuel type at the State, Census division, and U.S. levels.

The units for receipts are: 1) coal and petroleum coke, tons and million Btu per ton; 2) petroleum, barrels and million Btu per barrel.; and gases in thousand cubic feet (Mcf) and million Btu per thousand cubic foot.

Methodology to Estimate Biogenic and Non-biogenic Municipal Solid Waste:[4] Municipal Solid Waste (MSW) consumption for generation of electric power is split into its biogenic and non-biogenic components beginning with 2001 data by the following methodology:

- The tonnage of MSW is reported on the Form EIA-923. The composition of MSW and categorization of the components were obtained from the Environmental Protection Agency (EPA) publication, *Municipal Solid Waste in the United States: 2005 Facts and Figures.* The Btu contents of the components of MSW were obtained from various sources.
- The potential quantities of combustible MSW discards (which include all MSW material available for combustion with energy recovery, discards to landfill, and other disposal) were multiplied by their respective Btu contents. The EPA-based categories of MSW were then classified into renewable and non-renewable groupings. From this, EIA calculated how much of the energy potentially consumed from MSW was attributed to biogenic components and how much to non-biogenic components (see Table 1 and 2, below).[5]
- The percentages of biogenic and non-biogenic components of MSW are applied to the net and gross generation from MSW, splitting the generation into a renewable share (biogenic) and non-renewable share (non-biogenic). The tons of biogenic and non-biogenic components were estimated with the assumption that glass and metals were removed prior to combustion. The average Btu/ton for the biogenic and non-biogenic components is estimated by dividing the total Btu consumption by the total tons. Published net generation attributed to biogenic MSW and non-biogenic MSW is classified under Other Renewables and Other, respectively.

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

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

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

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

Useful Thermal Output (UTO): With the implementation of the Form EIA-923, "Power Plant Operations Report," in 2008, CHP plants were required to report total fuel consumed and electric power generation. Beginning with preliminary January 2008 data, EIA estimated the allocation of the total fuel consumed at CHP plants between electric power generation and UTO.

The estimated allocation methodology is summarized in the following paragraphs. The methodology was retroactively applied to 2004-2007 data. Prior to 2004, UTO was collected on the Form EIA-906 and an estimated allocation of fuel for electricity was not necessary.

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

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

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

Issues within Historical Data Series for Receipts and Cost and Quality of Fossil Fuels: Values for receipts of natural gas for 2001 forward do not include blast furnace gas or other gas.

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

Prior to 2008, regulated plants reported receipts data on the FERC Form 423. These plants, along with unregulated plants, now report receipts data on Schedule 2 of Form EIA-923. Because FERC issued waivers to Form 423 filing requirements to some plants who met certain criteria, and because not all types of generators were required to report (only steam turbines and combined cycle units reported), a significant number of plants either did not submit fossil fuel receipts data or submitted only a portion of their fossil fuel receipts. Since Form EIA-923 does not have exemptions based on generator type, or reporting waivers, receipts data from 2008 and later cannot be directly compared to previous years' data for the regulated sector.

Also beginning with January 2008 data, tables for total receipts included imputed quantities for plants with capacity one megawatt or more, to be consistent with other electric power data. Previous published receipts data were from plants at or over a 50 megawatt threshold, which was a legacy of their original collection as information for a regulatory agency, not as a survey to provide more meaningful estimates of totals for statistical purposes. Totals appeared to become smaller as more electric production came from unregulated plants, until the Form EIA-423 was created to help fill that gap. As a further improvement, estimation of all receipts for the universe normally depicted in the *EPA* (*i.e.,* one megawatt and above), with associated relative standard errors, provides a more complete assessment of the market.

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

Sensitive Data: The total delivered cost of fuel delivered to nonutilities, the commodity cost of fossil fuels, and fuel stocks are considered business sensitive.

Air Emissions

This section describes the methodology for calculating estimated emissions of carbon dioxide (CO_2) from electric generating plants for 1989 through 2009, as well as the estimated emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) from electric generating plants for 2001 through 2009. For a description of the methodology used for other years, see the technical notes to the *EPA 2003*.

Methodology Overview: Initial estimates of uncontrolled SO_2 and NO_x emissions for all plants are made by applying an emissions factor to fuel consumption data collected by EIA on the Form EIA-923. An emission factor is the average quantity of a pollutant released from a power plant when a unit of fuel is burned, assuming no use of pollution control equipment. The basic relationship is:

Emissions = Quantity of Fuel Consumed x Emission Factor

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

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

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

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

In the case of SO_2 and NO_x emissions, the factor applied to a fuel can also vary with the combustion system: a steam-producing boiler, a combustion turbine, or an internal combustion engine. In the case of boilers, NO_x emissions can also vary with the firing configuration of a boiler and whether or not the boiler is a wet-bottom or dry-bottom design.[6] These distinctions are shown in Tables A1 and A2.

For SO_2 and NO_x, the initial estimate of uncontrolled emissions is reduced to account for the plant's operational pollution control equipment, when data on control equipment are available from the historical Form EIA-767 survey (i.e., data for the years 2005 and earlier) and the EIA-860 and EIA-923 surveys for the years 2007 through 2010. A special case for removal of SO_2 is the fluidized bed boiler, in which the sulfur removal process is integral with the operation of the boiler. The SO_2 emission factors shown in Table A1 for fluidized bed boilers already account for 90 percent removal of SO_2 since, in effect, the plant has no uncontrolled emissions of this pollutant.

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

There are a number of reasons why the historical data are periodically revised. These include data revisions, revisions in emission and technology factors, and changes in methodology. For instance, the 2008 *EPA* report features a revision in historic CO2 values. This revision occurred due to a change in the accepted methodology regarding adjustments made for the percentage combustion of fuels.

The emissions estimation methodologies are described in more detail below.

CO_2 Emissions: CO_2 emissions are estimated using the information on fuel consumption in physical units and the heat content of fuel collected on the Form EIA-923 and predecessors. Heat content information is used to convert physical units to millions of Btu (MMBtu) consumed. To estimate CO_2 emissions, the fuel-specific emission factor from Table A3 is multiplied by the fuel consumption in MMBtu.

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

SO_2 and NO_x Emissions: To comply with environmental regulations controlling SO_2 emissions, many coal-fired generating plants have installed flue gas desulfurization (FGD) units. Similarly, NO_x control regulations require many fossil-fueled plants to install low-NO_x burners, selective catalytic reduction systems, or other technologies to reduce emissions. It is common for power plants to employ two or even three NO_x control technologies; accordingly, the NO_x emissions estimation approach accounts for the combined effect of the equipment (Table A4). However, control equipment information is available only for plants that reported on the Form EIA-923 and for historical data from the Form EIA-767. The Form EIA-860, EIA-923, and the historical EIA-767 surveys are limited to plants with boilers fired by combustible fuels[7] with a minimum generating capacity of 10 megawatts (nameplate). Pollution control equipment data are unavailable from EIA sources for plants that did not report on the historical EIA-767 survey, or the Forms EIA-860 and EIA-923.

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

- For steam electric plants, uncontrolled emissions are estimated using the emission factors shown in Tables A1 and A2 as well as reported data on fuel consumption, sulfur content, and boiler firing configuration. Controlled emissions are then determined when pollution control equipment is present. Although information on control equipment was not collected in 2006, updates for new installations during this period were made based on EPA data. Beginning in 2007, these data were collected on the Forms EIA-860 and EIA-923. For SO_2, the reported efficiency of the plant's FGD units is used to convert uncontrolled to controlled emission estimates. For NO_x, the reduction percentages shown in Table A4 are applied to the uncontrolled estimates.

- For plants and prime movers not reported on the historical Form EIA-767 survey or Forms EIA-860 and EIA-923, uncontrolled emissions are estimated using the Table A1 and Table A2 emission factors and the following data and assumptions:
    - Fuel consumption is taken from the Form EIA-923 and predecessors.
    - The sulfur content of the fuel is estimated from fuel receipts for the plant reported on the Form EIA-923. When plant-specific sulfur content data are unavailable, the national average sulfur content for the fuel, computed from the Form EIA-923 is applied to the plant.
    - As noted earlier, the emission factor for plants with boilers depends in part on the type of combustion system, including whether a boiler is wet-bottom or dry-bottom, and the boiler firing configuration. However, this boiler information is unavailable for steam electric plants that did not report on the historical Forms EIA-767 or EIA-860. For these cases, the plant is assumed to have a dry-bottom, non-cyclone boiler using a firing method that falls into the "All Other" category shown on Table A1.[8]
    - For the plants that did not report on the historical Form EIA-767 or EIA-860, pollution control equipment data are unavailable and the uncontrolled estimates are not reduced.
- If actual emissions of SO_2 or NO_x are reported in the EPA's CEMS data, the EIA estimates are replaced with the CEMS values, using the EIA estimates to allocate the CEMS plant-level data by fuel. If CEMS data are unavailable, the EIA estimates are used as the final values.

Conversion of Petroleum Coke to Liquid Petroleum

The quantity conversion is 5 barrels (of 42 U.S. gallons each) per short ton (2,000 pounds).

Relative Standard Error

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

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

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

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

Business Classification

Nonutility power producers consist of entities that own or operate electric generating units but are not subject to direct economic regulation of rates, such as by state utility commissions. Nonutility power producers do not have a designated franchised service area. In addition to entities whose primary business is the production and sale of electric power, entities with other primary business classifications can and do sell electric power. These can consist of, for example, manufacturing facilities and paper mills.

The EIA, in the *EPA* and other data products, classifies nonutility power producers into the following categories:

- The Electric Power Sector consists of the combination of utilities and independent power producers (IPPs) whose primary business is selling electricity in the public markets.

- The Industrial Sector are power producers whose primary business falls under NAICS[9] classifications of Agriculture, Forestry, Fishing, Mining, Construction, or Manufacturing.

- The Commercial Sector are those facilities where the primary business falls under NAICS classifications of Transportation and Public (non-electric) Utilities, Wholesale Trade, Retail Trade, Finance, Insurance, Services, Public Administration, and Real Estate.

Each of these nonutility sectors is further divided into facilities which do or do not operate as CHP plants.

The following is a list of the main NAICS classifications and the category of primary business activity within each classification.

Agriculture, Forestry, and Fishing

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

Mining

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

Construction

23

Manufacturing

311 Food and kindred products
3122 Tobacco products
314 Textile and mill products
315 Apparel and other finished products made from fabrics and similar materials
316 Leather and leather products
321 Lumber and wood products, except furniture
322 Paper and allied products (other than 322122 or 32213)
322122 Paper mills, except building paper
32213 Paperboard mills
323 Printing and publishing
325 Chemicals and allied products (other than 325188, 325211, 32512, or 325311)
32512 Industrial organic chemicals
325188 Industrial Inorganic Chemicals
325211 Plastics materials and resins
325311 Nitrogenous fertilizers
324 Petroleum refining and related industries (other than 32411)
32411 Petroleum refining
326 Rubber and miscellaneous plastic products
327 Stone, clay, glass, and concrete products (other than 32731)
32731 Cement, hydraulic
331 Primary metal industries (other than 331111 or 331312)
331111 Blast furnaces and steel mills
331312 Primary aluminum
332 Fabricated metal products, except machinery and transportation equipment
333 Industrial and commercial equipment and components except computer equipment
3345 Measuring, analyzing, and controlling instruments, photographic, medical, and optical goods, watches and clocks
335 Electronic and other electrical equipment and components except computer equipment
336 Transportation equipment
337 Furniture and fixtures
339 Miscellaneous manufacturing industries

Transportation and Public Utilities

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

Wholesale Trade

421 to 422

Retail Trade

441 to 454

Finance, Insurance, and Real Estate

521 to 533

Services

512 Motion pictures
514 Business services
514199 Miscellaneous services
541 Legal services
561 Engineering, accounting, research, and management
611 Education services

622 Health services
624 Social services
712 Museums, art galleries, and botanical and zoological gardens
713 Amusement and recreation services
721 Hotels
811 Miscellaneous repair services
8111 Automotive repair, services, and parking
812 Personal services
813 Membership organizations related services
814 Private households

Public Administration

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[1] The basic technique employed is described in the paper "Model-Based Sampling and Inference," on the EIA website. Additional references can be found on the InterStat website (http://interstat.statjournals.net/). See the following sources: Knaub, J.R., Jr. (1999a), "Using Prediction-Oriented Software for Survey Estimation," InterStat, August 1999, http://interstat.statjournals.net/; Knaub, J.R. Jr. (1999b), "Model-Based Sampling, Inference and Imputation," EIA web site:

http://www.eia.gov/cneaf/electricity/forms/eiawebme.pdf; Knaub, J.R., Jr. (2005), "Classical Ratio Estimator," InterStat, October 2005, http://interstat.statjournals.net/; Knaub, J.R., Jr. (2007a), "Cutoff Sampling and Inference," InterStat, April 2007, http://interstat.statjournals.net/; Knaub, J.R., Jr. (2008), "Cutoff Sampling." Definition in Encyclopedia of Survey Research Methods, Editor: Paul J. Lavrakas, Sage, to appear; Knaub, J.R., Jr. (2000), "Using Prediction-Oriented Software for Survey Estimation - Part II: Ratios of Totals," InterStat, June 2000, http://interstat.statjournals.net/; Knaub, J.R., Jr. (2001), "Using Prediction-Oriented Software for Survey Estimation - Part III: Full-Scale Study of Variance and Bias," InterStat, June 2001, http://interstat.statjournals.net/.

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

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[3] The Form EIA-923 superseded Forms EIA-906, EIA-920, EIA-423, FERC Form 423, and part of Form EIA-767 in 2008. However, it was used to collect certain 2007 data including environmental data that previously were collected on the Form EIA-767, and utility and nonutility data collected *annually* on the Forms EIA-906 and EIA-920.

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

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

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

[7] Boilers that rely entirely on waste heat to create steam, including the heat recovery portion of most combined cycle plants, did not report on the historical Form EIA-767 or EIA-923.

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

[9] Business classifications are based on the North American Industry Classification System (NAICS).

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

Fuel, Code, Source and Emission units			Combustion System Type/Firing Configuration							
Fuel And EIA Fuel Code	Source and Tables (As appropriate)	Emissions Units (Lbs = pounds, MMCF = million cubic feet, MG = thousand gallons)	Cyclone Boiler	Fluidized Bed Boiler	Opposed Firing Boiler	Spreader Stoker Boiler	Tangential Boiler	All Other Boiler Types	Combustion Turbine	Internal Combustion Engine
Agricultural Byproducts (AB)	Source: 1	Lbs per ton	0.08	0.01	0.08	0.08	0.08	0.08	NA	NA
Blast Furnace Gas (BFG)	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.6	0.06	0.6	0.6	0.6	0.6	0.6	0.6
Bituminous Coal (BIT)*	Source: 2, Table 1.1-3	Lbs per ton	38	3.8	38	38	38	38	NA	NA
Black Liquor (BLQ)	Source: 1	Lbs per ton **	7	0.7	7	7	7	7	NA	NA
Distillate Fuel Oil (DFO)*	Source: 2, Table 3.1-2a, 3.4-1 & 1.3-1	Lbs per MG	157	15.7	157	157	157	157	140	140
Jet Fuel (JF)*	Assumed to have emissions similar to DFO.	Lbs per MG	157	15.7	157	157	157	157	140	140
Kerosene (KER)*	Assumed to have emissions similar to DFO.	Lbs per MG	157	15.7	157	157	157	157	140	140
Landfill Gas (LFG)	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.6	0.06	0.6	0.6	0.6	0.6	0.6	0.6
Lignite Coal (LIG)*	Source: 2, Table 1.7-1	Lbs per ton	30	3	30	30	30	30	NA	NA

Municipal Solid Waste (MSW)	Source: 1	Lbs per ton	1.7	0.17	1.7	1.7	1.7	1.7	NA	NA
Natural Gas (NG)	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.6	0.06	0.6	0.6	0.6	0.6	0.6	0.6
Other Biomass Gas (OBG)	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.6	0.06	0.6	0.6	0.6	0.6	0.6	0.6
Other Biomass Liquids (OBL)*	Source: 1 (including footnotes 3 and 16 within source)	Lbs per MG	157	15.7	157	157	157	157	140	140
Other Biomass Solids (OBS)	Source: 1 (including footnote 11 within source)	Lbs per ton	0.23	0.02	0.23	0.23	0.23	0.23	NA	NA
Other Gases (OG)	Source: 1 (including footnote 7 within source)	Lbs per MMCF	0.6	0.06	0.6	0.6	0.6	0.6	0.6	0.6
Other (OTH)	Assumed to have emissions similar to NG.	Lbs per MMCF	0.6	0.06	0.6	0.6	0.6	0.6	0.6	0.6
Petroleum Coke (PC)*	Source: 1	Lbs per ton	39	3.9	39	39	39	39	NA	NA
Propane Gas (PG)	Sources: 1 (including footnote 7 within source); 2, Table 1.4-2 (including footnote d within source)	Lbs per MMCF	0.6	0.06	0.6	0.6	0.6	0.6	0.6	0.6
Residual Fuel Oil (RFO)*	Source: 2, Table 1.3-1	Lbs per MG	157	15.7	157	157	157	157	NA	NA
Synthetic Coal (SC)*	Assumed to have the emissions similar to Bituminous Coal.	Lbs per ton	38	3.8	38	38	38	38	NA	NA
Sludge Waste (SLW)	Source: 1 (including footnote 11 within source)	Lbs per ton **	2.8	0.28	2.8	2.8	2.8	2.8	NA	NA

Subbituminous Coal (SUB)*	Source: 2, Table 1.1-3	Lbs per ton	35	3.5	35	38	35	35	NA	NA
Tire-Derived Fuel (TDF)*	Source: 1 (including footnote 13 within source)	Lbs per ton	38	3.8	38	38	38	38	NA	NA
Waste Coal (WC)*	Source: 1 (including footnote 20 within source)	Lbs per ton	30	3	30	30	30	30	NA	NA
Wood Waste Liquids (WDL)*	Source: 1 (including footnotes 3 and 16 within source)	Lbs per MG	157	15.7	157	157	157	157	140	140
Wood Waste Solids (WDS)	Source: 1	Lbs per ton	0.29	0.08	0.29	0.08	0.29	0.29	NA	NA
Waste Oil (WO)*	Source: 2, Table 1.11-2	Lbs per MG	147	14.7	147	147	147	147	NA	NA

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

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

Sources:

1. Eastern Research Group, Inc. and E.H. Pechan & Associates, Inc., *Documentation for the 2002 Electric Generating Unit National Emissions Inventory* , Table 6, September 2004. Prepared for the U.S. Environmental Protection Agency, Emission Factor and Inventory Group (D205-01), Emissions, Monitoring and Analysis Division, Research Triangle Park; and

2. U.S. Environmental Protection Agency, AP 42, Fifth Edition (Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources); available at: http://www.epa.gov/ttn/chief/ap42/

Table A2. Nitrogen Oxides Uncontrolled Emission Factors

(Units and Factors)

Fuel, Code, Source, and Emission Units			Combustion System Type/Firing Configuration Factors for Wet-Bottom Boilers are in Brackets; All Other Boiler Factors are for Dry-Bottom							
Fuel And EIA Fuel Code	Source and Tables (As appropriate)	Emissions Units (Lbs = pounds, MMCF = million cubic feet, MG = thousand gallons)	Cyclone Boiler	Fluidized Bed Boiler	Opposed Firing Boiler	Spreader Stoker Boiler	Tangential Boiler	All Other Boiler Types	Combustion Turbine	Internal Combustion Engine
Agricultural Byproducts (AB)	Source: 1	Lbs per ton	1.2	1.2	1.2	1.2	1.2	1.2	NA	NA
Blast Furnace Gas (BFG)	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	15.4	15.4	15.4	15.4	15.4	15.4	30.4	256.55
Bituminous Coal (BIT)	Source: 2, Table 1.1-3	Lbs per ton	33	5	12 [31]	11	10.0 [14.0]	12.0 [31.0]	NA	NA
Black Liquor (BLQ)	Source: 1	Lbs per ton **	1.5	1.5	1.5	1.5	1.5	1.5	NA	NA
Distillate Fuel Oil (DFO)	Source: 2, Tables 3.4-1 & 1.3-1	Lbs per MG	24	24	24	24	24	24	122	443.8
Jet Fuel (JF)	Source: 2, Tables 3.1-2a, 3.4-1 & 1.3-1	Lbs per MG	24	24	24	24	24	24	118	432
Kerosene (KER)	Source: 2, Tables 3.1-2a, 3.4-1 & 1.3-1	Lbs per MG	24	24	24	24	24	24	118	432
Landfill Gas (LFG)	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	72.44	72.44	72.44	72.44	72.44	72.44	144	1215.22
Lignite Coal (LIG)	Source: 2, Table 1.7-1	Lbs per ton	15	3.6	6.3	5.8	7.1	6.3	NA	NA
Municipal Solid Waste (MSW)	Source: 1	Lbs per ton	5	5	5	5	5	5	NA	NA
Natural Gas (NG)	Source: 2, Tables 1.4-1, 3.1-1, and 3.4-1	Lbs per MMCF	280	280	280	280	170	280	328	2768

Other Biomass Gas (OBG)	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	112.83	112.83	112.83	112.83	112.83	112.83	313.6	2646.48
Other Biomass Liquids (OBL)	Source: 1 (including footnote 3 within source)	Lbs per MG	19	19	19	19	19	19	NA	NA
Other Biomass Solids (OBS)	Source: 1 (including footnote 11 within source)	Lbs per ton	2	2	2	2	2	2	NA	NA
Other Gases (OG)	Sources: 1 (including footnote 7 within source); EIA estimates	Lbs per MMCF	152.82	152.82	152.82	152.82	152.82	152.82	263.82	2226.41
Other (OTH)	Assumed to have emissions similar to natural gas.	Lbs per MMCF	280	280	280	280	170	280	328	2768
Petroleum Coke (PC)	Source: 1 (including footnote 8 within source)	Lbs per ton	21	5	21	21	21	21	NA	NA
Propane Gas (PG)	Sources: 3; EIA estimates	Lbs per MMCF	215	215	215	215	215	215	330.75	2791.22
Residual Fuel Oil (RFO)	Source: 2, Table 1.3-1	Lbs per MG	47	47	47	47	32	47	NA	NA
Synthetic Coal (SC)	Assumed to have emissions similar to Bituminous Coal.	Lbs per ton	33	5	12 [31]	11	10.0 [14.0]	12.0 [31.0]	NA	NA
Sludge Waste (SLW)	Source: 1 (including footnote 11 within source)	Lbs per ton **	5	5	5	5	5	5	NA	NA
Subbituminous Coal (SUB)	Source: 2, Table 1.1-3	Lbs per ton	17	5	7.4 [24]	8.8	7.2	7.4 [24.0]	NA	NA
Tire-Derived Fuel (TDF)	Source: 1 (including footnote 13 within source)	Lbs per ton	33	5	12 [31]	11	10.0 [14.0]	12.0 [31.0]	NA	NA
Waste Coal (WC)	Source: 1 (including footnote 20 within source)	Lbs per ton	15	3.6	6.3	5.8	7.1	6.3	NA	NA
Wood Waste Liquids (WDL)	Source: 1 (including footnote 16 within source)	Lbs per MG	5.43	5.43	5.43	5.43	5.43	5.43	NA	NA
Wood Waste Solids (WDS)	Source: 1	Lbs per ton	2.51	2	2.51	1.5	2.51	2.51	NA	NA

Waste Oil (WO)	Source: 2, Table 1.11-2	Lbs per MG	19	19	19	19	19	19	NA	NA

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

Sources:

1. Eastern Research Group, Inc. and E.H. Pechan & Associates, Inc., *Documentation for the 2002 Electric Generating Unit National Emissions Inventory* , Table 6, September 2004. Prepared for the U.S. Environmental Protection Agency, Emission Factor and Inventory Group (D205-01); Emissions, Monitoring and Analysis Division, Research Triangle Park;

2. U.S. Environmental Protection Agency, AP 42, Fifth Edition (Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources); available at: http://www.epa.gov/ttn/chief/ap42/; and

3. U.S. Environmental Protection Agency, Factor Information Retrieval (FIRE) Database, Version 6.25; available at: http://www.epa.gov/ttn/chief/software/fire/index.html

Table A3. Carbon Dioxide Uncontrolled Emission Factors

(Pounds of CO_2 per Million Btu)

Fuel, Code, Source, and Emission Factor		
Fuel And EIA Fuel Code	**Source and Tables (As appropriate)**	**Factor (Pounds of CO_2 Per Million Btu)*** **
Bituminous Coal (BIT)	Source: 1	205.3
Distillate Fuel Oil (DFO)	Source: 1	161.386
Geothermal (GEO)	Estimate from EIA, Office of Integrated Analysis and Forecasting	16.59983
Jet Fuel (JF)	Source: 1	156.258
Kerosene (KER)	Source: 1	159.535
Lignite Coal (LIG)	Source: 1	215.4
Municipal Solid Waste (MSW)	Source: 1 (including footnote 2 within source)	91.9
Natural Gas (NG)	Source: 1	117.08
Petroleum Coke (PC)	Source: 1	225.13
Propane Gas (PG)	Source: 1	139.178
Residual Fuel Oil (RFO)	Source: 1	173.906
Synthetic Coal (SC)	Assumed to have emissions similar to Bituminous Coal.	205.3
Subbituminous Coal (SUB)	Source: 1	212.7
Tire-Derived Fuel (TDF)	Source: 1	189.538
Waste Coal (WC)	Assumed to have emissions similar to Bituminous Coal.	205.3
Waste Oil (WO)	Source: 2, Table 1.11-3 (assumes typical heat content of 4.4 MMBtus per barrel)	210

Note: *** CO_2 factors do not vary by combustion system type or boiler firing configuration.

Sources: Energy Information Administration, Office of Integrated Analysis and Forecasting, Voluntary Reporting of Greenhouse Gases Program, *Table of Fuel and Energy Source: Codes and Emission Coefficients*; available at: http://www.eia.doe.gov/oiaf/1605/coefficients.html; and U.S. Environmental Protection Agency, *AP 42, Fifth Edition (Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources)*; available at: http://www.epa.gov/ttn/chief/ap42/.

Table A4. Nitrogen Oxides Control Technology Emissions Reduction Factors

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

1. Starting with 1995 data, reduction factors for advanced overfire air, low NO_x burners, and overfire air were reduced by 10 percent.

Sources: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report;" Babcock and Wilcox, Steam 41st Edition, 2005.

Table A5. Unit-of-Measure Equivalents

Unit	Equivalent	Unit
Kilowatt (kW)	1,000 (One Thousand)	Watts
Megawatt (MW)	1,000,000 (One Million)	Watts
Gigawatt (GW)	1,000,000,000 (One Billion)	Watts
Terawatt (TW)	1,000,000,000,000 (One Trillion)	Watts
Gigawatt	1,000,000 (One Million)	Kilowatts
Thousand Gigawatts	1,000,000,000 (One Billion)	Kilowatts
Kilowatthours (kWh)	1,000 (One Thousand)	Watthours
Megawatthours (MWh)	1,000,000 (One Million)	Watthours
Gigawatthours (GWh)	1,000,000,000 (One Billion)	Watthours
Terawatthours (TWh)	1,000,000,000,000 (One Trillion)	Watthours
Gigawatthours	1,000,000 (One Million)	Kilowatthours
Thousand Gigawatthours	1,000,000,000(One Billion)	Kilowatthours
U.S. Dollar	1,000 (One Thousand)	Mills
U.S. Cent	10 (Ten)	Mills

Source: Energy Information Administration, Office of Electricity, Renewables, and Uranium Statistics

EIA Electric Industry Data Collection